United States Government Accountability Office

GAO

Testimony

Before the Subcommittee on Highways, Transit and Pipelines, Committee on Transportation and Infrastructure, House of Representatives

For Release on Delivery
Expected at 10:00 a.m. EST
March 16, 2006

GAS PIPELINE SAFETY

Preliminary Observations on the Integrity Management Program and 7-Year Reassessment Requirement

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Physical Infrastructure Issues

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GAO-06-474T

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Highlights

Highlights of GAO-06-474T, a testimony before the Subcommittee on Highways, Transit, and Pipelines, Committee on Transportation and Infrastructure, House of Representatives

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GAS PIPELINE SAFETY

Preliminary Observations on the Integrity Management Program and 7-Year Reassessment Requirement

Why GAO Did This Study

About a dozen people are killed or injured in natural gas transmission pipeline incidents each year. In an effort to improve upon this safety record, the Pipeline Safety Improvement Act of 2002 requires that operators assess pipeline segments in about 20,000 miles of highly populated or frequented areas for safety risks, such as corrosion, welding defects, or incorrect operation. Half of these baseline assessments must be done by December 2007, and the remainder by December 2012. Operators must then repair or replace any defective pipelines, and reassess these pipeline segments for corrosion damage at least every 7 years. The Pipeline and Hazardous Materials Safety Administration (PHMSA) administers this program, called gas integrity management.

This testimony is based on ongoing work for this Subcommittee and for other committees, as required by the 2002 act. The testimony provides preliminary results on the safety effects of (1) PHMSA's gas integrity management program and (2) the requirement that operators reassess their natural gas pipelines at least every 7 years. It also discusses how PHMSA has acted to strengthen its enforcement program in response to recommendations GAO made in 2004.

GAO expects to issue two reports this fall that will address these and other topics.

www.gao.gov/cgi-bin/getrpt?GAO-06-474T.

To view the full product, including the scope and methodology, click on the link above. For more information, contact Katherine Siggerud at (202) 512-2834 or siggerudk@gao.gov.

What GAO Found

Early indications suggest that the gas transmission pipeline integrity management program enhances public safety by supplementing existing safety standards with risk-based management principles. Operators have reported that they have assessed about 6,700 miles as of December 2005 and completed 338 repairs for problems they are required to address immediately. Operators told GAO that the primary benefit of the program is the comprehensive knowledge they must acquire about the condition of their pipelines. For some operators, the integrity management program has prompted such assessments for the first time. Operators raised concerns about (1) their uncertainty over the level of documentation that PHMSA requires and (2) whether their pipelines need to be reassessed at least every 7 years.

The 7-year reassessment requirement is generally consistent with the industry consensus standard of at least every 5 to 10 years for reassessing pipelines operating under higher stress (higher operating pressure in relation to wall strength). The majority of transmission pipelines in the U.S. are estimated to be higher stress pipelines. However, most operators told GAO that the 7-year requirement is conservative for pipelines that operate under lower stress because they found few problems requiring reassessments earlier than the 15 to 20 years under the industry standard. Operators GAO contacted said that periodic reassessments are beneficial for finding and preventing problems; but they favored reassessments on severity of risk rather than a one-size-fits-all standard. Operators did not expect that the existence of an "overlap period" from 2010 through 2012, when operators will be conducting baseline assessments and reassessments at the same time, would create problems in finding resources to conduct reassessments.

PHMSA has developed a reasonable enforcement strategy framework that is responsive to GAO's earlier recommendations. PHMSA's strategy is aimed at reducing pipeline incidents and damage through direct enforcement and through prevention involving the pipeline industry and stakeholders (such as state regulators). Among other things, the strategy entails (1) using risk-based enforcement and dealing severely with significant noncompliance and repeat offenses, (2) increasing knowledge and accountability for results by clearly communicating expectations for operators' compliance, (3) developing comprehensive guidance tools and training inspectors on their use, and (4) effectively using state inspection capabilities.

Pipeline Failure Resulting from Corrosion

Source: CC Technologies, Inc. (Used by permission.)

Mr. Chairman and Members of the Subcommittee:

We appreciate the opportunity to participate in this oversight hearing on the Pipeline Safety Improvement Act of 2002. The act strengthens federal pipeline safety programs and enforcement, state oversight of pipeline operators, and public education on pipeline safety. The information that we and others will provide today should help the Congress as it prepares to reauthorize pipeline safety programs.

My statement is based on the preliminary results of our ongoing work for this Subcommittee and others. As directed by the 2002 act, we are assessing the effects on safety stemming from (1) the Pipeline and Hazardous Materials Safety Administration's (PHMSA) integrity management program for gas transmission pipelines and (2) the requirement that pipeline operators reassess their natural gas pipelines for certain safety risks at least every 7 years.[1] In addition, I would also like to briefly touch on how PHMSA has acted to strengthen its enforcement program. I testified on PHMSA's enforcement program before this Subcommittee almost 2 years ago,[2] and believe that this is a good opportunity to update you on some positive accomplishments.

Our work is based on our review of laws, regulations, and other PHMSA guidance, as well as discussions with a broad range of stakeholders, including industry trade associations, pipeline safety advocate groups, state pipeline regulators, and consensus standards organizations.[3] In addition, we contacted 25 pipeline operators about the matters that I will discuss today. We chose operators for which integrity management could have the greatest impact, all else being equal: larger and smaller operators with the highest proportion of pipelines in highly populated or frequented areas to total miles of pipeline. These operators represent about half of the miles of pipeline assessed to date.[4] We relied on pipeline operators' professional judgment in reporting on the conditions that they found during their assessments of safety risks. As part of our work, we assessed the internal controls and the reliability of the data elements needed for this engagement, and we determined that the data elements were sufficiently reliable for our purposes. We performed our work in accordance with generally accepted government auditing standards from August 2005 to March 2006.

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[1] Under integrity management, operators systematically assess the portions of their pipelines that are in highly populated or frequented areas (such as parks) for safety risks. Although the gas integrity management program applies to natural, toxic, and corrosive gases, the overwhelming majority of gas pipelines in the United States carry natural gas. Our work therefore focuses on natural gas. Transmission pipelines transport gas products from sources to communities and are primarily interstate. Distribution pipelines (local distribution companies) that carry natural gas to ultimate users, such as homes, are not subject to the 2002 act unless they are operated by companies that also operate transmission pipelines.

[2] GAO, *Pipeline Safety: Preliminary Information on the Office of Pipeline Safety's Efforts to Strengthen Its Enforcement Program*, GAO-04-875T (Washington, D.C.: June 16, 2004) and GAO, *Pipeline Safety: Management of the Office of Pipeline Safety's Enforcement Program Needs Further Strengthening*, GAO-04-801 (Washington, D.C.: July 23, 2004).

[3] Standards are technical specifications that pertain to products and processes, such as the size, strength, or technical performance of a product. National consensus standards are developed by standard-setting entities on the basis of an industry consensus. PHMSA's regulations incorporate reassessment standards developed by the American Society of Mechanical Engineers: *Managing the System Integrity of Gas Pipelines* (ASME B31.8S-2004).

[4] The information that we obtained from the 25 operators is not necessarily generalizable to all operators.

In summary:

- Implementation of integrity management is in its early stages as PHMSA's regulations were finalized in 2004. Early indications suggest that the gas integrity management program has enhanced public safety by requiring that operators identify and address the risks to pipeline segments located in areas that are most likely to affect public safety. Operators believe that the primary benefit of the program is the comprehensive knowledge they must acquire about the condition of their pipelines. However, operators have raised concerns (1) about their uncertainty over the level of documentation required by the program and (2) whether the requirement to reassess their pipelines at least every 7 years contribute to increased safety. PHMSA's initial inspections of 11 operators' integrity management programs have shown that operators are doing well in assessing their pipelines and making repairs but that they need to better document their management practices and decisions.

- Overall, pipeline operators have reported to PHMSA that, in the almost 6,700 miles of pipeline they have assessed, they have found 338 problems that required immediate repair or replacement[5]—about 1 problem every 20 miles, on average. The 25 operators that we contacted—which represent about half of the 6,700 miles assessed so far—told us that, if the 7-year requirement were not in place, they would reassess the pipeline segments located in highly populated or frequented areas every 10, 15, or 20 years following industry consensus standards. The 7-year reassessment requirement is similar to industry standards for pipelines operating under higher-stress (higher operating pressure in relation to wall strength) where the industry standard for reassessments is no more than 5 to 10 years, depending on operating pressure. However, operators told us that the 7-year reassessment requirement is conservative for pipelines operating under lower-stress, where the industry reassessment standard can extend to 15 to 20 years. The large majority of transmission pipelines in the U.S. are estimated to be higher-stress pipelines, based on information from industry associations. Most operators of lower-stress pipelines told us that they found few problems during baseline assessments that would require reassessments before 15 or 20 years. Operators that we contacted believed that periodic reassessments of their pipelines will be beneficial in finding and preventing problems. However, they favored conducting reassessments based on severity of risk rather than applying a one-size-fits-all standard. Operators did not expect that the existence of an "overlap period" from 2010 through 2012, when operators will be completing baseline assessments and beginning reassessments at the same time, would create problems in finding resources to conduct reassessments.[6] The existence of an overlap was an industry concern while the 2002 act was being debated.

[5] Operators have reported that about 20,000 miles of pipelines that are located in highly populated or frequented areas. Operators are required to make immediate repairs to their pipelines if they (1) determine the remaining strength of the pipe shows a predicted failure pressure of less than or equal to 1.1 times the maximum allowable operating pressure; (2) identify a dent that has any indication of metal loss, cracking, or a stress riser; or (3) determine, in their judgment, the assessment results require immediate action.

[6] Under the 2002 act, operators have until 2012 to complete their baseline assessments. However, under the 7-year reassessment requirement, operators that started their baseline assessments in 2003 would then need to reassess those pipeline segments in 2010.

- PHMSA has developed a reasonable enforcement strategy framework that is responsive to the recommendations that we made in 2004. PHMSA's strategy is aimed at reducing pipeline incidents and damage through both direct enforcement and prevention. The strategy entails, among other things, (1) using risk-based enforcement that clearly reflects potential risk and seriousness and dealing severely with operators' significant noncompliance and repeat offenses; (2) increasing knowledge and accountability for results by clearly communicating expectations for operator compliance; (3) developing comprehensive guidance tools, along with training inspectors on their use; and (4) effectively using state inspection capabilities.

Background

On average, about 3 people have died and about 8 people have been injured each year over the last 10 years in natural gas transmission pipeline incidents. The number of incidents has increased from 77 in 1996 to 122 and 200 in 2004 and 2005, respectively, mostly reflecting more frequent occurrence of property damage. Much of this increase may be attributed to increases in the price of gas (which has the effect of lowering the reporting threshold) over the past several years and to damage as a result of hurricanes in 2005.[7]

As a means of enhancing the security and safety of gas pipelines, the 2002 act included an integrity management structure that, in part, requires that operators of gas transmission pipelines systematically assess for safety risks the portions of their pipelines located in highly populated or frequently used areas, such as parks. Safety risks include corrosion, welding defects and failures, third-party damage (e.g., from excavation equipment), land movement, and incorrect operation. The act requires that operators perform these assessments (called baseline assessments) on half of the pipeline mileage in highly populated or frequented areas by December 2007 and the remainder by December 2012. Those pipeline segments potentially facing the greatest risks are to be assessed first. Operators must then repair or replace defective pipelines. Risk-based assessments are seen by many as having a greater potential to improve safety than focusing on compliance with safety standards regardless of the threat to pipeline safety.

The act further provides that pipeline segments in highly populated or frequented areas must be reassessed for safety risks at least every 7 years. PHMSA's regulations implemented the act by requiring that operators reassess their pipelines for corrosion damage every 7 years, using an assessment technique called confirmatory direct assessment.[8] Under these regulations, and consistent with industry national consensus standards, operators must also reassess their pipeline segments for any safety risk at

[7] An incident, for PHMSA reporting purposes, involves a death; injury requiring hospitalization; or property damage, including the price of natural gas lost during an incident, of $50,000 or more.
[8] Confirmatory direct assessment uses principles and techniques of direct assessment of direct assessment to identify internal and external corrosion of pipelines. Under confirmatory direct assessment, operators can meet PHMSA's rules by using a single assessment tool, rather than several tools or approaches that would provide more comprehensive information.

least every 5, 10, 15, or 20 years, depending on the pressure under which the pipeline segments are operated and the condition of the pipeline.

There are about 900 operators of about 300,000 miles of gas transmission and gathering pipelines in the United States. As of December 2005, according to PHMSA, 429 of these operators reported that about 20,000 miles of their pipelines lie in highly populated or frequented areas (about 7 percent of all transmission pipeline miles). Operators reported that they had as many as about 1,600 miles and as few as 0.02 miles of pipeline in these areas.

PHMSA, within the Department of Transportation, administers the national regulatory program to ensure the safe transportation of gas and hazardous liquids (e.g., oil, gasoline, and anhydrous ammonia) by pipeline. The agency attempts to ensure the safe operation of pipelines through regulation, national consensus standards, research, education (e.g., to prevent excavation-related damage), oversight of the industry through inspections, and enforcement when safety problems are found. PHMSA employs about 165 staff in its pipeline safety program, about half of whom are pipeline inspectors who inspect gas and hazardous liquid pipelines under integrity management and other more traditional compliance programs. Nine PHMSA inspectors are currently devoted to the gas integrity management program. In addition, PHMSA is assisted by inspectors in 48 states, the District of Columbia, and Puerto Rico.

Early Indications Suggest that Gas Integrity Management Enhances Public Safety, but Operators Raise Some Concerns About Implementation

While the gas integrity management program is still being implemented, early indications suggest that it enhances public safety by supplementing existing safety standards with risk-based management principles. Prior to the integrity management program, there were, and still are, minimum safety standards that operators must meet for the design, construction, testing, inspection, operation, and maintenance of gas transmission pipelines. These standards apply equally to all pipelines and provide the public with a basic level of protection from pipeline failures. However, minimum standards do not require operators to identify and address risks that are specific to their pipelines nor do they require operators to assess the integrity of their pipelines. While some operators did assess the integrity of some of their pipelines, others did not. Some pipelines have been in operation for 40 or more years with no assessment. The gas integrity management requirements, finalized in 2004, go beyond the existing safety standards by requiring operators, regardless of size, to routinely assess pipelines in highly populated or frequented areas for specific threats, take action to mitigate the threats, and document management practices and decision-making processes.

Representatives from the pipeline industry, safety advocate groups, and operators we have contacted agree that the integrity management program enhances public safety. Some operators noted that, although the program's requirements can be costly and time consuming to implement, the benefits to date are worth the cost. The primary benefit identified was the comprehensive knowledge the program requires all operators to have of their pipeline systems. For example, under integrity management, operators must gather and analyze information about their pipelines in highly populated or frequented areas to get a complete picture of the condition of those lines. This includes developing maps of the pipeline system and information on corrosion protection, exposed pipeline, threats from excavation or other third-party damage, and the installation of automatic shut off valves. Another benefit cited was improved communications within the company. Investigations of pipeline incidents have shown that, in some cases, an operator possessed information that could have prevented an incident but had not been shared with employees who needed it most. Integrity management requires operators to pull together pipeline data from various sources within the company to identify threats to the pipelines, leading to more interaction among different departments within pipeline companies. Finally, integrity management focuses operator resources in those areas where an incident could have the greatest impact.

While industry and operator representatives have provided examples of the early benefits of integrity management, operators must report semi-annually on performance measures that should quantitatively demonstrate the impact of the program over time. These measures include the total mileage of pipelines and the mileage of pipelines assessed in highly populated or frequented areas, as well as the number of repairs made and leaks, failures, and incidents identified in these areas. In the 2 years that operators have reported the results of integrity management, they have assessed about 6,700 miles of their 20,000 miles of pipelines located in highly populated or frequented areas and they have completed 338 repairs that were immediately required and another 998 repairs that were less urgent. While it is not possible to determine how many of these needed repairs would have been identified without integrity management, it is clear that the requirement to routinely assess pipelines enables operators to identify problems that may otherwise go undetected. For example, one operator told us that it had complied with all the minimum safety standards on its pipeline, and the pipeline appeared to be in good condition. The operator then assessed the condition of a segment of the pipeline under its integrity management program and found a serious problem causing it to shut the line down for immediate repair.

One of the most frequently cited concerns by the 25 operators we contacted was the uncertainty about the level of documentation needed to support their gas integrity management programs. PHMSA requires operators to develop an integrity management program and provides a broad framework for the elements that should be included in the program. Each operator must develop and document specific policies and procedures to demonstrate their commitment to compliance and implementation of the integrity management requirements. In addition, an operator must document any decisions made related to integrity management. For example, an operator must document how it identified the threats to its pipeline in highly populated or frequented areas and who was involved in identifying the threats, their qualifications, and the data they used. While the operators we contacted did not disagree with the need to document their policies and procedures, some said that the detailed documentation required for every decision is very time consuming and does not contribute to the safety of pipeline operations. Moreover, they are concerned that they will not know if they have enough documentation until their program has been inspected. After conducting 11 inspections, PHMSA found that, while operators are doing well in conducting assessments and making the identified repairs, they are having difficulty overall in the development and documentation of their management processes. Another concern raised by most of the operators is the requirement to reassess their pipelines at least every 7 years. I will discuss the 7-year reassessment requirement in more detail shortly.

As part of our assessment of the integrity management program, we are also examining how PHMSA and state pipeline agencies plan to oversee operator implementation of the program. To help federal and state inspectors prepare for and conduct integrity management inspections, PHMSA developed detailed inspection protocols tied to the integrity management regulations and a series of training courses covering the protocols and other relevant topics, such as corrosion and in-line inspection.[9] Furthermore, in response to our 2002 recommendation,[10] PHMSA has been working to improve its communication with states about their role in overseeing integrity management programs. For example, PHMSA's efforts include (1) inviting state inspectors to attend federal inspections, (2) creating a website containing inspection information, and (3) providing a series of updates through the National Association of Pipeline Safety Representatives. I am pleased to report that preliminary results from an ongoing survey of state pipeline agencies (with more than half the states responding thus far) show that the majority of states that reported believe that the communication from PHMSA has been very or extremely useful in helping them understand their role and responsibilities in conducting integrity management inspections.[11]

7-Year Reassessment Requirement May be Appropriate for Some Operators but Conservative for Others

Nationwide, pipeline operators reported to PHMSA that they have found, on average, about one problem requiring immediate repair or replacement for every 20 miles of pipeline assessed in highly populated or frequented areas. Operators we contacted recognize the benefits of reassessments; however, almost all would prefer following the industry national consensus standards that use safety risk, rather than a prescribed term, for determining when to reassess their pipelines. Most operators expect to be able to acquire the services and tools needed to conduct these reassessments including during an overlap period when they are starting to reassess pipeline segments while completing baseline assessments.

Operators Favor a Risk-based, Rather than a One-Size-Fits-All Reassessment Standard

As discussed earlier, as of December 2005, operators nationwide have notified PHMSA of 338 problems that required immediate repair in the 6,700 miles they have assessed—

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[9] In-line inspections are accomplished by running specialized tools through pipelines to detect problems, such as reduced wall thickness and cracks.

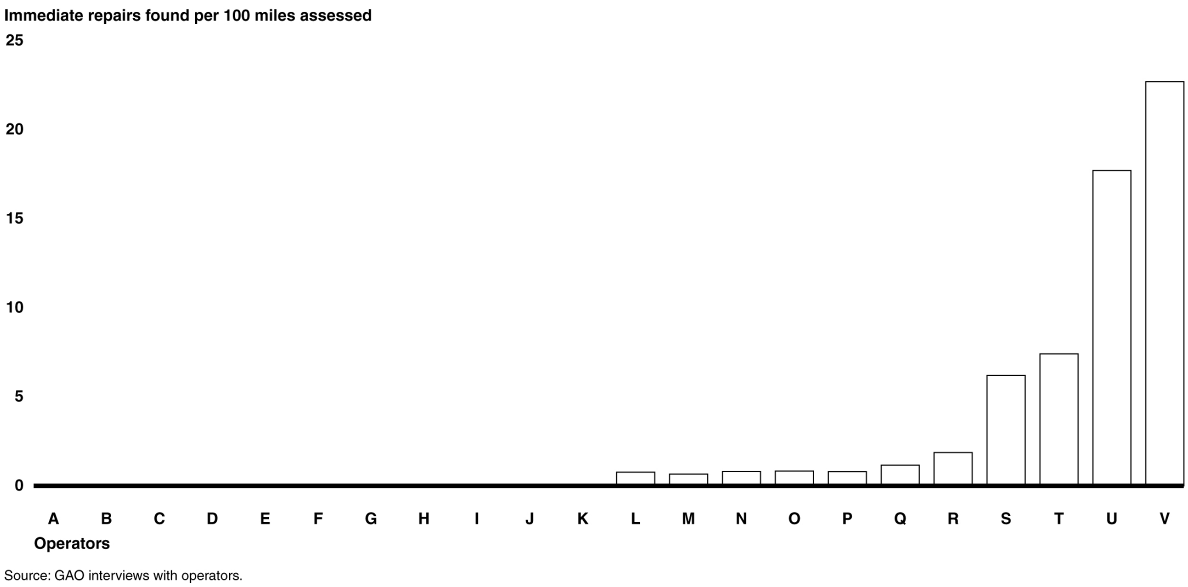
[10] GAO, *Pipeline Safety and Security: Improved Workforce Planning and Communication Needed,* GAO-02-785 (Washington, D.C.: Aug. 26, 2002).

[11] Twenty-nine states responded to the survey as of early March 2006. Three states indicated that PHMSA information was extremely useful, 15 states said the information was very useful, 3 states said it was moderately useful, 4 said it was somewhat useful, and 4 had no opinion.

about one immediate repair required for every 20 miles of pipeline assessed in highly populated or frequented areas.

The number of immediate repairs may be due, in part, to some operators systematically assessing for the first time as a result of the 2002 act. Of the 25 transmission operators and local distribution companies that we contacted, most told us that they found few safety problems that required reducing pressure and performing immediate repairs during baseline assessments covering (1) about 3,000 miles of pipeline in highly populated or frequented areas and about (2) 35,000 miles outside of these areas.[12] (See fig. 1.) Most operators reported finding pipelines in good condition and free of major defects, requiring only minor repairs or recoating. A few operators found more than 10 immediate repairs. Operators nonetheless found these assessments valuable in determining the condition of their pipelines and finding damage.

Figure 1: Number of Immediate Repairs Needed as Found During Baseline Assessments



Source: GAO discussions with operators.

Note: To prevent distortion, we excluded 3 of the 25 operators we contacted because they had assessed 0 miles of pipeline to date. This figure includes the immediate repairs for pipeline located both inside and outside of highly populated or frequented areas.

Most of the operators told us that, if the 7-year reassessment requirement was not in place, they would respond to the conditions that they identified during baseline assessments by reassessing their pipelines every 10, 15, or 20 years, based on industry consensus standards. These baseline assessment findings suggest that—at least for the operators we contacted—the 7-year requirement is conservative. However, the 7-year

[12] Pipeline operators, for example, told us that, when they run an in-line inspection tool through a pipeline, they will not collect data solely within the boundary of the highly populated or frequented area if the insertion and retrieval points for the tool extend beyond the highly populated or frequented area. Rather, they gather information on the pipeline's condition for the entire distance between the insertion and retrieval points because, in doing so, they gather additional insights into the condition of their pipeline.

reassessment requirement may be more appropriate for higher-stress pipelines than for lower-stress pipelines.

The 7-year reassessment requirement is generally more consistent with scientific- and engineering-based intervals for pipelines operating under higher-stress. Higher-stress transmission pipelines are typically those that transport natural gas across the country from a gathering area to a local distribution company. For higher-stress pipelines, the industry consensus standard sets maximum reassessment periods at 5 or 10 years, depending on operating pressure. PHMSA does not collect information in such a way that would allow us to readily estimate the percentage of all pipeline miles in highly populated or frequented areas that operate under higher pressure. For the 25 operators that we contacted, the operators told us that about three-fourths of their pipeline mileage in highly populated or frequented areas operated at higher pressures. Finally, industry data suggest that in the neighborhood of 250,000 miles of the 300,000 miles (over 80 percent) of all transmission pipelines nationwide may operate at higher pressure.

Some operators told us that the 7-year reassessment requirement is conservative for pipelines that operate under lower-stress. This is especially true for local distribution companies that use their transmission lines mainly to transport natural gas under lower pressures for several miles from larger cross-country lines in order to feed smaller distribution lines. They pointed out, for example, that in a lower-pressure environment, pipelines tend to leak rather than rupture. Leaks involve controlled, slow emissions that typically create little damage or risk to public safety. Most local distribution companies we spoke with reported finding few, if any, conditions during baseline assessments that would necessitate another assessment within 7 years. As a result, if the 7-year requirement did not exist, the local distribution companies would likely reassess every 15 to 20 years following industry consensus standards. Some of these operators often pointed out that since third-party damage poses the greatest threat to their systems. Operators added that third-party damage can happen at any time and that prevention and mitigation measures are the best ways to address it.[13]

Operators viewed a risk-based reassessment requirement such as in the consensus standard as valuable for public safety. Operators of both higher-stress and lower-stress pipelines indicated a preference for a risk-based reassessment requirement based on engineering standards rather than a prescriptive one-size-fits-all standard.[14] Such a risk-based reassessment standard would be consistent with the overall thrust of the integrity management program. Some operators noted that reassessing pipeline segments with few defects every 7 years takes resources away from riskier segments that require more attention. While PHMSA's regulations require that pipeline segments be reassessed only for corrosion problems at least every 7 years using a less intensive assessment technique

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[13] Prevention and mitigation measures include one-call programs, proper marking of the pipeline's location, inspection by air, and public education programs. In one-call programs, persons who want to dig in an area contact a clearinghouse. The clearinghouse notifies pipeline operators and others that someone is going to be digging near their pipeline, so that the operator can mark the pipeline's location prior to the digging work.

[14] On a related note, the Congress expressed a general preference for technical standards developed by consensus bodies over agency-unique standards in the National Technology Transfer and Advancement Act of 1995.

(confirmatory direct assessment) some operators point out that it has not worked out that way. They told us that, if they are going to the effort of assessing pipeline segments to meet the 7-year reassessment requirement, they will typically use more extensive testing—for both corrosion and for other problems--than required, because doing so will provide more comprehensive information. Thus, in most cases, operators plan to reassess their pipelines by using in-line inspections or direct assessment for problems in addition to corrosion sooner than required under PHMSA's rules.[15]

Services and Tools Are Likely to be Available for Reassessments

Most operators and inspection contractors we contacted told us that the services and tools needed to conduct periodic reassessments will likely be available to most operators. All of the operators reported that they plan to rely on contractors to conduct all or a portion of their reassessments and some have signed, or would like to sign, long-term contracts that extend contractor services through a number of years. However, few have scheduled reassessments with contractors, as they are several years in the future, and operators are concentrating on baseline assessments.

Nineteen of the 21 operators that reported both baseline and reassessment schedules to us said that that they primarily plan to use in-line inspection or direct assessment to reassess segments of their pipelines located in highly populated or frequented areas. In-line inspection contractors that we contacted report that there is capacity within the industry to meet current and future operator demands. Unlike the in-line inspection method, which is an established practice that many operators have used on their pipelines at least once prior to the integrity management program, the direct assessment method is new to both contractors and operators. Direct assessment contractors told us that there is limited expertise in this field and one contractor said that newer contractors coming into the market to meet demand may not be qualified.[16] The operators planning to use direct assessment for their pipelines are generally local distribution companies with smaller diameter pipelines that cannot accommodate in-line inspection tools.[17]

An industry concern about the 7-year reassessment requirement is that operators will be required to conduct reassessments starting in 2010 while they are still in the 10-year period (2003-2012) for conducting baseline assessments. Industry was concerned that this could create a spike in demand for contractor services resulting from an overlap of assessments and reassessments from 2010 through 2012, and operators would have to compete for the limited number of contractors to carry out both. The industry was worried that operators might not be able to meet the reassessment requirement and that

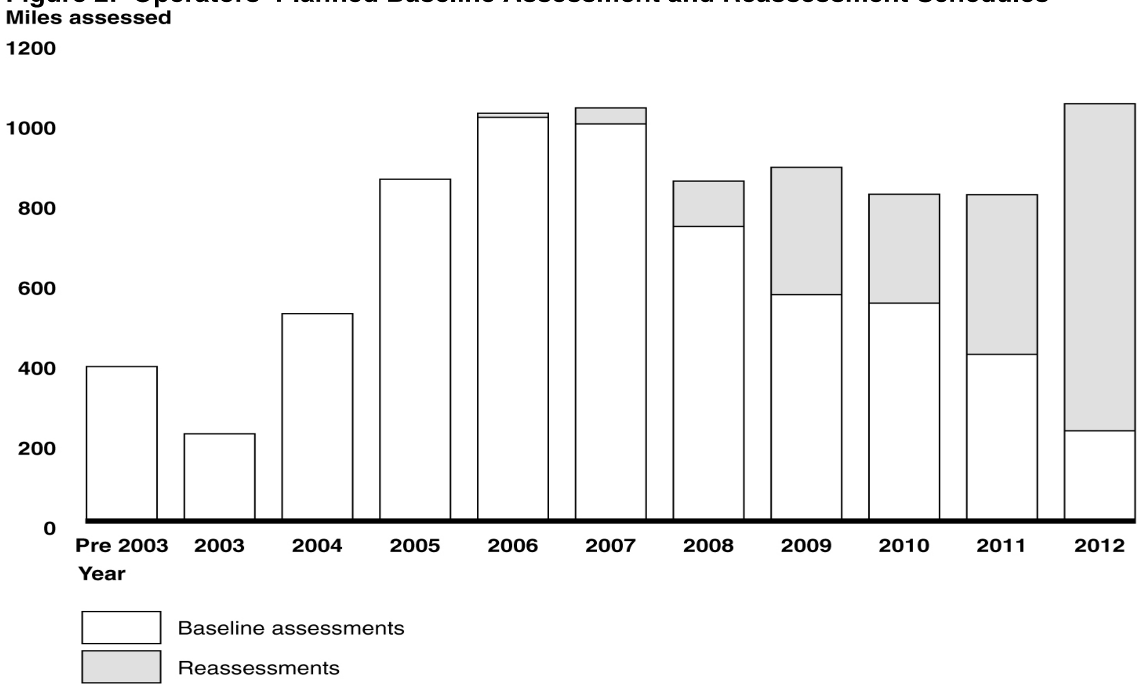
[15] Direct assessment is used to identify corrosion and other defects in pipelines. It is used when in-line inspection cannot be used and to avoid interrupting gas supply to a community fed by a single pipeline. Direct assessment involves several steps, including digging holes at intervals along a pipeline to examine suspected problem areas.

[16] To prepare for this hearing, we contacted the Inline Inspection Association, one company offering in-line inspection services, and two companies offering direct assessment services.

[17] According to industry estimates, 35 percent of all local distribution company pipelines (as measured in miles likely to be located in highly populated areas) cannot accommodate an in-line inspection tool, compared to only about 4 percent of transmission operators' pipelines.

it was unnecessarily burdensome.[18] Most operators that we contacted do not anticipate a spike and baseline activity should decrease as they begin to conduct reassessments. (See fig. 2.) They predict that operators will have conducted a large number of baseline assessments between 2005 and 2007 in order to meet the statutory deadline for completing at least half of their baseline assessments by December 2007 (2 years before the predicted overlap).

Figure 2: Operators' Planned Baseline Assessment and Reassessment Schedules



Source: GAO.

Note: This figure shows the baseline assessments conducted, or planned to be conducted as well as the reassessments that are planned in highly populated or frequented areas for the 20 of 25 operators we contacted. Five operators did not report their reassessment plans.

There has also been a concern about whether baseline assessments and reassessments would affect natural gas supply if pipelines are taken out of service or operate at reduced pressures when repairs are being made. We are addressing this issue and will report on it in the fall.

PHMSA Has Developed a Reasonable Framework for Its Enforcement Program

Recently, PHMSA reassessed its approach for enforcing pipeline safety standards in response to our concern that it lacked a comprehensive enforcement strategy. In August 2005, PHMSA adopted a strategy that focuses on using risk-based enforcement, increasing knowledge of and accountability for results, and improving its own enforcement activities. The strategy also links these efforts to goals to reduce and prevent incidents and damage, in addition to providing for periodic assessment of results. While we have neither reviewed the revised strategy in depth nor examined how

[18] The 2002 act allows operators to request a waiver from conducting reassessments when inspection tools are not available and when operators need to maintain product supply. PHMSA has not issued guidance on conditions under which it would grant a waiver.

it is being implemented, our preliminary view is that it is a reasonable framework that is responsive to the concerns that we raised in 2004.

PHMSA has established overall goals for its enforcement program to reduce incidents and damage due to operators' noncompliance. PHMSA also recognizes that incident and damage prevention is important, and its strategy includes a goal to influence operators' actions to this end. To meet these goals, PHMSA has developed a multi-pronged strategy that is directed at the pipeline industry and stakeholders (such as state regulators), and ensuring that its processes make effective use of its resources.

For example, PHMSA's strategy calls for using risk-based enforcement to, among other things, take enforcement actions that clearly reflect potential risk and seriousness and deal severely with significant operator noncompliance and repeat offenses. Second, the strategy calls for increasing knowledge and accountability for results through such actions as (1) soliciting input from operators, associations, and other stakeholders in developing and refining regulations, inspection protocols, and other guidance; (2) clearly communicating expectations for compliance and sharing lessons learned; and (3) assessing operator and industry compliance performance and making this information available. Third, the strategy, among other things, calls for improving PHMSA's own enforcement activities through developing comprehensive guidance tools and training inspectors on their use, and effectively using state inspection capabilities.

Finally, to understand progress being made in encouraging pipeline operators to improve their level of safety and, as a result, reduce accidents and fatalities, PHMSA annually will assess its overall enforcement results as well as various components of the program. Some of the program elements that it may assess are inspection and enforcement processes, such as the completeness and availability of compliance guidance, the presentation of operator and industry performance data, and the quality of inspection documentation and evidence.

Concluding Observations

Our work to date suggests that PHMSA's gas integrity management program should enhance pipeline safety, and operators support it. We have not identified major issues that need to be addressed at this time. We expect to provide additional insights into these issues when we report to this Subcommittee and others this fall.

Because the program is in its early phase of implementation, PHMSA is learning how to oversee the program and operators are learning how to meet its requirements. Similarly, operators are in the early stages of assessing their pipelines for safety problems. This means that the integrity management program will be going through this shake down period for another year or two as PHMSA and operators continue to gain experience.

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Mr. Chairman, this concludes my prepared statement. I would be pleased to respond to any questions that you or the other Members of the Subcommittee might have.

GAO Contacts and Staff Acknowledgement

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(542087)