# Final

# Regulatory Impact Analysis: Final Rule

## Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines

**PHMSA-RSPA-2004-19854**

**Office of Pipeline Safety**
**Pipeline and Hazardous Materials Safety Administration (PHMSA)**
**U.S. Department of Transportation**

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## EXECUTIVE SUMMARY

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is amending the Federal Pipeline Safety Regulations to require operators of gas distribution pipelines to develop and implement Integrity Management (IM) programs. The purpose of these programs is to enhance safety by identifying and reducing pipeline integrity risks. The rule addresses the statutory mandates and recommendations from the Department of Transportation's (DOT) Office of the Inspector General (OIG) and stakeholder groups.

The IM programs required by this rule are similar to those required for gas transmission pipelines but are tailored to reflect the differences in and among distribution pipelines. PHMSA requires operators of gas distribution pipelines to develop and implement IM plans that will better assure the integrity of their pipeline systems.

All IM program requirements pertain to distribution operators with the exception of master meter and small liquid petroleum gas (LPG) distribution systems. To minimize regulatory burdens, the rule establishes simpler requirements for master meter and LPG operators serving fewer than 100 customers from a single source, reflecting the relatively lower risk posed by these small pipeline systems.

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

**PRESENT VALUE OF BENEFITS, COSTS, and NET BENEFITS OF THE RULE CALCULATED OVER 50 YEARS**
**($ Millions)**

| Discount Rate | Benefits | Costs | Net Benefits |
|---|---|---|---|
| 3% | 2,942 to 4,373 | 2,783 | 159 to 1,590 |
| 7% | 1,639 to 2,437 | 1,618 | 21 to 719 |

The estimated monetary cost of the rule is $130 million in the first year and about $101 million in subsequent years, while the estimated annual monetary benefits are between $111 million and $165 million. DOT has classified this rulemaking as an economically significant regulatory action under Section 3(f)(1) of Executive Order 12866, and a significant regulatory action under the DOT's regulatory policies and procedures (44 FR 11034). There is substantial congressional, industry, and public interest in the rule.

PHMSA has also estimated, as required by the Regulatory Flexibility Act (RFA), that the rule would have an impact on many small operators. PHMSA estimates that approximately 9,090 small entities will be impacted by the rule. PHMSA cannot estimate the percent of revenues the costs of the rule represent for small operators, since the Agency does not have information on their revenues. The rule could result in a significant adverse economic impact for at least some of the small master meter and small LPG systems, if the costs exceed 1 percent of their revenues. A Final Regulatory Flexibility Analysis (FRFA), which discusses these issues has been completed and placed in the docket.

PHMSA determined that the rule would not impose annual expenditures on State, local, or tribal governments or the private sector in excess of $141.3 million, and thus does not require an Unfunded Mandates Act analysis.

# 1. INTRODUCTION

The Pipeline and Hazardous Materials Safety Administration (PHMSA) has issued Integrity Management Program (IM program) regulations for operators of hazardous liquid pipelines (49 CFR 195) and gas transmission pipelines (49 CFR Part 192). Those regulations require operators to continually assess, evaluate, repair, and validate through comprehensive analysis the integrity of pipeline segments, and to take actions to address applicable threats and integrity concerns. Similar regulations do not currently exist for gas distribution pipelines.

PHMSA is revising the Pipeline Safety Regulations to require operators of gas distribution pipelines to develop and implement programs that will better assure the integrity of their pipeline systems. PHMSA published a Notice of Proposed Rulemaking (NPRM) on June 25, 2008 (73 FR 36015), which proposed to extend its integrity management approach to the largest segment of the Nation's pipeline network—the gas distribution pipelines that directly serve homes, schools, businesses, and other natural gas consumers. Significant differences between distribution pipelines and gas transmission or hazardous liquid pipelines made it impossible simply to apply the existing regulations to distribution pipelines. The proposed rule incorporated the same basic principles as current integrity management regulations but with a slightly different approach to accommodate those differences.

Over the period 1989-2008, significant incidents associated with gas distribution pipeline systems result, on average, in more than 15 fatalities, over 62 serious injuries, and tens of millions of dollars of property damages annually.[1] The purpose of this regulation is to address the hazards that lead to those incidents as well as reduce gas loss by including leak management and excess flow valve (EFV) provisions.

This rule addresses recommendations from DOT's Inspector General and the National Transportation Safety Board (NTSB). It also implements requirements in the Pipeline Inspection, Protection, Enforcement and Safety Act (PIPES Act) of 2006.

## 1.1 Requirements of the Integrity Management Program

The requirements for distribution pipeline operators are described below.

### *Gas Distribution Pipeline Integrity Management (DIMP)*

The final rule revises 49 CFR Part 192 to add integrity management requirements applicable to distribution pipelines. This addresses statutory mandates and builds on previous similar requirements established for gas transmission pipelines. The final rule

[1] Natural Gas Distribution: Significant Incidents Summary Statistics: 1989-2008, Significant Pipeline Incidents, PHMSA.

also adds a requirement that operators install excess flow valves (EFV) on all new and replaced residential service lines serving single residences, as required by the PIPES Act.

The requirements for gas distribution operators and LPG operators with distribution systems serving 100 or more customers from a single source ("large" LPG operators[2]) are listed under section 1.1.1 below. These are followed by the requirements for master meter operators and small LPG operators.

### 1.1.1 Requirements for Gas Distribution Pipeline Operators and Large LPG Operators

Distribution pipeline operators are required to implement an IM program similar to those required for gas transmission pipelines.

PHMSA is adding a new *Subpart P – Gas Distribution Pipeline Integrity Management* to 49 U.S.C., Part 192 as follows:

§ 192.1001 What definitions apply to this subpart?
§ 192.1003 What do the regulations in this subpart cover?
§ 192.1005 What must a gas distribution operator (other than a master meter or small LPG operator) do to implement this subpart?
§ 192.1007 What are the required elements of an integrity management IM plan?
§ 192.1009 What must an operator report when plastic pipe compression couplings fail?
§ 192.1011 What records must an operator keep?
§ 192.1013 When may an operator deviate from required periodic inspections under this part?
§ 192.1015 What must a master meter or small liquefied petroleum gas (LPG) operator do to implement this subpart?

PHMSA is also revising section 192.383, Excess flow valve customer notification. The revised section will be titled "Excess flow valve installation," will eliminate the current requirement for operators to notify customers of the availability of EFVs, and will require EFVs to be installed on new and replaced service lines.

**Elements of an IM Plan**

A gas distribution operator must develop and implement an integrity management program that includes a written integrity management plan as specified in § 192.1007. An integrity management program is an overall approach by an operator to ensure the integrity of its gas distribution system. An integrity management plan is a written explanation of the mechanisms or procedures the operator will use to implement its integrity management program and to ensure compliance with the new subpart P. These operators must also comply with sections 192.1009 through 192.1013.

[2] The term "large" is used solely to differentiate these operators from the "small" LPG operators referred to in the rule. Both "large" and "small" LPG operators are small entities for the purposes of the Regulatory Flexibility Analysis.

The IM Plan must address:

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

(1) Identify the characteristics of the pipeline's design and operations and the environmental factors that are necessary to assess the applicable threats and risks to its gas distribution pipeline.
(2) Consider the information gained from past design, operations, and maintenance.
(3) Identify additional information needed and provide a plan for gaining that information over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities).
(4) Develop and implement a process by which the IM program will be reviewed periodically and refined and improved as needed.
(5) Provide for the capture and retention of data on any new pipeline installed. The data must include, at a minimum, the location where the new pipeline is installed and the material of which it is constructed.

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

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

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

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

(1) Develop and monitor performance measures from an established baseline to evaluate the effectiveness of its IM program. An operator must consider the

results of its performance monitoring in periodically re-evaluating the threats and risks. These performance measures must include the following:

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

(ii) Number of excavation damages;

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

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

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

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

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

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

### 1.1.2 Requirements for Master Meter Operators and Small LPG Operators

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

Section 192.1015 prescribes IM requirements applicable to these smaller operators. The major elements that these operators are required to include in their IM plans are the same as those in § 192.1007 applicable to other operators. The details of the elements are simplified somewhat, to reflect both the relative simplicity of these pipelines and the limited capability of the operators. For example, the required knowledge of their pipeline is focused on the approximate location and material of which it is constructed and required documentation of this knowledge is limited to documents showing the location and material of piping and appurtenances that are installed after the effective date of their IM programs and, to the extent known, in existence when the program becomes effective. These operators are not required to submit performance measures, which is consistent with their prior treatment with respect to annual reports. PHMSA is developing guidance suitable for use by master meter and small LPG operators to develop simple IM plans for their pipelines. This guidance will be made available via PHMSA's web site after this final rule is published.

The remainder of this report examines the benefits and costs of the regulatory changes are examined, as required by Executive Order 12866 and the Unfunded Mandates Reform Act. The final Regulatory Flexibility Analysis is filed separately in the docket.

## 2. BACKGROUND

The Nation's existing pipeline infrastructure, much of which is over 50 years old, requires regular safety and environmental reviews to ensure its reliability and integrity. To improve safety, PHMSA established Integrity Management requirements in years 2000 and 2002, for operators of hazardous liquid pipelines (49 CFR 195.452).

Subsequently, PHMSA issued IM program regulations for gas transmission pipelines in December 2003 (49 CFR Part 192, Subpart O). Both the hazardous liquid and gas transmission pipeline IM program regulations require operators to analyze risks and focus increased attention on safety, especially the portions of their pipeline that pose the highest risk. This increased attention must include physical inspection (assessment) of the pipe using in-line inspection, pressure testing, or direct assessment, remediation of anomalous conditions following the assessment, continual evaluation of the pipeline, application of additional preventive and mitigative measures, and development of performance measures.

Current IM program regulations, however, do not apply to gas distribution pipelines. Gas distribution pipelines deliver gas to residences and other end users and are different from hazardous liquid and gas transmission pipelines.

Distribution systems are composed of a grid of "mains" and "service lines." A main is a pipeline that serves as a common source of supply for multiple customers, often located under municipal streets that may be in heavily populated or congested areas. Service lines transport gas from the mains to the meters or customer-owned piping of residential, commercial, and industrial customers. Distribution pipelines can measure as large as 36 inches in diameter; however, most are much smaller, ranging in size from one-half inch service lines to 8 inches in diameter for some mains. These pipelines generally operate at lower pressures than the transmission pipelines and are owned and operated by local distribution companies. Distribution pipelines are constructed of a variety of materials, both metallic and non-metallic. Approximately half of the pipe in distribution systems is plastic. To reach the many end users they serve, distribution pipelines include extensive branching and interconnection, which is significantly different from the long, uninterrupted runs of transmission system pipe. These differences make it impractical to simply apply gas transmission integrity management requirements to distribution pipelines and instead necessitate integrity management program requirements tailored to distribution pipelines.

## 3. REGULATORY ANALYSIS

Executive Order 12866 directs all Federal agencies to consider the costs and benefits of "significant regulatory actions." Federal agencies are directed to develop a formal Regulatory Impact Analysis consistent with Office of Management and Budget (OMB) Circular A-4 for all "economically significant" rules, or those rules estimated to have an impact of $100 million or more in any one year. The Order also requires a determination as to whether a rule could adversely affect the economy in terms of productivity and employment, the environment, public health, safety, or State, local or tribal governments. This requirement applies to rulemakings that rescind or modify existing rules as well as to those that establish new requirements. The goal of the analysis is to provide decision makers with a clear indication of the most efficient alternative—that is, the alternative that generates the largest net benefits to society (ignoring distributional effects).

This regulatory analysis:

- Identifies the target problem, including a statement of the need for the action.
- Identifies available alternative approaches.
- Defines the baseline.
- Defines the scope and parameters of the analysis.
- Defines and evaluates the costs and benefits of the action and the main alternatives identified by the analysis.
- Compares the costs and benefits.
- Interprets the cost and benefit results.

## 4. IDENTIFICATION OF THE PROBLEM AND THE NEED FOR THE RULE

Although the gas distribution industry is subject to rate regulation, and the regulators act to reflect forces that otherwise would come from the market, the pipeline infrastructure is installed so that the local operator that delivers that product has somewhat of a natural monopoly.[3] Research on this specific industry has indicated that there are no robust market signals or incentives to prompt operators to thoroughly assess the condition of their pipelines or to implement integrity management programs. For example, the Government Accountability Office (GAO) has pointed out in a study of gas transmission operators[4] that the gas transmission integrity management program prompted some

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[3] See: http://www.naturalgas.org/business/industry.asp; http://www.naturalgas.org/naturalgas/distribution.asp; Fred Foldvary, The Progress Report. http://www.progress.org/fold74.htm.

[4] GAO, Gas Pipeline Safety, Preliminary Observations on the Integrity Management Program and 7-Year Reassessment Requirement, GOO-06-474T, Testimony Before the Subcommittee on Highways, Transit and Pipelines, Committee on Transportation and Infrastructure, U.S. House of Representatives. Statement

operators to make assessments of their pipelines for the first time. The market structure of the distribution industry may have led to distribution system operators spending less than the socially optimal amount of resources and attention to pipeline integrity.

Operators may also have inadequate information to assess the risks associated with gas distribution systems, because they may not have observed incidents involving death or serious injury in any given year (or decade, for that matter), and smaller operators are even less likely to see such incidents. Even though an incident in a particular pipeline is a low probability event, the risk is still inherent in the system itself, and consequences of an incident can be severe. Therefore, the aggregate safety impacts on a national basis justify more significant investment in risk management systems.

Recognizing these problems, PIPES Act mandates integrity management programs for distribution systems. Given this statutory mandate, the rest of this analysis seeks to identify the most efficient approach to integrity management. PHMSA considered other means of dealing with the problem before proposing new, comprehensive requirements. PHMSA has examined the feasibility of regulating at the State level. Currently gas pipeline operators are subject to differing State regulations. PHMSA has determined that the diversity in State-specific regulations dictates the need for Federal regulatory oversight. Each State's program must be certified, or subject to an agreement with PHMSA to act on its behalf, as a condition for Federal funding.

PHMSA has concluded that a better understanding on the part of operators of the risks posed by their pipeline systems, and a better focus of their actions to address the most significant of those risks is the most effective way to improve the Nation's already-commendable pipeline safety record. Consequently, PHMSA has been implementing integrity management requirements on various pipeline types as part of its program to improve pipeline safety. The historical record shows, however, that more adverse safety consequences result from accidents on distribution pipelines than from those on the pipelines already subject to IM program requirements. Based on PHMSA data from 2001 through 2008, 75 percent to 80 percent of all deaths and injuries occur on gas distribution systems. PHMSA data show that 11 percent of the incidents across all pipeline systems involve deaths or injuries, while the percentage for gas distribution pipelines during the same period is 24 percent and for transmission pipelines it is 3 percent. It is not possible to produce a significant improvement in pipeline safety without addressing distribution pipelines. Therefore, PHMSA has concluded that it is appropriate to establish IM program requirements that will foster a similar understanding of and focus on risk among distribution pipeline operators.

In 2004, the DOT Inspector General (IG) pointed out that recent accident trends for gas distribution pipelines were unfavorable and suggested the application of integrity management principles could help improve the safety of distribution pipelines. The IG acknowledged that the reason distribution pipeline operators were exempt from the

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of Katherine Siggerud, Director, Physical Infrastructure Issues, March 16, 2006. See: http://www.gao.gov/new.items/d06474t.pdf.

regulations was that distribution pipelines could not use the same inspection methods used for hazardous and transmission pipelines. Nevertheless, the IG concluded that there was no reason other elements of integrity management could not be implemented for distribution pipelines.

The IG recommended to Congress[5] that DOT 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 transmission pipeline IM plans. The Appropriations Committee then asked PHMSA "to report to the House and Senate Committees on Appropriations by May 1, 2005, detailing the extent to which integrity management program elements may be applied to the natural gas distribution pipeline industry in order to enhance distribution system safety."[6] PHMSA submitted the report "Assuring the Integrity of Gas Distribution Pipeline Systems" to Congress in June 2005, describing the program used to identify opportunities for improving the safety of distribution pipeline systems.

PHMSA developed the program in two phases. Phase 1 identified the nature of requirements that might be imposed and any additional guidance or consensus standards that might be needed to assist operators in implementing any integrity management requirements. Phase 2 included development of appropriate requirements by PHMSA and preparation of guidance/standards by appropriate bodies. During the development of Phase 1, PHMSA involved a large number of key stakeholder groups including State and Federal regulators, representatives from the spectrum of distribution operators, interested members of the public, and representatives of the Nation's fire service. The stakeholders agreed with the DOT IG and Congress's recommendations and concluded that it would be appropriate to modify the regulations to include a risk-based integrity management process for gas distribution pipelines.[7]

## 5. IDENTIFICATION OF AVAILABLE ALTERNATIVE APPROACHES

PHMSA considered several alternatives to assure the necessary protection from potential incidents caused by gas distribution pipelines, with the intention of selecting the alternative that is likely to result in the highest net benefits. PHMSA considered the following approaches:

- Apply existing gas transmission pipeline IM program regulations to gas distribution pipelines.
- Model State legislation by imposing requirements on excavators and others outside the regulatory jurisdiction of pipeline safety authorities.

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[5] "Progress and Challenges in Improving Pipeline Safety," Statement of the Honorable Kenneth M. Mead, Inspector General, Department of Transportation, before the Committee on Energy and Commerce, Subcommittee on Energy and Air Quality, U.S. House of Representatives, July 20, 2004.
[6] House of Representatives report 108-792, November 20, 2004.
[7] "Integrity Management for Gas Distribution, Report of Phase 1 Investigations," prepared by Joint Work/Study Groups, December 2005, U.S. DOT/PHMSA - Report: DIMP Phase 1, Doc. Number: RSPA-2004-19854-70, available at http://dmses.dot.gov/docimages/p84/388302.pdf.

- Develop guidance documents for adoption by States.
- Implement prescriptive Federal regulations, specifying in detail, actions that must be taken to assure distribution pipeline integrity.
- Implement risk-based, flexible, performance-oriented Federal regulations, establishing high-level elements that must be included in integrity management programs.

After considering all the alternatives, PHMSA selected the following alternative: implementation of risk-based, flexible, performance-oriented Federal regulations establishing high-level elements that must be included in integrity management programs.

### *5.1 Baseline: No Action*

This was used as the baseline against which PHMSA compared all other alternatives.

Regulatory analyses typically consider an alternative in which the agency would not take any action, because it would maintain the status quo. No new requirements would be levied. No costs would be incurred to implement new requirements. No new benefits would result.

In response to the mandate concerning IM programs for distribution systems contained in The Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (Public Law No: 109-468, Dec. 29, 2006), also known as the PIPES Act, PHMSA is initiating this rulemaking. PHMSA is extending 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 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 Integrity Management approach is designed to promote continuous improvement in pipeline safety by requiring all operators to identify and invest in risk control measures beyond core regulatory requirements existing today.

By not taking action, the Agency would be unresponsive to the congressional mandate in the PIPES Act, and there would likely be no reduction in the number of deaths, injuries, or property damages associated with risks related to the integrity management of distribution lines. Although this alternative would not lead to increased compliance costs, there would be no reduction in the societal costs associated with the deaths, injuries, and property damages associated with integrity management improvements. This alternative results in zero net benefits. Thus, this alternative is the baseline for comparison with other alternatives.

### 5.2 Apply existing gas transmission pipeline IM program regulations to gas distribution pipelines

This alternative was determined by PHMSA to be infeasible.

Gas distribution pipelines are different from hazardous liquid and gas transmission pipelines. Distribution systems combine main lines with an almost equal amount of mileage branching from the main lines to connect services to natural gas users. Lines are generally smaller in diameter, operate at much lower pressures, and are constructed of a variety of materials, both metallic and non-metallic. Approximately half of the pipe in distribution systems is plastic compared to very small amounts of plastic gas transmission pipeline. To reach the many end users they serve, distribution pipelines include extensive branching and interconnection compared to transmission systems that have long uninterrupted runs of pipe. These differences substantially distinguish distribution systems from transmission systems, and thus it is not technically feasible to apply gas transmission integrity management requirements to distribution pipelines. For instance, the low pressures, small diameters, and complex connections associated with distribution systems make it infeasible to use smart pigs or hydrotesting, techniques that are used by transmission lines for integrity management. Since a determination has been made that this alternative is not technically feasible to implement, there has been no attempt to estimate impacts. Consequently, no further consideration was given to this alternative.

### 5.3 Model State legislation, potentially imposing requirements on excavators and others outside the jurisdiction of pipeline safety authorities

This alternative was determined by PHMSA to be infeasible because PHMSA could not ensure that any or all of the States adopt the model State legislation.

According to the Integrity Management for Gas Distribution Report of Phase I Investigations, experience indicates that this option may not be practical for addressing the broad question of integrity management. The group references the failure of State legislatures to adopt an available model from the Common Ground effort to prevent excavation damage.[8]

In studying the issue, the study group found that model State legislation may be useful for narrower issues, such as improving excavation damage prevention through implementation of comprehensive damage prevention programs, including active enforcement.[9] The report concludes, "There are many factors affecting State approaches to regulation. It would be very unlikely that all States could adopt model legislation with sufficient consistency that would represent a national solution to integrity management concerns."

[8] The group was composed of representatives of the natural gas distribution industry, State pipeline regulatory authorities, and the public. Integrity Management for Gas Distribution: Report of Phase I Investigations," December 2005. Excavation Damage Group Report, p.71.
[9] Ibid. p.71.

After careful study, this option is not considered any further as a means of addressing the entire integrity management issue, because the integrity management study group found that the issues surrounding integrity management are broad and require a holistic approach at the Federal level. Not being operationally feasible, this alternative was not considered to be amenable to a comparison of the costs and benefits.

### *5.4 Guidance documents for adoption by States with the intent of States mandating use of the guidance*

As with the previous alternative, this alternative was determined by PHMSA to be infeasible because PHMSA could not ensure that any of the States would mandate the use of the guidance, therefore distribution safety would not improve.

The Integrity Management for Gas Distribution Report of Phase I Investigations determined that this option is essentially the same as option 5.3 above, except it contemplates States adopting the guidance as mandatory requirements. As with model legislation, the study group considered that adoption likely would not occur in many States. Although the Federal Government establishes basic safety standards, certified States are responsible for regulating intrastate pipelines. The study group notes that States typically have not uniformly adopted recommended approaches in the past. Selecting this option would thus provide only the illusion of a solution. The costs of such an approach would be relatively low, but if the conclusions of the study group are correct, there would also be low benefits and perhaps, insignificant net benefits. For these reasons, this alternative was not considered any further.

### *5.5 Prescriptive Federal regulation, specifying in detail actions that must be taken to assure distribution pipeline integrity*

This alternative was determined by PHMSA to be too inflexible to be applicable to all relevant situations that distribution system operators might confront.

The Integrity Management for Gas Distribution Report of Phase I Investigations reaffirms the need for a flexible Federal rule. The study group reasoned that a highly detailed prescriptive regulation would eliminate the flexibility needed to address the unique circumstances of individual States and operators. The study group reported, "The issues important to assuring the integrity of these diverse systems will vary. This diversity makes it difficult for any one prescriptive requirement to address all possible circumstances. It is important that any new requirements that are developed allow sufficient flexibility for the operators of distribution pipeline systems, and the State regulators who oversee their operations, to customize their integrity management efforts to address their specific systems, threats, and issues."[10]

Although some small operators might prefer a prescriptive regulation, most large operators want the flexibility of a performance-based regulation. The wide range in size and nature of distribution pipeline systems calls for a flexible approach to integrity

[10] Integrity Management for Gas Distribution. Report of Phase I Investigations. December 2005, p.13-14.

management rather than a single detailed set of requirements. Giving operators the guidance and allowing them to shape it to fit their particular system will assure integrity management efficiently and effectively. A detailed prescriptive rule was deemed by PHMSA to be too inflexible to be applicable to all relevant situations that distribution operators might face, since there is a wide spectrum of distribution operators, from master meter (mostly one-man operation) to large utilities covering thousands of miles of pipelines and over a million customers. Thus a prescriptive rule would be inappropriate and ineffective, resulting in many operators being required to perform tasks not appropriate for their pipeline systems.[11] These statements of the rule being ineffective and inappropriate suggest that there would likely be a low level of net benefits. For these reasons a prescriptive Federal regulation was evaluated no further.

### *5.6 Risk-based, flexible, performance-oriented Federal regulation, establishing high-level elements that must be included in integrity management programs*

This alternative was determined by PHMSA to be practicable and is compared in this document with the baseline "no action" alternative. As will be demonstrated, there are significant net benefits associated with this alternative.

This alternative, that is the subject of the rule, creates a high-level, flexible, and performance-based Federal regulation that requires gas distribution operators to develop and implement an integrity management program for their distribution pipeline systems. The regulation requires all operators of a distribution pipeline system to implement an integrity management program and would prescribe minimum requirements each operator must meet in doing so. An integrity management program is intended to manage the risks associated with an operator's pipeline system.

An integrity management plan would address, at a minimum, the following elements:

- Develop an understanding of their system, periodically reviewing and refining it as needed.
- Identify threats (existing and potential).
- Evaluate and rank risks.
- Identify and implement measures to mitigate risks.
- Measure performance, monitor results, and evaluate effectiveness.
- Periodically re-evaluate risks and consider the relevance of threats.
- Report results.

This also embraces the installation of EFVs. An operator would be required to install an EFV on newly installed or replaced service lines that operate continuously throughout the year at a pressure not less than 10 psig and serve a single-family residence, unless doing so would not be practicable. This requirement applies only to new or replaced service

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[11] Integrity Management for Gas Distribution: Report of Phase I Investigations," December 2005. Excavation Damage Group Report, p.72.

lines. There is no requirement for an operator to install an EFV retroactively on an existing service. The PIPES Act of 2006 mandated this requirement.

The requirement on EFVs is intended to replace the notification requirements in 49 CFR 192.383, which requires operators to notify the customer for new and replaced service lines about the availability and benefits derived for installing an EFV. There will be no need for the customer notification requirement if the rule goes into effect.

Federal pipeline safety law requires that States adopt requirements at least as stringent as those established by PHMSA to maintain their certification to exercise regulatory jurisdiction over intrastate pipeline safety. This alternative establishes basic requirements, while providing States the flexibility to accommodate the unique needs of different geographical areas and different communities of operators. Furthermore, the alternative does this while assuring that a Federal rule, which provides for a consistent approach to distribution integrity management, is implemented. For the reasons stated above, this alternative was selected.

## 6. INDUSTRY INFORMATION

The gas distribution industry is diverse, composed of some very small operators, such as master meter operators, serving only a few customers; medium-sized operators, the majority of which are municipal agencies, serving between 100 and 10,000 diverse customers; and large pipeline systems. In areas where gas service has been available for many years, there are thousands of miles of pipeline of various materials and ages. Newer systems can be more uniform, consisting of one or a few types of pipe with similar fittings and connections installed using uniform procedures.

### *6.1 Impacted Operators and Mileage*

The regulatory changes will apply to all operators of gas distribution systems, including master meter and LPG systems regulated under 49 CFR Part 192. Master meter and small LPG system operators, however, will be subject to a slightly simplified version of the requirements.

For this analysis, gas distribution systems will be divided into three categories:

(1) Gas distribution systems with over 12,000 services that are operated by local gas distribution companies or municipalities (i.e., local gas utilities).
(2) Gas distribution systems with 12,000 or fewer services that are operated by local gas utilities, and large LPG operators.
(3) Master meter and small LPG systems.

Each category will be affected somewhat differently by the rule. In particular, the costs that each of the operators in each category will face are expected to be different.

The first category covers the largest local gas utilities impacted by the rule. Industry sources report that, for management and operational purposes, local gas utilities begin to break their systems into districts when they have more than 12,000 services. As of 2004, there were approximately 201 operators in this category.

The second category covers the smaller local gas utilities impacted by the rule. This category does not include the master meter and small LPG systems impacted by the rule, since local gas utilities do not generally operate these systems. There were approximately 1,090 gas distribution operators in this category and approximately 52 large LPG operators.

The third category covers the master meter and small LPG operators impacted by the rule. These are generally very small gas distribution systems. The number of these systems is unknown, but, for this analysis, PHMSA estimates that approximately 8,000 of these systems would be impacted by the rule. This estimate is based on reports to PHMSA in 2004 from (1) 45 State pipeline safety agencies indicating that, collectively, 6,972 master meter systems were operating in their States, and (2) FEDSTAR data has information on 1,028 LPG operators and, of those, 52 LPG operators may be considered "large LPG operators" for the purposes of this evaluation. Because identifying master meter systems is often difficult and because some State pipeline safety regulators do not have jurisdiction over all master meter systems in their States, it is likely that the number of master meter systems reported by the States actually understates the number currently subject to Federal pipeline safety regulation.

Table 1 presents the numbers of systems, distribution main mileage, and services that will be used in this analysis. The numbers for the large and small local distribution systems are based on the situation in 2004. The estimated number of master meter and LPG systems is discussed above. The estimate for master meter and LPG distribution main mileage assumes that each operator has, on average, one mile of distribution mains.

**TABLE 1 NUMBER OF SYSTEMS, DISTRIBUTION MAIN MILEAGE, AND NUMBER OF SERVICES IMPACTED BY THE DIMP REQUIREMENTS**

| Characteristic | Number |
|---|---|
| ***Large Local Distribution Systems*** | |
| Number of systems | 201 |
| Distribution main mileage | 1,010,000 miles |
| Number of services | 54,900,000 |
| ***Small Local Distribution Systems and Large LPG Systems*** | |
| Number of systems | 1,142 |
| Distribution main mileage | 120,000 miles |
| Number of services | 5,270,000 |
| ***Master Meter and Small LPG Systems*** | |
| Estimated number of systems | 8,000 |
| Distribution main mileage | 8,000 miles |
| Number of services | 800,000 |
| ***Total*** | |
| Estimated number of systems | 9,343 |
| Distribution main mileage | 1,138,000 miles |
| Number of services | 60,970,000 |

Sources: Large and small local distribution systems—2004 data submitted to PHMSA; Master meter and LPG systems—PHMSA estimate of number of systems based on information from State pipeline safety agencies submitted to PHMSA in 2004 and PHMSA FEDSTAR data. For this analysis, PHMSA assumes that every master meter and LPG system has, on average, one mile of distribution main and 100 services.

As Table 1 indicates, PHMSA expects the rule to impact 9,343 operators with a combined total of 1,138,000 miles of distribution mains and 60,970,000 services. Furthermore, assuming that each service is, on average, 65 feet in length,[12] the total pipeline mileage impacted by the rule would be 1,888,578 (1,138,000 + (60,970,000 * 65) / 5280 feet per mile).

## 7. DEFINITION AND EVALUATION OF THE BENEFITS AND COSTS

The impact of the regulatory change consists of the benefits and costs attributable to that change. Table 2 presents a list of the benefits and costs considered in this analysis.[13]

[12] This is the current estimate used by PHMSA for the length of a service.
[13] All monetary values, unless otherwise indicated, are in 2008 constant dollars.

**TABLE 2 BENEFITS AND COSTS CONSIDERED IN THIS ANALYSIS**

| Benefits | Costs |
|---|---|
| • Reductions in the consequences of reportable incidents[14]<br>• Reductions in the consequences of non-reportable incidents<br>• A reduction in the probability of a major catastrophic incident<br>• Reductions in lost natural gas<br>• Reductions in emergency response costs<br>• Reductions in evacuations<br>• Reductions in dig-ins impacting non-gas underground facilities<br>• The end of the existing EFV notification requirement | • Development of an IM program<br>• Implementation of the IM program (data acquisition and analysis)<br>• Mitigation of risks (leak management, damage prevention, excess flow valve installation and other)<br>• Reporting to PHMSA and State Regulators<br>• Recordkeeping<br>• Management of the IM program |

### *7.1 Benefits*

The rule mandates the design and implementation of integrity management programs on natural gas distribution systems. Integrity management programs are designed to proactively address problems related to corrosion, damage by outside forces, pipeline defects, and pipeline equipment and operations. The benefits resulting from the rule are expected to result from the correction of problems that could cause pipeline failures before those failures occur, thereby averting pipeline accidents and any deaths, injuries, and property damages related to those accidents.

Pipeline breaks can result in explosions and fires that can impact human health and safety. The consequences of natural gas distribution system accidents include deaths, injuries, and property damage. Recent examples of distribution pipeline incidents include the following: On December 13, 2005, at 9:26 a.m., an apartment building exploded in Bergenfield, New Jersey, after natural gas migrated into the building from a damaged pipeline. Investigators found a break in an underground 1 1/4-inch steel natural gas distribution service line that was operating at 11 1/2 pounds psig. There were three fatalities and five injuries. Damage was estimated at $863,300. On August 21, 2004, a natural gas explosion destroyed a residence in DuBois, Pennsylvania. A leaking butt-

[14] See Title 49, Code of Federal Regulations, Part 191. §191.3 defines a reportable incident as: (1) An event that involves the release of gas from a pipeline or of liquefied natural gas or gas from an LNG facility and (i) A death, or personal injury necessitating in patient hospitalization; or (ii) estimated property damage, including the cost of gas lost, of the operator or others, or both, of $50,000 or more. (2) An event that results in an emergency shutdown of an LNG facility. (3) An event that is significant, in the judgment of the operator, even though it did not meet the criteria of paragraphs (1) or (2).

fusion joint in a 2-inch-diameter plastic main line pipe was the cause of the accident. Two residents were killed in this accident. Property damage was estimated at $800,000.[15]

To run a safe pipeline, operators must have adequate information, the ability to anticipate problems, and the means to ensure the pipeline integrity. Positive benefits are expected from the rule. Reduced numbers of deaths and injuries and reduced property damage are expected to be important benefits of the rule.

The rule is expected to reduce the frequency of future accidents through identification and remediation of problems before those problems can result in accidents. The rule will not eliminate all gas distribution system accidents. Estimates will need to be developed for the proportion expected to be eliminated, and where that is not practicable, assumptions will need to be made. In some cases, it will not be possible to quantify the benefits. In those cases, a qualitative discussion of the benefits will be presented.

In the preliminary regulatory evaluation for the proposed rule, for most of the requirements of the rule that addressed reductions in deaths, injuries, and property damages, it was assumed that there would be a 50 percent reduction in the societal costs associated with gas distribution pipeline incidents. At the time that this assumption was made, it was based merely on professional judgment. Since that time there are data available on incidents associated with onshore gas transmission pipelines that are subject to the integrity management rules that became effective in 2004. While a 5-year period may be too short to demonstrate fully the benefits of the integrity management rule for transmission pipelines, there may still be some preliminary insight offered as to what may be expected from a similar rule for distribution pipelines.

The average number of annual fatalities associated with onshore transmission pipelines from 1989 to 2003, inclusive, was 2.13. The average number of fatalities for 2004 through 2008 was 1, a reduction of about 53 percent. Average annual injuries for 1989 to 2003 were 10.3 and 4.6 for 2004-2008, a reduction of 55 percent.[16] There are some caveats with this observation. The first assessment in gas transmission began in 2003, but mostly in 2004. It took some time after assessments for operators to make repairs. Secondly, gas transmission IM rules required that initial assessments be focused on "weaker" pipe. The gas distribution integrity management rule does not include a requirement to perform assessments similar to those required of gas transmission, but will result in more patrolling, leak inspections, improved damage prevention and mitigation through excess flow valves.

A similar analysis for gas distribution pipelines, for which there are no integrity management rules in place, comparing the 1989-2003 period with the 2004-2008 period

[15] NTSB reports. See http://www.ntsb.gov/publictn/2007/PAB0701.htm.
[16] Source for transmission pipelines and the distribution pipelines in the next paragraph is PHMSA Significant Incident Files, July 14, 2009.
http://primis.phmsa.dot.gov/comm/reports/safety/PSI.html?nocache=2985.

shows a 23 percent decline in fatalities and a 42 percent decline in injuries. If the two pipeline systems were similar in risks presented and the management integrity rules were comparable in effectiveness, it could be speculated that the integrity rule for transmission pipelines was responsible for the 30 percentage point difference in fatality rate reduction (53 percent – 23 percent) and the 13 percent difference in the injury rate reduction (55 percent – 42 percent). These time period comparisons do not take into consideration trends in incidents and are intended to establish a basis for a lower estimate of effectiveness of the rule. An average of the differences in the rates derived above is 21.5 ([30+13]/2) percent; this analysis will use 20 percent for a lower range to estimate possible benefits.

This rule will benefit operators in many ways. Each of these benefits is addressed below.

### 7.1.1 <u>Benefits Resulting from a Reduction in the Consequences of Reportable Incidents</u>

From 2001 through 2005, PHMSA received reports on 711 natural gas distribution system incidents. Those incidents resulted in 58 deaths, 227 injuries requiring hospitalization, and approximately $594 million in property damage (in nominal, not constant dollars). The breakdown of incidents and consequences by year for 2001 through 2005, along with the estimated pipeline mileage for those years, is presented in Table 3.

**TABLE 3 REPORTED DISTRIBUTION SYSTEM INCIDENTS, 2001-2005**[17]

| Year | Incidents | Deaths | Injuries | Property Damage (Nominal Dollars) | Estimated Pipeline Miles (Mains plus Services) |
|---|---|---|---|---|---|
| 2001 | 124 | 5 | 46 | $14,071,486 | 1,837,277 |
| 2002 | 102 | 10 | 44 | $23,804,202 | 1,855,319 |
| 2003 | 141 | 11 | 58 | $21,032,408 | 1,865,679 |
| 2004 | 174 | 18 | 41 | $37,507,950 | 1,918,270 |
| 2005 | 170 | 14 | 38 | $497,696,278 | 1,823,136 |

Most of the $498 million (nominal dollars) in property damage for 2005 is attributable to the devastation caused by Hurricane Katrina. It should be noted that Table 3 does not include information attributable to incidents on master meter systems, since these operators are not required to report their incidents to PHMSA.[18] However, based on a 2002 DOT Report to Congress, from 1995 to 1999, there were two master meter system incidents, which resulted in two injuries and $200,000 in property damages. One incident resulted from corrosion and the other from construction/operation error.[19]

[17] Source: http://ops.dot.gov/stats/stats.htm.
[18] See 49 CFR 191.9.
[19] Assessment of the Need for an Improved Inspection Program for Master Meter Systems, A Report of the Secretary of Transportation to the Congress, prepared pursuant to Section 108 of Public Law 100-561, p.17.

**Benefits Resulting from Reportable Non-Excavation Incidents**

From 2001 through 2008, PHMSA received reports on 371 non-excavation incidents per million miles occurring on natural gas distribution systems. Those incidents resulted in 35 deaths, 125 injuries requiring hospitalization, and approximately $325 million in property damage (in nominal, not constant dollars). The breakdown of incidents and consequences by year for 2001 through 2008 is presented in Table 4.

**TABLE 4 REPORTED NON-EXCAVATION INCIDENTS ON GAS DISTRIBUTION SYSTEMS, 2001-2005[20]**

| Year | Number of Non-Excavation Gas Distribution Incidents Per Million Miles | Number of Non-Excavation Gas Distribution Deaths Per Million Miles | Number of Non-Excavation Gas Distribution Injuries Per Million Miles | Property Damage of Non-Excavation Gas Distribution Incidents Per Million Miles (Nominal Dollars) |
|---|---|---|---|---|
| 2001 | 32 | 1 | 15 | $3,800,158 |
| 2002 | 34 | 4 | 19 | $7,101,267 |
| 2003 | 36 | 4 | 11 | $5,621,362 |
| 2004 | 59 | 9 | 18 | $13,813,667 |
| 2005 | 54 | 5 | 16 | $251,678,757 |
| 2006 | 49 | 7 | 8 | $8,865,167 |
| 2007 | 49 | 3 | 14 | $9,370,111 |
| 2008 | 58 | 2 | 24 | $24,779,690 |
| Total | 371 | 35 | 125 | $325,030,179.00 |

Based on the information in Table 4, from 2001 through 2008, gas distribution systems experienced the following due to non-excavation incidents:

- 46 incidents per million miles per year.
- 4 deaths per million miles per year.
- 16 injuries requiring hospitalization per million miles per year.
- $40,628,772 *(in nominal dollars)* of property damage per million miles per year.

In order to develop an estimate of the expected benefits of this rule, PHMSA makes two adjustments to the raw expected values of deaths, injuries, and property damage based on results from 2001-2008. The first such adjustment is explained here, and serves to lower the expected value of damages: because of the devastation attributable to Hurricane Katrina, the property damage in 2005 was at least an order of magnitude greater than the property damage in any year from 1986 through 2004. As a consequence, PHMSA

[20] Source: http://ops.dot.gov/stats/stats.htm.

considers the property damage in 2005 to be an extreme outlier that is unlikely to reoccur in the near future. Furthermore, the focus of this analysis is integrity management, and PHMSA notes that integrity management is unlikely to have much impact on incidents resulting from extreme hurricane damage.

The property damage from 2001 through 2004 would appear to be more representative of the property damage generally experienced by gas distribution systems in recent years. From 2001 through 2004, PHMSA estimates that gas distribution systems experienced:

- $8,356,808 in property damage per million miles per year.

For this analysis, PHMSA assumes that incident consequences in the future will mirror those of the recent past (although due to the short duration of the consequences measured here, PHMSA makes an adjustment to this assumption in the section below). Specifically, with the exception of property damage, PHMSA assumes that the average figures developed from Table 4 for 2001 through 2008 will be representative of the future for non-excavation incidents. For property damage, PHMSA assumes that the average figure developed from Table 4 for 2001 through 2008 will be representative of the future for those incidents.

The Department of Transportation currently makes the following assumptions concerning the value of a statistical life and the value of an injury requiring hospitalization:

- The value of a statistical life is $5,800,000.[21]
- Injuries requiring hospitalization are valued at $562,500.

Multiplying the values for a statistical life and injuries requiring hospitalization by PHMSA's estimates for deaths and injuries puts those estimates into monetary terms. Multiplying those results, as well as the estimate for property damage, by the total mileage for the impacted pipeline yields estimates of the expected annual cost to society attributable to the deaths, injuries, and property damage resulting from non-excavation incidents on gas distribution systems.

Assuming the total impacted pipeline mileage is 1,888,578 miles, the expected annual cost to society attributable to deaths resulting from non-excavation incidents on gas distribution systems would be $44,080,000 (4 deaths per million miles per year * 1.9 million pipeline miles * $5,800,000); the expected annual cost to society attributable to injuries requiring hospitalization resulting from gas distribution system incidents would be $17,100,000 (16 injuries per million miles per year * 1.9 million pipeline miles * $562,500); and the expected annual costs to society attributable to reported property damage resulting from gas distribution system incidents would be $15,877,935

[21] On February 5, 2008, the Department issued a memorandum on the "Treatment of the Economic Value of a Statistical Life in the Departmental Analyses" directing DOT analysts to use $5.8 million as the best present estimate of the economic value of preventing human fatality. However, the Department requested a supplementary analysis be conducted using values of $3.2 million and $8.4 million for each life saved. The supplementary analysis is at the Appendix.

($8,356,808 per million miles per year * 1.9 million pipeline miles). In total, the expected annual cost to society attributable to deaths, serious injuries, and property damage resulting from non-excavation incidents on gas distribution systems reported to PHMSA would be $77,057,935 ($44,080,000 + $17,100,000 + $15,877,935).

The reported deaths, serious injuries, and property damage that the rule would prevent is unknown. The integrity management requirements for liquid pipelines and for gas transmission lines are not sufficiently similar to the requirements for it to be reasonably expected that the reductions they experienced would be similar to those that distribution systems might experience. Furthermore, the integrity management activities of those pipelines have not been ongoing for long enough to ensure that the full benefits of those activities are now being achieved. Finally, it would be difficult to separate out those benefits from the benefits attributable to other regulatory actions undertaken by PHMSA. PHMSA expects the impact of the integrity management activities contained in the rule to be significant. For this analysis, PHMSA assumes that the rule would prevent 20 to 50 percent of the reported deaths, serious injuries, and property damage, or $15,411,587 ($77,057,935 * .20) to $38,528,968 ($77,057,935 * .50), associated with reportable non-excavation incidents annually.

**Benefits Resulting from Reducing Reportable Excavation Incidents**

From 2001 through 2005, PHMSA received reports on 302 excavation incidents occurring on natural gas distribution systems. Those incidents resulted in 12 deaths, 78 injuries requiring hospitalization, and approximately $47 million in property damage (in nominal, not constant dollars). The breakdown of incidents and consequences by year for 2001 through 2005, along with the estimated pipeline mileage for those years, is presented in Table 5.

**TABLE 5 REPORTED EXCAVATION INCIDENTS ON GAS DISTRIBUTION SYSTEMS, 2001-2005[22]**

| Year | Incidents | Deaths | Injuries | Property Damage (Nominal Dollars) | Estimated Pipeline Miles (Mains plus Services) |
|---|---|---|---|---|---|
| 2001 | 65 | 3 | 19 | $7,149,371 | 1,837,277 |
| 2002 | 37 | 2 | 8 | $9,665,702 | 1,855,319 |
| 2003 | 73 | 4 | 37 | $10,543,725 | 1,865,679 |
| 2004 | 61 | 1 | 6 | $10,964,721 | 1,918,270 |
| 2005 | 66 | 2 | 8 | $8,782,981 | 1,823,136 |

Based on the information in Table 5, from 2001 through 2005, gas distribution systems experienced the following consequences due to excavation incidents:

[22] Source: http://ops.dot.gov/stats/stats.htm.

- 32.4 incidents per million miles per year.
- 1.3 deaths per million miles per year.
- 8.4 injuries requiring hospitalization per million miles per year.
- $5,460,750 (2006 dollars) of property damage per million miles per year.

For this analysis, PHMSA assumes that future incident consequences will mirror those of the recent past. Specifically, PHMSA assumes that the average figures developed from Table 5 for 2001 through 2005 will be representative of the future for excavation-related incidents.

Multiplying the values for a statistical life and injuries requiring hospitalization that were presented earlier by PHMSA's estimates for deaths and injuries puts those estimates into monetary terms. Multiplying those results, as well as the estimate for property damage, by the total mileage for the impacted pipeline yields estimates of the expected annual cost to society attributable to the deaths, injuries, and property damage resulting from excavation incidents on gas distribution systems.

Assuming the total impacted pipeline mileage is 1,888,578 miles, the expected annual cost to society attributable to deaths resulting from excavation incidents on gas distribution systems would be $14,326,000 (1.3 deaths per million miles per year * 1.9 million pipeline miles * $5,800,000); the expected annual cost to society attributable to injuries requiring hospitalization resulting from gas distribution system incidents would be $8,977,500 (8.4 injuries per million miles per year * 1.9 million pipeline miles * $562,500); and the expected annual costs to society attributable to reported property damage resulting from gas distribution system incidents would be $10,375,425 ($5,460,750 per million miles per year * 1.9 million pipeline miles). In total, the expected annual cost to society attributable to deaths, serious injuries, and property damage resulting from excavation incidents on gas distribution systems reported to PHMSA would be $33,678,925 ($14,326,000 + $8,977,500 + $10,375,425).

For this analysis, PHMSA assumes that the actions included in the rule will prevent 20 to 50 percent of the reported deaths, serious injuries, and property damage associated with reportable excavation incidents. PHMSA estimates that the annual benefits attributable to that reduction in consequences for reportable excavation incidents would be approximately $6,735,785 ($33,678,925 * .2) to $16,839,463 ($33,678,925 * 0.5).

PHMSA assumes that half of the reduction in consequences for reportable incidents would result from the EFV requirements or annual benefits of $3,367,893 ($16,839,643 * .2) to $8,419,731 ($16,839,643 * 0.5).

**Total Benefits Resulting from Reportable Incidents**

The total benefits resulting from reportable incidents attributable to the rule would range from $18,779,480 to $46,948,699 per year, which is the sum of the benefits attributable to reportable non-excavation incidents, $15,411,587 to $38,528,968 per year, plus the annual benefits attributable to the EFV requirements, $3,367,893 to $8,419,731.

### 7.1.2 Benefits Resulting from a Reduction in the Consequences of Non-Reportable Incidents

The rule is expected to impact not only the number of reportable incidents and their consequences, but also the number of non-reportable incidents and their consequences, as well. The impact of the regulatory changes on non-reportable incidents is unknown and must be estimated. To do this, it is necessary to estimate (1) the total number of federally non-reportable incidents, (2) the average cost of those incidents, and (3) the proportion or percentage of the federally non-reportable incidents that would be impacted by the rule.

**Estimate for the Total Number of Federally Non-Reportable Incidents**

PHMSA uses reports from the California Public Utility Commission as a proxy to estimate the non-reportable incidents for the entire country to evaluate the benefits of the regulation based on the number of incidents that would be expected.[23]

Section 122.2(d) of the California Public Utility Commission's General Order 112-E requires that pipeline operators submit quarterly reports to the Commission, and that those reports include information on:

- The gas leak incidents for which a telephonic report, a letter of explanation, or a DOT Form RSPA 7100.1 or 7100.2 was submitted.
- The gas leak incidents that involved escaping gas from an operator's facilities and property damage, including loss of gas, in excess of $1,000.
- All gas leak incidents that had property damage of between $0 and $1,000 involving fires, explosions, or excavation damage.

Table 6 presents the numbers of federally non-reportable gas distribution system incidents and their costs for 1998 through 2005 that were reported to the California Public Utility Commission under Section 122.2(d) of General Order 112-E.[24]

[23] According to the Texas Railroad Commission, 13 of the 305 distribution pipeline incidents reported in 2006 were reportable to DOT. This suggests that some States may have higher reporting thresholds than California. Using the higher reporting threshold, the average benefit of eliminating each non-reportable incident would be higher. Thus in this case the benefits may be understated. See: http://www.rrc.state.tx.us/data/pipeline.php.

[24] General Order 112-E Rule 122.2 d requires utilities to submit quarterly reports to the Commission of all gas leaks that involved loss of gas or property damage in excess of $1,000, involving fire, explosion, or underground dig-ins.

**TABLE 6 NON-REPORTABLE INCIDENTS IN CALIFORNIA, 1998-2005**

| Year | Number of Incidents | Aggregate Cost of Incidents – Loss of Gas and Property Damage (Nominal dollars) |
|---|---|---|
| 1998 | 6,276 | $3,003,388 |
| 1999 | 16,168 | $5,314,328 |
| 2000 | 15,537 | $6,093,456 |
| 2001 | 11,672 | $3,585,534 |
| 2002 | 9,344 | $2,667,416 |
| 2003 | 7,157 | $2,054,593 |
| 2004 | 9,293 | $2,229,366 |
| 2005 | 7,243 | $1,226,032 |
| **TOTAL** | **82,690** | **$26,174,113** |

Source: Communication from the California Public Utility Commission, April 4, 2007.

Data related to federally reportable incidents is excluded from the numbers presented in Table 6.

From 1998 through 2005, California gas distribution systems reported 73 incidents to PHMSA. This means that, for every incident reported to PHMSA, approximately 1,133 (82,690 / 73) non-reportable incidents occurred.

Of the 73 California gas distribution system incidents reported to PHMSA, 43 were caused by excavation damage. Thus, the proportion of reportable incidents caused by excavation damage was 43/73. Assuming the proportion of non-reportable incidents caused by excavation damage is the same, approximately 668 (1,133 * 43/73) of the 1,133 incidents were caused by excavation damage. Furthermore, approximately 465 (1,133 - 668) of the 1,133 non-reportable incidents were not caused by excavation damage.

Based on the information in Table 3, the average number of reportable gas distribution system incidents that occurred from 2001 through 2005 was 142 ((124 + 102 + 141 + 174 + 170)/5). Multiplying this figure by those for non-reportable incidents per reportable incident yields estimates of the numbers of non-reportable incidents that might be expected annually in the United States in the future. Those estimates are (1) 66,030 (142 * 465) non-reportable incidents not involving excavation damage, and (2) 94,856 (142 * 668) non-reportable incidents involving excavation damage. In total, there will be an estimated 160,886 (142 * 1,133) non-reportable incidents expected annually. These estimates do not include all non-reportable incidents that might occur, it must be recognized, but they do include those with the highest costs.

**The Average Cost of Non-Reportable Incidents**

As Table 6 indicates, the 82,690 federally non-reportable incidents reported to the State of California from 1998 through 2005 by gas distribution systems had a total cost of $26,174,113 (nominal). This is $317 (nominal) per incident ($26,174,113 / 82,690). Converted to 2006 dollars, the cost becomes $361 per incident.

Based on California's non-reportable information, PHMSA assumes that the average cost of federally non-reportable incidents is $350. [25]

**The Proportion of Federally Non-Reportable Incidents Impacted by the Rule**

The provisions included in the rule cannot be expected to end all non-reportable incidents. The proportion that it will end is unknown. PHMSA assumes the provisions will reduce the consequences of non-reportable incidents by 50 percent, although it may have a lower effectiveness than reportable incidents.

**Impact of the Rule on Federally Non-Reportable Incidents**

The rule is expected to result in an annual reduction of $4,622,110 ($350 * $66,030 * .2) to $11,555,250 ($350 * 66,030 * 0.5) in the costs of non-reportable incidents not involving excavation damage. Also, the rule is expected to result in an annual reduction of $3,319,960 ($350 * 94,856 * .2 * .5) to $8,299,900 ($350 * 94,856 * 0.5 * 0.5) in the costs of non-reportable incidents involving excavation damage due to its EFV provisions. In total, the rule is expected to reduce the annual costs of non-reportable incidents by $7,942,070 ($4,622,110 + $3,319,960) to $19,855,150 ($11,555,250 + $8,299,900).

### 7.1.3 Benefits of Avoiding an Accident with Low Probability and High Consequences

PHMSA made an adjustment to the expected value of property damage occurring from 2001 through 2005, since some of the property damage was caused by Hurricane Katrina in 2005 (an outlier), which skewed the damages above expectations and which this rule was not designed to mitigate. A more accurate expected value of benefits, perhaps reflective of a longer timeline and taking into account risks and consequences not experienced from 2001 through 2005, would show a higher expected benefit of this rule.[26] It is possible for high-consequence accidents to occur, in which there are a

[25] Using average real estate prices to compare property values, we can say that property values in California tend to be comparable to property values in various States, including Montana, Colorado, New York, Pennsylvania, Massachusetts, Connecticut, and New Jersey. Property values are estimated at $450,000 and over in these States. Property values tend to be lowest in Indiana, Ohio, North Dakota, and Iowa. The average home prices in the U.S. in October 2009, ranged between $199,000 to over $450,000. See: http://www.trulia.com/home_prices/. Using an average of $350 may overstate the benefits in some States.
[26] This assumption rests at least partly on a hypothesis that even if the short historical time series accurately reflects the expected probability of pipeline incidents, and even if that probability were expected to be normally distributed, the expected consequences of an event may not be normally distributed. In cases such as this, rare and extreme events would drive expected damages to a greater degree than their historical

disproportionately large number of casualties (i.e., deaths and serious injuries), since a portion of gas distribution piping is located in densely populated areas with schools and businesses containing a large number of people.

For example, the largest accident that has occurred in U.S. distribution pipeline history occurred on November 21, 1996, in San Juan, Puerto Rico. A leak from an LPG line resulted in an explosion in a commercial building that killed 33 people and injured at least 69.[27] There is some disagreement as to whether the pipeline leak was a proximate cause or whether there was first a fire that then ignited the leaking propane. Nevertheless, this accident demonstrates that high-consequence events can occur as a result of gas line leaks.

To estimate the benefits derived from avoiding the consequences of high-consequence events, since that type of event clearly would fall outside most 4- to 5-year time periods and was not reflected in the baseline data, international data were used.[28] A study completed recently by the Paul Scherer Institute (PSI) in Switzerland can be used as an indicator of the potential likelihood of a severe consequence of an event in the United States.[29] PSI's study was part of a comprehensive study of the safety of different energy systems. Although PSI concluded that natural gas has been demonstrably safer than other forms of energy, considering both transportation and use, it found that high-consequence accidents have occurred.

An accident occurred in Corlu, Turkey on August 9, 1992, in which 32 people were killed and 64 injured. The largest number of fatalities experienced as a result of a natural gas accident was found to have occurred in a 1995 accident in Taegu, Korea, in which 109 people were killed. Over the period analyzed (1969-2000), PSI found that 129 accidents occurred worldwide in which 5 or more persons were killed, resulting in 1,971 fatalities. During this period, 3 accidents involving more than 50 fatalities occurred within the countries comprising the Organization for Economic Cooperation and Development (OECD, which includes the United States).[30] Six such accidents occurred in non-OECD countries.

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averages suggest. This addition to the analysis is intended to capture the influence of a rare, extreme event on future expected impacts.

[27] NTSB Report Number PAR-97/01.

[28]PHMSA is confident that this study is applicable for estimating benefits derived from consequences of high-consequence events. The framework for this study encompassed an experience-based comparison of risk of accidents associated with the energy sector, with special emphasis on the natural gas chain. The analyses focus on accidents that resulted in at least five fatalities. For completeness and accuracy, the researchers noted that data concerning fatalities were superior to coverage of other types of consequences. The data used in this analysis includes information on the incidents reported worldwide. The databases (with more than 5 fatalities) used in the analyses are from the United States, Great Britain, Netherlands, Switzerland, Austria, Germany, Finland, and Italy. See: http://gabe.web.psi.ch/pdfs/PSI_Report/SVGW_PSI-Bericht-05-01.pdf. p. 12.

[29] Peter Burgherr and Stefan Hirschberg, Comparative Assessment of Natural Gas Accident Risks, PSI Bericht Nr. 05-01, January 2005, available at http://gabe.web.psi.ch/pdfs/PSI_Report/SVGW_PSI-Bericht-05-01.pdf.

[30] The number of energy-related accidents exhibited a distinct increase since the late 1960s. See: http://gabe.web.psi.ch/pdfs/PSI_Report/SVGW_PSI-Bericht-05-01.pdf, p. 15. PHMSA data shows that

The PSI study considered the frequency of accidents with different numbers of consequences in order to develop an estimate of the probability of large-consequence accidents. The data were normalized to allow comparison of data from different countries. The basis for normalization was the electric energy equivalent of the amount of gas consumed, in gigawatts electric per year ($GW_e$-yr). The probability estimate took the form of a curve estimating the probability of an accident of a given number of fatalities per $GW_e$-yr. From this curve, the probability of an accident in which 45 persons are killed is estimated to be 0.0001 per $GW_e$-yr. PHMSA has used this probability in its analysis.

The PSI report did not estimate the number of serious injuries that would occur in addition to the number of fatalities. The limited experience described above demonstrates that more injuries than fatalities generally occur in these rare events. This mirrors the experience for events of lesser consequence. PHMSA has assumed, for purposes of this analysis, that 90 persons would be seriously injured in an event in which 45 persons were killed.

Applying this probability estimate to the United States for purposes of this analysis required that the electric equivalent of U.S. gas consumption be calculated. The Energy Information Administration (EIA) reports that U.S. gas consumption in 2006 was 21,860,945 million cubic feet.[31] This amount was converted to an energy equivalent using a standard assumption of 35.6 megajoules per cubic meter ($MJ/m^3$). The resulting estimate of thermal energy used in the United States in 2006 in the form of natural gas is $2.2*10^{13}$ MJ. This thermal energy was then converted to electrical energy equivalent using an assumed efficiency factor of 0.35, the same factor used in the PSI study. The resulting estimate of electrical energy equivalent is 244.3 $GW_e$-yr.

This equivalent consumption amount was then multiplied by the probability per $GW_e$-yr inferred from the PSI study ($1*10^{-4}$). The resulting estimate of the probability of an accident in the United States that would involve 45 fatalities and 90 serious injuries is 0.0243 per year. That is, there is approximately a 2.4 percent chance in any given year that such an event would occur.

If that probability is correct, the number of such accidents that would be expected to occur in the United States in 50 years is thus 1.215. In 20 years, 0.486 events would be expected (i.e., there is a 48.6-percent chance of one event occurring in 20 years).[32]

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incidents on pipelines have experienced an upward trend over the years 1989 to 2008. Data source: http://primis.phmsa.dot.gov/comm/reports/safety/SigPSI.html?nocache=1425#_all.

[31] EIA data from www.eia.doe.gov.

[32] It is not certain that this would be indicative of future risk given the improvements made in pipeline safety. Risk is determined by various factors such as population density and pipeline characteristics and the composition of the gas in the pipeline. There is evidence that post-IM regulations, fatalities associated with transmission pipelines have decreased. Source: http://primis.phmsa.dot.gov/comm/reports/safety/SigPSI.html?nocache=1425#_all.

For analysis purposes, it is necessary to determine the monetary equivalent of the consequences of such an accident. Using the standard DOT assumptions for the value of a death and serious injury (described above), the consequences of one accident would be valued at $311.63 million.[33] Here, again, it would be unreasonable to assume that the improvements to be realized as a result of this rule will eliminate all possibility of a large-consequence accident. PHMSA does expect, though, that the efficacy of this rule in avoiding a large-scale accident will be greater than that for avoiding smaller-scale incidents because the key elements of DIMP that would be required by the rule are for operators to analyze risks and to focus their risk-avoidance activities on those areas where they can be most effective.

Risk includes consideration of the likelihood of an event, as well as its consequences. Thus, areas where very high consequences could occur as a result of an accident will receive greater attention under operator DIMP programs than will portions of their systems subject to average or lower risk. PHMSA assumes that this improved safety focus of DIMP activities will mean that this rule will contribute up to 75 percent to avoiding a large-consequence accident of this nature. The consequences avoided are thus estimated to be $233.72 million per event. In a 50-year analysis horizon, the avoided consequences would total $283.97 million. Over a 20-year analysis, the avoided consequences would be $113.59 million. On an annual basis, the avoided consequences would be $5.71 million, but the analysis only uses this number in the potential upper bound estimate of benefits, and for the lower estimate we will assume $2 million.

#### 7.1.4 Benefits Attributable to Reducing Lost Gas

As a consequence of distribution system leaks, natural gas is lost. Reducing the number of leaks through DIMP will reduce the quantity of natural gas that is lost. Although there have been many studies that estimate the aggregate volume of lost gas, there is often inadequate information at the operator level as to the levels of lost gas by individual firms. The requirements of the integrity management rule will obligate operators to take steps that will result in reducing gas lost during normal operations as well as gas lost due to leaks in the pipe infrastructure. The procedures required to be followed to be in compliance with the integrity management rule would likely not be taken in its absence.

The U.S. Environmental Protection Agency (EPA) estimates natural gas distribution system emissions of methane in 2005 at 1,303 gigagrams.[34] According to the EPA, those are "…mainly…fugitive emissions from gate stations and non-plastic piping (cast iron, steel)."[35] Some, of course, will also result from distribution system leaks in plastic

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[33] An accident of this magnitude would also result in significant consequences in terms of property damage. Such damage was not considered in the PSI study. The amount, although large, would likely be significantly less than the equivalent value of the deaths and injuries. For purposes of this analysis, PHMSA has conservatively ignored the contribution from property damage.

[34] U.S. EPA, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005," Public Review Draft, February 20, 2007, epa.gov/climatechange/emissions/downloads07/07Energy.pdf, pp. 3-46 to 3-47. A gigagram is a unit of weight equivalent to $10^9$ grams.

[35] U.S. EPA, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005," Public Review Draft, February 20, 2007, epa.gov/climatechange/emissions/downloads07/07Energy.pdf, p. 3-46.

piping. Assuming that (1) there are 0.052 billion cubic feet of methane per gigagram and (2) natural gas is 80 percent methane, the 1,303 gigagrams of methane emissions converts to 85 billion cubic feet (1,303 * 0.052 * 1/0.8) of natural gas. Assuming a city gate natural gas price of $8.67 per thousand cubic feet,[36] the total annual value of the lost gas in 2005 dollars is approximately $737 million (85 billion cubic feet * $8.67). This becomes $759 million when converted to 2006 dollars.

PHMSA's estimates regarding lost gas are based on several factors. According to EPA, methane emissions occur in all sectors of the natural gas industry, including distribution systems. These emissions result from normal operations, routine maintenance, fugitive leaks, and system upsets.[37] Methane can escape during pipeline venting and repair or, to a lesser extent, from valves and seals at compressor stations. Methane losses can occur from leaks (also referred to as fugitive emissions) in all parts of the infrastructure, from connections between pipes and vessels, to valves and equipment. According to the EPA, approximately 19 percent (or 61 billion cubic feet (Bcf)) of the emissions come from the distribution systems, 13 percent are fugitive emissions.[38] If we assume as EPA does a gas value of $3 per Mcf, the value of gas losses in distribution systems amounts to approximately $183 trillion (61 Bcf * $3,000).

According to an article in *Pipeline and Gas Journal*, many pipeline companies struggle with lost and unaccounted-for gas, which significantly adds to the company's bottom line. The author estimates that a typical company with 750 million MMBtu of throughput could be experiencing annual losses upward of $6 million. The author notes that companies can realize a "reduction in losses from .75 percent to .25 percent from improved practices and controls and provide the company with significant savings to repay the costs, to cover the costs of additional capital investments, and then provide continued bottom-line savings."[39]

EPA and the oil and natural gas industry identified cost-effective technologies and practices that can be employed to reduce methane emissions from oil and gas operations.[40] Some practices listed in the voluntary natural gas STAR program are of particular importance for this analysis.[41] Several practices listed by EPA can be indicative

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[36] This was the average city gate price in 2005, according to Energy Information Administration, "Natural Gas Annual 2005," November 16, 2006, www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/natural_gas_annual/current/pdf/table_022.pdf, p. 53.
[37] http://www.epa.gov/gasstar/basic-information/index.html#overview2.
[38] *Inventory of U.S Greenhouse Gases and Sinks: 1990-2006*, April 2008.
[39] Rick Feldman, "How to Implement a Successful Lost-Gas Turnaround Project." Pipeline and Gas Journal, July 2002.
[40] The amount of avoided emissions is based on the typical leak rates through gate valves (130 Mcf per year) and gate valve stem packing (120 Mcf per year) reported in EPA's *Lessons Learned for Directed Inspection and Maintenance at Gate Stations and Surface Facilities.*
[41] EPA calculates paybacks assuming a natural gas value of $3/Mcf in most cases. Actual payback may vary depending on individual partner operating circumstances. Among the energy entities detailing cost-effectiveness are: http://www.duke-energy.com/news/releases/2000/Oct/2000101101.html; http://www.facilitiesnet.com/energyefficiency/article/IFMA-Joins-EPAs-ENERGY-STAR-Program--7666; http://resources.bnet.com/topic/natural+gas+star+program.html;

of the importance of the expected benefits likely to be realized under the DIMP requirements:

- Installing EFVs in distribution lines will contain the amount of gas that is lost when a line is severed by ground movement or third-party damage. The flow is shut when the line is damaged and the gas is retained within the closed system. EPA estimates that the capital cost (including installation) is $10,000, the operation and maintenance cost per year is less than $100, and the return is realized in approximately 10 years. As a result of installing EFVs, EPA estimates methane savings of 16 Mcf per hour.[42]
- Inspecting and maintaining both internal and external components on pipeline valves can diminish lost product. EPA calculates methane savings could reach 2,500 Mcf per year. The capital costs including installation are less than $1,000, the operation and maintenance costs are between $100 and $1,000 per year, and the return on the investment occurs between 1 and 3 years.[43]
- Testing and repairing pressure safety valves to eliminate methane emissions from worn down valves is relatively cost-effective in reducing emissions. EPA calculates the methane savings at 170 Mcf per year. EPA calculates that the capital costs are less than $1,000, the operating and maintenance costs range between $100 and $1,000 per year, and the payback occurs in 3 to 10 years.[44]

PHMSA estimates that the regulation will reduce gas loss by including leak management and EFV provisions. PHMSA does not know the proportion of gas loss avoided by the implementation of DIMP; for the purposes of this analysis it is assumed to be 10 percent, or $76 million ($759 million * 0.10). This estimate seems reasonable given the foregoing information relating to lost gas and methane emissions by EPA and others.

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http://www.psc.state.ut.us/utilities/electric/08docs/08035T01/56449PacifiCorp%20Cost%20Effectiveness%20Report%2008-T01.doc; http://www.pawyo.org/pdf/epa_star_program.pdf; http://74.125.113.132/search?q=cache:VIqc-FzgoxMJ:webapp.psc.state.md.us/Intranet/CaseNum/NewIndex3_VOpenFile.cfm%3Ffilepath%3D%255C%255CColdfusion%255CEWorkingGroups%255CDRDG%255C%255CBGE%2520AMI-DR-Conservation%255C1-04-08%2520SB%2520Cost%2520Effectiveness%2520Presentation.ppt+star+program+cost+effectiveness&cd=12&hl=en&ct=clnk&gl=us; http://www.docstoc.com/docs/7830705/Natural-Gas-STAR-Program-Fact-Sheet-(PDF); http://www.puc.state.nh.us/Electric/NH%20EnergyEfficiencyPrograms/07-106/Attachment%20D%20-%20National%20Grid%20Program%20Cost-Effectiveness.pdf; and http://ase.org/content/article/detail/1497.

[42] The amount of avoided methane emissions is a function of the service line diameter and pressure. Based on the formula in the Pipeline Rules of Thumb Handbook (4th Edition, p. 278), 16 Mcf per hour is emitted from a ½ inch service line at 50 psig. This is the estimated hourly gas savings when an EFV is activated in response to a rupture along the service line. See: http://www.epa.gov/gasstar/documents/installexcessflowvalves.pdf

[43] The amount of avoided emissions is based on the typical leak rates through gate valves (130 Mcf per year) and gate valve stem packing (120 Mcf per year) reported in EPA's *Lessons Learned for Directed Inspection and Maintenance at Gate Stations and Surface Facilities.* See: http://www.epa.gov/gasstar/documents/performleakrepairduringpipelinereplacement.pdf.

[44] http://www.epa.gov/gasstar/documents/testandrepairpressuresafetyvalves.pdf

### 7.1.5 Benefits Resulting from Reduced Emergency Response Costs

When a gas distribution system incident occurs, local emergency responders, including fire and police, frequently go to the scene to ensure public safety. Although communities are already incurring some of the fixed costs of these services, a gas distribution system incident adds to the cost of emergency response through the cost of responding to more incidents, possibly through damaged equipment and emergency responder injuries or the possible necessity of maintaining a higher overall response capacity.

The number of studies of addressing the costs of firefighting is very limited. In a seminal 1991 paper, William Meade developed estimates for the fully loaded cost of local fire service (i.e., firefighting and other activities and services provided by local fire departments).[45] That paper estimated those costs to be between $25.8 billion and $46.4 billion in 1986, with $39.6 billion the "Most Likely Estimate" of the cost.[46] These estimates consist of the total annual cost of local career fire departments, plus an imputed annual cost for the services provided by volunteer fire departments.[47]

In 1986, according to the National Fire Protection Association, there were a total of 11,890,000 fire department calls.[48] Those included calls for fires, medical aid, false alarms, mutual aid, hazardous materials, other hazardous conditions, and other. Based on the best estimate (i.e., the "Most Likely Estimate") of the cost of local fire services in 1986 and the total number of fire department calls for that same year, a fire call in 1986 costs, on average, $3,331.

For this analysis, PHMSA assumes the cost of a fire department call to be equal to the average cost of a fire department call, $5,425 (this is the $3,331 estimate converted from 1986 to 2006 dollars).
PHMSA assumes that a local fire department will be called for:

- 100 percent of all reportable incidents.[49]
- 10 percent of all non-reportable incidents.

Based on information developed previously in this report, PHMSA expects:

- 85 reportable non-excavation incidents per year.
- 60 reportable excavation incidents per year.

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[45] William P. Meade, "A First Pass at Computing the Cost of Fire Safety in a Modern Society," *Fire Technology*, November 1991, pp. 341-345.
[46] William P. Meade, "A First Pass at Computing the Cost of Fire Safety in a Modern Society," *Fire Technology*, November 1991, pp. 344-345.
[47] William P. Meade, "A First Pass at Computing the Cost of Fire Safety in a Modern Society," *Fire Technology*, November 1991, pp. 344.
[48] Fax from Nancy Schwartz, National Fire Protection Association, to Dianne Sutherland, U.S. DOT, July 8, 1994.
[49] Conversations with local fire protection representatives have indicated that they want to be present at any incident involving a hazardous material.

- 66,030 non-reportable, non-excavation incidents per year.
- 94,856 non-reportable excavation incidents.

According to the National Volunteer Fire Council Fact Sheet,[50] (1) 73 percent of all firefighters are volunteers, and (2) of the 30,542 fire departments in the United States, 21,671 are staffed entirely by volunteers, while 5,271 are mostly volunteer, 1,582 are mostly career, and 2,018 are staffed entirely by career firefighters. Based on this information and, due to the high fixed costs in maintaining a fire department, PHMSA assumes that only 25 percent of the costs of those fire department calls are costs that would not be incurred by local communities in the absence of gas distribution system incidents.

Thus, PHMSA expects the annual cost savings to local communities and volunteer firefighters in the absence of gas distribution incidents to be $22,017,363 ((85 + 60 + 6,603 + 9,486) * $5,425*0.25). PHMSA does not know the exact savings before the rule goes into effect but assumes that the rule, if implemented, could result in from 20 percent to up to 50 percent of those savings, or $4,403,472 ($22,017,363 * .2) to $11,008,682 ($22,017,363 * 0.5).[51]

### 7.1.6 Cost Savings from Avoided Evacuations

When gas distribution system incidents occur, people may be evacuated as a precaution or because of the threat that the incident poses to the public. Table 7 presents information on evacuations resulting from gas distribution system incidents for 2004 and 2008.

**TABLE 7 EVACUATIONS RESULTING FROM REPORTED GAS DISTRIBUTION SYSTEM INCIDENTS, 2004-2005[52]**

| Year | Number of incidents with evacuations | Number of people evacuated | Total Elapsed Time until area was made safe | | Estimated Pipeline Miles (Mains and Services) |
|---|---|---|---|---|---|
| | | | Hours | Minutes | |
| 2004 | 45 | 4,275 | 144 | 8 | 1,927,061 |
| 2005 | 50 | 2,744 | 100 | 10 | 1,940,374 |
| **Total** | **95** | 7,019 | **244** | **18** | **3,867,435** |

Average time is 2.5 hours per incident.

[50] http://www.nvfc.org/pdf/2005-fact-sheet.pdf.

[51] There is some basis for the 50-percent estimate. First, historically, as population grows, urban areas become denser and rural areas become more urbanized. Second, housing starts increased by almost 50 percent in the years between 1991 and 2004. If we assume that no new pipeline regulations were enacted, based on historical housing and population data, we would see a larger impact on deaths and injuries, as larger and denser urban areas emerge and additional population moves near transmission pipelines that service urban areas.

[52] Source: http://ops.dot.gov/stats/stats.htm.

Based on the information in the table, from 2004 through 2005, an average of 1,814 people per million miles, per year, were evacuated due to reported gas distribution incidents.

The cost of evacuations is very difficult to estimate because there are numerous variables. Evacuation costs will include the expense for temporary lodging and food, lost wages, business disruptions, and inconvenience to the public. In addition, there are the costs of agencies assisting with the evacuation. A study that Battelle prepared for DOT, *"Comparative Risks of Hazardous Materials and Non-Hazardous Materials Truck Shipment Accidents/Incidents,"* cited the U.S. Nuclear Regulatory Commission estimate of $600 to $1,800 per person evacuated as well as the $1,000 per person evacuated used by the Transportation Research Board and by the Federal Railroad Administration (FRA) to estimate impacts from railroad evacuations as reasonable estimates.[53] Therefore, for this analysis PHMSA assumes a cost of $1,000 per person for evacuations to be reasonable.[54] This figure is used below, also.[55]

**Cost Savings Resulting from Reportable Non-Excavation Incidents**

Table 8 presents information on evacuations resulting from gas distribution system incidents for 2004 and 2005.

**TABLE 8 EVACUATIONS RESULTING FROM REPORTED NON-EXCAVATION INCIDENTS ON GAS DISTRIBUTION SYSTEMS, 2004-2005[56]**

| Year | Number of incidents with evacuations | Number of people evacuated | Total Elapsed Time until area was made safe | | Estimated Pipeline Miles (Mains and Services) |
|---|---|---|---|---|---|
| | | | Hours | Minutes | |
| 2004 | 29 | 530 | 207 | 20 | 1,918,270 |
| 2005 | 36 | 4,341 | 180 | 4 | 1,823,136 |
| **Total** | **65** | **4,871** | **387** | **24** | |

Based on the information in the table, from 2004 through 2005, an average of 1,329 people per million miles, per year were evacuated due to gas distribution incidents.

[53] "Comparative Risks of Hazardous Materials and Non-Hazardous Materials Truck Shipment Accidents/Incidents," Federal Motor Carrier Safety Administration, Washington, DC, March 2001, p. 2-14. See http://www.fmcsa.dot.gov/documents/hazmatriskfinalreport.pdf; http://www.fmcsa.dot.gov/Spanish/english/HMRiskFinalReport.htm.

[54] Gas pipeline incidents can cause further disruptions to nearby businesses and communities, preventing them from carrying on with everyday tasks. Customers and supplies may not be able to reach the establishments, and shipments may not be able to leave the establishments even when they are not directly impacted by an evacuation.

[55] We do not have a firm basis for comparing the costs of evacuation across all types of accidents. However, the basis for accepting this as a reasonable estimate is that these costs are based on evacuations related to accidents which cause releases of hazardous and non hazardous materials, which could be comparable to pipeline accidents.

[56] Source: http://ops.dot.gov/stats/stats.htm.

For this analysis, PHMSA assumes that incident consequences in the future will mirror those of the recent past. Specifically, PHMSA assumes that the 1,329 people per million miles per year evacuated because of gas distribution incidents will be representative of the future for non-excavation incidents.

Multiplying the estimate of the cost of evacuation per person, $1,000 (see 7.1.6 for the rationale for using this figure), by the number of people per million miles per year, 1,329, yields an estimate of the total cost of evacuations resulting from non-excavation incidents: $1,329,000 per million miles per year.

For analytical purposes, PHMSA assumes that as a result of the rule, 20 to 50 percent of the $1,329,000 per million miles per year cost can be avoided. Given that 1.9 million miles of pipeline would be impacted by the rule, the total annual cost savings resulting from non-excavation incidents is expected to be between $265,800 ( $1,329,000 * .2) and $1,262,550 ($1,329,000 * 0.5 * 1.9) per year.

**Benefits Resulting from Reportable Excavation Incidents**

Table 9 presents information on evacuations resulting from gas distribution system incidents for 2004 and 2005.

**TABLE 9 EVACUATIONS RESULTING FROM REPORTED EXCAVATION INCIDENTS ON GAS DISTRIBUTION SYSTEMS, 2004-2005[57]**

| Year | Number of incidents with evacuations | Number of people evacuated | Total Elapsed Time until area was made safe | | Estimated Pipeline Miles (Mains and Services) |
|---|---|---|---|---|---|
| | | | Hours | Minutes | |
| 2004 | 13 | 3,674 | 227 | 53 | 1,918,270 |
| 2005 | 15 | 384 | 141 | 10 | 1,823,136 |
| **Total** | **28** | **4,058** | **369** | **3** | |

Note: In one incident in 2004, 3,000 people were evacuated as a precaution.

Based on the information in the table, from 2004 through 2005, an average of 1,063 people per million miles, per year were evacuated due to reported excavation-related gas distribution incidents.[58, 59]

For this analysis, PHMSA assumes that incident consequences in the future will mirror those of the recent past. Specifically, PHMSA assumes that the 1,063 people per million

[57] Source: http://ops.dot.gov/stats/stats.htm.
[58] Precautionary evacuations are not uncommon. Many agencies and entities have plans and procedures for precautionary evacuations. See for example: http://www.epmag.com/Magazine/2009/1/item26696.php; http://management.energy.gov/policy_guidance/635.htm; http://www.fema.gov/pdf/emergency/nrf/nrf_massevacuationincidentannex.pdf.
[59] Based on preliminary incidents data from 2007, the average number of incidents is approximately the same over time.

miles per year evacuated because of gas distribution incidents will be representative of the future for excavation incidents absent this rulemaking.

Multiplying the estimate of the cost of evacuation per person, $1,000, by the number of people per million miles per year, 1,063, yields an estimate of the total cost of evacuations resulting from excavation incidents: $1,063,000 per million miles per year.

For analytical purposes, PHMSA assumes that through the actions included in the rule, between 20 and 50 percent of the $1,063,000 per million miles per year cost, or $212,600 to $531,500 per million miles per year, can be avoided. PHMSA assumes 50 percent of the reduction in evacuation costs would result from the EFV requirements.

The benefits attributable to the EFV requirements would be between $106,300 ($212,600 * .5) and $265,750 ($531,500 * 0.5) per million miles per year. Given that 1.9 million miles of pipeline would be impacted by the rule, the total annual cost savings associated with the EFV requirements are expected to be between $201,970 ($106,300 * 1.9) and $504,830 ($265,750 * 1.9).

**Total Benefit from Reduction in Evacuations**

In total, the annual benefit from the reduction in the number of evacuations related to reportable incidents would be the sum of the expected benefits from reportable non-excavation evacuations, $265,800 to $1,262,550 annually, and the expected benefits from reportable excavation evacuations, $201,970 to $504,830 annually, or $467,770 to $1,767,380 annually. The annual benefit from a reduction in the number of non-reportable incidents has not been estimated because the data needed for such estimation is unavailable. For this analysis, PHMSA assumes that the reduction in non-reportable evacuations, in total, would have a benefit that is at least equal to that of reportable evacuations, or between $467,770 and $1,767,380 annually. Thus, PHMSA estimates that the total benefit from the reduction in evacuations attributable to the rule would be between $935,540 ($467,770 * 2) and $3,534,760 annually ($1,767,380 * 2).

### 7.1.8 Cost Savings Associated with Ending the Currently Existing EFV Notification Requirement

By mandating the installation of EFVs, with limited exceptions, on all new and renewed single-family residential services operating at a minimum pressure of 10 psig, the rule renders moot the currently existing customer notification requirement concerning EFVs (see 49 CFR 192.383). Consequently, as part of the rule, PHMSA relieves distribution system operators of the EFV notification requirement. PHMSA estimates that 400,000 notifications annually would no longer need to be made (for the derivation of this estimate, see Section 7.2.4 of this report).

If the EFV notification requirement were to be rescinded, distribution system operators would experience lower costs because they would no longer need to (1) mail out EFV notifications or (2) answer the questions of those receiving the notifications.

With respect to the cost of mailing notifications, PHMSA makes the following assumptions:[60]

- The cost of postage is \$0.44.
- The cost of the physical copy of the notification is \$0.10.
- Preparing and mailing each notification takes 5 minutes of staff time.
- Those preparing and mailing the notifications have a fully loaded labor cost of \$17.60 per hour.

Based on these assumptions, the total cost savings attributable to not having to annually mail notifications to 400,000 single-family residential customers with new or renewed services would be approximately \$803,000 (400,000 * (\$0.44 + \$0.10 + (5/60 * \$17.60))) per year.

With respect to the cost of answering the questions of those receiving notifications, PHSMA makes the following assumptions:[61]

- 10 percent of all of those receiving EFV notifications will call for more information.
- The calls made will take, on average, 5 minutes to answer.
- Those answering the calls have a fully loaded labor cost of \$40 per hour.

Based on these assumptions, the total cost savings attributable to not being required to answer the questions of those receiving notifications about EFVs on their new or renewed service lines would be \$133,333 (400,000 * 0.1 * (5/60)*\$40) per year.

In total, the cost savings attributable to not being required to notify 400,000 customers annually would be \$924,000 (\$790,667 + \$133,333). This is PHMSA's estimate of the value of the regulatory relief that the gas distribution industry would realize annually by eliminating the EFV notification requirement.

### 7.1.9 Total Benefits

Table 10 presents a summary of the estimated benefits of the rule, along with the calculated total for those benefits. In total, the annual benefits of the rule are expected to range from \$111 million to \$165 million. The estimate of benefits does not include any estimate for the benefits associated with (1) reduced greenhouse gas (GHG) emissions, (2) increased public confidence, or (3) additional costs savings to industry.

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[60] These assumptions are based on, but not necessarily identical to, those found in the Final Rule for Excess Flow Valve Notification, which was published in the *Federal Register*, Vol. 63, 1998, pp. 5464-5471.
[61] Ibid.

**TABLE 10 ESTIMATED BENEFITS OF THE RULE**

| Benefit | Annual Estimate ($ Million) | |
|---|---|---|
| | Low | High |
| Reduced Reportable Incidents | 19 | 47 |
| Reduced Non-reportable Incidents | 8 | 20 |
| Reduced High Consequence Costs | 2 | 6 |
| Reduced Lost Gas | 76 | 76 |
| Reduced Emergency Response Costs | 4 | 11 |
| Reduced Evacuations | 1 | 4 |
| End of Existing EFV Notification Requirement | 1 | 1 |
| TOTAL | 111 | 165 |

The present value of the estimated $111 million to $165 million in expected annual benefits over 50 years using a 3 percent discount rate would be approximately $2,942 million to $4,373 million. The present value of the annual benefits over 50 years using a 7 percent discount rate would be approximately $1,639 million to $2,437 million.

**Potential benefits that are not quantified**

In addition to the reported deaths, injuries, and property damage, there will be other unquantified benefits realized through the rule. In addition to incident-related savings, PHMSA expects that the requirement for operators to better understand their systems and risks will lead them to make better decisions on how they use existing resources. Four areas in which these cost savings would definitely be realized are:

- Reduced costs associated with surveillance for replaced pipeline.
- Reduced costs associated with rapid response to severe leaks.
- Reduced costs associated with a reduction in the large number of leaks operators must monitor but are not required to excavate and repair.

With respect to the first of these, pipeline will be replaced and that replaced pipeline is expected to be less prone to leak than the pipeline it replaced. As a consequence, the pipeline will require less surveillance than the pipe it replaced. This will result in a cost savings to industry that will at least partially offset the cost of replacing the pipe and the inconvenience caused to customers by its replacement.

With respect to the second, the need for operators to rapidly respond to severe leaks is expected to decrease due to the expectation that there will be fewer severe leaks for which rapid response is needed. Operators are expected to experience a reduction in their costs as a consequence.

With respect to the third, when distribution integrity management is fully implemented, overall there are expected to be fewer leaks that operators will need to monitor. As a result, their costs will be reduced.

### *7.2 Costs*

The costs associated with the rule will be attributable to the following activities that will be required of natural gas distribution systems:

- Developing an integrity management program
- Implementing an integrity management program
- Mitigating risks
- Managing the integrity management program
- Reporting to PHMSA and State regulators
- Recordkeeping

Each of these activities and their associated costs are discussed below, following a brief overview of the key assumptions used in the calculation of the costs.

### 7.2.1 Assumptions Impacting Costs

**TABLE 11 KEY ASSUMPTIONS IMPACTING COST**

| Item | |
|---|---|
| ***Distribution System Characteristics**** | |
| Total miles of steel mains | 546,950 |
| Total miles of plastic mains | 531,365 |
| Total miles of cast iron mains ≤ 8" in diameter | 34,578 |
| Miles of bare steel main to be replaced with plastic | 57,297 |
| Miles of bare steel main to be replaced with coated steel | 18,682 |
| Miles of PVC + ABS mains | 45,000 |
| Total number of steel services | 22,496,190 |
| Total number of plastic services | 37,309,715 |
| Total number of cast iron services | 128,993 |
| Total number of copper services | 1,339,000 |
| Number of bare steel services | 4,554,000 |
| Number of PVC + ABS services | 1,900,000 |
| ***Costs**** | ***Assumed Value*** |
| Costs to replace cast iron (high density underground) | $90/foot |
| Costs to replace steel w/ coated steel | $77/foot |
| Costs to replace steel w/ plastic | $25/foot |
| Costs to replace steel w/ plastic (high density underground) | $45/foot |
| Cost to replace service – high density underground | $2,200/service |
| Cost to replace service – medium density underground | $1,500/service |
| Cost to replace service – low density underground | $1,000/service |
| Cost of EFV installation on new or replacement services for large operators | $20/service |
| Cost of EFV installation on new or replacement services for small operators | $30/service |
| Fully loaded cost of pipeline employees – Large and small operators | $70/hour |
| Fully loaded cost of pipeline employees – Master meter and small LPG systems | $50/hour |
| Cost of leak survey on a main | $175/mile |
| Cost of leak survey on a service | $2.25/service |
| ***Other*** | |
| Cast iron replacement programs | 65 percent of lines covered, so 35 percent of lines not covered*** |
| Bare steel replacement programs | 74 percent of lines covered, so 26 percent of lines not covered*** |
| Vintage plastic replacement activities | 75 percent of lines covered, so 25 percent of lines not covered** |

*2004 data.
**From industry sources (except for the fully loaded cost of master meter and small LPG system pipeline employees, which is a PHMSA estimate).
***From American Gas Foundation report. This is assumed to be valid for all local gas utilities.

### 7.2.2 <u>Developing an Integrity Management Program</u>

The rule requires that each gas distribution system operator develop a formal integrity management program within 18 months after the final rule is issued. As stated previously, the integrity management program is intended to manage the risks associated with the operator's pipeline system. For distribution operators other than master meter and small LPG gas operators, an operator must develop an integrity management plan that, at a minimum, addresses the following elements:

- Demonstrated knowledge of the pipeline system's infrastructure.
- Identification of existing and potential threats to the system.
- Risk evaluation and prioritization.
- Identification and implementation of risk mitigation measures.
- Performance measures, monitoring of results, and evaluation of program effectiveness.
- Periodic evaluation and, if necessary, improvement of the integrity management program.
- Periodic reporting of results.

Since integrity management programs are not currently required for gas distribution systems, the costs associated with developing such a program are unknown and must be estimated. Because requirements differ among the types of operators, the costs associated with developing an IM program will be estimated separately for large operators, small operators and large LPG gas systems, and master meter and small LPG gas systems.

Based on discussions with industry organizations representing the operators that will be affected by the regulatory changes, PHMSA has identified the following as the key activities associated with the development of a formal integrity management program:

- Preparing a written distribution integrity management plan.
- Identifying threats.

After receiving comments on the NPRM on §192.1005, PHMSA revised the final rule to eliminate the proposed requirement that operator procedures describe "the processes" for developing and implementing its IM program. This section now requires operators of gas distribution pipelines and of LPG distribution pipeline serving 100 or more customers from a single source to develop and implement an IM program no later than 18 months after the effective date of this final rule. PHMSA recognizes that IM programs are likely to improve as operators gain experience. This does not mean, however, that it is acceptable for programs developed and implemented within 18 months to be incomplete. Those programs should address all required elements. PHMSA expects operators to revise their plans, following initial implementation, to reflect lessons that they learn through implementing them.

The American Public Gas Association (APGA) Security and Integrity Foundation (SIF) will develop a model Distribution Integrity Management Program to assist small operators in developing integrity management programs meeting the requirements of a final rule. The end product will be a simple and handy, risk-based IM plan to help small operators hold down the cost of developing an IM program.

Additionally, the rule includes an even more simplified approach for developing an integrity management program aimed at master meter and small LPG systems. This will help master meter and small LPG systems control their integrity management program development costs.

Table 12 presents PHMSA's estimates of the costs for these activities listed by operator type. In total, PHMSA estimates that the cost of the activities will be approximately $52 million dollars in the first year and approximately $8 million in each subsequent year. Of this total, large operators will pay $24.8 million in the first year and $4.1 million in each subsequent year, small operators will pay $15.3 million in the first year and $1.9 million in each subsequent year, and master meter and small LPG systems will pay $11.2 million in the first year and $1.6 million in each subsequent year.

## TABLE 12 ESTIMATED COSTS OF DEVELOPING AN INTEGRITY MANAGEMENT PROGRAM

| Type of Operator and Activity | Number of Operators | Labor Hours per Operator | Labor Rate (Fully loaded cost per labor hour) | Total Annual Cost in Year 1 ($ Million) | Total Annual Cost in Year 2 and On ($ Million) |
|---|---|---|---|---|---|
| ***Large Operators*** | | | | | |
| DIMP Preparation | 201 | 960 | $70 | $13.5 | --- |
| Identifying threats | 201 | 800 | $70 | $11.3 | --- |
| Periodic updates and revisions | 201 | 288 | $70 | --- | $4.1 |
| TOTAL | | | | $24.8 | $4.1 |
| ***Small Operators and Large LPG Systems*** | | | | | |
| DIMP Preparation | 1,142 | Total cost per operator: $5,000 | | $5.7 | --- |
| Identifying Threats | 1,142 | 120 | $70 | $9.6 | --- |
| Periodic updates and revisions | 1,142 | 24 | $70 | --- | $1.9 |
| TOTAL | | | | $15.3 | $1.9 |
| ***Master Meter and Small LPG Systems*** | | | | | |
| DIMP Preparation | 8,000 | Total cost per operator: $1,000 | | $8.0 | --- |
| Identifying threats | 8,000 | 8 | $50 | $3.2 | --- |
| Periodic updates and revisions | 8,000 | 4 | $50 | --- | $1.6 |
| TOTAL | | | | $11.2 | $1.6 |
| ***Grand Total*** | | | | | |
| GRAND TOTAL | | | | $51.3 | $7.6 |

On a per operator basis, the cost of developing an IM program for 201 large operators will be approximately $123,000 ($24.8 million/201) in the first year and $20,000 ($4.1 million/201) in each subsequent year; the cost for 1,142 small operators will be approximately $13,400 ($15.3 million/1,142) in the first year and $1,700 ($1.9 million/1,142) in each subsequent year; and the cost for 8,000 master meter and LPG systems will be approximately $1,400 ($11.2 million/8,000) in the first year and less than $500 in each subsequent year.[62]

### 7.2.3 Implementing an Integrity Management Program

Distribution system operators will have 18 months after the final rule is issued to develop and implement their integrity management programs. The time allowed between the issuing of the final rule and integrity management program implementation will allow operators to make any modifications their operations and maintenance procedures may need, as well as any modifications their business practices may need.

Implementation of integrity management programs includes a variety of activities, such as assembling and reviewing information about the infrastructure of an operator's pipeline, evaluating threats and risks, measuring performance, and deciding on improvements. These activities will generally need to be undertaken by experienced pipeline safety professionals.

A key element of integrity management program implementation will be the active and continual integration of all information relevant to the integrity of the pipeline covered by that program. This integration is essential if pipeline operators are to fully consider the unique risks that each of their individual distribution systems pose. Successful integrity management requires operators to view their systems as a whole, and information integration is the general mechanism that will allow them to do that.

Based on discussions prior to publication of the NPRM with industry organizations representing operators that will be affected by the regulatory changes, PHMSA identified the following as key activities associated with the implementation of an integrity management program:

- Software acquisition (or upgrade)
- Data gathering and review
- Database maintenance

To avoid the excessive burden that might be involved in retrieving many archived records or conducting additional investigations (e.g., excavation) to discover information about the pipeline, operators are asked to develop the information from readily available data. PHMSA assumes that operators have considerable knowledge of their pipeline to support routine operations and maintenance, but this information may be distributed throughout the company, in possession of groups responsible for individual functions.

[62] See Table 1 for the number of systems impacted.

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

Table 13 presents PHMSA's estimates of the cost of integrity management implementation listed by type of operator. Those estimates were originally developed for the NPRM following discussions with industry representatives. PHMSA has since reduced the burden of information gathering in the rule. PHMSA estimates that to assemble the required information from readily available sources to the extent necessary to support development and implementation of IM programs, operators would expend less hours gathering the needed information. PHMSA has reduced the data gathering time estimated in the NPRM by approximately 20 percent in this analysis for operators to comply with the final rule.

For this analysis, only large operators are assumed to need to acquire or upgrade risk-analysis software. Software acquisition includes not only the purchase of risk-analysis software, but also the cost of any training that may be needed. It assumes that the operators have in-house personnel who can successfully operate the software (with training). In addition, only large operators are assumed to need significant database maintenance. The costs of database maintenance for small operators and master meter and small LPG systems are expected to be nominal.

In total, PHMSA estimates that the cost of the data analysis activities will be approximately $48 million dollars in the first year and $18 million in each subsequent year. Of this total, large operators will pay $29.8 million in the first year and $10.4 million in each subsequent year; small operators will pay $15.47 million in the first year and $6.1 million in each subsequent year; and master meter and small LPG systems will pay $2.4 million in the first year and $1.2 million in each subsequent year.

## TABLE 13 ESTIMATED COSTS OF IMPLEMENTING AN INTEGRITY MANAGEMENT PROGRAM

| Type of Operator and Activity | Number of Operators | Labor Hours per Operator | Labor Rate (Fully loaded cost per labor hour) | Total Annual Cost in Year 1 ($ Million) | Total Annual Cost in Year 2 and On ($ Million) |
|---|---|---|---|---|---|
| ***Large Operators*** | | | | | |
| Software | 201 | Total cost per operator: $25,000 | | $5.0 | --- |
| Data gathering and review | 201 | 1,760 in yr. 1; 384 in yrs. 2 & on | $70 | $24.8 | $5.4 |
| Database maintenance | 201 | Total cost per operator: $25,000 | | --- | $5.0 |
| TOTAL | | | | $29.8 | $10.4 |
| ***Small Operators and Large LPG Systems*** | | | | | |
| Software | 1,142 | --- | --- | --- | --- |
| Data gathering and review | 1,142 | 192 in yr. 1; 77 in yrs. 2 & on | $70 | $15.4 | $6.1 |
| Database maintenance | 1,142 | --- | --- | --- | --- |
| TOTAL | | | | $15.4 | $6.1 |
| ***Master Meter and Small LPG Systems*** | | | | | |
| Software | 8,000 | --- | --- | --- | --- |
| Data gathering and review | 8,000 | 6 in yr. 1; 3 in yrs. 2 & on | $50 | $2.4 | $1.2 |
| Database maintenance | 8,000 | --- | --- | --- | --- |
| TOTAL | | | | $2.4 | $1.2 |
| ***Grand Total*** | | | | | |
| GRAND TOTAL | | | | $47.5 | $17.8 |

On a per operator basis, the cost of implementing an integrity management program for large operators will be approximately $148,000 ($29.8 million/201) in the first year and $52,000 ($10.4 million/201) in each subsequent year. The cost for small operators will be approximately $13,500 ($15.4 million/1,142) in the first year and $5,300 ($6.1

million/1,142) in each subsequent year, and the cost for master meter and small LPG systems will be $300 ($2.4 million/8,000) in the first year and less than $150 ($1.2 million/8,000) in each subsequent year.

### 7.2.4 Mitigating Risks

As part of an overall integrity management program, the rule requires operators to take action to mitigate any known risks and thereby improve the safety of their systems. The specific actions taken will vary depending on the applicable threats, their prevalence, and the current risks posed by the pipelines. In addition to any other risk reduction programs they may implement, the rule requires all operators to implement an effective leak reduction program. Additionally, under the rule, EFV installation is mandatory with limited exceptions.[63]

***Leak Management***

Leakage is the principal failure mode for low-stress distribution pipelines. Most incidents on distribution pipelines result from the accumulation of gas that has leaked from the pipeline. In distribution systems one significant element of operator efforts to manage risks is identifying and fixing severe leaks. These leaks, whatever their cause, can lead to gas migration to buildings, accumulation in these buildings, ignition and fire—potentially causing injury or death to residents. All operators are currently required to periodically survey for leaks. PHMSA has included a definition for "hazardous leak" in the final rule. This definition is drawn from the Gas Piping Technology Committee (GPTC) guidelines already used by many operators to classify leaks. The DIMP requirements will strengthen existing leak detection requirements.[64] The five elements of a leak detection management plan are:

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

Operators that that do not repair, but monitor, non-hazardous leaks will need to include criteria in the DIMP plan for evaluating their potential hazard.

The net effect of leak management requirements in DIMP would be to reduce leak-caused incidents by redirecting operator resources to higher risk segments of piping.

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[63] See Excess Flow Valve Installation (Section 192.383 of the rule.)

[64] Some States have leak management requirements or programs exceeding Part 192; however, these are often tailored for the local conditions (or types of systems) and may not be applicable to all operators in a given State or throughout the country. At this time, they do not appear appropriate for national requirements, but can be considered by operators in developing their individualized risk control program.

Industry sources indicate that operators would increase their leak surveys as a consequence of the rule and would also increase the mileage of pipe replaced. Additional pipe may also be replaced for reasons other than leak management, of course. The requirement will help ensure that operators have leak management programs that adequately protect the public. Additionally, the requirement should help ensure that distribution system operators readily adopt any future improvements in leak management.

**EFV Installation**

An EFV is a device that can be installed in a service line to automatically shut off the flow of gas if that service line is severed or severely damaged downstream of the valve. EFVs can thus mitigate the consequences of such incidents.

As required by Section 11 of the PIPES Act, the rule requires gas distribution system operators to install EFVs on single-family residential service lines if:

- The service line is installed or entirely replaced after June 1, 2008.
- The service line operates continuously throughout the year at a pressure of not less than 10 psig.
- The service line is not connected to a gas stream with contaminants that could interfere with the operation of an EFV.
- The installation is not likely to cause loss of service to the residence or interfere with necessary operation or maintenance activities, such as purging liquids from the service line.
- An EFV is available that meets the performance standards in 49 C.F.R. 192.381.

Operators of natural gas service lines must report annually on the number of EFVs installed on their systems.

After discussions with industry organizations representing operators that will be affected by the regulatory changes, PHMSA estimates that an additional 400,000 EFVs would be installed annually as a direct consequence of the rule.[65] To derive this estimate, PHMSA assumes that large and small gas distribution system operators install approximately 1,250,000 new services annually and completely replace 500,000 services annually. Of these 1,750,000 services, approximately 31 percent, or 542,500 services (1,750,000 * 0.31), do not have the proper operating conditions for an EFV (i.e., they operate at less than 10 psig, are services off cast iron mains, or are multi-family services). Of the remaining 1,207,500 services (1,750,000 – 542,500), PHMSA estimates that 66 percent, or 796,950 services (1,207,500 * 0.66), would have EFV installed in them even in the absence of the rule. That leaves 410,550 services (1,207,500 – 796,950). Of those, approximately 10,550 are estimated to be inappropriate for EFVs because of line contaminants or other reasons. That leaves 400,000 services (410,550 – 10,550) annually upon which EFVs could be installed.

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[65] That is, 400,000 EFVs over and above what operators currently install would be installed as a consequence of the rule.

Of the 400,000 additional EFVs estimated to be installed annually to meet the requirement, PHMSA estimates that large operators would install 364,966 additional EFVs (400,000 * 54.9/60.17), while small operators would annually install 35,034 additional EFVs (400,000 * 5.27/60.17).[66] PHMSA expects that the installation, including the cost of EFVs, would be $20 for large operators and $30 for small operators per EFV. Consequently, the additional annual costs for large operators attributable to EFVs would be $7,299,320 (364,966 * $20), while the additional annual costs for small operators attributable to EFVs would be $1,051,020 (35,034 * $30). In total, the additional annual costs attributable to EFVs would be $8,350,340 ($7,299,320 + $1,051,020).[67]

**Mitigating Other Risks**

The rule would require operators to use their measured performance to determine whether further improvements are needed and, if so, to make appropriate changes to their integrity management programs, their infrastructure, and their operations and maintenance activities. All operators are required to conduct program re-evaluations (i.e., reviews of their measured performance) periodically, not to exceed 5 years. Consequently, operators will need to identify and make any changes needed to improve their IM programs.

The costs associated with this review requirement will be contingent on (1) the problems and issues revealed by the performance measures, (2) the frequency of reviews, and (3) the selected solutions to problems and approaches to handling issues. Because of these uncertainties, the costs of mitigating other risks are difficult to estimate. Based on professional experience with mitigation in other programs, for this analysis, PHMSA estimates that the costs of mitigating other risks will equal 10 percent of the sum of the estimates for all other mitigation.

***Estimated Costs of Mitigation***

The costs of mitigation resulting from the rule are unknown and must be estimated. PHMSA recognizes that there are significant differences among operators regarding risk assessment. Although mitigation of risk is a fundamental requirement, under the rule, operators retain the flexibility to choose the mitigative activities they pursue. PHMSA expects that operators will perform the most cost-effective mitigation activities to fulfill the requirements.

Table 14 presents the estimated costs of all field activities associated with the mitigation of risks required by the rule. As mentioned previously, for this analysis, the costs of

[66] From Table 1, large operators have 54,900,000 services and small operators have 5,270,000 services. In total, large and small operators together have 60,170,000 services.

[67] Master Meter Operators would also need to replace EFV per section 192.383. PHMSA expects few if any EFVs to be installed by these operators since the vast majority of these systems operate at less than 10 psig. PHMSA expects the costs to master meter operators and small LPG systems ensuing from this requirement to be very minimal. According to the industry representatives the cost of EFV installation is not a significant burden.

performing other activities are assumed to be equal to 10 percent of the combined estimated cost of all other field activities (i.e., 10 percent of the costs of replacing additional pipe plus the costs of performing more leak surveys plus the costs of installing additional EFVs). The estimates in Table 14 were developed after consultation with industry organizations representing operators that will be affected by the regulatory changes.

In developing the estimates presented in Table 14, it has been assumed,[68] that 35 percent of all cast iron lines are not currently covered by cast iron pipe replacement programs; 26 percent of all bare steel lines are not currently covered by bare steel replacement programs; and 25 percent of all plastic lines are not currently covered by vintage plastic replacement activities. Based on information received by PHMSA from industry sources, PHMSA assumed that for large operators:

- An additional 3.5 percent of cast iron mains and services will be replaced over a period of 50 years. This is 10 percent of the 35 percent of cast iron mains and services not currently covered by a replacement program.[69]
- An additional 1.3 percent of bare steel mains and services will be replaced over a period of 50 years. This is 5 percent of the 35 percent of bare steel mains and services not currently covered by a replacement program.[70]
- An additional 5 percent of copper services will be replaced over a period of 50 years.
- An additional 2.5 percent of plastic mains and services will be replaced over a period of 50 years.

Based on information received by PHMSA from industry sources, PHMSA assumed that for small operators:

- An additional 2.6 percent of bare steel mains and services will be replaced over a period of 50 years.
- An additional 10 percent of copper services will be replaced over a period of 50 years.
- An additional 5 percent of plastic mains and services will be replaced over a period of 50 years.

Based on information received by PHMSA from industry sources, PHMSA assumed that for master meter and small LPG systems:

- An additional 35 miles of bare steel mains will be replaced over a period of 50 years.
- An additional 3,604 bare steel services will be replaced over a period of 30 years.

[68] Assumptions are based upon information from industry sources, except where specified.
[69] See the American Gas Foundation, "Safety Performance and Integrity of Natural Gas Infrastructure," January 2005, at http://www.gasfoundation.org/ResearchStudies/safety_perf.htm.
[70] See the American Gas Foundation, "Safety Performance and Integrity of Natural Gas Infrastructure," January 2005, at http://www.gasfoundation.org/ResearchStudies/safety_perf.htm.

- An additional 49 miles of plastic mains will be replaced over a period of 30 years.
- An additional 3,615 plastic services will be replaced over a period of 30 years.

It should be noted, these actions are over and above replacement that is currently being undertaken by distribution system operators.

The estimated costs of cast iron and bare steel pipe replacement on mains used in this analysis ($475,200 per mile and $279,145 per mile, respectively) may be high given that technology allows plastic liners to be inserted inside existing pipe. According to industry representatives, this technology should be less costly than digging up and physically replacing the existing pipe. In addition, there are various advantages to using plastic liners, including cost and effectiveness factors.[71] Although plastic liners may not be considered by some as effective as new metal pipe, liners are a possible solution, provided adequate procedures and standards are followed. Operators have been using plastic liners as temporary measures, some for years, until pipelines finally get replaced. This technology is about 15 to 20 years old, and standards for certain plastic (e.g., polyethylene liners) are being considered now at ASTM.

The estimates in Table 14 are listed by type of operator. In total, PHMSA estimates that the cost of the field activities will be $60.4 million dollars in the second and each subsequent year. Of this total, large operators will pay $53.1 million in the second and each subsequent year, small operators will pay $5.8 million in the second and each subsequent year, and master meter and small LPG systems will pay $1.5 million in the second and each subsequent year.

On a per operator basis, the cost of integrity management program field activities for large operators will be approximately $264,000 in the second and each subsequent year, the cost for small operators will be approximately $5,000 in the second and each subsequent year, and the cost for master meter and small LPG systems will be less than $500 in the second and each subsequent year.

[71] See for example: http://www.nastt.org/store/technical_papersPDF/59.pdf; http://www.onepetro.org/mslib/servlet/onepetropreview?id=OTC-19937-MS&soc=OTC; http://www.hazeldengroup.com/rehab.doc; http://www.quadrantepp.com/assets/global/NorthAmerica/CaseStudies/cs_grain_07.pdf; http://www.aga.org/legislative/issuesummaries/plasticpipe.htm; http://www.contech-cpi.com/drainage/products_materials/pvc_abs/a2_linerpipe/169; http://www.unitedpipeline.com/content/127/safetyliner.aspx; http://www.allbusiness.com/mining/support-activities-mining-support-oil/784662-1.html; http://www.plasticpipe.org/pdf/pe_handbook_chapter_11_rehabilitation.pdf.

## TABLE 14 ESTIMATED COSTS OF INTEGRITY MANAGEMENT PROGRAM MITIGATION

| Type of Operator and Activity | Cost | Miles of main or number of services impacted, or labor hours required | Total Annual Cost in Year 1 ($ Million) | Total Annual Cost in Year 2 and On ($ Millions) |
|---|---|---|---|---|
| ***Large Operators*** | | | | |
| Replacing additional pipe-- | | | | |
| - ≤8" cast iron mains | $475,200/mile | 24.2 miles | $0 | $11.5 |
| -Cast iron services | $2,200/service | 90.3 services | $0 | $0.2 |
| -Bare steel mains | $279,145/mile | 17.5 miles | $0 | $4.9 |
| -Bare steel services | $2,200/service | 1,064 services | $0 | $2.3 |
| -Copper services | $2,200/service | 1,203.1 services | $0 | $2.6 |
| -Plastic mains | $132,000/mile | 19.9 miles | $0 | $2.6 |
| -Plastic services | $2,200/service | 854 services | $0 | $1.9 |
| -SUBTOTAL | | | $0 | $26.0 |
| Performing more leak surveys-- | | | | |
| -On mains | $175/mile | 50,500 miles | $0 | $8.8 |
| -On services | $2.25/service | 2,745,000 services | $0 | $6.2 |
| -SUBTOTAL | | | $0 | $15.0 |
| Installing additional EFVs on services | $20/service | 364,966 services | $0 | $7.3 |
| Performing other activities | | | $0 | $4.8 |
| TOTAL | | | $0 | $53.1 |
| ***Small Operators*** | | | | |
| Replacing additional pipe-- | | | | |
| -Bare steel mains | $279,145/mile | 4.2 miles | $0 | $1.2 |
| -Bare steel services | $1,500/service | 204.3 services | $0 | $0.3 |
| -Copper services | $1,000/service | 232.7 services | $0 | $0.2 |
| -Plastic (PVC, ABS) mains | $132,000/mile | 4.7 miles | $0 | $0.6 |
| -Plastic (PVC, ABS) services | $1,000/service | 163.9 services | $0 | $0.2 |
| -SUBTOTAL | | | $0 | $2.5 |

| Type of Operator and Activity | Cost | Miles of main or number of services impacted, or labor hours required | Total Annual Cost in Year 1 ($ Million) | Total Annual Cost in Year 2 and On ($ Millions) |
|---|---|---|---|---|
| Performing more leak surveys-- | | | | |
| -On mains | $175/mile | 6,000 miles | $0 | $1.1 |
| -On services | $2.25/service | 263,500 services | $0 | $0.6 |
| -SUBTOTAL | | | $0 | $1.7 |
| Installing additional EFVs on services | $30/service | 35,034 services | $0 | $1.1 |
| Performing other activities | | | $0 | $0.5 |
| TOTAL | | | $0 | $5.8 |
| ***Master Meter and LPG Systems*** | | | | |
| Replacing additional pipe-- | | | | |
| -Bare steel mains | $156,667/mile | 0.7 miles | $0 | $0.1 |
| -Bare steel services | $1,500/service | 72.1 services | $0 | $0.1 |
| -Copper services | $1,000/service | 679.4 services | $0 | $0.7 |
| -Plastic (PVC, ABS) mains | $132,000/mile | 1.6 miles | $0 | $0.2 |
| -Plastic (PVC, ABS) services | $1,000/service | 120.5 services | $0 | $0.1 |
| -SUBTOTAL | | | $0 | $1.2 |
| Performing more leak surveys-- | | | | |
| -On mains | $175/mile | 800 miles | $0 | $0.1 |
| -On services | $2.25/service | 80,000 services | $0 | $0.2 |
| -SUBTOTAL | | | $0 | $0.3 |
| Performing other activities | --- | --- | $0 | $0.0 |
| TOTAL | | | $0 | $1.5 |
| ***Grand Total*** | | | | |
| GRAND TOTAL | | | $0 | $60.4 |

Notes: (Assumptions based on information from industry sources, except where specified)
(1) Examples of activities that might be undertaken under "Performing other activities" include:
--Correcting cathodic protection deficiencies to combat external corrosion
--Installing pipe liners to combat internal corrosion
--Improving the accuracy of line locating to combat third party and operator damage
--Relocating facilities that are hard to protect to combat vandalism.
(2) For large operators:
--An additional 3.5 percent of cast iron mains and services are assumed to be replaced over a period of 50 years. This is 10 percent of the 35 percent of cast iron mains and services not currently covered by a replacement program (see the American Gas Foundation, "Safety Performance and Integrity of Natural Gas Infrastructure," January 2005, at http://www.gasfoundation.org/ResearchStudies/safety_perf.htm).

--An additional 1.3 percent of bare steel mains and services are assumed to be replaced over a period of 50 years. This is 5 percent of the 35 percent of bare steel mains and service not currently covered by a replacement program (see the American Gas Foundation, "Safety Performance and Integrity of Natural Gas Infrastructure," January 2005, at http://www.gasfoundation.org/ResearchStudies/safety_perf.htm).
--An additional 5 percent of copper services are assumed to be replaced over a period of 50 years.
--An additional 2.5 percent of plastic mains and services are assumed to be replaced over a period of 50 years.
--EFVs are installed annually on 364,966 services (see Sec. 6.3.3.3).
(3) For small operators:
--Steel and copper replacements are prorated from large operators using mileage or number of services, as appropriate.
--An additional 2.6 percent of bare steel mains and services are assumed to be replaced over a period of 50 years.
--An additional 10 percent of copper services are assumed to be replaced over a period of 50 years.
--An additional 5 percent of plastic mains and services are assumed to be replaced over a period of 50 years.
--EFVs are installed annually on 35,034 services (see Sec. 6.3.3.3).
(4) For master meter and small LPG systems:
--An additional 35 miles of bare steel mains are assumed to be replaced over a period of 50 years.
--An additional 3,604 bare steel services are assumed to be replaced over a period of 50 years.
--An additional 20,381 copper services are assumed to be replaced over a period of 30 years.
--An additional 49 miles of plastic mains are assumed to be replaced over a period of 30 years.
--An additional 3,615 plastic services are assumed to be replaced over a period of 30 years.

**State Requirements**

Distribution pipelines are intrastate pipelines. Under the pipeline safety program, certified States may exercise regulatory oversight of these operations. A certified State must enforce at least the Federal regulations, but may also impose additional requirements. States also foster programs that improve pipeline safety outside their regulatory structure, for example, via their rate setting process.

As noted above, the 2004-2005 NAPSR survey identified many States that impose additional safety requirements on gas distribution pipelines beyond those imposed by the Federal Government.[72] Many of these requirements address actions to prevent or detect damage by outside forces or to conduct additional surveys to detect and repair leaks. Approximately two-thirds of States have some type of program to require replacement of certain types of distribution pipeline (e.g., cast iron, uncoated steel, copper, and some kinds of plastic pipe) that are more prone to failures resulting in release of gas and therefore accident risk.

These additional State requirements help ensure the integrity and safety of gas distribution pipelines. PHMSA assumes that the costs associated with these requirements have already been incurred.

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[72] For a more detailed summary, see the Notice of Proposed Rulemaking. For details about the survey, see documents 73 and 74 in Docket RSPA-2004-19854.

**Gas Distribution System Operators with DIMP-like Programs**

There are significant differences among operators' risk assessment and safety programs, some are comprehensive while others are less so. PHMSA is attempting to standardize industry practices, while providing enough flexibility to accommodate the diversity. Some gas distribution operators are expected to already have some programs similar to the one in the rule. PHMSA expects that such programs cover perhaps as much as 25 percent of all distribution system mileage.

Some of the features of the DIMP programs that already have been implemented by operators are based on the State requirements mentioned previously. Some operators may have implemented other programs because they make good business sense. They reduce the overall costs of those operators. PHMSA assumes some operators may have already incurred some of the costs associated with these requirements, but because of the differences among operators' programs and the different ways they may choose to address the requirements, PHMSA cannot estimate the magnitude of the additional costs.

### 7.2.5 Reporting to PHMSA and State Regulators

Distribution system operators, with the exception of master meter operators and small LPG systems, must report performance measures. The report to PHMSA must be made as part of the annual report required by 49 CFR 191.11. That report must contain information about the following four performance measures:

- Number of hazardous leaks either eliminated or repaired, per §192.703(c), (unless all leaks are repaired when found), categorized by cause.
- Number of excavation damages.
- Number of excavation tickets.
- Total number of leaks either eliminated or repaired, categorized by cause.

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

The rule also requires operators to report, as part of the annual report, detailed information regarding compression coupling failures. Each operator must report, on an annual basis, information related to failure of compression couplings, excluding those that result only in non-hazardous leaks, as part of the annual report required by § 191.11 beginning with the report submitted March 15, 2011. This information must include, at a minimum, location of the failure in the system, nominal pipe size, material type, nature of failure including any contribution of local pipeline environment, coupling manufacturer, lot number and date of manufacture, and other information that can be found in markings on the failed coupling. An operator also must report this information to the State pipeline safety authority if a State exercises jurisdiction over the operator's pipeline. PHMSA will use this data to evaluate the scope of problems related to plastic compression couplings and to determine if changes to the regulations are appropriate to help prevent incidents caused by plastic coupling failure.

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

Distribution operators will incur additional reporting costs attributable to the rule. PHMSA expects the costs will depend on the type of operation and experience of the operator with reporting. PHMSA staff has observed that typically there is a learning curve when operators are subject to new requirements. Based on past experience with different rules, PHMSA estimates that the cost to add additional information to the annual report will be nominal. (The average hourly wage for a compliance officer is estimated at $40 per hour, including benefits. Assuming that the additional time to include these parameters in their annual reports is 1 hour per operator, the additional cost per operator, per year would be about $40 ($40*1)). It is assumed that the format of the information provided to PHMSA in the annual reports will be acceptable to the States and no additional reports or telephone communication will be needed to comply with the requirement.

### 7.2.6 <u>Recordkeeping</u>

In addition to the reporting requirements, this final rule requires each affected operator to develop and maintain a written integrity management plan, which includes initial plan development, recordkeeping and updates. These non-reporting requirements are covered by Integrity Management Program for Gas Distribution Pipelines, OMB Control Number: 2137-0625. Each operator, other than master meter operators and small LPG operators, must also collect and record one other specified performance measure and any other performance measures unique to the operator's pipeline that are needed to evaluate the effectiveness of the integrity management program.

Documentation requirements for master meter operators and small LPG operators are different from the requirements for other operators subject to this rule, consistent with their treatment in the rest of Part 192. Master meter operators and small LPG operators are not required to submit annual reports and are subject to much less stringent recordkeeping requirements. All operators must keep the records for 10 years.

Based on previous experience with recordkeeping requirements, PHMSA expects the cost of the required recordkeeping to be nominal. Some of the required records will be kept electronically, while others will be kept on paper. In the case of those kept electronically, the required recordkeeping will necessitate a company clerk entering data and in some cases scanning materials. In the case of those kept on paper, the required recordkeeping will necessitate a company clerk placing materials in file folders, placing the file folders in file cabinets, and retrieving files, when needed. It may also necessitate a system for signing materials in and out. Finally, in some cases, physical recordkeeping may necessitate the acquisition of file cabinets and file folders by some operators. The average hourly salary, including benefits, for a clerk is estimated at $20. Assuming that the average time to perform these tasks is one-half hour per month, or 6 hours per year, the total cost per operator, per year would be approximately $120 ($20*6). There is no expectation that the recordkeeping would require operators to hire additional personnel. Neither is there an expectation that the recordkeeping would require operators to acquire new computers or peripherals.

### 7.2.7 Managing the Distribution Integrity Management Program

Each operator will need to manage its distribution integrity management program. That management will help ensure the proper functioning of each operator's program, including coordination among and between its various parts. In addition to providing oversight and guidance, the managers of each operator's program will serve as points of contact and advocates for the program within the operator's management structure.

Because the program is new, the costs of managing it are unknown and consequently must be estimated. Table 15 presents PHMSA's estimates of the costs of managing the program for large operators, small operators, and master meter and small LPG systems, as well as the total cost to the gas distribution industry of managing the integrity management program. The estimates in Table 15 were developed following discussions with gas distribution industry representatives.

PHMSA's estimates assume that the management requirements will be significantly greater in the first year, when the programs are being created, than in subsequent years. For example, PHMSA estimates that large operators will need to devote one-half of a labor year to integrity management program management in the first year, but only one-quarter of a labor year to management in subsequent years.

In total, PHMSA estimates that the cost of DIMP management will be $31 million in the first year and $16 million in each subsequent year. Of this total, large operators will incur costs of $14.0 million in the first year and $7.0 million in each subsequent year, small operators will incur costs of $7.7 million in the first year and $3.8 million in each subsequent year, and master meter and small LPG systems will incur costs of $9.6 million in the first year and $4.8 million in each subsequent year.

**TABLE 15 ESTIMATED COSTS OF DISTRIBUTION IM PROGRAM MANAGEMENT**

| Type of Operator | Number of Operators | Hours per Operator | Labor Rate (Fully loaded cost per hour) | Total Annual Cost in Year 1 ($ Million) | Total Annual Cost in Year 2 and On ($ Million) |
|---|---|---|---|---|---|
| Large Operators | 201 | 996 in yr. 1; 498 in yrs. 2 & on | $70 | 14.0 | 7.0 |
| Small Operators | 1,142 | 96 in yr. 1; 48 in yrs. 2 & on | $70 | 7.7 | 3.8 |
| Master Meter and small LPG Systems | 8,000 | 24 in yr. 1; 12 in yrs. 2 & on | $50 | 9.6 | 4.8 |
| TOTAL | | | | 31.3 | 15.6 |

On a per operator basis, the cost of managing an integrity management program for large operators will be approximately $70,000 ($14 million/201) in the first year and $35,000 ($7 million/201) in each subsequent year. The cost for small operators will be approximately $6,700 ($7.7 million/1,142) in the first year and $3,300 ($3.8 million/1,142) in each subsequent year, and the cost for master meter and small LPG systems will be approximately $1,200 ($9.6 million/8,000) in the first year and $600 ($4.8 million/8,000) in each subsequent year.

PHMSA's estimates may overstate the net additional cost of management attributable to the rule. Currently, operators have activities and programs in place, including leak and damage prevention programs, which will likely be brought under the DIMP umbrella by those operators if the rule is implemented. Those activities and programs, as a consequence, may need less management than they did before. This potential reduction in the cost of managing currently existing activities is not included in PHMSA's estimates.

#### 7.2.8 Total Cost

Table 16 summarizes the costs associated with the rule. In total, PHMSA expects the rule to cost operators $130 million in the first year and $101 million in the second and subsequent years. Of this total, large operators will incur costs of $68.6 million in the first year and $74.6 million every year thereafter, small operators will incur costs of $38.4 million in the first year and $17.6 million every year thereafter, and master meter and smaller LPG systems will incur costs of $23.2 million in the first year and $9.1 million every year thereafter.

**TABLE 16 COSTS ASSOCIATED WITH THE DISTRIBUTION INTEGRITY MANAGEMENT PROGRAM**

| Type of Operator and Cost Category | Total Annual Cost in Year 1 ($ Million) | Total Annual Cost in Year 2 and On ($ Millions) |
|---|---|---|
| ***Large Operators*** | | |
| Developing an IM Program | $24.8 | $4.1 |
| Implementing an IM Program | $29.8 | $10.4 |
| Mitigation | --- | $53.1 |
| Reporting | Nominal | Nominal |
| Recordkeeping | Nominal | Nominal |
| Management | $14.0 | $7.0 |
| LARGE OPERATOR TOTAL | $68.6 | $74.6 |
| ***Small Operators and Large LPG Operators*** | | |
| Developing and IM Program | $15.3 | $1.9 |
| Implementing an IM Program | $15.4 | $6.1 |
| Mitigation | --- | $5.8 |
| Reporting | Nominal | Nominal |
| Recordkeeping | Nominal | Nominal |
| Management | $7.7 | $3.8 |
| SMALL OPERATOR TOTAL | $38.4 | $17.6 |
| ***Master Meter and Small LPG Operators*** | | |
| Developing and IM Program | $11.2 | $1.6 |
| Implementing an IM Program | $2.4 | $1.2 |
| Mitigation | --- | $1.5 |
| Reporting | Nominal | Nominal |
| Recordkeeping | Nominal | Nominal |
| Management | $9.6 | $4.8 |
| MASTER METER AND LPG SYSTEM TOTAL | $23.2 | $9.1 |
| GRAND TOTAL | $130.2 | $101.3 |

On a per operator basis, the total cost of an integrity management program for large operators will be approximately $341,000 ($68.6 million/201) in the first year and $371,000 ($74.6 million/201) in each subsequent year. The cost for small operators will be approximately $33,600 ($38.4 million/1,142) in the first year and $15,400 ($17.6 million/1,142) in each subsequent year, and the cost for master meter and small LPG systems will be approximately $2,900 ($23.2 million/8,000) in the first year and $1,100 ($9.1 million/8,000) in each subsequent year.

Based on the total cost estimates for the first and subsequent years, the present value of the costs of the rule calculated over 50 years with a 3 percent discount rate would be $2,783 million, while the present value of the rule calculated over 50 years with a 7 percent discount rate would be $1,618 million.

### *7.3 Comparison of Benefits and Costs*

The benefits resulting from the rule are estimated to range from $111 million to $165 million per year. The costs of the rule are estimated to be $130 million in the first year and $101 million in each subsequent year. Table 17 gives the present values for these estimated benefits and costs over 50 years at 3 percent and 7 percent discount rates.

**TABLE 17 PRESENT VALUE OF BENEFITS, COSTS, and NET BENEFITS OF THE RULE CALCULATED OVER 50 YEARS**
**($ Millions)**

| Discount Rate | Benefits | Costs | Net Benefits |
|---|---|---|---|
| 3% | 2,942 to 4,373 | 2,783 | 159 to 1,590 |
| 7% | 1,639 to 2,437 | 1,618 | 21 to 719 |

As shown in Table 17, the estimated present value of net benefits of the rule is positive at each discount rate. At the 3 percent discount rate there are approximately $159 million to $1.6 billion in net benefits over the 50-year period, and at 7 percent there are approximately $21 million to $719 million over the 50-year period.

## 8. BREAK-EVEN ANALYSIS

The benefit-cost analysis in previous sections depended upon making assumptions about the effectiveness of the rule in reducing various components of the societal costs associated with gas distribution systems. For example, the analysis assumes that the rule will reduce 20 to 50 percent of the costs associated with reportable incidents and 10 percent of the costs associated with lost gas. The predicted outcome of the analysis in terms of net benefits will vary as the levels of effectiveness vary.

An alternative evaluation of the rule's assumptions, and the robustness of the Agency's conclusions, is to determine the overall level of effectiveness in reducing societal costs associated with gas distribution systems that must be attained to cover the estimated costs of the rule. From the benefit analysis earlier in this report, the annual societal costs are approximately those illustrated in Table 18.

**TABLE 18 CONTRIBUTORS TO SOCIETAL COSTS**[73]

| Incidents and other Contributors to Societal Costs Associated with Gas Distribution | Annual Estimate ($ Million) |
|---|---|
| Reportable Incidents | 87 |
| Non-reportable Incidents | 56 |
| High consequence incidents | 8 |
| Lost Gas | 759 |
| Emergency Response Costs | 44 |
| Evacuations | 5 |
| Non-Gas Excavations | 108 |
| Existing EFV Notification Requirement | 1 |
| | |
| TOTAL | 1,068 |

The costs of the rule are estimated to be approximately $130 million the first year and about $101 million in each year thereafter. If there are to be the level of benefits to equal those costs, then the rule would have to be about 12.2 percent ($130/1,068*100) effective in reducing overall societal costs the first year, and about 9.5 percent ($101/1,068*100) effective in subsequent years.

## 9. SUMMARY AND CONCLUSIONS

PHMSA is revising the Pipeline Safety Regulations to require operators of gas distribution pipelines to develop and implement programs that will better assure the integrity of their pipeline systems. The regulations require distribution pipeline operators to implement an IM program similar to those required for gas transmission pipelines.

The rule is expected to impact 201 local gas utilities with over 12,000 services, 1,090 local gas utilities with 12,000 or fewer services, and approximately 8,000 master meter and LPG systems. The larger local gas utilities are estimated to have over 1 million miles of mains and nearly 55 million services, while the smaller utilities are estimated to have over 100 thousand miles of mains and approximately 5 million services. Master meter and LPG systems are estimated to have 8 thousand miles of mains and 800 thousand services.

The readily monetized annual benefits resulting from the rule are estimated to be between $111 million and $165 million. The monetized benefits include:

- Reductions in the consequences of reportable incidents.
- Reductions in the consequences of non-reportable incidents.

[73] The benefits listed in Table 10 are not derived by multiplying values in Table 18 by .2 and .5, respectively, but are calculated in the analyses in sections 7.1.1 thorough 7.1.8 (with the exception of benefits of lost gas, which are 10 percent of total lost gas).

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

The costs of the rule are estimated to be $130.2 million in the first year and $101.3 million in each subsequent year. The costs include:

- Development of an IM program.
- Implementation of the IM program.
- Mitigation of risks.
- Reporting to PHMSA and State regulators.
- Recordkeeping.
- Management of the IM program.

The present value of the monetized benefits of the rule is estimated to be between $2,942 million and $4,373 million calculated over 50 years using a 3 percent discount rate and about $1,639 million and $2,437 million calculated over 50 years using a 7 percent discount rate. The present value of the estimated costs of the rule would be expected to be $2,783 million over 50 years using a 3 percent discount rate and about $1,618 million over 50 years using a 7 percent discount rate. Based on these calculations, the best estimate of the present value of expected net benefits is approximately between $21 million and $1.6 billion over a 50-year period.

Another conclusion is that the societal costs associated with the risks and hazards of gas distribution systems need to be reduced by approximately 12.2 percent the first year and about 9.5 percent annually in subsequent years for the benefits of the rule to exceed the costs.

This economic evaluation suggests that the rule is in the public interest because there are expected net benefits, and there is a relatively low rate of realized benefits for the rule to have positive net benefits.

## APPENDIX A: Supplementary Statistical Value of Life Analysis

This supplementary analysis illustrates how varying the statistical value of life affects the expected net benefits of the rule.

The statistical value of fatalities is one component of societal costs of incidents associated with gas distribution pipelines. Above, $5.8 million was the value of statistical life (VSL) used. When using a VSL of $3.2 million, the societal costs will be lower and when using a VSL of $8.4 million, the total societal costs will be higher. The present value of **net** benefits is calculated by subtracting the present value of the total costs of complying with the rule from the present value of the **total** benefits of reducing deaths, injuries, and property damage expected.

The total annual societal costs are equal to the sum of the costs of fatalities, injuries, and property damage. Total societal costs represent the potential benefits if all incidents could be eliminated. Actual benefits depend upon the effectiveness of the requirements in reducing incidents. The annual estimated total benefits of the rule are expected to be between $111 million and $165 million per year. If we assume, for example, that the rule is expected to prevent about half of the approximately 10 fatalities per year, at $5.8 per statistical life, these prevented fatalities represent $29 million of the total expected benefits.

If the value of life is $3.2 million, the benefits of prevented fatalities are only $16 million and total benefits fall to between $95 million and $149 million. At $8.4 million per fatality, the total benefits rise to between $153 million ($111 million + 5 * $8.4 million) and $207 million ($165 million + 5 * $8.4 million)

The effects of these changes on net benefits are illustrated below.

**Exhibit A-1 Present Value of Cost, Present Value of Benefits and Net Benefits Using a VSL of $3.2 Million, $5.8 Million and $8.4 Million Discounted at 3 Percent ($ Million)**

| VSL | Total Annual Benefits | Present Value of Benefits Discounted Over 50 years | Present Value of Costs Discounted Over 50 years | Net Benefits |
|---|---|---|---|---|
| 3.2 | 95 to 149 | 2,518 to 3,949 | 2,783 | (265) to 1,166 |
| 5.8 | 111 to 165 | 2,942 to 4,373 | 2,783 | 159 to 1,590 |
| 8.4 | 153 to 207 | 4,055 to 5,486 | 2,783 | 1,272 to 2,703 |

At a 3 percent discount rate and a VSL of $5.8 million, the present value of net benefits over 50 years ranges from about $159 million to about $1.6 billion; for VSLs of $3.2 million and $8.4 million, the present value of net benefits over 50 year ranges from about minus $265 million to about $1.2 billion and $1.3 billion to $2.7 billion, respectively.

**Exhibit A-2 Present Value of Cost, Present Value of Benefits and Net Benefits Using a VSL of $3.2 Million, $5.8 Million and $8.4 Million Discounted at 7 Percent ($ Million)**

| VSL | Total Annual Benefits | Present Value of Benefits Discounted Over 50 years | Present Value of Costs Discounted Over 50 years | Net Benefits |
|---|---|---|---|---|
| 3.2 | 95 to 149 | 1,403 to 2,200 | 1,618 | (215) to 582 |
| 5.8 | 111 to 165 | 1,639 to 2,437 | 1,618 | 21 to 819 |
| 8.4 | 153 to 207 | 2,259 to 3,057 | 1,618 | 641 to 1,439 |

At a 7 percent discount rate and a VSL of $5.8 million, the present value of net benefits over 50 years ranges from about $21 million to $819 million; for VSLs of $3.2 million and $8.4 million, the present value of net benefits over 50 years ranges from about minus $215 million to about $582 million and $641 million to about $1.4 billion, respectively.

Not unexpectedly, net benefits are higher with a higher VSL and lower with a lower VSL. However, at a statistical value of life of $3.2 million, the net benefits are negative at the low estimate of benefits at both 3 percent and 7 percent discount rates.

## APPENDIX B: Estimates of Average Cost per Life Saved

After the first year of the DIMP rule, the annual recurring compliance costs are estimated at about $101 million. The projected benefits that are expected from compliance with the rule are reduced deaths, injuries, and property damages, as well as reduced lost gas. For the three years, 2006-2008, there was an average of 10 fatalities, 40 injuries, about $33 million in property damages, and an estimated $759 million in lost gas per year associated with gas distribution systems. (There were some other societal costs such as emergency response costs, evacuation costs, and costs associated with non-reportable incidents that are not included in the monetary losses cited here.)

For illustrative purposes the regulatory evaluation assumed that half of the deaths, injuries, and property damages associated with gas distribution systems could be reduced by the rule, and 10 percent of the lost gas could be prevented. Thus, the projected annual benefits for these four items were estimated to be 5 lives saved, 20 serious injuries prevented, $16.5 million in property damages prevented, and $75.9 million in lost gas saved. To estimate the cost per life saved, the costs of compliance must be allocated to obtaining the other benefits of the rule and then the remainder of the compliance costs can be compared to the estimated lives saved.

Although the regulatory analysis demonstrated positive net benefits from compliance with the DIMP rule, to estimate a conservative cost per life saved, let us assume that there are zero net benefits associated with reduced injuries, property damages, and lost gas. That is, the costs of reducing those three societal costs are equal to the monetary value of the benefits. The annual monetary values of these three benefits are $11.3 million (20 injuries * $562,500 per injury requiring hospitalization) for reduced injuries; $16.5 million (half of $33 million) in reduced property damages; and $75.9 million (10 percent of $759 million) in reduced lost gas. These benefits total $103.7 million, which is $2.7 million more than the annual compliance costs of the rule, and suggest that under the assumptions in this example, there is no cost associated with saving 5 lives per year.

As an alternative, let us assume that the benefits of reduced injuries, property damages, and lost gas are half of those in the example above, but that the net benefits of those three categories are still held at zero. Then the annual monetary benefits of reduced injuries, property damages, and lost gas are the sum of $5.6 million (half of the $11.3 million above) plus $8.3 million (half of the $16.5 million above) for a total of about $89.8 million. With zero net benefits for those reductions, costs are also $89.8 million. Then costs associated with saving 5 lives are the remainder of annual compliance costs, which are $11.2 million ($101 million-$89.2 million) or about $2.24 million per life saved ($11.2 milion/5 lives), considerably less than DOT's latest suggested value of statistical life, $5.8 million. The $2.24 million cost per life saved is also lower than the $3.2 million that DOT guidance suggests for alternative analysis of rules.