509.403 Definitions.

Debarring official means the Suspension and Debarment Official within the Office of the Chief Acquisition Officer.

* * * * *

Suspending official means the Suspension and Debarment Official within the Office of the Chief Acquisition Officer.

9. Revise section 509.405 to read as follows:

509.405 Effect of listing.

509.405–1 Continuation of current contracts.

(a) When a contractor appears on the current EPLS, consider terminating a contract under any of the following circumstances:

(1) Any circumstances giving rise to the debarment or suspension also constitute a default in the contractor's performance of the contract.

(2) The contractor presents a significant risk to the Government in completing the contract.

(3) The conduct that provides the cause of the suspension, proposed debarment, or debarment involved a GSA contract.

(b) Before terminating a contract when a contractor appears on the current EPLS, consider the following factors:

(1) Seriousness of the cause for debarment or suspension.

(2) Extent of contract performance.

(3) Potential costs of termination and reprocurement.

(4) Need for or urgency of the requirement, contract coverage, and the impact of delay for reprocurement.

(5) Availability of other safeguards to protect the Government's interest until completion of the contract.

(6) Availability of alternate competitive sources to meet the requirement (*e.g.*, other multiple award contracts, readily available commercial items).

(c) The responsibilities of the agency head under FAR 9.405–1 are delegated to the GSA Suspension and Debarment Official.

509.405–2 Restrictions on subcontracting.

The responsibilities of the agency head under FAR 9.405–2(a) are delegated to the GSA Suspension and Debarment Official.

10. Revise section 509.406–1 to read as follows:

509.406–1 General.

The Suspension and Debarment Official is the designee under FAR 9.406–1(c).

11. Amend section 509.406–3 by—

a. Removing from paragraphs (a) and (b), the words ''debarring official'' and adding the words ''Suspension and Debarment Official'' in its place each time it appears;

b. Removing from paragraph (b)(2), the word ''Number'' and adding the word ''Numbers'' in its place;

c. Removing paragraph (b)(7);

d. Revising paragraph (c); and

e. Removing from paragraph (d), the words ''debarring official'' and adding the words ''Suspension and Debarment Official'' in its place each time it appears.

The revised text reads as follows:

509.406–3 Procedures.

* * * * *

(c) *Review.* The Suspension and Debarment Official will review the report, and after coordinating with assigned legal counsel—

(1) Initiate debarment action;

(2) Decline debarment action;

(3) Request additional information; or

(4) Refer the matter to the OIG for further investigation and development of a case file.

* * * * *

509.407–1 [Amended]

12. Amend section 509.407–1 by removing the words ''suspending official'' and adding ''Suspension and Debarment Official'' in its place.

509.407–3 [Amended]

13. Amend section 509.407–3 by removing the words ''suspending official'' and adding ''Suspension and Debarment Official'' in its place each time it appears.

PART 552—SOLICITATION PROVISIONS AND CONTRACT CLAUSES

552.209–70 through 552.209–73 [Removed]

14. Sections 552.209–70 through 552.209–73 are removed.

[FR Doc. E8–14392 Filed 6–24–08; 8:45 am]

BILLING CODE 6820–61–S

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Part 192

[Docket No. PHMSA–RSPA–2004–19854]

RIN 2137–AE15

Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines

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

ACTION: Notice of proposed rulemaking.

SUMMARY: PHMSA proposes to amend 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 the proposed rule would be similar to those currently required for gas transmission pipelines, but tailored to reflect the differences in and among distribution systems. In accordance with Federal law, the proposed rule would require operators to install excess flow valves on certain new and replaced residential service lines, subject to feasibility criteria outlined in the rule. Based on the required risk assessments and enhanced controls, the proposed rule also would establish procedures and standards permitting 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 proposed rule would establish simpler requirements for master meter and liquefied petroleum gas (LPG) operators, reflecting the relatively lower risk of these small pipeline systems.

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

DATES: Anyone may submit written comments on proposed regulatory changes by September 23, 2008. PHMSA will consider late-filed comments to the extent possible.

ADDRESSES: Comments 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.

Privacy Act Statement

Anyone can search the electronic form of all comments received in response to any of our dockets by the name of the individual submitting the comment (or signing the comment, if submitted on behalf of an association, business, labor union, etc.). DOT's complete Privacy Act Statement was published in the **Federal Register** on April 11, 2000 (65 FR 19477).

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

SUPPLEMENTARY INFORMATION: The following subjects are addressed in this preamble:

I. Background

A. Integrity Management

PHMSA is initiating this rulemaking proceeding in order to extend its integrity management approach to the largest segment of the Nation's pipeline network—the distribution systems that directly serve homes, schools, businesses, and other natural gas consumers. Beginning in 2000, the agency has promulgated regulations requiring 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) to 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.

The IM regulations for hazardous liquid and gas transmission pipelines are similar. Fundamentally, both require that operators analyze their pipelines to identify and manage factors that affect risks to the pipeline and risks posed by the pipeline. Operators must integrate the best available information about their pipelines to inform their risk decisions. Both rules require that operators identify segments of their pipelines where an incident could cause serious consequences and focus priority attention in those areas. Both rules also require that operators implement a program to provide greater assurance of the integrity of these pipeline segments. Actions required in these segments include assessments utilizing in-line inspection tools, pressure testing, direct assessment, or other technology that provides an equivalent understanding of the pipe condition. While existing regulations required prompt repair of safety-significant problems, the IM regulations require operators to inspect their lines and perform repairs within a period of time commensurate with the safety significance of the problems found. The rules also require that operators implement measures that will help prevent accidents from occurring on their high-consequence segments and that will mitigate the consequences if an accident does occur.

Although it is too early to draw statistically-significant conclusions about the effectiveness of the IM programs for transmission pipelines, early indications are very favorable. The initial inspections under IM have identified tens of thousands of locations where the pipelines were damaged (including damage by external force/excavation and by conditions like corrosion) and repairs were made before accidents could occur. Operators have implemented additional safety measures to address higher-risk situations, many of which are unique to their individual circumstances. These early successes have fueled interest in extending the IM approach to gas distribution pipeline systems.

B. Nature of U.S. Distribution Pipeline Systems

As of 2006, more than 1.2 million miles of gas mains are in service in the U.S. ''Mains'' are the pipelines providing a common supply to a certain number (often hundreds) of homes and businesses. These pipelines are often located under city streets and range in size from less than 2 inches in diameter to more than 8 inches in diameter. These mains feed over 63 million ''services.'' A ''service'' is the pipe that connects to a main and delivers gas to an individual customer, at the meter. Service lines are usually very small, less than 1-inch in diameter except for those serving larger industrial and commercial customers. The length of service lines varies widely. In dense urban areas where townhouses are built right up to the sidewalk, a service line may be only a few feet long. In rural areas, service lines may be several hundred feet long, perhaps as long as a mile. PHMSA uses 65 feet as its estimate of the average length of a service line. Applying that value, the 63 million services represent nearly another 800,000 miles of pipeline, meaning that the total amount of pipeline in U.S. distribution pipeline systems is approximately two million miles. Use of natural gas continues to grow in the U.S., and the amount of distribution pipeline in service increases accordingly. Since 2001, an additional 5.1 million customers have been added, representing an increase of over 173,000 miles of distribution pipeline.

Natural gas has been distributed by pipeline in some areas for over a hundred years. Pipeline systems in these areas were originally small, serving a few customers. These systems often merged as larger distribution companies were formed. The materials in use in some of these systems reflect older (*e.g.*, cast iron, copper, bare steel) as well as newer (*e.g.*, polyethylene plastic and cathodically-protected coated steel) technologies. Two-thirds of States have programs that require distribution pipeline operators to replace older pipe,[1] but much of the pipe in service is still many decades old.

In other areas, distribution of natural gas by pipeline is a relatively new phenomenon. In some rural areas, for example, gas may not have been available until a transmission pipeline was routed into the vicinity. Then, municipalities or distribution companies may have created a distribution system to bring natural gas service to customers for whom it was previously unavailable. Systems of this nature tend to be relatively uniform in age and type of materials, but the threats to integrity (such as electrical interference from other buried substructures and localized flooding or vehicular traffic patterns) may still vary from one location to another. Diversity of the gas pipeline system will likely increase as systems age, new customers are added, and portions of the original systems are replaced. The bulk of newer gas distribution pipeline systems, and replacements for older pipe, are comprised of plastic pipe. More than half of the pipelines in U.S. gas distribution systems are non-metallic.

C. Safety of Distribution Pipeline Systems

By operation of the Federal Pipeline Safety Laws, 49 U.S.C. 60102, the Federal government has assumed ultimate responsibility for the safety oversight of distribution pipeline operators. PHMSA's regulations in 49 CFR Part 192 establish a minimum set of safety requirements that all States must implement, although States may impose more stringent requirements on intrastate systems. PHMSA also collects data concerning distribution system mileage, incidents that occur on distribution systems, their leak repair experience and other information about the size, age and material(s) of construction of their distribution piping. PHMSA considered this information, its historical trends, and projected patterns in proposing IM regulations for distribution pipelines.

Incidents on distribution pipelines kill and injure more people than incidents on gas transmission pipelines. As noted above, nearly two million miles of distribution pipelines are in operation in the U.S., compared with approximately 300,000 miles of gas transmission pipelines. In addition, distribution pipelines are almost all located in populated areas. Large portions of gas transmission pipelines traverse rural areas where there are few people. Largely because of these differences, incidents on distribution pipelines in 2006 resulted in five times as many fatalities (16 vs. 3) and six times as many serious injuries (25 vs. 4) as those on gas transmission pipelines, even though the total number of incidents on each type of pipeline was about the same (141 vs. 134). Because of the much larger number of miles of distribution pipeline, the normalized rate of fatalities and injuries (i.e., the number per 100,000 miles) is similar for the two types of lines, with a slightly lower rate for distribution lines. As described further below, the trend in gas distribution incidents involving fatalities and serious injuries (those requiring hospitalization) was downward from 1990–2002. In the years since, however, the number has again started to increase.

D. Distribution Pipeline Safety Regulation

Pursuant to Federal law, most oversight of gas distribution pipeline systems is performed directly by States. Under 49 U.S.C. 60105 and 60106, a State may exercise jurisdiction over intrastate gas distribution operations within the State if its pipeline safety program is certified by PHMSA or if it enters into an agency agreement with DOT. Under these provisions, 48 States (excluding only Alaska and Hawaii) and the District of Columbia currently exercise safety jurisdiction over some or all gas distribution operations within their boundaries. States must implement the minimum standards established by PHMSA but have a variety of ways in which they can oversee distribution pipeline safety. They can simply mirror the Federal pipeline safety program; they can impose additional requirements, beyond the Federal minimum; they can engage in special oversight programs with individual operators or groups of operators; or finally, they can provide incentives for safety improvements, often through their rate-setting authority.

It is appropriate that the principal actions for regulating distribution pipeline safety rest with the States. States need to balance safety and affordability. They need to ensure that the particular needs of their citizenry are fulfilled. They also need to ensure that the applied safety standards are appropriate for the unique environment in which gas distribution occurs. Distribution pipeline systems are limited in geographic scope, although some systems serve many thousands of customers. The environment in which they operate significantly affects the safety issues that they face. Factors such as weather (dry/wet, hot/subject to freezing), soil conditions (corrosivity), and the local economy (significant construction and excavation activity) can significantly shape the threats affecting individual distribution operators and the actions necessary to address those threats. Proximity to gas-producing regions also can be important, as natural gas that is distributed near production areas may be subject to less processing and may contain more contaminants, with greater potential to affect system integrity, than gas that is processed for long-distance transportation.

States must have flexibility to deal with their local circumstances. It would be both ineffective and inefficient, for example, to impose frost heave damage requirements in the desert southwest. States address these differences by imposing some requirements that exceed those in the Federal safety code.

The National Association of Pipeline Safety Representatives (NAPSR)[2] surveyed its members to determine the extent to which they impose requirements or programs that exceed the Federal minimum.[3] The survey, addressed to each State pipeline safety program manager, asked whether the State imposes additional requirements or has infrastructure safety improvement programs implemented that exceed the federal minimum requirements. NAPSR asked its members to provide a brief description of any positive responses.

Forty-eight State agencies and the District of Columbia responded to the NAPSR survey. All but six reported some requirements or programs exceeding the Federal minimum standards. The results were as follows:

- 20 States have additional reporting requirements;

[1] Some of these programs involve a limited number of operators, as described further below.

[2] NAPSR's members are the managers of the pipeline safety regulatory staff from each state (and the District of Columbia) that is certified by, or a designated agent of, DOT for regulatory oversight.

[3] NAPSR conducted the survey in 2004–2005.

• 11 States provide enhanced oversight and observation of work/testing on the pipelines;
• 11 States have additional damage prevention requirements;
• 13 States require additional leak testing;
• 11 States impose leak response requirements (including eight of the 13 that require additional leak testing);
• Eight States impose either additional odorant requirements or more frequent testing;
• Six States impose additional design and installation requirements;
• Six States impose additional training and qualification of operator personnel requirements.
• Six States impose additional requirements related to cathodic protection systems used to protect steel pipe from corrosion;
• Six States require their State regulators to approve operators' operating and maintenance plans;
• Five States impose operating pressure requirements;
• Five States impose additional customer meter requirements;
• Three States require that operators cap off abandoned service lines after specified periods;
• Four States extend operator responsibility for maintenance of service/customer lines;
• Four States encourage safety enhancement through rate cases, and approve the operation of distribution pipeline systems by specific companies;
• One State requires its operators to conduct an annual evaluation of all cast iron and unprotected steel pipe in their distribution systems; and
• One State requires its operators to remediate any evidence found of corrosion within 90 days.

The most significant area in which States reported actions beyond Federal standards was replacement of aging and inferior infrastructure. Thirty-three States, or two-thirds of those responding, reported they have some kind of program for replacing infrastructure, including cast-iron pipe, uncoated steel pipe, copper pipe, and some types of plastic pipe. These programs varied in scope and schedule, often reflecting the relative amount of targeted infrastructure present in each State. NAPSR collected the following data on pipe replacement programs:

• Twelve States reported their programs involved all (or nearly all) operators;
• Sixteen States reported their programs involved one or a limited number of operators, often in response to past accidents or rate cases;
• Four States provided no information from which to estimate the scope of their programs;
• Eight States reported that their programs are complete (*i.e.*, all targeted infrastructure has been replaced) or will be completed by 2010;
• Eight States reported that their programs will be complete by about 2020;
• Four States reported that their programs would not be complete until after 2020; and
• Twelve States did not report an expected completion date.

These results indicate States can and do exercise authority beyond minimum Federal requirements. Additional requirements are focused in scope, and vary from State to State, based on local needs and issues. Programs to replace older, inferior infrastructure are the most widespread practice beyond Federal requirements. Such programs are in progress in two-thirds of the States, although some of these programs are of limited scope (i.e., affecting a single operator).

Still, despite these State efforts, serious incidents continue to occur on distribution pipeline systems. As discussed above, the number of serious incidents per mile is similar to that for gas transmission pipelines, but there are many more miles of distribution pipelines. As a result, serious incidents on gas distribution pipelines kill or injure more people annually than do incidents on gas transmission pipelines. Even if the number of serious incidents on transmission pipelines is significantly reduced, major improvement in overall safety will not be achieved unless the number of incidents on distribution pipelines is also reduced. PHMSA's approach to achieving improvement for gas transmission pipelines was to require that each operator analyze its own pipeline's risks, through an integrity management program, and address them as necessary. PHMSA concludes that the same approach is appropriate for distribution pipelines.

Although the additional State requirements provide protection beyond the minimum Federal standards to help assure the integrity of distribution pipeline systems, the requirements vary by State. No State requires a comprehensive systematic evaluation and management of the risks associated with operating gas distribution pipelines similar to PHMSA's existing IM requirements or to the requirements we are proposing in this Notice. Nevertheless, some State imposed requirements likely encompass individual actions operators would be required to take under an IM program, offsetting the costs for those operators to comply with this rule.

The National Association of Regulatory Utility Commissioners (NARUC) has also considered the need for additional safety regulation. NARUC members represent Public Service/Safety Commissions under whose auspices States usually conduct pipeline safety regulatory programs. As such, NARUC represents executive management of State pipeline safety programs. In February 2005, the NARUC Board of Directors adopted a resolution encouraging development of an approach to distribution IM using risk-based, technically-sound, and cost-effective performance-based measures. NARUC recommended an approach based on the notion that operators are knowledgeable about their infrastructure and can identify and respond to threats against their systems in order to reduce the risk of system failures while balancing the need to ensure continued safe, reliable service at a minimal financial cost.

NARUC based its resolution on the long-standing commitment of industry and government to operate the United States' gas pipeline system reliably and safely. They acknowledged recent examinations by regulators, legislators, and gas distribution pipeline operators to determine the most effective approach to maintaining and enhancing distribution system integrity and safety. NARUC commented that States must take into account varying circumstances including: geography, energy customer base, local economy, system age and construction materials, size of distribution operations and consumption patterns of gas customers (ranging from large-volume manufacturers to mid-size businesses to single-family residences), as well as a State's overall executive policies and goals.

NARUC noted that due to significant structural, geographical, and functional differences among gas transmission and distribution companies, it would be infeasible to apply many transmission integrity requirements to distribution systems. NARUC further noted any adjustment to an operator's distribution IM program should be responsive to the operator's safety performance, existing regulations, and current practices affecting such performance.

E. Applicability of Integrity Management Plans (IMP) to Distribution Pipeline Systems

The basic premise of the integrity management programs for gas transmission and hazardous liquid pipelines—that safety is improved by identifying risks and taking actions to address them—is applicable to distribution pipeline systems. However, because of the differences between distribution pipeline systems and pipeline systems covered by current IM regulations, the physical inspections (e.g. In-Line Inspection tools and Direct Assessment methods) of pipeline segments required by the current IM regulations cannot be required on distribution pipelines. Because the same IM regulations will not work, a different type of integrity management approach is necessary.

Distribution Systems Are Located in Highly Populated Areas

The first element of existing IM program requirements for transmission pipelines is to identify so-called ''high consequence areas''—those segments of the pipeline where an incident/break could produce serious harm to people or the environment. This is important for hazardous liquid and gas transmission pipelines because both traverse large distances, including areas that are sparsely populated or where risk of serious environmental damage would be small. Identifying high consequence areas improves the effectiveness of integrity management requirements by focusing inspection and assessment efforts on the pipe where significant consequences could occur.

As described above, gas distribution pipeline systems are different. Unlike transmission pipelines, they do not traverse long distances and generally do not include significant areas of limited population. They operate almost entirely in populated areas, because their purpose is to provide gas service to the residences and businesses of those populations. Thus, by contrast to a transmission pipeline, identifying areas where the gas distribution pipeline is near concentrations of people would not tend to identify a limited portion of the pipeline on which integrity management attention should be focused. Some other means of prioritizing operator attention, based on risk, is needed for distribution pipelines.

Challenges of Assessment or Testing

As described above, distribution pipeline systems consist of a complex network of mains and services. They include considerable lengths of pipeline of very small diameter and many non-metallic materials. They also include extensive branching, with a typical city main being connected to a new service roughly every one hundred feet. These differences make it impossible to use many of the techniques required by the existing IMP regulations to assess the physical condition of the pipeline. One technique (in-line inspection) involves passing through the inside of a pipeline inspection tools that use magnetic detection techniques to identify areas where the wall of a steel pipe has been thinned by corrosion or damage. Another (direct assessment) involves using indirect inspection tools to identify areas where the electrical current imposed on steel pipes to prevent corrosion is interrupted or is experiencing interference. Distribution pipelines are too small and have too many connections to allow in-line inspection tools to pass through the lines, and approximately half of the distribution pipeline system is non-metallic (e.g., plastic), meaning that neither the internal tools nor the indirect inspections used for direct assessment can be used. Pressure testing (isolating a pipe and filling it with water or air at high pressure to see if it leaks) can be used, but would require that service be cut off to all customers served by the portion of the system being tested. A continuing program of such testing would essentially constitute the natural gas equivalent of ''rolling blackouts'' and would be unacceptable to the American public. Distribution pipelines can be inspected by digging to expose the pipeline, and operators are required to do such inspections when pipe must be excavated for other reasons. Digging up all distribution pipelines on a periodic basis, however, is clearly impractical.

For these reasons, the inspection requirements of current IMP regulations cannot be used for distribution pipelines.

Some other approach is needed. As described below, PHMSA worked with stakeholder groups and held two public meetings to help determine how best to apply IMP principles in the gas distribution pipeline environment.[4] These public meetings are discussed further below.

II. American Gas Foundation Study

The gas distribution industry recognized the need to consider its safety record and to determine if additional actions are needed. In late 2003, the American Gas Foundation (AGF) launched a study of the safety performance and integrity of gas distribution pipeline systems. Currently, operators must report an incident to PHMSA if it meets the reporting criteria in 49 CFR Part 191. The AGF study examined the record of incidents reported to PHMSA on gas distribution pipeline systems from 1990 through 2002 (the latest year for which data were complete at the time the study began) and compared that record to incidents reported for transmission pipelines over the same period.

The AGF study analyzed trends in reported incidents and focused specifically on incidents involving deaths or injuries requiring hospitalization (called ''serious incidents'' in the study). A joint team, the Distribution Infrastructure Government-Industry Team (DIGIT), was established to oversee the AGF study. This team consisted of representatives of the AGF, the American Public Gas Association, and State pipeline safety regulators. PHMSA took part in DIGIT as an observer.

The AGF published its findings in January 2005.[5] The AGF study found a downward trend in serious incidents over the 13-year period analyzed at a 95 percent statistical confidence level. (No statistically significant trend was found when considering all reported incidents.) The number of serious incidents per 100,000 miles of distribution pipeline was essentially the same as that for gas transmission pipelines over the analyzed period. There are many more miles of distribution pipelines, however. Historically, distribution pipeline incidents result in more deaths and injuries than incidents on gas transmission or hazardous liquid pipelines, largely because distribution lines are located in populated areas and constitute a much larger share of the mileage of working pipelines.

AGF found the primary cause of serious incidents was outside force damage, principally third-party excavation. Outside force damage represented 47 percent of serious incidents over the analyzed period. Corrosion caused 6.5 percent of serious incidents, and all other causes contributed less than 10 percent each.

AGF also examined practices gas distribution operators use to address threats to their systems, both those required by regulation and those performed voluntarily. The study found no obvious gaps and that industry practices exist to address known threats. Further, the study concluded (as for

[4] The public meetings concerning integrity management requirements were held on December 16, 2004 and September 21, 2005. A third meeting, on June 17, 2005, focused exclusively on appropriate requirements for excess flow valves. Summaries of all meetings are in the docket.

[5] American Gas Foundation, ''Safety Performance and Integrity of the Natural Gas Distribution Infrastructure,'' January 2005, available at *http://www.aga.org/Template.cfm/Section=Non-AGA_Studies_Forecasts_Stats&template.*

hazardous liquid pipelines and gas transmission pipelines) serious incidents continue to occur (albeit rarely) despite compliance with existing regulations.

III Recommendations or Mandates of Oversight Bodies

A. DOT Inspector General

In a report published June 14, 2004,[6] the DOT's Inspector General (IG) found that recent accident trends for gas distribution pipelines are not favorable. The IG noted that nearly all of the natural gas distribution pipelines are located in highly-populated areas, such as business districts and residential communities, where a rupture could have the most significant consequences. As a result, the audit pointed out for the 10-year period from 1994 through 2003, accidents on natural gas distribution pipelines have resulted in more fatalities and injuries than accidents on hazardous liquid and natural gas transmission lines combined.

The IG also recognized that applying risk management principles to distribution pipelines could help reverse these trends. In testimony before Congress in July 2004,[7] the IG recommended that PHMSA should define an approach for requiring operators of distribution pipeline systems to implement some form of integrity management or enhanced safety program with elements similar to those required in hazardous liquid and gas transmission pipeline integrity management programs.

B. National Transportation Safety Board

The National Transportation Safety Board (NTSB) investigates serious pipeline accidents, including those that occur on gas distribution pipeline systems. Over the years, the NTSB has made several recommendations to improve safety regulation of gas distribution pipelines. In particular, the NTSB has recommended the use of excess flow valves (EFVs) in all new construction and replaced service pipelines.

EFVs have received significant attention as a mitigation option for gas distribution systems. Current Federal regulations require that operators notify service line customers for new and replaced service lines of the availability and potential safety benefits of installing EFVs.[8] In lieu of this notification, operators may elect to install the valves voluntarily when certain conditions apply. The valves are generally applicable for new installations or complete service piping replacement for single-family residential homes, where the operating pressure is greater than 10 pounds per square inch (psi). Operators must install the valve if the customer agrees to pay for the cost of such installation. Discussions with operators indicate that approximately 30% of distribution system operators are installing the valves as a routine part of new and replaced service installations in situations in which they apply. Many of these are larger distribution operators, so the percentage of new and replaced service line installations voluntarily including EFVs is higher.

PHMSA conducted additional studies on the effectiveness of the valves and on the experience that has been gained as a result of their use. NAPSR assisted in these studies. PHMSA concluded that EFVs, if specified and installed correctly, operate reliably to cut off the supply of gas in the event of major damage to the downstream service line (e.g., excavation damage). While performance problems had occurred with early installation of EFVs, the data also show that the valves seldom now suffer false activations, cutting off the supply of gas when no damage has occurred.

EFVs installed in new construction or replaced service lines would mitigate an incident occurring on service lines in which the line was severed. The valves are designed to operate in the event of line ruptures that result in major flow of gas. At the same time, they are an inexpensive option for mitigating such incidents. The valves themselves cost less than $20 and the cost to install them, when a service line is being installed or replaced is nominal. They will not operate in the event of small leaks. They will not operate in the event of leaks or problems within a customer's residence or business, downstream of their pressure regulator, including situations in which a fire in a residence results in a breach of a gas appliance line in the residence.

PHMSA asked Allegro Energy Consulting to review incident report records to estimate how many incidents might have been mitigated by the presence of an excess flow valve had one been installed at construction or during repair. Allegro reviewed 634 incident reports submitted between 1999 and 2003. They screened out those that did not involve service lines, that were obviously slow leaks, or which otherwise did not appear to meet the criteria as incidents for which an excess flow valve would be beneficial. As a result, Allegro identified 101 incidents in which the presence of an EFV might have mitigated consequences over this five-year period. To be clear, this is an estimate. The incident reports do not include some information (e.g., gas flow rate) that is necessary to ascertain definitively whether an excess flow valve would have been effective. They do not include information on whether the 25% of fatalities or injuries in which automobiles struck gas meter set assemblies at the side of homes could have been prevented by an EFV shutting off gas flow.

PHMSA also conducted a public meeting concerning EFVs, which is described in Section VI below.

C. Congressional Mandate

Subsequent to the stakeholder groups' recommendations discussed below and the public meeting, Congress passed the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (PIPES Act), which the President signed into law in December 2006. The Act included a mandate that PHMSA require gas distribution operators to implement integrity management programs and to install EFVs in all new or replaced residential gas service lines where operating conditions are suitable for available valves, beginning June 1, 2008. This proposed rule includes requirements addressing this mandate, which will no longer require the customer notification requirements of § 192.383. Thus, we are proposing to repeal this requirement.

IV. Stakeholder Groups

A. Stakeholder Groups' Involvement

In 2004, as described above, the IG recommended that PHMSA establish IM requirements for distribution pipelines, including elements similar to those in the IM regulations for hazardous liquid and gas transmission pipelines (except for those related to physical inspection (i.e., assessment, of the pipeline). The IG highlighted this recommendation in testimony before Congress in 2004, and a report of the fiscal year (FY) 2005 Conference Committee on Appropriations required DOT to report its plans to establish such regulations. PHMSA filed its report in June 2005. A copy of the report is in the docket.

PHMSA's report to Congress described the work of four stakeholder groups to investigate opportunities to enhance the safety of distribution pipelines. The four multi-stakeholder groups (viz. Excavation Damage Group, Data Group, Risk Control Practices Group and Strategic Operations Group), representing State regulators, the public, and the gas distribution industry,

[6] Audit report SC–2004–064, issued June 14, 2004.

[7] *Id.*

[8] 49 CFR 192.383.

collected and analyzed available information and issued a report of their investigations in December 2005. A copy of the report is in the docket. The groups agreed IM requirements for transmission pipelines could not be applied directly to distribution systems because gas distribution pipeline systems differ significantly from transmission pipelines in their design. The groups also found that diversity among gas distribution pipeline operators and systems was so great that prescriptive requirements suitable for all circumstances could not be established. Instead, the groups found it would be more appropriate to require all distribution pipeline operators, regardless of size, to implement an IM program, including seven key elements. These seven elements are described below under ''Stakeholder Group Findings.''

The groups concluded that distribution IM requirements should apply to all distribution pipeline systems, rather than just to portions of systems in high-consequence areas. Distribution pipeline systems are located in populated areas, where incidents are likely to produce serious consequences. Because distribution pipelines operate at very low pressures, failures typically appear as leaks. Experience shows gas released through leaks can migrate underground and collect in nearby buildings or other locations. These leaks can result in fires and explosions in locations not directly on the pipeline. Thus, the method used to identify high consequence areas along transmission pipelines—predicated on the likelihood that a fire or explosion would occur at the rupture location—would be irrelevant to gas distribution systems.

The stakeholder groups generally concluded IM requirements for distribution pipelines should be established by a regulation that sets high-level performance objectives with implementation guidelines. This approach would allow States flexibility in implementing IM programs suited to their particular circumstances; operators flexibility in better identifying the sources of risk to their pipelines; and more focused actions aimed at addressing those risks.

B. Stakeholder Groups' Findings

The stakeholder groups made the following findings and conclusions about the current state of gas distribution pipeline safety and integrity:

1. Distribution pipeline safety and excavation damage prevention are intrinsically linked. Excavation damage poses, by far, the most significant threat to the safety and integrity of gas distribution pipeline systems. Therefore, excavation damage prevention presents the greatest opportunity for gas distribution system safety improvements. Any effort to improve distribution pipeline safety is flawed if it does not seriously address excavation damage prevention.

2. The dominant cause of reportable distribution pipeline incidents is ''excavation damage,'' while ''other outside force'' and ''natural force'' are the second and third leading causes.

3. Corrosion is the principal cause of distribution pipeline leaks removed for both mains and service lines, but it causes relatively few incidents.

4. ''Excavation damage'' is nearly as significant as ''corrosion damage'' in causing service line leaks.

5. Excavation damage and material/weld failures, respectively, are the second and third leading causes of leaks for both mains and service lines.

6. Corrosion causes approximately four percent of incidents, indicating operators are managing corrosion to prevent it from becoming one of the major contributors to reportable incidents.

7. The rate of reportable distribution incidents resulting in deaths and injuries has decreased from 1990 to 2002. (Note that the Inspector General's analysis and AGF study were conducted for different periods.)

8. No statistically significant trend could be determined for total reportable distribution incidents for the same period.

9. There is a downward trend for reportable incidents resulting in deaths or injuries caused by damage from outside force.

10. Although not statistically analyzed, the data suggest a slight downward trend in corrosion-caused leaks, and a decreasing trend in leaks caused by third-party damage.

C. Stakeholder Conclusions

Based on their findings, the groups concluded:

1. The most useful option for imposing distribution IM requirements would be a high-level, flexible Federal regulation, with implementation guidance.

2. Seven elements could describe the basic structure of a high-level, flexible Federal regulation addressing distribution IM. Each operator would have to do the following regarding its pipeline system:

- Develop a written program describing management of the integrity of the distribution system;
- Have an understanding of the system, including the conditions and factors important to assessing risks;
- Identify threats applicable to the system, including potential future threats;
- Assess risks and characterize the relative significance of applicable threats to the system;
- Identify and put in place appropriate risk-control practices (or modify current risk-control practices) to prevent and mitigate risks from applicable threats consistent with the significance of these threats;
- Develop and monitor performance measures to evaluate effectiveness of programs, periodically evaluate program effectiveness, and adjust programs as needed to assure effectiveness; and
- Periodically report a select set of performance measures to jurisdictional regulatory authorities.

3. Because a distribution IM program would cover the entire distribution system, there is no need to identify high-consequence areas.

4. A distribution IM program should consider threats identified in the PHMSA Annual Distribution Report, PHMSA Form 7100.1–1, as ''Cause of Leaks'' in Part C:

- Corrosion;
- Natural Forces;
- Excavation Damage;
- Other Outside Force;
- Material or Welds (Construction);
- Equipment;
- Operations; and
- Other

5. Distribution IM requirements should not exclude any class or group of local distribution companies.

6. Operators may need guidance materials to comply with a high-level, risk-based, flexible federal rule. Small operators may need more precise compliance guidance.

7. Implementation of elements of distribution IM regulations should be based on information reasonably accessible to an operator and on information an operator can collect on a going-forward basis. Regulations should not require extensive research.

8. The most useful performance measures at the national level could be incidents (per mile or per service), number of excavation damages per ''ticket,''[9] the status of implementing elements of the rule, the amount of pipe that is not state-of-the-art, and a redefined measure or measures related to leaks.

9. Operator-specific performance measures are unique and must match

[9] A ticket is the information the underground facility operator receives from the one-call notification center.

the specific risk-control practices of its distribution IM program.

10. The operator should periodically evaluate the effectiveness of its distribution IM program. Programs should specify the period for evaluating program effectiveness, which should be as frequently as needed to assure distribution system integrity.

11. Operators should review and implement Common Ground Alliance (CGA) Best Practices, and other industry practices as appropriate, to reduce damages to their facilities. Similarly, other affected stakeholders should review and implement applicable CGA Best Practices.

12. A joint stakeholder group formed to conduct an annual review of safety performance metrics data, to resolve issues, and to produce a national performance metrics report would be of considerable value.

D. Findings Relevant to Leak Management

As described above, the stakeholder groups found that although corrosion is the dominant cause of leaks repaired on gas distribution pipeline systems, corrosion accounts for only four percent of gas distribution incidents. This reflects the importance and effectiveness of leak management practices operators currently use. The stakeholder groups agreed leak management is an important risk control practice and should be a part of a gas distribution IM program, along with excavation damage prevention.

According to the stakeholder groups, the essential elements of an effective leak management program are as follows:

- Locate the leak;
- Evaluate its severity;
- Act appropriately to mitigate the leak;
- Keep records; and
- Self-assess to determine if additional actions are necessary to keep the system safe.

These elements are collectively referred to by the acronym LEAKS, representing the first letter of each element.

E. Stakeholder Considerations Regarding Excess Flow Valves

The stakeholder groups devoted considerable attention to excess flow valves (EFVs) in the context of potential IM program requirements. As described above, an EFV is designed to stop the flow of gas in a service line experiencing major leakage, generally caused by excavation damage. The device prevents consequences associated with a significant escape of gas and its ignition. An EFV in a service line provides no protection for breaks downstream of the meter (in homes). Since pressure is reduced at the meter and the flow through, even a completely severed line in the home poses much less risk than if the same break were to occur on the higher-pressure service line upstream of the meter.

The stakeholder groups considered the use of EFVs for IM and reached the following conclusions:

1. Information drawn from surveys of State practices and operational experience for currently installed EFVs indicated:

- Over 6.3 million EFVs have been installed in the United States (i.e., protecting approximately 10% of all services).
- If correctly specified and installed, EFVs work as designed.
- EFVs will not work in all applications—for example, EFVs will not work in up to 60 percent of new services in Connecticut, a State favoring their use, because the service lines operate at pressures below that required for EFVs to function.

2. Regulations should not require installation of EFVs on all new and replaced service lines. EFVs are one risk-control practice operators should consider along with others.

3. Operators, as part of their distribution IM program, should consider the mitigative value of installing EFVs.

In their findings, the stakeholder groups considered the NTSB's recommendation that DOT require installation of EFVs on all new and replaced gas service lines where operating pressure exceeds 10 psig.[10] This recommendation resulted from the NTSB's investigation of a 1998 accident in South Riding, Virginia, which destroyed a new home and killed one of its occupants.[11] The NTSB concluded the accident was caused by gas escaping from a hole in the gas service line and the flow through that hole was of sufficient magnitude that an EFV would have prevented the accident.

Comments From Fire Service Organizations

The stakeholders also considered comments from representatives of the fire service organizations. The International Association of Fire Chiefs and the International Association of Fire Fighters wrote to the Secretary of Transportation in early 2004 urging DOT to require installation of EFVs. The organizations commented that fire fighters are often first to respond to incidents involving fires fueled by escaping gas and their lives were at risk in doing so. The same organizations, along with the National Volunteer Fire Council and the Congressional Fire Services Institute, wrote to PHMSA again in 2005 after reviewing draft reports of the Risk Control Practices stakeholder group. The fire service organizations reiterated their recommendation about mandatory EFV installation and disagreed with the group's conclusion that EFVs should be treated under distribution IM requirements as one of the available mitigation options.

(Note that the conclusions of the stakeholder groups are reported here for completeness, but that many have been rendered moot by the statutory mandate, enacted after the stakeholder group deliberations, that installation of EFVs be made mandatory)

Surveys

In conjunction with stakeholder group findings, PHMSA considered the results of several surveys evaluating the prevalence and efficacy of EFVs in gas distribution systems. One survey, conducted by the National Regulatory Research Institute (NRRI), a university-based research arm of the National Association of Regulatory Utility Commissioners (NARUC), surveyed State regulatory commissioners, partly in response to PHMSA's interest in the subject. A second survey conducted by the National Association of Pipeline Safety Representatives (NAPSR)[12] obtained results from pipeline safety program managers in all States (and the District of Columbia) with regulatory jurisdiction over distribution pipeline safety. A third survey, sponsored by PHMSA and conducted by Oak Ridge National Laboratory, examined in more detail the experience of nine gas distribution operators, some of whom install EFVs voluntarily and others who install in conformance with the requirements of 49 CFR 192.383. Results of all three surveys are available in the docket for this rulemaking.

The surveys indicate EFVs, if correctly sized and installed, operate reliably. Instances of false closure, where gas flow stops even though the service line is undamaged, rarely occur. Likewise, the valves function reliably when service lines are damaged. In fact, one potential problem with EFVs —the increased risk that excavation-related

[10] NTSB, "Natural Gas Explosion and Fire at South Riding Virginia, July 7, 1998," Pipeline Accident Report PAR–01/01, June 12, 2001.

[11] Ibid.

[12] NAPSR is an organization consisting of the state pipeline safety program manager from each state that exercises jurisdiction over pipeline safety.

damage will go unreported—is directly related to their effectiveness in stopping the flow of gas from a severed gas line. In some cases, particularly where directional boring[13] is used, excavators may not even 0be aware they have damaged a gas service line. When an excavator damages a service line not protected by an EFV, gas is released and the excavator must stop work and notify the gas distributor to protect the safety of its own personnel and the house at which they are working. If an EFV is installed, the EFV functions to stop the flow of gas, and an irresponsible excavator can finish its work, re-fill the hole, and leave the site. Only later, when the residents discover they have no gas service, is the damage reported. The gas distribution operator must then re-excavate to locate and repair the damage, increasing the expense of the repair. Although anecdotal evidence shows excavators do not always notify operators of damage to service lines, PHMSA does not have the data to determine if this is a prevalent problem.

V. Public Meetings

A. Public Meetings Concerning Distribution Integrity Management

PHMSA conducted two public meetings to collect and evaluate public comments on the potential for adding IMP requirements for distribution pipelines. During the first meeting, held December 16, 2004, presentations were made concerning the then-draft AGF study discussed above and the DOT IG's recommendation. Comments made at this meeting resulted in the stakeholder group investigations, which are discussed in section VI.

The second public meeting, held on September 21, 2005, included presentations describing the stakeholder group investigations, which were then in progress. Participants included representatives of industry, State regulators, PHMSA, and the public, including persons involved in the stakeholder investigations. Key points made by meeting participants included the following:

- There must be a balance among improved safety, reliability, and costs. For municipal operators, cost trade-off involves potential effects on other community services, including public safety.
- The primary cause of incidents on distribution systems is outside force damage, and any action must address this threat. Operators have limited ability to prevent excavation damage, and excavators are not typically under the jurisdiction of pipeline safety authorities. Comprehensive damage prevention programs can reduce incidence of excavation damage.
- Leak management is an important element in assuring the integrity of gas distribution pipelines.
- The majority of companies affected by any new distribution IM requirements are small companies, and the needs of those operators differ from larger companies. Smaller companies will likely require more detailed guidance for implementing new rules.

Summaries of both public meetings are in the docket.

B. EFV Public Meeting

On June 17, 2005, PHMSA conducted a public meeting to discuss EFV performance, notification, and installation issues. The meeting included panel discussions involving members of industry, State governments, fire service organizations, the National Association of Fire Protection, advocacy groups, the NTSB, and researchers who analyzed EFV performance.

Industry participants included representatives of companies voluntarily installing EFVs and those installing only when a customer requested. These company representatives said they analyzed the costs and benefits of installing EFVs under local conditions in deciding whether to install EFVs. Factors in these analyses include the size and growth rate of company service areas, costs of maintaining records related to notifications, experience with load growth after initial installation (which can result in a need to replace EFVs), and the relative effectiveness of alternative actions to reduce the threat of excavation damage. Operators also noted they have experienced instances in which excavators damaged a line equipped with an EFV, but the damage was not reported to the operator, increasing operator costs to repair the damage.

PHMSA and Allegro Energy described PHMSA-sponsored research on EFV performance (discussed above). The research examined incidents reported on gas distribution systems over a five-year period (634 events)—the Allegro Energy analysis described above. The PHMSA study examined these narratives and concluded EFVs could have been a factor in mitigating 101 (approximately 16 percent) of the analyzed incidents.

The NTSB reported that serious accidents on gas distribution systems prompted its recommendation that PHMSA require EFV installation. Recognizing that States conduct most regulatory oversight of distribution operators, the NTSB contacted all State governors in 1996, recommending they establish requirements for mandatory installation,. The responses to those recommendations—indicating States look to PHMSA for safety standards—reinforced the NTSB's support for a Federal requirement.

Representatives of State pipeline safety authorities, utility commissioners, and regulatory program managers described the factors considered by States in evaluating EFVs. They said local conditions could affect decisions on whether to use the valves. Initial installation costs are small, but life-cycle costs must be considered. They reported that EFVs provide protection from a limited scope of incidents involving significant damage to, or severance of, a service line. Many operators reported their belief that their resources are better spent attempting to reduce the frequency of those events rather than on installing EFVs. While all agree damage reduction activities can improve safety for existing gas services, they believe retrofit installation of EFVs, where the service line is not being replaced for other reasons, is impractical.

Public safety advocates expressed significant concern with the manner in which operators are implementing the notification requirements in 49 CFR § 192.383. Often the ''customer'' notified about the availability of EFVs for newly installed services is a builder/developer rather than the resident of a home. Experience indicates few builders/developers elect to have EFVs installed. When homes are then occupied shortly after the gas service is installed, the customer neither enjoys the protection of an EFV nor has the opportunity to decide to pay for the added protection.

Comments From Fire Service Representatives

Fire fighters participated in the stakeholder groups and public meetings. Because the consequences of accidents on gas distribution pipelines generally result from fires fed by escaping gas, fire fighters have a significant interest in reducing the frequency and consequences of such events.

As described above, the International Association of Fire Chiefs, the

[13] Underground utilities are usually installed by digging a trench, laying the pipe or cable in the trench and refilling it. In such installations, damage to other utilities would be obvious. Directional boring is a technique used when trenching is impractical, often when utilities must be installed below paved surfaces. When directional boring is used, a service line could be damaged or severed. If an installed EFV operates properly to shut off the flow of gas, the installer may not even be aware that a gas service line has been damaged.

International Association of Fire Fighters, the National Volunteer Fire Council, and the Congressional Fire Services Institute support a requirement to install EFVs in all new and replaced service lines where installation is suitable. Additionally, these organizations support IM programs for gas distribution operators to identify and evaluate specific risks associated with their systems and to implement measures to minimize those risks. The organizations agreed most operators will need guidance to implement these requirements and small operators are likely to need guidance that is more precise. These organizations also believe it is vital for operators to implement strategies to reduce the frequency of outside force damage. The comments of these organizations are in the report of the stakeholder group investigations and are in the docket.

Representatives of the National Association of State Fire Marshals (NASFM) and the National Fire Protection Association (NFPA) participated in stakeholder groups. State Fire Marshals are responsible for overseeing compliance with State fire codes and related building standards, training fire fighters, and other duties based on State agency assignments. NFPA is a professional association responsible for developing American National Standards Institute approved consensus standards related to fire safety.

NASFM also supports mandatory installation of EFVs. In comments made at the June 2005 public meeting on EFVs and the September 2005 public meeting on distribution IM, NASFM also supported a comprehensive approach to IM. This approach would address all threats, prioritize them for action, and deal with them based on importance.

NFPA also supports IM requirements for gas distribution pipelines and agrees new requirements for distribution systems will primarily affect smaller operators who will need detailed guidance to implement them. NFPA acknowledges EFVs will reliably stop gas flow if the flow exceeds their trip point, but cautions that the valves are not a panacea because damage to a service line may not always result in sufficient flow to trip an EFV.

A complete summary of this meeting is available in the docket.

VI. Guidance for IM

As described above, the stakeholder groups concluded operators would need guidance to implement a regulation requiring operators to meet high-level performance objectives to improve IM. The diversity among distribution systems and the size/capabilities of distribution operators make it impractical to require specific, detailed actions in the regulation. In particular, the stakeholder groups described above reported to PHMSA that operators need guidance to describe the following:

1. Information they should gather through routine activities to improve their understanding of the distribution system infrastructure.
2. How best to assemble detailed information on pipe characteristics (including material, manufacturer, batch, etc.) to strengthen their understanding of the system and to support current and future risk-management activities.
3. Threat evaluation processes and data needed to support this evaluation.
4. Options for evaluating the relative importance of threats.
5. How to perform risk analysis, encompassing situations from small, simple distribution systems to large and complicated ones, and how to use the results of these analyses.
6. Decision processes and criteria for choosing among prevention, detection, and mitigation measures.
7. Options for measuring safety program effectiveness and determining the situations under which different measures would be meaningful.
8. How to evaluate the overall effectiveness of the program such as how to determine if the program is being implemented as described and how to determine if the program is producing improvements.
9. How to structure a comprehensive leak management program, which is fundamental to successful management of distribution risk. At a minimum, operators need guidance to implement the LEAKS program or the following:

—Determine how local conditions and system knowledge should affect the frequency and type of leak surveys.
—Identify methods/criteria for evaluating the severity of leaks and need for action.
—Describe records an operator should maintain to permit trending and identification of underlying problems.
—Identify performance metrics and the types of analyses in which the operator should consider them.

On March 2, 2006, PHMSA asked the Gas Piping Technology Committee (GPTC), a standards-developing body, to prepare guidance. GPTC is accredited by the American National Standards Institute (ANSI), the governing body for consensus standards development in the U.S. GPTC has historically prepared guidance to assist operators in implementing various parts of natural gas pipeline safety regulations in 49 CFR Part 192. GPTC agreed and formed a Distribution Integrity Guidance Task Force to develop guidance. The GPTC guidance will provide suggestions for operators concerning options they could use to implement the high-level requirements in a final rule. The GPTC will describe the scope and content of the guidance at a public meeting during the comment period.

The GPTC guidance is designed to assist operators in developing their distribution integrity management programs. PHMSA expects the guidance will provide options that operators can use to implement the DIMP requirements and that inspectors, primarily from State pipeline safety agencies, also will use the guidance as examples of actions an operator could take to comply with the rule. It will be up to each operator to develop its plan implementing the DIMP requirements. The GPTC guidance is only intended to assist operators; operators may use other approaches. Whatever approach and guidance an operator uses to develop its plan, it will be up to the operator to demonstrate how its approach satisfies the DIMP requirements. When inspectors identify deficiencies in operator plans and procedures intended to satisfy the requirements, they will use existing enforcement tools, based on non-compliance with the rule (not with the guidance) to cause operators to comply. PHMSA is not proposing to incorporate by reference the GPTC guidance.

PHMSA understands the GPTC guidance will be published for public comment, as part of the ANSI approval process, after this NPRM is published.

PHMSA also is supporting work by the American Public Gas Association (APGA) Security and Integrity Foundation (SIF) to develop more specific guidance for use by the smallest operators. These are usually municipalities that have limited resources to develop IM programs. SIF is a non-profit 501(c)(3) corporation, which was established by the APGA in 2004. The SIF is dedicated to promoting the security and operational integrity and safety of small natural gas distribution and utilization facilities. The SIF will focus its resources on enhancing the abilities of gas utility operators to prevent, mitigate and repair damage to the nation's small gas distribution infrastructure. In this work, SIF is using the GPTC guidance to develop a computer program that will assist small operators in developing their IM programs.

PHMSA and NAPSR have formed a joint workgroup to develop a framework for oversight of the Federal requirements for the distribution integrity management program. This joint workgroup is charged with developing an oversight program that provides consistency in the States' oversight of operator plans. The guidance developed by GPTC will be key to this process. States have the responsibility for designing and implementing their oversight programs, but PHMSA needs certain information from these programs to evaluate the effectiveness of the new Federal requirements, report results to Congress and organizations that oversee us, and determine if future changes are needed. PHMSA's goal in this workgroup is to provide regular reporting on progress and results of inspections of distribution operators' compliance with the final DIMP rule.

VII. Applicability to Small and Simple Distribution Systems; Request for Comments

A. Master Meter and Liquefied Petroleum Gas (LPG) Operators

We believe IM regulations for master meter and LPG operators should be limited because these systems are simple and seem to pose relatively little risk.

By contrast to other local distribution systems, master meter system operators receive gas at a single meter (the master meter) and operate small pipeline systems to deliver the gas from the meter to a small number of users. A typical example of a master meter operator is a trailer park where the trailer park owner/operator receives gas from a local distribution company and distributes it, via underground piping, to individual trailer pads. Master meter pipeline systems tend to cover limited geographical areas. They are simple systems, often including only one type of pipe, operating at a single pressure, and having no equipment other than pipe, meters, service pressure regulators, and valves.

Master meter operators are subject to the requirements of Parts 191 and 192, but some requirements are modified to better suit these simpler systems. For example, master meter operators must have damage prevention plans under § 192.614, but their plans do not have to be written. Similarly, these operators must provide notification of incidents by telephone (§ 191.5) but do not have to submit written incident reports (§ 191.9) or annual reports (§ 191.11). These modifications recognize these systems are generally simple and represent less risk.

LPG systems are small systems, mostly in rural areas, that use liquefied petroleum gas to serve a number of customers, usually in areas not served by natural gas transmission lines. Like master meter pipeline systems, LPG systems are simple and tend to cover limited geographical areas. Further, we estimate each master meter and LPG system operator has, on average, 100 services at low pressure. Very small operators with less than ten services and no portion of their systems in public areas will not be subject to the requirements of this proposed rule because these small operators are generally exempt from Part 192.[14]

PHMSA's review of reported incidents shows few incidents occur in master meter and LPG systems. Because of the relative simplicity of these pipeline systems, a risk analysis would provide much less useful information than an analysis of a more complicated distribution system. Master meter operators often exercise more positive control over excavations near their pipelines, thereby providing enhanced protection from third-party damage, the leading cause of distribution system incidents.

Based on this analysis and the distinctions that already exist in the regulations, the proposed rule would limit the scope of the IM requirements for master meter operators and LPG operators. Under the proposal, these operators would not have to perform risk analyses as part of their IM program because the relative simplicity of their systems makes the effort to perform the analysis more burdensome than beneficial. Additionally, these operators will not have to report performance measures, although they will need to maintain internal records of performance for inspection purposes.

PHMSA invites public comment on the following:

- Whether these IM limitations are appropriate for master meter and LPG system operators;
- Whether we should further limit the IM requirements for these operators; or
- Whether we should exempt these operators from IM requirements.

B. Very Small Distribution Systems

PHMSA notes there may be some local distribution systems of limited area and simple design for which similar limited IM requirements may be appropriate. There is currently no regulatory precedent for differentiating among local distribution systems to identify a class of operators to exempt from certain requirements. PHMSA would consider limiting IM requirements for other operators of small, simple systems if we can establish reasonable criteria to identify operators for which such limitations are appropriate.

PHMSA does not consider the number of customers an appropriate selection criterion. Size, as measured by number of customers, is not directly correlated to risk. For example, a system serving several thousand customers that was installed over a brief period (e.g., after a transmission line was installed nearby providing a source of gas) could be quite uniform in design and materials. On the other hand, a system serving a few hundred customers that has been installed piecemeal over many years could have multiple types of material, including older materials subjected to age-related degradation, etc. In this example, the larger system would be expected to pose considerably less risk than the smaller. Rather than the system's size, PHMSA considers that appropriate criteria would identify systems with characteristics similar to those of master meter systems and representative of low risk. PHMSA proposes the following basis for making this distinction:

1. The system operates at a single pressure;
2. The system may include valves, meters, and service pressure regulators, but no other equipment;
3. The physical environment (i.e., potential for corrosion) is similar throughout the entire system;
4. Most of the system was installed at one time, consisting of one material. Additions may have been made later of another material, but those additions are limited and their location is known; and
5. The system location allows the operator to exercise control over most third-party excavation.

PHMSA invites comment on whether limited IM requirements should also apply to operators of simple distribution pipeline systems and on whether the above criteria would be appropriate for identifying systems to which to apply this limitation.

VIII. Plastic Pipe Issues

A. Plastic Pipeline Database and Availability of Failure Information

A significant amount of gas distribution pipeline is made of plastic. Very little plastic pipe is used in other pipeline systems. The Plastic Pipe Data Committee (PPDC), a voluntary group

[14] Section 192.1(b)(6) states the requirements of Part 192 do not apply to operators of ''any pipeline system that transports only petroleum gas or petroleum gas/air mixtures to—(i) Fewer than 10 customers, if no portion of the system is located in a public place.''

consisting of representatives of industry, the NTSB, State pipeline safety regulators and PHMSA, and administered by the American Gas Association (AGA), monitors in-service performance of plastic pipe. Participating operators send information on problems occurring with plastic pipe and related fittings in their pipeline systems. PPDC periodically analyzes this information to identify adverse performance trends and problems potentially requiring action by plastic pipe users. PPDC information has limited distribution and is generally not available to operators who do not participate in the program. Gas distribution pipeline operators whose systems include significant amounts of plastic pipe would be better able to carry out an IM program with knowledge of plastic pipe performance issues.

PHMSA believes changes to the PPDC process could significantly improve operator insight into the risks associated with plastic distribution pipelines. In particular, more data of better quality and improved availability of results from PPDC data analysis could help inform operators of potential integrity issues related to their plastic pipe. Changes PHMSA would consider valuable include the following:

- Changing the current system of data collection, analysis, and communication to allow all operators better access to information on ''suspect'' materials in their systems (once analysis identifies a potential generic problem);
- Adding new requirements to facilitate operator use of PPDC information; and
- Adding requirements for information gathering on existing installed piping and equipment when normal operation and maintenance exposes the pipe.

PHMSA intends to discuss with AGA how to strengthen the PPDC process and improve availability of results and to encourage AGA to continue related discussions with PPDC members. PHMSA also invites public comment as to whether the PPDC, administered by AGA, is adequately objective to evaluate and report to the industry information concerning plastic pipe failures, or whether PHMSA should seek a new independent third party to perform this function.

PPDC is an independent entity. PHMSA cannot dictate the actions that PPDC takes. PPDC may not agree to changes that would provide information to operators who do not participate, and who cannot now include in their analyses failures that occur at non-participating operators. Further, it is uncertain whether a different independent third party can be identified that would be willing and able to assume the task of analyzing failure information. Given the importance of plastic pipe integrity to distribution pipeline system safety, PHMSA has included in this proposed rule requirements for all operators to report data on failures that occur in plastic pipe/fittings. We are proposing that reports be made within 90 days of the occurrence of a failure. PHMSA will collect the data and ensure that the data are analyzed and that appropriate insights are communicated to all distribution pipeline operators for their consideration as part of their integrity management programs. PHMSA may take additional actions if analysis of reported failures indicates additional regulatory action is appropriate. PHMSA is proposing that a report be submitted within 90 days because we consider 90 days to be reasonable time for conducting detailed failure cause analysis. PHMSA invites public comment on whether some other reporting frequency is preferable and adequate to identify trends (e.g., quarterly reporting, annual reporting).

The proposed requirements to collect and report data on plastic pipe failures from the final rule may not be necessary if another group agrees to perform these functions. PHMSA invites comments on the appropriateness of the proposed reporting requirements.

B. Plastic Pipe Marking

Having better information on pipe type and its history would improve operators' ability to manage their risk. In many cases, records are inadequate to determine exactly what type of pipe is installed in particular locations in distribution systems. It would be convenient if pipe was marked so that operators could collect this information by examining the pipe when it is excavated for other reasons. Unfortunately, plastic pipe has not historically included any permanent markings that would allow operators to determine the particular type of plastic, its age, or other key parameters.

PHMSA recognizes there are many technical issues associated with pipe marking, and developing solutions requires discussion with all affected organizations. Technical issues include the label contents, durability, size, visibility, and spacing. PHMSA plans to discuss these issues further with pipeline manufacturers, operators, AGA, and State pipeline safety regulators. Thereafter, PHMSA plans to ask the American Society of Testing and Materials (ASTM) to revise its current standard for plastic pipe marking (i.e., ASTM D2513). PHMSA could then consider incorporating the standards into federal regulations.

PHMSA invites comments on the desirability of requiring permanent markings on plastic pipe, on the related technical and logistical issues, and on its proposed approach to rely on ASTM to establish appropriate standards.

IX. Monitoring the Effectiveness of Actions

It is important that any program intended to improve safety include measurable attributes that can demonstrate whether the program is being effective. The existing IMP requirements for hazardous liquid and gas transmission pipelines both require operators to monitor performance and to review their programs periodically to determine if there is a need to change. This proposed rule contains similar requirements for distribution pipeline system operators. Similarly, it is important for PHMSA to be able to measure whether its actions are having the desired effect—improved safety.

The ultimate measure of distribution pipeline system safety is the number of deaths and injuries and the amount of property damage caused by incidents on distribution pipeline systems. Fortunately, however, incidents occur relatively infrequently. The number of deaths and injuries and the amount of damage are thus lagging indicators of performance that cannot reliably capture safety trends other than over long periods of time. Other interim measures are needed to provide information in a shorter period to evaluate the effectiveness of any new integrity management requirements implemented for distribution pipeline systems. This proposed rule requires that distribution pipeline operators submit to PHMSA annually the number of leaks repaired (by cause), the number of excavation damages and the number of ''tickets'' (representative of the amount of excavation activity), and the number of EFVs installed. PHMSA will use these data to evaluate the effectiveness of new distribution integrity management requirements until sufficient time has passed that trends in the overall number of incidents, deaths, serious injuries, and property damage should be apparent. PHMSA solicits comments on whether the paperwork burdens associated with the collection of this data is justified by the usefulness of this information. PHMSA also invites comment on other measures that might be used to monitor effectiveness in this interim period.

X. Deviating From Required Intervals Based on Operator's DIMP

The underlying purpose of all of PHMSA's integrity management requirements is to improve knowledge of the condition of each operator's pipeline and to use that information to identify new risk control solutions and to better focus risk reduction efforts. PHMSA concludes, based on our experience with hazardous liquid and gas transmission integrity management, that this process is working and is producing a more efficient and effective approach to controlling pipeline risk. PHMSA considers that implementing integrity management for distribution pipelines should offer additional opportunities to improve efficiency in assuring safety. Improving efficiency in assuring safety requires, however, that it be possible to reduce efforts that have marginal effect on controlling risk in order to shift resources to more effective actions.

As part of our continuing effort to improve efficiency and to make the approach to pipeline safety more risk-based, we are proposing an approach that would allow operators and the States to have more of a role in setting compliance intervals for distribution operators within a state. Rather than continue to require distribution operators to comply with intervals set by existing federal regulation in Part 192, this approach would let an operator use its distribution integrity plan, and the risk assessment on which it is based, to propose alternative intervals for Part 192 requirements that they must now implement periodically.[15] Operators could propose extended intervals for threats and areas (e.g., portions of pipeline systems) where risk is low, making the application of these requirements more risk-based.

Operators would be required to submit their proposed intervals to the jurisdictional regulatory authority (usually the State) for review and determination that the proposal will provide an adequate level of pipeline safety. States would base their decisions on their review of the operator's risk analysis and on their own knowledge of the safety performance of, and issues affecting, each operator. While operators would likely propose only longer intervals, States could exercise their existing authority to impose requirements more restrictive than Federal minimums to require shorter intervals where necessary based on risk. PHMSA intends to work with NAPSR to develop guidance States can use in making decisions concerning changes to the intervals for periodic requirements.

As an example, operators are now required to inspect pipelines potentially subject to atmospheric corrosion, including service lines entering customer gas meters, at least every three years. Many meters are located inside homes where, in many cases, no one is available during the day to provide access, and where the environment is unlikely to be particularly corrosive. Operators must arrange with residents for access, and must sometimes make multiple visits in order to complete their inspections. The industry is seeking regulatory changes based on these difficulties to reduce the frequency of required inspections of inside meters. An alternative approach might be for operators to establish that corrosion of pipelines in residences is low-risk, and to propose an alternate interval for conducting these inspections. States would have the flexibility to accept or modify operator adjustments to these inspection intervals based on their local circumstances and their understanding of operators' risk.

We seek comment on the following issues:

- What are the advantages and disadvantages of allowing operators and States to set intervals for each distribution operator on required activities using a risk-based approach driven by thorough analysis of individual operator performance data?
- Should there be some limit on the amount by which an operator can deviate from currently-prescribed intervals (e.g., no more than twice the interval in the Federal regulation)?
- How would a State establish guidance for implementing such a process?
- What additional performance data and analysis would be required?
- What costs to the States would be associated with such a process?
- What cost savings to operators could result from such changes?
- On what basis should a State judge the operators' engineering basis adequate?

XI. Prevention Through People

Historically, PHMSA's pipeline integrity management programs have focused on assuring the physical and structural soundness of the pipe. This is a key element to the safe transportation of hazardous materials, including transportation by pipeline. However, it is only part of the safety picture. The role of people, including control center operators, in preventing and reducing risk is another critical component in managing the integrity of pipeline systems, including distribution piping.

The proposed IM program regulations include requirements for operators to understand the threats affecting the integrity of their systems and to implement appropriate actions to mitigate risks associated with these threats. These include a first step towards instituting a ''Prevention through People'' (PTP) program to address human impacts on pipeline system integrity. Human impacts include both errors contributing to events and intervention to prevent or mitigate events. As part of considering the threat of inappropriate operation (*i.e.,* inappropriate actions by people), this proposed rule would have operators evaluate the potential for human error, considering existing regulatory programs (e.g. Operator Qualification, Drug and Alcohol Testing, Damage Prevention, Public Education) , and any voluntary supplemental programs the operator now implements, in preventing and mitigating risk. An operator would be required to include in its written IM program a separate section on ''Assuring Individual Performance,'' in which they would identify 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).

Several existing regulations strengthen the effectiveness of the role of people in managing safety. These include Damage Prevention Program in § 192.614, Public Awareness in § 192.616, Qualification of Pipeline Personnel in subpart N under Part 192, and drug and alcohol testing in Part 199. The evaluation required by this proposed rule would consider the effects of these programs, and a PTP program would integrate these existing efforts and would address the risks associated with human factors as

[15] Operators are currently required to take the following periodic actions:

1. Cathodic Protection (CP) must be tested once per year. Rectifiers and moving/active components must be inspected six times per year (192.465)

2. Operators must reevaluate pipelines without CP every 3 years and provide CP if active corrosion is found (192.465)

3. Pipe exposed to the atmosphere must be inspected for corrosion every 3 years (§ 192.481)

4. Leak surveys must be conducted annually in business districts and at least every 5 years (3 if cathodically unprotected and electrical surveys are impractical) outside of business districts (§ 192.723)

5. Pressure limiting devices must be tested at least annually (§ 192.739)

6. Each valve necessary for safe system operation must be tested annually (§ 192.747)

7. Vaults housing pressure regulating equipment must be inspected annually (§ 192.749)

8. Mains must be patrolled 4 times a year in business districts and twice per year outside business districts (§ 192.721)

enumerated in Section 12 of the PIPES Act, as well as the opportunities for people to mitigate risks. PHMSA is separately developing proposed requirements for control room management, which would also become a part of the PTP program and a consideration for integrity management of distribution pipeline systems.

A PTP program could include regulations and a system to identify and communicate noteworthy best practices. Because human interaction with gas distribution systems contributes to the risk these systems pose, PHMSA believes a PTP effort has strong potential to reduce distribution system risk. PHMSA invites public comment on the PTP concept and on any other requirements that should be included in this or a future IM program rulemaking.

PHMSA also requests public comment on how operators are currently addressing human factors, including fatigue, in their ongoing efforts to manage the integrity of their distribution pipelines.

XII. Summary Description of Proposed Rule

Over the past eight years, more than 1,000 incidents on distribution pipelines have resulted in fatalities, serious injuries, or major property damage. Excavation damage and other outside forces caused most of these incidents. This proposal reduces system operating risks and the probability of failure by requiring operators to establish a documented, systematic approach to evaluating and managing risks associated with their pipeline systems. In this NPRM, PHMSA proposes to add a new subpart to the Federal pipeline safety regulations to require gas distribution pipeline operators to develop and implement IM programs covering the seven IM program elements identified by PHMSA and representatives of States, industry, and the public who participated in the stakeholder groups. The proposed rule also implements the legislative direction that PHMSA prescribe minimum standards for IM programs for distribution pipelines. As discussed above, PHMSA requested GPTC to develop more detailed guidance to assist distribution operators in implementing a new rule and States in overseeing these requirements.

The proposed regulation would require operators to develop and implement written IM programs addressing the following elements:

- Knowledge of infrastructure;
- Identification of threats;
- Evaluation and prioritization of risks;
- Mitigation of risks;
- Measurement and monitoring of performance;
- Periodic evaluation and improvement; and
- Reporting of results.

The proposed rule implements the legislative direction that PHMSA require distribution pipeline operators to install an EFV in each newly-installed or replaced service line serving a single-family residence for which a suitable valve is commercially-available and where conditions are suitable. Suitable conditions include:

- Operation continuously throughout the year at a pressure not less than 10 psig;
- No history of liquids or contaminants in the gas flow which would interfere with operation of the valve; and
- Where installation is not likely to cause a loss of service to the residence; or
- Interfere with required operation and maintenance activities.

Any installation will have to comply with the performance standards in § 192.381. The proposed requirement to install EFVs will make it unnecessary for operators to notify customers of EFV availability as currently required by § 192.383. Thus, this proposal would repeal the customer notification requirement.

Because of the significant diversity among distribution pipeline operators and systems, the IM requirements in the proposed rule are high-level and performance-based. The proposal specifies the required program elements, but does not prescribe specific methods of implementation. Prescriptive, how-to requirements would likely not fit the circumstances of all operators. Still, PHMSA recognizes many operators will want additional detail about actions they may take to implement the performance-based regulatory requirements. This is the reason PHMSA asked GPTC to develop guidance providing examples of methods that satisfy the requirements. Also, as discussed earlier, the APGA SIF intends to use the GPTC guidance to develop model IM programs for its small municipal members.

XIII. Section-by-Section Analysis

Section 192.383 Excess flow valve customer notification. This section currently requires operators to notify customers about EFV availability for installation and install an EFV if the customer so requests and agrees to bear all associated costs. The proposed requirements in this NPRM would require operators to install EFVs in new or replaced service lines unless certain conditions preclude installation. We are repealing this existing requirement because the proposed new requirements render the notification requirements in this section unnecessary.

Section 192.1001 What do the regulations in this subpart cover? These proposed rules will apply to all operators of gas distribution systems subject to Part 192. The proposed rules would require each operator of a distribution pipeline system to implement an IM program with prescribed minimum requirements. Under the proposal, IM requirements applicable to master meter operators and operators of liquid propane gas (LPG) distribution systems will be much more limited than those applicable to larger operators. For example, the proposal would not require these operators to install EFVs and would not have them evaluate and prioritize risks and report results.

Section 192.1003 What definitions apply to this subpart? PHMSA proposes to add a definition for the term ''damage'' as used in § 192.1005.

Section 192.1005 What must a gas distribution operator (other than a master meter or LPG operator) do to implement this subpart? The proposed rule would require gas distribution operators, other than master meter or LPG distribution system operators (*see* § 192.1015), to develop a formal IM program with certain prescribed elements and to implement their programs no later than 18 months after the final rule becomes effective. The IM program is to manage and reduce the risks associated with the operator's pipeline system.

Section 192.1007 What are the required IM program elements? The proposed rule defines the minimum elements each operator's IM program must include. Master meter and LPG operators will include only some elements in their programs. For gas distribution operators other than master meter or LPG operators, the required program elements are as follows:

a. Knowledge of the system's infrastructure. To develop an IM program, an operator must identify threats applicable to its pipeline system and analyze the risks its pipeline system poses. Operators cannot do this without understanding their pipeline systems. Generally, the operator should know information such as location, material composition, piping sizes, construction methods, date of installation, soil conditions, pressure (operating and design), operating experience, performance data, condition of the system, and any other characteristics that help identify the applicable threats and risks.

An operator may not know some necessary information about its infrastructure. In some cases, distribution systems include pipe installed several decades ago, and reliable records may not exist to provide complete information. In other cases, distribution systems have grown by acquisition and merger, as multiple pipeline systems came under common ownership. Complete records may not have been transferred during these changes in ownership, again leading to gaps in the knowledge an operator has about its pipeline system. This proposed rule does not require operators to engage in extensive investigative programs to uncover information, nor does it require operators to conduct excavations for the sole purpose of revealing information about buried pipe.

An operator must assemble as complete an understanding of its infrastructure as possible using information the operator has on hand from ongoing design, operations, and maintenance activities. An operator's IM program must identify what additional information the operator needs to know about its infrastructure, and must provide for gaining that additional knowledge over time through normal activities. For example, situations in which buried pipe must be exposed for maintenance or other purposes present an opportunity to collect data about the pipe and its environment at very little or no additional cost. An operator's IM program must provide for identification and use of such opportunities to improve knowledge of the distribution system infrastructure.

b. Identify threats (existing and potential). Operators need to evaluate their pipeline systems and the environments in which the pipelines operate to identify specific threats the pipelines face and to determine what are appropriate actions to manage the threats and minimize the risk. Threats affecting pipeline systems are generally grouped into broad categories. This proposed rule uses the same categories as does the form operators use to report incidents occurring on their distribution pipeline systems (Form PHMSA F 7100.1). Not all threat categories are applicable to all pipelines. For example, corrosion does not affect plastic pipe. Additionally, the categories often represent a grouping of similar threats, not all of which may affect a given pipeline. Although all buried metal pipe is generally considered subject to potential external corrosion, not all pipeline systems are subject to internal corrosion. Outside force may be an applicable threat, but outside force from earthquake movement may or may not be an issue. The proposed rule would require operators to identify both existing threats and potential threats. For example, outside force from landslide or earth movement may be a potential threat to a distribution pipeline system servicing an expanding community, even though currently, the pipeline system is not affected by such problems.

In considering the threat of inappropriate operation, operators would be required to evaluate the effects that actions of its personnel can have on pipeline safety.

c. Evaluate and prioritize risk. Simply knowing what threats exist is not sufficient to understand and manage risk posed to distribution pipeline systems. Operators must determine the likelihood that a system failure would be caused by any given threat. Therefore, the proposed rule would require operators to evaluate each applicable threat and estimate the risk to the pipeline. An operator may subdivide the system into regions (areas within a distribution system consisting of mains, services and other appurtenances) with similar characteristics and reasonably consistent risk, and for which similar actions would be effective in reducing risk.

d. Identify and implement measures to address risks. Once the relative risks are known, operators can take action to mitigate those risks and thus improve safety. The specific actions appropriate for an operator to take will vary depending on the applicable threats, their prevalence, and the risks posed by a leak or failure on the operator's pipeline.

The proposed rule would require operators to identify and implement appropriate risk reduction strategies. Under the proposal, operators would be required to implement at least two risk reduction strategies—an effective leak management program and an enhanced damage prevention program. Since excavation damage is the leading cause of incidents on gas distribution pipeline systems, having effective measures to minimize the likelihood of such damage would be a valuable risk reduction method. Low-pressure distribution pipelines tend to fail by leaking, except in some cases of excavation damage. Leaking gas tends to migrate and can accumulate in buildings and other confined areas where fires and explosion can result. Leaks can be identified and corrected before injury to people and property occurs. Distribution pipeline operators typically have established leak management programs. This is the reason, for example, why leaks resulting from corrosion represent 36 percent of leaks repaired on distribution mains and 25 percent on service lines, while corrosion is the cause of less than five percent of distribution pipeline incidents.[16] An effective leak management program is thus a valuable risk reduction strategy for all distribution pipeline operators.

Each operator would be required to develop an IM program with a separate section on ''Assuring Individual Performance'' to improve the safety performance of its personnel. This is a first step towards implementing an integrated approach to assuring PTP.

e. Measure performance, monitor results, and evaluate effectiveness. The proposed rule would require each operator to measure its performance and report certain measures periodically to PHMSA and State regulatory authorities. Only by measuring results can an operator know if its risk reduction efforts are effective. As proposed, operators would have to make changes to their programs to improve effectiveness if performance measurement indicates improvement is needed. Regulators will use the reported performance measures to evaluate overall effectiveness in reducing risk from gas distribution pipeline systems. Further changes to regulations or to oversight (e.g., frequency of inspections) may be appropriate depending on the data analysis findings.

f. Periodic Evaluation and Improvement. Operators would use measured performance to determine whether further improvements are needed and to make necessary changes in their IM programs. Operators would have to evaluate their programs periodically. Operators should determine how often these reviews are appropriate. For large, complex systems, sufficient data and experience may be available to make annual reviews meaningful. For small, simple systems, there may not be sufficient information to make an annual review meaningful. Whatever the size of the system, all operators will have to conduct a complete program evaluation at least once every five years.

g. Report results. The proposed rule would require each operator to measure its performance and report certain measures periodically to PHMSA and State regulatory authorities. The proposal would require operators to

[16] Integrity Management for Gas Distribution, Report of Phase 1 Investigations, December 2005, Attachment 4, page 18. Based on data reported to PHMSA by distribution pipeline operators for 2004.

report four of the required performance measures each March to PHMSA as part of the annual report required by § 191.11. Combining this reporting with the annual report already required will minimize the additional burden on operators to provide this information. Operators would also be required to report these four measures to the State pipeline safety authority where the gas distribution pipeline is located. Operators also would be required to retain records of the remaining listed performance measures for ten years.

Section 192.1009 What must an operator report when plastic pipeline fails? Plastic pipe (including fittings, couplings, valves and joints) forms a significant portion of many distribution pipeline systems. Plastic pipe is used very little in other pipeline systems. Knowledge of potential weaknesses in its plastic pipe is thus particularly important for a distribution pipeline operator analyzing the risk from its system. This section would require that operators report all plastic pipe failures to PHMSA within 90 days after a failure. PHMSA will collect this information and will assure that it is analyzed to identify and communicate significant information about potential vulnerabilities associated with plastic pipe. Distribution pipeline operators will then be able to take this information into consideration in their risk analyses.

Section 192.1011 When must an Excess Flow Valve (EFV) be installed? Gas distribution operators, except for master meter and LPG operators, would be required to install an EFV in each new or replaced service line installed for a single-family residence if a suitable valve is commercially available and certain operating conditions are present for the EFV to function. The required operating conditions are: the operating pressure in the service line must be 10 psig or greater; the gas stream must be free of contaminants and liquids potentially interfering with valve operation; installation must not result in loss of service to the residence; the presence of an EFV must not interfere with required operation and maintenance activities; and the EFV must meet the performance criteria listed in 49 CFR § 192.381.

Section 192.1013 How does an operator file a report with PHMSA? This section describes where an operator is to send required reports. PHMSA prefers electronic submissions.

Section 192.1015 What records must an operator keep? The proposed rule requires an operator to make a number of decisions and to perform a number of analyses to determine and implement risk reduction methods most appropriate to its distribution pipeline system. It is critical that an operator retain knowledge of the basis for its decisions for the operator to effectively implement and modify its IM program. The proposed rule specifies the records an operator would have to keep to serve this purpose. These records also will allow PHMSA (or the applicable State oversight agency) to review the operator's analyses, decisions, and actions to determine through inspections if they are reasonable and comply with the proposed requirements.

Section 192.1017 When may an operator deviate from required periodic inspections of this part? Various provisions of Part 192 require all distribution pipeline operators to perform actions at prescribed intervals. 49 CFR 192.481, for example, requires all operators to perform atmospheric corrosion inspection at fixed three-year intervals, without regard to system-specific risk factors. It is likely that some of these actions could be performed at less frequent intervals (based on lower risk) with no difference in safety outcomes. The resources made available by reducing action intervals, where appropriate, could be used to address more risk-significant problems. Thus, deviating from intervals now specified in other sections of Part 192 could allow operators to be more risk-based in application of their resources.

This section would allow operators to use their risk analyses to propose changes to the intervals for periodic requirements included in other sections of Part 192. Operators would be required to submit their proposals to jurisdictional safety regulators (usually States) for review and determination that the proposal will assure an adequate level of pipeline safety.

Section 192.1019 What must a master meter or liquefied petroleum gas (LPG) operator do to implement this subpart? This section specifies the requirements master meter and LPG operators must meet. Gas distribution systems operated by master meter and LPG operators are subject to the requirements of Part 192, but these systems are generally smaller and pose less risk than systems operated by other gas distribution operators. Master meter and LPG systems cover a smaller geographic area, over which the operator usually has more control. In particular, the operator usually has more control over excavation activity, which is the leading cause of damage to gas distribution pipeline systems. To reflect these differences, we are proposing a more limited and simpler set of IM program requirements for these operators. They must develop and implement written IM programs containing the elements required of other gas distribution operators, except an IM program for a master meter or LPG operation need not include the elements for evaluating and prioritizing risks and reporting results. There will be no EFV installation requirements. Also, the level of detail in these IM programs should be much less to reflect the relative simplicity of these pipeline systems. In a separate guidance document, we will provide a model IM program these operators may use. A draft of this guidance is available in the docket to this rulemaking. We request comment on this draft guidance.

Guidance. To carry out the proposed requirements, operators will have to make a number of reasonably complex decisions and analyses to understand their systems, evaluate threats and risks, and implement risk reduction methods. While it is impractical to specify a single method for how operators should make these decisions/analyses, it is possible to provide guidance concerning factors operators should consider This document will provide guidance in carrying out several requirements. PHMSA expects GPTC to develop more detailed guidance to assist operators in implementing a final rule. Once the GPTC guidance is available, PHMSA may modify the proposed guidance. This draft guidance document is available in the docket to this rulemaking

XIV. Regulatory Analyses and Notices

A. Statutory/Legal Authority for This Rulemaking

This notice of proposed rulemaking 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 proposed integrity management program regulations are issued under this authority and address the NTSB's and DOT Inspector General's 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. 109–468, Dec. 29, 2006).

B. Executive Order 12866 and DOT Regulatory Policies and Procedures

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

The proposed requirements would affect an estimated 9,291 natural gas operators with a combined total of 1,138,000 miles of mains and 60,970,000 services. Of these operators, 201 are local gas utilities with more than 12 thousand services, 1,090 are local gas utilities with 12 thousand or fewer services, and 8,000 are master meter and LPG systems.

The monetized benefits resulting from the proposed rule are estimated to be $214 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; and
• Elimination of the existing EFV notification requirement.

The costs of the proposed rule are estimated to be $155.1 million in the first year and $104.1 million in each subsequent year. Those costs cover:

• Development of an IMP;
• Implementation of the IMP;
• Mitigation of risks;
• Reporting to PHMSA and State Regulators;
• Recordkeeping; and
• Management of the IMP.

The analysis finds that, for those costs and benefits that can be quantified, the present value of net benefits are expected to be between $1.5 billion and $2.8 billion over a fifty year period after all of the requirements are implemented. Also significant is that the proposed rule is expected to be cost-effective if it results in eliminating only approximately 14.5 percent of the societal costs associated with gas distribution systems.

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 proposed IM program requirements apply to gas distribution pipeline operators and require operators of gas distribution pipelines to develop and implement IMPs 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 proposed rule will affect 9,007 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 1,007 small operators among the local gas distribution utilities with 12,000 or fewer services and 8,000 master meter and LPG systems, all of which are small.

Furthermore, PHMSA estimates the proposed rule will cost each local gas utility with 12,000 or fewer services on average approximately $40,000 in the first year and $17,000 in each subsequent year. PHMSA also estimates that the proposed rule will cost master meter and LPG systems on average approximately $3,000 in the first year and $1,000 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 proposed rule may be significant for at least some of the small entities. Therefore, PHMSA believes that the proposed rule could result in a significant adverse economic impact for some of the smallest affected entities. PHMSA invites comments on these assumptions.

PHMSA has tried to minimize costs for these small operators. As mentioned earlier, small operators' IM programs will not have to include the elements for evaluating and prioritizing risks and for reporting results and there will be no EFV installation requirements. PHMSA is also providing a manual for small operators to guide their compliance with the proposed rule and PHMSA will continue to evaluate alternative methods of compliance that reduce the burden on small businesses while retaining an appropriate level of pipeline safety. 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. PHMSA is requesting comment on a proposed information collection. PHMSA is also giving notice that the proposed collection of information has been submitted to OMB for review and approval.

This NPRM proposes additional information collection requirements. Those requirements result from affected natural gas distribution system operators having to (1) prepare a distribution integrity management program (DIMP); (2) document their DIMP procedures and processes; (3) prepare periodic revisions to their IM programs; (4) keep records, and (5) report periodically to PHMSA and the States. PHMSA evaluated the NPRM, as required by the Paperwork Reduction Act of 1995 (44 U.S.C. 3507(d)), and believes the burden hours to industry resulting from the NPRM will be 681,379 in the first year and 85,597 hours in each subsequent year. Large and small operators will bear the largest share of the information collection burden. Master meter and Liquid Petroleum Gas system operators are estimated to require 20 hours each to comply in the first year and to make brief (less than ¼ hour) updates to the initial information in subsequent years.

Pursuant to 44 U.S.C. 3506(c)(2)(B), PHMSA solicits comments concerning: whether these information collection requirements are necessary for PHMSA to properly perform its functions, including whether the information has practical utility; the accuracy of PHMSA's estimates of the burden of the information collection requirements; the quality, utility, and clarity of the information to be collected; and whether the burden of collecting information on those who are to respond, including through the use of automated collection techniques or other forms of information technology, may be minimized.

E. Executive Order 13084

This NPRM has been analyzed under principles and criteria contained in Executive Order 13084 (''Consultation and Coordination with Indian Tribal Governments''). Because this NPRM 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 NPRM 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 proposed 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 what we are proposing. Under 49 U.S.C. 60107, PHMSA gives participating States grant money 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 proposed requirements. We expect to increase money available to help States.

PHMSA has concluded this proposed rule does not propose 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 proposed rule would serve to preempt any currently established State requirements in this area. States would have the ability to augment pipeline safety requirements for pipelines, but would not be able to approve safety requirements less stringent than those contained within this proposed rule.

Although the consultation requirements do not apply, the States have played an integral role in helping develop the proposed requirements. State pipeline safety regulatory agencies participated in the stakeholder groups that helped develop the findings on which this proposal 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 NPRM 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 NPRM as a significant energy action.

H. Unfunded Mandates

PHMSA estimates that this NPRM 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 $132 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 the NPRM's objectives.

I. National Environmental Policy Act

PHMSA analyzed this NPRM 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 preliminarily determined this action will not significantly affect the quality of the human environment. The Environmental Assessment is 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 proposes to amend 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, and 60118; and 49 CFR 1.53.

§ 192.383 [Removed]

2. Section 192.383 is removed.

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

Subpart P—Gas Distribution Pipeline Integrity Management (IM)

Subpart P—Gas Distribution Pipeline Integrity Management (IM)

§ 192.1001 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. A gas distribution operator, other than a master meter or liquefied petroleum (LPG) operator, must follow the requirements in §§ 192.1005 through 192.1017 of this subpart. A master meter operator or LPG operator of a gas distribution pipeline must follow the requirements in § 192.1019 of this subpart.

§ 192.1003 What definitions apply to this subpart?

The following definitions apply to this subpart:

Damage means any impact or exposure resulting in the repair or replacement of an underground facility, related appurtenance, or materials supporting the pipeline.

§ 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 [INSERT DATE 18 MONTHS AFTER PUBLICATION OF THE FINAL RULE IN THE **Federal Register**] 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.

§ 192.1007 What are the required integrity management (IM) program elements?

(a) *Knowledge.* An operator must demonstrate an understanding of the gas distribution system.

(1) Identify the characteristics of the system and the environmental factors that are necessary to assess the applicable threats and risks to the gas distribution system.

(2) Understand the information gained from past design and operations.

(3) Identify additional information needed and provide a plan for gaining that information over time through normal activities.

(4) Develop a process by which the program will be continually refined and improved.

(5) Provide for the capture and retention of data on any piping system installed after the operator's IM program becomes effective. The data must include, at a minimum, the location where the new piping and appurtenances are installed and the material of which they are 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 or weld failure, equipment malfunction, inappropriate operation, and any other concerns that could threaten the integrity of the pipeline. An operator must gather data from the following sources to identify existing and potential threats: incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and ''one call'' and excavation damage experience. 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.

(c) *Evaluate and prioritize risk.* An operator must evaluate the risks associated with its distribution pipeline system. In this evaluation, the operator must determine the relative probability of each threat and estimate and prioritize the risks posed to the pipeline system. 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 the system into regions (areas within a distribution system consisting of mains, services and other appurtenances) with similar characteristics and reasonably consistent risk, and for which similar actions 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 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).

(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, per § 192.703(c), 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) Number of EFVs installed;

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

(vi) Number of hazardous leaks either eliminated or repaired per § 192.703(c), categorized by material; and

(vii) Any additional measures to evaluate the effectiveness of the operator's program in controlling each identified threat.

(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 re-evaluation at least every five years. The operator must consider the results of the performance monitoring in these evaluations.

(g) *Report results.* Report the four measures listed in paragraphs (e)(1)(i) through (e)(1)(iv) of this section, annually by March 15, to PHMSA as part of the annual report required by § 191.11 of this chapter. An operator also must report these four measures to the State pipeline safety authority in the State where the gas distribution pipeline is located.

§ 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.

§ 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 [INSERT DATE 90 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **Federal Register**], 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.

§ 192.1013 How does an operator file a report with PHMSA?

An operator must send any performance report required by this subpart to the Information Resource Manager as follows:

(a) Through the online electronic reporting system available at PHMSA's home page at *http://phmsa.dot.gov;*

(b) Via facsimile to (202) 493–2311; or

(c) Mail: PHMSA—Information Resource Manager, U.S. Department of Transportation-East Building, 1200 New Jersey Avenue, SE., Washington, DC 20590.

§ 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.

§ 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.

§ 192.1019 What must a master meter or liquefied petroleum gas (LPG) operator do to implement this subpart?

(a) *General.* No later than [INSERT DATE 18 MONTHS AFTER PUBLICATION OF THE FINAL RULE IN THE **Federal Register**] the operator of a master meter or a liquefied petroleum gas (LPG) gas distribution pipeline must develop and fully implement a written IM program. The IM program must contain, at a minimum, elements in paragraphs (a)(1) through (a)(5) of this section. The IM program for these pipelines should reflect the relative simplicity of these types of systems.

(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.

(b) *Records.* The operator must maintain, for the useful life of the pipeline, the following records:

(1) A written IM program in accordance with this section;

(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.

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William H. Gute,

Deputy Associate Administrator for Pipeline Safety.

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