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September 2006

NATURAL GAS PIPELINE SAFETY

Risk-Based Standards Should Allow Operators to Better Tailor Reassessments to Pipeline Threats

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GAO-06-945

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Highlights

Highlights of GAO-06-945, a report to congressional committees

September 2006

NATURAL GAS PIPELINE SAFETY

Risk-Based Standards Should Allow Operators to Better Tailor Reassessments to Pipeline Threats

Why GAO Did This Study

The Pipeline Safety Improvement Act of 2002 requires that operators (1) assess gas transmission pipeline segments in about 20,000 miles of highly populated or frequently used areas by 2012 for safety threats, such as incorrect operation and corrosion (called baseline assessments), (2) remedy defects, and (3) reassess these segments at least every 7 years. Under the Pipeline and Hazardous Materials Safety Administration's (PHMSA) regulations, operators must reassess their pipeline segments for corrosion at least every 7 years and for all safety threats at least every 10, 15, or 20 years, based on industry consensus standards—and more frequently if conditions warrant. Operators must also carry out other prevention and mitigation measures.

To meet a requirement in the 2002 act, this study addresses how the results of baseline assessments and other information inform us on the need to reassess gas transmission pipelines every 7 years and whether inspection services and tools are likely to be available to do so, among other things. In conducting its work, GAO contacted 52 operators that have carried out about two-thirds of the baseline assessments conducted to date.

What GAO Recommends

The Congress should consider allowing gas transmission pipeline operators to reassess their pipelines using risk-based standards. In commenting on a draft of this report, the Department of Transportation generally agreed with it and the Department of Energy stated that it had no comments.

www.gao.gov/cgi-bin/getrpt?GAO-06-945.

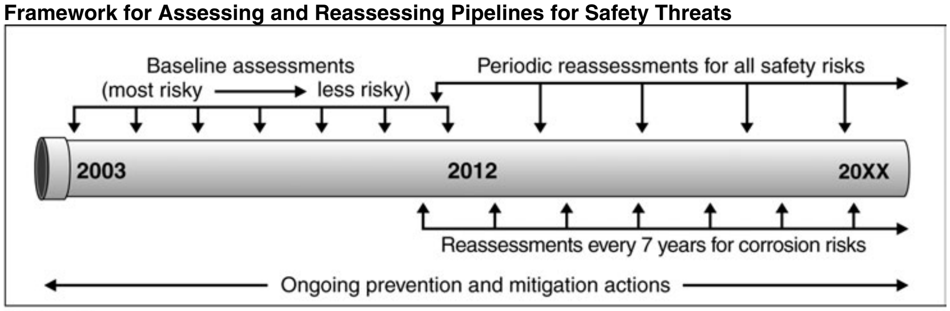
To view the full product, including the scope and methodology, click on the link above. For more information, contact Katherine Siggerud (202) 512-2834 or siggerudk@gao.gov.

What GAO Found

Periodic reassessments of gas transmission pipelines are useful because safety threats can change. However, the 7-year requirement appears to be conservative because (1) most operators found few major problems during baseline assessments, and (2) serious pipeline incidents involving corrosion are rare, among other reasons. Through December 2005 (latest data available), 76 percent of the operators (182 of 241) that had begun baseline assessments reported to PHMSA that their pipelines required only minor repairs. These results are encouraging because operators are required to assess their riskiest segments first. Since operators are also required to repair these problems, the overall safety and condition of their pipelines should be enhanced before reassessments begin. In addition, PHMSA data suggest that serious gas transmission pipeline problems due to corrosion are rare. For example, there have been no deaths or injuries as a result of incidents due to corrosion since 2001. Of the 52 operators contacted that have calculated reassessment intervals, the large majority (20 of 23) told GAO that based on conditions identified during baseline assessments, they could safely reassess their pipelines for corrosion, every 10, 15, or 20 years—as industry consensus standards prescribe unless pipeline conditions warrant an earlier assessment.

Sufficient resources may be available for operators' reassessment activities, but some uncertainty exists. For the most part, the 52 operators that GAO contacted expect to be able to obtain the services and tools needed through 2012. However, they expressed some concern about whether enough qualified vendors for the confirmatory and direct assessment methods (above-ground inspections followed by excavations) would be available. Industry associations and GAO attempted to determine the degree to which activity would increase from 2010 to 2012, when operators begin reassessing pipelines while completing baseline assessments. An industry effort showed an increase in assessment and reassessment activity, but GAO's showed a decrease. The reasons for the differences are not clear but may be due, in part, to differences in the operators contacted and the methodologies used in collecting this information.

Framework for Assessing and Reassessing Pipelines for Safety Threats



Source: GAO.

Contents

Abbreviations

AGA	American Gas Association
INGAA	Interstate Natural Gas Association of America
PHMSA	Pipeline and Hazardous Materials Safety Administration

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Congressional Committees:

Gas transmission pipelines are one of the nation's safest modes of freight transportation: nationwide about three people have died and about eight have been injured annually, on average, over the past decade because of natural gas pipeline incidents from all causes.[1] To enhance the safety of gas transmission pipelines, the Pipeline Safety Improvement Act of 2002 requires that operators of these pipelines develop programs to assess and mitigate safety threats, such as leaks or ruptures due to incorrect operation or corrosion, to pipeline segments that are located in highly populated and frequently used areas, such as parks. Specifically, operators are required to perform baseline assessments on one-half of the gas transmission pipeline mileage located in these areas by December 2007 and the remainder by December 2012. Pipeline segments that potentially face the greatest risks of failure from leaks or ruptures are to be assessed first.

The 2002 act also requires that operators reassess these pipeline segments for safety threats at least every 7 years. Under flexibility provided by the act, the federal regulator—the Pipeline and Hazardous Materials Safety Administration (PHMSA)—requires that operators reassess these pipeline segments for *corrosion damage* at least every 7 years in its implementing regulations, because corrosion is the most frequent cause of failures that can occur over time.[2] It also incorporated, as mandatory, voluntary industry consensus standards on maximum reassessment intervals into these regulations for other types of safety threats. The industry standards require that operators reassess gas pipelines at least every 10, 15, or 20 years for all safety risks, depending primarily on the condition of the pipelines and the pressure under which they operate. If conditions warrant, reassessments must occur more frequently.

[1]Transmission pipelines move products from sources to communities. An incident, for PHMSA reporting purposes, involves a death, an injury requiring hospitalization, or property damage (including the value of any loss of gas) of $50,000 or more.

[2]Other types of failures are independent of time, such as damage from excavation, land movement, or incorrect operation.

The 2002 act required that we assess the 7-year reassessment requirement. To do so, we examined (1) the extent to which findings from baseline assessments and other information inform us about the need to reassess gas transmission pipelines for safety risks at least every 7 years and (2) the ability of operators to obtain the services and tools needed to perform the reassessments. These two topics are the main focus of this report. We also examined the potential impact of periodic assessments on the nation's natural gas supply. (See app. I.) This report deals mostly with natural gas transmission pipelines, which represent the overwhelming majority of gas pipelines.[3]

To understand how the findings from operators' baseline assessments and other information inform us about the need to reassess gas transmission pipelines at least every 7 years, we reviewed laws, regulations, and other PHMSA guidance. We discussed this issue with PHMSA, other federal agencies, industry associations, companies that perform research in this area, state safety representatives, and safety advocacy groups. We also obtained information from 52 gas pipeline operators for which baseline assessments and reassessments could have the greatest impact, all else being equal: larger and smaller transmission pipelines and local distribution companies (pipeline companies that take gas from transmission pipelines and distribute it to end users) with the highest proportion of pipeline miles in highly populated and frequently used areas to total system miles. Overall, these operators have assessed about 21 percent of the 20,000 miles of gas transmission pipeline that operators have reported as being within highly populated or frequently used areas.[4] In addition, we analyzed data from PHMSA for 241 operators that reported, in 2004 and 2005, on the number of immediate repairs conducted after completing their baseline assessments.[5] To determine the extent to which gas transmission pipeline operators and local distribution companies will likely have the resources to reassess their pipelines at least every 7 years, we asked operators, inspection tool contractors, and industry associations about the availability of equipment, equipment operators, and data analysts

[3]Other types of gas pipelines transport hydrogen and carbon dioxide.

[4]It would have been insightful to be able to assess the effects of operators' assessment activity in relation to the volume of gas flowing through their pipelines and the overall capacity of the pipelines. However, this information was not readily available.

[5]Nationwide, there are about 900 operators, 447 of which have reported to PHMSA that they operate pipelines in highly populated or frequently used areas. Of these, 241 have reported to PHMSA that they have completed some baseline assessments.

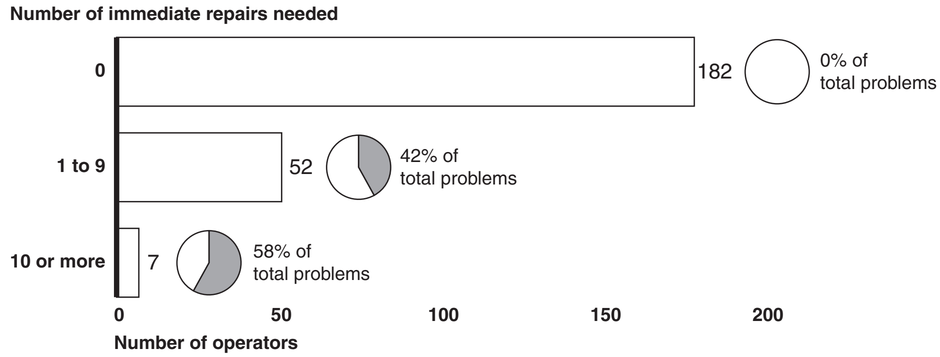
to interpret results. We also synthesized the information from the 52 operators to determine the aggregate level of actual and planned assessments and reassessments through 2012 and compared our findings with the results from an Interstate Natural Gas Association of America and American Gas Association data collection effort on the same topic. 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 between August 2005 and August 2006 in accordance with generally accepted government auditing standards. (See app. II for additional details on our scope and methodology.)

Results in Brief

Periodic reassessments of pipeline threats are beneficial because threats—such as the corrosive nature of the gas being transported—can change over time. Baseline assessment findings conducted to date and the generally safe condition of gas transmission pipelines, suggest that the 7-year reassessment requirement appears to be conservative. Through December 2005 (latest data available), 76 percent of the operators (182 of 241) reporting baseline assessment activity reported to PHMSA that their gas transmission pipelines were in good condition and free of major defects, requiring only minor repairs. (See fig. 1.) Most of the 340 problems reported were concentrated in just seven pipelines.[6] (These assessments reported by the 241 operators covered about 6,700 miles, or about one-third of the nationwide total to be assessed by 2012.) Because PHMSA does not require operators to identify the nature of the problems, we do not know how many, if any, were corrosion related.

[6]Pipeline operators are required to report the number of scheduled and immediate repairs completed. They may have found other problems but not have completed the repairs. These repairs are reported only after they are completed.

Figure 1: Most Operators Reported That Their Gas Transmission Pipelines Are in Good Condition, as of December 2005



Source: GAO presentation of PHMSA data.

Note: Results of 241 operators that reported to PHMSA that they completed 6,700 miles of baseline assessments. Of those operators that reported no problems, 82 operate smaller pipeline systems (1 to 49 miles), 41 operate mid-sized systems (50 to 199 miles) and 59 operate larger systems (200 or more miles).

These results are encouraging, since operators are required to assess their riskiest segments first and 54 percent of the operators we contacted that have begun baseline assessments told us that they had not conducted risk-based assessments before the onset of the gas integrity management program. This suggests that, overall, operators that have thus performed baselines assessments are doing a good job in managing corrosion. Furthermore, since operators are required to repair these gas transmission pipelines the overall safety and condition of the pipeline system should be improved before reassessments begin toward the end of the decade. In addition, PHMSA data show corrosion incidents are rare: over the past 5-1/2 years (from January 2001 through early July 2006), there were 26 corrosion-related incidents over the 295,000-mile transmission system per year, on average—none of which resulted in death or injury.[7]

[7]In the last 10½ years, PHMSA data show that 236 corrosion-related incidents occurred, only 2 of which resulted in deaths or injuries. One of the incidents resulted in 12 deaths and two injuries. The other incident resulted in one injury. Neither incident occurred in a highly populated or frequently used area.

Of the 52 operators that we contacted, 23 have calculated reassessment intervals. Based on conditions identified during baseline assessments, 20 of these 23 operators indicated that they would reassess their gas transmission pipelines at the *maximum* allowable intervals prescribed by industry consensus standards—if the 7-year reassessment requirement were not in place.[8] Most operators we contacted (42 of 52 or 81 percent) told us that they prefer following industry consensus standards that base reassessment intervals on the characteristics and conditions of pipelines and that were developed using historical information and research. Although the industry consensus standards recognize that corrosion does not occur at a rapid rate, they allow for maximum reassessment intervals for time-dependent threats of 10, 15, or 20 years only if the operator can adequately demonstrate that corrosion will not become a threat within the chosen time interval. If not, then the reassessment must occur more frequently, perhaps at 7 or even fewer years. Federal policy encourages the use of industry consensus standards, and PHMSA's implementing regulations incorporate three other industry consensus standards.

PHMSA and state pipeline agencies are conducting inspections that should serve as a check as to whether operators have identified threats facing these gas transmission pipeline segments and have determined appropriate reassessment intervals. Initial results from 137 federal and state inspections show that operators are doing well on assessing their pipelines and making repairs. PHMSA and state agencies plan to inspect all operators' compliance with integrity management, including reassessment requirements and complete most of them by 2009 to, among other things, ensure that operators continually and appropriately assess the conditions of their pipeline segments. Finally, basing reassessments for corrosion on risk would be consistent with the risk-based approach to improving pipeline safety (called integrity management) set out in the 2002 act. We recently reported that PHMSA's implementation of the gas integrity management program is designed to enhance public safety.[9]

[8]The remaining three operators told us that they could reassess their pipelines at intervals shorter than the industry consensus standards but longer than 7 years, based on the condition of their pipelines.

[9]For a discussion on the effect of integrity management on public safety, see *Natural Gas Pipeline Safety: Integrity Management Enhances Public Safety, but Consistency of Performance Measures Should Be Improved*, GAO-06-946 (Washington, D.C.: Sept. 8, 2006).

Sufficient resources may be available for operators to reassess their gas transmission pipelines, but some uncertainty exists. For the most part, the 52 operators and four inspection contractors we contacted told us that services and tools needed to conduct assessments have been readily available for baseline assessments, and they do not anticipate difficulties obtaining these resources in the future. Operators that reported both baseline and reassessment schedules told us they plan to reassess 42 percent of their pipeline miles in highly populated or frequently used areas using in-line inspection.[10] Operators we contacted said that the in-line inspection industry is well established and has the capacity to expand readily. Operators plan to use direct assessment or confirmatory direct assessment methods in reassessing another 54 percent of their pipeline miles.[11] However, they told us that expertise in direct assessment methods is limited; therefore, they may not be as readily available to all operators. Industry associations and we asked operators to estimate the number of miles of gas transmission pipeline they planned to assess through 2012 in order to determine whether an increase in overall assessment activity would occur because of the overlap between completing baseline assessments and beginning reassessments from 2010 through 2012. The results were conflicting: the industry found an increase in activity, while we found a decrease. The reasons for these contrasting findings are unclear but may be due, in part, to the difference in methods used in collecting this information.

We suggest that the Congress amend the Pipeline Safety Improvement Act of 2002 to permit pipeline operators to reassess their gas transmission pipeline segments at intervals based on risk factors, technical data, and engineering analyses. Such a revision would allow PHMSA to establish maximum reassessment intervals, and to require shorter reassessment intervals as conditions warrant.

In commenting on a draft of this report, the Department of Transportation generally agreed with the report's findings. The Department of Energy had no comments.

[10]In-line inspection involves running a specialized tool through a pipeline to detect and record anomalies, such as metal loss and damage.

[11]Direct assessment and confirmatory direct assessment involve using above-ground detection instruments, and then excavating suspected problem areas.

Background

The United States has about a 295,000-mile network of gas transmission pipelines that are owned and operated by approximately 900 operators. These pipelines are important to the nation because they transport nearly all the natural gas used, which provides about a quarter of the nation's energy supply. Pipelines do not experience many of the safety threats faced by other forms of freight transportation because they are mostly underground; but they are subject to failures that occur over time—such as leaks and ruptures resulting from corrosion[12] or welding defects—and failures that are independent of time—such as damage from excavation, land movement, or incorrect operation.

For the most part, two types of pipelines transport gas products: (1) gas transmission pipelines and (2) local distribution pipelines. Gas transmission pipelines typically move gas products over long distances from sources to communities and are primarily interstate. They typically operate at a higher stress level (higher operating pressure in relation to wall strength). By contrast, local distribution pipelines receive gas from transmission pipelines and distribute it to commercial and residential end users. Local distribution pipelines, which are primarily intrastate, typically operate under lower-stress conditions. Local distribution companies may also operate small portions of transmission pipelines—typically under lower stress—and are therefore subject to the assessment and reassessment requirements of the Pipeline Safety Improvement Act of 2002.[13]

Before the 2002 act, operators were subject to PHMSA's minimum safety standards for the design, construction, testing, inspection, operation, and maintenance of gas transmission pipelines; these standards are applied to all pipelines. However, this approach does not account for differences in the kinds of threats and the degrees of risk that pipelines face. For example, pipelines located in the Pacific Northwest are more susceptible to damage from geologic hazards, such as land movement, than pipelines in some other areas of the country; but PHMSA's safety standards do not take

[12]The Federal Highway Administration estimates the average annual cost of corrosion to gas and hazardous liquid transmission pipelines at $7 billion for, among other things, maintenance and failures. See Federal Highway Administration, *Tech Brief: Corrosion Costs and Preventive Strategies in the United States*, study performed by CC Technologies, March 2002.

[13]Gas transmission pipeline operators and local distribution companies also operate medium-stress pipelines.

these threats into account in a systematic way.[14] By contrast, the risk-based approach of the 2002 act—called the integrity management approach—requires pipeline operators to develop programs to systematically identify threats and mitigate risks to gas transmission pipeline segments located in highly populated or frequently used areas.[15] In addition to PHMSA's integrity management program, operators must still meet the minimum safety standards.

As of December 2005 (latest data available), 447 gas pipeline operators reported to PHMSA that about 20,000 miles of their pipelines (about 7 percent of all gas transmission pipeline miles) lie in highly populated or frequently used areas. Individual operators reported that they have as many as about 1,600 miles and as few as 0.02 miles of transmission pipeline in these areas.

Under PHMSA's regulations, gas pipeline operators may use any of three primary approaches to conduct baseline assessments on pipeline segments lying in highly populated or frequently used areas.

- *In-line inspection*: In-line inspection involves running a specialized tool through the pipeline to detect and record anomalies, such as metal loss and damage. In-line inspection allows operators to determine the nature of any problems without either shutting down the pipeline for extended periods or potentially damaging the pipeline, as in hydrostatic testing (described below). In-line inspection devices can be run only from facilities established for launching and retrieving them. These launching and retrieval locations may extend beyond highly populated or frequently used areas. Operators will typically gather information along the entire distance between launching and retrieval locations to gain additional safety information; this is called over-testing.

[14]Under its minimum safety standards, PHMSA requires stronger pipelines in more highly populated areas. In addition, operators are required to annually evaluate their pipelines for population growth, which may cause operators to reduce operating pressure or upgrade pipelines.

[15]The regulatory definition of highly populated or frequently used area is involved. Some examples of these areas are (1) an area with 20 or more buildings that could be affected by a pipeline incident; (2) a location where a potential impact of a pipeline rupture contains an area or open structure that is occupied by 20 or more people on at least 50 days in a 12-month period (e.g., a camp site); and (3) a facility occupied by persons that would be difficult to evacuate, such as a hospital.

- *Direct assessment*: Direct assessment is a nonintrusive, above-ground instrument inspection that uses two or more types of diagnostic tools, such as a close interval survey, at predetermined intervals along the pipeline.[16] Once the data are analyzed, the operator excavates and inspects segments of the pipeline suspected to have safety threats.

- *Hydrostatic testing*: Hydrostatic testing entails sealing off a portion of the pipeline, removing the gas product, filling it with water, and increasing the pressure of the water above the rated strength of the pipeline to test its integrity. If the pipeline leaks or ruptures, the pipeline is excavated to determine the cause of the failure. Operators must shut down pipelines to perform hydrostatic testing. Also, this form of testing can damage the pipeline due to high pressure testing. Finally, operators must be able to dispose of large quantities of water in an environmentally responsible manner.

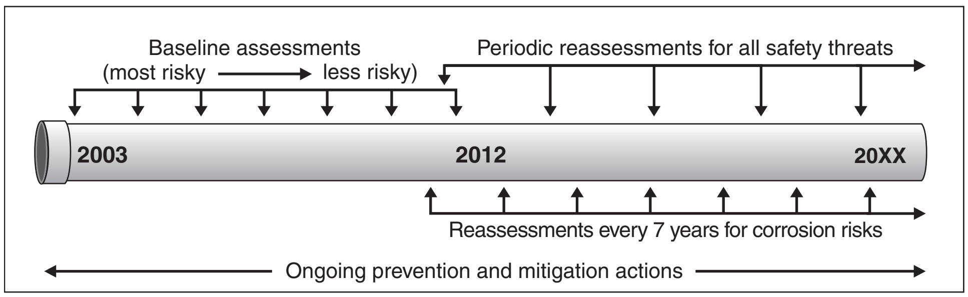
Under PHMSA's regulations, which incorporate voluntary industry consensus standards for managing the system integrity of gas pipelines,[17] operators must reassess their gas transmission pipeline segments for safety threats overall at least every 10, 15, or 20 years (consistent with industry consensus standards), depending on the condition of the pipelines and the stress under which the pipeline segments are operated. PHMSA's regulations allow operators to limit the statutorily required 7-year reassessment to corrosion damage. In performing reassessments to meet the 7-year requirement, operators may employ a technique called confirmatory direct assessment. This technique is similar to direct assessment; however, operators are required to use only one type of assessment tool, rather than at least two types required under direct assessment. According to PHMSA, it allowed this more limited assessment because the 7-year reassessment for corrosion confirms the acceptable integrity of a gas transmission pipeline, already ensured by assessments and reassessments for safety threats conducted at 10-, 15-, or 20-year

[16]A close interval survey is used to assess the coating of covered pipelines for corrosion damage.

[17]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. For more details about industry consensus standards, see the National Association of Corrosion Engineers: *Standard Recommended Practice – Pipeline External Corrosion Direct Assessment* (NACE RP002-2002) and the American Society of Mechanical Engineers: *Managing the System Integrity of Gas Pipelines* (ASME B31.8S-2004).

intervals under the industry consensus standards incorporated in the agency's regulations. (See fig. 2.) About 2010, operators will be expected to begin reassessing some segments of their pipelines for corrosion under the 7-year reassessment requirement while they are completing baseline assessments of other segments—called "the overlap."

Figure 2: Reassessments Every 7 Years for Corrosion Supplement Broader Periodic Reassessments



Source: GAO.

Note: Periodic reassessments occur at least every 10, 15, or 20 years. Both periodic and 7-year reassessments are supposed to occur more frequently if conditions warrant.

It is important to note that the reassessment intervals under the industry consensus standards, the 7-year reassessment requirement for corrosion, and PHMSA's regulations for time-dependent threats represent the *maximum* number of years between reassessments. If pipeline conditions dictate more frequent reassessments—for example, 5 or fewer years—then pipeline operators must do so to comply with PHMSA's regulations.[18] In addition, between reassessments, operators must continually ensure that their gas transmission pipelines are safe. PHMSA's regulations require all operators—whether or not they are located in highly populated or frequently used areas to patrol their pipelines, survey for leakage, maintain valves, ensure that corrosion-preventing cathodic protection is

[18]Pipeline conditions and threats change over time. For example, housing may be built around pipelines, possibly increasing the threat of excavation damage. Another example is that over time the quality of the gas being shipped through the pipeline may change and may be more corrosive.

working properly,[19] and take prevention and mitigation measures to prevent excavation damage.

PHMSA, within the Department of Transportation, attempts to ensure the safe operation of pipelines through regulation, industry 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 people in its pipeline safety program, about half of whom are pipeline inspectors who inspect operators' implementation of integrity management programs for gas and hazardous liquid (e.g., oil, gasoline, and anhydrous ammonia) pipelines, in addition to other more traditional compliance programs. PHMSA currently has 22 inspectors trained to conduct integrity management inspections, of which 9 are devoted exclusively to the program. In addition, PHMSA expects to be assisted by about 180 inspectors in 46 states and the District of Columbia in overseeing intrastate natural gas transmission pipelines.

The 7-Year Reassessment Requirement Appears to Be Conservative

Periodic reassessments of pipeline threats are beneficial because threats—such as the corrosive nature of the gas being transported—can change over time. Baseline assessment findings conducted to date and the generally safe condition of gas transmission pipelines suggest that the 7-year requirement appears to be conservative. Most operators of gas transmission pipelines reported to PHMSA that their baseline assessments have disclosed 340 problems for which immediate repairs have been made. This is encouraging because these pipeline segments are supposed to be the riskiest and few have been systematically assessed until now. Regarding the industry safety record, the industry is generally safe and no corrosion-related incidents resulting in deaths or injuries have occurred in the past 5-1/2 years (from January 2001 through early July 2006) anywhere in the nation, let alone in highly populated or frequently used areas.[20] It is therefore likely to be safe in most cases to allow longer *maximum* intervals that coincide with industry consensus standards. PHMSA and state pipeline agencies plan to inspect all operators' integrity management

[19]Cathodic protection involves a small electrical voltage between a structure and the ground to control corrosion.

[20]As noted earlier, an average of three people have died and eight have been injured over a 10 1/2-year period, from all causes of natural gas transmission pipeline incidents.

activities, which should serve as a safeguard if longer reassessment intervals for corrosion are permitted.

Most Operators Have Reported That Their Gas Transmission Pipelines Are Mostly Free of Serious Problems

Through December 2005 (latest data available), 76 percent of the operators (182 of 241) reporting baseline assessment activity to PHMSA told the agency that their gas transmission pipelines were in good condition and free of major defects, requiring only minor repairs. (These assessments covered about 6,700 miles, or about one-third of the nationwide total to be assessed). The remaining 59 operators reported 340 problems for which immediate repairs have been completed. (See fig. 1.)

Fifty-two operators (21 percent) reported nine or fewer problems for which immediate repairs have been completed; and seven operators (3 percent) reported 10 or more problems. Most of the problems stem from the seven operators reporting 10 or more problems and concern only a small portion of their gas transmission pipelines. Specifically, these seven operators represent nearly 60 percent of the total problems requiring immediate repairs, and the problems occurred in only 7 percent of 6,700 miles of baseline assessments conducted.[21] Since PHMSA does not require that operators report to it the nature of the problems, we do not know how many of the 340 problems, if any, were due to corrosion.

We contacted 52 operators about the baseline assessments they have completed and their plans for the rest, and the results were largely consistent with the overall data reported to PHMSA. Forty-four of these operators have begun baseline assessments, and 37 of these 44 (84 percent) told us that they found few safety problems that required reducing pipeline pressure and performing immediate repairs in response to baseline assessments in highly populated or frequently used areas. These 44 operators have assessed about 4,100 miles of gas transmission pipeline, representing about 61 percent of the 6,700 miles of baseline assessment results reported to PHMSA and about 21 percent of the total number of pipeline miles in highly populated or frequently used areas nationwide.

It is encouraging that the majority of operators nationwide reported few or no problems involving immediate repairs, because (1) operators are to assess pipeline segments facing the greatest risk of failure from leaks or

[21]As noted earlier, product flow and pipeline capacity can be useful to understand the extent of problems and their effect. However, this measurement was not practical.

ruptures first, as required by the 2002 act, and (2) 54 percent of the operators we contacted (28 of 52) had not conducted risk-based assessments of their pipeline segments for safety threats prior to the integrity management program.

Although the PHMSA regulations focus the 7-year reassessment requirement on corrosion because it is the most frequent cause of time-dependent pipeline incidents,[22] the industry has had a good safety record prior to and during the initial years of integrity management. It is not possible to determine which incidents occurred in highly populated or frequently used areas from summary historical data published by PHMSA. However, nationwide, these incidents are relatively rare. Over the past 5½ years (from January 2001 through early July 2006), there were 143 corrosion-related incidents over the 295,000-mile transmission system (26 per year, on average)—none of which resulted in death or injury. In addition, according to PHMSA, during the first 2 years of integrity management (2004 and 2005), operators reported that corrosion caused 49 leaks,[23] 16 failures, and two incidents involving significant property damage, but no fatalities and injuries, in highly populated or frequently used areas.

Both the positive results found during baseline assessments conducted to date and the overall good safety industry record suggest that gas transmission pipeline operators that have thus far performed baseline assessments overall are doing a good job in managing corrosion. Further, since operators, are required to identify and repair significant problems, the overall safety and condition of the gas transmission pipeline system should be enhanced before reassessments begin toward the end of the decade.

[22]Third-party damage is a significant cause of gas transmission pipeline incidents. In addition, third-party damage can cause pipeline dents that may lead to corrosion.

[23]Leaks from gas transmission pipelines can allow methane to escape into the atmosphere. Methane is a potent greenhouse gas that contributes to climate change. See U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003*, April 2005.

Operators Support Baseline Assessments and Reassessments but Prefer a Risk-based Reassessment Requirement Over a Fixed One

Because many gas transmission pipelines had never been assessed before integrity management, operators we contacted pointed out that the new knowledge gained through baseline assessments represents one of the greatest benefits of the integrity management program. They also support reassessments, in part because all operators are subject to the same requirements. However, most support a risk-based reassessment requirement, consistent with overall integrity management, over the fixed 7-year requirement prescribed by the 2002 act. Operators also told us they prefer a risk-based reassessment requirement that is based on research and historical information. Most operators told us they prefer reassessing pipelines based on the characteristics and conditions of the pipeline rather than on the 7-year requirement prescribed in the 2002 act. About 80 percent of the 52 operators that we contacted prefer that reassessment intervals be based on the condition and characteristics of the pipeline segment. About half of these operators (28) expressed a preference for the industry consensus standard developed by the American Society of Mechanical Engineers (ASME B31.8S-2004) for setting reassessment intervals for time-dependent threats because it incorporates a risk-based approach (for pipeline failure) and is based on science and engineering knowledge. This standard sets reassessment intervals at a *maximum* of 10 years for high-stress pipeline segments, 15 years for medium-stress segments, and 20 years for low-stress segments. Maximum reassessment intervals, such as those in the industry consensus standard, incorporate such risk concepts as built-in safety factors (e.g., wall stress, test pressure, or predicted failure) and pipeline conditions. The maximum intervals of 10, 15, and 20 years are based on worst-case corrosion growth rates.

The industry consensus standards were developed in 2001 and updated in 2004 based on, among other things, (1) the experience and expertise of engineers, consultants, operators, local distribution companies, and pipeline manufacturers; (2) more than 20 technical studies conducted by the Gas Technology Institute, ranging from pipeline design factors to natural gas pipeline risk management; and (3) other industry consensus standards, including the National Association of Corrosion Engineers standards, on topics such as corrosion. Contributors have been practicing aspects of risk-based assessments for over 10 years. This standard serves as a foundation for most sections of PHMSA's integrity management regulations. The mechanical engineering society's standard was reviewed by the American National Standards Institute.[24] The institute found that the standard was developed in an environment of openness, balance, consensus, and due process and therefore approved it as an American National Standard.

While the mechanical engineering standards are voluntary for the industry, PHMSA incorporated them as mandatory in its gas transmission integrity management regulations. The mechanical engineering society's standard for setting reassessment intervals is not the only industry consensus standard in PHMSA's integrity management regulations. The regulations incorporate other industry consensus standards for using direct assessment for corrosion, calculating pipeline wall strength, and for determining temporary reductions in operating pressure. In addition, it is federal policy to encourage the use of industry consensus standards: the Congress expressed a preference for technical standards developed by consensus bodies over agency-unique standards in the National Technology Transfer and Advancement Act of 1995. The Office of Management and Budget's Circular A-119 provides guidance to federal agencies on the use of voluntary consensus standards, including the attributes that define such standards.

Of the 52 operators we contacted, 44 had undertaken baseline assessments, and 23 of the 44 have calculated their own reassessment intervals.[25] Twenty of these 23 operators indicated that, based on the conditions they identified during their baseline assessments, they would reassess their gas transmission pipelines at maximum intervals of 10, 15, or 20 years—as allowed by industry consensus standards—if the 7-year reassessment requirement were not in place. The remaining three operators told us that they would reassess their pipelines at intervals shorter than the industry consensus standards but longer than 7 years because of the conditions of their pipelines. These results add weight to our assessment that the 7-year requirement may be conservative for most pipelines.

[24]The American National Standards Institute is a private, nonprofit organization whose mission is to promote and facilitate voluntary consensus standards and promote their integrity. The Institute does not approve the technical merits of proposed national standards.

[25]The other 21 operators (1) have not calculated reassessment intervals; (2) do not intend to, given the prescriptive federal (7 years) or state (5 years in Texas) reassessment requirements; or (3) did not supply us with information on their reassessment intervals.

Safeguards Exist if Industry Consensus Standards for Corrosion Reassessments Are Allowed

Industry consensus standards allow for *maximum* reassessment intervals for time-dependent threats of 10, 15, or 20 years only if the operator can adequately demonstrate that corrosion will not become a threat within the chosen time interval. If an operator cannot demonstrate that corrosion does not pose a threat, (e.g., threats posed by shipping gas that is more corrosive then was shipped previously), then the reassessment must occur sooner, perhaps at 7 or even 5 or fewer years. Furthermore, according to industry consensus standards, it typically takes longer than the 10, 15, or 20 years specified in the standard for corrosion problems to result in a leak or rupture.

As a means of ensuring that assessments and reassessments are done competently, PHMSA regulations and industry consensus standards require that operators develop and document the steps they take to ensure the quality of these activities. This includes ensuring that persons involved are competent and able to carry out the activities. In addition, operators are encouraged to conduct internal audits of their quality control approaches and third-party reviews of their entire integrity management programs.

It is important to note that, in addition to periodic reassessments, operators must perform prevention and mitigation activities on a continual basis. PHMSA regulations require that all operators of gas transmission pipelines, including those outside highly populated or frequently used areas, patrol their pipelines, survey for leakage, maintain valves, ensure that corrosion-preventing cathodic protection is working properly, and take other prevention and mitigation measures.

Finally, PHMSA and the state pipeline agencies are inspecting operators' integrity management plans that were mandated by the 2002 act to provide their gas transmission pipeline reassessment approaches and intervals, among other things, to ensure that operators continually and appropriately assess the conditions of their pipeline segments in highly populated or frequently used areas. These inspections should serve as a check on whether operators have identified threats facing these pipeline segments and determined appropriate reassessment intervals. PHMSA and states have begun inspections and expect to complete most of the first round no later than 2009. As of June 2006, PHMSA had completed 20 of about 100 inspections and, as of January 2006, states had begun or had completed 117 of about 670 inspections.[26] Initial results from these inspections show that operators are doing well in assessing their pipelines and making repairs, but some need to better document their programs. Based on the initial inspection results to date, PHMSA and states did not find many issues that warranted enforcement actions.

Sufficient Resources May Be Available for Pipeline Reassessments

Although some uncertainty exists, sufficient resources may be available for operators to reassess their gas transmission pipelines. 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. However, operators expressed their uncertainty about whether qualified direct assessment and confirmatory direct assessment contractors will be available. This is important because operators plan to use these methods to reassess about half of their pipeline mileage.

Contractors told us that they will likely have the capacity to meet demands, even during periods when baseline assessments and reassessments may overlap. The severity of this overlap, however, remains unclear. Although operators that we contacted expect baseline assessment and reassessment activity to decrease from 2010 through 2012, an Interstate National Gas Association of America (INGAA) and American Gas Association (AGA) polling of their members suggests that activity will rise markedly.[27]

[26]See GAO-06-946 for additional information on the results of PHMSA and state inspections.

[27]INGAA represents the natural gas industry, including transmission pipeline operators. According to INGAA, it represents virtually all of the interstate natural gas transmission pipeline companies operating in the United States. Its members transport over 95 percent of the nation's natural gas. AGA represents local energy utility companies, including pipeline companies, which deliver natural gas to homes, businesses, and industries throughout the United States. According to AGA, its members account for roughly 83 percent of all natural gas delivered by the nation's local natural gas distribution companies.

Operators Report that Services and Tools Are Likely to Be Available for Reassessments

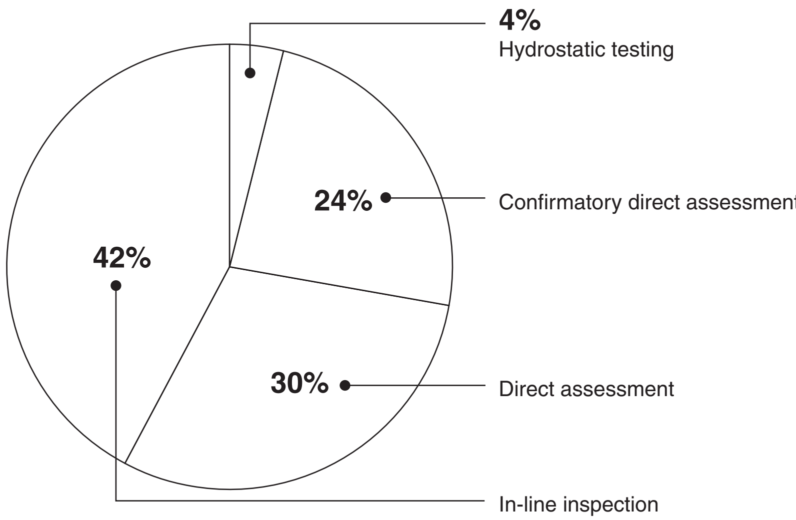
Thirty-seven out of 52 operators (71 percent), one in-line inspection association, and all four inspection contractors that provide direct assessment or in-line inspection tool services that we contacted told us that the services and tools needed to conduct periodic reassessments will likely be available to most operators.[28] All but 3 of the operators reported that they plan to rely on contractors to conduct all or a portion of their reassessments, and 9 of 52 operators 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.

The 48 operators that reported both baseline and reassessment schedules told us that they plan to reassess 42 percent of their gas transmission pipeline miles in highly populated or frequently used areas, using in-line inspection, and 54 percent of their miles using direct assessment or confirmatory direct assessment methods.[29] (See fig. 3.) Operators expect to assess only 4 percent of their pipeline miles using hydrostatic testing for several reasons: (1) this form of testing requires shutting down their pipelines, (2) other assessment methods yield more robust information about the condition of their pipelines, (3) hydrostatic testing can weaken or damage pipelines, and (4) large quantities of water must be disposed of in an environmentally responsible manner.

[28]We contacted the Inline Inspection Association, two companies offering in-line inspection services, and two companies offering direct assessment services. In our assessment of the public safety effects of integrity management, we reported that 94 percent of the operators we contacted had no major concerns about their ability to complete *baseline* assessments. (See GAO-06-946.) The difference in these findings may be due to the fact that operators have 10 years to complete baseline assessments but must reassess pipeline segments every 7 years or in a shorter period if conditions warrant. The shorter reassessment period could heighten demand for inspection services and tools.

[29]Some operators we contacted reported that the cost of using confirmatory direct assessment as compared with other assessment tools and the limited time savings before conducting a full assessment as reasons for not planning to use this method.

Figure 3: Operators Contacted Plan to Reassess Nearly All of the Mileage in Highly Populated or Frequently Used Areas Using In-line Inspection and Direct Assessment Tools



Source: GAO discussions with 48 operators.

Note: Some operators may use one type of assessment tool on one portion of their gas transmission pipeline and another type of assessment tool on another portion.

The Inline Inspection Association and the two in-line inspection contractors that we contacted told us that sufficient capacity exists within the industry to meet current and future operator demands. However, operators and inspection contractors expressed uncertainty about whether qualified direct assessment and confirmatory direct assessment contractors will be available. This is important because operators plan to use these methods to reassess about half of their gas transmission pipeline mileage. Unlike the in-line inspection method, which is an established and less intrusive practice that 27 of 52 operators have used on their pipelines at least once prior to the integrity management program, two direct assessment contractors told us that there is limited expertise in this field. One said that newer contractors coming into the market to meet demand may not be qualified. The operators planning to use direct assessment for their pipelines are generally those with smaller-diameter pipelines that cannot accommodate in-line inspection tools.[30] At a recent INGAA integrity management workshop, in-line inspection and direct assessment inspection contractors emphasized that, although they currently have the resources to meet operator demand and continue to train new inspectors, operators need to plan ahead to ensure resource availability for future years, when resources may be more constrained. The workshop also highlighted technological developments for assessment tools that will make assessments more efficient. Other stakeholders have told us that there are new tools being developed that will enable smaller-diameter pipelines to accommodate in-line inspection tools. For example, the Department of Energy is developing tiny robotic sensors that can detect flaws in plastic natural gas pipelines without interrupting the flow of gas.

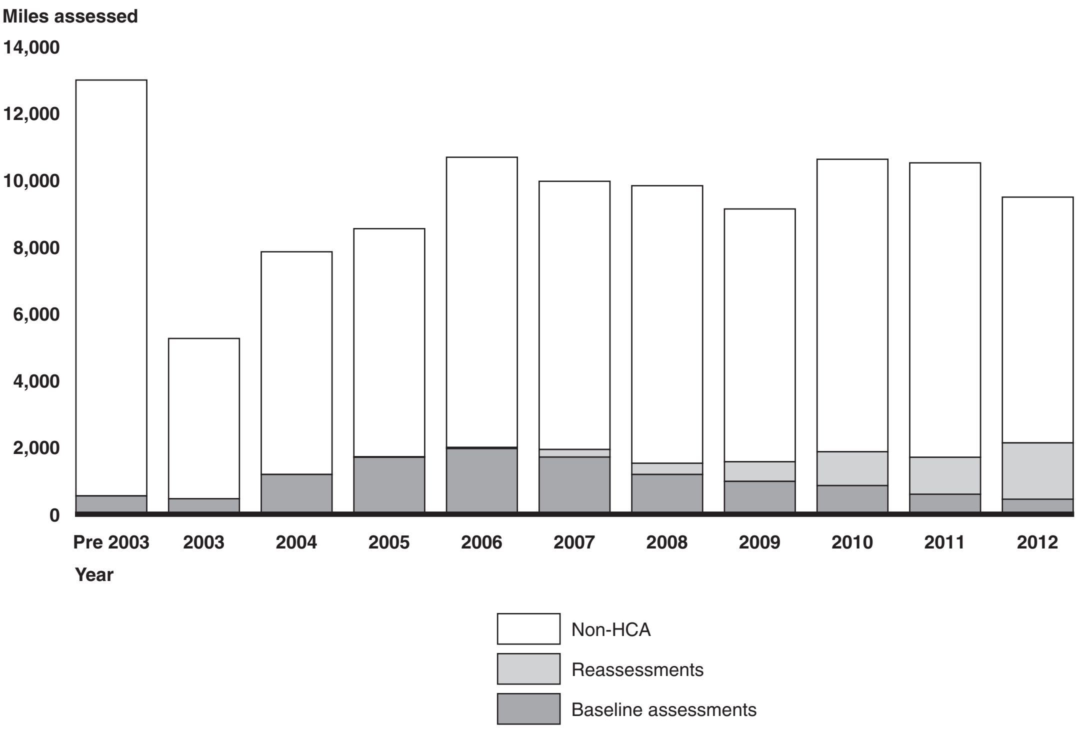
The Amount of Assessment Activity Occurring in the Overlap Period Is Uncertain

An industry concern about the 7-year reassessment requirement is that operators will be required to conduct reassessments starting no later than 2010, while they are still in the 10-year period (2003 through 2012) for conducting baseline assessments. Industry is concerned that this could create a spike in demand for contractor services, and operators would have to compete for the limited number of contractors to carry out both. As a result, operators might not be able to meet the reassessment requirement.[31] The information provided by the operators that we contacted shows a marked overall increase in assessment and reassessment activity in 2010 (a 16 percent increase over 2009 activity) and then a gradual decrease of activity through 2012. (See fig. 4.) Operators expect this decrease because they plan to have completed 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 (3 years before the predicted overlap).

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

[31]The 2002 act allows operators to request a waiver from conducting reassessments when inspection tools are not available. PHMSA regulations require that operators apply for a waiver when inspection tools are not available to conduct assessments within the required reassessment period and that the actions the operator is taking in the interim ensures the integrity of the pipeline. Environmental requirements may also affect the scheduling of assessments, repairs and modifications, and the choice of assessment tools. (See app. I.) Few of the 52 operators that we contacted mentioned this as a concern.

Figure 4: Baseline Assessment and Reassessment Activities Are Expected to Decrease during the Overlap Period, According to Operators We Contacted



Source: GAO discussions with 52 operators.

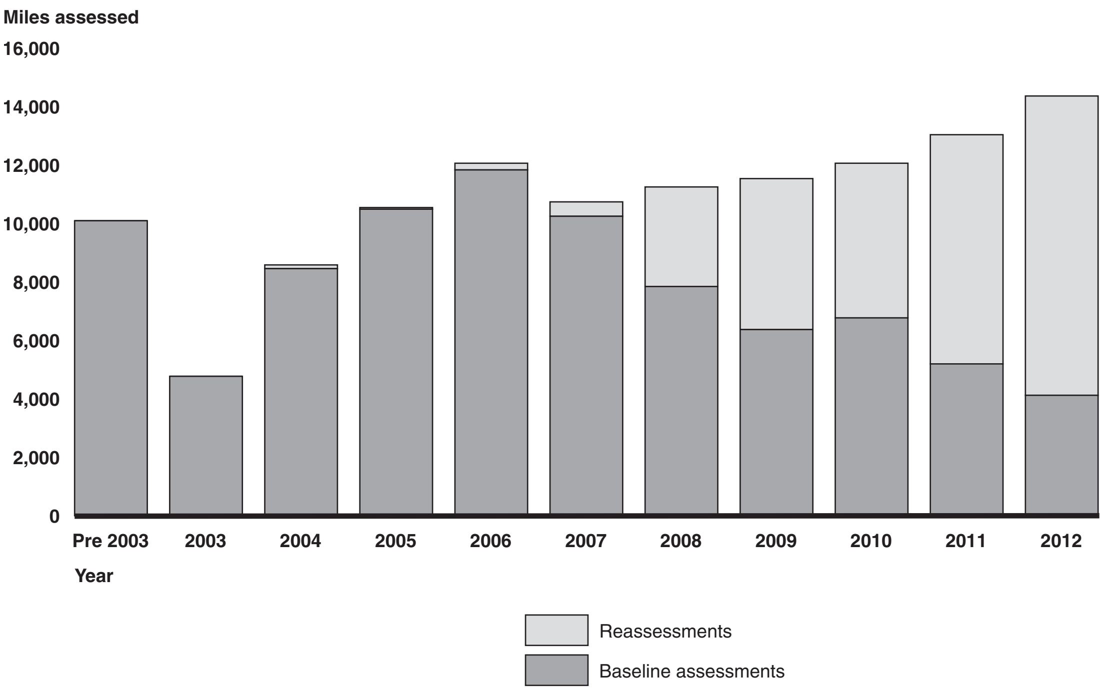
Note: These results are based on information obtained from 47 of 52 operators we contacted, covering 154,000 miles of gas transmission pipeline, 12,000 miles of which are in highly populated or frequently used areas. Five operators did not report their reassessment plans. We did not ask operators to separate baseline assessments and reassessments in areas that are not highly populated or frequently used.

In contrast, INGAA and AGA, after polling their members in 2006, found a steady overall increase in total expected baseline assessments and reassessments during the overlap period. INGAA and AGA found that baseline assessments and reassessments would start to increase in 2009 and rise steadily through 2012.[32] (See fig. 5.) Assessment activity would

[32]Although INGAA, AGA, and we collected information differently on the extent that baseline assessments and reassessments would be conducted inside and outside highly populated or frequently used areas, both efforts collected information on overall baseline assessment and reassessment activity. As a result, the overall results of both efforts are comparable and are shown in figure 6.

increase by 5 percent in 2010 over the 2009 level; in 2011, by 8 percent over the preceding year; and in 2012, by 10 percent over the 2011 level.

Figure 5: Baseline and Reassessment Activities Are Expected to Increase during the Overlap Period, According to INGAA and AGA

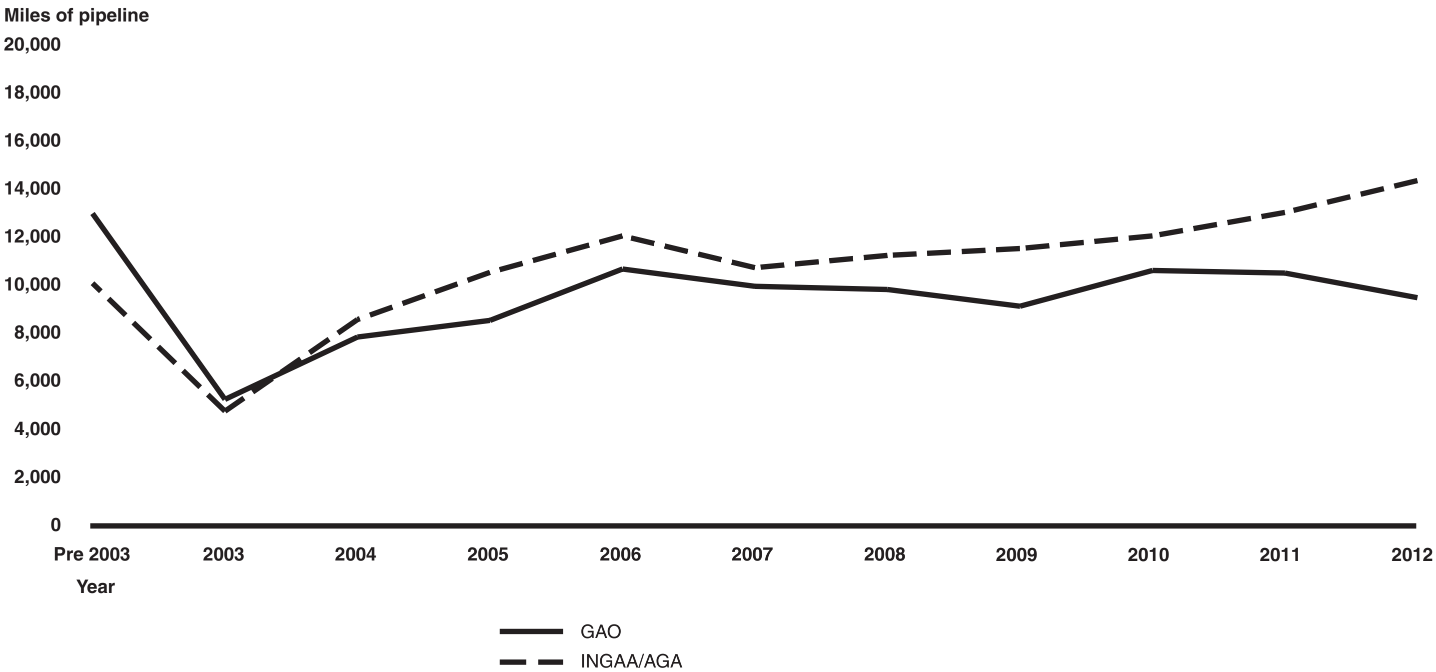


Source: GAO analysis of INGAA and AGA results.

Note: These results are based on responses from 56 operators covering 180,000 miles of gas transmission pipeline, 11,000 miles of which are in frequently used or highly populated areas.

The difference between our findings and those of INGAA and AGA is not easy to explain. (See fig. 6.) Both efforts reported on comparable numbers of operators (47 for us and 56 for INGAA/AGA) and total transmission pipeline miles (154,000 for us and 180,000 for INGAA/AGA). To some extent, the difference may be due to the variations in the pipeline operators that responded to both efforts. About 72 percent of operators we polled were different from those polled by INGAA and AGA. However, even where both efforts collected information from the same operators, the information was sometimes markedly different. Another reason for the difference may be due to methodology. For example, we gathered our information through semistructured interviews with a systematically selected set of pipeline operators based on larger and smaller transmission pipelines and local distribution companies with the highest proportion of pipeline miles in highly populated or frequently used areas to total system miles, among other things. INGAA and AGA gathered their information by sending out a self-administered data collection instrument to their members, and reported results based on those members who responded. In addition, INGAA and AGA asked operators for data somewhat differently from methods we used, which may have led to some differences in results.

Figure 6: GAO and INGAA/AGA Results Show Different Trends in Assessment Activity during the Overlap Period



Sources: GAO discussions with 52 operators and GAO analysis of INGAA/AGA results.

Note: See text for possible reasons for the difference in results. Readers should not interpret these results to suggest that operators are not planning to complete all required baseline assessment activities by the end of 2012.

Conclusions

Evidence as a result of baseline assessments, the industry's overall safety record, the existence of accepted risk-based assessment standards, and PHMSA's actions to inspect how operators are identifying corrosion threats to their pipelines and setting reassessment intervals suggests a risk-based approach to reassessing gas transmission pipeline segments for corrosion can achieve the safety objectives of the 2002 act. Evidence gathered to date suggests that operators that have thus performed baseline assessments are doing a good job overall managing corrosion. Since the large majority of pipeline operators that we contacted had not systematically assessed their transmission pipelines for corrosion risks before the onset of the gas integrity management program, if corrosion were a rapidly growing problem, we would have expected a larger proportion of pipelines to report problems requiring immediate repairs. But, this was not the case. Furthermore, adopting a risk-based approach to setting reassessment intervals does not automatically allow operators to reassess their pipeline segments less frequently than under the 7-year requirement. Rather, if conditions warrant, an operator would be required to reassess a pipeline segment as frequently as needed—perhaps even more frequently than every 7 years. Finally, a risk-based reassessment requirement would be consistent with the overall approach to integrity management that the Congress put in place with the 2002 act.

Safeguards are in place to ensure that gas transmission operators determine reassessment intervals competently. PHMSA regulations and industry consensus standards require that operators ensure that persons involved have the experience and expertise to carry out the activities. Operators are also encouraged to conduct internal audits of their quality control approaches and third-party reviews of their integrity management programs. PHMSA and the state pipeline agencies are inspecting operators' compliance with integrity management reassessment requirements, among other things, to ensure that operators continually and appropriately assess the conditions of their gas transmission pipeline segments in highly populated or frequently used areas.

In summary, the available evidence supports a conclusion that a risk-based reassessment approach based on technical data, risk factors, and engineering analyses can achieve the 2002 act's safety objectives. Such an approach would provide for reassessments to be tailored to the corrosion threats faced by the pipeline segment and would not result in reassessments that are either too infrequent or premature. Evidence to date suggests that gas transmission pipelines are generally in good shape based on assessments, following up with immediate repairs and safeguards being in place to ensure operators determine reassessments appropriately. In our view, it is not necessary to wait until baseline assessments and a round of reassessments have been completed before considering whether to retain or modify the 7-year reassessment requirement.

Matter for Congressional Consideration

To better align reassessments with safety risks, the Congress should consider amending section 14 of the Pipeline Safety Improvement Act of 2002 to permit pipeline operators to reassess their gas transmission pipeline segments at intervals based on technical data, risk factors, and engineering analyses. Such a revision would allow PHMSA to establish maximum reassessment intervals, and to require shorter reassessment intervals as conditions warrant.

Agency Comments and Our Evaluation

We provided a draft of this report to the Departments of Transportation and Energy for their review and comment. The Department of Transportation generally agreed with the report's findings. The Department of Energy had no comments.

We are sending copies of this report to congressional committees and subcommittees with responsibility for transportation safety issues; the Secretary of Transportation; the Secretary of Energy; the Administrator, PHMSA; the Assistant Administrator and Chief Safety Officer, PHMSA; the Deputy Secretary for Natural Gas and Petroleum Technology, Department of Energy; and the Director, Office of Management and Budget. We will also make copies available to others upon request. This report will be available at no charge on the GAO Web site at http://www.gao.gov.

If you have any questions about this report, please contact me at (202) 512-2834 or siggerudk@gao.gov. Contact points for our Offices of Congressional Relations and Public Affairs may be found on the last page of this report. Staff who made key contributions to this report are listed in appendix III.

Katherine Siggerud

Katherine A. Siggerud
Director, Physical Infrastructure Issues

Congressional Committees

The Honorable Ted Stevens
Chairman
The Honorable Daniel K. Inouye
Co-Chairman
Committee on Commerce, Science
and Transportation
United States Senate

The Honorable Don Young
Chairman
The Honorable James L. Oberstar
Ranking Democratic Member
Committee on Transportation
and Infrastructure
House of Representatives

The Honorable Joe Barton
Chairman
The Honorable John D. Dingell
Ranking Minority Member
Committee on Energy and Commerce
House of Representatives

Impact of Periodic Reassessments on Natural Gas Supply May Be Less than Foreseen

As the Pipeline Safety Improvement Act of 2002 was being considered, the Interstate Natural Gas Association of America (INGAA) analyzed the possible impact of requiring assessments and periodic reassessments and found that significant disruptions in the natural gas supply and considerable price increases could occur.[1] A more moderate impact was predicted in three subsequent analyses—(1) two reviews of the INGAA study performed for the Pipeline and Hazardous Materials Administration (PHMSA) by the John A. Volpe National Transportation Systems Center and by the Department of Energy during the congressional debate over the pipeline bill, and (2) a post-act PHMSA evaluation of its implementing regulations.[2] A waiver provision was included in the 2002 act after INGAA's study was completed; this may serve as a safety valve if it appears that the natural gas supply may be disrupted. Finally, our discussions with 50 natural gas pipeline operators also suggest a more moderate potential impact than INGAA found.

INGAA Study Expected Significant Supply Disruptions and Price Increases

INGAA's study estimated that periodic assessments under integrity management could lead to a monthly reduction in natural gas supply of about 1 to 3 percent, along with price increases to customers, among others, ranging from $382 million to over $1 billion (in 2002 dollars) from 2002 through 2010, depending on the frequency of assessments.[3] Most of this price increase would be due to supply disruption and some due to capital expenditures. INGAA considered the monthly reduction in supply to be significant because it assumed that gas transmission pipelines would be

[1]Prepared for The INGAA Foundation, Inc., by Energy and Environmental Analysis, Inc., *Consumer Effects of the Anticipated Integrity Rule for High Consequence Areas*, 2002.

[2]See, Department of Transportation docket, RSPA-00-7666, *Energy Impact Statement for Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines)*, March 28, 2002, prepared by John A. Volpe National Transportation Systems Center and the U.S. Department of Transportation; Comments from U.S. Department of Energy on INGAA's *Consumer Effects of the Anticipated Integrity Rule for High Consequence Areas*, April 2, 2002; and Research and Special Programs Administration, *Final Regulatory Evaluation*, *Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines)*, March 28, 2002.

[3]The National Petroleum Council also discussed the supply effects of the integrity management program, including that some pipelines may be removed from service if it is not economically efficient to repair them. The council did not estimate the extent that these abandonments might occur or the resulting price increases, if any. See *Balancing Natural Gas Policy: Fueling the Demands of a Growing Economy Volume V, Transmission and Distribution Task Group and LNG Subgroup Report*, September 2003.

removed from service during testing and that some areas of the country would be more vulnerable to supply disruptions than others.

PHMSA-commissioned Reviews and PHMSA's Regulatory Evaluation Predict More Moderate Impacts

Both Volpe's and the Department of Energy's 2002 reviews of the INGAA study concluded that gas transmission pipelines would not be significantly affected by periodic assessments. The reviews, however, did not attempt to quantify overall estimates of gas disruptions or price impacts. Rather, they examined the major assumptions in the INGAA study and discussed whether the study's results seemed reasonable. PHMSA's final regulatory evaluation, which was completed in 2004 to assess the impact of PHMSA's regulations on implementing the 2002 act, concluded that transmission pipelines' natural gas supply may be somewhat disrupted as a result of assessments and that cost increases may occur. However, PHMSA acknowledged that it could not estimate the impact of assessments on gas prices. In general, the reviews found that the INGAA study's estimates of price impacts represent a worst-case scenario because of several overly pessimistic assumptions. For example, the INGAA study

- **underestimated the ability of the pipeline network to mitigate disruptions**. INGAA assumed that pipeline assessments would generally reduce pipeline capacity temporarily, thereby disrupting the supply and increasing the price of natural gas. Yet, both Volpe's and the Department of Energy's reviews found that the INGAA study did not sufficiently account for redundancies in the nation's natural gas transmission pipeline network. Redundancies enable operators to mitigate potential disruptions during assessments by rerouting gas through the network.

Operators we contacted that have higher-stress gas transmission pipelines[4] generally indicated that their pipeline infrastructure is versatile and includes such redundancies as parallel pipelines or looping capabilities that allow gas to flow to customers while portions of the pipeline are assessed or repaired.[5] (See fig. 7.) Operators of lower-stress pipelines[6] reported that they typically use a set of laterals,[7] which feed an interconnected gas distribution system and allow them to plan around disruptions. In addition, lower-stress operators can use liquid or compressed natural gas that is located at their facilities or transported by trucks to specified locations. Forty-four of the 50 natural gas operators (88 percent) that we contacted have some type of alternative gas supply, such as storage facilities and other gas suppliers, to meet customers' short-term needs.

[4]Higher-stress pipelines operate under pressure at or above 50 percent of the pressure that will cause a pipeline to deform (called yield strength).

[5]A looping capability involves installing a segment of pipeline adjacent to an existing pipeline. The segment of pipeline connects to the existing pipeline at both ends of a loop, which allows more gas to be moved through the pipeline system.

[6]Lower-stress pipelines operate pressure at or below 30 percent of a pipeline's yield strength.

[7]A lateral is a segment of a pipeline that branches off of the main or transmission line to transport the product to a termination point, such as a tank farm or a metering station.

Figure 7: Parallel Natural Gas Transmission Pipelines Can Help Maintain Product Supply

Source: PHMSA.

- **assumed that a large amount of transmission mileage would require assessments because of over-testing.** The INGAA study concluded that the number of gas transmission pipeline miles within highly populated or frequently used areas is only about 5 percent of the total mileage in the U.S. Nonetheless, the study assumed that over 80 percent of mainline interstate pipeline miles would require assessing, because the pipeline miles that are located within the highly populated areas are scattered throughout the pipeline system, and inspection methods like in-line testing can only be inserted and retrieved in certain locations that may lie outside highly populated or frequently used locations. As a result, the study assumed that operators of these pipelines would assess over 1,500 percent more miles than are within the highly populated areas. On the basis of comments from industry groups, PHMSA's regulatory evaluation assumed that operators would assess about 625 percent more miles when using in-line inspection testing and about 25 percent more miles when using hydrostatic testing, but no over-testing when using the direct assessment method. Baseline assessment results to date seem to support the lower over-testing estimate: as of December 31, 2005, on the basis of performance reports submitted to PHMSA, operators assessed about 650 percent more miles overall than are located in highly populated or frequently used areas.[8]

- **assumed that only hydrostatic testing would be used on delivery laterals.** The INGAA study predicted that operators would use only hydrostatic testing on lateral gas transmission pipelines because it assumed that very few laterals can accommodate in-line testing. Under hydrostatic testing, water pressure is used to test the condition of pipelines; therefore, all of the capacity of a pipeline segment must be removed for a period of time.

  Volpe's review concluded that this particular assumption represents the worst possible impact of assessments on lateral pipelines because it does not allow for the use of in-line testing or direct assessment. Based on discussions with operators and public comments on PHMSA's draft regulatory analysis, the PHMSA regulatory evaluation also assumed that few operators would use hydrostatic testing. INGAA's study also did not address the development of new technologies that could allow

[8]Over-testing, although not without costs, provides safety benefits because additional information is collected about the condition of pipelines. The operators' reports do not indicate which inspection method was used to conduct the inspections.

in-line inspection of smaller diameter pipelines. As discussed earlier, new technology is being developed. Finally, operators we contacted reported that they do not plan to use hydrostatic testing extensively. As discussed earlier, only about 4 percent of the mileage will be reassessed using hydrostatic testing. This testing will typically be over relatively small lengths of pipeline (from 0.8 to 331 miles).

- **did not incorporate the ability of operators to obtain waivers**. The INGAA study did not consider the possible impact of a waiver provision in the 2002 act on maintaining the natural gas supply. This was understandable because the waiver provision was added to the bills under consideration after the INGAA study was completed. The act allows the PHMSA to waive or modify any requirement for operators to conduct reassessments when they need to maintain product supply as long as it is consistent with pipeline safety.[9] Twenty-one of the 50 natural gas operators (42 percent) that we contacted said that they would consider applying for a waiver, if needed, and 23 (46 percent) told us that they did not plan to apply for a waiver. Three of the operators were uncertain, and the remaining three operators did not provide us with a response. Fourteen of the 26 operators that either did not plan to apply for a waiver or were unsure about doing so said that it is too early to determine the need for applying for waivers. They obtained the necessary equipment to conduct assessments or developed plans for handling potential natural gas supply disruptions.[10]

[9]Under PHMSA's regulations, an operator must apply for a waiver at least 180 days before the required reassessment interval, unless natural gas supply issues make the period impractical. If so, the operator must apply as soon as the need for the waiver is known.

[10]Eleven operators we contacted did not provide reasons for not planning to apply for a waiver. One operator reported that it would wait for regulatory changes for reassessments before applying for a waiver.

Operators Contacted Found Assessments Have Had Minimal Impact on Supply

Pipeline operators we contacted told us that assessments and repairs of even their riskiest gas transmission pipelines have not significantly disrupted the natural gas supplied to customers, such as local distribution companies and power plants. These 50 natural gas transmission operators and local distribution companies had assessed about 4,100 miles of pipeline in highly populated or frequently used areas, as of December 2005 (latest data available)—or about 21 percent of the total gas transmission mileage in these areas in the nation and about 62 percent of the pipeline mileage located in frequently used or highly populated areas assessed to date. Of the 44 operators that have begun baseline assessments, 26 (59 percent) indicated that their assessments and repairs did not require them to shut down their pipelines or reduce their operating pressure. Sixteen operators (36 percent) reported minor disruptions in their gas supply because they temporarily shut down pipelines and reduced operating pressure to conduct assessments or repairs. These operators told us that they used alternative gas sources, such as liquefied natural gas, to sustain their customers' gas supply. The remaining two operators (5 percent) were located in regions that have limited excess gas capacity. Both operators reported that they could not meet all of the natural gas needs of their customers when their pipelines were shut down to perform assessments or repairs. Some customers, especially those with interruptible contracts,[11] did not receive gas from the pipelines for several days, but they were able to obtain gas from alternative sources.

Eleven of the 44 operators were located in regions that have limited excess gas capacity—the Northeast, the Rocky Mountains, and the Southwest—and reported minor supply disruptions. Five of the 11 operators—all of which operate lower-stress gas transmission pipelines—reported that none of these disruptions in natural gas supply were caused by assessments or repairs. Four operators reported instances in which immediate repairs caused a reduction in operating pressure; however, they maintained natural gas supply by relying on alternative gas sources.[12] Since PHMSA does not

[11]Although interruptible contracts with pipeline operators or local distribution companies vary in terms and conditions, they generally allow for service interruptions that are caused by system operating conditions (e.g., when pipeline pressure is threatened by high rates of natural gas consumption), among other things.

[12]We did not ask operators about the degree to which they reduced operating pressure and the reduction in the amount of gas that they could deliver. Nevertheless, they were able to use alternative sources to maintain product supply while they made repairs to their pipelines.

require that operators report to it the nature of the problems, we do not know how many immediate repairs, if any, were due to corrosion. And, as previously mentioned, 2 of the 11 operators reported natural gas supply disruptions; although they had to shut down their pipelines due to assessments or repairs, customers were able to obtain natural gas from other sources.

In early 2006, INGAA and AGA polled their members about their experiences with and plans for conducting assessments and reassessments during off-peak and peak months.[13] Overall, INGAA and AGA found that, from 2003 to 2012, members plan to conduct 76 percent of their baseline assessments and reassessments on their gas transmission pipelines (as measured in miles) during the off-peak spring and summer months, 18 percent in the fall, and 6 percent in the winter. According to an INGAA official, most of the assessment activity that results in temporary reductions in gas supply due to repairs being made will likely affect markets regionally. If assessments occur when pipelines are constrained for capacity, an increase in delivered gas prices will occur. Overall, assessments will only affect small groups of the nation's population, but they will have a consumer price impact in those affected areas.

Our findings from these operators, while not necessarily representative of all operators, are encouraging. First, these findings do represent a sizeable proportion (61 percent) of the mileage assessed to date. Second, the segments that operators assessed were supposed to be the riskiest segments (those most susceptible to ruptures or leaks) of the gas transmission pipelines located in highly populated or frequently used areas. If so, there should be fewer repairs needed for subsequent baseline assessments of less risky segments, and hence fewer disruptions in supply.

[13]According to a Department of Energy official, on- and off-peak periods vary based on location. For example, in the South, fall and winter months are often off-peak while the reverse is true in northern states (e.g., for heating needs).

Post-act Industry Polling Found Members Plan to Modify and Repair Pipelines, Which May Affect Natural Gas Supply

The 2006 INGAA and AGA polling of their members did not explicitly ask for the extent to which their members experienced supply disruptions because of baseline assessments or repairs. However, INGAA and AGA did ask members to identify the amount of pipeline modifications and repairs that would be necessary for conducting baseline assessments and reassessments, activities that could disrupt supply. Overall, INGAA and AGA found that about 50,000 of the 180,000 miles of gas transmission pipelines that were reported by responding operators are scheduled for or have already undergone (1) modifications to allow in-line inspection tools to access pipeline segments (2) repairs to eliminate major defects or (3) monitoring for minor problems.[14] According to a senior INGAA official, assessments and pipeline modifications can generally follow a prearranged schedule; however, pipeline repairs are unpredictable. Repairs often require pipelines to be shut down, which could have an effect on natural gas supply.[15] However, PHMSA officials report that only the worst pipeline problems require pipelines to be shutdown for repair. From 2003 to 2012, 38,000 of the 50,000 pipeline miles (76 percent) have been scheduled for

[14]In its September 2003 report, cited earlier, the National Petroleum Council estimated that conducting baseline assessments over 10 years, gas transmission pipeline operators will spend about $1.1 billion annually on replacing existing pipeline infrastructure.

[15]In March 2006, PHMSA issued a final rule that requires operators to use a risk-based approach to determine which onshore gathering pipelines are subject to PHMSA's gas pipeline safety rules and which of these rules the lines must meet. The application of these rules may result in interruption of service to carry out repairs. However, the rules do not impose requirements for operators to assess their pipelines in the same manner as the integrity management program. Therefore, any interruptions caused by the need to carry out repairs would be the result of normal operation and maintenance activities. Gathering lines collect natural gas from production facilities and transport them to transmission or distribution lines. There are about 15,000 miles of onshore gathering lines nationwide.

modifications or repairs during the off-peak spring and summer months to mitigate supply disruptions.[16]

Department of Energy Expects Little Disruption in the Natural Gas Supply

Officials from the Office of Oil and Gas within the Department of Energy told us that the integrity management program, including the 7-year reassessment requirement, is not likely to significantly disrupt the natural gas supply. They told us that operators have, among other things, sufficient system redundancies, such as parallel lines, to maintain product supply. The Department of Energy has completed several regional analyses of the possible effects of the disruptions in the natural gas supply caused by such events as extreme weather conditions (e.g., extended cold periods and hurricanes). It is completing other analyses as well. However, because these are being done at the regional level, their results are too broad to help inform us about more localized and subregional potential disruptions.

[16]Complying with environmental laws, such as those dealing with habitats, may also affect scheduling of modifications and repairs. The Pipeline Safety Improvement Act of 2002 required the establishment of a federal interagency committee to develop and ensure implementation of a coordinated environmental review and permitting process to enable operators to complete baseline assessments, including pipeline repairs, with minimal adverse effects to the environment such as harming unique species or habitat in the specified time periods. The interagency committee has established a working group to develop a joint regulatory approach to streamlining. In addition, PHMSA has designed and is testing a Web-based environmental permit review process to (1) provide early electronic notification of proposed pipeline repairs to federal agencies and solicit input from state and local agencies involved in the review process for pipeline repairs and (2) expedite coordination and approval of recommended best practices for operators to use to manage environmental damage when repairing their pipelines in environmentally important areas.

Scope and Methodology

To understand how the findings from operators' baseline assessments inform us about the need to reassess gas transmission pipelines at least every 7 years, we reviewed the requirements of the Pipeline Safety Improvement Act of 2002 and PHMSA's implementing regulations. We also reviewed information about setting reassessment intervals for gas transmission pipelines, including industry consensus standards for maximum reassessment intervals developed by the American Society of Mechanical Engineers, and documents obtained from PHMSA, industry, and other stakeholders. We discussed this issue with officials from PHMSA, other federal agencies, industry associations, companies that perform research in this area, state safety representatives, and safety advocacy groups. (These organizations are listed at the end of this appendix.)

We also analyzed data from PHMSA on the number of immediate repairs reported by operators as a result of baseline assessments conducted through December 2005 (latest data available) and the number of natural gas pipeline incidents reported to PHMSA.

We contacted 52 pipeline operators (50 natural gas and 2 hydrogen operators) from among the 447 operators that reported that they operate gas transmission pipelines in highly populated or frequently used areas. Forty-four of these operators have begun baseline assessments. We selected those operators for which the baseline assessments and reassessments could be expected to have the greatest impact, all else being equal: larger and smaller transmission pipelines and local distribution companies with the highest proportion of pipeline miles in highly populated or frequently used areas to total system miles. We also selected operators located in three regions of the country that several studies and our stakeholders consider to be vulnerable to energy supply disruptions: the Northeast, the Southwest, and the Rocky Mountains.

The 52 operators reported that they have assessed about 4,100 of the 6,700 miles (61 percent) of pipeline segments, as of December 2005. Overall, these operators have assessed about 21 percent of the 20,000 miles of pipeline that operators have reported as being within highly populated or frequently used areas. Because we used a nonprobability method of selecting these operators, we cannot project our findings nationwide.[1] Contacting a larger number of operators or selecting them through a statistical sample would not have been feasible due to resource and time constraints. Nonetheless, these 52 operators do represent a substantial portion of the miles assessed to date and of the total number of reported miles of pipeline in highly populated or frequently used areas.

For these 52 operators, we conducted semistructured interviews to collect qualitative and quantitative information on the degree to which they found anomalies during the baseline assessments and, based on these results, the frequency with which they would reassess these pipeline segments under American Society for Mechanical Engineers standards for managing the system integrity of gas pipelines (ASME B31.8S-2004) if the 7-year reassessment requirement were not in place. As part of our work, we asked operators to identify the steps that they take to ensure the quality of their baseline assessments and reassessments, such as ensuring that competent persons are involved in determining reassessment intervals and conducting periodic internal or third-party reviews of their integrity management programs, as recommended by PHMSA regulations and industry standards. We relied on the operators' professional judgment in reporting on the conditions they found during their assessments.

To determine the extent to which gas transmission pipeline operators and local distribution companies will likely have the resources to reassess their pipelines, at least every 7 years, we synthesized testimonial and documentary evidence obtained from our discussions with (1) 52 operators (as described above) and (2) pipeline assessment tool contractors, direct assessment vendors, and industry associations on the prospective availability of equipment, equipment operators, and data analysts to interpret results. We synthesized the information from the 52 operators to determine the aggregate level of actual and planned assessments and reassessments through 2012. We compared our findings with the results from an INGAA/AGA data collection effort, conducted in 2006, on the same topic. We then discussed our results with INGAA and analyzed the data obtained from both efforts to try to understand any differences in results.

[1]Results from nonprobability samples cannot be used to make inferences about a population because, in a nonprobability sample, some elements of the population being studied have no chance or have an unknown chance of being selected as part of the sample.

To assess the reliability of information provided to us from PHMSA, INGAA, and AGA, we performed a number of analyses. For the information provided to us from PHMSA, we compared the number of immediate repairs operators reported to us to the number of immediate repairs they reported to PHMSA. To assess the reliability of the data provided to us from INGAA and AGA, we also compared the reported responses of operators that were included in INGAA/AGA's and our efforts. In addition, we checked the accuracy of INGAA/AGA's calculations. We determined that the data were sufficiently reliable for the types of analyses we present in this report.

Other Aspects of Our Work

To determine the potential impact of the 7-year reassessment requirement on the nation's natural gas supply, we contacted officials from PHMSA, the Department of Energy, industry associations, and research firms to discuss how the potential shutdown of gas transmission pipelines or operation under reduced pressure—as a result of baseline assessments, reassessments, and repairs—might affect the continued supply of natural gas. We also obtained information from the Department of Energy on the results of analyses of the overall vulnerability of natural gas supplies in several regions of the nation to extreme conditions, such as extreme cold weather.

Further, we asked the 50 natural gas operators that we contacted about the vulnerability of their pipelines to supply disruption and the potential impact on customers. This included 11 operators located in the three regions of the country that have limited excess supply gas capacity. We also discussed how their baseline assessments and any resulting repairs have affected their customers to date. Finally, we compared operators' experiences in performing assessments, reassessments, and repairs to the assumptions made in the 2002 INGAA study of the potential effects of the proposed integrity management program, two reviews of this study, and PHMSA's final regulatory evaluation. The reviews were performed by the John A. Volpe National Transportation Systems Center and the Department of Energy at the request of PHMSA.[2]

[2]As cited in appendix I.

Organizations Contacted

In addition to the 52 pipeline operators and four inspection contractors that we contacted, we met with or contacted the following organizations:

Department of Transportation

Office of Inspector General
Pipeline and Hazardous Materials Safety Administration

Other Federal Agencies

Department of Energy
Federal Energy Regulatory Commission
National Institute of Standards and Technology
National Transportation Safety Board

Industry Associations

American Gas Association
American Public Gas Association
Inline Inspection Association
Interstate Natural Gas Association of America
Midwest Energy Association
Northeast Gas Association

State Regulatory Associations

National Association of Pipeline Safety Representatives
National Association of Regulatory Utility Commissioners
New Jersey Public Utility Commission

Research Firms

Energy and Environmental Analysis, Inc.
Battelle
Gas Technology Institute
John A. Volpe National Transportation Systems Center
Pipeline Research Council International

Technical Experts

American Society of Mechanical Engineers
American Society for Testing and Materials
Kiefner and Associates, Inc.
National Association of Corrosion Engineers

Pipeline Safety Advocacy Groups

Common Ground Alliance
Cook Inlet Keeper
Pipeline Safety Trust

Contact and Staff Acknowledgments

GAO Contact

Katherine Siggerud (202) 512-2834 or siggerudk@gao.gov

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