

**TESTIMONY OF
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PRESIDENT
WILLIAMS GAS PIPELINE COMPANY**

**ON BEHALF OF THE
INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA**

**BEFORE THE
SUBCOMMITTEE ON ENERGY AND AIR QUALITY
COMMITTEE ON ENERGY AND COMMERCE
U.S. HOUSE OF REPRESENTATIVES**

**REGARDING THE
PIPELINE INSPECTION, PROTECTION, ENFORCEMENT AND SAFETY ACT
OF 2006 AND SAFETY ASSESSMENT INTERVALS FOR NATURAL
GAS PIPELINES**

MARCH 12, 2008

Mr. Chairman and Members of the Subcommittee:

Good morning. My name is Phil Wright, and I am President of Williams Gas Pipeline. I am testifying today on behalf of the Interstate Natural Gas Association of America (INGAA). INGAA represents the interstate and interprovincial natural gas pipeline industry in North America. INGAA's members transport over 90 percent of the natural gas consumed in the United States through a network of approximately 200,000 miles of transmission pipeline. These transmission pipelines are analogous to the interstate highway system – in other words, large capacity systems spanning multiple states or regions.

Williams is the nation's second-largest transporter of natural gas, transporting about 12 percent of the natural gas consumed in the United States. We operate three interstate pipelines which provide natural gas to major markets on both the east and west coasts including Atlanta, the Carolinas, Washington, D.C., Philadelphia, New York, Portland, Seattle and Florida. These systems total about 15,000 miles of pipe, transporting natural gas from the Gulf of Mexico, Canada, the Rocky Mountains, LNG importation terminals, and other production areas.

INDUSTRY BACKGROUND

Mr. Chairman, natural gas provides 25 percent of the energy consumed in the U.S. annually, second only to petroleum and roughly equal to coal. From home heating and cooking, to industrial processes, to power generation, natural gas is a versatile and strategically important energy resource. Looking forward, it is noteworthy that natural gas has the lowest greenhouse gas emissions of any of the fossil fuels relied on by our economy.

As a result of the regulatory restructuring of the industry during the 1980s and early 1990s, interstate natural gas pipelines no longer buy or sell natural gas. Interstate pipeline operators do not take title to the natural gas moving through our pipelines. Instead, pipeline companies sell transportation capacity much the same as a railroad, airline or trucking company.

Because the natural gas pipeline network is essentially a “just-in-time” delivery system, with limited storage capacity, customers large and small depend on reliable around-the-clock service. That is an important reason why the safe and reliable operation of our pipeline systems is so important. According to U.S. Department of Transportation data, the natural gas transmission pipelines operated by INGAA's members and by others historically have been the safest mode of transportation in the United States. The interstate pipeline industry, working cooperatively with the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the U.S. Department of Transportation, is taking affirmative steps to make this valuable infrastructure even safer.

Congressional involvement in pipeline safety dates back almost 40 years to enactment of the Natural Gas Pipeline Safety Act in 1968. This legislation borrowed heavily from the engineering standards that had been developed over previous decades. The goals of this federal legislation were to ensure the consistent use of best practices for pipeline safety across the entire industry, to encourage continual improvement in safety procedures and to verify compliance. While subsequent reauthorization bills have improved upon the original, the core objectives of the federal pipeline safety law have remained a constant.

Mr. Chairman, I would like to make one important point about the future of natural gas and associated transportation infrastructure. This Committee is in the midst of exploring the parameters of legislation to mandate a reduction in U.S. greenhouse gas emissions. Given its environmental benefits, natural gas will be critical to the success of a national climate change mitigation program, especially in the first few decades. In order for natural gas to fulfill its role as the only realistic “bridge” to and critical supply of a low-carbon energy economy, the United States will need both increased natural gas supplies and the infrastructure to deliver those supplies. The supply/demand balance in the natural gas market already is tight, as reflected in the record high prices for the commodity and in price volatility.

We are witnessing the growing dependence on natural gas throughout the year – not just in the winter months – and this has implications for pipeline safety requirements; in particular, federal requirements that necessitate taking lines out of service for inspection and maintenance. We all recognize that pipeline safety and reliability are critical to public safety and to public acceptance of necessary pipeline infrastructure. Our goal is to achieve both scientifically-based safety requirements and the reliable delivery of natural gas to customers.

HOW SAFE ARE NATURAL GAS TRANSMISSION PIPELINES?

While not perfect, the safety record of natural gas transmission lines compares very well to other modes of transportation. Because natural gas pipelines are buried and isolated from the public, pipeline accidents involving fatalities and injuries are rare. And our people and our continuously improving practices are driving to eliminate them.

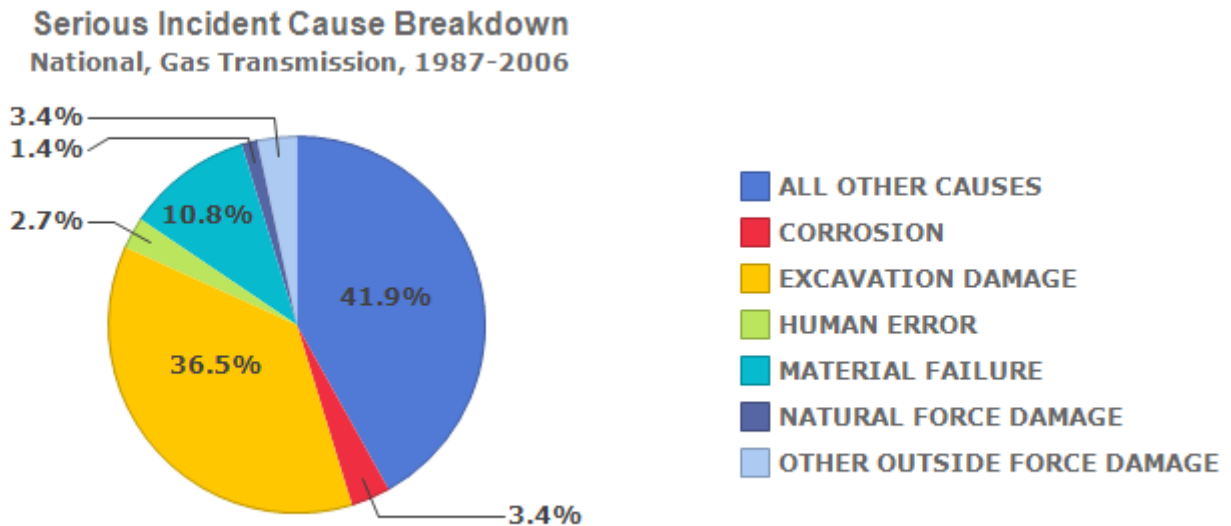
In 2007,¹ there was only a single general public fatality due to a natural gas transmission line accident. (This occurred in connection with an external corrosion failure on a natural gas transmission pipeline in rural Louisiana.) The other six fatalities that occurred since 2002 in connection with natural gas transmission pipeline accidents involved pipeline employees, pipeline contractors or third-party excavators working in the vicinity of pipeline facilities. Injuries resulting from incidents on natural gas transmission pipelines during 2002-2007 totaled 33. These injuries involved pipeline employees, pipeline contractors working on the pipeline facilities and third-party excavators,

¹ http://primis.phmsa.dot.gov/comm/reports/safety/cpi.html#_ngtrans

For perspective, the natural gas transmission industry transported approximately 22 trillion cubic feet of natural gas in 2006, containing an energy content equal to about 2.7 times the energy output of all the nuclear power plants in the United States.²

In 2006, INGAA came before this Committee and recommended that PHMSA modify its data reporting criteria to reflect pipeline accident trends more accurately. At the time, PHMSA defined a “reportable incident” as one that resulted in: (1) a fatality, (2) an injury, or (3) property damage in excess of \$50,000. The property damage metric skewed the data, because it was not adjusted for inflation and because it included the value of the natural gas lost in connection with the incident. As this Committee knows, natural gas commodity prices have increased significantly over the last eight years. This development, wholly unrelated to the nature of the incidents being reported to PHMSA, caused an abnormal increase in the number of “reportable accidents”. Minor pipeline leaks that would not have met the threshold for a reportable incident several years ago were being reported simply due to the increased value of the natural gas lost. This provided policymakers and the public with a misleading picture of pipeline accident trends.

Beginning in 2006, PHMSA modified its accident reporting criteria and revised data back to 2002 to mitigate the effect of volatile natural gas commodity prices. Pipeline accident data now is segregated into two categories – “serious” incidents³ and “significant” incidents⁴. “Serious” incidents are those that result in a fatality or an injury requiring in-patient hospitalization. “Significant” incidents include both “serious” incidents plus incidents that cause \$50,000 in property damage (damage, repair and natural gas lost). In addition, PHMSA now indexes the components of the \$50,000 property damage threshold.



Source: PHMSA Significant Incidents Files Oct 19, 2007

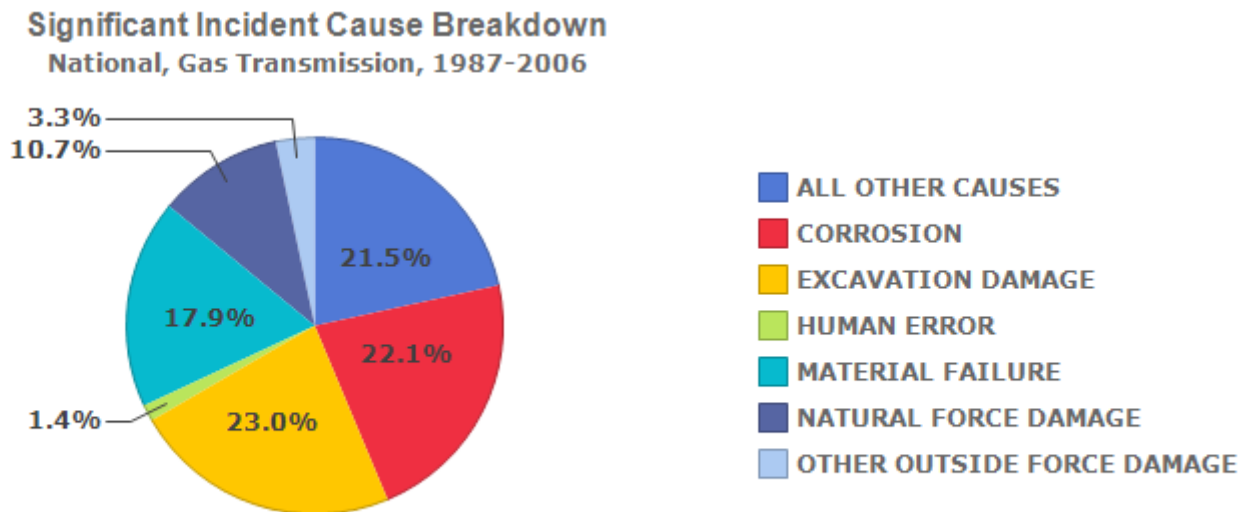
² U.S. Energy Information Administration data for 2006.

³ <http://primis.phmsa.dot.gov/comm/reports/safety/SerPSI.html>

⁴ <http://primis.phmsa.dot.gov/comm/reports/safety/SigPSI.html>

INGAA suggests that policymakers should focus most intently on the causes of “serious” incidents – those resulting in a fatality or major injury. The chart above outlines the causes of serious incidents, and as you can see, the leading cause is excavation damage, followed by material failure and then other outside force damage (typically a vehicle collision with above-ground pipeline equipment). Corrosion causes only 3.4 percent of “serious” accidents. These statistics demonstrate clearly why excavation damage prevention has been, and will continue to be, a primary focus of the industry’s safety efforts.

Now let us look at “significant” incidents involving natural gas transmission pipelines. Again, this category includes both “serious” incidents and pipeline leaks that do not result in a fatality or major injury. Given the dollar threshold that determines whether an incident is “significant”, PHMSA has tracked incident costs since 2002. For example, property damage to the public (not to pipeline operators themselves) caused by “significant” incidents totaled \$793,500 dollars in 2007. Corrosion is a more prominent cause of “significant” incidents than it is for “serious” incidents, second only to excavation damage. Still, corrosion accounts for only 22 percent of the total number of “significant” incidents. The integrity management program and its regimen of periodic inspections are focused almost exclusively on detecting and mitigating corrosion.



Source: PHMSA Significant Incidents Files Oct 19, 2007

Detailed incident information such as this is useful for spotting trends, correlating results with the technologies and management processes that have been implemented to improve pipeline safety, and targeting resources to areas that offer the greatest promise for achieving additional improvements in pipeline safety.

INTEGRITY MANAGEMENT PROGRAM FOR NATURAL GAS TRANSMISSION PIPELINES

The most significant provision of the Pipeline Safety Improvement Act of 2002 (“PSIA”) dealt with the “Integrity Management Program” (“IMP”) for natural gas transmission pipelines. Section 14 of the PSIA requires operators of natural gas transmission pipelines to: (1) identify all the segments of their pipelines located in “high consequence areas” (areas where the pipeline adjacent to significant population); (2) develop an integrity management program to reduce the risks to the public in these high consequence areas; (3) undertake structured baseline integrity assessments (inspections) of all pipeline segments located in high consequence areas (HCAs), to be completed within 10 years of enactment; (4) develop a process for repairing any anomalies⁵ found as a result of these inspections; and (5) reassess these segments of pipeline every seven years thereafter, in order to verify continued pipe integrity.

The PSIA requires that these integrity inspections be performed using one of the following methods: (1) an internal inspection device (or a “smart pig”); (2) hydrostatic pressure testing (filling the pipe up with water and pressurizing it well above operating pressures to verify a safety margin); (3) direct assessment (digging up and visually inspecting sections of pipe); or (4) “other alternative methods that the Secretary of Transportation determines would provide an equal or greater level of safety.” The pipeline operator is then required by regulations implementing the 2002 law to repair all non-innocuous anomalies and to adjust operation and maintenance practices to minimize “reportable incidents”. Internal inspection devices are the primary means for performing integrity assessments of natural gas transmission pipelines, because these are the most versatile and efficient devices. The other assessment alternatives prescribed by the law are useful when smart pig technology cannot be effectively used. A drawback associated with these other alternatives is that they require a pipeline to cease or significantly curtail natural gas delivery operations for periods of time or require extensive excavation of the pipeline.

The natural gas pipeline industry was one of the inventors of internal inspection “smart pig” devices decades ago, and the capabilities and effectiveness of these devices as analytical tools has increased steadily. Still, the pipeline industry must address some practical issues in order to utilize these devices more fully.

First, only the newest pipelines were engineered to accept such inspection devices. Prior to this, pipelines often were built with tight pipe bends, non-full pipe diameter valves, continuous sections of pipe with varying diameters, and side lateral piping. Such pipeline systems need to be modified to allow the use of internal inspection devices.

The other practical issue is modifying pipelines to launch and receive internal inspection devices. Since a pipeline is buried underground for virtually its entire length, the installation of aboveground pig launchers and receivers usually is done at or near other

⁵ An anomaly is defined as a possible precursor to a future incident.

above ground locations, such as compressor stations. Compressor stations typically are spaced 75 to 100 miles apart. Therefore, a separate set of launchers and receivers must be installed for every segment between compressors and occasionally new sites must be acquired for these pigging facilities.

The natural gas pipeline industry will use hydrostatic pressure testing and direct assessment for segments of transmission pipeline that cannot be modified effectively to accommodate smart pigs, or in other special circumstances. There are issues associated with both hydrostatic pressure testing and direct assessment technology.

In the case of hydrostatic pressure testing, an entire section of pipeline must be taken out of service for an extended period of time, limiting the ability to deliver gas to downstream customers and potentially causing market disruptions as a result. In addition, hydrostatic testing – filling a pipeline up with water at great pressure to see if the pipe fails – is a potentially destructive testing method that must take into account pipeline characteristics so that it does not exacerbate some conditions while resolving others.

Direct assessment (DA) is generally defined as an inspection method in which sections of pipe are excavated and visually inspected at intervals along the right-of-way based on sophisticated above ground electrical surveys that identify potential problem areas for further examination. The amount of excavation and subsequent disturbance of landowner's property involved with this technology is significant, and the level of disturbance does not decrease with future reassessments of the same section of pipe. The disturbance to other infrastructure, including roads and other utilities, caused by direct assessment also creates some level of risk and inconvenience for the public.

While pipeline modifications and inspection activity generally follow a pre-arranged schedule, repair and mitigation work is unpredictable. A pipeline operator does not know, ahead of time, how many anomalies an inspection will find, how severe such anomalies will be, or how quickly they will need to be repaired. Repair work often requires systems to be shut down, even if the original inspection work did not affect system operations.

Baseline integrity assessments – the type of work in which our industry now is engaged – are an effective means of identifying corrosion problems and any material defects that were not discovered when a pipeline was constructed. While material defects are less common, they are essentially eliminated for the life of the pipeline once they are identified and repaired. Corrosion is an on-going phenomenon that is managed and controlled utilizing many techniques. Periodic reassessments are an effective method for identifying whether corrosion prevention systems are adequately preventing this “time-dependent” deterioration.

INTEGRITY MANAGEMENT PROGRESS TO DATE

Based on data for the first half of the IMP inspection baseline period, there is ample basis for concluding that our pipelines are safe and that they are becoming safer by removing the possible precursors to future incidents. It also is clear that the industry is dutifully implementing the IMP program prescribed by Congress. For example, all INGAA member companies have been subject to in-depth IMP audits by PHMSA to assure that the programs are comprehensive and implemented consistently.

PHMSA has reported⁶ on IMP progress achieved through the end of 2006. (Comprehensive 2007 industry data will not be available publically until April) Consequently, we will rely on data from a survey of INGAA member companies to illustrate trends through 2007.

The following statistics will help put this reported data in perspective. First, there are approximately 293,950 miles of gas transmission pipeline in the United States. INGAA's member companies account for approximately 200,000 miles (or about two-thirds) of this total, with the remainder being owned by *intrastate* transmission systems or Local Distribution Companies (LDC). The INGAA IMP survey results cover 191,041 miles, which includes over 95 percent of the total mileage owned by INGAA member companies. Second, there are approximately 19,950 miles of transmission pipeline in HCAs (i.e., mileage subject to gas integrity rule). This represents about 6.5 percent of total natural gas transmission pipeline mileage in the United States.

The INGAA IMP survey results reflect 9,051 miles or roughly 45 percent of total pipeline mileage in HCAs in the United States. It should be noted that the majority of HCA mileage (more than 10,000 miles) is owned by *intrastate* pipeline and local distribution companies, which makes sense because these operators tend to have facilities located closer to populated areas. The INGAA survey does not include data on these pipeline systems.

INGAA HCA Pipeline Miles Inspected to Date –

- Based on INGAA IMP survey results, over 4,847 miles have been inspected through 2007, which exceeds the Congressional requirement of 50 percent of the baseline being assessed by December 2007 by 1 percent.

Additional INGAA Pipeline Miles Inspected (non-HCA pipeline) –

- Based on INGAA IMP survey results, an additional 41,335 miles of pipeline not located in HCAs has been assessed and repaired utilizing the same methodologies.

⁶ <http://primis.phmsa.dot.gov/gasimp/PerformanceMeasures.htm>

Rightly, the PSIA prioritized the inspection of pipelines operating in HCAs. Still, as a practical matter, the resources and effort required to obtain inspection data for HCAs has resulted in the inspection of total pipeline mileage that exceeds the HCA mileage by several multiples. Here is why this has occurred.

The vast majority of the assessments to date have been completed using smart pig devices. As discussed, these devices are launched and received at above ground locations that typically coincide with the location of compressor stations. Therefore, even if a 100-mile pipeline segment contains only five miles of HCA, it is necessary to assess the entire 100-mile segment between compressor stations. This results in significant “over-testing” on our systems. Any problems identified by these inspections, whether in an HCA or not, are remediated.

As you can see from the data, only about seven percent of total gas transmission pipeline mileage is located in HCAs. Yet, due to the over-testing situation, we anticipate that about 55 to 60 percent of total natural gas transmission pipeline mileage actually will be inspected during the 10-year IMP baseline period.

Now let us look at what the IMP integrity inspections have found to date. For this data, we focus on filed information from HCA segments, since these are the segments specifically covered under the integrity management program and reported to PHMSA.

There have not been any “serious incidents” due to time-dependent causes (i.e., corrosion) in natural gas transmission pipeline segments within HCAs since the reporting of such data to PHMSA began in 2002. Even before that, there was no history of “serious” natural gas pipeline incidents in high population density areas due to time-dependent causes. This likely is attributable to the industry practices that have made such events a remote probability and the additional regulatory requirements for high density areas that have been part of the federal pipeline safety regulations (for natural gas transmission pipelines) since 1970.

The number of “reportable incidents” for all causes (and just time-dependent causes) for all HCAs and separately for the mileage that INGAA members operate is as follows:

| Year | All Gas Transmission Reportable Incidents in HCAs | INGAA Reportable Incidents in HCAs |
|----------------|---|------------------------------------|
| 2004 | 9 (2) | 3 (0) |
| 2005 | 10 (0) | 3 (0) |
| 2006 | 11 (1) | 2 (0) |
| 2007 | Data Not Yet Available | 4 (0) |
| Miles Reported | 19,950 miles | 9,051 miles |

We highlight the time-dependent defects in the data for these incidents, because these are the types of defects that are the prime target of reassessment under the integrity management program. By time-dependent, we mean problems with the pipeline that develop and grow over time, and, therefore, should be examined on a periodic basis. The most prevalent time-dependent defect is corrosion; therefore, the IMP reassessment effort is focused most intently on corrosion identification and mitigation.

Most reportable incidents caused by excavation damage (more than 85 percent) result in an immediate pipeline failure, so periodic IMP assessments are unlikely to reduce these types of accidents in any significant way. Assessments on a periodic schedule are, therefore, most effective for managing time-dependent anomalies such as corrosion.

One of the primary reasons for the IMP program is to discover and repair anomalies that may lead to a future incident. The IMP baseline inspection program is discovering the isolated anomalies that have grown since pipelines were put in service, despite the extensive corrosion prevention systems. In most cases, these pipelines have operated, and will continue to operate, incident free for many decades.

We have identified the number of “immediate” and “scheduled” repairs that have been generated by the IMP inspections thus far. These are anomalies in pipelines that have not resulted in an incident, but are repaired as a precautionary measure. “Immediate repairs” and “scheduled repairs” are defined terms under both PHMSA regulations and engineering consensus standards. As the name suggests, immediate repairs require immediate action by the operator, due to a higher probability of a reportable incident or leak in the future. Scheduled repair situations are those that require repair within a longer time period because of their lower probability of failure.

The number of “immediate” repairs (repair within five days of discovery) of anomalies found in HCAs performed by all gas transmission operators and performed by INGAA members alone is as follows:

| Year | All Gas Transmission “Immediate” Repairs in HCAs | INGAA “Immediate” Repairs in HCAs |
|-------------------------------|--|-----------------------------------|
| 2004 | 104 | 34 |
| 2005 | 261 | 48 |
| 2006 | 157 | 21 |
| 2007 | Not Available Yet | 39 |
| HCA Mileage Inspected to Date | 10,396 | 4847 |

The number of “scheduled repairs” (repair generally within one year of discovery) of anomalies found in HCAs by inspections is as follows:

| Year | All Gas Transmission “Scheduled” Repairs in HCAs | INGAA “Scheduled” Repairs in HCAs |
|-------------------------------|--|-----------------------------------|
| 2004 | 599 | 133 |
| 2005 | 378 | 67 |
| 2006 | 338 | 54 |
| 2007 | Not Available Yet | 55 |
| HCA Mileage Inspected to Date | 10,396 | 4847 |

While we are only halfway through the baseline assessment period, the results support favorable conclusions about the integrity of the gas transmission pipeline system, the effectiveness of maintenance practices undertaken by individual pipeline operators, the earlier regulatory requirements of PHMSA, and the additive value of the new IMP. “Immediate” repairs in HCAs have removed 2.9 anomalies per every 100 pipeline miles of inspected HCA pipe. “Scheduled” repairs have removed an additional 6.4 anomalies per 100 miles of inspected HCA pipe. By completing these “immediate” and “scheduled” repairs in a timely fashion, the pipeline industry has reduced significantly the possibility of future incidents due to corrosion.

As “immediate” and “scheduled” time-dependent precursors are found and repaired during the baseline period, we expect the number of time-dependent significant incidents in HCA areas to approach zero, because the gestation period for these anomalies to grow to failure is significantly longer than the present or proposed risk based re-assessment interval.

It is worth emphasizing that data from operators who have completed more than one such periodic integrity assessment over a number of years strongly suggests a dramatic decrease in the occurrence of time-dependent precursors requiring repairs the second time around. Technical analysis undertaken in 2005 by the Pipeline Research Council International (PRCI)⁷, an international standards-setting and research group, demonstrated a significant reduction in the number of serious anomalies found during risk-based reassessments, suggesting that baseline assessments using smart pig technology are extremely effective in identifying potential problems before they manifest themselves into safety risks. This research report also reconfirms the detailed recommendations for setting the risk-based interval contained in the American Society of Mechanical Engineers consensus standard ASME B31.8S.

⁷ *Integrity Management Reinspection Intervals Evaluation*, Pipeline Research Council International, Inc., December 2005

One important benefit of the integrity management program is verifying and re-certifying the safety of older pipeline systems. Many of the gas pipelines being inspected under this IMP are 50 to 60 years old. While it is often hard for non-engineers to accept, well-maintained natural gas transmission pipelines can operate safely for many decades. Natural gas transmission pipelines are built to be robust and are not subject to the same operational stresses as vehicles. Much of the inspection data highlighted in the research comes from pipelines that were built in the 1940s and 1950s. And yet, after all these years, the number of anomalies found on a per-mile basis is low. Once these anomalies are repaired, the “clock can be reset,” and these pipelines can operate safely and reliably for many additional decades.

SEVEN-YEAR REASSESSMENT INTERVAL

Under the PSIA, gas transmission pipeline operators have 10 years within which to conduct baseline integrity assessments on all pipeline segments located in HCAs. Operators also are required by law to begin reassessing previously-inspected pipe seven years after the initial baseline and every seven years thereafter. PHMSA has interpreted these requirements to mean that, for segments baseline-inspected in 2003 through 2005 (including those for which a prior assessment is relied upon), reassessments must be done in years 2010 through 2012 – *even though baseline inspections are still being conducted.*

In 2001, INGAA provided Congress with a proposed industry consensus standard on reassessment intervals that had been developed by the ASME. The ASME B31.8S consensus engineering standard used several criteria to determine a reassessment interval for a particular segment of pipe, such as the operating pressure of a pipe relative to its strength and the type of inspection technique used. This risk-based standard utilized a “decision matrix” based on detailed engineering analysis of basic corrosion mechanisms, correlation with over 30 years of inline smart pig inspection results, more than 60 years of operational and performance data of natural gas transmission pipelines utilizing corrosion prevention practices and actual pipeline incident reports.

The ASME standard proposes a conservative 10-year reassessment interval for typical natural gas transmission pipelines operating at high pressure, which represent most of the gas transmission pipeline mileage. The standard suggested longer inspection intervals for lower pressure lines, which represent a lower risk and a smaller portion of the gas transmission pipeline mileage. The standard also suggested shorter intervals for pipeline segments operating in higher-risk environments, including environments where unusually aggressive corrosion would be more likely to occur.

Why is INGAA so concerned about the seven-year reassessment interval? First, there is the “overlap” of baseline inspections and reassessments in years 2010 through 2012. The ability to meet the required volume of inspections is daunting given the limited number of inspection contractors and equipment available. In addition, this stepped up level of inspection activity would be difficult to accommodate without affecting gas system deliverability. This last point is critical. Some assume that we are focusing on the reassessment interval only because of the costs to industry. In fact, our costs will be

modest compared to the potential costs to consumers in the form of higher natural gas commodity prices if pipeline capacity becomes too constrained due to the level of simultaneous inspection activity. Some regions of the country can handle more frequent reductions in pipeline deliverability, due to the volume of pipeline capacity serving those regions. The Chicago region and the Gulf Coast, for example, are equipped to handle frequent pipeline capacity interruptions due to the abundance of pipeline capacity in those regions. Other regions, such as the Northeast, New England, Florida, California and the Pacific Northwest, face greater risk that gas commodity prices will be affected if pipeline capacity is reduced too often. These downstream market effects should be considered carefully, especially during the baseline inspection period when pipeline modifications (to accommodate inspection equipment), inspections, and repair work will be at peak levels.

Some also suggest that, if the pipeline industry is technically capable of inspecting its lines for corrosion more frequently than engineering standards suggest, then it should do so and not worry about the costs or the logistics. Yes, large interstate pipelines could, in fact, be inspected more frequently than every seven years, especially once systems have been modified to accommodate smart pig devices. Still, just because pipelines can be inspected more often, does not make it rational to require a very conservative one-size-fits-all inspection policy. Most automobile manufacturers recommend oil changes every 3000 miles and only every 10,000 miles for some newer technology cars. While Congress could instead mandate that all vehicle owners change their oil every 1000 miles, there would be little, if any, additional benefit from more frequent oil changes, and the cost would take divert owners' money away from other, more beneficial maintenance activities.

The Integrity Management Program requires industry to identify and mitigate risks to the public associated with operating its facilities. Inspections are only one tool for achieving that end, and are not a tool that singlehandedly can accomplish all of the required goals of the program. As previously discussed, corrosion is the primary focus of the reassessments undertaken pursuant to the Integrity Management Program. Corrosion causes about 22 percent of the "significant" failures on gas transmission lines, and only 3.4 percent of the failures that result in "serious" incidents.

It is vital that an effective integrity management program utilize a risk-based approach to focus attention and resources, and that this program include strategies to address all risks. This would suggest that a shift in focus from the lowest cause of incidents to the highest is warranted.

RECOMMENDATION FROM GAO

Fortunately Mr. Chairman, you do not have to make a decision on this reassessment question based upon INGAA's recommendation alone. When Congress enacted the PSIA in 2002, it required the Government Accountability Office (GAO) to conduct an analysis of natural gas pipeline reassessment intervals and report back to Congress with any recommended changes to the seven-year requirement. The title of the GAO report,

completed in September of 2006 (GAO-06-945), sums up its conclusion – “Natural Gas Pipeline Safety: Risk-Based Standards Should Allow Operators to Better Tailor Reassessments to Pipeline Threats.” This title also concisely states INGAA’s position on integrity assessments and on pipeline safety activities in general. That is, safety programs and activities should be based upon a reasoned determination of the risks to the public, with procedures focused upon reducing those risks to the greatest extent possible.

The current seven-year reassessment interval mandate requires natural gas transmission operators to focus inordinate resources on areas that present relatively low risk to the public, especially once the baseline integrity reassessments are completed and identified problems are repaired. To quote the GAO report:

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 short reassessment intervals as conditions warrant.

SPECIAL PERMITS AND RECOMMENDATION FROM DOT

The Department of Transportation has agreed with INGAA on the importance of risk-based reassessment intervals, and the challenges presented by the current one-size-fits-all approach. During the 2006 debate on the Pipeline Inspection, Protection, Enforcement, and Safety (PIPES) Act, several members of the Senate expressed concern about modifying the seven-year requirement, but suggested instead that PHMSA could waive the seven-year reassessment interval, where justified, based on the Pipeline Safety Act’s existing waiver authority. The PHMSA Administrator at the time, Adm. Thomas Barrett, confirmed that PHMSA had adequate waiver authority, but expressed a preference for Congress amending the statute to allow specifically for risk-based intervals. Congress ultimately retained the seven-year interval, but pursuant to the PIPES Act did require PHMSA to make a recommendation to Congress on a statutory change regarding reassessment intervals.

Pending Congressional action on removing the seven-year requirement, PHMSA has initiated a “special permit” process that would, in effect, allow for longer reassessment intervals when technically justified. PHMSA proposed a “special permit” process for risk based inspection intervals at a Technical Pipeline Safety Standards Committee (an advisory committee to PHMSA) meeting in December. The response to the proposed IMP special permit process from governmental, public and industry participants generally was very positive.

While INGAA certainly supports the “special permits” process, we remain convinced that the best course is for Congress to repeal the seven-year requirement and to authorize PHMSA specifically to adopt rules governing risk-based determinations. The “special permits” process likely will be confined to individual waivers, a “one-off” process that

likely will be administratively cumbersome and resource-intensive for both the regulator and the industry. We also have concerns that a case-by-case waiver process could result in inconsistent results for pipeline facilities and pipeline owners that otherwise are operating under very similar circumstances.

This is why we urge Congress to consider seriously the recommendation made by Deputy Secretary of Transportation Adm. Thomas Barrett, dated November 27, 2007. Adm. Barrett outlined the numerous reasons why the seven-year requirement is illogical under most circumstances, and how this requirement could present gas deliverability problems unless changed (or unless PHMSA waives the requirements in most cases). His letter to Congress cited the GAO recommendation as well and urged Congress to authorize “DOT to establish rules setting risk-based intervals for reassessment of natural gas transmission pipelines.” Adm. Barrett’s letter included a list of technically-based criteria PHMSA would use in determining what an appropriate reassessment interval would be for each pipeline segment. He also included proposed statutory language consistent with the GAO recommendation.

INGAA strongly endorses this statutory change. We believe a clear statutory mandate from Congress authorizing the adoption of risk-based intervals would lead to a more efficient allocation of PHMSA resources and greater consistency for the industry.

DAMAGE PREVENTION AND WORKING WITH COMMUNITIES

The “serious” incident data cited earlier in my testimony points to the importance of damage prevention as a means to avoid fatalities and injuries. The PIPES Act took an important step forward by creating incentives for states to adopt improved damage prevention programs that meet nine critical elements. INGAA was pleased to join last year with the American Gas Association, the Association of Oil Pipelines, American Petroleum Institute, the Associated General Contractors and the National Utility Contractors Association in creating the Excavation Damage Prevention Initiative (EDPI). The purpose of the EDPI was to provide general guidance for states on how they can meet the nine elements articulated by Congress in 2006, in order to create a more consistent process for evaluating state programs prior to receiving federal grant dollars. Working together, the members of the EDPI developed a “roadmap” for states to follow in developing damage prevention programs that meet the goals outlined in the PIPES Act. We hope this roadmap will be used by the states, and by DOT, in determining which programs are worthy of state grant funds.

Our regulator and our industry are tackling the difficult and multi-faceted issue of excavation damage prevention. For example, following up on its commitment made during the 2006 PIPES Act debate, PHMSA encouraged my own company to participate in a pilot of the “Adopt-A-Community” program. We have embraced this challenge. Our approach integrates new GPS technology with a focused local community solution. Williams and the Virginia Utility Protection Service have joined in an effort to:

- Explore the needs of state and local agencies and authorities in order to take the initiative on reducing the risk of excavation damage on underground facilities.
- Enhance community awareness and exchange ideas to protect pipeline facilities from encroachment and thus improve public safety.
- Deploy newly available GPS and geo-coding technology to minimize mistakes in communications between pipeline operators, one-call system operators and prospective excavators.
- Integrate available databases to enhance planning and sharing of land use information among underground facility operators and public safety stakeholders.

While this effort focuses on just one part of improving the excavation damage prevention system, we feel it is an important contribution that can be replicated throughout the United States.

PIPELINE SAFETY USER FEES

For several decades, the federal pipeline safety program has been funded almost exclusively through industry user fees. The law that authorized the user fee program for pipeline safety activities (P.L. 99-272, 49 USC 60301) limited the collection of such fees to hazardous liquid and natural gas **transmission** pipeline operators and LNG terminal owners. This limitation made sense at that time, because the federal pipeline safety program then focused almost exclusively on the regulation of interstate transmission pipelines and LNG terminals.

This now has changed, because the PIPES Act both created a new “distribution integrity management program,” and increased the potential state government matching grants (which fund state-related pipeline safety programs focused on gas distribution and intrastate pipeline oversight) from the original “up to 50 percent” of state budgets to “up to 80 percent” of state budgets. The new law has greatly expanded the scope of PHMSA activity associated with natural gas distribution pipelines and has increased the potential level of federal financial support for state activities associated with gas distribution pipelines. Yet, due to the prohibition in the current law, natural gas distribution pipelines pay no federal user fees to support these activities.

The current statutory limitation compels natural gas and hazardous liquid transmission pipelines to support regulatory programs that benefit a segment of the industry that is not paying its fair share. It seems fundamental that, if government programs are to be funded using a user fee structure, then the actual users of such programs should be expected to pay their fair share of such costs.

There is no reason to believe that assessing federal user fees on distribution pipelines will have any adverse effect on state programs, contrary to the assertions that have been made by some. It also is not unprecedented to have pipelines pay both federal and state user fees. For example, interstate pipelines with facilities located in those states that participate in the oversight of interstate pipelines pay both a federal user fee and a state user fee. There is no reason why distribution pipeline operators cannot do the same.

Distribution pipeline operators also have suggested that transmission pipelines should continue to pick up the costs for these distribution-related safety activities, and then attempt to recover such costs in the rates charged to distribution pipeline companies. This argument fails to acknowledge that many natural gas transmission pipeline customers do not pay the maximum FERC-approved rate that would allow for full recovery of such costs. Pipeline customers have, for years, demanded discounts from the FERC-approved rate where competitive situations allow for choice among pipeline services. The large volume of discounted pipeline transactions means that pipelines are not guaranteed to recover all of their FERC-approved costs in competitive environment. Natural gas distribution companies often are the beneficiaries of this discounting.

It is entirely reasonable to ask that each segment of the pipeline industry pay for its fair share of the federal pipeline safety program. We hope Congress will address this disparity by authorizing PHMSA to collect pipeline safety user fees from natural gas distribution companies.

CONCLUSION

Mr. Chairman, INGAA and its members have worked in good faith since 2001 to convince Congress that a risk-based solution for determining reassessment intervals is the best alternative from a public safety standpoint. Since then, both GAO and the DOT have analyzed this issue and have joined with INGAA in recommending to Congress that the inflexible seven-year requirement be repealed in favor of risk-based standards. In the 40 years since the Natural Gas Pipeline Safety Act was enacted, this likely is the single pipeline safety issue that has received the greatest analysis. All of the reasoned analysis points in one direction. We believe that the burden of proof has been met, and therefore urge you and the Committee to enact the statutory change recommended by DOT and GAO.

Thank you for agreeing to conduct this hearing, and for inviting me to participate today. Please let us know if you have any additional questions, or need additional information.

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Summary of Testimony:

The Interstate Natural Gas Association of America (INGAA) represents virtually all the natural gas pipeline companies in the U.S. and Canada. Our industry has a long history of safe operation, but we are always looking for ways to reduce accidents associated with our pipelines.

The Pipeline Safety Improvement Act of 2002 (PSIA) created the Integrity Management Program for natural gas transmission pipelines as a way to verify the safety of our systems, identify potential problems, and mitigate any identified safety risks in a timely manner. The PSIA requires all pipeline segments located in populated areas to have a baseline integrity assessment within ten years of enactment (December 2012), and periodic reassessments every seven years. The INGAA member companies are on-track for assessing all of the pipeline segments covered under the program within the 10-year baseline.

Going forward, INGAA believes that reassessment intervals should be established for each pipeline segment using a risk-based approach to determine the appropriate timeframe. Both the GAO and DOT have determined that the current seven-year reassessment requirement is “too conservative,” and forces pipeline operators to expend time and resources in a manner which does not provide the best level of safety to the public. To quote the title of the GAO report: “Risk-Based Standards Should Allow Operators to Better Tailor Reassessments to Pipeline Threats.” We urge Congress to modify the statute to reflect the recommendations from GAO and DOT.

Looking at the most significant safety risks for our pipelines, INGAA supports improved state damage prevention programs. Williams is undertaking a voluntary effort, in conjunction with PHMSA, to establish a pilot program for educating local communities on pipeline safety issues, and taking action to reduce to probability of pipeline accidents.

INGAA also urges Congress to amend the pipeline safety statute to allow PHMSA to collect pipeline safety user fees directly from all program users, including natural gas distribution companies.

We thank the Subcommittee for the opportunity to testify.