Assuring the Integrity of Gas Distribution Pipeline Systems

A Report to the Congress

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Submitted by:

Office of Pipeline Safety
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Acronyms

AGA – American Gas Association
AGF – American Gas Foundation
APGA – American Public Gas Association
CFR – Code of Federal Regulations
DA – Direct Assessment
DOT – Department of Transportation
EIA – Energy Information Administration
EFV – Excess Flow Valve
FR – Federal Register
ILI – In-line inspection
IM – Integrity Management
IMP – Integrity Management Plan
LP – Liquid propane
NAPSR – National Association of Pipeline Safety Representatives
NARUC – National Association of Regulatory Utility Commissioners
OPS – Office of Pipeline Safety
PHMSA – Pipeline and Hazardous Materials Safety Administration
USC – United States Code

Executive Summary

The FY 2005 Conference Committee on Appropriations asked[1] the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) Office of Pipeline Safety (OPS) to submit a report detailing the extent to which integrity management plan elements may be applied to gas distribution pipeline systems to enhance safety. "Integrity management" refers to programs that OPS has required of hazardous liquid and gas transmission pipeline operators, through rules promulgated within the last five years. Integrity management requirements have not yet been established for gas distribution pipeline systems. The Department of Transportation's (DOT) Inspector General recommended that OPS take this action in testimony before the Congress in 2004.[2]

The principal focus of the existing integrity management regulations for pipelines is to identify the portions of the pipeline system that pose the most risk; to inspect the physical condition of those portions of the pipelines; and to repair any defects that could challenge the pipeline integrity. The fundamental principles of integrity management require: understanding the infrastructure and the risks it poses, and then taking actions to address those risks. There are significant differences in the design of gas distribution pipeline systems compared to the pipelines subject to current integrity management regulations. These include pipe size, operating pressure, materials, and the large number of branches and connections in distribution systems. These design differences significantly limit the applicability of the inspection techniques currently in use for those pipelines to distribution pipeline systems. The challenge is to develop appropriate methods to apply the principles of integrity management to enhance the safety of distribution pipeline systems, while remaining mindful of costs and service disruptions and their potential impact on consumers.

Gas distribution pipelines, those that deliver gas directly to consumers, are almost entirely under the regulatory oversight of state agencies. OPS has implemented a program jointly with its state partners and a broad range of stakeholders, to identify means appropriate to distribution pipelines to focus attention on areas that pose the highest risk and to better assure the integrity of those portions of the distribution systems, in other words, integrity management.

The first phase of the program is to be completed in 2005 and will identify 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. This phase will include consideration of a multi-faceted set of potential approaches, including regulations and guidance, but will also consider a national education program, development of new inspection technologies, and legislative models that states could adopt. The second phase, to begin in January 2006, will include development of appropriate requirements by OPS and preparation of guidance/standards by appropriate bodies.

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[1] House of Representatives Report 108-792, November 20, 2004.

[2] "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.

1. Program Overview

The DOT Inspector General, in testimony before Congress in July 2004,[3] recommended that OPS should define an approach for requiring operators of distribution pipeline systems to implement some form of integrity management or enhanced safety program with elements similar to those required in hazardous liquid and gas transmission pipeline integrity management programs. The Appropriations Committee asked OPS "to report to the House and Senate Committees on Appropriations by May 1, 2005, detailing the extent to which integrity management plan [IMP] elements may be applied to the natural gas distribution pipeline industry in order to enhance distribution system safety".[4]

Industry and government have long been committed to the safe operation of the Nation's 1.9 million miles of natural gas distribution pipelines. Building on the existing set of requirements, regulators and pipeline operators continue to examine natural gas distribution practices to understand the most effective approaches to improving the integrity and safety of these systems.

During the past five years, OPS (as part of PHMSA) has promulgated regulations designed to improve the integrity of liquid and gas transmission pipelines. Together with our State partners, PHMSA has undertaken inspection of the programs by which operators are implementing these regulations. Implementation of these regulations has led both to improvements in the operators' knowledge of their pipelines, and to identification and repair of thousands of defects in these pipelines. OPS also regulates distribution pipeline systems.[5] Pursuant to agreements among OPS and the States, state inspectors perform most of the inspection and enforcement of the pipeline safety regulations on gas distribution systems. OPS ensures that State programs provide safety oversight in compliance with the Federal pipeline safety regulations.

OPS and our State partners developed a program through which we will thoroughly reexamine means for strengthening the safety of distribution pipeline systems. This program will address the three elements of the strategy described by the DOT Inspector General: (a) understanding the infrastructure; (b) identifying and characterizing the threats; and (c) determining how best to manage the known risks (prevention, detection and mitigation). These three elements are essentially the same as those underlying the transmission pipeline integrity management regulations. The program will provide the basis for establishing integrity management requirements for distribution pipeline systems. These requirements must be different than those that have been applied to hazardous liquid and gas transmission

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[3] Ibid.

[4] House of Representatives Report 108-792, November 20, 2004.

[5] Gas transmission pipelines transport gas from areas where it is produced to areas where it is consumed. These pipelines are generally steel, of large diameter, operate at high pressures, and traverse long distances, sometimes more than 1,000 miles. Distribution pipeline systems are the network of pipes in communities that provide gas directly to consumers. They consist of small diameter pipelines, operating at low pressure, and constructed of a variety of materials. Distribution pipelines exist as a network with many branches in short distances (e.g., a service line connection for each house on a city street). The differences between the two types of pipelines can lead to a need to use different approaches to assuring safety, as described in this report.

pipelines, because the models and tools prescribed by those regulations have only very limited applicability to distribution pipeline systems.

The program presented in this Report was designed to identify opportunities for improving the safety of distribution pipeline systems. Our analysis of the past few years of data identified that in order to address safety threats to distribution pipelines, there are a number of target audiences that PHMSA needs to involve in developing strategies to reduce these threats. Accordingly, OPS is involving a larger number of key stakeholder groups than contacted in the past, including State and Federal regulators, representatives from the spectrum of distribution operators, interested members of the public, and representatives of our Nation's fire service. These participants are organized into work/study groups that will gather and analyze data to help focus the effort and ultimately identify options for attaining improved safety. In addition, OPS will be posting information on a public web site as the program activities progress, to offer an opportunity for other interested members of the public to comment.

OPS organized the program in two major phases. During the remainder of 2005 (Phase 1) work/study groups will gather and analyze data, and develop the elements of a safety improvement program. During the following year (Phase 2) OPS and pipeline standards development organizations (if needed) will work to develop requirements, guidelines and standards that will be implemented using some combination of four options favored by a consensus of the stakeholder group.

- The first option is a high level, risk-based, performance-oriented Federal regulation.
- The second option is supplemental information through one or more guidelines or national consensus standards describing choices on how the spectrum of distribution pipeline operators might apply fundamental risk-based principles to achieve the desired improvements. States would then have the opportunity to draw on the standards and guidance to promulgate regulations describing how the unique set of operators they regulate should implement improvements satisfying the Federal requirements.
- Third is a structured nation-wide education program on preventing excavation damage, focused on the new 811 one-call program.
- The final option is development of innovative safety technologies capable of producing observable safety improvements.

The requirements that may result from this program could prove expensive for operators to implement. The view of an executive steering group[6] was that it is important to consider all costs related to new efforts to prevent and mitigate distribution line incidents together, in order to assure the most cost-effective solution. Thus, the group emphasized the importance of evaluating all options for preventing, detecting and mitigating threats to public safety consistently. For example, the group indicated its preference that use of excess flow valves (EFVs) as a means of mitigating the impact of severed gas distribution lines should be

[6] See Section 6 for a description of the groups involved in the Action Plan

considered as part of the overall distribution safety improvement program, rather than being addressed in a separate Federal mandate.

2. Regulation of Distribution Systems and the Role of State/Federal Governments

The principal authority for regulating the safety of gas distribution pipeline systems is exercised by State governments. Under 49 USC 60105 and 60106, States may exercise jurisdiction if their pipeline safety programs are certified by the DOT or if they enter into an agreement with DOT absent certification. At this time, all States except Alaska and Hawaii exercise safety jurisdiction under these provisions. States have a variety of ways in which they can oversee distribution pipeline safety. They can simply mirror the Federal pipeline safety program. They can impose additional requirements, beyond the Federal minimum. They can engage in special oversight programs with individual operators or groups of operators. Finally, they can provide incentives for safety improvements, often through their rate-setting authority.

The Federal government has ultimate responsibility in regulating intrastate distribution pipeline operators. The Federal standards in 49 CFR Part 192 establish a minimum set of safety requirements that all states must implement. The DOT also collects data concerning distribution system mileage, incidents that occur on systems, their leak repair experience and other information about the size, age and material(s) of construction of their distribution piping. Initial consideration of an approach to integrity management for distribution pipeline systems will seek to identify changes that could be made in DOT data collection that would help improve the ability of State and Federal regulators to analyze and more clearly understand distribution system's operating experience. The Office of Pipeline Safety will define further what improvements are needed and will determine if changes to its data collection forms are needed.

OPS provides funding for the operation of State pipeline safety programs through a grant program that funds States' oversight efforts. OPS has, in the past, identified emphasis areas for State focus in their oversight programs. These emphasis areas have included content of state regulations, pursuit of special initiatives, approaches to inspection of operators, and data collection and reporting. OPS can adjust its criteria for state funding grants to assure that appropriate emphasis exists in each State's program.

One area for special grant allocation resources is damage prevention – being proactive to reduce the likelihood that distribution pipelines will be damaged during excavation work. (This is a principal threat to the integrity of distribution pipelines).

OPS is also engaged in work with state fire marshals, and has included a representative of this community in the distribution integrity management program. Representatives of public interest groups are also involved in helping to define the appropriate approaches to assuring distribution system integrity. This inclusiveness demonstrates the willingness of OPS and States to go beyond previous efforts to improve the assurance of distribution pipeline system safety. The OPS will also seek other input through posting documents related to this program on a web site.

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

States must have flexibility to deal with their local circumstances. It would be both ineffective and inefficient, for example, to impose requirements intended to address frost heave damage in the desert southwest. Integrity management requirements for distribution pipeline systems will be structured in a manner that allows States the necessary flexibility in implementation.

3. The Gas Distribution Safety Baseline

In order to know what opportunities there are to enhance distribution pipeline safety, we must first examine where and how operators are performing today.

There is very significant diversity among gas distribution pipeline operators in the United States. The size and technical depth of operators of distribution pipeline systems, the nature of the systems they operate, the requirements they must meet, and the practices that they use to assure safety all vary widely. An understanding of these differences, and the current approach to sharing and using practices that go beyond the regulations, i.e., the "baseline" level of program management, will be useful in understanding the approach being taken to enhance distribution integrity management.

Diversity of Operators

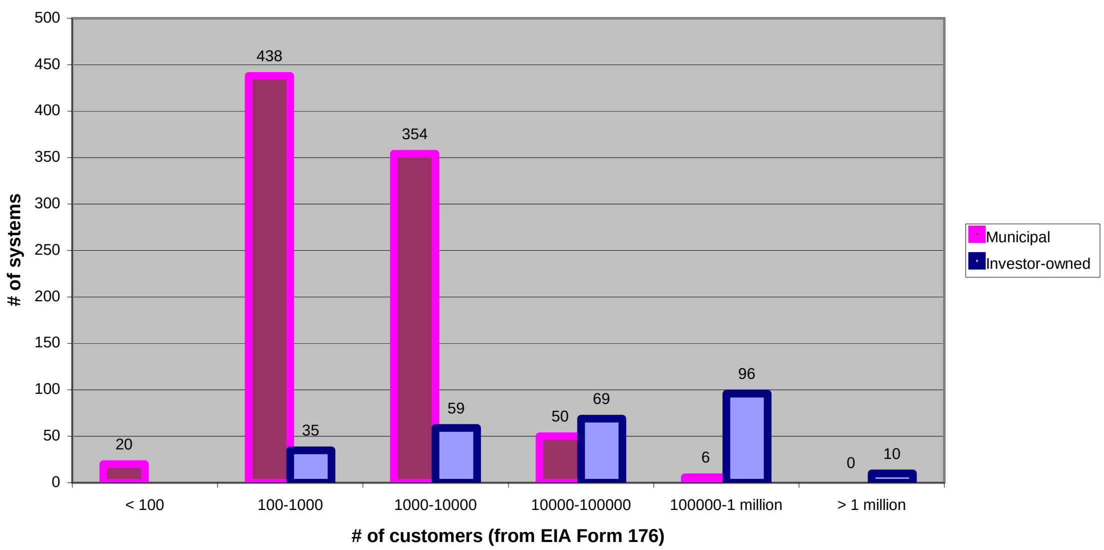
Operators of distribution pipeline systems subject to OPS/State safety regulation are of four different types:

- Master meter systems (e.g., trailer parks, individual multi-occupancy buildings)
- Publicly owned (e.g., town/city/county) municipal utilities
- Investor-owned utilities
- Propane gas distribution systems

The order within this list represents the prevalence of each type of operator. There are approximately 1,000 publicly owned utilities delivering gas to consumers in the United States. By contrast, there are approximately 250 investor-owned utilities engaged in this business.

There are several thousand master meter operators and a few hundred liquid propane (LP) gas systems that are subject to the safety regulations in 49 CFR Part 192.

Figure 1 - Distribution systems subject to 49 CFR 192
(Prepared by APGA from E IA data)



Note: EIA does not maintain data on the number of customers served by master meter systems or liquid propane (LP) gas systems. There are several thousand master meter operators, the vast majority of which serve less than 100 customers. There are approximately 200 LP gas systems most of which also serve less than 100 customers.

Within each of these groups, the size of individual operators also varies widely, as shown in Figure 1. Publicly-owned utilities tend to be smaller, with a majority serving less than 1,000 customers. In general, investor-owned utilities tend to be larger, with slightly over 100 companies serving more than 100,000 customers each. There are examples, though, of publicly owned utilities serving 100,000 customers and of investor-owned companies serving less than 1,000. The variability makes it difficult to generalize regarding these groups. The particular circumstances of each operator must be taken into account.

Master meter operators are businesses such as apartment complexes, or mobile home or trailer parks, or are government entities like housing authorities and universities that receive gas from an outside supplier and distribute it via pipelines located within their facilities. These operators are generally small, with a large majority serving fewer than 100 customers. Distribution of gas, or operation of the distribution systems, is not their principal business. Propane system operators subject to pipeline regulation are also small. Propane used in individual installations, such as a rural farm with its own propane tank, is not subject to regulation as a pipeline system. Propane systems become subject to regulation when they distribute gas, by pipeline, to 10 or more customers. The large majority of these systems likely serve fewer than 100 customers.

Diversity of Infrastructure

The pipeline systems operated by these operators are also subject to much variation.

Natural gas has been distributed by pipeline in some areas for over a hundred years. Pipeline systems in these areas were originally small, serving a few customers. These systems merged as larger distribution companies were formed. The materials in use in some of these systems reflect older (e.g., cast iron, copper, bare steel) as well as newer (e.g., polyethylene plastic and cathodically protected coated steel) technology.

In other areas, distribution of natural gas by pipeline is a relatively new phenomenon. In some rural areas, for example, gas may not have been available until a transmission pipeline was routed into the vicinity. Then, municipalities or distribution companies may have created a distribution system to bring natural gas service to customers for whom it was previously unavailable. Systems of this nature tend to be relatively uniform in age and type of materials, but the threats to integrity (such as electrical interference from other buried substructures and localized flooding or vehicular traffic patterns) may still vary from one location to another. Additional diversity will likely be introduced as systems age, new customers are added, and portions of the original systems are replaced.

Individual master meter systems and propane systems tend to be relatively uniform due to their small size and limited geographical extent.

Existing Regulations and Practices

The Federal pipeline safety standards in 49 CFR Part 192 provide a common base of requirements applicable to distribution pipeline systems. These standards address design, construction and operation of pipeline systems as well as requirements affecting inspection, maintenance, repair and testing and also qualification of pipeline operations personnel. States are required to adopt these standards as one of the criteria for certifying their pipeline safety programs or for entering into an agreement with OPS to exercise safety jurisdiction. States can, and do, impose additional requirements where appropriate.

The National Association of Pipeline Safety Representatives (NAPSR) is an organization consisting of the senior regulatory program manager from each State that exercises pipeline safety jurisdiction. NAPSR recently conducted a survey of its members to identify the extent of additional State requirements that go beyond Part 192. The survey identified that most States impose some additional requirements. A majority impose stricter criteria for reporting incidents and/or requires that operators notify the regulator of construction or testing that would provide an opportunity for the regulator to examine the pipeline and observe safety-significant work. These type of requirements reflect the close oversight relationship that exists between most state regulatory programs and the operators they regulate. State regulators generally interact routinely with operators under their jurisdiction, and therefore know their systems and personnel. States are actively engaged, on a daily basis, in overseeing safe operations. Additionally, approximately 25 percent of the States impose requirements for leak surveys beyond those required in Part 192.

The NAPSR survey also identified that approximately 65 percent of States have a program to replace some types of distribution piping. This may include cast iron pipe, uncoated and unprotected steel pipe, or certain types of plastic pipe that have been found to be subject to deterioration in service. The replacement programs vary in scope. In some cases, they involve all (or nearly all) of the operators in a State. In other cases, they may involve individual operators and may have been initiated as a result of an incident or event that highlighted problems associated with the aging material.

A summary of the NAPSR survey results is included as Attachment 1 to this report.

In addition to the NAPSR survey, OPS contacted several larger investor-owned utilities to obtain information about their safety practices that exceed minimum regulatory requirements. The operators surveyed, all of which serve mid- to large-sized cities, all reported that they use risk evaluation to help direct work on their pipelines. This supports a conclusion of the American Gas Foundation (AGF) that 82% of companies they surveyed use risk control practices.[7] Use of risk models is not currently required of distribution system operators. Neither OPS nor States have audited these models or their application. We therefore cannot comment yet on the thoroughness of the approaches used, but note with satisfaction that the concept of using an estimate of risk to manage safety activities is becoming widely prevalent.

OPS' discussions also identified that the larger operators all had pipe management programs that included replacing portions of their system: where problems had been experienced identifying materials susceptible to failure; where certain construction practices potentially leading to problems may have been used; that include their older pipelines; or based on estimated risk. Again, this reinforces the AGF conclusion that 65% of surveyed companies had replacement programs.[8] (It should be noted that replacement of pipe in highly built-up urban areas can be difficult due to the number and complexity of buried infrastructure facilities and the difficulty of working in the urban environment.)

The operators contacted by OPS also perform leak surveys more frequently, based on unique operating conditions, than would be required by regulations and implement special practices to reduce third party damage.

Most of the operators contacted by OPS also reported that they have elected to install excess flow valves (EFV) for new and replacement services, which goes beyond the regulatory requirement that customers be apprised of the availability of EFVs and that they be installed if the customer agrees to pay for them.

The most prevalent safety practice followed by distribution system operators that is not required by Part 192 is membership in damage prevention programs, most often referred to as "one-call" programs. The AGF reports that over 95 percent of operators belong to such

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[7] American Gas Foundation, "Safety Performance and Integrity of the Natural Gas Distribution Infrastructure", January 2005, p. 5-11.
[8] Ibid, p. 5-13.

programs.[9] Most states require gas utilities to belong to one-call programs. The breadth of participation in these activities provides a basis to presume that excavation damage incidents can be reduced. However, unfortunately, these incidents continue to occur. They are undoubtedly less prevalent than they would be in the absence of one-call programs, but they still represent a threat to distribution pipeline systems. This program will specifically include a review of industry practices and other approaches to prevent or reduce damage to identify ways in which their effectiveness can be improved.

Insights from Incident Data

The principal source of information available about distribution pipeline system safety and integrity is the data resulting from incident reports submitted to OPS. These reports are filed by operators, pursuant to 49 CFR 191.9, and include events occurring on jurisdictional pipelines that involve either: 1) a death or personal injury necessitating in-patient hospitalization; 2) estimated property damage, including cost of gas lost, of the operator or others, or both, of $50,000 or more; or 3) events that are significant, in the judgment of the operator, even if neither of the other criteria is met or exceeded.

OPS changed its incident report form in 2004 to require that the cause of incidents be reported more precisely. All incidents reported prior to that time were attributed by the reporting operator to one of five major causes, one of which was "other." Using the revised forms, operators identify one of seven major causes, which are further subdivided into 25 second-level causes. This change is intended to improve our understanding of the factors that result in gas pipeline incidents.

The set of incident data submitted by operators represents significant problems that occur on the pipeline. It does not include all events involving or exacerbated by natural gas from distribution pipeline systems. For example, problems with an appliance in a customer's home could result in an accumulation of gas, an explosion, and fire, potentially resulting in injury or death. Although the media may report such events as gas pipeline incidents, they are not. OPS has no regulatory authority over customer-owned piping or gas appliances, and operators are not required to report such events to OPS. Customer piping within homes and businesses is regulated by local building codes, often based on the National Fuel Gas Code or other model codes.

There have been two recent studies that considered recent distribution incident experience. One was conducted by the AGF, under the oversight of a committee formed of representatives from AGF members and state pipeline safety regulators. The results of this study were reported in "Safety Performance and Integrity of the Natural Gas Distribution Infrastructure," published by AGF in January 2005. The other was performed by Allegro Energy Consulting, in late 2004, under contract to OPS.

The AGF study covered the period from 1990 to 2002. During that period, AGF found a statistically significant downward trend in "serious" incidents, defined as those involving a

[9] Ibid, p. 5-12.

death or injury. (AGF chose to focus on these incidents because the reporting criteria are not as subjective as "significant to the operator" nor do local economic factors or inflation affect reporting of an event wherever or whenever it occurs.) The AGF concluded there were approximately 1.6 serious incidents per 100,000 miles of distribution pipeline during 2002. The AGF study identified that nearly half of the serious incidents occurring during the study period were a result of outside force damage. The only other cause category contributing to more than 10 percent of serious incidents was "other" which was responsible for almost 27 percent.

The Allegro study re-evaluated five years of incident report data (1999-2003) to re-classify them to the new cause categories. This was accomplished by reviewing the narrative description of the incident that the operator provided when submitting the original report. Allegro considered 634 incidents reported in the five-year period. One third of them involved death or injury, i.e., would have been considered "serious" incidents by the AGF study. Nearly one half were reported due to the cost of damages alone. Six percent of the incidents apparently did not meet any of the reporting criteria, but they were still retained in the Allegro analysis.

Allegro's re-classification was successful in reducing the number of incidents for which the cause could not be attributed from the 27 percent noted in the AGF study to 12 percent. Allegro further found that a large majority of the incidents (67%) were caused by outside force damage. The new cause categories permitted Allegro to break the outside force damage category down into several components. Thirty-eight percent of the incidents were caused by excavation and mechanical damage (the vast majority caused by third parties), but 29 percent were caused by other sources of outside force. This new category included two major components: "fire first" and vehicle damage, each representing 11 percent of the total number of incidents.

The fire first events represent incidents in which a building was on fire and the operator responded, but the fire was not caused by a gas leak. In many cases, the gas supply system in the building is compromised or damaged by the fire and contributes to its intensity until the gas can be shut off. Fire first incidents are not caused by problems in the gas distribution system and cannot be addressed in a distribution integrity management program.

The vehicle-related events represent incidents in which a vehicle impacts a portion of the pipeline system, often the above-ground meter assembly. The accidents resulted from multiple causes, including drivers operating their vehicles while intoxicated and unattended vehicles rolling into the pipeline system. Allegro found that this category of incidents, while representing 11 percent of all incidents, involved 25 percent of the fatal incidents over the period studied. Thus, these data tell us that 1 out of 4 of the fatal incidents during this period <u>could not have been prevented by any preventive action taken on the pipeline</u>. Reducing the number of these incidents is likely to require actions that affect persons not under the regulatory jurisdiction of OPS or State pipeline regulatory authorities, i.e., vehicle operators.

A summary of the Allegro report is included as Attachment 2.

Innovative Practices

The American Gas Association (AGA) each year sponsors groups from among its members to identify innovative practices that they employ to improve operational performance and safety. These groups typically evaluate approximately five topic areas (e.g., damage prevention, main and service replacement, system reliability). In each area, practices of member companies are shared, innovative practices are identified, and the information is exchanged with participants at a roundtable forum. Detailed information is available only to companies that have participated in the groups.

These forums serve a useful purpose and can contribute to expanding the understanding and application of innovative practices. This expansion can occur among participants, which are generally the larger, investor-owned companies. The results of these efforts are not available to operators that do not directly participate in the program, particularly publicly-owned operators that are not usually members of AGA.

OPS believes that these activities have a positive impact on the reduction of incidents disproportionate to the percentage of operators that participate. There are two reasons for believing this: the large-operator participants operate a much larger percentage of the total distribution pipeline mileage than their numbers might suggest; and smaller operators, particularly those with only a few persons on staff and a limited amount of pipeline mileage, generally have much better detailed knowledge of their systems and the issues that affect them.

Nevertheless, the impact of these activities is limited. Participation is not available to municipal operators who are not AGA members and often lack the staff resources necessary to become involved in this kind of outside activity. Also, not all AGA members participate in these activities.

Monitoring the Effectiveness of Actions

It is important that the effectiveness of whatever actions are taken to improve distribution pipeline safety be monitored. The ultimate measure of distribution pipeline system safety is the number of deaths and injuries and the amount of property damage caused by incidents on distribution pipeline systems. Fortunately, however, incidents occur relatively infrequently. Other interim measures are needed to evaluate the effectiveness of any new integrity management requirements implemented for distribution pipeline systems. An interim measure might be how any new regulatory initiatives impact system operators (e.g., the number of assessments or repairs that have been conducted is an interim measure of the effectiveness of the hazardous liquid and gas transmission integrity management rules). The program described in this report includes development of a way to measure these impacts and to develop a baseline from which improvements can be measured.

4. Evaluation of Applicability of Transmission IM Program and Practices

OPS promulgated regulations in recent years requiring that pipeline operators (other than distribution pipeline operators) implement integrity management programs. These regulations apply to operators of hazardous liquid pipelines (49 CFR 195.452, published at 65 FR 75378 and 67 FR 2136) and to operators of gas transmission pipelines (49 CFR 192, Subpart O, published at 68 FR 69778). It is reasonable to ask why the same techniques used in these regulations cannot simply be applied to gas distribution pipeline systems. Both regulations set requirements for making best use of information to set safety priorities and to perform continuous evaluations.

Integrity Management Elements

The integrity management regulations for hazardous liquid and gas transmission pipelines are similar. Both require that operators identify segments of their pipeline where an incident could create high consequences. Both require that operators implement a program to assure the integrity of these pipeline segments. An operator's integrity management program must include an assessment of the risk posed by the pipeline and use of that risk information to prioritize certain actions. Principal among these actions is the conduct of inspections/ assessments utilizing in-line inspection tools, pressure testing, direct assessment, or other technology that provides an equivalent understanding of the pipe condition. Anomalous conditions identified by the inspections must be repaired within a period commensurate with the safety significance of the anomaly.

Applicability to Distribution Pipeline Systems

The basic premise of the integrity management programs for gas transmission and hazardous liquid pipelines – identify the risks and take actions to address them – is obviously applicable to distribution pipeline systems. However, many of the techniques used to implement this premise for hazardous liquid and gas transmission pipelines are of more limited applicability to distribution systems.

<u>Identifying High Consequence Areas</u>

The first element of existing integrity management programs is to identify those segments of the pipeline where an incident/break could result in high consequences. This is important for hazardous liquid and gas transmission pipelines because both traverse large distances, including areas that are sparsely populated or where accident consequences would be small. So-called high consequence areas are identified in order to improve the effectiveness of integrity management requirements by focusing efforts on the pipe where significant consequences could occur.

a. Hazardous liquid pipelines

Hazardous liquids generally do not evaporate if released during a pipe break. Released liquids can spread to adjacent areas and cause adverse consequences to people, local flora and fauna, or drinking water supplies. OPS, working with State heritage and resource conservation programs, has identified areas in the U.S. that include population concentrations, habitats for threatened and endangered species, and sources of drinking water. Hazardous liquid pipeline operators are required to compare these locations to the location of their pipelines, identify where accidental releases from their pipelines could affect these areas, and focus their integrity management efforts on those pipeline segments. This approach is not applicable to natural gas pipelines, since natural gas is lighter than air and will disperse into the atmosphere rather than flow overland to nearby areas.

b. Gas transmission pipelines

The risk from gas pipeline releases is ignition of the gas and the resulting fire or combustion occurring near the location of the pipeline. For gas transmission pipelines, pipeline segments that could cause significant consequences are identified using a mathematical correlation based on past incidents that estimates the distance from the pipeline that could be affected by a resulting fire occurring from the ignition of the released gas along the pipeline. Operators of natural gas transmission pipelines are required to evaluate “potential impact circles” based on this calculated distance to determine whether the circles encompass a threshold number of residences, locations where people congregate, or locations where there are populations that would be difficult to evacuate. Gas transmission pipeline integrity management activities are focused on these pipeline segments.

c. Gas distribution pipelines

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

Further, the mathematical correlation used to estimate the area that could be affected by an incident on a gas transmission pipeline is not applicable to most distribution pipelines. It presumes that pipe failure and the potentially resulting fire will occur at the location of the pipeline leak/failures. This is a reasonable assumption for high-pressure transmission pipelines, where the internal pressures create stresses that expand small leaks into ruptures. The assumption is inappropriate for distribution systems, since they do not operate at high pressures. Leaks from low-pressure distribution pipelines do not usually progress to failures. Instead, gas that is released from the pipeline migrates underground. The released gas can collect in confined spaces, such as nearby buildings, and result in fires that occur at locations away from the pipeline.

The techniques used to identify hazardous liquid and gas transmission pipeline segments where incidents can result in high consequences are not applicable to gas distribution pipeline systems. Some other means of focusing integrity management attention is needed.

Assessing Pipeline Integrity

The techniques used to conduct inspections/assessments of hazardous liquid and gas transmission pipelines have limited usefulness for gas distribution pipeline systems. These techniques are:

- In-line inspection
- Pressure testing
- Direct Assessment

a. In-line Inspection

In-line inspection (ILI) is conducted by passing a tool through the pipeline that examines the pipe wall to identify areas where the wall has been damaged or where wall thickness has been reduced, such as by corrosion. The tools used must be of a size that will fit in the pipeline. The tools fit tightly and are pushed along by the pressure of the moving gas or liquid in the pipeline. The sensors used to examine the pipe wall almost always make use of a magnetic flux imposed on the pipe wall, and thus only work with ferrous metal pipelines.

The vast majority of pipelines in distribution pipeline systems are of small diameter, some less than one inch in diameter. ILI tools cannot be made that will fit these small-diameter pipelines using currently available technology. The gas pressure in distribution pipeline systems is also generally too low to propel a tool, even if current technology provided one to fit in the line. In addition, a large portion (as much as half) of the pipe in distribution pipeline systems is plastic. The sensors used in in-line inspection tools cannot examine plastic pipe walls. Finally, distribution pipeline systems exist as a network of interconnected pipe rather than as single runs of pipe traversing long distances. It is not practical for in-line inspection tools to negotiate the many turns and interconnections that exist in distribution pipeline networks.

ILI tools have limited utility in assuring distribution pipeline integrity.

b. Pressure testing

Pressure testing is a traditional means of testing a pipeline. The ends of a section of pipe to be tested are closed, using valves or temporary plugs, and the fluid (water or gas) between those ends is raised in pressure until it produces stresses in the pipe wall that are near those that the pipe was designed to withstand. These pressures are much higher than those experienced during normal operation. Weak areas, such as result from corrosion that reduces pipe wall thickness, are identified by leaks or ruptures during this pressure test. Such areas are found and repaired, and the test is repeated until the pipe is demonstrated to be able to hold the high pressure. This assures a significant safety margin for subsequent operation at the lower pressures normally experienced in operation.

All pipes can be tested using pressure tests. Virtually all pipes are initially subjected to pressure tests at the mills where the pipe is produced to verify the adequacy of the manufacturing process. Distribution pipelines are also pressure tested prior to being placed into service, as required by 49 CFR 192, Subpart J. However, use of pressure testing on installed pipeline systems can pose significant difficulties.

Pipe to be pressure tested must be taken out of service. The act of plugging the ends to contain the high test pressure precludes using the pipe at the same time to transport gas. Use of pressure testing in gas distribution pipeline systems thus would require that gas service to customers be interrupted for the duration of the test. Each affected customer would have to be visited to assure that valves controlling gas flow to pilot lights are closed, so that gas would not enter the structure when service is resumed and potentially result in an ignition. Each affected customer must again be visited once gas flow is resumed to re-open those valves and re-light pilot lights. This process is time consuming and costly. Errors in carrying out this process could result in the very consequence (i.e., ignition and a fire) that integrity management programs are intended to prevent.

Additional difficulties are introduced by the interconnected network nature of gas distribution pipeline systems. Pressure testing a single length of pipe requires that the two ends be closed. Where interconnections and branches occur frequently (e.g., every block in most city systems), it is not practical to test the segments between each branch point individually. Thus, each branching pipe must be closed, increasing the number of excavations that must be made and the complexity of conducting the test. Additionally, each service connection off of a gas main must be plugged to permit pressure testing of the main. Pressure testing of service lines requires that they be plugged at the point at which they enter the customer's location, requiring disturbance of the customer's property or work within their home/business.

Pressure testing of distribution pipeline systems, while possible, is extremely costly and impractical.

c. Direct Assessment

As use of in-line inspection devices can also be impractical for some gas transmission pipelines, an alternative method of assessment, called Direct Assessment, was developed. In-line inspection of gas transmission pipeline can be impractical because of changes in pipe diameter or valves that obstruct the passage of the ILI test device. Additionally, it is also impractical to remove some transmission pipelines from service for pressure testing (e.g., a pipeline that is the sole source of gas supply for a community). Direct Assessment was developed as an assessment method for transmission pipelines that cannot be tested by these other methods. Direct Assessment does not require service interruption. It uses indirect inspection methods to identify locations where corrosion could be occurring on the pipeline. These locations are then excavated, examined, and repaired as needed.

Direct Assessment is a new technique that has been validated for transmission pipelines. The formal and comprehensive process associated with Direct Assessment has not been demonstrated to be effective for distribution pipeline systems and there are technical reasons to believe that it will not be effective in that environment.

The indirect inspection techniques that are used as part of Direct Assessment for determining where excavation and direct examination are needed involve looking for inconsistencies in the electrical current imposed on steel pipelines to prevent corrosion (cathodic protection). These techniques are not applicable for plastic pipe, and there is no practical method for conducting an indirect examination of plastic pipe. Since approximately half of piping in distribution pipeline systems is plastic, Direct Assessment can simply not be used on approximately half of distribution network piping.

Even for metal pipe, application of Direct Assessment in a distribution network environment will be, at best, problematic. The distribution pipelines posing the highest risk tend to be older systems that are cast iron, bare steel (i.e., not coated to protect against corrosion), and coated steel pipe not subject to cathodic protection. The indirect inspection methods used as part of Direct Assessment have very limited applicability for these types of pipe. The methods usually rely on detecting minor variations in the cathodic protection current that could indicate breaks in the pipe coating where corrosion could be occurring. These areas are then excavated so that the pipe can be examined directly to determine if corrosion is present. The indirect methods cannot identify specific areas where there is a higher likelihood of corrosion if the entire pipe surface is uncoated or if there is no impressed cathodic current in which to look for variations. Again, the indirect inspection methods do not work or are very difficult to apply for these situations.

Coated steel pipe that is cathodically protected is the ideal environment for use of Direct Assessment on transmission pipelines. Its use for similar pipe in distribution pipeline systems is not as straightforward. Distribution pipelines are installed in urban environments in which they share space with other underground utilities including water pipes, cable TV, fiber optic, telephone, and electric service. These other underground services can result in significant electrical interference that could make it difficult or impossible to evaluate small changes in the electrical current imposed on cathodically-protected pipelines to identify breaks in pipe coating, etc. That is precisely the purpose of the indirect examinations, as breaks in coatings are areas where corrosion could occur and direct examination may be appropriate. Further research would be required to estimate with certainty the percentage of distribution pipeline where Direct Assessment, as defined for transmission pipelines, may prove practical, but it is likely to be small.

Direct Assessment, then, cannot be used on approximately half of distribution pipelines (i.e., plastic pipe). It is of limited, if any, value for the riskiest distribution pipe (i.e., cast iron, bare steel, and non-cathodically-protected steel). It may have, at best, limited applicability for the pipe that is best protected and likely of least risk (i.e., coated cathodically-protected steel pipe).

Applicability of Current IMP Practices

As discussed above, the traditional techniques used as part of integrity management programs for hazardous liquid and gas transmission pipelines are not appropriate for use with distribution pipeline systems. The methods used to identify pipeline segments where high consequences can occur do not accommodate the different nature of incidents on distribution pipeline systems. The means used to inspect the condition of the pipelines are often impractical (in-line inspection), costly and impractical (pressure testing), or of questionable and likely little value (Direct Assessment).

Additional work, through this program, is needed to identify practical ways to address integrity management questions for distribution pipeline systems, including how to identify pipe that requires additional attention and the appropriate actions to apply to that pipe.

5. Principles Guiding the PHMSA Approach

If the tools and methods used for integrity management of other pipeline systems cannot simply be applied to distribution pipeline systems, then it is necessary to identify new approaches using a set of basic guiding principles. Stakeholder groups have also recognized this need and have taken actions that inform our principles.

The National Association of Regulatory Utility Commissioners (NARUC) is an organization whose members include the governmental agencies that are engaged in the regulation of utilities in each State. NARUC considered the issue of assuring the integrity of distribution pipeline systems at its winter meeting, held in Washington, DC in February 2005. NARUC adopted a resolution at that meeting supporting the joint efforts of OPS, gas distribution pipeline operators and other stakeholders to develop an approach to better assure distribution pipeline integrity. NARUC recognized the effort already invested in this area and the difficulties involved, as summarized above. NARUC recommended that an approach be developed,

> that uses risk-based, technically sound and cost-effective measures, which reflect that stakeholders are: knowledgeable of the infrastructure; can identify threats against their systems; and can take appropriate measures to reduce the risk of system failures while balancing the needs to ensure continued safe operation, reliable service, and the implications of any increased financial demands on the customer.

The NARUC resolution is included as Attachment 3 to this report.

The Board of the American Public Gas Association (APGA) has also approved a similar resolution. APGA is a national trade association comprised of about 600 natural gas utilities owned and operated by the governments of the communities they serve. The APGA recognizes the reduction in incident rates over the past two decades, but that serious distribution incidents continue to occur. They note that assuring the safety of the public living and working near their pipelines is their number one priority, and resolve that it is appropriate for OPS to consider how integrity management principles can be incorporated into distribution pipeline safety programs. The APGA offers several considerations, including:

- the differences between distribution and transmission pipeline systems described above,
- the primary role of state regulators,
- actions now taken by operators and states that go beyond minimum regulations,
- the need to recognize potential financial burdens, and
- the need to assure system reliability and continuity of service.

The APGA resolution is included as Attachment 4 to this report.

Finally, last December, the American Gas Association (AGA) Board endorsed addressing distribution integrity by taking a common sense, risk-based, and technically defensible approach that would not place an undue burden on consumers. The American Gas Association represents 195 local energy utility companies that deliver natural gas to more than 56 million homes, businesses and industries throughout the United States. The AGA committed to working with State and Federal regulators, pertinent standards bodies, industry and the public to consider any proposal to enhance the safe, reliable and efficient delivery of natural gas.

These actions reflect the long-standing commitment of industry and government to safe operation of the nation's 1.9 million mile natural gas pipeline system. Regulators, legislators and pipeline operators independently and jointly have been examining natural gas distribution practices to determine the most effective approach to distribution system integrity and safety. In developing recommendations for an effective, systematic approach to distribution integrity, it is vital to take into account the unique characteristics and functions of gas distribution lines.

The following principles apply to this program:

1. Improving the integrity and safety of the Nation's distribution infrastructure will require further strengthening of the relationship among State regulators, Federal regulators, operators, the public and others who have a role to play in pipeline safety. This improvement should be based on recognition of a shared interest in improving safety and on enhanced openness in achieving this improvement

2. Distribution integrity management should be based on the threats to distribution safety, as well as how existing regulations and practices address these threats.

3. States should exercise their prerogative to choose how they regulate distribution pipeline safety, consistent with their specific needs, including their ability to establish regulations that exceed the minimum Federal requirements.

4. Any process identified for distribution integrity must be risk-based, technically defensible and cost beneficial.

5. Any new regulation must consider the added financial burden placed on the consumer, as well as the impact of expenditures by municipalities on resources available for other community safety improvements.

6. Any new integrity management provisions must ensure continued reliability of service to the consumer.

7. Progress in implementing improvements should be measurable from the current baseline level.

8. The approach to identifying improvements to distribution integrity should be a consensus process that includes the involvement of State and Federal regulators, pertinent standards bodies, industry and the public.

9. Any new integrity management provisions must recognize that there are significant structural, geographic and functional differences between gas transmission and distribution systems.

6. Plan and Schedule for Defining and Implementing Distribution Integrity Management Requirements

Defining and implementing distribution integrity management requirements is a multi-phased effort intended to develop an approach that will address the three elements of the strategy described by the DOT Inspector General:

- understand the infrastructure,
- identify and characterize the threats, and
- determine how best to manage the known risks (prevention, detection and mitigation).

The first phase, being conducted during calendar year 2005, involves actively seeking out additional information about the issues affecting distribution system integrity. PHMSA is evaluating the history of the spectrum of relevant threats to identify trends and is searching out those risk control practices that are being used effectively today by some operators and that can be advanced for broader application in the distribution industry, appropriate to the specific circumstances of individual distribution pipeline systems.

During this phase, PHMSA is working with a number of groups comprised of state pipeline safety regulators, pipeline operators, and representatives of the public. These groups augment PHMSA resources, allowing us to draw on dozens of experts. Those participating in these groups are themselves supported by technical staff in their parent organizations. The groups are thus bringing to bear the extensive knowledge of the companies that operate distribution systems and the state regulators who are most directly involved in their oversight. These groups are gathering data and making technical findings in a number of areas that will inform PHMSA efforts in phase 2. There are four work/study groups:

- Data group – evaluating existing data and collecting more data as needed to identify the nature, significance, and trends in threats affecting distribution pipeline systems and the effectiveness of current programs addressing these threats
- Risk Control Practices group – identifying the applicability and effectiveness of practices currently being used to control risk, whether required by State or federal regulations or implemented voluntarily by operators
- Excavation Damage Prevention group – considering more specifically actions that have been effective in addressing the most significant threat affecting distribution pipeline systems
- Strategic Options group – considering means by which effective risk control practices can be implemented across the broad range of distribution pipeline system operators and gathering data on the costs and benefits of doing so

A Coordinating Group consisting of the chairman of the NARUC pipeline safety committee, officers of NAPSR, and managers from the major trade associations facilitates the discussion and assures that the work/study groups have necessary administrative and technical support. An Executive Steering Group that includes State Commissioners responsible for pipeline safety regulation, distribution company officers (from corporate operators), senior managers (from municipal operators), a public representative, and executives from AGA and APGA provides high-level input incorporating the perspectives of their respective organizations.

All group meetings are open to the public to maximize the broadest possible input. Meeting locations and agendas are posted on a public web site[10]. The web site also provides public access to all of the information discussed during group meetings and to written documents that the groups develop. Members of the public can submit comments via the web site and will be given a specific opportunity to hear about the activities of these groups and to provide comments during a public meeting scheduled to be held in September 2005.

The Executive Steering Group met for the first time on March 16, 2005, and discussed a number of high-level options for which detailed information should be gathered (see Section 7). The work/study groups met for the first time March 29-31, 2005, and met for a second time May 17-19, 2005. The work/study groups are also conducting teleconferences, collecting information from existing databases and from operator/state participants and preparing written records of their consideration. As described above, these records are being made available to the public via the web site. These initial meetings have identified a developing consensus around a small number of elements that would be appropriate for distribution integrity management requirements and the continuing process is helping clarify what those elements would entail.

The action plan describing the activities of the distribution integrity management work/study groups is provided as Attachment 5.

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[10] http://www.cycla.com/dimp

PHMSA/OPS will use the information developed by the work/study groups during Phase 1 to develop appropriate requirements, and to develop or sponsor development of guidance, during Phase 2. Phase 2 will be conducted during calendar year 2006.

7. Options Being Considered

In preparation for the work of the distribution integrity management work/study groups, OPS solicited views on the options available to address the issues raised by the DOT Inspector General in 2004 and to better assure distribution system integrity. OPS considered information generated during the rulemaking concerning gas transmission pipeline integrity management, consulted with our State partners and the industry trade associations, and elicited public views through a public meeting held in Washington, DC, on December 16, 2004. Seven high-level options were identified for consideration:

Option 1. Structured Nationwide public education program, similar to the Smokey The Bear campaigns, directed at reducing incidents of outside force related to excavation and highlighting 3-digit dialing to one-call centers

Option 2. Model State legislation, potentially imposing requirements on excavators and others outside the regulatory jurisdiction of pipeline safety authorities

Option 3. National guidelines or consensus standards, providing guidance to states and operators for implementing integrity management approaches

Option 4. Guidance documents for adoption by States, similar in scope to option 3 but with the intent of states mandating use of the guidance

Option 5. Risk-based, flexible, performance-oriented Federal regulation, establishing high-level elements that must be included in integrity management programs

Option 6. Prescriptive Federal regulation, specifying in detail actions that must be taken to assure distribution pipeline integrity

Option 7. Development of innovative safety technology, to provide means not now available for addressing the integrity of distribution pipelines

OPS discussed these options with the distribution integrity management Executive Steering Group (described above) at its March 16, 2005, meeting. The preponderance of views within that group was that four of the options, in combination, were worthy of more intensive near-term consideration. These were options 1, 3, 5, and 7.

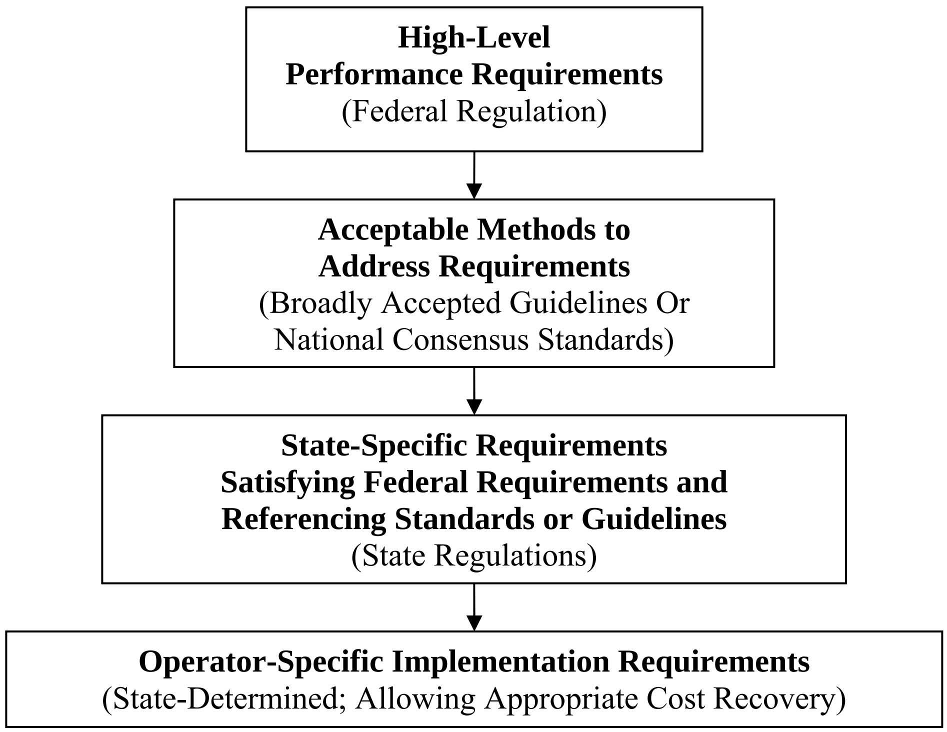
- Option 1 – a Nationwide education program – this would address persons outside the jurisdiction of pipeline safety regulators (e.g., construction excavators and other parties) who represent a significant portion of the risk to distribution pipelines. These persons would be unaffected by any changes to pipeline safety regulations.
- Option 5 – a high-level framework outlined by a rule, implemented in conjunction with more detailed guidance (Option 3) − this would establish basic requirements while allowing states the flexibility to accommodate the unique needs of different geographic areas and different communities of operators.
- Option 7 – continued investment in research and development – this could help to develop new methods of inspecting the networks of small-diameter pipelines, of varying materials, which constitute distribution pipeline systems.

The comments made by the Executive Steering Group suggested that Option 2, model State legislation, could be of interest but is likely of less immediate importance. State legislation also could address, as does Option 1, constituencies outside regulatory jurisdiction that pose risks to pipelines (e.g., those excavating in the vicinity of pipelines) but with mandatory requirements and enforcement options. Option 4, guidance adopted by States, also has potential for later use, if states find it appropriate to mandate use of all or portions of the guidance that would be developed under Option 3.

Only Option 6, a prescriptive Federal regulation, was regarded by most Executive Steering Group participants as being less useful. The comments expressed at the December 16, 2004, public meeting also reflected general agreement on this point. The comments in both cases pointed to several reasons that establishing prescriptive requirements that would effectively and efficiently address distribution integrity would be very difficult, or perhaps impossible. As described above, there is significant diversity among distribution pipeline operators and the systems they operate. This makes it less feasible for a single prescriptive regulation to establish requirements appropriate for all situations. Requirements appropriate for one class of operators might be ineffective and/or inefficient for others. For example, an analytical risk model that might be appropriate for a large system, installed over an extended period and that includes many different pipe materials, could be unnecessary for a small system consisting of a single type of material installed over a limited period. Requiring that the smaller system operator implement such a risk model would pose a significant burden, for no safety benefit.

The combination of a high-level Federal rule (Option 5) with guidance (Option 3) could help assure the flexibility needed to address the wide variations in the gas distribution pipeline community. Figure 2 is intended to depict how this combination might be structured.

Figure 2 - Relationship among Federal Requirements, Standards or Guidelines, and State Requirements



As depicted in Figure 2, a Federal regulation could be used to establish the high-level performance requirements driving safety improvement. An example of such a set of requirements is contained in Figure 3 below. Because the requirements in this example are very high-level and require implementation of a set of management practices, some set of standards or guidance likely would be needed to describe how these requirements might be satisfied *by any of the spectrum of regulated distribution pipeline operators*. A proven approach to describing optional implementation approaches that are satisfactory to the industry and regulatory communities is the development of national consensus standards. Another proven alternative, which seems preferable at this time, would be development of a set of guidelines, again describing acceptable implementation options.

Figure 3 - Example High-Level Federal Performance Requirements

1. The operator shall develop a program plan that describes how it manages the integrity of its distribution system, focusing on how it will satisfy the requirements below.
2. The operator shall identify threats applicable to its system.
3. The operator shall characterize the relative significance of applicable threats to its piping system.
4. The operator shall identify and implement appropriate practices (or modify current practices) to prevent, and mitigate the risk from applicable threats consistent with the significance of these threats.
5. The operator shall develop and monitor performance measures to allow it to evaluate the effectiveness of improvements implemented.
6. The operator shall periodically evaluate the effectiveness of its program and make adjustments dictated by its evaluation.
7. The operator shall periodically report to the jurisdictional regulatory authority a select set of performance measures.

For the vast majority of gas distribution pipeline systems, the States are the jurisdictional regulatory authority. States adopt Federal regulations and, in the process, have the choice either to adopt them as stated, or to expand and focus these requirements to clarify acceptable implementation approaches or address specific State needs. The approach in Figure 2 shows how the States could draw upon the set of standards or guidelines, developed specifically to describe implementation choices, to clarify their expectations on how operators would satisfy the requirements. By explicitly referencing the guidelines or standards, the States could minimize the operators' uncertainty on how the requirements might acceptably be implemented. States might also describe different implementation approaches as acceptable for each type of operator or type of pipeline under their jurisdiction. Such an approach would explicitly recognize the differences among States and among operators within a single State.

The bottom element in Figure 2 is included to recognize the fact that many distribution pipeline operators are subject to rate regulation. Such regulation should explicitly recognize the cost of implementing new requirements designed to allow their systems to be operated more safely. Therefore, increases in operating and maintenance costs, as well as costs of capital improvements, should be addressed in ratemaking for the operators subject to any new safety related regulations.

In fleshing out appropriate actions to implement high-level performance requirements such as those listed in Figure 3, it will be necessary to bridge the gap between those requirements and the guidance/standards that will be needed. The work/study groups will need to identify the questions that operators and state regulators must answer to assure that the performance-based requirements are being fulfilled. These questions, in turn, will inform findings regarding the number and nature of guidelines or standards that are needed.

PHMSA/OPS has preliminarily concluded that this approach will be used to establish distribution integrity management requirements. The distribution integrity management work/study groups are directing their primary focus on gathering and analyzing information to help clarify the elements that would be most effective in such a combination of requirements and guidance. OPS will consider the results of work/study group activities in its development of requirements in Phase 2, as described above, and could revise its conclusion regarding the preferred approach if work/study group activities identify unforeseen reasons why this approach might not be effective.

Specific Attention to Excess Flow Valves

Excess flow valves (EFVs) are an additional mitigation element that will be considered as part of this program. EFVs are devices that can be installed in each service line and that may shut off gas flow if the line is severed downstream of the valve. They represent a measure that may mitigate the consequences of some incidents if they occur despite the preventive actions that may be taken to reduce the chances of that happening. In this regard, their use would be similar to additional preventive and mitigative measures that operators of hazardous liquid and gas transmission pipelines are required to consider as part of the integrity management regulations applicable to those pipelines, such as emergency flow restricting devices for hazardous liquid pipelines or automatic/remote control valves for gas transmission.

EFVs have received a significant amount of attention as a mitigation option for gas distribution systems. At present, Federal regulations require that operators notify service line customers for new and replaced service lines of the availability and potential safety benefits of installing EFVs.[11] In lieu of this notification, operators may elect to voluntarily install the valves, when certain conditions apply. The valves are generally applicable for new installations or complete service piping replacement for single-family residential homes, where the operating pressure is greater than 10 pounds per square inch (psi). Operators must install the valves if the customer agrees to pay for the cost of such installations. Discussions with operators have identified that some distribution system operators are installing the valves as a routine part of new and replaced service installations in situations in which they apply.

The National Transportation Safety Board has made several recommendations regarding the use of EFVs in new construction and replaced pipelines. Organizations representing fire fighters and fire chiefs have expressed support for increased use of the valves, believing that their use would contribute to public safety and could reduce the number of fire fighter injuries that occur when gas contributes to the magnitude of fires to which they must respond. OPS is conducting additional studies on the effectiveness of the valves and on the experience that has been gained as a result of their use.

Further study is needed. EFVs would not mitigate all incidents occurring on service lines. The valves are designed to operate in the event of line ruptures that result in major flow of gas. They will not operate in the event of small leaks. They will not operate in the event of leaks or problems within a customer's residence or business, downstream of their pressure regulator, including situations in which a fire in a residence results in a breach of a gas appliance line in the residence. OPS asked Allegro Energy Consulting to review OPS

[11] 49 CFR 192.383

incident report records to estimate how many incidents might have been mitigated by the presence of an excess flow valve. Allegro reviewed 634 incident reports submitted between 1999 and 2003. They screened out those that did not involve service lines, that were obviously slow leaks, or which otherwise did not appear to meet the criteria as incidents for which an excess flow valve would be beneficial. As a result, Allegro identified 101 incidents in which the presence of an EFV might have mitigated consequences over this five year period. To be clear, this is an upper-bound estimate. The incident reports do not include some information (e.g., gas flow rate) that is necessary to definitively ascertain whether an excess flow valve would have been effective nor do they include information on whether the 25% of fatalities or injuries in automobile accidents involving gas meter set assemblies could have been prevented by an EFV shutting off gas flow.

EFVs are one option for mitigating potential gas distribution incidents. The distribution integrity management Executive Steering Group believes that implementation of any requirement related to excess flow valves should be done in conjunction with a holistic approach to integrity management, as was done for preventive and mitigative options in the hazardous liquid and gas transmission integrity management rules. OPS has directed the work/study groups described above to further evaluate potential requirements for use of EFVs as part of a distribution integrity management program, while OPS and NARUC conduct other data gathering and analysis activities.

8. Conclusion

Integrity management requirements for hazardous liquid and gas transmission pipelines are focused on physical inspections of the condition of those pipelines in areas where an accident could result in high consequences. Gas distribution pipeline systems are very different from these other types of pipelines. Distribution pipeline systems use many different kinds of pipe material, in varying sizes including very small pipes (e.g., less than one inch in diameter), and exist in areas in which physical inspection of the pipe is very difficult.

PHMSA/OPS has embarked on a two-phase program to identify alternate means of better assuring the integrity of distribution pipeline systems. PHMSA/OPS expects this program to result in publication of high-level requirements in a federal rule that will be augmented by necessary guidelines or standards. In the first phase, PHMSA/OPS is working with a number of work/study groups composed of state pipeline safety regulators, industry personnel, and representatives of the public to identify and analyze information that will help to identify effective approaches to assuring distribution system integrity. Discussions within these groups are revealing a developing consensus on the high-level elements that would be appropriate in such a regulation. In the second Phase, PHMSA/OPS will develop appropriate requirements and will develop or sponsor development of necessary guidelines or standards.

The first phase of this program will be completed by the end of 2005. PHMSA/OPS expects that proposed requirements for assuring integrity of distribution pipeline systems will be published for public comment by the end of the third quarter of calendar year 2006.

Attachments:

1. NAPSR State Survey Results -- State Requirements beyond Federal Regulations Gas Distribution Systems
2. Summary of Allegro Report – Safety Incidents on Natural Gas Distribution Systems: Understanding the Hazards, April 2005
3. NARUC Resolution on Distribution Integrity Management, February 16, 2005
4. Position of the American Public Gas Association on Distribution Integrity Management
5. PHMSA/OPS Phase 1 Action Plan

Attachment 1
NAPSR State Survey Results
State Requirements beyond Federal Regulations
Gas Distribution Systems

State Requirements beyond Federal Regulations
Gas Distribution Systems

Federal Regulations published in 49 CFR Parts 191 and 192 are applicable to all gas distribution systems in the U.S. Oversight of the safety of most of these systems falls under State jurisdiction. States can exercise jurisdiction if their pipeline safety programs are certified under 49 U.S.C. 60105 or if they enter into agreements with the Secretary of Transportation under 49 U.S.C. 60106. At this time, all states except Alaska and Hawaii are certified or party to agreements, as is the District of Columbia. States must enforce at least the federal regulations, but may also impose additional requirements that go beyond those regulations. States also foster programs that improve pipeline safety outside their regulatory structure, e.g., via their rate setting process.

The National Association of Pipeline Safety Representatives (NAPSR)[12] conducted a survey of its members to estimate the extent to which they impose requirements or programs that exceed the federal minimum. The survey consisted of a questionnaire that asked each state pipeline safety program manger to indicate whether their state imposes additional requirements or has infrastructure safety improvement programs implemented outside the scope of their regulations. NAPSR members were asked to provide a brief description of any positive responses. The survey was conducted over a brief period, and thus was somewhat limited in the detail provided with responses.

Forty-eight state agencies and the District of Columbia responded to the NAPSR survey. All but 6 reported some requirements or programs exceeding the federal minimum standards.

- Twenty-five states, or just over half of the respondents, reported that they required reports of events that need not be reported under federal regulations (20 states) and/or that they provide enhanced oversight and observation of work/testing on the pipelines (11 states).
- Eleven states (22 percent) impose additional requirements intended to prevent or detect damage to the pipeline by outside parties
- Thirteen states (26 percent) impose requirements for leak testing beyond the federal minimum. Additionally, eleven states (including 8 of the same) impose additional requirements related to responses to leaks.
- Eight states (16 percent) require more frequent testing or have other additional requirements related to the odorant that is added to gas in distribution systems to allow residents to detect leaks before they cause adverse consequences.
- Six states (12 percent) impose additional requirements related to design and installation.
- Six states (12 percent) impose additional requirements related to training and qualification of operator personnel.
- Six states (12 percent) impose additional requirements related to cathodic protection systems used to protect steel pipe from corrosion.

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

- Five states (10 percent) require that operator's Operating and Maintenance plans be filed with or approved by the state regulator.
- Five states (10 percent) impose requirements related to operating pressures.
- Five states impose additional requirements regarding location of or protection for customer meters.
- Three states (6 percent) have requirements that operators cap off abandoned service lines after specified periods.
- Four states extend operator responsibility for maintenance of service/customer lines.
- Four states reported that they exercise authority beyond the scope of the federal safety regulations in: ordering changes in the public interest, encouraging safety enhancement through rate cases, and approving the operation of distribution pipeline systems by specific companies.
- One state requires its operators to conduct an annual evaluation of all cast iron and unprotected steel pipe in their distribution systems.
- One state requires that its operators remediate any evidence found of corrosion within 90 days.
- All but one responding state reported that they have more frequent contact and involvement with operators in their state than does the federal Office of Pipeline Safety with operators under its jurisdiction.

The most significant area in which states reported actions beyond federal standards was that of replacement of aging and inferior infrastructure. Thirty-three states, or two-thirds of those responding, reported that they have some kind of program for replacement of infrastructure, including cast iron pipe, uncoated steel pipe, copper pipe, and some types of plastic pipe. These programs varied in scope and schedule, often reflecting the relative amount of targeted infrastructure present in each state.

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

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

Attachment 2
Summary of Allegro Report
Safety Incidents on Natural Gas Distribution Systems: Understanding the Hazards

Introduction and Summary

Background to Study

Undertaken for the Office of Pipeline Safety, this study evaluates the safety record of gas distribution systems

This report examines the safety record of the natural gas distribution system over the period 1985 – 2003, with special emphasis on the incidents reported to the U.S. Department of Transportation's Office of Pipeline Safety (OPS) for the years 1999 through 2003. OPS contracted with Allegro Energy Consulting to undertake this work as part of the agency's multi-faceted initiative to improve the safety record of these systems. Gas distribution systems are involved in far more fatalities and injuries than the other types of pipelines that the agency regulates (gas transmission and hazardous liquid), and often are in the news because of incidents involving explosions and evacuations, a fact that has focused the attention of regulators, the Congress, industry and the public.

Understanding the diverse hazards was a central goal

Strategies for improving the safety performance can only be developed after examining the record. This report takes this first step, examining in detail the information provided by the industry to the OPS regarding reportable safety incidents. That information was then reclassified into the diverse hazards reflected in the record. With the better understanding of the hazards – the causes and circumstances surrounding the incidents – a broad partnership of stakeholders can develop more finely targeted strategies to manage and control the risks involved. The ultimate goal is to prevent incidents from occurring.

Data for this study from DOT's PHMSA, available on the internet

Data for this report are drawn mainly from the Department of Transportation's Pipeline and Hazardous Materials Administration ("PHMSA")[1], which is the primary Federal regulator of the safety-related aspects of natural gas pipeline operations through its Office of Pipeline Safety ("OPS"). Most of the data have been taken directly from the agency's website, http://ops.dot.gov.

[1] PHMSA, established in February 2005, is the successor agency to Research and Special Programs Administration ("RSPA").

Gas Distribution System Is All Most Consumers Know of Gas

Distribution utilities are everywhere people are, operating a million miles of mains and over 56 million services

The natural gas distribution system is central to the energy supply for the American public. Natural gas distributors operate a million miles of mains and over 56 million "services" – connections to consumer's meters. Through this network, energy flows to provide heat to residences, commercial establishments like businesses, churches, and schools, and to power manufacturing plants and industry. To most end-users, distribution *is* the gas supply system, since its mains and service lines go right to the customer's door, even though other industry segments have been involved in moving the gas from the production well to end-user. The other parts of the industry – production and processing facilities and gathering and transmission pipelines – are also vital, but are largely invisible to the consuming public.

Concentrated where people live, so increased likelihood of consequences of failures

Necessarily, gas distribution systems must be concentrated where consumers live and work. Therefore, safety is a unique challenge for gas distributors because of this high concentration of pipelines presents the increased possibility that any failures in the system could carry high consequences in the form of property damage or personal injuries. Ongoing construction, development, and maintenance also increase the likelihood that commercial firms, other utilities, or customers themselves could inadvertently damage mains and other equipment. Adding to the challenge is the fact that service lines and meters are generally on the customer's property, which are not always within the distribution operator's control.

Highlights of Findings

From 1985-87, there were an average of 170 reportable incidents per year on the nation's gas distribution systems, and from 2001-03, there were an average of 124 per year. While this is a 27% decline, the improvement in the record was concentrated in the early years.

Over the 1985-2003 period, there were also an average of 11 gas distribution incidents per year that involved a fatality, and an average of 43 per year that involved an injury. Those involving a fatality, while small in number, did not show a sustained downward trend. Incidents involving an injury have trended downward overall, but not steadily.

Over the 1999-2003 period, the focus of this report, there were 634 incidents reported by gas distribution operators on PHMSA Form F 7100.1, for an average of 127 per year. Over the five years, there were 40 incidents involving a fatality, and 181 incidents involving an injury.

The PHMSA incident reporting form in use until early 2004 employed cause categories that were too broad to assess the real hazards that were involved in natural gas distribution incidents.

On the old form, pre-revision, Damage by Outside Force was the reported cause for 61% of the incidents from 1999-2003, but this cause category is really a group of disparate hazards. The category "Other" was the reported cause of 25% of the incidents; this catchall obscures information vital to understanding the real cause. Furthermore, these two categories accounted for 90% of the incidents involving a fatality and 73% of the incidents involving an injury.

For this report, Allegro Energy Consulting used the operator's narrative filed with the PHMSA Form F 7100.1 over the five year period 1999-2003 to reclassify the incidents from the five cause categories in use that time to the 7 first-level and 25 second-level cause categories in use since the form's revision in early 2004.

Excavation and Mechanical Damage and Other Outside Force are still the largest cause categories but the separation is crucial for the insight necessary to address the underlying issues.

The reclassification effort succeeded in moving 60% of the incidents formerly classified as "Other" into a more meaningful category. The new combined category of Miscellaneous/Unknown (the revised version of Other causes) now accounts for just 12% of incidents.

The new 25 second-level cause categories, combined with other information such as the part of the system involved, provide much information for consideration in developing strategies to address the safety record.

Excavation/Mechanical Damage accounts for 38% of the incidents, 75% of which involved the kinds of activities that are subject to One-Call statutes. *Most of these incidents occurred on Mains and Service Lines. This category was also the largest cause of incidents involving injuries. Participants in One-Call programs – the entities who pay for the programs such as electric, phone, cable, and water utilities -- are among the parties causing the damage. Thus, strategies to address the issue may involve stricter enforcement of One-Call statutes, but will also require involvement, and cooperation, of these other utilities. In fact, almost 10% of the Excavation/Mechanical Damage incidents are caused by operators themselves (or their contractors), so additional training or behavior changes may be required. Another issue is tradesmen such as plumbers, where One-Call statutes are not relevant, but where additional "good practices" may be needed.*

Fire/Explosion as the Primary Cause ("Fire First" in this report) accounts for 11% of the incidents. *In these incidents, a fire caused by other factors such as faulty wiring secondarily involves an otherwise sound natural gas system. During the 1999-2003 period, the guidance in the instructions for Form 7100.1 directed operators not to report these incidents "unless the damage to facilities subject to Part 192 exceeds $50,000." Since most damage is to residences or other buildings, not facilities subject to Part 192, most of these incidents did not get reported. Reporting is inconsistent, however, with one utility accounting for 25 out of the 71 Fire First incidents. The reporting of these incidents will increase, however, since it is now an accepted cause category. Thus, these incidents must be addressed. Particularly since these incidents largely involve non-jurisdictional facilities, and facilities outside the operator's control, formulating an effective strategy for dealing with the incidents will require a broad partnership of stakeholders.*

Vehicles Unrelated to Excavation Activity cause 11% of the incidents, 2/3 of them involving Meter Set Assemblies. *These incidents are an excellent illustration of the difference between the hazards faced by the gas distribution system and other pipeline types that PHMSA regulates, such as gas transmission and oil pipelines. Vehicles were involved in 25% of the incidents causing a fatality, the largest share of any of the 25 causes. Again, only a coalition of stakeholders can develop an approach to reducing these incidents.*

Non-jurisdictional assets or facilities are also an issue in the incidents involving "Miscellaneous" causes, where 23 out of 40 (at least) occurred on customer piping or appliances.

Operator Error, which accounts for just 6% of all reportable incidents, causes 16% of the incidents involving an injury, an over-representation.

This examination clearly points out many ways that the hazards causing gas distribution incidents are diverse, different from those faced by gas transmission and oil pipelines, often outside of the operator's control, and often outside of the regulatory reach of the Office of Pipeline Safety. Because these incidents clearly have a societal impact, in deaths, injuries, property damage, burden on first responders in the community, and in a host of other ways, they must be addressed, however. Formulating a set of strategies that will reduce their occurrence and mitigate their impact will require a broad partnership of stakeholders.

Summary and Conclusions

This examination of safety incidents filed by gas distribution operators on PHMSA Form F 7100.1 has highlighted a number of factors that are central to understanding the performance of these systems:

- The conventional wisdom that the preponderance of gas distribution incidents are caused by outside force damage is correct, but is based on categories that are too broad to allow the development of effective strategies for performance improvement.
- By reclassifying incidents to the 7 first-level and 25 second-level cause categories of the revised PHMSA Form F 7100.1, we begin to see the diversity of hazards involved in reportable gas distribution incidents.
- Excavation and Mechanical Damage, while it accounts for the greatest share of incidents at 38%, is only part of the story. "Other Outside Force Damage," which includes vehicle-related incidents and incidents caused by an existing fire or explosion unrelated to the gas system, is also important. It accounted for 29% of all incidents, and caused the largest share of incidents (73%) involving a Meter Set Assembly.
- In fact, Other Outside Force Damage causes the highest share of incidents involving a fatality – 40%. Vehicle-related incidents alone, a subset of Other Outside Force Damage, account for 25% of the incidents involving a fatality.
- The largest cause of incidents involving an injury is Excavation and Mechanical Damage, and they occurred primarily on Mains and Service Lines.
- Reclassification of the old category "Other," which formerly accounted for 25% of the incidents, successfully distributed more than half of the incidents to a more meaningful cause category. The remaining incidents classified as Miscellaneous illustrate the diversity of the hazards involved in the gas distribution safety incidents. Some of these occurred on customer piping, outside of OPS jurisdiction.
- The issue of OPS jurisdiction is also important in the Other Outside Force Category, some of which involved customer piping, and some of which reflect the secondary involvement of the gas system during an unrelated fire.

- There is inconsistent reporting of incidents that involve facilities outside of OPS jurisdiction. The inconsistency carries a variety of problems. For instance, the data cannot be compared state-to-state or utility-to-utility. Furthermore, the inconsistency also obscures the real picture of failures on gas distribution systems, and thus the data can only be used with extreme caution in measuring, for instance, the success of regulation in enhancing public safety.

The issue of the incidents on non-jurisdictional facilities highlights the fact that the role of natural gas in modern life is such that its safety impacts touch everyone. That the activity or equipment involved in an incident is outside of DOT jurisdiction (or reportable criteria) does not mean that the incident did not occur, or that it did not have an impact on people, communities and their resources. It does mean that the hazard that caused the incident is unlikely to be "fixed" with the wave of DOT's regulatory wand, or operator qualification standards, or even the most strictly enforced One-Call statutes.

Because of the diversity of the hazards, as well as the jurisdictional issues, only a broad partnership of stakeholders will succeed in developing the breadth of programs that might improve the record and prevent deaths and injuries as well as property damage and other consequences. Such a broad approach may be one way to address the underlying issues without heavy-handed regulation, or protracted debate that comes with trying to assign blame among different parties. This partnership might include:

- DOT
- Operators and their trade associations and education foundations
- States, including State Fire Marshals, utility regulators, pipeline safety regulators
- Other utilities (electric, telephone, cable, water, sewer)
- Building trades; developers; architects; City/town zoning boards
- Damage prevention organizations such as Common Ground Alliance
- Insurers and insurance underwriters
- Homeowners and other customers

This report reviews the safety record and in so doing, identifies some of the issues and targets areas for further exploration. The development of specific strategies to address these issues is outside the scope of this work, and as noted, will best be undertaken by a broad coalition that can improve the safety for all.

Attachment 3
NARUC Resolution on Distribution Integrity Management
February 16, 2005

Resolution on Distribution Integrity Management

WHEREAS, Industry and government have long been committed to operating the nation's 2.2 million mile natural gas pipeline system with outstanding reliability and safety; *and*

WHEREAS, Regulators, legislators, and natural gas distribution pipeline operators have independently, as well as jointly, been examining natural gas distribution practices to determine the most effective approach to maintaining and enhancing distribution system integrity and safety; *and*

WHEREAS, State regulatory agencies have primary responsibility for regulating natural gas distribution pipeline safety and play a critical role in ensuring distribution integrity and in meeting the unique demands of their State's energy needs; *and*

WHEREAS, When developing regulation, State regulatory agencies must take into account their State's varying geography, energy customer base, local economy, system age and materials of construction, size and complexity of distribution operations, and consumption patterns of natural gas customers ranging from large-volume manufacturers to mid-size businesses to single-family residences, as well as the State's overall executive policies and goals; *and*

WHEREAS, There are significant structural, geographic and functional differences between gas transmission and distribution systems, and these differences make it infeasible to apply many transmission integrity management requirements to natural gas distribution systems; *and*

WHEREAS, Any adjustment to an operator's distribution integrity management program should be responsive to that operator's distribution system safety performance, existing regulations and current practices that can affect such performance, *and*

WHEREAS, The American Gas Foundation study entitled, *Safety Performance and Integrity of the Natural Gas Distribution Infrastructure*, presents results based on a consensus between industry and government stakeholders, including NARUC, thus providing an appropriate beginning to determine effective approaches to improving distribution integrity management; *now therefore be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners (NARUC), convened at its February 2005 Winter Meetings in Washington, DC, encourages States, the Federal Office of Pipeline Safety, gas distribution pipeline operators, and other stakeholders to develop an approach to distribution integrity management that uses risk-based, technically sound and cost-effective measures, which reflect that stakeholders are: knowledgeable of the infrastructure; can identify threats against their systems; and can take appropriate measures to reduce the risk of system failures while balancing the needs to ensure continued safe operation, reliable service and the implications of any increased financial demands on the consumer.

Sponsored by the Committee on Gas
Adopted by the NARUC Board of Directors February 16, 2005

Attachment 4
Position of the American Public Gas Association on Distribution Integrity Management

Position of the American Public Gas Association on Distribution Integrity Management

The American Public Gas Association (APGA) is a national trade association comprised of about 600 natural gas utilities owned and operated by the governments of the communities they serve. APGA and its members believe that:

1. Assuring the safety of the public living and working near our natural gas distribution mains and services is our number one priority,
2. The number of serious distribution incidents has declined sharply over the past two decades, yet serious distribution incidents, primarily caused by excavators, still occur,
3. Integrity management principles can be applied to distribution piping systems to potentially further improve distribution pipeline safety,
4. Historical data has been analyzed in a study by the American Gas Foundation to quantify on a national level the causes and consequences of distribution incidents, and
5. Threats to and inspection and mitigation techniques available for distribution piping systems are markedly different than those of transmission piping systems,

Therefore, the American Public Gas Association resolves that:

It is appropriate for the Research and Special Programs Administration (RSPA) to consider how integrity management principles can be incorporated into its distribution pipeline safety programs.

In considering incorporating integrity management principles into its distribution pipeline safety programs RSPA should consider:

1. That significant differences exist between distribution and transmission piping including size, pressure, materials, threats, feasible inspection technologies and other factors that will require a different approach than was used for integrity management of gas transmission and hazardous liquid pipelines,
2. That distribution piping is primarily regulated by states which can and in many cases have enacted additional requirements above and beyond federal regulations,
3. That many distribution operators have either voluntarily or by agreement with states implemented integrity management programs addressing specific threats,
4. The relative significance of each specific threat to distribution piping systems,
5. The prevention and mitigation techniques available for these distribution-specific threats,
6. The effect prevention and mitigation techniques will have on system reliability and continuity of service,
7. The extent to which current state and federal pipeline safety regulations and operator programs address specific threats to distribution piping systems,
8. The financial impacts of any new requirements on gas customers already reeling under high gas prices, and
9. The financial and administrative burden any new requirements will impose on operators, particularly on small entities.

Attachment 5
PHMSA/OPS Phase 1 Action Plan

Distribution Integrity Management
Phase 1 Action Plan

<u>Products</u>

Interim findings will be produced by June 2005. Final products for Phase 1 will be available in December 2005. The interim findings will address:

- Options selected for examination and expected areas of application,
- Scope of guidance or standards identified as necessary to support assurance of integrity management,
- Guidance or standard development organizations identified (if needed).

The principal final product from this effort will be an assemblage of data, information, and analyses that support a set of activities that could be promulgated within regulations, guidance and standards. Supporting products will include:

- Description of existing regulations at the State and Federal levels and identification of areas in which additional regulations could contribute to distribution safety,
- Description of existing practices that go beyond the regulations, their areas of applicability, and an initial characterization of their effectiveness,
- Summary of what existing leakage and incident data tell us about threats to safety, and recommendation of additional data that should be assembled and analyzed to support improving distribution safety performance,
- Findings for consideration by guidelines or standards development organizations on:
    - The scope of guidelines/standards needed,
    - The elements or features that need to be addressed in each standard/guideline,
    - The range of operator or pipeline types,
    - The timeframe on which the standards/guidelines are needed.
- Information to support the evaluation of the costs and benefits associated with practices that are candidates for incorporation in standards or guidelines,
- Analysis of available experience with EFVs including:
    - Conditions under which their application is considered feasible and potential beneficial,
    - Experience with their performance and effectiveness,
    - Costs and benefits of installation and operation.
- Documentation of consideration of alternative options.

Work/Study Groups:

Work/study groups have been assembled to address specific issues related to identifying and characterizing approaches to improve the safety of distribution pipeline systems. Representation on each group consists of at least one NAPSR and one industry person together with other representatives selected for their particular expertise in the areas to be investigated by the group. Each group includes representation from small operators to ensure access to their perspectives. Representatives of the public participate on work/study groups. A separate group with responsibilities as described will address each of the areas below.

1. *Strategic Options Group* - This group will:
   a. Initially identify candidate options to implement improvements in distribution system safety,
   b. Identify areas of applicability associated with each option,
   c. Considering information from the other groups, suggest methods by which selected approaches to improve distribution safety might best be implemented,
   d. Identify candidate program performance measures that will support evaluation of the impact of implementing integrity management requirements,
   e. Provide findings on the scope and elements to be identified for any standard or guidance development efforts suggested by the group.

   Approaches resulting from this program could include educational initiatives, technology development, standards or guidance development, and regulatory or legislative initiatives. Strong consideration will be given to state-identified approaches to facilitate the implementation of the desired safety improvements.

   The strategic options group will also gather data and estimate costs and benefits of various approaches to improve distribution safety, including practices currently in place in various states. Information gathered will include available cost/benefit analysis used to support cost recovery allowance for practices currently considered to be effective.

2. *Risk control practices group* - This group will identify and evaluate the applicability and effectiveness of current regulations (Federal and State) as well as current risk control practices and programs employed by government and industry to address the spectrum of threats to the safety of distribution pipeline systems. For activities identified as candidate requirements and practices, the group will identify the industry segments to which they are most applicable. A separate group will address the outside force/excavation threat. In addition, this group will:
   a. Identify gaps in current regulations, standards and practices, and the threats they are designed to address;
   b. Develop information concerning current practices for prevention, detection, and mitigation of applicable threats;
   c. Review and characterize available models and practices used to evaluate and integrate information to support decisions on applicability of threats, useful risk management measures, and segment priority for implementing safety improvements;
   d. Identify and evaluate current and potential approaches for the use of financial incentives to advance safety improvements;
   e. Identify and evaluate current practices, consensus standards and guidance on EFV installation, testing and maintenance; and
   f. Provide findings on the scope and elements to be identified for any standard or guidance development efforts suggested by the group.

3. *Data group* - This group will assemble existing information, including studies, to identify the nature, significance, and trends in threats affecting distribution pipeline systems. It will also assemble information and evaluate the effectiveness of current programs addressing those threats. In carrying out its work, the group will identify the industry segments to which data are applicable. In addition, this group will:
    a. Evaluate data for each State to determine if any significant differences or similarities exist that may impact the findings of this program;
    b. Determine whether and to what extent data other than incidents should be considered (e.g., data on the physical characteristics, location, physical environment, and protection of existing pipelines may support understanding of the nature and management of threats to integrity);
    c. In cooperation with the strategic options group, identify candidate changes in reporting requirements to facilitate future evaluation of the effectiveness of actions implemented as a result of this plan;
    d. Identify and evaluate performance data on EFVs (e.g., numbers installed, incidents mitigated, EFV malfunctions) from those states where extensive use of EFVs has been made. Where possible, the impact on EFV performance of local criteria and guidance for design, installation and maintenance will be considered;
    e. Determine whether data can be used to characterize the risk from the spectrum of distribution operators. These data could potentially influence the nature of requirements for the smallest operators; and
    f. Provide findings on the scope and elements to be incorporated in any standard or guidance development efforts suggested by the group.

4. *Excavation damage prevention group* – This group will examine a spectrum of approaches to achieve increased safety against this threat. This will include evaluation of the Common Ground Alliance database and related information to identify practices being used to prevent excavation damage, their effectiveness, and the extent of their application, identifying the factors of greatest importance in assuring the application and effectiveness of existing practices, and identifying candidate areas of improvement based on the breadth of application of the most effective currently defined practices. In addition, the group will provide comments on the scope and elements that should be incorporated in any useful new approaches that may be identified during the group's activities.

These four work/study groups will be supported by an assigned support staff comprised of knowledgeable individuals from industry, the States and the Federal regulatory agencies.