TESTIMONY OF
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BEFORE THE
SUBCOMMITTEE ON SURFACE TRANSPORTATION
AND MERCHANT MARINE INFRASTRUCTURE
COMMITTEE ON COMMERCE, SCIENCE AND TRANSPORTATION
UNITED STATES SENATE

HEARING REGARDING
PIPELINE SAFETY SINCE SAN BRUNO AND OTHER RECENT INCIDENTS

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Mr. Chairman and Members of the Subcommittee:

I am Donald F. Santa, president and CEO of the Interstate Natural Gas Association of America, or INGAA. Our members operate approximately 200,000 miles of natural gas transmission pipelines, representing two-thirds of the nation's total natural gas transmission mileage and about 90 percent of the total interstate natural gas transmission mileage in the United States. The pipeline systems operated by INGAA's members are analogous to the interstate highway system, transporting natural gas across state and regional boundaries.

Let me state at the outset that INGAA appreciates the work of the National Transportation Safety Board (NTSB) to develop pipeline safety recommendations as part of its San Bruno accident investigation. Furthermore, our association agrees with the goals served by those recommendations: to reduce pipeline accidents and restore the public confidence of the safety of the natural gas infrastructure.

Some of NTSB's key recommendations include confirming the safe maximum allowable operating pressure (MAOP) for pre-1970 pipes, expanding and/or modifying integrity management principles beyond the current focus on populated areas, improving accident response times using both personnel and automation (such as valves), and the need for improved inspection technologies.

The NTSB recommendations are aggressive and aspirational. Still, there is much work needed to transform these recommendations into a concrete, practicable and achievable plan for realizing the pipeline safety goals that we share. INGAA advocates a phased approach that would build on the well-founded, existing approach of reducing risks to the greatest number of people in the most effective way. We believe that S. 275 accomplishes these objectives. S. 275 and a similar bill emerging in the House provide a well-considered framework for achieving groundbreaking improvements to the federal pipeline safety program. Therefore, Congress should enact this legislation this year.

INGAA COMMITMENTS

Pipeline safety has improved consistently over the decades through the application and continuous refinement of consensus standards, technology, law and regulation. Because of this work, pipeline transportation remains the safest method of moving energy supplies within the United States. Still, in the wake of the San Bruno accident last year, we recognized more needed to be done to improve the safety of natural gas transmission pipelines and to regain public confidence in the safety of our pipeline infrastructure. Last December, INGAA's board of directors established a board-level task force to pursue these objectives. This task force produced a set of aggressive guiding principles, anchored by the goal of zero pipeline incidents, which subsequently were adopted by our board of directors. The guiding principles are as follows:

1. Our goal is zero incidents – a perfect record of safety and reliability for the national pipeline system. We will work every day toward this goal.
2. We are committed to safety culture as a critical dimension to continuously improve our industry performance.
3. We will be relentless in our pursuit of improving by learning from the past and anticipating the future.
4. We are committed to applying integrity management principles on a system-wide basis.
5. We will engage our stakeholders – from the local community to the national level – so they understand and can participate in reducing risk.

At first blush, the goal of zero incidents may sound daunting. Still, we were inspired by the substantial results achieved by other industries that set similar goals. Commercial aviation stands out as an example. A quote from Vince Lombardi captures the idea well: "Perfection is not attainable. But if we chase perfection, we may capture excellence."

Developing and adopting these guiding principles was an important first step, but we knew that the real test of INGAA's commitment to pipeline safety would be the specific actions we as an industry were prepared to take in response to this challenge. As part of its response to the "call to action" issued by Secretary of Transportation Ray LaHood, INGAA committed publicly to a nine-point action plan to improve pipeline safety. The INGAA action plan includes commitments to do the following:

1. Apply risk management beyond High Consequence Areas (HCAs, or populated areas).
2. Raise the standards for corrosion anomaly management.
3. Demonstrate "fitness for service" on pre-regulation (or pre-1970) pipelines.
4. Shorten pipeline isolation and response time to one hour.
5. Improve integrity management communication and data.
6. Implement the Pipelines and Informed Planning Alliance guidance.
7. Evaluate, refine and improve threat assessment and mitigation.
8. Implement management systems across INGAA members.
9. Provide forums for stakeholder engagement and emergency officials.

We will be working with the Pipeline and Hazardous Materials Administration (PHMSA) and other pipeline safety stakeholders to implement these action items, either through regulation or on our own accord. (The complete plan of action can be downloaded from INGAA's website.) For purposes of the discussion today on S. 275 and the recent NTSB recommendations, I want to focus on three of the nine items addressed in our action plan.

EXPANSION OF INTEGRITY MANAGEMENT

Mr. Chairman, you and many members of the subcommittee may be familiar with Integrity Management Program, or IMP. The integrity management program is the cornerstone of the pipeline safety enhancements included in the Pipeline Safety Improvement Act of 2002. Briefly, the IMP requires operators to identify pipeline segments in populated areas (known as High Consequence Areas, or HCAs), perform baseline assessments of all such segments by December 2012, and reassess those segments every seven years thereafter. The baseline assessments are close to completion, and many segments already have been reassessed.

There are approximately 300,000 miles of natural gas transmission pipelines in the United States. Of this, about 18,000 miles, or six percent, is located in an HCA. Because in-line inspection devices, commonly known as "smart pigs," are used most often for these assessments and because of practical considerations affecting how these devices are inserted and retrieved from pipelines, pipeline operators ultimately will assess about 65 percent of the total natural gas transmission pipeline mileage by the end of next year. Completing the baseline assessments will be an important milestone. It is an opportune time to begin contemplating the next steps for natural gas transmission pipeline integrity management.

INGAA's members already have committed to go further, and over time plan to extend integrity management principles beyond HCAs. Our plan is based upon a phased approach, looking specifically at assessing those pipelines located in close proximity to where people live and work. Using the integrity management principles contained in the American Society of Mechanical Engineers (ASME) standard B31.8S, INGAA has proposed that integrity management principles be extended to cover 70 percent of the people who live or work in close proximity to pipelines by 2020, and 100 percent of the people who live or work in close proximity to pipelines by 2030.

As is common with such efforts, the final increments of this integrity work will be the most difficult and most expensive to complete. As noted, the majority of this work is being performed with smart pig devices, which increasingly are able to perform more accurate and comprehensive testing. Still, some natural gas transmission pipeline segments cannot readily accommodate such devices, since these pipelines were constructed before the technology was invented and were not engineered to accommodate smart pig devices. In addition, some low-pressure, low flow, small-diameter pipelines cannot accommodate smart pigs – at least based upon current technology.

A phased approach to covering additional pipeline segments beyond HCAs is important because it will be necessary both to undertake significant pipe modification and to develop and deploy improved in-line inspection technologies that do not exist today. Our commitment to cover 100 percent of the population living or working near pipelines is based on the assumption that new technology will provide the answer. It could not be achieved fully today given the configuration of the pipeline system and the state of current technology. Still, it is the aspirational goal that the industry should be setting for itself.

Section 7 of S. 275 would require the Secretary of Transportation to evaluate an extension of integrity management beyond HCAs, and then proceed with a rulemaking within one year. The bill also would direct the Secretary to re-evaluate the class location regulations for natural gas transmission pipelines. These regulations pre-date new technology advancements and the application of integrity management and now largely are redundant because class location and IMP address the same issue – reducing risk in populated areas. The need for these legacy regulations will be even less compelling as integrity management is broadened. Section 7 of S. 275 is consistent with our goals for expanding integrity management.

FITNESS FOR SERVICE OF PRE-REGULATION PIPELINES

The Natural Gas Pipeline Safety Act was enacted in 1968, and regulations implementing the new law took effect in 1970. Prior to this, pipeline operators utilized the ASME B31.8 standard to determine a pipeline's "fitness for service." (This standard did not require consistent record keeping.) The new regulations provided operators of pre-regulation pipelines with several options for confirming the Maximum Allowable Operating Pressure (MAOP) of the pipeline. Pre-regulation pipelines could determine MAOP through pressure testing, in the same manner required of pipelines constructed after 1970, or they could demonstrate, using verifiable records, past operating history to confirm the basis for the then-current MAOP. Many pre-1970 pipelines elected this second option, which has come to be known as the "grandfather clause."

Engineering and operational history supports the assertion that older pipelines are perfectly capable of safely remaining in service for many decades to come. Just as with an older home, pipelines that are well maintained can continue to provide reliable service. INGAA does not agree with the notion that older pipelines should be replaced simply due to their age. Age should not be the sole determinative factor in deciding whether to replace a natural gas transmission pipeline. *Fitness for service is the correct focus.* If a pipeline is unfit for service, then it must be repaired or replaced – regardless of age.

About 60 percent of U.S. natural gas transmission pipeline mileage was installed before 1970. Most of these pipelines are performing well and have records that the pipe had been pressure tested. INGAA supports a process for confirming the "fitness for service" of pre-regulation (or pre-1970) pipelines located in HCAs. This directly addresses the fact pattern in the San Bruno accident. INGAA believes that for all natural gas transmission pipelines operating in HCAs, an operator must either produce adequate records verifying a pipeline's fitness for service or reconfirm the fitness of that pipeline by pressure testing or utilizing an equivalent new technology. INGAA believes there must be a workable timeframe for completing this retesting to avoid significant adverse consumer energy price impacts due to testing-related pipeline capacity constraints and service disruptions. INGAA suggests that such work be completed by 2020.

Section 27 of S. 275 is consistent with the approach we support, and we believe it represents an effective legislative response to the San Bruno accident. INGAA's recommendation to reconfirm the MAOP in HCAs with testing or new technology, within a reasonable timeframe, is focused, rational, and demonstrability improves safety. Conversely, if the NTSB recommendation were implemented verbatim into regulation, all pre-1970 pipes would be required to undergo a specific type of hydrostatic pressure test, presenting a very problematic mandate. It is important to recognize that a pipeline must be completely removed from service, perhaps for up to several weeks, in order to be pressure tested hydrostatically. Moving beyond HCAs to cover all pre-1970 pipeline mileage would increase greatly the likelihood and magnitude of transportation service disruptions and increase consumer energy prices due to pipeline capacity constraints. Furthermore, with hydrostatic testing costs of approximately $250,000 to $500,000 *per mile* and with approximately 179,000 miles of pre-1970 natural gas transmission pipelines in the United States, the direct cost of such testing alone could have a significant impact on consumer energy costs when included in natural gas pipeline rates. This clearly is an area that should be subject to a rigorous cost-benefit analysis and where the availability of less costly and less disruptive alternatives to achieve the same safety goals should be considered.

The INGAA action plan closely mirrors S. 275 on this issue. We believe pre-1970 pipe segments, located in HCAs, that do not have pressure test records should meet certain fitness-for-service requirements by 2020. The lessons learned from this effort, which would be focused on decreasing the risk to people, could then be applied to broader pipeline segments beyond 2020. A key "enabler" for expanding such testing will be the development and commercialization of smart pig technology that could substitute for a hydrostatic test, and thereby dramatically decrease testing costs and service disruptions, while at the same time provide better data to operators. We believe that smart pig research and development ultimately will be critical to meeting the goals of the NTSB recommendation on pre-regulation pipelines.

PIPELINE ISOLATION AND RESPONSE TIME

Incident response time is another part of the INGAA action plan. Based on our meetings with emergency responders, the key issues for improving incident response and mitigation are, first, rapid recognition and, second, certainty of response. INGAA's members have committed to have personnel on-site to coordinate with emergency responders, and within an HCA, to isolate a damaged pipe section, within one hour. In areas where an operator cannot get workers to an incident scene promptly, automation (such as automatic or remotely-controlled valves) is an option. Still, automation will not provide that prompt face-to-face interface preferred by emergency responders.

Incident response should focus on performance, not specific technology. Automatic and remotely controlled valves may be part of improving response time, but they are not the only solution and alone are not a complete solution. Valves cannot prevent an incident, nor are they likely to reduce the number injuries or fatalities in the unlikely event of a natural gas pipeline rupture and fire. Even with an automatic or remote controlled valve, a high-pressure natural gas pipeline can take significant time to depressurize following a rupture. Most of the human impacts from a rupture occur in the first few seconds, well before any valve technology could reduce the flow of natural gas. It is important for policymakers to understand that the primary benefit of isolating a damaged pipe segment – either through personnel or through automation – is to mitigate property damage from fire and allow emergency responders access to the impacted area.

INGAA supports section 5 of S. 275, which directs PHMSA to develop a regulation for the installation of automatic and remotely controlled valves on all new pipelines (including pipe replacements). We would suggest, however, that such a requirement be focused on pipe segments located in HCAs. Additionally, INGAA supports the provision in H.R. 2937 that would require the Secretary to review and report incident response time for existing pipe segments located in HCAs.

NTSB's recommendations for valve automation and spacing, taken literally, are very prescriptive and would result in the dedication of significant resources to an issue that does not prevent accidents from happening.

PIPELINE TECHNOLOGY RESEARCH AND DEVELOPMENT

A common theme in this testimony has been the role that new technologies can play in making it possible to chart a practicable and achievable course for reaching the pipeline safety goals that all of us share. The further development of smart pig technologies is absolutely critical to achieving these goals. It will be important for industry, government and other pipeline stakeholders to work together closely to develop a research and development road map for the pipeline safety technologies needed, an efficient and effective work plan for developing and deploying these technologies, and a means to fund this important R&D work.

CONCLUSION

Mr. Chairman, thank you once again for providing INGAA with the opportunity to testify today. Our key messages are these: first, reducing risk to people must remain the primary focus of the federal pipeline safety program; second, S. 275 would provide a constructive framework for enhancing the pipeline safety program in a way that maintains this important focus; and, third, given that we are at such a critical moment in the evolution of our pipeline safety program, it is important for Congress to act this year to enact the reauthorization bill