S. HRG. 111–1014

ENSURING THE SAFETY OF OUR NATION'S PIPELINES

HEARING

BEFORE THE

SUBCOMMITTEE ON SURFACE TRANSPORTATION AND MERCHANT MARINE INFRASTRUCTURE, SAFETY, AND SECURITY

OF THE

COMMITTEE ON COMMERCE, SCIENCE, AND TRANSPORTATION
UNITED STATES SENATE

ONE HUNDRED ELEVENTH CONGRESS

SECOND SESSION

JUNE 24, 2010

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ENSURING THE SAFETY OF OUR NATION'S PIPELINES

THURSDAY, JUNE 24, 2010

U.S. SENATE,
SUBCOMMITTEE ON SURFACE TRANSPORTATION AND
MERCHANT MARINE INFRASTRUCTURE SAFETY, AND SECURITY,
COMMITTEE ON COMMERCE, SCIENCE, AND TRANSPORTATION,
Washington, DC.

The Subcommittee met, pursuant to notice, at 2:31 p.m. in room SR–253, Russell Senate Office Building, Hon. Frank R. Lautenberg, Chairman of the Subcommittee, presiding.

OPENING STATEMENT OF HON. FRANK R. LAUTENBERG, U.S. SENATOR FROM NEW JERSEY

Senator LAUTENBERG. Good afternoon, everyone. I want to welcome you, those who are here, to this hearing on pipeline safety.

Two weeks ago, workers in Weston, Texas, were digging up clay for a dirt contracting company and a tragedy occurred. The bulldozer inadvertently ruptured a natural gas pipeline, causing a fatal blast that left two persons dead and three others injured. Unfortunately, this was not an isolated incident. Just 1 day earlier, another worker in Texas was killed after a construction crew that was digging a hole for a utility pole accidentally struck a natural gas line.

The fact is that while pipelines are by and large a safe form of transportation, when there is an accident the consequences can be deadly. There are nearly 2.5 million miles of pipelines today moving oil and gas within states and across the country. We've got to do all that we can to keep these pipelines safe and to reduce the frequency of accidents.

In 2006, we made significant progress in pipeline safety when we passed the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006, also known as the PIPES Act. There is no doubt that the PIPES Act has improved pipeline safety. As we look to reauthorize the law this year, we want to hear from people who know, our witnesses, how the PIPES Act has worked and what we can do to improve it.

For instance, a provision that I authored in that law requires that service lines to single-family homes be fitted with excess flow valves which can automatically shut off a pipeline if a sudden change in pressure is detected. I'm interested in hearing from our witnesses whether or not this requirement should be expanded to other types of buildings.

The law also addresses the difficult problem of digging and excavation. Nearly 35 percent of all serious pipeline incidents during the last 10 years were caused by excavation damage, the single most common cause of these accidents.

The PIPES Act improved excavation safety by strengthening the One-Call system, which makes it easier for construction crews to notify utility companies about digging projects and therefore dramatically reducing pipeline accidents. Under that system, construction crews must call one phone number before digging, giving utility companies time to identify and mark hidden pipes if they haven't already done so. This system is now working better because of the PIPES Act, although we've still got to work to improve and increase awareness of the program. That's why I authored a resolution, passed by the Senate, to make April Call Before You Dig Month, to promote safe digging practices, including 811, the national Call Before You Dig Number.

So I look forward to hearing from today's witnesses about their views on the safety of our Nation's pipelines and the reauthorization of the PIPES Act. I also look forward to hearing from Administrator Quarterman about what she's doing to make sure that the Office of Pipeline Safety is vigilant in its oversight responsibilities.

Before we hear from our panels, I would call on Senator Johanns.

STATEMENT OF HON. MIKE JOHANNS, U.S. SENATOR FROM NEBRASKA

Senator JOHANNS. Thank you very much. I won't give a long opening statement, but I do want to offer a thought or two just to maybe kind of queue up in your minds some of my interest in this hearing today. Somebody laid in front of me these pictures of damage that obviously occurred at some event, and I look at them and I wonder to myself not only the impact on human life, but the impact on the environment. That's especially true these days as we look to the Gulf and the issues that are out there.

I raise that because today I want to get a better understanding relative to a project that is going on in Nebraska, the Keystone pipeline project. All of a sudden my office is starting to get calls from concerned people. Here's what's driving that. Our greatest natural resource in our state, some would argue, is the Ogallala Aquifer. It is literally an underground lake that stretches for miles and miles and miles and miles. It's not just in Nebraska; it's in other states also.

The concern is that this pipeline is going to traverse that, and so now citizens are worried about safety. So I'm going to want to know who's responsible, what's the ins and outs of that, who do we call that can help us address these concerns, and what the relationship between the various Federal agencies would be.

This project is even more complicated because it originates in Canada and it therefore crosses the Canadian border. I appreciate that there's an international element to what's going on here, too.

So I didn't want to catch anybody by surprise. I thank the chairman for giving me an opportunity to raise that in my opening statement. With that, thank you.

Senator LAUTENBERG. Thanks very much.

Now I welcome our first panel of witnesses: Ms. Cynthia Quarterman, Administrator, Pipeline and Hazardous Materials Safety Administration. Ms. Quarterman, this is your first time before this subcommittee since your confirmation and we welcome you and look forward to hearing your testimony. Just to show that I'm impartial, all statements will be limited to 5 minutes. Thank you.

Please, Ms. Quarterman.

STATEMENT OF HON. CYNTHIA L. QUARTERMAN, ADMINISTRATOR, PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION, U.S. DEPARTMENT OF TRANSPORTATION

Ms. QUARTERMAN. Thank you. Chairman Lautenberg, members of the Committee: Thank you for the opportunity to appear today. Your interest in pipeline safety is very much appreciated.

Like Secretary LaHood, safety is my top priority for PHMSA. The lessons learned from current and past tragedies have significantly influenced the safety policies underlying the laws and regulations related to pipeline safety. Thanks to the Congress and especially to this subcommittee the Department has made tremendous strides in improving the pipeline safety program.

I'm pleased to update you on PHMSA's progress in ensuring the safety of our Nation's pipeline transportation system through implementing the mandates of the PIPES Act of 2006. The Act has played a major role in maintaining a safe and reliable pipeline network. Thanks to your help, PHMSA has developed a forward-leaning pipeline safety program. A reauthorized program promises to build on that progress.

PHMSA has worked aggressively to respond to Congressional interest and implement the PIPES Act. It has made significant progress in implementing its statutory requirements to build safer communities. PHMSA has been working with many governmental partners to promote safety, such as the National Transportation Safety Board, the Department's Office of Inspector General, and the Government Accountability Office, implementing strategic approaches to address their safety recommendations.

Since its last reauthorization, PHMSA has gone from a high of 16 open NTSB pipeline recommendations to today's low of 9 open recommendations. Of the remaining nine, none of the recommendations are classified as unacceptable and several should close before the year's end. There are no outstanding IG recommendations for the pipeline program and the two outstanding GAO recommendations should be closed by year's end as well.

PHMSA has made great progress in strengthening its industry oversight program. The PIPES Act reauthorized PHMSA to increase its inspection and enforcement staffing from 94 in Fiscal Year 2007 to 135 in Fiscal Year 2010. PHMSA has instituted a new, more aggressive recruiting strategy to promptly fill vacant inspection and enforcement positions. PHMSA has taken advantage of higher penalty authority by imposing and collecting larger penalties where appropriate. PHMSA has set records in its enforcement processes, proposing $19 million in administrative civil penalties since 2006, or an average $183,000 per proposed penalty.

PHMSA has added integrity management requirements to natural gas distribution networks to address pipelines, where safety risks have the most impact on citizens. PHMSA has also worked to improve the internal operations of pipeline companies' control rooms. This action removes the pipeline program's control room standards from the NTSB top ten list and replaces it with NTSB praise.

PHMSA has established valuable state partnerships on oversight, emergency response, and damage prevention. Funding to state pipeline safety programs has increased. In 2010 PHMSA will cover 54 percent of the pipeline safety program costs for states, compared with 45 percent in 2006.

PHMSA has also maintained strong relationships with Federal, state, local, and other emergency response agencies to effectively respond to pipeline incidents and emergencies. Following incidents, PHMSA staff remain in constant contact with investigatory and additional oversight agencies to not only ensure public safety and operator compliance, but to share information and participate in remediation activities.

PHMSA and its partners have done a good job helping reduce the number of pipeline incidents related to excavation damage over the past few years. Since 2006, excavation damage has gone from 37.5 percent as the cause of serious incidents to 12.7 percent today.

All of us at PHMSA are proud of the accomplishments to date in implementing the PIPES Act, although we acknowledge there is still more work to be done. As the Administrator of this agency, I assure you that all of my staff and all of our stakeholders know that safety is PHMSA's top priority.

We look forward to working with Congress to reauthorize the Pipeline Safety Act and I welcome any questions you might have.

[The prepared statement of Ms. Quarterman follows:]

PREPARED STATEMENT OF HON. CYNTHIA L. QUARTERMAN, ADMINISTRATOR, PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION, U.S. DEPARTMENT OF TRANSPORTATION

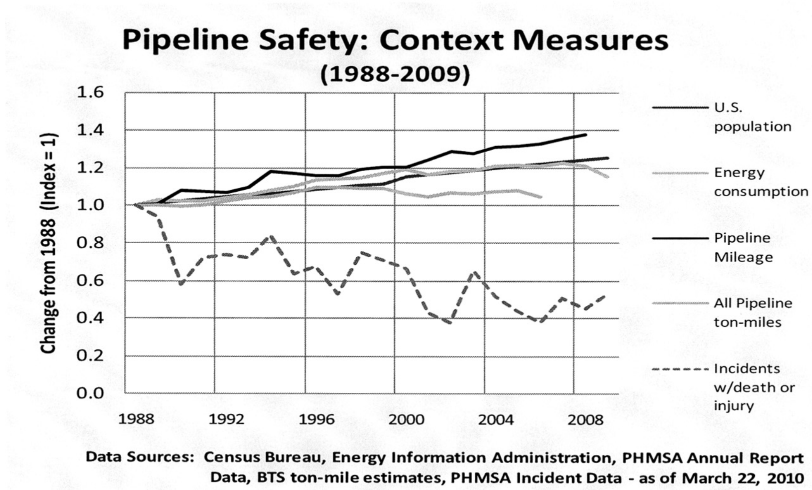
Chairman Rockefeller, Ranking Member Hutchison, members of the Committee, thank you for the opportunity to appear today. Safety is Secretary LaHood's top priority and it is PHMSA's top priority as well. PHMSA is also committed to reducing risks in pipeline transportation. PHMSA employees are encouraged to bring up new and creative ideas and to challenge each other and their supervisors so that the best safety solutions are put forward. As our Nation's reliance on the safe and environmentally sound transportation of hazardous materials is increasing, the Pipeline and Hazardous Materials Safety Administration's (PHMSA) safety oversight of the Nation's pipelines provides critical protection for the American people and our environment.

PHMSA works with many governmental partners to promote safety. The National Transportation Safety Board (NTSB), the Department's Office of Inspector General (OIG), the Government Accountability Office (GAO), and, of course, the U.S. Congress and the states all have a vested interest in the safe and reliable operation of the Nation's pipeline infrastructure. PHMSA is working aggressively to be responsive to all of these organizations and their recommendations. Since 2006, PHMSA's accomplishments include: closing the three open OIG recommendations; making significant progress on the GAO's recommendations on incident reporting with the last action due out this summer; and making substantial progress on all of the NTSB recommendations. When the Pipeline Inspection Protection Enforcement and Safety (PIPES) Act of 2006 passed, NTSB had thirteen open recommendations to PHMSA. Over the last several years, NTSB has closed nine of those recommendations and it is currently working to address the remaining four recommendations as well as a few new recommendations. PHMSA does not currently have any open unacceptable recommendations.

I am pleased to brief you on the significant progress PHMSA's Pipeline Safety Program has made since the passage of the PIPES Act in December, 2006. PHMSA looks forward to working with you to build on this solid foundation.

I. Implementation of the PIPES Act

PHMSA has made significant progress in fulfilling the statutory requirements of the PIPES Act, which has resulted in safer communities today. The number of serious pipeline incidents—those involving death or injury—has declined by 50 percent over the last twenty years. Yet over the same period, all the traditional measures of risk exposure have risen—population, energy consumption, pipeline ton-miles. We aim to continue the downward long-term trend in pipeline incidents.



A brief description of PHMSA's successful use of the tools provided by Congress in the PIPES Act to improve the safety record of the Nation follows.

A. PHMSA Has Increased the Strength of Integrity Management Programs and Enforcement Activities

The PIPES Act broadened the scope of the systems-based approach to assessing and managing safety related risks. The additional initiatives included: (1) increasing enforcement activity, transparency, and data quality; (2) implementing an integrity management program for distribution pipelines, and; (3) requiring a management plan to reduce risks associated with human factors, including operator fatigue in pipeline control centers, and implementing NTSB recommendations on the Supervisory Control and Data Acquisitions (SCADA) systems in pipelines. We are pleased with the positive results from increasing the systems risk management approach, which this Committee helped devise.

1. PHMSA Has Increased Enforcement and Improved Transparency and Data Quality

PHMSA has used its full enforcement authority to give teeth to its systems-based approach to risk management and increase pipeline company management accountability for safety. The PIPES Act, and the appropriations that followed, authorized PHMSA to increase its inspection and enforcement staffing to 135 in FY 2010 from 94 inspection and enforcement staff in FY 2007. PHMSA is in the process of an aggressive recruitment effort to fill these positions as soon as possible.

Also, PHMSA has embraced enforcement transparency by leveraging its website and data bases to provide on-the-spot information to stakeholders. Within months after the 2006 PIPES Act was signed into law, we launched an enforcement transparency website. The website provides public access to a variety of reports and enforcement program information that goes beyond what is required by the PIPES Act. This site provides year-by-year reports on cases initiated and closed, the status of different types of enforcement cases, and reports on civil penalty cases showing the amounts proposed, assessed, and collected. Information and documents on individual cases are also provided. These documents include the initial notices that allege operator violations or inadequacies; operator responses to these allegations; and the orders documenting PHMSA's final determinations. In addition, PHMSA provides monthly updated enforcement summaries to the public. Use of the enforcement transparency website has climbed steadily since its inception in May 2007 and averaged more than 1,500 hits per day in 2009. In 2010, we expanded and improved the information on civil penalty cases and began displaying enforcement data from state pipeline safety agencies.

In addition to increased staffing and online function, the PIPES Act also gave PHMSA a much needed enforcement tool—the Safety Order. In January 2009, PHMSA published a final rule establishing the process by which PHMSA conducts Safety Order proceedings to address pipeline integrity risks to public safety, property, or the environment.

Finally, the PIPES Act now requires that senior executive officers of pipeline companies certify their pipeline integrity management program performance on an annual and semi-annual basis. As predicted, the certification requirement has increased management's accountability and the accuracy in performance reporting.

PHMSA also undertook a significant effort to improve data consistency and quality culminating in a new generation of data reporting that will begin this summer. First, PHMSA published a final rule in August 2009 to align cause categories across natural gas transmission and distribution incident reports. Second, PHMSA sought and received Office of Management and Budget approval for new forms and additional data collections. Third, PHMSA updated its guidance and forms regarding incident reporting. Fourth, PHMSA proposed revisions to the reporting requirements in Part 191 and expects to issue a final rule. While all seemingly small changes, the process allowed for coordination and input from state pipeline safety agencies and other Federal agencies ultimately resulting in raising industry awareness. This effort specifically addressed Congress' mandates to modify reporting requirements to ensure that incident data accurately reflects incident trends over time and collects data on controller fatigue.

2. PHMSA Has Established a Gas Distribution Integrity Management Program (DIMP)

Pursuant to the authority granted in the 2006 PIPES Act, PHMSA issued a final rule in December 2009 requiring operators of gas distribution pipelines to develop and implement integrity management programs to manage and reduce risks in gas distribution pipeline systems. These programs are intended to enhance safety by identifying and reducing pipeline integrity risks. The requirements for the integrity management programs are similar to those required for gas transmission pipelines, but tailored to reflect the differences in and among distribution pipelines. The regulation requires operators to develop and implement plans for monitoring and improving the condition of their systems, in addition to complying with current code requirements. The rule also requires distribution operators to install excess flow valves in new and replaced service lines for single family residences where conditions are suitable for their use. The rule applies to the entire network of distribution pipelines and the thousands of small and large companies that deliver natural gas over the 2 million miles of pipelines serving American communities, not just high consequence areas.

PHMSA made tremendous efforts getting ready for the implementation of DIMP. We developed consensus standards, guidance, training, IT systems, and data to increase understanding of the new regulations. We are especially mindful of the increased oversight requirements associated with the program. Getting 50 states to implement a performance standard takes a lot more preparation than preparing a single Federal entity. Accordingly, we have worked with our state partners to prepare them by assuring thorough training, education, and effective enforcement compliance.

3. PHMSA Has Established Control Room Management Requirements

Pursuant to the authority granted in the PIPES Act, PHMSA issued a final rule on December 4, 2009, to address human factors and other aspects of control room management for pipelines remotely operated and controlled by personnel using SCADA systems. Operators must define the roles and responsibilities of controllers and provide controllers with the necessary information, training, and processes to fulfill these responsibilities. Controllers must manage SCADA alarms; assure control room considerations are taken into account when changing pipeline equipment or configurations, and review reportable incidents or accidents to determine whether control room actions contributed to the event. Operators must also implement methods to prevent controller fatigue. These regulations will enhance pipeline safety by coupling strengthened control room management with improved controller training and fatigue prevention measures.

The regulations apply to all hazardous liquid pipelines, and gas transmission and distribution pipelines that meet certain risk criteria. This rule not only responds to the PIPES Act mandate but also addresses a NTSB safety recommendation regarding controller fatigue that was on the NTSB's Most Wanted list. A public workshop is planned for November 2010 to present preliminary guidance materials. Programmatic inspections will be conducted between September 2011 and February 2013.

B. PHMSA is Enhancing Pipeline Safety with Increased Assistance to States, Damage Prevention Education, Technical Assistance Grants, and Public Access to Information

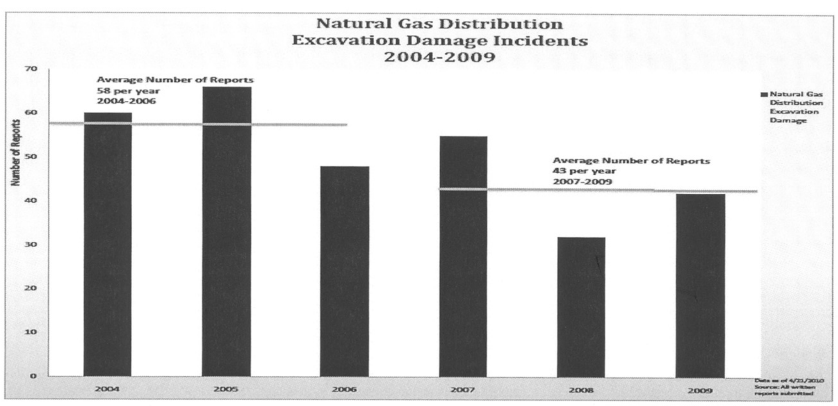
1. PHMSA Has Strengthened Its Assistance to States

State pipeline safety agencies oversee the bulk of the 2.5 million miles of pipeline infrastructure. Specifically, states are responsible for oversight of virtually all gas distribution pipelines, gas gathering pipelines and intrastate gas transmission, as well as 88 percent of intrastate hazardous materials liquid pipelines and 20 percent of the interstate gas pipelines. PHMSA maintains primary responsibility for the remaining pipelines, including all interstate hazardous liquid pipelines and 80 percent of the interstate gas pipelines. States employ approximately 63 percent of the inspector workforce. The expansion of the Federal pipeline safety initiatives, such as DIMP and integrity management, has increased the resource demands on both Federal and state pipeline safety agencies.

In recognition, Congress increased PHMSA's ability to provide grants to state pipeline safety agencies to offset the costs associated with the statutory requirements for their inspection and enforcement programs. In addition, Congress gave PHMSA considerable resources to expand its relationship with state pipeline safety agencies, enabling increased policy collaboration, training, information sharing, and data quality and collection. In FY 2010, PHMSA's $40.5 million appropriation to support state programs will fund 54 percent of state pipeline safety programs. Additionally, the President's FY 2011 request includes an increase in funds to support state programs totaling approximately $44.5 million, which would reflect a 65 percent funding of the state pipeline safety programs. These States are PHMSA's strongest asset in assuring the safety of pipelines in American communities.

2. PHMSA Has Strengthened Damage Prevention Efforts

The vast majority of America's pipeline network is underground making pipelines vulnerable to "dig-ins" by third-party excavators. While excavation damage is 100 percent preventable, it remains a leading cause of pipeline incidents involving fatalities and injuries. Three-quarters of all serious consequences from pipeline failures relate to distribution systems and more than one-third of these failures are caused by excavation damage. PHMSA's goal is to significantly reduce excavation damage with strong outreach and public awareness programs. As evident in the chart below, PHMSA is making progress.



The PIPES Act authorizes PHMSA to award State Damage Prevention (SDP) grants to fund improvements in damage prevention programs. Each state has established laws, regulations, and procedures shaping its state damage prevention program. Since 2008, PHMSA provided over $4 million in SDP grants to 30 distinct state organizations. Eligible grantees include: state one-call centers, state pipeline safety agencies, or any organization created by state law and designated by the Governor as the authorized recipient of the funding.

SDP grants reinforce nine specific elements that make up the components of an effective damage prevention program, under the PIPES Act:

1. Enhances communications between operators and excavators;
2. Fosters support and partnership of all stakeholders;
3. Encourages operator's use of performance measures for locators;
4. Encourages partnership in employee training;
5. Encourages partnership in public education;
6. Defines roles of enforcement agencies in resolving issues;
7. Encourages fair and consistent enforcement of the law;
8. Encourages use of technology to improve the locating process; and
9. Encourages use of data analysis to continually improve program effectiveness.

PHMSA's Technological Development Grants program makes grants to an organization or entity (not including for-profit entities) to develop technologies that will facilitate the prevention of pipeline damage caused by demolition, excavation, tunneling, or construction activities. A total of $500,000 was appropriated for the program in 2009. Two awards have been made to date.

PHMSA also uses the authority in the PIPES Act to promote public education awareness with national programs such as, "811—Call Before You Dig Program" through the Common Ground Alliance (CGA). PHMSA provided over $2.2 million in funding assistance for CGA's 811 advertising campaign since 2002.

PHMSA is proud of its continued and steady leadership in supporting national and state damage prevention programs. In March 2010, we participated in the CGA's annual meeting highlighting the importance of the National "811—Call Before You Dig Program." In April 2010, Transportation Secretary LaHood acknowledged the importance of calling before you dig by establishing April as "National Safe Digging Month." The U.S. Senate and the House of Representatives both introduced resolutions designating April 2010 as "National Safe Digging Month." At our urging, forty states, including those represented by the members of this committee, also followed suit. The efforts driven and supported by PHMSA, involved the CGA, many states, and damage prevention stakeholders from around the country, who are advocates for safe excavation practices.

3. PHMSA Has Launched the Technical Assistance Grant Program

The PIPES Act empowers PHMSA to encourage communities to take part in efforts to develop technical solutions for environmental and emergency planning, zoning, and land use management near pipelines, and to prevent damage to pipelines. Under this authorization, PHMSA created the Technical Assistance Grant (TAG) program to provide grants to local communities and organizations for technical assistance related to pipeline safety issues. Technical assistance is defined as engineering or other scientific analysis of pipeline safety issues. The funding can also be used to help promote public participation in official proceedings.

In 2009, PHMSA selected 21 communities and organizations to receive funding through the agency's TAG program. Grants, totaling $1 million, were used to foster open communication between the public and pipeline operators on pipeline safety and environmental issues, and perform other important tasks. Examples of such projects include the use of geographic information systems for enhanced pipeline monitoring and public awareness campaigns to promote the sharing of information between pipeline operators and landowners.

Each technical assistance grant recipient must provide a report to PHMSA within one year of its award demonstrating completion of the work as outlined in its grant agreement. PHMSA is thoroughly overseeing this process and will evaluate the expected outcomes of each grant recipient. PHMSA's Community Assistance and Technical Services Managers will offer their technical support to communities and organizations as well to address pipeline safety questions that may arise during the course of the grant agreement period.

4. PHMSA's Pipelines and Informed Planning Alliance Advances Smart Growth along Pipelines in Our Communities

In addition to the grants, PHMSA has conducted other activities to inform the public and engage public interest and participation in all of its initiatives. We funded publicly accessible, Internet broadcast viewing of two pipeline events sponsored by the Pipeline Safety Trust, including a focus on safer land use planning. We have made one grant and may make others to professional associations of county and city government officials to represent the public in the Pipelines and Informed Planning Alliance (PIPA). PIPA is an initiative organized by PHMSA to encourage the development and use of risk-informed land use guidelines to protect pipelines and communities.

A companion effort is helping communities understand where pipelines are located, who owns and operates them, and what other information is available for community planning. Following the passage of the PIPES Act, PHMSA worked with the Department of Homeland Security (DHS)/Transportation Security Administration (TSA) to resolve concerns about sensitive security sensitive information. Vital information that communities need for land use, environmental, and emergency planning around pipelines is now publicly available through PHMSA's National Pipeline Mapping System (NPMS). We continue to work with states, industry, and other stakeholders to make the NPMS information more accurate and useful.

C. PHMSA Has Adopted Additional Regulatory Enhancements and has Sponsored Congressional Required Studies

In addition to the programmatic authorizations already discussed, Congress provided PHMSA with the authority to address narrow, but significant, gaps in its safety regulations. The gaps related to regulating low stress pipelines, effective response to emergency disruption of pipeline operations, regulation of direct sale natural gas pipelines, and the coordination of pipeline security responsibility. PHMSA has addressed all of these additional regulatory initiatives in the PIPES Act.

Low Stress Pipelines. Under the direction of the PIPES Act, PHMSA regulates rural low-stress hazardous liquid pipelines to the same standards as other hazardous liquid pipelines. Low stress pipelines operate at or below 20 percent specified minimum yield strength. PHMSA had already regulated low stress hazardous liquid pipelines that were in populated areas or that crossed commercially navigable waterways. The PIPES Act directed PHMSA to regulate all low stress line including those rural low stress lines that could pose a threat to unusually sensitive environmental areas. On June 3, 2008, we published a Final Rule, Low Stress I, as phase one of a two phase process to complete the regulatory mandate in the PIPES Act. Low Stress I brought under safety regulation those rural low-stress pipelines that pose the greatest risk to environmentally sensitive areas, particularly low stress lines that are 8⅝ inches or greater in diameter and located in or within a ½-mile of an unusually sensitive area. PHMSA issued a notice of proposed rulemaking for Low Stress II which was published in the Federal Register on June 22, 2010, to bring the remainder of the unregulated low stress pipelines under our safety regulation.

Emergency Waiver of Pipeline Safety Requirements. The PIPES Act authorized PHMSA to waive compliance with certain Federal pipeline safety requirements without notice and opportunity for a hearing if needed to address an emergency involving pipeline transportation. In the wake of Hurricane Katrina, Congress recognized that in an emergency, it would not be feasible to provide for notice and opportunity for a hearing, as required for other waivers. PHMSA issued a final rule on January 16, 2009, to process emergency special permits when necessary to address an actual or impending emergency caused by a natural or manmade disaster.

Clarify Regulation of Direct Sale Natural Gas Pipelines. PHMSA issued an advisory bulletin on May 13, 2008, advising operators that the PIPES Act eliminated the exception of direct sale natural gas pipelines from the definition of an interstate gas pipeline facility. PHMSA is now responsible for regulatory oversight and enforcement of these lines.

OIG Recommendations Regarding Pipeline Security Annex. PHMSA has addressed all three recommendations in the OIG report to Congress on DOT actions to implement the pipeline security annex between DOT and the DHS. We finalized the action plan for implementing the annex. We formalized each agency's security roles and responsibilities and helped develop a Pipeline Security Incident Response Protocols plan for responding to potential terrorist actions. We coordinate efforts to minimize duplicative security inspections and we have almost daily communication with DHS concerning pipeline safety events and security incidents.

In the PIPES Act, Congress also requested that PHMSA undertake certain studies to attend to specific concerns brought to light by certain natural disasters and the aging infrastructure of the pipeline system. We appreciate the opportunity to show Congress that we are working diligently with our stakeholders and other governmental departments to address petroleum capacity, leak detection, and internal corrosion concerns, as well as to determine appropriate risk assessment intervals. PHMSA has conducted and reported to Congress on all the required studies.

Petroleum Capacity Market Study. On June 1, 2008, PHMSA submitted to Congress a final report on the domestic transport capacity of petroleum products by pipeline and to reduce the likelihood of shortages of petroleum products or price disruptions due to shortages of pipeline capacity.

Leak Detection Systems Study. On June 23, 2009, PHMSA submitted to Congress a final report describing the capabilities and limitations of leak detection systems used by hazardous liquid pipeline operators. The report also discusses ongoing investment by PHMSA and research to improve the sensitivity of leak detection technology, particularly for hazardous liquid operators. As we stated in the report, PHMSA has adequate oversight to evaluate the leak detection capability of individual operators and has exercised authority as needed to compel systems upgrades where warranted.

Internal Corrosion Control Regulations Study. In June 2009, PHMSA submitted to Congress a final report of its thorough review of the Federal pipeline safety internal corrosion control regulations, accident history, research findings, and consensus standards to determine if such regulations are adequate. Although we found that existing regulations are generally sufficient to achieve safety and environmental protection goals, we were also considering other near- and long-term actions to further reduce the risk of internal corrosion.

Seven-Year Risk Assessment Study. In November 2007, PHMSA reported to Congress on its review of the GAO report on the seven-year assessment interval.

II. Building on a Solid Foundation

PHMSA is building a solid foundation to advance pipeline safety. That said, we are committed to completing the two remaining initiatives authorized by PIPES Act—completing the notice of proposed rulemaking to regulate low stress pipelines this year, and taking the next step to implement Federal enforcement of third party excavation damage to pipelines.

PHMSA has accomplished many goals with its state partners; at the same time however, it is important that states continue to receive the resources they need to implement not only damage prevention initiatives but the distribution integrity management program.

PHMSA also plans to update its enforcement strategy and penalties to deter future noncompliance and incentivize better performance. We continue to make full use of the increased administrative civil penalty authority granted in the Pipeline Safety Improvement Act of 2002. It is evident from the comparable periods before and after the PIPES Act, PHMSA has doubled the proposed pipeline safety administrative civil penalties it issued to operators, and the average per case has more than tripled. Specifically, between 2004 and 2006, PHMSA proposed $10 million in administrative civil penalties, with an average proposed civil penalty of $57,000; and, between 2007 and 2009, PHMSA proposed $19 million in administrative civil penalties and an average proposed civil penalty of $183,000. Furthermore, the average administrative civil penalty proposed per individual violation[1] has increased from approximately $16,000 in 2002 to an average of approximately $100,000 today. PHMSA issues operators proposed administrative civil penalties for probable violations identified during inspections or investigations. Proposed penalties are communicated to operators in Notices of Probable Violation and operators have the right to respond to these allegations before a penalty is assessed in a Final Order. Penalties are an effective tool to ensure operator accountability, but the current cap on PHMSA's administrative civil penalties of up to $100,000 per violation, per day and up to $1 million for a related series of violations may limit PHMSA's enforcement efforts.

We look forward to seeing our integrity management programs continue to mature and yield results. With this in mind we will continue to look at performance measures and ways we can improve the data that we collect. Having better data will enable us to make risk based informed regulatory decisions.

With the anticipated increase in transportation of new products like ethanol, hydrogen, carbon dioxide, and potentially other bio-fuels, we are working to ensure a solid regulatory framework to prevent accidents and ensure safety. We currently regulate pipelines transporting ethanol blends and to the extent new biofuels are developed in the future that involve pipeline transportation, PHMSA is committed to taking whatever steps are necessary to ensure that such transportation will be conducted safely. We coordinate with other Federal agencies to forecast the transportation implications from the inception of marketing new fuels, as part of a sys-

[1] Each Notice of Probable Violation case usually contains multiple individual violations.

temic oversight process. We coordinate with other countries to benefit from their experience. We continue to work with individual operators, identifying safety concerns that must be satisfied, both with the infrastructure and with the surrounding community. For example, ethanol poses very unique emergency response challenges, and PHMSA is responsible for helping communities prepare. We have also been a part of the interagency Carbon Capture and Sequestration Task Force in which issues related to carbon dioxide pipeline transportation are being addressed. We collaborate with the pipeline industry, the renewable fuels organizations, and others like emergency responder organizations and the National Commission on Energy Policy, to investigate and solve technical challenges.

III. Responding to Current Challenges

While PHMSA is gearing up to deal with the new challenges we expect to see through an increased use of pipelines to transport renewable fuels, we are continuing to exert vigilant and visionary leadership to remain steps ahead of the pipeline safety issues we're faced with today.

A. PHMSA Coordinates With Federal, State, Local and Private Parties to Respond to and Investigate Pipeline Accidents and Incidents

PHMSA has established strong relationships with other organizations involved in responding to pipeline incidents and emergencies. When we respond to an incident, our primary concern is the public's safety and to determine an operator's compliance with PHMSA regulations. We are often times requested to share information and support the investigations of other agencies, including the National Transportation Safety Board, the U.S. Chemical Safety and Hazard Investigation Board, the Occupational Safety and Health Administration and other Federal, State, and local response agencies. PHMSA staff remains in constant contact with the Transportation Security Administration to share information related to pipeline and other transportation failures to identify each agency's jurisdictional authority, roles, and responsibilities. In addition, PHMSA has a long history of working closely with local emergency officials in response to pipeline emergencies and our staff effectively participates in incidents where there is an Integrated Command System.

B. PHMSA Provides Routine Training to Staff on Ethics

PHMSA employees must understand that clear lines exist between being a regulator and the regulated. We want to ensure our employees are clear on what current Federal policies exist on accepting gifts, dealing with prohibited sources, responding to bribes, and other ethics related issues. Employees are trained on Federal ethics guidelines when initially becoming a new PHMSA employee. PHMSA inspectors and other staff are also provided annual refresher training on ethics standards, and on a periodic basis on relevant ethics topics.

C. PHMSA is Reminding Operators of Their Obligations to Have an Effective Oil Spill Response Plan

The events in the Gulf are a clear reminder of the devastating impact a serious oil spill can have on the environment and human activities. PHMSA recently issued an advisory bulletin to operators of onshore oil pipelines and facilities to remind them of their responsibilities under the Federal Water Pollution Control Act. In the advisory, owners and operators of oil transport systems are advised of their responsibility to have and to periodically review and update their facility oil spill response plan to reduce the environmental impact of oil discharges. PHMSA regulations require onshore oil pipeline operators to prepare, review, and update oil spill response plans for their facilities periodically, and whenever significant changes may occur. The advisory requires operators to review their facility response plans in view of the Gulf incident to ensure they comply with all applicable requirements. Once an operator reviews its plan and indicates changes are necessary, they must update and submit those plans to PHMSA. If no changes are necessary, operators must notify us that the review has occurred.

D. PHMSA is Preparing an Offshore Pipeline Action Plan

PHMSA is in the process of reviewing its current policies and procedures related to all offshore pipelines to determine what actions should be taken to improve its oversight of those pipelines. In addition, PHMSA is currently in stage one of a three stage process to conduct an integrated inspection of BP Pipeline North America's U.S. assets, including the company's 6,800-mile pipeline system. Stage one of the BP integrated inspection involves assembling and analyzing a considerable amount of data covering BP's system to understand recent inspection history, safety performance, and processes and procedures. After the pre-inspection phase is complete, PHMSA's integrated inspection team will be better equipped to develop an inspection plan that is focused on BP's higher risks areas to assure compliance and improve performance.

In closing, we look forward to working with Congress to address these issues and to reauthorize the pipeline safety program. PHMSA very much appreciates the opportunity to report on the status of our progress with PIPES Act implementation and I am committed to full compliance. Thank you. I would be pleased to answer any questions you may have.

Senator LAUTENBERG. Thank you very much.

Ms. Hersman, we're pleased to hear from you, the Chairman of the National Transportation Safety Board, and we welcome you back to the Subcommittee. We look forward to hearing from you.

STATEMENT OF HON. DEBORAH A.P. HERSMAN, CHAIRMAN, NATIONAL TRANSPORTATION SAFETY BOARD

Ms. HERSMAN. Thank you, Chairman Lautenberg, Ranking Member Thune, and Senator Johanns. Thank you for the opportunity to address the Committee on the important issue of pipeline safety.

The NTSB is responsible for determining the probable cause of accidents and issuing recommendations to prevent them from happening again. Our responsibilities also include evaluating the effectiveness of safety programs of other agencies, including PHMSA. PHMSA has made significant improvements in the last 5 years, in large part because of statutory mandates in the Pipeline Safety Improvement Act of 2002, as well as the PIPES Act of 2006. In general, PHMSA has been responsive to NTSB's pipeline safety recommendations. Between January 1, 2002, and January 1, 2010, the NTSB issued 24 recommendations to PHMSA. As of today, only eight of those recommendations remain open and only one issued prior to 2002 remains open.

PHMSA's more notable accomplishments include regulations addressing integrity management programs for gas transmission, hazardous liquid, and natural gas distribution lines, regulations for improved education among emergency response agencies and the public, and the implementation of the 811 One-Call system.

Yet, there are some areas of concern that remain. One of these concerns gained much attention following corrosion failures on a BP Exploration low-stress pipeline serving the Trans-Alaska Pipeline in 2006. The leak along this low-stress pipeline resulted in more stringent PHMSA regulations, but these regulations overlook most low-stress and on-and offshore gathering pipelines, leaving thousands of miles of pipelines unregulated.

However, just this past week, PHMSA outlined safety requirements for all rural low-stress pipelines not already covered. The NTSB applauds these efforts, and we look forward to evaluating their proposal in greater detail.

Another area of concern is risk-based pipeline safety programs, which provide operators with the responsibility to develop, implement, and evaluate individual programs and plans. PHMSA has the responsibility to review these plans for regulatory compliance and to conduct audits to evaluate their effectiveness. However, in recent pipeline investigations, the NTSB has seen indications that PHMSA and operator oversight have not been adequate.

This photo is from a November 1, 2007, rupture of a propane pipeline in Carmichael, Mississippi, which resulted in two fatalities and seven injuries and property damage exceeding $3 million. It is the responsibility of the pipeline operator to raise public awareness about the pipeline. The operator in this case hired two contractors to administer its program, but the mailing list did not include all of the residential addresses within the mailing area. The mistake was not caught until after the accident. The NTSB recommended that PHMSA initiate a review of all public education programs.

Likewise, consideration of pipeline leak history is an important factor in an operator's integrity management plan. But in a 2004 Kingman, Kansas, pipeline rupture, we discovered that the operator left out the leak history. PHMSA did not identify that history in their oversight, resulting in a deferred inspection. The pipeline ruptured 2 years before it was scheduled for an inspection.

In 2009, in Palm City, Florida, an 18-inch diameter gas transmission pipeline ruptured in the busy Florida Turnpike right of way. Luckily, there were no fatalities. But, as you can see from this photograph, the explosion created a crater over 110 feet long and 17 feet wide. The pipeline operator had not properly identified this location, and it was not covered in their integrity management plan. We're still investigating this accident to determine the cause of this oversight.

As a result of these accidents and other investigations, the NTSB believes that PHMSA must establish a more aggressive oversight framework so that risk-based integrity management programs are not only effectively designed, but effectively executed as well.

We have a strong working relationship with PHMSA, and we find PHMSA in most cases to be a responsive partner in protecting the public wellbeing. However, as I stated today, there are a few issues that remain of concern to the NTSB, which we hope to see PHMSA address in the near future.

Thank you, and I look forward to answering your questions.

[The prepared statement of Ms. Hersman follows:]

PREPARED STATEMENT OF HON. DEBORAH A.P. HERSMAN, CHAIRMAN, NATIONAL TRANSPORTATION SAFETY BOARD

Introduction/Overview

Chairman Lautenberg, Ranking Member Thune, members of the Subcommittee, thank you for the opportunity to address you today on the reauthorization of the U.S. Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA). PHMSA has made significant progress over the past 5 years. Much of the credit for this success is due to the implementation of statutory mandates included in the Pipeline Safety Improvement Act of 2002, as well as the Pipeline, Inspection, Protection, Enforcement and Safety (PIPES) Act of 2006.

PHMSA has been responsive to the National Transportation Safety Board's (NTSB) pipeline safety recommendations. Between January 1, 2002, and June 1, 2010, the NTSB issued twenty-four pipeline recommendations to PHMSA. As of this date, nine remain open and fifteen have been closed following a NTSB assessment that PHMSA had taken an "acceptable action" or "acceptable alternate action" in response to the recommendation. None were closed with the categorization of "unacceptable action." Additionally, only one recommendation issued prior to 2002 remains open.

Noteworthy accomplishments by PHMSA include implementing regulations addressing integrity management programs for gas transmission pipelines, hazardous liquid pipelines, and natural gas distribution pipeline systems. Regulations and improved industry practices also are in place for expanded public awareness and education programs meant to heighten the awareness of the American public and regional emergency response agencies. The implementation of the 811 one-call system requires the identification and marking of buried pipelines before excavation work occurs.

Additionally, partnerships between the industry and PHMSA have led to a number of joint initiatives, such as development of training programs for public and municipal officials, enhanced collection and analysis of accident data, and greater coordination with state agencies that have been delegated enforcement authority by PHMSA for Federal pipeline safety standards.

As a result of the NTSB's 2005 Safety Study, *Supervisory Control and Data Acquisition (SCADA)in Liquid Pipelines,* the Board issued Safety Recommendations P–05–1 through –3 which called on PHMSA to: (1) require hazardous liquid pipeline operators to follow the American Petroleum Institute's recommended practice for the use of graphics on SCADA computer screens, (2) require pipeline companies to have a policy for the review and audit of SCADA alarms, and (3) require training for pipeline controllers to include simulator or noncomputerized simulations for controller recognition of abnormal operating conditions, particularly leak events. These three recommendations were also incorporated directly into the PIPES Act. PHMSA published a final rule on December 4, 2009, that included the recommended requirements and applied them to all pipeline systems.

Despite these notable and varied accomplishments, NTSB has concerns about certain other aspects of PHMSA's pipeline safety program. Two such areas specifically addressed in the PIPES Act are the regulation of low-stress pipeline systems and requirements for the use of excess flow valves.

Regulation of Low-Stress Pipeline Systems

Corrosion failures on the BP Exploration, Inc.'s, low-stress oil transit lines from the Prudhoe Bay oil fields to the Trans Alaska pipeline in 2006 raised concerns among Members of Congress about the potential pollution of environmentally sensitive areas. As a result, Congress included provisions in the PIPES Act mandating that PHMSA issue regulations subjecting low-stress hazardous liquid pipelines near unusually sensitive environmental areas to the same standards and regulations as other hazardous liquid pipelines. Low-stress pipelines are those that are operated at a stress level of 20 percent or less of their strength ratings.

At the time the PIPES Act was enacted, Federal pipeline safety regulations only applied to low-stress pipelines that were located in populated areas, crossed navigable waterways, or carried highly volatile liquids, such as compressed liquefied propane. In a Notice of Proposed Rulemaking (NPRM), "Pipeline Safety: Protecting Unusually Sensitive Areas from Rural Onshore Hazardous Liquid Gathering Lines and Low-Stress Lines", published on September 6, 2006, PHMSA proposed regulations for rural low-stress pipelines that have a diameter of at least 8⅝ inches and that are within ¼ mile of an area defined as unusually sensitive. (The distance in the final rule is ½ mile.)

The NPRM also proposed regulations for rural gathering lines that operate at a stress level greater than 20 percent, have a diameter between 6⅝ and 8⅝ inches and are within ¼ mile of an area defined as unusually sensitive. A "gathering line" is a pipeline with a diameter of 8⅝ inches or less that transports petroleum from a production facility. Again, at the time the PIPES Act was enacted, only gathering lines in populated areas were subject to Federal pipeline regulations.

Exempted from the proposed requirements in the NPRM were gathering lines in the inlets of the Gulf of Mexico. Certain gathering lines in inlets of the Gulf of Mexico are subject to burial requirements to ensure that the lines are not exposed and do not pose a hazard to navigation. Otherwise, they are not regulated.

In comments submitted by the NTSB on November 21, 2006, we note that most low-stress pipelines and on- and off-shore gathering pipelines would remain essentially unregulated. The NTSB also notes that the NPRM would apply a less stringent patchwork of requirements to address corrosion and excavation damages to those low-stress pipelines and gathering pipelines covered by the proposed standards. The NTSB states its belief that the standards codified in Title 49 Code of Federal Regulations, Part 195 for hazardous liquid pipelines should also apply in its entirety to the low-stress pipelines and gathering lines. PHMSA published the final rule on June 3, 2008, without significant change to the NPRM. Publication of this final rule concluded phase one of PHMSA's two phase plan to implement its PIPES mandate to regulate low-stress pipelines.

On June 22, 2010, PHMSA published a second NPRM regarding the regulation of all rural onshore hazardous liquid low-stress pipelines. This second NPRM represents phase two of PHMSA's implementation of its mandate in the PIPES Act. In this NPRM, PHMSA proposes safety requirements for all rural low-stress pipelines not included under the phase one final rule. Specifically, the low-stress pipelines captured under the new NPRM include: (1) rural low-stress pipelines of a diameter less than 8⅝ inches located in or within one-half mile of an unusually sensitive area and (2) all other rural low-stress pipelines that were not included under phase one. PHMSA estimates that the NPRM will apply to 1,384 miles of low-stress pipelines not covered by the previous rule. It appears this latest NPRM will apply to onshore gathering lines that are also low-stress pipelines. However, the NPRM does not address gathering lines in the inlets of the Gulf of Mexico or offshore gathering lines. The NTSB has not had the opportunity to evaluate fully the specific requirements proposed in the NPRM; however, we will submit comments to PHMSA.

The tragedy in the Gulf of Mexico involving the *Deepwater Horizon* drilling platform is a grim reminder of the damage that a major oil spill can cause. While the magnitude of the *Deepwater Horizon* spill is far greater than any known pipeline failure, the events in the Gulf should remind those involved in the pipeline industry that all pipelines must be sufficiently safeguarded and regulated in order to protect the public and the environment.

Integrity Management Programs for Distribution Systems and the Use of Excess Flow Valves

The PIPES Act also mandates that DOT prescribe minimum standards for integrity management programs for distribution pipeline systems. On June 25, 2008, PHMSA published a NPRM, "Integrity Management Program for Gas Distribution Pipelines," with proposed regulations that would require operators of gas distribution pipelines to develop and implement integrity management programs with the same objectives as the existing integrity management programs for hazardous liquid and gas transmission pipelines.

Integrity management programs for hazardous liquid and gas transmission pipelines typically require operators to assess the condition of their pipelines by using "in-line" inspection tools that travel through the pipeline to determine the nature and extent of any defects or pressure testing that yields information about the integrity of the pipeline. Such techniques are not feasible for typical distribution pipeline systems because of the differences in the design and operating parameters between distribution pipeline systems and hazardous liquid and gas transmission pipelines.

Further, the failure of a distribution pipeline is often initially detected from reports of a gas leak rather than a catastrophic rupture. As result, development and implementation of an effective leak management program is an important element of an integrity management program for a distribution pipeline.

PHMSA acknowledged these differences in the NPRM and properly emphasized the importance of various leak detection methods as essential elements of an integrity management program for distribution pipeline systems.

In its comments on the NPRM, the NTSB emphasized that while an effective leak detection program is a crucial element of the overall leak management program, the use of equipment that prevents or mitigates leaks is equally important. One such device that mitigates a gas pipeline leak is an "excess flow valve." An excess flow valve is a device installed on the distribution line, usually serving a user residence or facility, that detects an abnormally high flow rate, and when an excess flow is detected, automatically closes a valve, thus shutting off the flow of gas through the distribution line. The NPRM did not adequately address this aspect of leak management, other than incorporating the mandate for PHMSA to require excess flow valves on new or replacement distribution lines serving single-family residences. PHMSA complied with this provision of the PIPES Act on December 4, 2009, when it published the final rule on integrity management programs for distribution pipeline systems.

The NTSB has long advocated the use of excess flow valves in gas distribution pipeline systems as an effective means of preventing explosions caused by natural gas leaking from distribution systems. On July 7, 1998, a natural gas explosion and fire destroyed a newly constructed residence in South Riding, Virginia, a suburb of Washington. The accident caused one fatality and one serious injury. The NTSB determined that the gas service line to the home had failed and that an uncontrolled release of gas had accumulated in the basement and subsequently ignited. The NTSB concluded from its investigation that had an excess flow valve been installed in the service line, the valve would have closed shortly after the hole in the service line developed and the explosion likely would not have occurred. The NTSB recommended that PHMSA require excess flow valves be installed in all new and renewed gas service lines, regardless of a customer's classification, when the operating conditions are compatible with readily available valves. The NTSB believes that apartment buildings, other multifamily dwellings, and commercial properties are susceptible to the same risks from leaking gas lines as single-family residences, and we believe this gap in the law and the regulations should be eliminated.

Oversight of Integrity Management and Other Risk-Based Pipeline Safety Programs

Over the past decade or more, PHMSA has adopted a risk-based assessment approach for regulating the DOT pipeline safety program. PHMSA has successfully built a partnership with various facets of the pipeline industry to develop, implement and execute a multi-part pipeline safety program. All stakeholders, including PHMSA, have, in the NTSB's view, come to rely heavily upon this approach. The NTSB believes that a risk-based approach can be an effective method to develop and execute the pipeline safety program, and there are many positive elements to PHMSA's approach.

The DOT pipeline safety regulations based on risk assessment principles provide the structure, content, and scope for many aspects of the overall pipeline safety program. Within this regulatory framework, pipeline operators have the flexibility and responsibility to develop their individual programs and plans, determine the specific performance standards, implement their plans and programs, and conduct periodic self-evaluations that best fit their particular pipeline systems. PHMSA likewise has the responsibility to review pipeline operators' plans and programs for regulatory compliance and effectiveness.

The NTSB believes that with the risk-based assessment there should be increased responsibilities on both the individual pipeline operators and PHMSA. Operators must diligently and objectively scrutinize the effectiveness of their programs, identify areas for improvement, and implement corrective measures. PHMSA, as the regulator, must also do the same in its audits of the operators' programs and in self-assessments of its own programs. In short, both operator and regulator need to verify whether risk-based assessments are being executed as planned, and more importantly, whether these programs are effective.

In its recent pipeline investigations, the NTSB discovered indications that PHMSA and operator oversight of risk-based assessment programs, specifically integrity management programs and public education programs, has been lacking and has failed to detect flaws and weaknesses in such programs.

In its investigation of the October 2004, rupture of an anhydrous ammonia pipeline near Kingman, Kansas, the NTSB identified deficiencies in PHMSA's auditing procedures when evaluating the operator's integrity management program. The operator did not include assessments of leak history when calculating relative risk scores for various segments of the pipeline. These relative risk scores were used to establish an initial baseline assessment of the integrity of the pipeline in the decisionmaking process for prioritizing the inspection schedule. Though PHMSA did find omissions of other risk factors during its review of the operator's integrity management program, PHMSA did not identify the omission of the leak history data during its initial review or during a subsequent review of the corrected plan. Consequently, the ruptured pipeline segment was not scheduled for a baseline assessment until 2006, almost 2 years after the October 27, 2004, rupture. The NTSB recommended that PHMSA require an operator to revise its pipeline risk assessment plan whenever it has failed to consider one or more risk factors that can affect pipeline integrity.

The November 1, 2007, rupture of a propane pipeline in Carmichael, Mississippi, resulted in two fatalities, seven injuries, and property damage exceeding $3 million. Before the accident, the pipeline operator relied upon contractors to obtain accurate mailing data and ensure that mailings to the public were completed. However, the operator did not perform oversight to ensure that all appropriate recipients were on the mailing lists and that the mailings met appropriate regulatory requirements. The operator also had not taken any action to determine whether recipients who received the mailings understood the guidance they contained. The NTSB determined that the pipeline operator failed to properly assess its public awareness and education program by relying upon contractors without appropriate oversight. The NTSB recommended that PHMSA initiate a program to evaluate pipeline operators' public education programs, including the operators' self-evaluations of the effectiveness of their public education programs.

On May 4, 2009, an 18-inch diameter gas transmission pipeline with an operating pressure of 850 psi ruptured near Palm City, Florida. The rupture was located in the Florida Turnpike right-of-way, between I–95 and the Florida Turnpike. The turnpike and interstate were closed for approximately 3 hours due to the accident. Two gas transmission pipelines operated by the same pipeline company were also located in the right-of-way but were reportedly not damaged.

The force of the released gas created a crater approximately 116.5 feet long by 17 feet wide by approximately 2.8 feet deep. Roughly 104 feet of the pipe was ejected from the ruptured pipeline and landed next to the crater. The closest edge of the crater was approximately 25 feet from the northbound paved edge of the Florida Turnpike.

There was no ignition of the released gas, and no fatalities were reported. However, two people were injured when their car reportedly hit debris, ran off the road, and turned over; a Deputy Sheriff was hospitalized after walking through a gas cloud; and the accident resulted in the evacuation of a nearby school and residential community.

The NTSB's ongoing investigation has determined that at the time of the accident, the operator had not identified the ruptured segment as located within a high consequence area, and therefore not covered by the operator's integrity management plan. However, an independent evaluation done by PHMSA at the NTSB's request shows the segment in fact is in a high consequence area. The NTSB is collecting documentation that will determine the cause of this error.

As a result of these investigations, the NTSB is concerned that the level of self-evaluation and oversight currently being exercised is not uniformly applied by some pipeline operators and PHMSA to ensure that the risk-based safety programs are effective. The NTSB believes that to ensure effective risk-based integrity management programs are employed throughout the pipeline industry, PHMSA must establish an aggressive oversight program that thoroughly examines each operator's decisionmaking process for each element of its integrity management program.

Recent Accidents in Texas

The two most recent pipeline accidents in Cleburne, Texas and Darrouzett, Texas, involved third-party excavation damage resulting in ruptures, fires, and explosions. Preliminary information from both investigations indicates that prior to the start of excavation activities, neither pipeline was marked or identified. Both investigations will determine the reasons why and how these lapses occurred.

Cleburne, TX Summary

On June 7, 2010, a natural gas transmission pipeline measuring 36-inches in diameter near Cleburne, Texas was struck and ruptured by a contractor for an electrical cooperative that was installing a pole for a power line. One member of the contractor's crew was drilling a hole while operating an auger affixed to a truck when the auger struck and punctured the transmission pipeline. An ignition and explosion of the escaping gas resulted, and the operator of the auger was killed. Six other crewmen were hospitalized.

The accident pipeline had a nominal wall thickness of 0.5-inch. The pipeline was operating at 950 psi at the time of the accident. The maximum allowable operating pressure is 1,050 psi. The pipeline, constructed in 1971, is 388 miles long, originating in Coyanosa, Texas and terminating in Ennis, Texas.

A second pipeline operated by a different pipeline company also traversed the accident area. Workmen in the area reported that they saw markers for the second pipeline. A NTSB investigator and Texas Railroad Commission personnel visiting the site also observed markers for the second pipeline, but the ruptured pipeline was not marked.

The NTSB is currently investigating this accident with the assistance of PHMSA and the Texas Railroad Commission (the state regulatory agency for pipeline safety).

Darrouzett, TX Summary

(The NTSB delegated the on-scene investigation of this accident to the Texas Railroad Commission, which is the state agency responsible for regulation of intrastate pipelines.)

On June 8, 2010, a natural gas nonregulated gathering line measuring 14-inches was struck by a third-party contractor near Darrouzett, Texas. The maximum allowable operating pressure of the gathering line was 700 psi; the line was operating at approximately 500 psi. The line begins in Follett, Texas, travels into Oklahoma, continues west and then returns to Texas near the Hansford/Sherman County area. The line is fed by many gathering lines in the area and ends at the plant in Sherman, Texas.

At the time of the incident, six contractor personnel were working in the area. Two persons were killed, one critically injured, and three others escaped injury. A bulldozer working in a caliche pit struck the 14-inch natural gas pipeline sometime before 4 p.m. The pipeline operator's SCADA system picked up a pressure loss and began closing valves to isolate the ruptured section of the pipeline. The fire was extinguished by 8 p.m.

Preliminary information from the Texas Railroad Commission indicates that the excavator had not requested a permit to work in the area or that there were any pipeline markers at the accident scene. The accident gathering line is not regulated under DOT pipeline regulations.

PHMSA accident statistics over the past decade (2000–2009), identify corrosion as the leading cause of all reported pipeline accidents. The second leading reported cause is damage from third-party excavators. Despite the focus on one-call systems, marking of pipelines prior to excavation, and other measures, the two accidents in Texas are a reminder that excavation damage remains a serious concern.

Closing

In summary, PHMSA has made great strides in addressing a number of matters mandated by Congress in the Pipeline Safety Improvement Act of 2002, as well as the Pipeline, Inspection, Protection, Enforcement and Safety Act of 2006. The NTSB believes more can be done in these areas and looks forward to a constructive dialogue with PHMSA and DOT as we advance the interests of pipeline safety, and thus the safety of people living and working near, and receiving service from, our Nation's pipelines.

This concludes my testimony and I would be happy to answer any questions you may have.

Senator LAUTENBERG. Thank you very much.

We are alerted to the fact that at about 3 o'clock a vote may occur, so we'll try to stick to our time limitations here.

Ms. Quarterman, despite the moratorium on offshore drilling, today's *New York Times* reports that BP is planning to move forward with a risky drilling project off the coast of Alaska. This is at a depth of 24,000 feet and several miles of horizontal pipe to connect to the TransCanada Pipeline. In May your agency warned BP that it was in probable violation of Federal standards because of corrosion on the Endicott Pipeline to which this new project connects.

Given BP's track record of irresponsibility and carelessness, do you think that this project should be stopped?

Ms. QUARTERMAN. Mr. Chairman, as you're aware, PHMSA is responsible for pipeline safety regulations. We are not responsible for the actual project that's at issue here in the North Slope. I believe that is within the Department of Interior's jurisdiction.

I can tell you that, as a result of the *Deepwater Horizon* incident, we at PHMSA have taken a very strong look at BP, and within the past couple of weeks I have spoken with, met with, the President of BP North America Pipelines and explained to him that we would be looking very closely at their program, we would be doing an integrated inspection of their entire system, and that we are going to be very focused over the next year looking at them.

With respect to the particular pipeline at issue, I believe that we have issued a warning letter to BP with respect to the Endicott Pipeline on the North Slope, and they have sent in a response. We are planning a field inspection this year to verify whether or not that has been adequately addressed.

Senator LAUTENBERG. We have to be on constant alert there.

Ms. QUARTERMAN. Absolutely.

Senator LAUTENBERG. Ms. Hersman, PHMSA is responsible for overseeing pipeline construction and transportation, while the Federal Energy Regulatory Commission is responsible for approving the location of the pipeline. I ask you and I'll ask Ms. Quarterman, how can communities best determine the real impact of a proposed pipeline when two agencies with different regulations are responsible for overseeing pipelines?

Ms. HERSMAN. Mr. Chairman, the Safety Board has not investigated any accidents where the siting has been a particular issue, but we have investigated a number of accidents where we expressed concern about pipeline issues. A proposed pipeline between

New Jersey and Manhattan, just like any other pipeline, deserves attention. It's going to be in a high-consequence area. It's a very populous urban area. There are potentially going to be three river crossings. There are many challenges with respect to siting any pipeline in those kinds of conditions.

We would want to make sure that they have adequate remote control shutoff valves, that they have corrosion detection, and that the pipeline is marked. I would defer to Administrator Quarterman on how they would oversee that construction.

Senator LAUTENBERG. Yes. The question is one of approving the location. How can we get that done when two agencies with different regulations are responsible? Ms. Quarterman?

Ms. QUARTERMAN. As I'm sure you're aware, the FERC is responsible for siting of natural gas pipeline facilities and we at PHMSA on the staff level try to work closely with them in helping their evaluation. We do have state contacts that go out to their hearings, their public hearings, and answer any safety-related questions. However, not having jurisdiction over the siting portion of that, we really cannot speak to the siting issues. We try to coordinate with FERC as much as possible. I'm scheduled to meet with the chairman the beginning of next month.

Senator LAUTENBERG. Ms. Hersman, in quick form, the NTSB has long recommended the installation of excess flow valves on all new and renewed natural gas service lines. In 2006, in the PIPES Act, I included the requirement that excess flow valves be installed on gas lines that serve single-family homes. How can excess flow valves be effectively installed in apartment buildings or multiple dwellings and commercial buildings?

Ms. HERSMAN. Mr. Chairman, in quick order, the Safety Board thinks that excess flow valves should be installed as widely as possible, including multi-dwelling residences, such as apartment buildings, and commercial and industrial facilities. That is the only recommendation prior to 2002 that remains in an open status to PHMSA, because, even though the PIPES Act required single-family dwellings to be equipped, we think that requirement doesn't go far enough and we'd like to see it universally applied.

Senator LAUTENBERG. We need your help there.

Senator Johanns.

Senator JOHANNS. Thank you, Mr. Chairman.

The mission statement of the Office of Pipeline Safety indicates that environmental safety is within their jurisdiction. In fact, quoting from that mission statement, it says: "OPS is the primary Federal regulatory agency responsible for ensuring the safe, reliable, and environmentally sound operation of America's energy pipelines."

Mr. Weimer—and I hope I'm pronouncing that correctly—in his testimony says that he's concerned that PHMSA is not involved enough in the siting and environmental review process and expresses that concern. In fact, I think he even uses the words that it's "disconnected."

Now, as I said in my opening statement, there's a pipeline project coming through Nebraska. Part of it goes over the Ogallala Aquifer. I'm very familiar with that. I can tell you that in some areas the water table is high enough where if you dug a fencepost hole, if you know what I'm talking about, it would fill with water. So you worry that that pipe literally is transmitting oil right through the water table right over the Ogallala Aquifer.

What assurance can you give me—and then I want to add one other qualifier. I understand that this project involves a Canadian company, so I think this is managed or oversight is provided by the Department of State, further complicating matters. Tell me how PHMSA fits into this and what kind of oversight you would provide? Do you feel like you've been a player in this process?

Ms. QUARTERMAN. I believe you're referring to the TransCanada Keystone XL Project.

Senator JOHANNS. Right.

Ms. QUARTERMAN. And that is one that originates in Canada and comes down to the United States through your state. Within the United States, the FERC does have jurisdiction over siting of gas pipelines. However, it does not have jurisdiction over the siting of hazardous liquids pipelines under the Interstate Commerce Act. So the only authority, other than the states, at a Federal level who has any oversight into the siting of that project would be the Department of State. Because it does cross international lines, they have to provide a Presidential permit to be able to cross the border, and they are doing any environmental analysis associated with that.

Again, we would coordinate with them in terms of providing comments, but we are not a cooperating agency with them on their environmental impact statement. So our obligations would be, once the Department of State has approved this Presidential permit and the siting with the states, to ensure that the pipeline project, once it starts going into the ground, is safe in terms of the construction, the operation, the maintenance of the pipeline.

Senator JOHANNS. I must admit—and I'm not making any claims about this being unsafe. Maybe it's the safest pipeline ever going to be constructed in world history. But having said that, when I think of the State Department I think of them doing many great things. I'm not sure environmental assessment would have come to mind until I learned about this project. I think you're probably agreeing with me.

How can I assure Nebraska residents that an appropriate assessment has been done? Because I think of all of the expertise relative to pipelines in the Federal Government, I can't imagine it would be at the State Department.

Ms. QUARTERMAN. Well, I think that Nebraska, as a state, has a role to play in this process, certainly being involved in any scoping meetings that may go and getting the Nebraska authorities involved in siting of the project and determining whether or not the right of way is appropriate. That would be the only advice I could give at that level.

Senator JOHANNS. Are you Mr. Chairman?

STATEMENT OF HON. JOHN THUNE, U.S. SENATOR FROM SOUTH DAKOTA

Senator THUNE [presiding]. I guess so.

Senator JOHANNS. Gosh, that's surprising.

Senator THUNE. That's quite a thought.

Senator JOHANNS. I have run out of time, but let me just wrap up and say, none of this is very reassuring to me, and you understand why. This is a big project with significant issues. We've got a very, very important natural resource, and I just want to make sure it's properly assessed and protected, so when I'm asked about it I can say either you have something to worry about or you have nothing to worry about.

Senator THUNE. Senator Hutchison.

STATEMENT OF HON. KAY BAILEY HUTCHISON, U.S. SENATOR FROM TEXAS

Senator HUTCHISON. Thank you, Mr. Chairman. I'm sorry I was late because we had an Appropriations Committee hearing.

But I wanted to just say a couple of things. In the past few weeks, Texas has had two major fatal pipeline accidents, both of which were excavation accidents. Any excavation accident is a preventable one. So I wanted to ask you basically two questions. One is, do you think that we can improve on the One-Call system? Are there a number of states that don't participate in the One-Call system? And should we be doing something about that, to stop having exemptions from the One-Call system? That would be number one.

Number two, I'll submit my opening statement for the record, but the other thing of course, representing a coastal state, that I worry about is that the Pipeline Hazardous Materials Safety Administration regulates offshore transmission lines in state waters, but the Minerals Management Service has jurisdiction for offshore pipelines in the outer continental shelf. So I'm concerned that regulations might not be uniform, that there might be confusion when there is an accident about who does what. Is that a concern in your opinion, Ms. Quarterman or Ms. Hersman, and should we be dealing with that in this authorization?

Ms. QUARTERMAN. Well, first let me speak to the excavation damage issue. I fully agree with you that those two incidents were absolutely preventable and, had all the correct steps been taken both by the people excavating to call and the people owning the pipeline to mark the line and mark it correctly, that those incidents would not have occurred.

Since the PIPES Act of 2006, in about 2007, PHMSA worked to create the National 811 Number and has been providing funding to the Common Ground Alliance, which deals not only with pipelines but with other underground utilities, to support publishing information.

Senator HUTCHISON. What is the participation level of states? Is it high or is it low?

Ms. QUARTERMAN. The states are actually very, very much participating at a high level. Unfortunately, there are some states that have the exemptions that you refer to, and I have to say during my speeches to all the organizations that might be affected by this I repeatedly tell them the exemptions are not something that we believe are appropriate. For example, with respect to the State of Maryland, they were very recently creating a One-Call law and they were going to exempt the Department of Transportation. We called and talked to them and were able to help them come to the conclusion that wasn't the right decision.

We have a lot of work to do on some states. Some states are doing a fantastic job. But it is a gradual process. I think we could be doing a lot more if we had more funding on this. We are providing state damage prevention grants of about $2 million a year to all the states who come and request money to work on damage prevention. We also have $1 million in One-Call grants that go to the States as well. So there's a lot being done, but obviously until 8-1-1 becomes recognized the same as 9-1-1 we would not have done our job completely.

Senator HUTCHISON. On the coastal issue?

Ms. QUARTERMAN. Yes, on the coastal issue, the jurisdiction is somewhat confusing. PHMSA has two memoranda of understanding with the Department of Interior and with the Coast Guard and also with EPA with respect to, for example, oil spill response. One memorandum of understanding divides the authority on who should get oil spill response plans between those different agencies, and PHMSA gets the plans for onshore pipelines and MMS gets it for offshore pipelines and other offshore facilities. I think that maybe there's a piece of legislation under consideration to change that.

With respect to the jurisdiction over pipelines on the outer continental shelf, MMS has jurisdiction over those that are production pipelines, production-related facilities. PHMSA has those that are on the outer continental shelf that are transportation-related and the states have those that are in state water.

Senator HUTCHISON. Yes, I know. My time is up, so I won't pursue it further. But any input you can offer on this reauthorization that would help with those conflicts, I would appreciate.

Thank you, Mr. Chairman.

[The prepared statement of Senator Hutchison follows:]

PREPARED STATEMENT OF HON. KAY BAILEY HUTCHISON, SENATOR FROM TEXAS

Thank you, Senator Lautenberg, and thank you for holding this afternoon's hearing. It is certainly timely. The ongoing *Deepwater Horizon* crisis in the Gulf is an unfortunate wake-up call not only to oil production safety, but to the safety of the Nation's vast oil and gas pipeline system. While the safety record for pipelines has continued to improve, particularly when viewed in terms of exposure, it is important for our Committee to consider what more needs to be done as we begin the process of reauthorizing the Pipeline and Hazardous Materials Safety Administration, whose current authorization expires in September.

I also want to welcome of all our witnesses today. I will not be able to stay for the entire hearing, but will likely have follow-up questions for the witnesses after the hearing.

The oil and gas industry is a foundation of the Texas economy, and contributes greatly to the quality of life all Americans enjoy. Texas produces one quarter of the Nation's refined petrochemical products, and 30 percent of the Nation's natural gas supplies. It is not surprising, then, that Texas has more miles of pipeline than any other State—over 220,000 miles, located both on-shore and in the Gulf of Mexico. My constituents, therefore, have a very direct stake in pipeline safety.

In just the past few weeks, there have been two deadly gas pipeline accidents in Texas, both of which resulted from pipeline damage during excavation work. The accidents highlight the need to focus more attention on the national "One-Call" program. Every accident caused by excavation is a preventable accident, and I want to ensure to the extent I can, that the Texas Excavation Safety System (TESS), and the One-Call systems in other States, are consulted by all developers, construction companies, and others with a need to dig in the vicinity of a pipeline. "Call before you dig" can mean the difference of life or death.

Because of the *Deepwater* oil spill, I—and probably many of my colleagues—will also want to learn more about the safety regulations that apply to off-shore pipelines. For example, does it makes sense for PHMSA (fim-za) to regulate off-shore transmission lines in state waters, while the Minerals Management Service (MMS) has jurisdiction for off-shore pipelines in the Outer Continental Shelf? I am concerned that regulations may not be uniform and that in the event of an accident, there could be confusion about who is in charge. I would also like to understand what PHMSA, MMS, and the pipeline companies are doing to address the unique environment for underwater pipelines, including corrosion, and threats caused by vessels and hurricanes.

The last two reauthorizations of PHMSA have transformed how pipelines are regulated in this country, from a system of traditional enforcement by Federal and State inspectors, to a system built on "integrity management". Under integrity management, inspectors still conduct inspections, but the pipeline owners themselves must take responsibility for inspecting and making repairs to critical portions of their lines on a scheduled basis. Integrity management appears to be working well, but I will be interested in learning whether all of our panelists today agree.

Finally, I am interested the witnesses' recommendations, in particular those of Ms. Quarterman, for reauthorizing PHMSA. I hope the Administration will be sending Congress a formal proposal in the very near term. Thank you, Mr. Chairman.

Senator THUNE. Thank you, Senator Hutchison.

Let me, until the Chairman gets back from the vote, hopefully in the next few minutes, ask a couple of questions, and then I'm going to have to run and vote, too. But I do want to thank you for appearing here today.

Pipeline transportation is crucial to our Nation's economy. Without it, we don't have a way of meeting the energy needs of American homes and businesses. I think pipelines are going to play an important role in America's energy future, too. In South Dakota, as has already been referenced, the first of two TransCanada Pipelines was recently completed and is now transporting crude oil from Canada to markets in the Midwest. The second one, Keystone XL, is currently awaiting approval and could start construction as early as next summer, and once completed this pipeline is going to transport crude oil to markets in Oklahoma and the Gulf. So I want to come back to a question in just a moment about that.

But another area of interest that I think is important in terms of America's future energy requirements and our capability to meet those requirements is the development of some of these specialized pipelines to transport ethanol and biofuels. There's a company in South Dakota called POET, which is the world's largest producer of ethanol, and Magellan Midstream Partners, who together have proposed the construction of a 1,700-mile ethanol pipeline from South Dakota to the East Coast. Moving ethanol by pipeline would be cheaper, more efficient, and safer than moving the product by truck or rail as it is done today. I think that this ambitious and innovative proposal is very encouraging and exciting, particularly as we try to chart a course toward energy independence.

So a couple of questions on those subjects. One dealing with Keystone pipeline I would direct to you, Ms. Quarterman, and that is what requirements did PHMSA impose on Keystone in approving Keystone's request to operate the pipeline at a higher than normal pressure?

Ms. QUARTERMAN. Are you referring to Keystone 1?

Senator THUNE. Keystone 1. Well, Keystone 1 is the one that's completed.

Ms. QUARTERMAN. Yes.

Senator THUNE. So focus on that, because Keystone 2 is still in the process.

Ms. QUARTERMAN. We are actually reviewing a request for Keystone XL to have the same authorities. With respect to Keystone 1, there were additional requirements on that pipeline. I don't know them off the top of my head. I will have to provide you those for the record, but there were additional requirements.

[The information referred to follows:]

DEPARTMENT OF TRANSPORTATION

PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION (PHMSA)

Special Permit

Docket Number:	PHMSA–2006–26617
Pipeline Operator:	TransCanada Keystone Pipeline, L.P.
Date Requested:	November 17, 2006
Code Section(s):	49 CFR 195.106

Grant of Special Permit

Based on the findings set forth below, the Pipeline and Hazardous Materials Safety Administration (PHMSA) grants this special permit to TransCanada Keystone Pipeline, L.P. (Keystone). This special permit allows Keystone to design, construct and operate two new crude oil pipelines using a design factor and operating stress level of 80 percent of the steel pipe's specified minimum yield strength (SMYS) in rural areas. The current regulations in 49 CFR 195.106 limit the design factor and operating stress level for hazardous liquids pipelines to 72 percent of SMYS. This special permit is subject to the conditions set forth below.

Except for the non-covered portions of the pipelines described below, this special permit covers two proposed pipelines in the United States:

- The 1,025-mile, 30-inch, Mainline from the Canadian border at Cavalier County, North Dakota, traversing the States of South Dakota, Nebraska, Kansas and Missouri, to Wood River, Illinois; and
- The 291-mile, 36-inch, Cushing Extension from Jefferson County, Nebraska, through Kansas, to Cushing (Marion County), Oklahoma.

This special permit does not cover certain portions of the Mainline and Cushing Extension pipelines. These non-covered portions are the following:

- Pipeline segments operating in high consequence areas (HCAs) described as commercially navigable waterways in 49 CFR 195.450;
- Pipeline segments operating in HCAs described as high population areas in 49 CFR 195.450;
- Pipeline segments operating at highway, railroad and road crossings; and
- Piping located within pump stations, mainline valve assemblies, pigging facilities and measurement facilities.

For the purpose of this special permit, the "special permit area" means the area consisting of the entire pipeline right-of-way for those segments of the pipeline that will operate above 72 percent of SMYS.

Findings

PHMSA finds that granting this special permit to Keystone to operate two new crude oil pipelines at a pressure corresponding to a hoop stress of up to 80 percent SMYS is not inconsistent with pipeline safety. Doing so will provide a level of safety equal to, or greater than, that which would be provided if the pipelines were operated under existing regulations. We do so because the special permit analysis shows the following:

- Keystone's special permit application describes actions for the life cycle of each proposed pipeline addressing pipe and material quality, construction quality control, pre-in service strength testing, the Supervisory Control and Data Acquisition (SCADA) system inclusive of leak detection, operations and maintenance and integrity management. The aggregate affect of these actions and PHMSA's conditions provide for more inspections and oversight than would occur on pipelines installed under existing regulations; and

- The conditions contained in this special permit grant require Keystone to more closely inspect and monitor the pipelines over its operational life than similar pipelines installed without a special permit.

Conditions

The grant of this special permit is subject to the following conditions:

1. Steel Properties: The skelp/plate must be micro alloyed, fine grain, fully killed steel with calcium treatment and continuous casting.

2. Manufacturing Standards: The pipe must be manufactured according to American Petroleum Institute Specification 5L, *Specification for Line Pipe* (API 5L), product specification level 2 (PSL 2), supplementary requirements (SR) for maximum operating pressures and minimum operating temperatures. Pipe carbon equivalents must be at or below 0.23 percent based on the material chemistry parameter (Pcm) formula.

3. Transportation Standards: The pipe delivered by rail car must be transported according to the API Recommended Practice 5L1, *Recommended Practice for Railroad Transportation of Line Pipe* (API 5L1).

4. Fracture Control: API 5L and other specifications and standards address the steel pipe toughness properties needed to resist crack initiation. Keystone must institute an overall fracture control plan addressing steel pipe properties necessary to resist crack initiation and propagation. The plan must include acceptable Charpy Impact and Drop Weight Tear Test values, which are measures of a steel pipeline's toughness and resistance to fracture. The fracture control plan, which must be submitted to PHMSA headquarters, must be in accordance with API 5L, Appendix F and must include the following tests:

a. SR 5A—Fracture Toughness Testing for Shear Area: Test results must indicate at least 85 percent minimum average shear area for all X–70 heats and 80 percent minimum shear area for all X–80 heats with a minimum result of 80 percent shear area for any single test. The test results must also ensure a ductile fracture;

b. SR 5B—Fracture Toughness Testing for Absorbed Energy; and

c. SR 6—Fracture Toughness Testing by Drop Weight Tear Test: Test results must be at least 80 percent of the average shear area for all heats with a minimum result of 60 percent of the shear area for any single test. The test results must also ensure a ductile fracture.

The above fracture initiation, propagation and arrest plan must account for the entire range of pipeline operating temperatures, pressures and product compositions planned for the pipeline diameter, grade and operating stress levels, including maximum pressures and minimum temperatures for startup and shut down conditions associated with the special permit area. If the fracture control plan for the pipe in the special permit area does not meet these specifications, Keystone must submit to PHMSA headquarters an alternative plan providing an acceptable method to resist crack initiation, crack propagation and to arrest ductile fractures in the special permit area.

5. Steel Plate Quality Control: The steel mill and/or pipe rolling mill must incorporate a comprehensive plate/coil mill and pipe mill inspection program to check for defects and inclusions that could affect the pipe quality. This program must include a plate or rolled pipe (body and all ends) ultrasonic testing (UT) inspection program per ASTM A578 to check for imperfections such as laminations. An inspection protocol for centerline segregation evaluation using a test method referred to as slab macro-etching must be employed to check for inclusions that may form as the steel plate cools after it has been cast. A minimum of one macro-etch or a suitable alternative test must be performed from the first or second heat (manufacturing run) of each sequence (approximately four heats) and graded on the Mannesmann scale or equivalent. Test results with a Mannesmann scale rating of one or two out of a possible five scale are acceptable.

6. Pipe Seam Quality Control: A quality assurance program must be instituted for pipe weld seams. The pipe weld seam tests must meet the minimum requirements for tensile strength in API 5L for the appropriate pipe grade properties. A pipe weld seam hardness test using the Vickers hardness testing of a cross-section from the weld seam must be performed on one length of pipe from each heat. The maximum weld seam and heat affected zone hardness must be a maximum of 280 Vickers hardness (Hv10). The hardness tests must include a minimum of two readings for each heat affected zone, two readings in the weld

metal and two readings in each section of pipe base metal for a total of 10 readings. The pipe weld seam must be 100 percent UT inspected after expansion and hydrostatic testing per APL 5L.

7. Monitoring for Seam Fatigue from Transportation: Keystone must inspect the double submerged arc welded pipe seams of the delivered pipe using properly calibrated manual or automatic UT techniques. For each lay down area, a minimum of one pipe section from the bottom layer of pipes of the first five rail car shipments from each pipe mill must be inspected. The entire longitudinal weld seam must be tested and the results appropriately documented. For helical seam submerged arc welded pipe, Keystone must test and document the weld seam in the area along the transportation bearing surfaces and all other exposed weld areas during the test. Each pipe section test record must be traceable to the pipe section tested. PHMSA headquarters must be notified of any flaws that exceeded specifications and needed to be removed. Keystone's findings will determine if PHMSA will require the testing program be expanded to include a larger sampling population for seam defects originating during pipeline transportation.

8. Puncture Resistance: Steel pipe must be puncture resistant to an excavator weighing up to 65 tons with a general purpose tooth size of 3.54 inches by 0.137 inches. Puncture resistance will be calculated based on industry established calculations such as the Pipeline Research Council International's *Reliability Based Prevention of Mechanical Damage to Pipelines* calculation method.

9. Mill Hydrostatic Test: The pipe must be subjected to a mill hydrostatic test pressure of 95 percent of SMYS or greater for 10 seconds. Any mill hydrostatic test failures must be reported to PHMSA headquarters with the reason for the test failure.

10. Pipe Coating: The application of a corrosion resistant coating to the steel pipe must be subject to a coating application quality control program. The program must address pipe surface cleanliness standards, blast cleaning, application temperature control, adhesion, cathodic disbondment, moisture permeation, bending, minimum coating thickness, coating imperfections and coating repair.

11. Field Coating: Keystone must implement a field girth weld joint coating application specification and quality standards to ensure pipe surface cleanliness, application temperature control, adhesion quality, cathodic disbondment, moisture permeation, bending, minimum coating thickness, holiday detection and repair quality must be implemented in field conditions. Field joint coatings must be non-shielding to cathodic protection (CP). Field coating applicators must use valid coating procedures and be trained to use these procedures. Keystone will perform follow-up tests on field-applied coating to confirm adequate adhesion to metal and mill coating.

12. Coatings for Trenchless Installation: Coatings used for directional bore, slick bore and other trenchless installation methods must resist abrasions and other damages that may occur due to rocks and other obstructions encountered in this installation technique.

13. Bends Quality: Certification records of factory induction bends and/or factory weld bends must be obtained and retained. All bends, flanges and fittings must have carbon equivalents (CE) equal to or below 0.42 or a pre-heat procedure must be applied prior to welding for CE above 0.42.

14. Fittings: All pressure rated fittings and components (including flanges, valves, gaskets, pressure vessels and pumps) must be rated for a pressure rating commensurate with the MOP of the pipeline.

15. Design Factor—Pipelines: Pipe installed under this special permit may use a 0.80 design factor. Pipe installed in pump stations, road crossings, railroad crossings, launcher/receiver fabrications, population HCAs and navigable waters must comply with the design factor in 49 CFR 195.106. If portions of the pipeline become population HCAs during the operational life of the pipeline, Keystone will apply to PHMSA headquarters for a special permit for the affected pipeline sections.

16. Temperature Control: The pipeline operating temperatures must be less than 150 degrees Fahrenheit.

17. Overpressure Protection Control: Mainline pipeline overpressure protection must be limited to a maximum of 110 percent MOP consistent with 49 CFR 195.406(b).

18. Construction Plans and Schedule: The construction plans, schedule and specifications must be submitted to the appropriate PHMSA regional office for

review within 2 months of the anticipated construction start date. Subsequent plans and schedule revisions must also be submitted to the PHMSA regional office.

19. Welding Procedures: The appropriate PHMSA regional office must be notified within 14 days of the beginning of welding procedure qualification activities. Automated or manual welding procedure documentation must be submitted to the same PHMSA regional office for review. For X–80 pipe, Keystone must conform to revised procedures contained in the 20th edition of API Standard 1104, *Welding of Pipelines and Related Facilities* (API 1104), Appendix A, or by an alternative procedure approved by PHMSA headquarters.

20. Depth of Cover: The soil cover must be maintained at a minimum depth of 48 inches in all areas except consolidated rock. In areas where conditions prevent the maintenance of 42 inches of cover, Keystone must employ additional protective measures to alert the public and excavators to the presence of the pipeline. The additional measures shall include placing warning tape and additional pipeline markers along the affected pipeline segment. In areas where the pipeline is susceptible to threats from chisel plowing or other activities, the top of the pipeline must be installed at least one foot below the deepest penetration above the pipeline. If routine patrols indicate the possible loss of cover over the pipeline, Keystone must perform a depth of cover study and replace cover as necessary to meet the minimum depth of cover requirements specified herein. If the replacement of cover is impractical or not possible, Keystone must install other protective measures including warning tape and closely spaced signs.

21. Construction Quality: A construction quality assurance plan for quality standards and controls must be maintained throughout the construction phase with respect to: inspection, pipe hauling and stringing, field bending, welding, non-destructive examination (NDE) of girth welds, field joint coating, pipeline coating integrity tests, lowering of the pipeline in the ditch, padding materials to protect the pipeline, backfilling, alternating current (AC) interference mitigation and CP systems. All girth welds must be NDE by radiography or alternative means. The NDE examiner must have all current required certifications.

22. Interference Currents Control: Control of induced alternating current from parallel electric transmission lines and other interference issues that may affect the pipeline must be incorporated into the design of the pipeline and addressed during the construction phase. Issues identified and not originally addressed in the design phase must be brought to PHMSA headquarters' attention. An induced AC program to protect the pipeline from corrosion caused by stray currents must be in place and functioning within 6 months after placing the pipeline in service.

23. Test Level: The pre-in service hydrostatic test must be to a pressure producing a hoop stress of 100 percent SMYS and 1.25 X MOP in areas to operate to 80 percent SMYS. The hydrostatic test results from each test after completion of each pipeline must be submitted to PHMSA headquarters.

24. Assessment of Test Failures: Any pipe failure occurring during the pre-in service hydrostatic test must undergo a root cause failure analysis to include a metallurgical examination of the failed pipe. The results of this examination must preclude a systemic pipeline material issue and the results must be reported to PHMSA headquarters and the appropriate PHMSA regional office.

25. Supervisory Control and Data Acquisition (SCADA) System: A SCADA system to provide remote monitoring and control of the entire pipeline system must be employed.

26. SCADA System—General:

a. Scan rate shall be fast enough to minimize overpressure conditions (overpressure control system), provide very responsive abnormal operation indications to controllers and detect small leaks within technology limitations;

b. Must meet the requirements of regulations developed as a result of the findings of the National Transportation Safety Board, *Supervisory Control and Data Acquisition (SCADA) in Liquid Pipelines, Safety Study*, NTSB/SS–05/02 specifically including:

— Operator displays shall adhere to guidance provided in API Recommended Practice 1165, *Recommended Practice for Pipeline SCADA Display* (API RP 1165)

— Operators must have a policy for the review/audit of alarms for false alarm reduction and near miss or lessons learned criteria

— SCADA controller training shall include simulator for controller recognition of abnormal operating conditions, in particular leak events

— See item 27b below on fatigue management

— Install computer-based leak detection system on all lines unless an engineering analysis determines that such a system is not necessary

c. Develop and implement shift change procedures for controllers;

d. Verify point-to-point display screens and SCADA system inputs before placing the line in service;

e. Implement individual controller log-in provisions;

f. Establish and maintain a secure operating control room environment;

g. Establish controls to functionally test the pipeline in an off-line mode prior to beginning the line fill and placing the pipeline in service; and

h. Provide SCADA computer process load information tracking.

27. SCADA—Alarm Management: Alarm Management Policy and Procedures shall address:

a. Alarm priorities determination;

b. Controllers' authority and responsibility;

c. Clear alarm and event descriptors that are understood by controllers;

d. Number of alarms;

e. Potential systemic system issues;

f. Unnecessary alarms;

g. Controllers' performance regarding alarm or event response;

h. Alarm indication of abnormal operating conditions (ADCs);

i. Combination AOCs or sequential alarms and events; and

j. Workload concerns.

28. SCADA—Leak Detection System (LDS): The LDS Plan shall include provisions for:

a. Implementing applicable provisions in API Recommended Practice 1130, *Computational Pipeline Monitoring for Liquid Pipelines* (API RP 1130), as appropriate;

b. Addressing the following leak detection system testing and validation issues:

— Routine testing to ensure degradation has not affected functionality

— Validation of the ability of the LDS to detect small leaks and modification of the LDS as necessary to enhance its accuracy to detect small leaks

— Conduct a risk analysis of pipeline segments to identify additional actions that would enhance public safety or environmental protection

c. Developing data validation plan (ensure input data to SCADA is valid);

d. Defining leak detection criteria in the following areas:

— Minimum size of leak to be detected regardless of pipeline operating conditions including slack and transient conditions

— Leak location accuracy for various pipeline conditions

— Response time for various pipeline conditions

e. Providing redundancy plans for hardware and software and a periodic test requirement for equipment to be used live (also applies to SCADA equipment).

29. SCADA—Pipeline Model and Simulator: The Thermal-Hydraulic Pipeline Model/ Simulator including pressure control system shall include a Model Validation/Verification Plan.

30. SCADA—Training: The training and qualification plan (including simulator training) for controllers shall:

a. Emphasize procedures for detecting and mitigating leaks;

b. Include a fatigue management plan and implementation of a shift rotation schedule that minimizes possible fatigue concerns;

c. Define controller maximum hours of service limitations;

d. Meet the requirements of regulations developed as a result of the guidance provided in the American Society of Mechanical Engineers Standard B31Q, *Pipeline Personnel Qualification Standard* (ASME B31Q), September 2006 for developing qualification program plans;

e. Include and implement a full training simulator capable of replaying near miss or lesson learned scenarios for training purposes;

f. Implement tabletop exercises periodically that allow controllers to provide feedback to the exercises, participate in exercise scenario development and actively participate in the exercise;

g. Include field visits for controllers accompanied by field personnel who will respond to call-outs for that specific facility location;

h. Provide facility specifics in regard to the position certain equipment devices will default to upon power loss;

i. Include color blind and hearing provisions and testing if these are required to identify alarm priority or equipment status;

j. Training components for task specific abnormal operating conditions and generic abnormal operating conditions;

k. If controllers are required to respond to "800" calls, include a training program conveying proper procedures for responding to emergency calls, notification of other pipeline operators in the area when affecting a common pipeline corridor and education on the types of communications supplied to emergency responders and the public using API Recommended Practice 1162, *Public Awareness Programs for Pipeline Operators* (API RP 1162);

l. Implement on-the-job training component intervals established by performance review to include thorough documentation of all items covered during oral communication instruction; and

m. Implement a substantiated qualification program for re-qualification intervals addressing program requirements for circumstances resulting in disqualification, procedure documentation for maximum controller absences before a period of review, shadowing, retraining, and addressing interim performance verification measures between re-qualification intervals.

31. SCADA—Calibration and Maintenance: The calibration and maintenance plan for the instrumentation and SCADA system shall be developed using guidance provided in API 1130. Instrumentation repairs shall be tracked and documentation provided regarding prioritization of these repairs. Controller log notes shall periodically be reviewed for concerns regarding mechanical problems. This information will be tracked and prioritized.

32. SCADA—Leak Detection Manual: The Leak Detection Manual shall be prepared using guidance provided in Canadian Standards Association, *Oil and Gas Pipeline Systems*, CSA Z662–03, Annex E, Section E.5.2, Leak Detection Manual.

33. Mainline Valve Control: Mainline valves located on either side of a pipeline segment containing an HCA where personnel response time to the valve exceeds 1 hour must be remotely controlled by the SCADA system. The SCADA system must be capable of opening and closing the valve and monitoring the valve position, upstream pressure and downstream pressure.

34. Pipeline Inspection: The pipeline must be capable of passing in line inspection (ILI) tools. All headers and other segments covered under this special permit that do not allow the passage of an ILI device must have a corrosion mitigation plan.

35. Internal Corrosion: Keystone shall limit sediment and water (S&W) to 0.5 percent by volume and report S&W testing results to PHMSA in the 180-day and annual reports. Keystone shall also report upset conditions causing S&W level excursions above the limit. This report shall also contain remedial measures Keystone has taken to prevent a recurrence of excursions above the S&W limits. Keystone must run cleaning pigs twice in the first full year of operation and as necessary in succeeding years based on the analysis of oil constituents, weight loss coupons located in areas with the greatest internal corrosion threat and other internal corrosion threats. Keystone will send their analyses and further actions, if any, to PHMSA.

36. Cathodic Protection (CP): The initial CP system must be operational within 6 months of placing a pipeline segment in service.

37. Interference Current Surveys: Interference surveys must be performed within 6 months of placing the pipeline in service to ensure compliance with applica-

ble NACE International Standard Recommended Practices 0169 and 0177 (NACE RP 0169 and NACE RP 0177) for interference current levels. If interference currents are found, Keystone will determine if there have been any adverse affects to the pipeline and mitigate the affects as necessary. Keystone will report the results of any negative finding and the associated mitigative efforts to the appropriate PHMSA regional office.

38. Corrosion Surveys: Corrosion surveys of the affected pipeline must be completed within 6 months of placing the respective CP system(s) in operation to ensure adequate external corrosion protection per NACE RP 0169. The survey will also address the proper number and location of CP test stations as well as AC interference mitigation and AC grounding programs per NACE RP 0177. At least one CP test station must be located within each HCA with a maximum spacing between test stations of one-half mile within the HCA. If placement of a test station within an HCA is impractical, the test station must be placed at the nearest practical location. If any annual test station reading fails to meet 49 CFR 195, Subpart H requirements, remedial actions must occur within 6 months. Remedial actions must include a close interval survey on each side of the affected test station and all modifications to the CP system necessary to ensure adequate external corrosion control.

39. Initial Close Interval Survey (CIS)—Initial: A CIS must be performed on the pipeline within 2 years of the pipeline in-service date. The CIS results must be integrated with the baseline ILI to determine whether further action is needed.

40. Pipeline Markers: Keystone must employ line-of-sight markings on the pipeline in the special permit area except in agricultural areas or large water crossings such as lakes where line of sight markers are impractical. The marking of pipelines is also subject to Federal Energy Regulatory Commission orders or environmental permits and local restrictions. Additional markers must be placed along the pipeline in areas where the pipeline is buried less than 42 inches.

41. Monitoring of Ground Movement: An effective monitoring/mitigation plan must be in place to monitor for and mitigate issues of unstable soil and ground movement.

42. Initial In-Line Inspection (ILI): Keystone must perform a baseline ILI in association with the construction of the pipeline using a high-resolution Magnetic Flux Leakage (MFL) tool to be completed within 3 years of placing a pipeline segment in service. The high-resolution MFL tool must be capable of gouge detection. Keystone must perform a baseline geometry tool run after completion of the hydrostatic strength test and backfill of the pipeline, but no later than 6 months after placing the pipeline in service under a special permit. The ILI data summary sheets and planned digs with associated ILI tool readings will be sent to the PHMSA regional office. The PHMSA regional office will be given at least 14 days notice before confirmation digs are executed onsite. The dimensional data and other characteristics extracted from these digs will be shared with the PHMSA regional office. Keystone will also compare dimensional data and other characteristics extracted from the digs and compare them with ILI tool data. If there are large variations between dig data and ILI tool data, Keystone will submit PHMSA a plan on further actions, inclusive of more digs, to calibrate their analysis and remediation process.

43. Future ILI: Future ILI inspection must be performed on the entire pipeline subject to the special permit, on a frequency consistent with 49 CFR 195.452(j)(3), assessment intervals, or on a frequency determined by fatigue studies based on actual operating conditions, inclusive of flaw and corrosion growth models.

44. Verification of Reassessment Interval: Keystone must submit a new fatigue analysis to validate the pipeline reassessment interval annually for the first 5 years after placing the pipeline subject to this special permit in service. The analysis must be performed on the segment experiencing the most severe historical pressure cycling conditions using actual pipeline pressure data.

45. Two years after the pipeline in-service date, Keystone will use all data gathered on pipeline section experiencing the most pressure cycles to determine effect on flaw growth that passed manufacturing standards and installation specifications. This study will be performed by an independent party agreed to by Keystone and PHMSA headquarters. Furthermore, this study will be shared with PHMSA headquarters as soon as practical after its completion, preferably before baseline assessment begins. These findings will determine if an ultra-

sonic crack detection tool must be launched in that pipeline section to confirm crack growth with Keystone's crack growth predictive models.

46. Direct Assessment Plan: Headers, mainline valve bypasses and other sections covered by this special permit that cannot accommodate ILI tools must be part of a Direct Assessment (DA) plan or other acceptable integrity monitoring method using External and Internal Corrosion Direct Assessment criteria (ECDA/ICDA).

47. Damage Prevention Program: The Common Ground Alliance (CGA) damage prevention best practices applicable to pipelines must be incorporated into the Keystone's damage prevention program.

48. Anomaly Evaluation and Repair: Anomaly evaluations and repairs in the special permit area must be performed based upon the following:

a. Immediate Repair Conditions: Follow 195.452(h)(4)(i) except designate the calculated remaining strength failure pressure ratio (FPR) = < 1.16;

b. 60-Day Conditions: No changes to 195.452(h)(4)(ii);

c. 180-Day Conditions: Follow 195.452(H)(4)(iii) with exceptions for the following conditions which must be scheduled for repair within 180 days:

— Calculated FPR = < 1.32

— Areas of general corrosion with predicted metal loss greater than 40 percent

— Predicted metal loss is greater than 40 percent of nominal wall that is located at a crossing of another pipeline

— Gouge or groove greater than 8 percent of nominal wall

d. Each anomaly not repaired under the immediate repair requirements must have a corrosion growth rate and ILI tool tolerance assigned per the Integrity Management Program (IMP) to determine the maximum re-inspection interval.

e. Anomaly Assessment Methods: Keystone must confirm the remaining strength (RSTRENG) effective area, R–STRENG—0.85dL and ASME B31G assessment methods are valid for the pipe diameter, wall thickness, grade, operating pressure, operating stress level and operating temperature. Keystone must also use the most conservative method until confirmation of the proper method is made to PHMSA headquarters.

f. Flow Stress: Remaining strength calculations for X–80 pipe must use a flow stress equal to the average of the ultimate (tensile) strength and the SMYS.

g. Dents: For initial construction and the initial geometry tool run, any dent with a depth greater than 2 percent of the nominal pipe diameter must be removed unless the dent is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. For the purposes of this condition, a "dent" is a depression that produces a gross disturbance in the curvature of the pipe wall without reducing the pipe wall thickness. The depth of the dent is measured as the gap between the lowest point of the dent and the prolongation of the original contour of the pipe.

49. Reporting—Immediate: Keystone must notify the appropriate PHMSA regional office within 24 hours of any non-reportable leaks originating in the pipe body in the special permit area.

50. Reporting—180 Day: Within 180 days of the pipeline in-service date under a special permit, Keystone shall report on its compliance with special permit conditions to PHMSA headquarters and the appropriate regional office. The report must also include pipeline operating pressure data, including all pressures and pressure cycles versus time. The data format must include both raw data in a tabular format and a graphical format. Any alternative formats must be approved by PHMSA headquarters.

51. Annual Reporting: Following approval of the special permit, Keystone must annually report the following:

a. The results of any ILI or direct assessment results performed within the special permit area during the previous year;

b. The results of all internal corrosion management programs including the results of:

— S&W analyses

— Report of processing plant upset conditions where elevated levels of S&W are introduced into the pipeline

— Corrosion inhibitor and biocide injection

— Internal cleaning program

— Wall loss coupon tests

c. Any new integrity threats identified within the special permit area during the previous year;

d. Any encroachment in the special permit area, including the number of new residences or public gathering areas;

e. Any HCA changes in the special permit area during the previous year;

f. Any reportable incidents associated with the special permit area that occurred during the previous year;

g. Any leaks on the pipeline in the special permit area that occurred during the previous year;

h. A list of all repairs on the pipeline in the special permit area during the previous year;

i. On-going damage prevention initiatives on the pipeline in the special permit area and a discussion of their success or failure;

j. Any changes in procedures used to assess and/or monitor the pipeline operating under this special permit;

k. Any company mergers, acquisitions, transfers of assets, or other events affecting the regulatory responsibility of the company operating the pipeline to which this special permit applies; and

l. A report of pipeline operating pressure data to include all pressures and pressure cycles versus time. The data format must include both raw data in a tabular format and a graphical format. Any alternative formats must be approved by PHMSA headquarters.

Limitations

Should Keystone fail to comply with any conditions of this special permit, or should PHMSA determine this special permit is no longer appropriate or that this special permit is inconsistent with pipeline safety, PHMSA may revoke this special permit and require Keystone to comply with the regulatory requirements in 49 CFR 195.106.

Background and Process

The Keystone Pipeline is a 1,845-mile international and interstate crude oil pipeline project developed by TransCanada Keystone Pipeline L.P., a wholly-owned subsidiary of TransCanada Pipelines Limited. The Keystone Pipeline will transport a nominal capacity of 435,000 barrels per day of crude oil from western Canada's sedimentary basin producing areas in Alberta to refineries in the United States. Keystone indicates it has filed an application with the U.S. Department of State for a Presidential Permit for the Keystone Pipeline since the project involves construction, operation and maintenance of facilities for the importation of petroleum from a foreign country. Keystone anticipates receiving all necessary government approvals by November 2007 and beginning construction in late 2007. The targeted in-service date is during the fourth quarter of 2009.

The existing regulations in 49 CFR 195.106 provide the method used by pipeline operators to establish the MOP of a proposed pipeline by using the design formula contained in that section. The formula incorporates a design factor, also called a derating factor, which is fixed at 0.72 for an onshore pipeline. Keystone requests the use of a 0.80 design factor in the formula instead of 0.72 design factor.

PHMSA previously granted waivers to four natural gas pipeline operators to operate certain pipelines at a hoop stresses up to 80 percent SMYS. The Keystone pipeline project represents the first request by an operator in the United States for approval to design and operate a hazardous liquid (crude oil) pipeline beyond the existing regulatory maximum level. Canadian standards already allow operators to design and operate hazardous liquids pipelines at 80 percent SMYS.

On January 15, March 27, and April 17, 2006, PHMSA conducted technical meetings to learn more about the technical merits of Keystone's proposal to operate at 80 percent SMYS and to answer questions posed by internal and external subject matter experts. The meetings resulted in numerous technical information requests and deliverables, to which Keystone satisfactorily responded.

PHMSA also secured the services of experts in the field of steel pipeline fracture mechanics, leak detection and SCADA systems to assist in the review of appropriate areas of Keystone's application. The experts' reports are included in the public docket.

On February 8, 2007, PHMSA posted a notice of this special permit request in the Federal Register (FR) (72 FR 6042). In the same FR notice we informed the public that we have changed the name granting such a request to a special permit. The request letter, the FR notice, supplemental information and all other pertinent documents are available for review under Docket Number PHMSA–2006–26617, in the DOT's Document Management System.

Two comments were received and posted to the public docket concerning the Keystone pipeline project request for a special permit. One commenter listed a number of recommended and relevant conditions for hazardous liquid pipelines to operate at 80 percent SMYS. The conditions developed by PHMSA and incorporated into the grant of special permit include the concerns of the commenter. The second commenter did not provide substantive comments relevant to the special permit request.

Authority: 49 U.S.C. 60118(c) and 49 CFR 1.53.

Issued in Washington, D.C. on April 30, 2007.

JEFFREY D. WIESE,
Acting Associate Administrator
for Pipeline Safety.

Senator THUNE. If you could, that would be great. It's a question that we frequently get asked back in South Dakota.

In your written testimony you stated that PHMSA has increased its assistance to state pipeline safety agencies. I'm wondering if there are other improvements that can be made in terms of the coordination between PHMSA and the states.

Ms. QUARTERMAN. Well, there are always improvements that can be made. One that was discussed is coordinating the damage prevention laws to make sure that none of the states have exemptions. But we work very closely with our state partners and the National Association of State Pipeline Representatives as well. Perhaps the question is best left to them. I think we have a good working relationship and we'd like to keep it that way.

Senator THUNE. Tell me what your agency can do to assist in the development of ethanol and other biofuel pipelines?

Ms. QUARTERMAN. Well, we have been doing—we do have money for research and we have been using some of that money to research different products that are being considered, biofuel products that are being considered for pipeline transportation.

We have also been working with the fire organizations to deal with issues, especially with respect to ethanol and how do you respond to an ethanol fire in a pipeline. So we've been working quite a bit on those issues.

Senator THUNE. Mr. Chairman, I'd probably better run over and vote since there's about 1 minute left, so I'll flip the gavel back to you. Welcome back.

Senator LAUTENBERG [presiding]. Well, thank you. I'd like to give you time to vote. Thank you.

I understand that some of the questions that I had asked were discussed. So with that, I'll say thank you and, being mindful of the fact that we keep the record open for some time and if questions are submitted we ask for your prompt response not more than a week after you get the questions. We thank each one of you for making your testimony.

With that, we'll call the second panel. The second panel is Mr. Rocco D'Alessandro, Tim Felt, Mr. Sypolt, and Mr. Weimer.

[Pause.]

That was the fastest relay I've run for a long time. I got to the floor and voted and got back within about a 10-minute cycle. So that was pretty good. I worked off some of the energy that I might have saved for you folks.

We look forward to your testimony. Mr. D'Alessandro, Executive Vice President of Operations, Nicor Gas and representing the American Gas Association; Mr. Felt, President and CEO of Colonial Pipeline and representing the Association of Oil Pipelines; Mr. Gary Sypolt, Dominion Energy, representing the Interstate Natural Gas Association of America; and Mr. Carl Weimer, Executive Director of the Pipeline Safety Trust.

Mr. D'Alessandro, I think each of you have heard that we have a 5-minute time limit and we're going to stick fairly closely to it so we can give each person a chance to testify. Mr. D'Alessandro, we look forward to hearing from you now.

STATEMENT OF ROCCO D'ALESSANDRO, EXECUTIVE VICE PRESIDENT OF OPERATIONS, NICOR GAS ON BEHALF OF THE AMERICAN GAS ASSOCIATION

Mr. D'ALESSANDRO. Good afternoon, Mr. Chairman, members of the Committee. I'm pleased to appear before you today. Pipeline safety is a critically important issue and we thank you for holding this hearing.

I'm testifying today on behalf of American Gas Association. Founded in 1918, AGA represents 195 local energy companies that deliver natural gas throughout the United States. There are more than 70 million natural gas customers in the U.S., of which 91 percent, or 65 million, receive their gas from AGA members.

Mr. Chairman, members of the Committee: Our message today is a simple one. We believe that the current pipeline safety law is working well and should be reauthorized this year. The 2006 PIPES Act included several significant mandates that the industry is in the process of implementing. Given this, we do not believe there's a need for change in the pipeline safety statute at this time, but rather urge the Committee to reauthorize the current law.

Safety is our top priority. We spend an estimated $7 billion each year in safety-related activities. A large percentage of our effort over the last several years has been focused on working with Federal and state regulators in the development and implementation of rules specific to the mandates that were contained in the 2006 PIPES Act.

Specifically, there were four core provisions of the PIPES Act that are key to enhancing the safety of distribution pipelines: excavation damage prevention, distribution integrity management plans, called DIMP, excess flow valves, and control room management.

Excavation damage represents the single greatest threat to distribution system safety, reliability, and integrity. Regulators, natural gas operators, and other stakeholders are continually working to improve excavation damage prevention programs. It is having a positive impact, but, as always, more can be done.

The PIPES Act required DOT to establish an integrity management program for distribution pipeline operators. DOT published the final DIMP rule on December 4 of last year. The effective date was February 12 of this year and operators have been given until August 2 of 2011 to write and implement the program. This will impact 1,450 operators, 2.1 million miles of piping, and 70 million customers.

The final rules allow operators to develop a DIMP plan that is appropriate for the operating characteristics of their delivery systems and the customers that they serve. I'm pleased to report that the operators are working aggressively to implement the DIMP rule.

The PIPES Act mandated that DOT require distribution gas utilities install an excess flow valve on new and replacement service lines for single-family residences if the service line met specific conditions beginning on June 1, 2008. Operators have installed an estimated 950,000 excess flow valves since that date.

I do want to emphasize that Congress was absolutely correct in limiting the EFV mandate to single-family residence dwellings. It is inadvisable to attempt a mandatory nationwide installation of EFVs beyond the single-family resident class to multiple-family dwellings, commercial and industrial customers, due to the inherent uncertainties and complexities associated with the service lines and the significant variations in gas load. Inadvertent EFV shutdown of a commercial or industrial facility, like a hospital, chemical plant, could create greater safety hazards than the release of gas the EFV was attempting to prevent.

There are two issues that I'd like to bring to the Committee's attention as we believe there are some additional regulatory actions that DOT should be encouraged to take to ensure that the existing statutes continue to be efficiently implemented. Now that DOT has promulgated the DIMP regulation, it can modify the assessment requirements for low-stress transmission pipe operated by distribution gas utilities covered by TIMP. Since low-stress transmission lines operate more like distribution lines, we believe the low-stress pipelines are better covered under the DIMP, which would result in all low-stress lines being covered under the robust DIMP regulation.

The other issue I want to bring to attention deals with high-consequence areas, HCAs. There has been some talk of perhaps changing the TIMP regulation by eliminating the HCA definition and requiring operators to perform assessment on all 300,000 miles of natural gas transmission pipeline. Internal instrument, or smart pigging, inspections are usually not practical for transmission pipelines operated by distribution gas utilities, because usually the pipes are not piggable.

As part of its TIMP regulation, DOT has already included provisions for pipeline operators to have an added layer of protection on low-stress pipelines outside of HCA areas, known as Preventive and Mitigation Measures. AGA we strongly discourage making a change to TIMP HCA criteria.

In summary, many of the mandates within the 2006 PIPES Act have just become regulations and the government and industry are working hard to implement these regulations. AGA believes that Congressional passage of pipeline safety reauthorization this year will send a positive message that the current law is working and emphasize the commitment that Congress and all the industry stakeholders have to securing the safety of the Nation's pipeline system. We look forward to working with you to secure reauthorization this year.

[The prepared statement of Mr. D'Alessandro follows:]

PREPARED STATEMENT OF ROCCO D'ALESSANDRO, EXECUTIVE VICE PRESIDENT OF OPERATIONS, NICOR GAS ON BEHALF OF THE AMERICAN GAS ASSOCIATION

Good morning, Mr. Chairman and members of the Committee. I am pleased to appear before you today. Pipeline safety is a critically important issue, and I thank you for not only holding this hearing, but for all the work that you and your colleagues have done over the years to ensure that America has the safest, most reliable pipeline system in the world. My name is Rocco D'Alessandro and I am the Executive Vice President of Operations for Nicor Gas, based in Illinois. Nicor Gas is the largest natural gas distributor in northern Illinois, serving more than 2 million customers in 643 communities. Ninety-six percent of homes in our service territory use natural gas. We serve our customers utilizing 32,000 miles of gas distribution main and almost 2 million gas services. There are also 1175 miles of transmission pipelines integrated into Nicor's distribution system.

I am testifying today on behalf of the American Gas Association (AGA). Founded in 1918, AGA represents 195 local energy companies that deliver natural gas throughout the United States. There are more than 70 million residential, commercial and industrial natural gas customers in the U.S., of which 91 percent—nearly 65 million customers—receive their gas from AGA members. Today, natural gas meets almost one-fourth of the United States' energy needs.

Distribution pipelines are operated by natural gas utilities, sometimes called "local distribution companies" or LDCs. The gas utility's distribution pipes are the last, critical link in the natural gas delivery chain. Gas distribution utilities bring natural gas service to customers' front doors. To most customers, their local utilities are the "face of the industry." Our customers see our name on their bills, our trucks in the streets and our company sponsorship of many civic initiatives. We live in the communities we serve and interact daily with our customers and with the state regulators who oversee pipeline safety. Consequently, we take very seriously the responsibility of continuing to deliver natural gas to our communities safely, reliably and affordably. The distribution pipeline system is an interconnected network of transmission mains, distribution mains, and service lines.

Mr. Chairman and members of the Committee, AGA believes that *the current pipeline safety law is working well and that there is no need to make changes to the pipeline safety statute*. I want to assure the Committee that the natural gas industry has worked vigorously to implement the significant provisions of the 2002 and 2006 Pipeline Safety Acts. The industry safety performance has been exceptional and AGA expects it to improve further after some of the recent pipeline safety mandates have been fully implemented. For instance, the industry has already begun marshalling resources to implement the Distribution Integrity Management Program (DIMP) and Control Room Management regulations that were promulgated in December 2009.

We strongly urge a straight reauthorization, so as to allow the full implementation and refinement of each of the various regulations that have been promulgated since the 2006 Pipeline Safety reauthorization. We do not believe any new legislative action is needed.

Regulatory Authority

As part of an agreement with the Federal Government, in most states, state pipeline safety authorities have *primary* responsibility to regulate natural gas utilities as well as intrastate transmission pipeline companies. State governments are encouraged to adopt as minimum standards the Federal safety standards promulgated by the Department of Transportation (DOT). The states may also choose to adopt standards that are more stringent than the Federal ones, and many have done so. LDCs are in frequent contact with state pipeline safety inspectors. As a result of these interactions, distribution operator facilities are subject to more frequent and closer inspections than required by the Federal pipeline safety regulations.

Commitment to Safety

Our commitment to safety extends beyond government oversight. Indeed, safety is our top priority—a source of pride and a matter of corporate policy for every company. These policies are carried out in specific and unique ways. Each company employs safety professionals, provides on-going employee evaluation and safety training, conducts rigorous system inspections, testing, and maintenance, repair and replacement programs, distributes public safety information, and complies with a wide range of Federal and state safety regulations and requirements. Individual company efforts are supplemented by collaborative activities in the safety committees of regional and national trade organizations. Examples of these groups include AGA, the American Public Gas Association and the Interstate Natural Gas Association of America.

Natural gas utilities have long made safety their number one priority. We spend an estimated $7 billion each year in safety-related activities. Approximately half of this money is spent in complying with Federal and state regulations. The other half is spent as part of our companies' voluntary commitment to ensure that our systems are safe and that the communities we serve are protected. Moreover, we are continually refining our safety practices.

A large percentage of our effort over the last several years has been focused on working with Federal and state regulators in the development and implementation of rules specific to these and other legislative mandates that were contained in the 2002 and 2006 PIPES Acts. I want to assure the Committee that the natural gas distribution industry has worked vigorously to implement those provisions that related to our sector. From a regulatory perspective, the past 10 years have easily included far more significant pipeline safety rulemakings than any other decade since the creation of the Federal pipeline safety code in 1971. Highlights include:

- Approximately 2.1 million miles of distribution system piping are covered under the recently promulgated Distribution Integrity Management regulation;
- More than 50,000 miles of transmission pipelines operated by distribution gas utilities are covered by the Transmission Integrity Management Program;
- An estimated 950,000 excess flow valves have been installed since June 1, 2008;
- 25,000 natural gas distribution employees are continually qualified through testing. The average 30 qualification tests for each employee results in 750,000 documented qualifications;
- Locations of all natural gas transmission and hazardous liquids pipelines have been added to the Federal National Pipeline Mapping System;
- A pipeline awareness program has been developed and implemented for almost 1,600 natural gas operators; and
- Approximately 1,100 controllers are covered under the recently promulgated Control Room Management regulation, which includes requirements to address employee fatigue.

Specifically, there were four core provisions of the PIPES Act of 2006 that are key to enhancing the safety of the distribution pipeline system—Excavation Damage Prevention, DIMP, Excess Flow Valves (EFV), and Control Room Management.

Excavation Damage Prevention

Excavation damage represents the single greatest threat to distribution system safety, reliability and integrity. A number of initiatives have helped to reduce excavation damage and resulting incidents. These include a new three digit number, "811", that excavators can use to call before they dig, a nationwide education program promoting 811, "best practices" to reduce excavation damage and regional "Common Ground Alliances" that are focused on preventing excavation damage. Additionally, AGA and other partners established April as National Safe Digging Month, encouraging individuals to dial 811 before embarking on any digging or excavation project. Since the Call 811 campaign was launched, there has been approximately a 40 percent reduction in safety-related incidents. A significant cause for this reduction is the work done by the pipeline industry in promoting the use of 811. Regulators, natural gas operators, and other stakeholders are continually working to improve excavation damage prevention programs. This concerted effort, combined with the effort that states are undertaking to create robust, and effective, state damage prevention programs based on the elements contained in the 2006 PIPES Act, is having a positive impact. But as always, more can be done—and we will continue to remain vigilant in collaborating with other stakeholders and the public to ensure the safety of our pipeline systems.

Distribution Integrity Management

The 2006 PIPES Act required the DOT to establish a regulation prescribing standards for integrity management programs for distribution pipeline operators. The DOT published the final rule establishing natural gas DIMP requirements on December 4, 2009. The effective date of the rule was February 12, 2010. Operators must develop a written program and begin implementation of DIMP prior to August 2, 2011.

The DOT's Pipeline and Hazardous Materials Safety Administration (PHMSA) previously implemented integrity management regulations for hazardous liquid and gas transmission pipelines. Because there are significant differences between gas distribution pipeline systems and the systems of gas transmission or hazardous liquid operators, it would have been impractical to apply the existing regulations to distribution pipelines. The DIMP final rule requires operators to develop and implement individualized integrity management programs, in addition to PHMSA's core pipeline safety regulations.

The DIMP final rule is a comprehensive regulation that provides an added layer of protection to the already-strong pipeline safety programs in use by local distribution companies. It represents the most significant rulemaking affecting natural gas distribution operators since the inception of the Federal pipeline safety code in 1971. It will impact more than 1,400 operators, 2.1 million miles of piping, and 70 million customers. The final rule effectively takes into consideration the wide differences that exist between natural gas distribution operators. It also allows operators to develop a DIMP plan that is appropriate for the operating characteristics of their distribution delivery system and the customers that they serve.

The final rule requires that all distribution pipeline operators, regardless of size, implement an integrity management program that contains seven key elements:

1. Develop and implement a written integrity management plan.
2. Know its infrastructure.
3. Identify threats, both existing and of potential future importance.
4. Assess and prioritize risks.
5. Identify and implement appropriate measures to mitigate risks.
6. Measure performance, monitor results, and evaluate the effectiveness of its programs, making changes where needed.
7. Periodically report performance measures to its regulator.

Operators are aggressively implementing this rule. Workshops have been conducted throughout the Nation. Webinars and audio conferences have been held. Software programs have been developed specifically for distribution integrity management. The Gas Pipeline Technology Committee (comprised of Federal and state regulators, pipeline operators, manufacturers, and the public) has developed a guidance document to support implementation of the DIMP regulation. I am pleased to inform the Committee that all affected stakeholders are working to make this an effective regulation.

As discussed previously, low stress transmission pipelines are integrated into the gas distribution system. Distribution operators and state regulators will better manage the integrity of the distribution system when the TIMP and DIMP regulations are harmonized.

Excess Flow Valves

EFVs are installed by natural gas distribution utilities as one method to reduce the potential consequences when a service line is significantly damaged due to the impact of outside forces such as excavation damage. An EFV is usually installed in the pipe where the service line originates, near the main. EFVs function similar to a fuse in an electric panel that closes automatically to eliminate the flow of gas to the home for large leaks that exceed the EFV's closure flow rate. EFVs are not designed to shut off the flow of gas if a line break occurs on the customer's side of the gas meter. The device will not work properly for the low pressure and gas volumes in a customer's interior or exterior piping system that connects gas appliances. EFVs also cannot distinguish small gas leaks from changing gas loads. Instead, they help mitigate the potential consequences for events that could have a high rate, high volume gas release. These are the types of events that occur during excavation damage.

Natural gas utilities have been installing EFVs widely on single family residence service lines since the late 1990s, when operators were given the option of either installing them voluntarily or notifying customers of their availability, and then installing them upon request. The 2006 PIPES Act mandated that DOT require natural gas distribution utilities install an EFV on new and replacement service lines for single family residences, if the service line met specific conditions, beginning on June 1, 2008.

AGA supported the 2006 Congressional mandate for EFVs. Indeed, operators were voluntarily installing EFVs before the June 2008 Congressional deadline. The DIMP final rule codified the congressional mandate to install EFVs in services to single-family residences. I do want to emphasize that Congress was absolutely correct in limiting the EFV mandate to single-family residential dwellings. Single family residence dwellings are very uniform and only about 15 percent of the dwellings have problems with EFV installation (*e.g.,* pressure too low, dirt, or contaminates in the gas).

Due to the inherent uncertainties and complexities associated with service lines to multiple-family dwellings, commercial and industrial customers, however, it is inadvisable to attempt mandatory nation-wide installation of EFVs beyond the single-family residential class. Multi-family dwellings, commercial, and industrial customers are subject to significant variations in gas loads. Since EFVs are designed to shut down when there is a significant change in gas flow, these variations could result in the inadvertent closure of an EFV and interruption of gas service for multiple days. An inadvertent EFV shutoff of commercial and industrial facilities, like hospitals or chemical plants, could create greater safety hazards than the release of gas the EFV was attempting to prevent.

Control Room Management

In December 2009, DOT promulgated the final regulation for Pipeline Control Room Management, requiring pipeline operators to develop, implement and submit a human factors management plan designed to reduce risks associated with human factors for employees working in a pipeline control room. As a part of their plan, pipeline operators must address fatigue and establish a maximum limit on the number of hours worked by pipeline controllers.

AGA commends DOT for putting forth a final rule that enhances safety and is practical, reasonable, and cost-effective. Similarly to the DIMP, the rule takes into consideration the inherent differences that exist between natural gas pipeline operators and hazardous liquids pipeline operators. There has never been a documented accident that has been directly caused by the controller of a natural gas pipeline. Yet, AGA and its members are supportive of the regulation and are active in working to develop national standards that identify recommended practices for pipeline operators to consider in developing their plan. The final rule actually goes beyond the Congressional mandate in the area of controller fatigue by requiring operators to:

- Establish shift lengths and schedule rotations that provide controllers off-duty time sufficient to achieve 8 hours of continuous sleep;
- Educate controllers and supervisors in fatigue mitigation strategies and how off-duty activities contribute to fatigue; and
- Train controllers and supervisors to recognize the effects of fatigue.

The National Transportation Safety Board (NTSB) has expressed its support of the new regulation by closing its recommendation for pipeline operators to address fatigue. On February 18, 2010, the NTSB issued a press release that stated: "The Board was pleased to report that the Pipeline and Hazardous Materials Safety Administration has published a final rule establishing new bases for managing fatigue in the pipeline industry." The Board called the rule "a significant step forward for an industry that did not previously have any rules governing hours of service." The Board, therefore, closed the recommendation "Acceptable Alternate Action" and has removed fatigue in the pipeline industry from its "Most Wanted" list.

Public Awareness Programs

Beyond the significant requirements of the 2006 PIPES Act, the PIPES Act of 2002 directed DOT to put in place standards and criteria to improve public awareness of pipeline operations. Beginning June 20, 2005, the DOT required all pipeline operators to develop and implement public awareness programs based on the American Petroleum Institute (API) Recommended Practice (RP) 1162, "Public Awareness Programs for Pipeline Operators."

AGA applauds the DOT for working with the public, emergency responders, and industry to improve the public's awareness of pipelines. AGA's position is that the public awareness initiative has been successful and has effectively improved the public's awareness of the pipeline infrastructure and appropriate actions to be taken in the event of a pipeline emergency. API RP 1162 was developed by a joint stakeholder task group that included state and Federal safety regulators, public representatives, emergency responders, and pipeline operators. Operators adhered to the 12-step guide outlined by the DOT to develop public awareness programs. Operators are required to assess their public awareness programs for effectiveness and to identify opportunities for program improvement. These evaluations are required on a four-year interval, so operators are currently working to meet the first evaluation deadline of June 2010. During the second half of 2010, state and Federal pipeline safety inspectors will review the effectiveness of operators' public awareness programs. Industry looks forward to working with the DOT to identify performance metrics that are critical in assessing program effectiveness.

In response to an NTSB recommendation, industry is working to ensure that 911 operators are identified as an important stakeholder audience and receive all needed pipeline awareness information. AGA and the industry look forward to continuing to work with all regulatory agencies to improve the methods utilized to educate the public regarding pipeline safety.

Miscellaneous Issues

Low Stress Gas Pipelines

There are some additional regulatory actions that DOT should be encouraged to take to ensure that the existing statute continues to be efficiently implemented. Specifically, now that DOT has promulgated the DIMP regulation, it can modify the assessment requirements for low stress transmission pipelines operated by natural gas distribution utilities. Currently, low stress pipelines are covered under the Transmission Integrity Management Program (TIMP) regulation, which was promulgated in December 2003 by DOT. However, since low stress transmission lines operate more like distribution lines, AGA believes the low stress pipelines are better covered under DIMP. Making this change would not have an adverse effect on pipeline safety. Rather, we believe, it would enhance safety by allowing low stress pipelines to be covered under DIMP which would result in ALL low stress lines being covered under the robust DIMP regulation, and not just lines within high consequence areas.

There are fundamental differences between the high stress pipelines predominately operated by interstate operators—and the low stress pipelines, which are predominately operated by gas distribution utilities. A typical high stress interstate transmission pipeline will operate between 500 pounds per square inch (psi) and 1,000 psi and have stress levels up to 80 percent Specified Minimum Yield Strength (SMYS). Whereas, a typical low stress transmission pipeline will operate anywhere between 150 psi and 400 psi and have stress levels below 30 percent SMYS. Low stress transmission pipelines are usually embedded in the distribution network operated by utilities and are often very similar to higher pressure distribution pipelines. Moreover, many CANNOT be inspected by in-line inspection tools ("smart pigs") because of their, small diameters, valves in the line, layouts that include sharp turns and angles, relatively low operating pressures. DOT has already started regulatory initiatives to apply traditional distribution inspection and corrosion prevention techniques to low stress pipelines in lieu of the rigid TIMP assessments.

DOT has the regulatory authority to manage low stress transmission pipelines under DIMP. The issue was discussed during reauthorization of the 2002 Act. Congress anticipated that the pipelines included in TIMP might change and 42 U.S.C. 60109(c)1 states that DOT would define the facilities that will be included in TIMP in chapter 192 of title 49, Code of Federal Regulations, *including any subsequent modifications*. DIMP was finalized in December 2009 and AGA believes safety can be enhanced if DOT harmonizes the requirements in TIMP and DIMP.

High Consequence Areas

There has been some talk of perhaps changing TIMP, by eliminating the High Consequence Areas (HCA) definition, and requiring operators to perform TIMP assessments for all 300,000 miles of natural gas transmission pipelines.

As previously stated, internal instrument (smart pig) inspections are usually not practical for transmission pipelines operated by distribution gas utilities, because the pipelines are usually not piggable. As part of its regulation on TIMP, DOT has already included provisions for pipeline operators to have an added layer of protection on the low-stress pipelines outside of HCAs known as Preventive and Mitigative (P&M) measures in Subpart O of the Federal Pipeline Safety Code. These P&M measures consist of enhanced protection against the threats of external and internal corrosion as well as third party excavation damage.

Finally, there is a long list of regulatory safety requirements separate from the integrity management assessments that are used to manage safety for all pipelines inside and outside of HCAs. These include leak inspections, corrosion control, surveillance and patrolling, repair criteria, etc. Pipeline operators have upgraded their mapping systems and are continually collecting population data for the sole purpose of identifying HCAs that exist on their system so that they can use the risk-based principles required by the current TIMP regulation. AGA would strongly discourage making a change to the TIMP–HCA criteria.

Summary

Many of the mandates within the 2006 PIPES Act have just become regulation and government and industry are working to implement these regulations. AGA believes that Congressional passage of pipeline safety reauthorization this year will send a positive message that the current law is working, and emphasize the commitment that Congress and all the industry stakeholders have to securing the safety of the Nation's pipeline system. We look forward to working with you to secure reauthorization this year.

Senator LAUTENBERG. Thanks very much, Mr. D'Alessandro.

Mr. Felt, you're next, please.

STATEMENT OF TIMOTHY C. FELT, PRESIDENT AND CEO, COLONIAL PIPELINE COMPANY ON BEHALF OF THE ASSOCIATION OF OIL PIPE LINES (AOPL) AND THE AMERICAN PETROLEUM INSTITUTE (API)

Mr. FELT. Thank you, Chairman Lautenberg and members of the Subcommittee. I am Tim Felt, President and CEO of Colonial Pipeline, and I appreciate the opportunity to appear on behalf of AOPL and API. Colonial Pipeline operates a 5,500-mile pipeline system that begins in Houston, crosses the South and East before terminating at New York harbor. When measured by volume transported, Colonial is the largest refined products pipeline in the world, every day delivering about 100 million gallons of gasoline, diesel fuel, jet fuel, heating oil, and fuels for the U.S. military.

Pipelines have the best safety record of any transportation mode and are the most reliable, economical, and environmentally favorable way to transport oil to refineries and refined products to the communities where we live. We are proud of our improved safety record, but we are not content, as we strive for zero releases.

Pipelines have every incentive to invest in safety. The consequences of a failure could include injury to our neighbors, our employees, our community, our contractors, and the environment. We could also incur costly repairs, cleanups, litigation, and fines, and in the event of a problem on a pipeline we may not be able to meet our commitments to our customers. That breakdown in reliability can have a longer term impact on our business. The public expects pipelines to be safe and reliable and we believe we are meeting that expectation.

Our control room operators are trained to respond to an event on the pipeline by closing valves and quickly shutting down pumps. Pipeline operators are required to establish response plans which are submitted to the Office of Pipeline Safety within the Department of Transportation. We are required to plan for worst case discharges and to conduct emergency response drills on worst case scenarios with local responders to ensure that emergency preparedness is at a continued state of readiness.

Over the last decade, Congress and OPS have asked more of pipelines and the industry has done more. Pipelines have spent billions of dollars on integrity management, far exceeding earlier estimates. As a result, liquid pipeline spills along rights of way have decreased over the past decade in both volume and the number of releases.

Pipeline operators are required to develop integrity management plans for segments of pipelines that could affect high consequence areas, those near population centers, navigable waterways, drinking water intakes, or sensitive environmental areas. Liquid pipeline operators conducted baseline assessments to identify potential hazards to their pipelines and are implementing plans to address those threats. This includes in-line inspection by smart pigs. Full reassessments are under way, must be done within 5 years of the baseline assessments, and are required into the future.

Pipeline operators take additional steps to maintain integrity of pipelines, which include cathodic protection to control corrosion, patrols of rights of way to detect or head off encroachment or damage, and extensive use of computer systems to monitor the operations of the pipeline.

I want to thank the Congress and this committee for your prior work on pipeline safety, including establishment of 811 as the national Call Before You Dig Number. Colonial and other pipelines are supporters of One-Call centers, which serve as a clearinghouse for excavation activities mentioned in 811 calls. I am a board member and past chairman of the Common Ground Alliance, a place where underground utility operators can partner with government, excavators, and the public to pursue best practices on damage prevention.

I also want to thank Chairman Lautenberg and this committee for its work on Senate Resolution 472, which supported the designation of April as the National Safe Digging Month.

The pipeline industry asks for additional help protecting pipelines from excavation damage, a leading cause of significant pipeline incidents. Many states have been improving their damage prevention programs, but some state damage prevention laws are incomplete, inadequate, or inadequately enforced. 41 states allow some exemptions from the One-Call system for State agencies, municipalities, or local entities. These exemptions create a gap in enforcement and safety.

We believe OPS is headed in the right direction with its proposal of last year for Federal enforcement in States with inadequate programs. We urge OPS to complete this rulemaking and even require termination of these exemptions by the States or risk Federal enforcement or loss of grant funds.

Congress has provided OPS a thorough set of tools to regulate pipeline safety and they are working. We see no reason for Congress to greatly expand the pipeline safety program or impose significant new mandates upon the industry. We do believe Congress should encourage OPS to complete its rule on damage prevention, disallowing any exemptions to One-Call requirements and pushing States to improve and enforce State damage prevention programs.

We look forward to working with Congress, OPS, and other stakeholders to improve pipeline safety and reauthorize pipeline safety laws. Thank you.

[The prepared statement of Mr. Felt follows:]

PREPARED STATEMENT OF TIMOTHY C. FELT, PRESIDENT AND CEO, COLONIAL PIPELINE COMPANY ON BEHALF OF THE ASSOCIATION OF OIL PIPE LINES (AOPL) AND THE AMERICAN PETROLEUM INSTITUTE (API)

Introduction

I am Tim Felt, President and CEO of Colonial Pipeline Company. I appreciate this opportunity to appear before the Subcommittee today on behalf of AOPL and the American Petroleum Institute (API).

Colonial Pipeline is headquartered in suburban Atlanta, Georgia, from where we operate a pipeline system consisting of 5,519 miles of pipeline, beginning in Houston and crossing the South and East before terminating at the New York harbor. When measuring by volume transported, Colonial is the largest refined products pipeline in the world, daily delivering about 100 million gallons of gasoline, diesel fuel, jet fuel, home heating oil and fuels for the U.S. military.

AOPL is an incorporated trade association representing 51 liquid pipeline transmission companies. API represents over 400 companies involved in all aspects of the oil and natural gas industry, including exploration, production, transportation, refining and marketing. Together, the two organizations represent the operators of 85 percent of total U.S. oil pipeline mileage in the United States.

I will discuss the industry's commitment to safety, our improved safety record, and our view that pipeline safety reauthorization should remain focused on existing programs, specifically damage prevention.

Liquid Pipelines Overview

Pipelines are the safest, most reliable, economical and environmentally favorable way to transport oil and petroleum products, other energy liquids, and chemicals, throughout the U.S.

Liquid pipelines bring crude oil to the Nation's refineries and petroleum products to our communities, including all grades of gasoline, diesel, jet fuel, home heating oil, kerosene, and propane. Some of our members transport renewable fuels via pipeline, as well. Our members transport carbon dioxide to oil and natural gas fields, where it is used to enhance production. In addition to providing fuels for the transportation sector (including cars, trucks, trains, ships and airplanes), we provide hydrocarbon feedstocks for use by many other industries, including food, pharmaceuticals, plastics, chemicals, and road construction. America depends on the network of more than 170,000 miles of hazardous liquid pipelines to safely and efficiently move energy to fuel our Nation's economic engine.

Hazardous liquid pipelines transport more than 17 percent of freight moved in America, yet pipelines account for only 2 percent of the country's freight bill. Approximately 2.5 cents of the cost of a gallon of gasoline to an end-user can be attributed to pipeline transportation,[1] resulting in a low and predictable price for pipeline customers (referred to as "shippers"). Liquid pipeline transportation rates are regulated by the Federal Energy Regulatory Commission (FERC). Rates are generally stable and predictable, and do not fluctuate with changes in crude oil and gasoline or other fuel prices. Typically, pipelines only take custody of the product tendered for transportation and, as such, are unaffected by changes in the price of commodities being transported.

Pipelines are the preferred mode of transportation for crude and refined products. The approximate share of domestic shipments, measured in barrels of product moved per mile, is:[2]

- Pipelines—68 percent
- Water Carriers—25 percent
- Trucks—4 percent
- Rail—3 percent

Our industry had a wake-up call after the Bellingham, Washington fatalities in 1999. Congress and the Office of Pipeline Safety asked more of pipelines, and industry has done more. As a result of enhancements to pipeline safety laws, implementing regulations, and vigorous industry efforts, liquid pipeline spills along rights-of-way have decreased over the past decade, in terms of both the number of spills and the volume of product released per 1,000 barrel-miles[3] transported.

In addition to its record of fewest releases, pipeline transportation enjoys the lowest input energy requirement and carbon footprint as compared to other transportation modes (barge, truck, rail, and marine). Replacing a medium-sized pipeline that transports 150,000 barrels of gasoline a day would require operating more than 750 trucks or a 225-car train every day. Use of trucks or trains would increase mobile source greenhouse gas emissions, wear and tear on our transportation infrastructure, road congestion, and the number and volume of releases.

[1] "Liquid Transportation Fuels from Coal and Biomass: Technological Status, Costs, and Environmental Impacts," National Academy of Sciences, 2009.
[2] Association of Oil Pipe Lines, *Shifts in Petroleum Transportation*, 2009.
[3] One barrel mile equals one barrel (or 42 gallons) transported one mile.

Pipeline Operators Insist on Safety

Pipelines have every incentive to invest in safety. Indeed, in our members' view, there are no incentives to cut corners on pipeline safety. Most important is the potential for injury or loss of life to members of the public and our employees and contractors. If a pipeline experiences a failure or a release, there are numerous consequences for the operator. We could also incur potentially costly repairs, cleanup, litigation, and fines. Next, the pipeline may not be able to accommodate our customers. Finally, the pipeline company's reputation could be hurt.

Operators of liquid pipelines invest millions of dollars annually to maintain their pipelines and comply with Federal pipeline safety laws and regulations. Liquid pipeline assets are inspected regularly and monitored continuously, using a combination of practices. Pipeline operators continually seek to reduce the risk of accidental releases by taking measures to minimize the probability and severity of incidents. These measures include proper pipeline route selection, design, construction, operation, and maintenance, as well as comprehensive public awareness and excavation damage prevention programs.

The frequency of releases from liquid pipelines decreased from 2 incidents per thousand miles in 1999–2001 to 0.7 incidents per thousand miles in 2006–2008, a decline of 63 percent. Similarly, the number of barrels released per 1,000 miles decreased from 629 in 1999–2001 to 330 in 2006–2008, a decline of 48 percent. The industry is proud of this record, but continues to strive for zero releases, zero injuries, zero fatalities and no operational interruptions.

On many pipelines, operators also seek to minimize the consequences of a release through the use of automated systems that detect releases or other abnormal operating conditions and quickly shut off product flow to isolate the incident. Pipeline operators are required to put response plans in place, under the 1990 Oil Pollution Act. These plans are submitted to and reviewed by the Office of Pipeline Safety (OPS) within the Department of Transportation (DOT). Operators must change their plans and notify OPS within 30 days if any operational situation arises that would impact response efforts. Pipeline operators are required to conduct emergency response drills on worst-case discharges, and conduct exercises in cooperation with local first responders to ensure that emergency preparedness and planning is at a continued state of readiness. These response drills are conducted under the National Preparedness for Response Plan (PREP) guidelines issued jointly with OPS, the Environmental Protection Agency (EPA), and the U.S. Coast Guard. Our operators are trained on all elements of PREP guidelines and they are required to conduct equipment deployment drills and are subject to random full drills conducted by OPS.

In 1998, the U.S. oil pipeline industry launched an Environmental and Safety Initiative (ESI) to make further improvements in spill and accident prevention. The ESI promotes inter-company learning, improves pipeline operations and integrity, and provides opportunities for information sharing. An important part of the ESI is the liquid pipeline industry's voluntary reporting system, the Pipeline Performance Tracking System (PPTS), which tracks spills and allows operators to learn from industry data. Another key element of the ESI is the Performance Excellence Team (PET), which seeks to promote inter-company learning to improve pipeline operations and integrity, and provides methods and opportunities for information sharing.

Pipeline Safety Laws and Regulations

In 1979, Congress enacted comprehensive safety legislation governing the transportation of liquids by pipeline in the Hazardous Liquids Pipeline Safety Act of 1979 (HLPSA, 49 U.S.C. 2001). HLPSA added to previous laws and regulations and expanded the existing statutory authority for safety regulation. Since then, several new laws have been passed to govern the liquids pipeline industry, including: the Pipeline Safety Act (PSA) of 1994, the Pipeline Safety Improvement Act of 2002 (PSA), and the Pipeline Inspection Protection, Enforcement, and Safety Act of 2006 (PIPES).

Pipeline safety is closely regulated by the Pipeline and Hazardous Materials Safety Administration (PHMSA) which includes OPS. PHMSA's OPS is responsible for establishing and enforcing regulations to assure the safety of liquid pipelines (Title 49 CFR Parts 190–199). OPS sets prescriptive performance-based regulations and standards that are intended to address the dynamic nature of pipeline operations.

Integrity Management

Most pipeline operators are required under Federal regulations (Title 49 CFR, Part 195.450 and 452) to develop an Integrity Management Plan (IMP), for pipelines that could affect High Consequence Areas (HCAs). HCAs for liquid pipelines include any of the following:

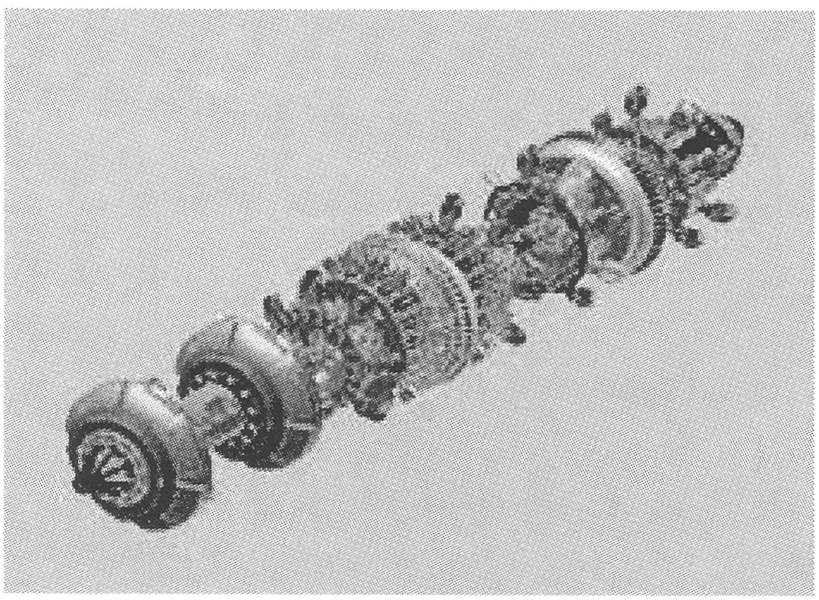
- Population centers, urbanized areas, or areas with large population density;
- Commercially navigable waters; and
- Unusually sensitive areas such as water supplies and ecological reserves.

Pipeline operators are required in their IMPs to identify segments that could impact HCAs, conduct periodic integrity assessments on those segments at intervals not to exceed 5 years, and review assessment results to make mitigation and repair decisions. A risk-based approach establishes the appropriate assessment interval within the five-year period. When identifying segments which could affect HCAs, operators conduct risk assessments and consider local topographical characteristics, operational and design characteristics of a pipeline, and the properties of transported commodities in determining potential impacts of an incident.

In their IMPs, all operators conduct a baseline assessment that identifies threats to the pipeline and subsequently apply technologies to mitigate each threat. These baseline assessments also set a point of comparison for subsequent assessments so that operators may gauge the impact of time-dependent threats, like corrosion. Liquid pipeline baseline assessments for pipelines that could affect HCAs were completed for existing pipelines by March 2008.

Assessments include in-line inspection by "smart pigs", which detect features in the pipe that need to be addressed, such as corrosion, pipeline deformation, cracking and others. This technology includes sensitive internal detection devices, such as magnetic flux leakage tools (MFL) and ultrasonic testing, to examine pipeline wall thickness and detect other anomalies. Another assessment method used by pipeline operators is pressure-testing. Many operators use these same techniques beyond pipeline segments which could affect HCAs.

Diagram of a Smart Pig



Pipeline companies perform visual inspections along rights-of-way, including from the air, for signs of damage, leakage, and encroachment. Pipeline controllers are also trained to identify signs of leaks and respond quickly to shut off pipeline flow, contact first responders (company and local government emergency response), and government officials.

Pipeline automation and supervisory control and data acquisition (SCADA) systems use various techniques to monitor for pipeline leaks. Software monitors pipeline pressure instruments and volumetric metering equipment and uses algorithms to search the data for a signal that may indicate a leak on the pipeline.

In some cases, an operator will install check valves, which automatically prevent backflow into a pipeline during a shutdown, or remote control valves that can be monitored with SCADA systems from a control room and closed if an accident occurs. These valves must be installed if an operator determines they are needed to protect an HCA in the event of a release.[5] Special attention is given to waterway crossings. It is common practice to locate block valves on each side of a waterway.

There are two ways in which pipe is protected from external corrosion: through the use of coatings and by impressed current that makes a pipe act as a cathode. Since corrosion is an electro-chemical process, this electrical charge inhibits corrosion even if the protective coating has been damaged. A protective coating is applied to steel pipe at the pipe mill to help prevent corrosion when placed into service. During the pipeline construction process, construction crews apply protective coatings to joints to safeguard the outside surface of pipeline girth welds from corrosion.

Costs of Integrity Management Programs

Liquid pipelines have implemented comprehensive programs to ensure compliance with PHMSA's IMP regulations, and have incurred significant costs associated with these activities. It was estimated by DOT before implementation that the liquid pipeline industry would spend approximately $279.5 million from 2001–2007 to comply with the IMP regulations.[6] However, industry experience demonstrates that the actual costs far exceed DOT's early projection.

Data from a subset of the industry illustrates the extent of these integrity-related costs. Lines representing less than 15 percent of the total DOT-regulated pipeline mileage, including systems that transport refined products, crude oil, and natural gas liquids, estimate expenditures in excess of $1 billion on required pipeline integrity management activities in the years from 2005 through 2009. In other words, in just the past 5 years these pipelines alone exceeded by nearly four times DOT's estimated cost for the total industry for the period 2001–2007. These figures, moreover, do not include integrity costs associated with DOT-regulated storage tanks, which would add substantially to the total. With finite resources, pipeline operators need to be able to rank risk and consequence, and apply resources accordingly. Pipeline operators should not be required to treat every mile of pipe with the same level of oversight.

It is important to note that as integrity management tools become more sophisticated, they are more effective at identifying issues for pipeline operators to consider. As a result, integrity management compliance costs have trended upward since implementation of the IMP regulations, a trend that the industry expects to continue in the coming years.

Damage Prevention and One-Call

Excavation damage to pipelines is less frequent today, but often results in extremely high consequences. Incidents from excavation damage by third parties accounted for only 7 percent of release incidents from 1999 to 2008. However, 31 percent of all significant incidents (those that result in spills of 50 barrels or more, fire, explosion, evacuation, injury or death) come from excavation damage by third parties. Further, at an even higher frequency, pipelines suffer damages from third parties that are not severe enough to cause a release at the time of excavation.

To protect communities, sensitive environmental areas, as well as the pipeline itself, the pipeline industry and other operators of underground facilities joined together to create notification centers that are used by those preparing to conduct excavation close to underground facilities. These centers—called One-Call Centers—serve as the clearinghouse for excavation activities that are planned close to pipelines and other underground utilities. Established by Federal law in 2007, 811 is the national "call-before-you-dig" number which informs operators, homeowners, and excavators about the location of underground utilities before they dig to prevent unintentional damage to underground infrastructure, including pipelines.

When calling 811 from anywhere in the country, a call is routed to the local One-Call Center. Local One-Call Center operators discern the location of the proposed excavation and route information about the proposed excavation to affected infrastructure companies. Under One-Call regulations, excavators must wait a specified amount of time before beginning any excavation project, to allow operators of underground infrastructure time to locate and mark underground infrastructure to protect it from excavation-related damage.

[5] 49 CFR Part 195.452.
[6] Five Year Review of Oil Pricing Index, FERC Stats and Regs (Order), 71 Fed. Reg. 15,329, 15,331 (March 28, 2006).

In addition, pipeline operators, associations, state regulators and Federal and state agencies take part in the Common Ground Alliance (CGA), an association that promotes effective damage prevention practices for all underground utility industry stakeholders to ensure public safety, environmental protection, public awareness and education to guard against excavation damage. Membership in CGA spans 1,400 members and sponsors, demonstrating that damage prevention is everyone's responsibility. Industry has worked closely with CGA to develop best practices and participates fully in its damage prevention programs, including the establishment and implementation of 811.

The Need for Improved Damage Prevention Enforcement

We believe more must be done to encourage adherence to state damage prevention laws and strengthen state and national programs already in place. We recognize and support the role of the states in preventing damage to pipelines. However, in some cases, state excavation damage prevention laws are weak or incomplete, or are not adequately enforced.

On October 29, 2009, OPS issued an Advance Notice of Proposed Rulemaking (ANPRM) regarding how it will exert its authority to enforce excavation damage prevention laws in states with inadequate damage prevention programs. API and AOPL submitted comments that supported OPS enforcement in states with inadequate excavation damage prevention programs and reinforced that OPS should not exert its authority in states with strong programs. OPS is headed in the right direction on this important issue. While supporting the ANRPM, we suggested some important changes to the proposed rule. We urge OPS to complete this rulemaking expeditiously. AOPL and API support more aggressive enforcement, recognizing it will apply equally to pipeline operators should they fail to adhere to excavation damage prevention laws.

In many states, state agencies, municipalities and other local entities are exempted from requirements to use the One-Call system before they undertake excavation activities. These exemptions create a gap in enforcement and safety, because the threat of pipeline damage is the same regardless of who the excavator is or who he works for. This is of heightened importance now with the expected increase of infrastructure development, especially road building, resulting from recent stimulus funding.

Under the proposed rule, OPS would assess a state's damage prevention program and make the determinations of adequacy or inadequacy called for by Congress. We believe OPS should promulgate a final rule that prohibits state programs from being determined "adequate" if they allow One-Call exemptions for state agencies, municipalities, and other commercial excavators.

As AOPL and API commented in the rulemaking,[7] we recommended that as a minimum requirement in a state damage prevention program, all excavators, including state agencies and municipalities:

(1) use state One-Call systems prior to excavation;

(2) follow location information or markings established by pipeline operators;

(3) report all excavation damage to pipeline operators; and

(4) immediately notify emergency responders when excavation damage results in a release of pipeline products.

Section 2 of the Pipeline Safety Inspection, Protection, and Enforcement (PIPES) Act of 2006 granted OPS the authority to grant funds for damage prevention programs to states adhering to the nine damage prevention principles included in the bill. The Secretary is to "take into consideration the commitment of each State to ensuring the effectiveness of its damage prevention program, including legislative and regulatory actions taken by the state." Such grants are limited and are not enough to incentivize strong state damage prevention programs. Nevertheless, we believe OPS should withhold damage prevention grant funds from states whose programs do not meet the fundamental minimum requirements we suggested.

PIPES Act Implementation

The PIPES Act of 2006 directed both DOT and the liquids pipeline industry to comply with several new and significant safety mandates. Below are several noteworthy provisions of the PIPES Act that have been implemented, or are in the implementation process:

- *Damage prevention enforcement*—Section 2 of the PIPES Act granted OPS limited authority to enforce damage prevention laws in states which do not have

[7] December 14, 2009 letter to Jeffrey D. Wiese regarding 74 FR 55797 (October 29, 2009).

qualified state damage prevention programs. It also established civil penalties applicable to excavators and individuals that fail to use an available One-Call system, ignore markings, or operate without reasonable care. As previously mentioned, OPS issued an ANPRM on October 29, 2009, outlining and collecting input on where and how it might exercise its authority to enforce damage prevention laws in states. AOPL and API provided comments and recommended that OPS move forward with a final rule to promote more effective and streamlined damage prevention rules that will promote safety and respect for pipelines. Finally, OPS has exercised its authority to award state damage prevention grants, promoting stronger state damage prevention programs.

- *Control room management (CRM)*—Section 12 in the PIPES Act required OPS to promulgate regulations requiring pipeline operators to develop a control room management plan. A final rule was published on December 9, 2009, that requires operators to define the roles and responsibilities of controllers and provide them with the necessary information, training, and processes to fulfill their responsibilities. Operators must include in their plans how they will address controller fatigue and length of work shifts. It further requires operators to manage SCADA alarms, assure control room considerations are taken into account when changing pipeline equipment or configurations, and review reportable incidents or accidents to determine whether control room actions contributed to the event. As a result of this regulation, the National Transportation Safety Board (NTSB) removed the issue of pipeline controller fatigue from its Federal Most Wanted List of Transportation Safety Improvement. The liquid pipeline industry supports the implementation of the CRM rule, but we hope to resolve on-going issues with OPS's definition of "controllers" and "control rooms" in upcoming workshops. If an overly broad definition is applied, it will cause significant operational problems for pipeline operators.
- *Accident reporting requirements*—OPS implemented new accident reporting requirements that address whether control room personnel are involved in and contribute to an accident.
- *Regulatory exemption eliminated for low stress pipelines*—Section 4 of the PIPES Act required a new rule to remove exemptions for rural low-stress lines, which operate at less than 20 percent of their specified minimum yield strength (SMYS). On June 3, 2008, OPS issued regulations for rural low-stress pipelines of 8 5/8" diameter or more within ½ mile of an Unusually Sensitive Area. All rural low-stress lines are required to submit an annual infrastructure report under this rule, as well. Generally, we believe this was the right approach. The liquid pipeline industry will review and provide comments to PHMSA on the recent Notice of Proposed Rulemaking (NPRM)[8] that would apply Part 195 requirements to all rural low-stress lines not included in the phase one rule.

Pipeline Safety Reauthorization

AOPL and API believe OPS is doing a responsible job with the authorities granted in the PIPES Act of 2006 and previous statutes. The results of these programs should be assessed thoroughly before Congress imposes new mandates. The results of the PIPES Act improvements may not be fully apparent for several years. Making additional changes before the programs mandated by the PIPES Act of 2006 have come into full effect is premature and could dilute the efforts of OPS and the industry.

If Congress chooses to make changes to the existing pipeline safety program in pipeline safety reauthorization legislation, AOPL and API believe any such changes should be focused on addressing existing OPS programs. We also suggest the reauthorization should be for a longer period than 4 years, in order to provide more predictability and stability for the pipeline safety program and the industry that must implement it. The PIPES Act and previous legislative efforts have given OPS a thorough set of tools and authorities to effectively regulate liquid pipelines. There is no reason for Congress to greatly expand the pipeline safety program or impose significant new mandates upon OPS or the industry in a new reauthorization bill.

We do believe OPS should move quickly to improve excavation damage prevention programs in the states, and, most importantly, should remove exemptions for state and municipal governments from One-Call requirements. Such exemptions create unnecessary opportunities for third-party damage to pipelines. AOPL and API believe Congress should encourage OPS to move forward to issue a final rule on damage prevention based on the October 2009 ANPRM, disallowing any exemptions to One-Call requirements.

[8] 75 *Fed. Reg*. 35366; June 22, 2010.

We look forward to working with Congress, OPS and other stakeholders to improve pipeline safety and reauthorize the pipeline safety laws.

I am happy to respond to any questions.

Senator LAUTENBERG. Thanks very much, Mr. Felt.

Mr. Sypolt, CEO of Dominion Energy and representing the Interstate Natural Gas Association of America, correct?

STATEMENT OF GARY L. SYPOLT, CEO, DOMINION ENERGY ON BEHALF OF THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

Mr. SYPOLT. Correct.

Senator LAUTENBERG. Please proceed, Mr. Sypolt.

Mr. SYPOLT. Chairman Lautenberg, members of the Subcommittee: Thank you for inviting me to testify today on the pipeline of the Nation's energy safety network. I am Gary Sypolt, CEO of Dominion Energy. Dominion is one of the Nation's largest producers and transporters of energy, with a portfolio of more than 27,500 megawatts of power generation, 12,000 miles of natural gas transmission, gathering, and storage pipeline, and 6,000 miles of electric transmission lines.

Today I am testifying on behalf of the Interstate Natural Gas Association of America, or INGAA, which represents the interstate natural gas pipeline industry in North America. INGAA's members transport the vast majority of the natural gas consumed in the U.S. through a network of about 220,000 miles of large-diameter pipeline. These transmission pipelines are analagous to the interstate highway system. In other words, these are high-capacity transportation systems spanning multiple states or regions.

Natural gas is increasingly being discussed in the context of the climate change debate as a partner with renewables in reducing overall emissions from the power and transportation sectors. Many of you might also have heard about the recent boom in new domestic natural gas supply development, particularly from shale deposits. Our industry continues to expand at impressive levels due to the growth in both natural gas supply and demand.

As we expand, though, the natural gas pipeline network is touching more and more people, and these people want to be assured that this infrastructure is safe and reliable. In other words, safety is and always will be our industry's main focus.

By all measures, natural gas transmission pipelines are safe, but our safety record is not perfect. Accidents have happened and our job is to continuously improve our technologies and processes so that the number of accidents continues to decline.

My written testimony highlights some of the statistics with respect to accidents in the natural gas transmission sector. The main point I would like to make is that our primary focus has been on protecting people and as a result the number of fatalities and injuries associated with our pipelines is low. We want it to be even lower.

One of the main programs that industry has implemented over the last decade has been the integrity management program, or IMP. This program, which was mandated by Congress in 2002, requires natural gas transmission pipelines to: one, identify all segments located in populated areas, called high consequence areas;

two, undertake assessments or inspections of those segments within 10 years; three, remediate any problems uncovered, including precursors to future problems; and four, undertake reassessments every 7 years thereafter.

We are far along in this process. In fact, we have already started to perform reassessments as we are finishing baseline work. My written testimony includes some data on the results of the work done thus far.

There are two important take-aways from this work that I would like to share with the Subcommittee. First, the data strongly suggests that on reassessments the number of precursors to corrosion we are finding are significantly lower than those found in baseline assessments. Since corrosion is a time-dependent phenomenon that occurs over a fairly predictable timeframe, these periodic reassessments are able to catch corrosion precursors before they manifest themselves into failures.

The other take-away is that the technology for conducting these assessments, primarily internal inspection devices known as smart pigs, continues to develop and improve over time. A new generation of these devices is currently employed and is giving us a more granular view of the conditions of our pipeline system.

The last 4 years have also seen several additional improvements in pipeline safety. My written testimony includes a discussion of the safety initiatives that have been completed in recent years.

This leads me to one of my main points. The pipeline safety program, at least with respect to natural gas transmission pipelines, is working well to reduce accidents and to protect the public. PHMSA has the authority it needs to improve standards over time. INGA believes that, given this level of performance and in addition the short amount of time remaining in this Congress, a simple reauthorization of the Pipeline Safety Act is the logical step for Congress to make. We support a straightforward reauthorization that leaves the current programs in place and pledge to work with you in enacting such a bill.

However, if you choose to pursue a broader bill we offer the three following suggestions: One, damage prevention is critical in our industry. State One-Call programs are critical to avoiding accidents and preventing fatalities and injuries. I'm pleased to say that our home State of Virginia serves as a model for this Nation. But despite all the progress, some improvements still need to be made. Two recent accidents in Texas caused by third party excavation damage demonstrate the need to make further improvements to state damage prevention programs. We'd like to work with you in suggesting some improvements.

Two, as we implement the IMP program it is becoming clear that the 7-year reassessment requirement mandated by the 2002 reauthorization bill is not necessary. A more informed, risk-based approach is more logical for determining the appropriate reassessment period. Both the GAO and PHMSA have recommended that Congress update this requirement. We support those recommendations.

Third, we ask that Congress charge the PHMSA with identifying and retiring legacy regulations that have become redundant in the new integrity management era.

Mr. Chairman, we are proud of the pipeline improvements that have been made in the industry over the last decade. We hope that you agree much has improved. Thank you again for graciously inviting me to testify today and I will be happy to take questions at the appropriate time.

[The prepared statement of Mr. Sypolt follows:]

PREPARED STATEMENT OF GARY L. SYPOLT, CEO, DOMINION ENERGY ON BEHALF OF THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

Mr. Chairman and members of the Subcommittee:

Good afternoon. My name is Gary Sypolt, and I am CEO of Dominion Energy. Dominion Energy is the natural gas-related business unit of Dominion Resources. Dominion Resources is one of the Nation's largest producers and transporters of energy, with a portfolio of more than 27,500 megawatts of generation, 12,000 miles of natural gas transmission, gathering and storage pipeline and 6,000 miles of electric transmission lines. Dominion operates the Nation's largest natural gas storage system with 942 billion cubic feet of storage capacity, and owns and operates the Cove Point liquefied natural gas facility in Maryland. We also serve retail energy customers in 12 states. Our corporate headquarters are in Richmond, Virginia.

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 the vast majority of the natural gas consumed in the United States through a network of approximately 220,000 miles of transmission pipeline. These transmission pipelines are analogous to the interstate highway system; in other words, these are large capacity transportation systems spanning multiple states or regions.

Natural Gas

While natural gas has been an important part of the United States energy supply portfolio for many years, the recent focus on energy security and controlling emissions of greenhouse gases is making natural gas even more important to America's energy future. Natural gas currently provides about 25 percent of the total energy utilized in the Nation. This includes fueling the generation of about 20 percent of our electricity and heating the bulk of our homes and businesses. The clean-burning properties of natural gas make it an attractive resource for the future as the U.S. looks for ways to reduce carbon and other emissions. Many experts have advocated natural gas as a logical "partner" for renewable power resources, with natural gas providing reliable electricity when conditions do not permit the operation of solar and/or wind generation. In addition, natural gas remains a largely domestic energy resource. The U.S. produces approximately 85 percent of the natural gas consumed domestically; most of the remaining natural gas supplies are imported from Canada. Only about 2 percent of our natural gas supply is imported from outside of North America. There is little doubt that natural gas can fulfill its potential as a long-term contributor to the U.S. energy future. Natural gas supplies have grown dramatically in just the last 5 years, and it is estimated that the U.S. natural gas resource base can supply us for more than 100 years at current consumption levels.

Regulatory Structure of the Interstate Natural Gas Transmission System

Mr. Chairman, I am going to limit my comments to the segment of the natural gas delivery system represented by INGAA—the interstate natural gas transmission system. As I mentioned, interstate natural gas transmission pipelines can be compared to the interstate highway system and as such, cross state boundaries and have a significant impact on interstate commerce. Congress recognized the inherently interstate nature of this commerce by enacting the Natural Gas Act to provide for Federal economic regulation of interstate pipelines in 1938 and, shortly thereafter, expanded this Federal role to include siting authority for such pipelines. This law now is administered by the Federal Energy Regulatory Commission (FERC).

With regard to pipeline safety, Congress enacted the Natural Gas Pipeline Safety Act in 1968. This law (as amended) provides for the exclusive regulation of interstate natural gas and hazardous liquid pipelines by the Office of Pipeline Safety (OPS) located in the Pipeline and Hazardous Materials Safety Administration (PHMSA). The authority to regulate intrastate pipelines is largely delegated to state pipeline safety agencies.

It is worth noting that with regard to the Nation's interstate natural gas pipelines, the regulation of economic matters and the regulation of safety matters have always been handled by two separate entities. The exclusive safety focus of PHMSA has been an advantage of the agency. Over the years, some have suggested an expansion of PHMSA's authority beyond safety matters. Given the importance of the mission, and the fact that PHMSA has a relatively small staff, we are concerned about any movement away from safety. INGAA urges Congress and the Administration to maintain that exclusive safety focus for PHMSA.

Following enactment of the Natural Gas Pipeline Safety Act, OPS adopted pipeline safety regulations (in 1970) for natural gas transmission pipelines based on engineering consensus standards developed by the American Society of Mechanical Engineers. These engineering consensus standards first were adopted by the industry in 1953 and had been continually updated over the following decades. OPS established performance measures (*e.g.*, pipeline accident reports, company activity records and engineering documentation) and initiated a formal inspection and enforcement program for interstate natural gas transmission pipeline systems. Conversely, natural gas intrastate or distribution piping safety guidelines were implemented under similar pipeline safety regulations and were delegated to the state pipeline safety agencies. Hazardous liquid pipelines were incorporated into the OPS regulatory structure in 1984.

The pipeline safety processes of INGAA member companies and the applicable regulations for natural gas transmission pipelines have evolved and become more refined over the last 40 years as new technology has became available, new physical properties have been identified through engineering and scientific analysis, and societal expectations have changed. These substantive changes in processes and regulations have been accomplished through:

- Continuing research,
- Improved practices and processes,
- Revised engineering consensus standards,
- New regulatory initiatives,
- Focused Congressional actions, and
- Improved education and training.

Natural Gas Transmission Pipelines are the Safest Mode of Energy Transportation

While natural gas transmission pipeline operators will not be satisfied without continuous safety improvement, the safety record of our industry compares very well to other modes of transportation and energy delivery. One way to measure safety performance is to identify the number of accidents involving a fatality or injury. These are classified as "serious" incidents by OPS. Because natural gas pipelines are buried and typically are in isolated locations, pipeline accidents involving fatalities and injuries are very rare.

For example, the chart below (from OPS) sets forth safety statistics for natural gas transmission pipelines since the last Pipeline Safety Act reauthorization. This chart first depicts the categories of fatalities and injuries. It also categorizes property damage based on whether it is damage to public property or damage to the pipeline operator's property and the amount of natural gas lost to the atmosphere during both the accident and the subsequent repair of the pipeline.

National Gas Transmission Onshore: Consequences Summary Statistics: 2005–2009

Year	Public Fatalities		Industry Fatalities		Public Injuries		Industry Injuries		Total Property Damage (C) (D)	Damage to Public Property (E) (C)		Damage to Industry Property (F) (C)		Value of Product Lost (C)	
2005	0	0%	0	0%	2	40%	3	60%	$214,506,403	$98,072,639	45%	$105,375,752	49%	$11,058,012	5%
2006	1	33%	2	66%	1	33%	2	66%	$31,020,029	$2,869,452	9%	$20,882,094	67%	$7,268,481	23%
2007	1	50%	1	50%	1	14%	6	85%	$44,562,382	$1,630,991	3%	$24,096,641	54%	$18,834,750	42%
2008	0	0%	0	0%	2	40%	3	60%	$111,608,494	$6,643,699	6%	$98,424,350	88%	$6,540,445	5%
2009	0	0%	0	0%	7	63%	4	36%	$31,789,417	$2,005,498	6%	$25,216,056	79%	$4,567,863	14%
Totals	2	40%	3	60%	13	41%	18	58%	$433,486,727	$111,222,281	25%	$273,994,894	63%	$48,269,552	11%

From 2005 to 2009,[1] there have been two public fatalities due to natural gas transmission line accidents. One in 2006 involved a bystander near an incident caused by excavation damage to the pipeline, and the other in 2007 involved a driver in an automobile near a pipeline incident caused by corrosion. The three non-pub-

[1] Additional information is available in individual pipeline incident reports *http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.ebdc7a8a7e39f2e55cf2031050248a0c/?vgnextoid=fdd2dfa122a1d110VgnVCM1000009ed07898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print*.

lic natural gas transmission pipeline fatalities since 2005 were a third-party excavator, a pipeline employee and a contractor working for a pipeline company.

During this same period, 2005 to 2009, there were 13 injuries to the public. Four of these occurred when citizens were in vehicles that struck and damaged pipeline facilities. There were also five injuries to third-party excavators and 13 injuries to either pipeline employees or contractors working for the pipeline company.

As you can see from the chart, on the average, natural gas transmission pipeline incidents do not greatly affect public property. The exception in 2005 primarily was attributable to $85 million of damage to a power plant adjacent to a pipeline accident. The large amount of industry property damage in 2005 was related to the Katrina/Rita hurricane damage in the Gulf Coast region and the large number in 2008 was largely due to a tornado destroying a pipeline compressor station ($85 million).

Progress Since the Last Reauthorization

Pipeline Integrity Program

Section 14 of the Pipeline Safety Improvement Act of 2002 (PSIA) mandated an integrity management program for natural gas transmission pipelines. Specifically, the PSIA requires operators of natural gas transmission pipelines to: (1) identify all the segments of their pipelines located in areas where the pipeline is adjacent to significant population density, known as high consequence areas (HCAs); (2) develop an integrity management program (IMP) to reduce the risks to the public in these HCAs; (3) undertake structured baseline integrity assessments (inspections) of all pipeline segments located in HCAs, to be completed within 10 years of enactment; (4) develop a process for repairing any anomalies [2] found as a result of these inspections; and (5) reassess these segments of pipeline every 7 years thereafter in order to verify continued pipe integrity.

The PSIA requires that these integrity inspections be performed using one of four methods: (1) an inline inspection device, alternatively called 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."

Following such inspections, a pipeline operator is required by the PHMSA regulations implementing the PSIA to repair all non-innocuous anomalies and adjust operation and maintenance practices (*i.e.,* apply additional corrosion protection measures in active corrosion areas to prevent further corrosion growth) to minimize the probability of "serious incidents." [3]

Baseline IMP assessments—the type of work in which our industry now is engaged—are an effective means of identifying any material or original construction defects that were not discovered when a pipeline was built as well as active corrosion problems. Corrosion is an on-going, time-based phenomenon that is managed and controlled using integrated technologies and processes (*e.g.,* cathodic protection, pipe coatings). Internal inspection devices are the predominant means for performing integrity assessments of natural gas transmission pipelines, because these are the most versatile and efficient devices for this inspection process. The other assessment alternatives prescribed by statute 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 significant periods of time (*e.g.,* hydrostatic pressure test) or else require extensive excavation of the pipeline during every assessment (*e.g.,* direct assessment).

Periodic risk-based reassessments are an effective method for identifying whether corrosion prevention systems are adequately preventing this "time-dependent" deterioration. While material and original construction defects are not common, they are for practical purposes eliminated for the remaining life of the pipeline once they are identified during a smart pig assessment (or the post-construction hydrostatic test) and repaired. Recently designed smart pigs can also effectively identify small dents in the pipeline. These dents may or may not be precursors for a corrosion failure, depending upon whether the pipe has been gouged. Sorting through these dents to identify actual corrosion precursors is a current focus using these updated smart pig devices.

[2] An anomaly is defined as a precursor to a possible reportable incident in the future.

[3] "The rule will *significantly reduce the likelihood* of pipeline accidents that result in *deaths* and *serious injuries*."; Page 69800, Federal Register/Vol. 68, No. 240/December 15, 2003.

Based on data from over three quarters of the IMP inspection baseline period (2002–2009), there is ample basis for concluding that the integrity of our pipelines is being maintained and that such pipelines are becoming safer as a result of eliminating the precursors to possible future accidents. It also is clear that the industry is dutifully implementing the IMP program prescribed by Congress, since all INGAA member companies have been subject to in-depth IMP audits by PHMSA to assure that the programs are comprehensive and implemented consistently according to Congressional mandates and PHMSA requirements.

PHMSA has received the reports on IMP progress achieved through the end of 2009 and the data is presented on the following tables. The first table depicts the transmission pipelines that have been subject to an assessment for the first time under the IMP program (baseline). Let me highlight a particular performance measure. The "Immediate" category includes small isolated anomalies (*e.g.,* corrosion, pipe dent with a gouge) that should be repaired quickly, since these situations might lead to a leak or pipe rupture within a short period of time. The "Scheduled" category addresses individual anomalies (*e.g.,* corrosion) that should be repaired or reassessed before they grow to the "Immediate" category. The bottom row depicts the rate (per mile) of finding either "Immediate" or "Scheduled" category anomalies after decades of operation (*e.g.,* 10–50 years).

Baseline IMP Data for Gas Transmission Pipeline Integrity Program	Natural Gas Onshore Transmission Miles within U.S.	Transmission Pipeline Miles Assessed per Year Coincidently with the IMP program	Total Number of Miles of Pipelines within HCAs	Miles of Pipe Assessed within HCAs per Year	Number of Immediate Category Anomalies (failure precursors) within an HCA	Number of Scheduled Category of Anomalies within an HCA
2004	298,207	31,273	21,764	3,997	104	599
2005	297,968	19,516	20,561	2,908	261	378
2006	293,696	20,250	19,949	3,500	169	342
2007	291,898	25,940	19,277	4,661	258	452
2008	295,779	20,258	19,568	2,454	146	217
2009 (preliminary)	283,975	22,015	18,663	2,269	124	251
Cumulative Baseline Inspection Results		139,252		19,789	1,062	2,239
Rate of Anomalies found (dents & corrosion) in the Baseline Assessment (per Mile)					*.054*	*.113*

As these "Immediate" and "Scheduled" time-dependent precursors (*e.g.,* anomalies that could possibly grow in size) are remediated and rendered benign, we expect that the rate of "Immediate" and "Scheduled" anomalies will decrease with subsequent assessments. This is because the gestation period of these corrosion anomalies to grow (if corrosion is active) to failure is significantly longer than either the present prescriptive seven-year reassessment requirement or the risk-based reassessment intervals recommended by GAO and consensus standards organizations (see later discussion).

Since the inception of the IMP program in 2002 through 2009, there have been *no reported significant incidents* caused by corrosion to pipelines within the HCAs that have been assessed.

The next table depicts the results of reassessments that are occurring concurrently on natural gas transmission pipelines that had been previously assessed under the IMP baseline program. As with the baseline assessment, "Immediate" and "Scheduled" precursors are identified, assessed to determine if they have changed and then remediated. As shown in the fourth row, the rate of occurrence of these corrosion anomalies and dents is significantly reduced from the baseline assessment.

Reassessment Data for Gas Transmission Pipeline Integrity Program	Miles of Pipe Re-Assessed within an HCAs per Year	Immediate Categories of Anomalies (failure precursors) within an HCA	Scheduled Categories of Anomalies within an HCA
2008	348	9	4
2009 (preliminary)	903	20	16
Cumulative Reassessment Inspection Results	1,285	29	20
Rate of Anomalies (dents & corrosion) found in the Reassessment (per Mile)		*.023*	*.016*
Rate of Corrosion Anomalies (only) found in the Reassessment (per Mile)		*.003*	*.011*

In addition, the last row[4] depicts the low rate of corrosion anomalies found on the reassessments, the main focus of the IMP program. It is worth emphasizing that other data obtained from pipeline operators who have completed multiple integrity assessments over a number of years, and reviewed by GAO, strongly suggests a dramatic decrease in the occurrence of time-dependent precursors requiring repairs in subsequent assessments. This is due to corrective action being implemented based on prior integrity assessments. Also, technical analysis[5] undertaken in 2005 by the Pipeline Research Council International (PRCI), an international consensus research group, demonstrated a significant reduction in the number of serious anomalies found during risk-based reassessments (as compared to baseline assessments), suggesting that risk-based assessments using smart pig technology are extremely effective in identifying potential problems before they manifest themselves into safety problems.

Pipeline Controller Regulation

In 2001, the National Transportation Safety Board (NTSB) issued a report concerning fatigue among hazardous liquid pipeline controllers. In response, OPS undertook an effort from 2002 to 2008 to investigate pipeline control operator fatigue and identify possible solutions. While the NTSB report did not focus on natural gas transmission pipeline control room operators, INGAA participated extensively in this study effort. OPS issued a Notice of Proposed Rulemaking on this matter in September 2008. During the rulemaking, INGAA proactively worked with other pipeline trade associations to recommend changes to the proposal that would reflect the difference of practices and risks between hazardous liquid, natural gas transmission and natural gas distribution control operations. Since the rule was finalized in December 2009, INGAA member companies, working in collaboration with the Southern Gas Association, have developed an implementation manual for natural gas transmission and distribution operators. This implementation manual has been reviewed by OPS and NTSB. In February 2010, the NTSB announced that it was satisfied that its recommendation on control room personnel fatigue had been addressed by these actions. As a result, control room operator fatigue was removed from the NTSB list of "Most Wanted" safety improvements.

Improved Incident Data and Transparency

In 2007, INGAA requested that OPS reassess the reporting criteria for reportable incidents and suggested that incident forms be amended to facilitate better data analysis of the causes and consequences of these incidents. For example, the value of natural gas lost from an incident is included in total property damage numbers. As natural gas prices increased dramatically over the last 10 years, this metric caused an increase in reportable incidents since property damage above a fixed threshold is one trigger for reporting an incident. INGAA asserted that incident data should not be artificially impacted by natural gas commodity prices. OPS undertook an effort to modify its data requirements and the result is an accident reporting form that more accurately depicts the severity of incidents. We believe this data will assist the industry, OPS and concerned public assessing the risk of natural gas transmission pipelines and determining whether modified practices and procedures are reducing the occurrence of pipeline accidents.

Allowing Increased Operating Pressure in Specific Transmission Pipelines

In 2006, several INGAA member companies requested that OPS consider allowing newer pipelines with improved technologies to operate a higher operating pressure. The "safety factors" for natural gas pipelines were established in the 1950s and OPS

[4] IMP data collected by OPS, enhanced by detailed interviews with INGAA respondents

[5] *Integrity Management Reinspection Intervals Evaluation,* Pipeline Research Council International, Inc., December 2005.

adopted those safety factors in the original pipeline safety regulations promulgated in the 1970s. Since then, pipeline technologies and processes have advanced tremendously (*e.g.,* materials, IMP, smart pigs). The operating pressure proposed by the pipelines already was part of international engineering consensus standards, and Canada has utilized these refined criteria since the 1980s. The United Kingdom adopted these criteria for their existing pipeline infrastructure in the 1990s after it determined that this change would result in no effective reduction in the safety. The U.K. also concluded that these updated criteria would enable more efficient use of the country's existing infrastructure and thereby obviate the need to construct additional pipeline capacity (along with all of the disruption that would cause in such a densely populated country). Utilizing extensive prior research and international experience, OPS issued several special permits to allow higher operating pressures than previously allowed under regulations and to assess the benefits of additional design, construction, operating and maintenance requirements imposed as a condition for such permits. This exploratory work has resulted in a new regulation that will allow higher operating pressure on new pipelines that meet much stricter criteria for design, construction, operation and maintenance.

Improved Material and Construction Practices for Natural Gas Transmission Pipelines

The natural gas transmission pipeline infrastructure in the U.S. has expanded significantly in the last decade to meet increased demand for natural gas and to connect new natural gas supply basins to consuming markets. This surge in new pipeline construction required many new material sources, especially steel pipe. At the same time, OPS adopted more stringent material, construction and inspection regulatory requirements for projects approved with special permits (allowing increased operating pressure in specific transmission pipelines) that exceeded those for comparable pipelines in other nations. The conjunction of these two events resulted in the unacceptable performance of a sample of steel pipe in a particular pipeline project during pre-service integrity testing. INGAA, in cooperation with OPS, embarked on an unprecedented effort to identify the phenomenon that caused these pre-service pipe quality issues and to implement processes and procedures to minimize the occurrence of these events in the future. All pipelines wishing to operate at higher pressures (under these new regulatory requirements) have quickly adopted these practices and procedures. This cooperative process resulted in significantly faster implementation of solutions than would have occurred under the traditional engineering consensus standards process or a rulemaking by the agency.

Concurrently, INGAA has focused on identifying ways to improve the process for constructing new natural gas transmission pipelines. This requires a reassessment of the traditional Quality Assurance and Quality Control (QA/QC) processes and practices in light of changes in materials, technology, the expectations of industry and regulators. The same implementation model used in the pipe quality effort is being utilized to affect change quickly in the construction process.

Incorporation of Safety Culture

INGAA member companies are exploring new avenues for improving employee and public safety performance. While important, there are limits on the ability to achieve improvements based solely on traditional techniques such as training, qualification and increased inspection. Pipeline workers—whether pipeline employees, contractors or excavators—must be motivated to make safety a primary focus. There must be a safety culture. Safety culture has been described as an inherent attitude toward safety of an individual, whether they are supervised or not supervised. Our goal is to create and improve this safety culture.

The U.S. Chemical Safety Board has advocated safety culture as a constructive means to improve safety performance, and INGAA has embraced this philosophy. The natural gas transmission pipeline industry has had an excellent employee safety record over the decades and we have extended that focus and thought process to encompass work practices as they impact public safety. We are now in the third year of implementing this process and have invited our contractor community (members of the INGAA Foundation, which is affiliated with INGAA) to adopt the philosophy as well.

Recommendations to Improve the Pipeline Safety Act

The regulatory and process changes referenced in this testimony all point to a pipeline safety regime that is working well to minimize risk to the public. INGAA believes that the existing pipeline safety program has been a success, especially with respect to natural gas transmission efforts. For this reason, we would endorse a simple reauthorization bill that reauthorizes the pipeline safety program for 4 years without any new regulatory programs or mandates. Given the success of the program over the last 4 years, the expiration of the current authorization in September, and the short time remaining in this Congress, a simple reauthorization bill is a logical solution. Still, should Congress choose to move beyond a simple reauthorization bill, we would offer the following suggestions, which build on existing efforts under the law.

Removal of Exclusions from Participating in Excavation Damage Prevention Program

The "serious" incident data cited earlier in my testimony points to the importance of damage prevention as an essential means to avoid fatalities and injuries. The Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (PIPES Act) took an important step forward by creating incentives for states to adopt improved damage prevention programs that meet nine critical elements identified in the Act. This was an important step in raising the performance bar across the states.

One of the larger issues still existing in some of the State excavation damage prevention programs is the categorical exclusion of certain excavators from the notification requirements of state "one-call" systems. These excluded groups often include entities such as state highway departments (and their contractors), municipal governments and railroads, who together represent a significant percentage of excavation activity each year. In order to provide the public with maximum protection, exemptions from state one-call programs should be strongly discouraged. We recommend that such one-call exemptions be a factor that PHMSA must consider when deciding whether to make annual state pipeline safety grants and one-call grants.

The importance of damage prevention was highlighted in two recent pipeline accidents in Texas. On June 7, an intrastate natural gas pipeline near Dallas was struck by utility workers building a power line, causing one fatality and eight injuries. The next day, another intrastate natural gas pipeline in the Texas Panhandle was struck by a bulldozer engaged in construction work, causing two fatalities and one injury. The Texas Railroad Commission (which regulates these pipelines) and the National Transportation Safety Board are investigating these accidents, so the precise causes remain unknown. However, it is clear that some sort of miscommunication occurred between the excavators and the pipeline operators. Effective communication is the key, but the fact that these preventable accidents are still happening means that more remains to be done. An effective damage prevention effort is about more than just making the first call; it also means full participation by all excavators and underground utility operators, accurate and timely marking of underground utilities when a call is made, and using due caution when excavating around marked underground utilities. Every state program should actively be moving toward these goals.

Risk-Based Interval for Reassessments in the Integrity Management Program

During the last reauthorization, INGAA petitioned Congress to remove the statutory requirement for mandatory reassessments every 7 years for natural gas transmission pipeline in HCAs. We have previously provided Congress with the rationale supporting this amendment, along with detailed technical support and evidence of the concurrence by many groups including OPS, GAO, international pipeline safety experts and the American Society of Mechanical Engineers (ASME).

As part of the PIPES Act, Congress directed OPS to present a recommendation on whether to amend the law governing reassessment intervals on natural gas transmission pipelines. Deputy Secretary of Transportation Adm. Thomas Barrett outlined the numerous reasons why the seven-year requirement should be rescinded in a memo to Congress dated November 27, 2007. The GAO developed a report[6] on this issue as well, stating in 2006:

> *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.*

Since then, OPS and the industry have gathered additional documentation, data and experience that validate the previous request. We believe a clear statutory mandate from Congress authorizing the adoption of risk-based intervals would not reduce safety performance, but would enhance safety through a more efficient and effective allocation of industry and PHMSA resources.

[6] GAO–06–945, *Natural Gas Pipeline Safety: Risk-Based Standards Should Allow Operators to Better Tailor Reassessments to Pipeline Threats,* September 2006.

Review of Legacy PHMSA Regulatory Requirements in Light of New Technology and Processes

One of the benefits of the IMP was the improvement of pipeline management practices due to new technology and processes. Much of the justification of the cost effectiveness of the new IMP regulatory program was that legacy pipeline safety requirements, such as class location upgrades, would be superseded by new, more sophisticated regulations and practices. While the industry has adopted the new, more sophisticated practices and has documented them in consensus standards, redundant legacy OPS regulations, such as mandatory class location upgrades, remain in place. This causes an unnecessary overlap in procedures to achieve the same safety goals.

INGAA would request that Congress charge PHMSA and consensus standards organizations such as the ASME with examining whether parts of the present compendium of pipeline safety regulations have become redundant in light of changes in technology and processes adopted by more recent regulations. If the record supports a conclusion that such legacy requirements are redundant and unnecessary, we ask that such regulations be rescinded in favor of the new (and more effective) integrity management requirements.

Conclusion

Mr. Chairman, this subcommittee and the Congress can take pride in the fact that the pipeline safety efforts embarked upon by you and your colleagues have improved public safety significantly in the last decade. An energy delivery system that was, by all measures, already the safest in the nation, has continued to define new boundaries for developing a safety culture and reducing risk to the public. Given the importance of natural gas in America's energy future, the construction and operation of a safe transportation system for natural gas is critical. INGAA and its members will not be satisfied without continuous safety improvement, but we have worked hard in implementing the Congressional goals articulated in the PIPES Act and in the PSIA. The safety performance metrics collected by PHMSA from the member companies of INGAA demonstrate this commitment. This is an effective safety program, and we hope you agree that any changes should build on existing programs and successes.

Thank you for holding this hearing and for inviting me to participate on behalf of INGAA. Please let us know if you have any additional questions, or need additional information.

Senator LAUTENBERG. Thank you very much.

Mr. Weimer.

STATEMENT OF CARL WEIMER, EXECUTIVE DIRECTOR, PIPELINE SAFETY TRUST

Mr. WEIMER. Chairman Lautenberg, Ranking Member Thune, and members of the Subcommittee: Thank you for inviting me to speak today on the important subject of pipeline safety. My name is Carl Weimer and I'm the Executive Director of the Pipeline Safety Trust. The Pipeline Safety Trust is the only nonprofit organization in the country that strives to provide a voice for those affected by pipelines. With that in mind, we are here today to speak for the relatives of the 58 people who have been killed, the 225 people who have been injured, and for those who have been burdened by over $900 million in property damage from pipeline incidents that have occurred since we last spoke to this committee in November 2006.

We provided many ideas for improvements in our written testimony, but would like to concentrate on just a few of them here this afternoon. Our priority for this year's reauthorization is the expansion of the integrity management rules to more miles of pipeline. Integrity management has been one of the most important aspects of both the Pipeline Safety Improvement Act of 2002 and the PIPES Act of 2006, and it's what requires that once a pipeline is put in the ground that it is ever inspected again.

Currently only 44 percent of hazardous liquid pipelines and only 7 percent of natural gas transmission pipelines fall under these important integrity management inspection rules. Of all the deaths caused by these types of pipelines since 2002, over 75 percent of them have occurred on pipelines not required to meet these rules.

This summer will be the 10-year anniversary of the Carlsbad, New Mexico, pipeline explosion that killed 12 people. In response, Congress passed the Pipeline Safety Improvement Act of 2002, which required integrity management of natural gas transmission pipelines within certain high consequence areas. Unfortunately, these areas are still so narrowly defined that they don't even include the Carlsbad pipeline area where 12 people died. People who live and work near pipelines in more rural areas interpret this to mean that Congress and PHMSA have decided their lives are not worth protecting with these same important integrity management rules.

When integrity management was first conceived, leaders within Congress and PHMSA stated that in the future these types of inspection requirements would be expanded. We believe the future is now and that the industry now has the experience and the equipment necessary to begin similar inspections on the over 300,000 miles of pipelines that currently have no such requirements.

For these reasons, the Trust asks you to direct PHMSA to initiate a rulemaking to implement a similar integrity management program on all the pipelines that fall outside of the current rules.

In the PIPES Act of 2006, Congress made clear its desire that states move forward with damage prevention programs. We hope Congress will encourage PHMSA to continue to move forward with its recent proposed rulemaking regarding damage prevention. There is also a huge lack of valid data regarding excavation damage to pipelines that makes it nearly impossible to implement programs strategically and cost-effectively. We hope Congress will require PHMSA to ensure there is a valid mandatory reporting requirement for excavation damage.

After 2 years of work, a multi-stakeholder group of more than 150 people from around the country, the Pipelines and Informed Planning Alliance, is about to release a report that makes recommendations for actions that local government can take to protect people and pipelines through their land use regulations when new development is proposed near pipelines. This effort is a holdover from the 2002 reauthorization and will implement the recommendations of a Congressionally mandated Transportation Research Board report.

Such development encroachment near pipelines is a growing problem nationwide and the Trust asks that this year Congress authorize $500,000 per year to promote, disseminate, and provide technical assistance to local governments regarding the PIPA recommendations so they are actually aware that they exist.

Finally, there is still a good deal of work to do for PHMSA to finalize the low-stress pipeline mandates of the PIPES Act and to institute similar rules for unregulated sections of natural gas gathering and production pipelines, particularly in urban areas. Technical assistance grants to communities need to be authorized and funded so local communities can learn more about the pipelines in their midst, and industry public awareness programs need to be upgraded to ensure their effectiveness, as the NTSB has recently noted in one of their recommendations.

Congress needs to ensure that PHMSA has the resources necessary to ensure that the many miles of new pipelines being constructed are adequately inspected during construction and that the public and local government is adequately involved in the review of special permits, spill response plans, and the designation of high consequence areas.

Thank you again for this opportunity to testify today. We hope you will consider some of the ideas we have brought forward, and we'd be glad to answer any questions now or in the future.

[The prepared statement of Mr. Weimer follows:]

PREPARED STATEMENT OF CARL WEIMER, EXECUTIVE DIRECTOR, PIPELINE SAFETY TRUST

Good afternoon, Chairman Lautenberg, Ranking Member Thune and members of the Subcommittee. Thank you for inviting me to speak today on the important subject of pipeline safety. My name is Carl Weimer and I am testifying today as the Executive Director of the Pipeline Safety Trust. I am also a member of the Pipeline and Hazardous Materials Safety Administration's (PHMSA) Technical Hazardous Liquid Pipeline Safety Standard Committee, as well as a member of the steering committee for PHMSA's Pipelines and Informed Planning Alliance. I also serve on the Governor-appointed Washington State Citizens Committee on Pipeline Safety, and bring a local government perspective to these discussions as an elected member of the Whatcom County Council in Washington State.

The Pipeline Safety Trust came into being after the 1999 Olympic Pipe Line tragedy in Bellingham, Washington that left three young people dead, wiped out every living thing in a beautiful salmon stream, and caused millions of dollars of economic disruption. After investigating this tragedy, the U.S. Department of Justice (DOJ) recognized the need for an independent organization that would provide informed comment and advice to both pipeline companies and government regulators, and would provide the public with an independent clearinghouse of pipeline safety information. The Federal trial court agreed with the DOJ's recommendation and awarded the Pipeline Safety Trust $4 million which was used as an initial endowment for the long-term continuation of the Trust's mission.

The vision of the Pipeline Safety Trust is simple. We believe that communities should feel safe when pipelines run through them, and trust that their government is proactively working to prevent pipeline hazards. We believe that local communities who have the most to lose if a pipeline fails should be included in discussions of how best to prevent pipeline failures. And we believe that only when trusted partnerships between pipeline companies, government, communities, and safety advocates are formed, will pipelines truly be safer.

We also believe that trust in pipeline safety increases in proportion to the amount of verifiable scientific information that is readily available for all concerned to review. For the most part outside review increases the confidence in pipeline safety as those with concerns learn that in fact pipelines truly are a safe way to transport fuels. In those instances when safety has lapsed such review will help to more quickly correct the situation and create a push for even greater levels of safety. Consequently, one of the Trust's highest priorities is to make available as much relevant and accurate information as possible for independent review.

It is hard to ignore the current disaster in the Gulf of Mexico when talking about the safety of moving those same fuels by pipeline. In the past few weeks many people have tried to make a connection between that disaster and the safety of our onshore pipeline system. There are certainly many parallel lessons that should be reviewed, but in many ways PHMSA learned these hard lessons 10 years ago when pipelines failed in Washington and New Mexico killing 15 people. At that time PHMSA, then RSPA, was very much like MMS is today—regulation only when industry approved it, utilizing industry standards even if they had gaps, very little enforcement, no transparency to the public, and conflicted in its mission. Fortunately I am happy to report that it is our opinion that PHMSA learned many of those hard lessons and has made many significant changes for the better. While there is always room for improvement, as we will point out today, PHMSA is a very different agency today than MMS, and people should avoid the temptation to paint all agencies dealing with oil with the same brush.

The Pipeline Safety Trust is the only non-profit organization in the country that strives to provide a voice for those affected by pipelines. With that in mind, we are here today to speak for the relatives of the 58 people who have been killed by pipeline incidents since we last spoke to this committee on November 16, 2006. We are speaking for the 225 people who have been injured, and those who have been burdened by over $900 million in property damage from pipeline incidents that have occurred since we were last here 4 years ago.

In my testimony this morning I will cover the following areas that are still in need of improvement:

- Expanding the miles of pipelines that fall under the Integrity Management rules.
- Continuing to push state agencies on damage prevention.
- Implementing the Pipelines and Informed Planning Alliance (PIPA) recommendations.
- Correcting the pipeline siting vs. safety disconnect, and ensuring PHMSA's ability to provide inspections when pipelines are being constructed.
- Continuing implementation and funding of Technical Assistance Grants to Communities.
- Continuing to make more pipeline safety information publicly available.
- Moving forward to address unregulated pipelines and clarifying regulations of gathering and production pipelines.
- Making public awareness programs meaningful and measurable.
- Implementing expansion of Excess Flow Valve requirements.
- Concerns with industry developed standards being incorporated into Federal regulations.

Expanding the Miles of Pipelines That Fall under the Integrity Management Rules

In response to horrific pipeline tragedies, Congress required integrity management in High Consequence Areas (HCAs) as a way to protect the people who live, work and play near pipelines, as well to protect sensitive environmental areas and this Nation's critical energy infrastructure. Before integrity management, a pipeline company could install a pipeline transporting huge quantities of often explosive fuel and leave it uninspected indefinitely—even for 50, 60, or 70 years. Even today only 7 percent of natural gas transmission pipelines and 44 percent of hazardous liquid pipelines fall under these inspection programs.

To be blunt, it is not "safe" to wait until a pipeline explodes to learn about its integrity. Consider these examples where people died when pipelines outside of High Consequence Areas and thereby not covered by the current integrity management requirements ruptured and exploded:

- An extended family of 12 that was killed when a pipeline that falls outside of the current integrity management requirements failed while they were camping at their favorite fishing hole in New Mexico 10 year ago this summer. Tens years later this same area is still not protected by the integrity management program.
- Corbin Fawcett who was killed while driving down an interstate highway north of New Orleans on a beautiful day in December of 2007 when an natural gas pipeline that falls outside of the current integrity management requirements exploded under his car.
- Maddie and Naquandra Mitchel, a grandmother and her granddaughter, who were killed in Mississippi in 2007 trying to escape from their home when a pipeline that falls outside of the current integrity management requirements ruptured and exploded.

The examples are too numerous; in fact, since these rules began to be implemented in 2001, over 75 percent of all the deaths caused by these types of pipelines have occurred in areas that fall outside of the current integrity management requirements. People who live, work or play near pipelines in a more rural areas interpret this to mean that Congress and PHMSA have decided their lives are not worth protecting with these important integrity management rules.

The current concept of requiring integrity management programs only for pipelines in High Consequence Areas also is not sufficiently protective of America's economy. Regardless of where a pipeline fails, there will be a significant economic impact on the downstream markets. For instance, when the El Paso natural gas pipeline failed in 2000 in a non-High Consequence Area, the staff of the Federal Energy Regulatory Commission estimated that the restriction in gas supply cost the people of California hundreds of millions of dollars. Every time a major liquid pipeline serving a refinery goes down the price of gasoline in the region skyrockets until the pipeline can be repaired and supplies returned to normal. Congress experienced this not too long ago when a BP pipeline in Alaska failed from corrosion and the American people paid millions of dollars in higher gas prices. When it comes to consumer's pocketbooks, and the welfare of the economy, every mile of pipeline is of high consequence, so every mile should be inspected so that the American people have reliable and safe pipeline infrastructure.

The Pipeline Safety Trust believes that limiting integrity management programs to High Consequence Areas made good sense when these programs were just starting nearly 10 years ago. At that time many in the industry had very little experience with these inspection techniques and knew little about how to categorize and respond to anomalies found. Furthermore, there was a real shortage of inline inspection tools and experienced contractors to operate them. Hazardous liquid pipeline operators have now completed at least one round of inspections and are well into the second round. Natural gas transmission operators are approaching completion of their first round of inspections. It is clear that the industry now has the experience and infrastructure necessary to move forward with an expansion of integrity management so that people who live, work and play near all the pipelines in this country are safe.

Many progressive pipeline operators already apply integrity management rules to significantly more miles of their pipelines than required by Federal regulations. These companies do this because they think it is good business, and we couldn't agree more. Unfortunately not all companies voluntarily provide these needed safety precautions, and even those that do are not required to respond to the problems found as they would be if these areas were covered by the integrity management rules. It is also important to point out that natural gas pipeline operators are not even required to report to PHMSA the problems they find outside of High Consequence Areas. This reporting needs to be mandated so that PHMSA can have a better understanding of the safety of this Nation's pipelines.

Since integrity management programs began in 2001, more than 34,000 anomalies found in High Consequence Areas have been repaired based on integrity management requirements. It is now time to find the thousands of anomalies on those sections of pipelines that fall outside of these areas by expanding integrity management to all hazardous liquid and natural gas transmission pipelines. The American people who live, work, and play in these uninspected areas deserve these protections.

Implementation of Integrity Management rules have been one of the most important aspects of both the Pipeline Safety Improvement Act of 2002 and the Pipeline Inspection, Protection, Enforcement and Safety (PIPES) Act of 2006. The earlier Act focused mainly on transmission pipelines and the PIPES Act extended Integrity Management to the much larger realm of distribution pipelines. All of these efforts represent a significant increase in regulations meant to increase pipeline safety, and we would like to commend both PHMSA and the industry for the initial implementation of these programs. It is now time to expand this important program to all hazardous liquid and natural gas transmission pipelines.

For these reasons the Trust asks that you direct PHMSA to initiate a rulemaking by a date certain to implement a similar Integrity Management program on all the pipelines that fall outside of current HCAs.

Concerns with Possible Changes to Integrity Management

Since nearly the time integrity management was passed for natural gas transmission pipelines as part of the Pipeline Safety Improvement Act of 2002 some within the natural gas industry have lobbied for a relaxation of the 7-year re-inspection interval that Congress set. The pipeline Safety Trust opposes any relaxation of this re-inspection interval for the following reasons:

1. The baseline inspection period has not even been reached yet, and we believe that it is necessary to go through two or three re-inspections to determine whether the system is actually working and if it makes sense to change the re-inspection interval. Some companies have not even completed one round of inspections yet. During the first round many anomalies with the pipelines were identified and repaired. Subsequent rounds of inspections should tell us how quickly new anomalies appear and at what rates they are growing. Without that information from ongoing re-inspections it is too early to propose changing the re-inspection interval.

2. The industry also argues that Instead of a standard re-inspection interval that would allow all companies' results to be compared, each company, based on its own internal findings, should be allowed to design its own re-inspection program for each individual segment of its pipelines. This engineered, risk-based approach may be feasible, but it places much of the authority to draft the requirements with each company unless PHMSA has the extensive resources necessary to review each program to ensure it is no less protective than the current seven-year re-inspection intervals. We doubt PHMSA has such resources, and this proposed system also includes no way for the public to review and comment on the proposed engineered risk-based re-inspection proposals.

3. There is also increasing mileage of large high pressure natural gas pipelines in areas with very high density populations. The consequences if one of these pipelines should fail in such an area would be catastrophic. Before there is any consideration to changes in the re-inspection interval for these types of natural gas pipelines PHMSA should reassess the safety protocols in place to ensure that it is impossible for a pipeline to fail in such an area from any cause that is within the operator's controls (corrosion, materials, operation, maintenance, inspections, etc.).

For these reasons, we continue to oppose any change to the seven-year re-inspection interval for natural gas transmission pipelines.

Continuing to Push State Agencies on Damage Prevention

Property owners, contractors, and utility companies digging in the vicinity of pipelines are still one of the major causes of pipeline incidents, and for distribution pipelines over the past 5 years excavation damage is the leading cause of deaths and injuries. Unfortunately, not all states have implemented needed changes to their utility damage prevention rules and programs to help counter this significant threat to pipelines.

In the PIPES Act of 2006 Congress made clear its desire that states move forward with damage prevention programs by defining the nine elements that are required to have an effective state damage prevention program. The Trust is pleased that PHMSA has recently announced its intent to adopt rules to incorporate these nine elements, and their intent to evaluate the states progress in complying with them. We also support PHMSA's plan to exert its own authority to enforce damage prevention laws in states that won't adopt effective damage prevention laws. We hope Congress will encourage PHMSA to move forward with this proposed rulemaking in a timely manner, and make it clear to the states that Federal money for pipeline safety programs depends upon significant progress in implementing better damage prevention programs.

It may also be necessary for Congress to clarify important parts of good damage prevention programs. Many states have exemptions to their damage prevention "one-call" rules for a variety of stakeholders including municipalities, state transportation departments, railroads, farmers, and property owners. We believe such exemptions, except in cases of emergencies, are unwarranted for municipalities, state transportation departments and the railroads, and urge both Congress and PHMSA to make it clear that these types of exemptions are not acceptable in an effective damage prevention program. While we are skeptical regarding exemptions of any type, limited exemptions for the farm community and homeowners in specific circumstances may be necessary to make the programs efficient, affordable and enforceable.

Although PHMSA likes to call itself a data-driven agency, there is a serious lack of data to determine the extent, causes, or perpetrators of excavation damage to pipelines. For example, the PHMSA incident database only includes about 70 total pipeline incidents nationwide in 2008 caused by excavation damage. Yet the Common Ground Alliance's 2008 DIRT database reports well over 60,000 excavation events that affected the operation of natural gas systems alone.

Why are PHMSA's numbers so low? PHMSA only requires natural gas pipeline operators to file reports when there is a death, hospitalization, or over $50,000 of property damage measured in 1984 dollars (about $90,000+ in today's dollars). Industry complaints about reporting requirements may be part of the reason that reporting thresholds are so high, but Section 15 of the PIPES Act also required PHMSA to respond to a GAO report to ensure that "incident data gathered accurately reflects incident trends over time," which is why data is normalized to 1984 dollars. While this makes good sense for tracking property damage, nowhere did GAO or Congress recommend that thousands of incidents related to excavation damage be left out of the database thereby creating another data gap making it impossible to track the larger problem of excavation damage trends over time.

The Common Ground Alliance's database—while more telling—cannot be relied on for complete and valid data for two reasons: (1) reporting is voluntary and consequently of a "hit and miss" nature; and (2) reporting is anonymous, making the data not verifiable. Without valid and complete data it will be impossible to actually measure whether damage prevention programs are well targeted or effective.

For these reasons, the Trust asks that Congress direct PHMSA to correct this substantial data gap by ensuring a more accurate reporting and database for excavation damage to ensure that the effort and money being spent is well targeted and effective. Because most states have taken on the responsibility of operating state-based damage prevention programs it may well be easiest to just have PHMSA require states to adopt reporting requirements as part of their damage prevention programs.

One existing example is in Texas where in 2007 Texas adopted regulations requiring both pipeline operators and excavators to report excavation damage to pipelines. These reports are submitted directly to the Texas Railroad Commission's website, and anyone can search the database for incidents in specific locations, on specific pipelines, by specific excavators, or for the individual damage report forms. This system seems to give Texas regulators and involved stakeholders adequate information to target damage prevention and enforcement activities, and track improvement over time. More information is available at: *http://www.rrc.state.tx.us/programs/damageprevention/index.php*.

This type of state-based reporting system can go hand-in-hand with PHMSA's recent Advanced Notice of Proposed Rulemaking about better defining adequate damage prevention programs. While some consistency between state reporting requirements may be necessary so state programs can be adequately evaluated and compared, this ultimately may be an easier reporting system to institute than either the expansion of PHMSA's or refining of CGA's.

Implementing the Pipelines and Informed Planning Alliance (PIPA) Recommendations

Section 11 of the Pipeline Safety Improvement Act of 2002 included a requirement that PHMSA and FERC provide a study of population encroachment on and near pipeline rights-of-way. That requirement led to the Transportation Research Board's (TRB) October 2004 report *Transmission Pipelines and Land Use*, which recommended that PHMSA "develop risk-informed land use guidance for application by stakeholders." PHMSA formed the Pipelines and Informed Planning Alliance (PIPA) in late 2007 with the intent of drafting a report that would include specific recommended practices that local governments, land developers, and others could use to increase safety when development was to occur near transmission pipelines.

Most large pipelines were placed in rural areas years ago, but as the populated areas around our cities expand it has led to a growing encroachment of residential and commercial development near large high-pressure pipelines. This increases the risk to the pipelines from related construction activities, as well as to the people who ultimately live and work nearby if something should go wrong with the pipeline.

After more than 2 years of work by more than 150 representatives of a wide range of stakeholders, the draft report and the associated 46 recommendations are finally due to be released sometime this summer. This will be the first time information of this nature has been made widely available to local planners, planning commissions, and elected officials when considering the approval of land uses near transmission pipelines. We fully agree with the sentiment of Congress in the Pipeline Safety Improvement Act of 2002 that,

> *"The Secretary shall encourage Federal agencies and State and local governments to adopt and implement appropriate practices, laws, and ordinances, as identified in the report, to address the risks and hazards associated with encroachment upon pipeline rights-of-way . . ."*

A recent statewide survey of local government planning directors conducted by the Pipeline Safety Trust showed that to successfully implement these needed "practices, laws, and ordinances" will take a good deal of well targeted education and promotion by a wide range of stakeholders outside of the pipeline industry and PHMSA. In order to make this effort successful, the Trust asks that this year Congress authorize, just as was authorized in PIPES for the successful promotion of the 811 "One-Call" number, $500,000/year to promote, disseminate, and provide technical assistance regarding the PIPA recommendations.

Correcting the Pipeline Siting vs. Safety Disconnect, and Ensuring PHMSA's Ability to Provide Inspections When Pipelines Are Being Constructed

With thousands of new miles of pipelines in the works, the disconnect between the agencies that site new pipelines and PHMSA, the agency that is responsible for the safety of the pipelines once they are in services, has become quite apparent. While siting agencies go through supposed comprehensive environmental review processes, these processes are functionally separate from the special permits or response plans or high consequence area analyses that are overseen by PHMSA. Many of the PHMSA determinations go through very limited public process (special permits), or processes that take place after the pipeline siting approval is granted (emergency response plans), and some are totally kept from the public (high consequence areas). How can local governments and citizens assess the real potential impact of a pipeline if the environmental review and the safety review processes are so disconnected?

It also appears that siting agencies such as the Federal Energy Regulatory Commission, the U.S. State Department, and state agencies pay little or no attention to the past safety and construction histories of the companies they are granting permits to. These permits, which allow the pipeline companies to build new pipelines, also authorize these companies to condemn people's property.

About a year ago, PHMSA held a special workshop to go over the numerous problems they found during just 35 inspections of pipelines under construction. These inspections found significant problems with the pipe coating, the pipe itself, the welding, the excavation methods, the testing, etc. PHMSA's findings, and stories we have heard from people across the country, call into question the current system of inspections for the construction of new pipelines. This construction phase is critical for the ongoing safety of these pipelines for years to come. Since PHMSA has authority over the safety of pipelines once they are put into service, it makes sense to us that during construction they also are conducting field inspections and sufficiently reviewing records to ensure these pipelines are being constructed properly. Unfortunately, there is a built-in disincentive for PHMSA to spend the necessary time to ensure proper construction. Under current rules PHMSA receives no revenue from these companies until product begins to flow through the pipelines, so any staff time spent on these pre-operational inspections has to be paid for from money collected for other purposes from already operational pipelines.

For these reasons, the Pipeline Safety Trust asks that Congress pass new Cost Recovery fees, similar to those included in Section 17 of the PIPES act for LNG facility reviews, to allow PHMSA to recoup their costs related to providing safety information during the review process for new pipelines and legitimate inspections during the construction phase without taking resources away from other existing activities.

Continuing the Implementation and Funding of Technical Assistance Grants to Communities

Over the past year and a half, PHMSA has started the implementation of the Community Technical Assistance Grant program that was authorized as part of the Pipeline Safety Improvement Act of 2002 and clarified in the PIPES Act. Under this program more than a million dollars of grant money has been awarded to communities across the country that wanted to hire independent technical advisors so they could learn more about the pipelines running through and surrounding them, or be valid participants in various pipeline safety processes.

In the first round of grants, PHMSA funded projects in communities in seventeen states from California to Florida. Local governments gained assistance so they could better consider risks when residential and commercial developments are planned near existing pipelines. Neighborhood associations gained the ability to hire experts so they could better understand the "real" versus the imagined issues with pipelines in their neighborhoods. And farm groups learned first-hand about the impacts of already-built pipelines on other farming communities so they could be better informed as they participate in the processes involving the proposed routing of a pipeline through the lands where they have lived and labored for generations. Overall, we viewed the implementation of the first round of this new grant program as a huge success.

Ongoing funding for these grants is not clear, so the Trust asks that you ensure the reauthorization of these grants to continue to help involve those most at risk if something goes wrong with a pipeline. We further ask that you do whatever is necessary to ensure that the authorized funds are actually appropriated.

One area that should be considered with any new grant program is the amount of promotion and time it takes to get the word out about new sources of grant money. The Pipeline Safety Trust worked hard during the first round to promote this program to ensure that local government and citizen groups around the country knew about it and applied. Such targeted promotion, especially for a new grant program, is needed to ensure that PHMSA receives enough strong grant applications to choose from. During the application period for the second round of these grants, promotion was not as well organized and we have since learned from several groups around the country that they did not apply because they had no idea the grants were available again. While this will certainly correct itself as the knowledge of this grant program grows, we hope that PHMSA continues to provide adequate promotion and that Congress will take the long-term view of the value of this program while it grows to maturity.

Finally, we hope that PHMSA will resist the pressure to spend the money on applications that do not meet the Congressional intent of the program. While the second round of grants have not yet been announced, we have heard from some local governments around the country that municipal gas utilities have tried to apply for these grant funds to undertake pipeline projects that are clearly part of their existing pipeline maintenance and operation requirements. Funding municipal utilities with this community technical assistance grant money is clearly outside of the intent of what Congress approved this program for, and will cause a rush by such utilities that will overwhelm this limited funding. We ask that Congress expressly state—throughout the reauthorization process and in its final reauthorization legislation—that this grant program is not to fund the activities of any pipeline operator, public or private.

Continuing to Make More Pipeline Safety Information Publicly Available

Over the past two reauthorization cycles, PHMSA has done a good job of providing increased transparency for many aspects of pipeline safety. In the Trust's opinion, one of the true successes of PIPES has been the rapid implementation by PHMSA of the enforcement transparency section of the act. It is now possible for affected communities to log onto the PHMSA website (*http://primis.phmsa.dot.gov/comm/reports/enforce/Enforcement.html*) and review enforcement actions regarding local pipelines. This transparency should increase the public's trust that our system of enforcement of pipeline safety regulations is working adequately or will provide the information necessary for the public to push for improvements in that system. PHMSA has also significantly upgraded their incident data availability and accuracy, and continues to improve their already excellent "stakeholder communication" website.

One area where PHMSA could go even further in transparency would be a web-based system that would allow public access to basic inspection information about specific pipelines. An inspection transparency system would allow the affected public to review when PHMSA and its state partners inspected particular pipelines, what types of inspections were performed, what was found, and how any concerns were rectified. Inspection transparency should increase the public's trust in the checks and balances in place to make pipelines safe. We have been told by PHMSA that such a system is in the works. We hope that Congress will inquire about the design and timeline for implementation of this "in-the-works" system, and if it does not meet the above criteria require PHMSA to institute an Inspection Transparency system, just as you required PHMSA to institute the successful Enforcement Transparency in the PIPES Act of 2006.

There is also a need to make other information more readily available. This includes information about:

- *High Consequence Areas (HCAs).* These are defined in Federal regulations and are used to determine what pipelines fall under more stringent integrity management safety regulations. Unfortunately, this information is not made available to local government and citizens so they know if they are included in such improved safety regimes. Local government and citizens also would have a much better day-to-day grasp of their local areas and be able to point out inaccuracies or changes in HCA designations.
- *Emergency Spill Response Plans.* As has been learned in the recent Gulf of Mexico tragedy, it is crucial that these types of spill response plans are well designed, adequately meet worst-case scenarios, and use the most up-to-date technologies. While 49 CFR § 194 requires onshore oil pipeline operators to prepare spill response plans, including worst case scenarios, those plans are difficult for the public to access. To our knowledge the plans are not public documents, and they certainly are not easily available documents.

  The review and adoption of such response plans is also a process that does not include the public. In fact PHMSA has argued that they are not required to follow any public processes, such as NEPA, for the review of these plans. If the Gulf tragedy has taught us nothing else it should have taught us that the industry and agencies could use all the help they can get to ensure such response plans will work in the case of a real emergency.

It is always our belief that greater transparency in all aspects of pipeline safety will lead to increased involvement, review and ultimately safety. There are many organizations, local and state government agencies, and academic institutions that have expertise and an interest in preventing the release of fuels to the environment. Greater transparency would help involve these entities and provide ideas from outside of the industry. The State of Washington has passed rules that when complete spill plans are submitted for approval the plans are required to be made publicly available, interested parties are notified, and there is a 30 day period for interested parties to comment on the contents of the proposed plan. We urge Congress to require PHMSA to develop similar requirements for the adoption of spill response plans across the country, and that such plans for new pipelines be integrated into the environmental reviews required as part of the pipeline siting process.

- *State Agency Partners.* States are provided with millions of dollars of operating funds each year by the Federal Government to help in the oversight of our Nation's pipelines. While there is no doubt that such involvement from the states increases pipeline safety, different states have different authority, and states put different emphasis in different program areas. Each year PHMSA audits each participating state program, yet the results of those program audits are not easily available. We believe that these yearly audits should be available on PHMSA's website and that some basic comparable metrics for states should be developed.

Moving Forward to Address Unregulated Pipelines and Clarifying Regulations of Gathering and Production Pipelines

After numerous spills from low stress pipelines on Alaska's North Slope, Congress directed PHMSA to move forward with new rules to better regulate them. Section 4 of PIPES required PHMSA to "issue regulations subjecting low-stress hazardous liquid pipelines to the *same standards and regulations as other hazardous liquid pipelines*" (emphasis added) with limited exceptions for pipelines regulated by the U.S. Coast Guard and certain short-length pipelines serving refining, manufacturing, or truck, rail, or vessel terminal facilities. This section's clear directive to PHMSA to have these rules adopted by December 31, 2007, has only been partially followed since PHMSA decided to implement this directive in a phased approach, and so far PHMSA has only adopted phase one of those rules and made no announcement about phase two. Congress needs to require clear answers from PHMSA regarding the initiation and implementation of the phase 2 rules.

Meanwhile, significant drilling for natural gas has led to a large expansion of gathering and production pipelines in highly-populated urban areas. For instance, in Fort Worth Texas there are already 1,000 producing gas wells within the city limits and at least that many more planned. Development of improved gas drilling methods has led to thousands of new wells being drilled and proposed in more populated areas of Texas, Arkansas, Louisiana, Pennsylvania and New York. Pipelines will connect all these wells, and the regulatory oversight of these pipelines in these areas is less than clear and in some cases non-existent. The standards for PHMSA's rules to determine which pipelines fall under minimum Federal regulations were written by the American Petroleum Institute and incorporated by reference into the regulations. If the public wants to review these standards they have to buy a copy of this part of the Federal regulations from API for $126. What the API written standards actually require provides much wiggle room for gas producers to design their systems to avoid regulations. PHMSA also only regulates a limited amount of these gathering and production pipelines, and leaves the rest of the regulations up to the states if they choose to assert any authority. We believe it is time to ensure that any gathering or production pipeline in a populated area with similar size and pressure characteristics as other currently regulated pipelines fall under the same level of minimum Federal regulations. At a minimum we think Congress should require PHMSA or the National Transportation Safety Board to produce a study on the onshore gas production and gathering pipelines that are not covered by current Federal standards. This study should explain what pipelines are not covered, what the extent of them is, how many are located in populated areas, the relative risk, and a proposed regulatory regime for inclusion of all these pipelines under minimum Federal standards.

Making Public Awareness Programs Meaningful and Measurable

The Pipeline Safety Improvement Act of 2002 required pipeline operators to provide people living and working near pipelines basic pipeline safety information, and gave PHMSA the authority to set public awareness program standards and design program materials. In response to this Congressional mandate, PHMSA set rules that incorporated by reference the American Petroleum Institute's (API) recommended practice (RP) 1162 as the standard for these public awareness programs. According to RP 1162's *Foreword* (page iii) of API recommended practice, the intended audiences were not represented in the development of RP 1162, though they were allowed to provide "feedback." The omission of representatives from these audiences from the voting committee reduces the depth of understanding the RP could have had regarding the barriers and incentives for such programs, and undercuts the credibility of the recommended actions. The public awareness program regulations—49 CFR § 192.616 and 49 CRF § 195.440—mandate that operators comply with RP 1162. In essence, this amounts to the drafting of Federal regulations without the equal participation of the stakeholders the regulations are meant to involve. With non-technical subject matter, such as this recommended practice deals with, it is difficult to justify excluding the intended audiences from the process and allowing the regulated industries to write their own rules.

This public awareness effort represented a huge and important undertaking for the pipeline industry, and as such the effectiveness of it will evolve over time. We were happy that the rules included a clause that set evaluation requirements that require verifiable continuous improvements. While we understand that the initial years of this program have been difficult, we have been disappointed in some of these efforts as they were clearly farmed out to contractors to meet the letter of the requirement instead of the intent of the requirement. Recently, the National Transportation Safety Board cited the failure of these programs in the investigation report of a deadly pipeline explosion in Mississippi that killed a girl and her grandmother.

An evaluation of the first 5 years of this program is due this year, and API has been working on an update of this recommended practice for some time now. One of the draft proposals from API is to remove the requirement to measure whether the programs have led to actual changes in behavior. PHMSA plans to hold a workshop on these public awareness programs in late June. We hope that Congress will keep a close eye on the discussions of this issue over the coming months and be prepared to step in and clarify that the intent of this program is to change the behavior of the intended audiences to make pipelines safer, not to count how many innocuous brochures can be mailed.

Implementing Expansion of Excess Flow Valve Requirements

One of the Trust's priorities that was well addressed in the PIPES Act was to require the use of Excess Flow Valves (EFVs) on distribution pipelines for most new and replaced service lines in single family residential housing. While this was a huge step forward, the National Transportation Safety Board (NTSB) has continued to push for an expansion of the use of EVFs in multi-family and commercial applications "*when the operating conditions are compatible with readily available valves*."

From closely following the deliberations of PHMSA's Large Excess Flow Valve Team, it is our opinion that there are thousands of potentially compatible structures being constructed or renewed which could be afforded greater safety by the installation of Excess Flow Valves (EFVs). It is clear from the data provided by PHMSA (see *figure 1* below) that the services lines serving a majority of these types of structure fall within the size constraints of commercially available EFVs. It is also clear from the data (see *figure 2*) that the vast majority of these gas services are provided at pressures that avoid the concerns regarding low pressure lines.

Figure 1 (Source—PHMSA's—Interim Evaluation: Response To NTSB Recommendation P–01–2)

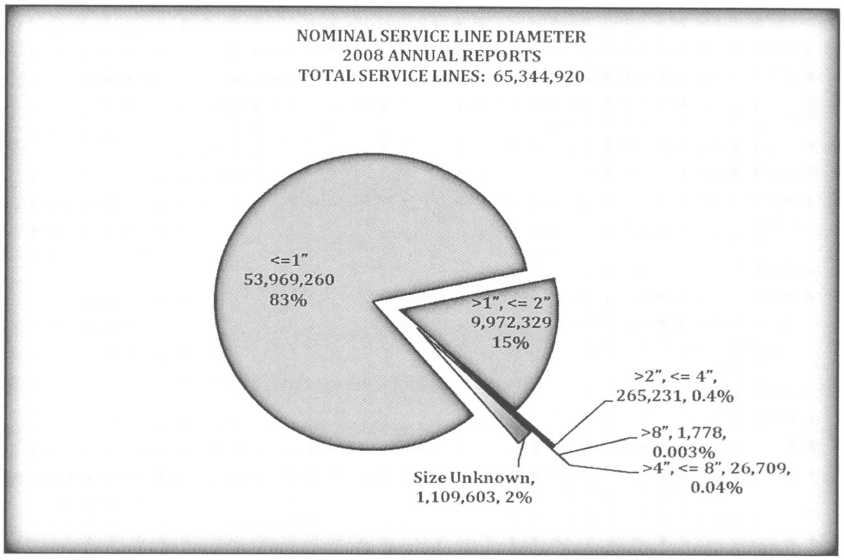
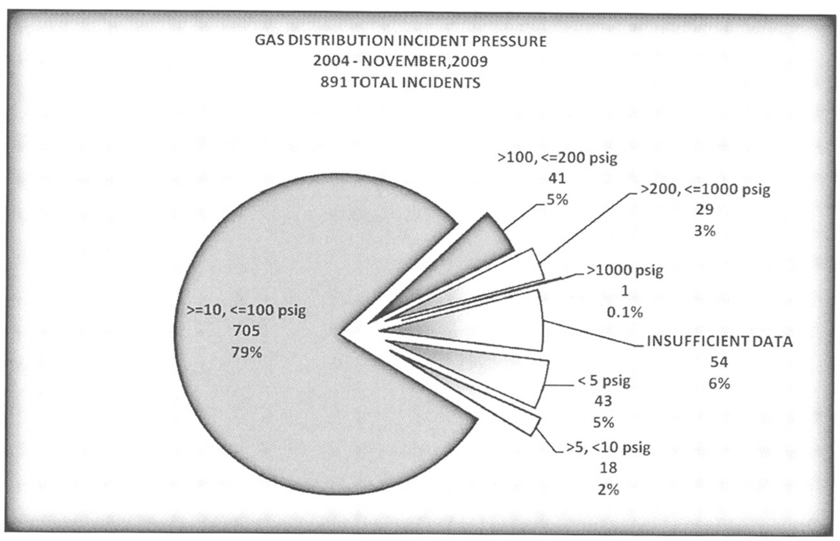


Figure 2 (Source—PHMSA's—Interim Evaluation: Response To NTSB Recommendation P–01–2)



The one significant hurdle to overcome is to avoid EFVs to structures where the demand load varies greatly or could change over time. There are many multi-family residential, small office, and retail structures that for all intents and purposes have the same load profiles as a single family residence. For these types of applications PHMSA and the industry need to move forward with rules to require installation of EFVs for new and renewed gas service.

From our perspective, it would be difficult to engineer the application of EFVs to avoid the problems associated with load fluctuation for such structures as hospitals, multi-tenant commercial buildings, and industrial facilities. We agree with the industry's concerns about the installation of EFVs for these types of applications, and believe more study is needed both in terms of these large applications as well as the effectiveness of EFVs on current applications.

The real difficulty is drafting rules that clearly define which additional applications are within the needed expansion of the rules and which applications are not. We are disappointed that some in the industry—as a way to stop all movement toward improved safety rules—always point to the types of structures that are difficult or impossible to serve with EFVs. Instead, they should be searching for a way to increase the safety of thousands of people who live or work within buildings that could clearly be served by EFVs. The Pipeline Safety Trust urges Congress to direct PHMSA to undertake a rulemaking—as the National Transportation Safety Board has requested—that would require EFVs be installed on the many types of structures where "*operating conditions are compatible with readily available valves*."

Concerns with Industry Developed Standards Being Incorporated into Federal Regulations

There has been increasing attention because of the Gulf of Mexico tragedy to the practice by Federal agencies of incorporating into their regulations standards that outside organizations developed. Like MMS, PHMSA has incorporated by reference into its regulations standards developed by organizations made up in whole or in part of industry representatives. A review of the Code of Federal Regulations under which PHMSA operates finds the following numbers of incorporated standards:

Standards Incorporated by Reference in 49 CFR Parts 192, 193, 195
(As of 6/9/2010)

CFR Part	Topic	Standards*
192	Natural and Other Gas	39
193	Liquefied Natural Gas	8
195	Hazardous Liquids	38
		Total 85

*Note: Some standards may be incorporated by reference in more than one CFR Part.

Those standards were developed by the following organizations:

American Gas Association (AGA)
American Petroleum Institute (API)
American Society for Testing and Materials (ASTM)
American Society of Civil Engineers (ASCE)
ASME International (ASME)
Gas Technology Institute (GTI)
Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS)
NACE International (NACE)
National Fire Protection Association (NFPA)
Pipeline Research Council International, Inc. (PRCI)
Plastics Pipe Institute, Inc. (PPI)

While the Pipeline Safety Trust has not done an extensive review of these organizations or their standard setting practices, it is of great concern to us—and we believe it should be to Congress as well—whenever an organization whose mission is to represent the regulated industry is—in essence—writing regulations that members of the organization must follow. A very quick review of the mission statements of some of these organizations reveals statements like these below that show, at a minimum, a conflict between the best possible regulations for the entire public and the economic interests of the industry.

> API—"We speak for the oil and natural gas industry to the public, Congress and the executive branch, state governments and the media. We negotiate with regulatory agencies, represent the industry in legal proceedings, participate in coalitions and work in partnership with other associations to achieve our members' public policy goals."
>
> AGA—"Focuses on the advocacy of natural gas issues that are priorities for the membership and that are achievable in a cost-effective way." "Delivers measurable value to AGA members."
>
> PPI—"PPI members share a common interest in broadening awareness and creating opportunities that expand market share and extend the use of plastics pipe in all its many applications." "The mission of The Plastics Pipe Institute is to make plastics the material of choice for all piping applications."
>
> PRCI—"PRCI is a community of the world's leading pipeline companies, and the vendors, service providers, equipment manufacturers, and other organizations supporting our industry."

The pipeline industry has considerable knowledge and expertise that needs to be tapped to draft standards that are technically correct and that can be implemented efficiently. But we also know the industry's standard setting practices exclude experts and stakeholders who can bring a broader "public good" view to standard setting. We also know that when a regulatory agency needs to adopt industry-developed standards it is a "red flag" that the agency lacks the resources and expertise to develop these standards on its own.

It should be noted that the development of such standards is not an open process where interested members of the public or experts outside the industry (such as those in universities and colleges) can review the material and comment. One of the most ridiculous examples of this one sided process was the development of the Public Awareness standard (API RP 1162) which now governs how pipeline companies have to communicate with the affected public. The process was controlled by industry, even though industry has no particular expertise in this type of public awareness or communication. The many possible independent experts and organizations in the field of communications and education were not sought and ultimately were not a part of the development of this standard.

Even once the standards are incorporated by reference into Federal regulations the standards remain the property of the standard setting organization and are not provided by PHMSA in their published regulations. If the public, state regulators, or academic institutions want to review the standards they have to purchase a copy from the organization that drafted them. In many cases, this further removes review of the standards from those outside of the industry. Below are just a handful of examples of the cost to purchase for review the standards that are part of the Federal pipeline regulations:

Sample Cost of Pipeline Safety Standards Incorporated by Reference Into Federal Regulations

(As of 6/8/2010)

Standard	Organization	Code of Federal Regulations (Incorporated by Reference)	Cost
ANSI/API Spec 5L/ISO 3183 "Specification for Line Pipe"	API	49 CFR § 192.55, § 192.112, § 192.113, § 195.106	$245.00
ASME B31.4 –2002 "Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids"	ASME	49 CFR § 195.452	$129.00
GRI 02/0057 (2002) "Internal Corrosion Direct Assessment of Gas Transmission Pipelines Methodology"	GTI	49 CFR § 192.927	$295.00
NACE Standard RP0502–2002 "Pipeline External Corrosion Direct Assessment Methodology"	NACE	49 CFR § 192.923, § 192.925, § 192.931, § 192.935, § 192.939, § 195.588	$83.00
A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe"	PRCI	49 CFR § 192.933, § 192.485, §195.452	$995.00

The Pipeline Safety Trust asks that Congress carefully review the use of industry developed standards in minimum Federal pipeline safety regulations, as well as the development of risk-based programs that are not required to go through any sort of public review.

Summary of Testimony

As stated previously, the Pipeline Safety Improvement Act of 2002 and the Pipeline Inspection, Protection, Enforcement and Safety (PIPES) Act of 2006, have required many valuable and significant new pipeline safety efforts, including Integrity Management, increasing damage prevention efforts, greater transparency, and increasing the number of inspectors and the amount of fines. The Trust is very pleased with all of these efforts and does not see the need for any huge new programs during this reauthorization. Our recommendations build upon the important foundation that Congress has built during the past 10 years. What is always needed is constant vigilance so pipeline safety does not once again return to a system where the regulated control the regulators, and where what is easy takes precedence over what is safe.

Thank you again for this opportunity to testify today. The Pipeline Safety Trust hopes that you will closely consider the concerns we have raised and the requests we have made. If you have any questions now or at anytime in the future, the Trust would be pleased to answer them.

Senator LAUTENBERG. Thank you very much, Mr. Weimer.

You mentioned the fact that we've required excess flow valves. I authored a provision in the 2006 PIPES Act that required the devices for single-family homes and I think there is universal approval of this requirement. But they are not required currently for apartment or commercial buildings. In the reauthorization of pipeline safety legislation, what can Congress do to protect the people who live in dwellings other than single-family homes? I ask you, Mr. Weimer. What do you think we can do?

Mr. WEIMER. Well, NTSB still has a recommendation on the table that hasn't been fully met to include multi-family residences and commercial retail types of businesses. I think the key to that—and PHMSA has had a work group that looked at this—is when the load demand is similar to what a single-family residence is, and there are many of those, that they need to move forward on a rulemaking to include those types of businesses.

There are thousands of structures that have a load demand similar to a single-family residence and PHMSA just needs to come up with a rulemaking to define where that line is, because we do agree with the industry that there are some situations—chemical plants, hospitals—where excess flow valves may just not make sense. But there are lots of buildings they do, and we need to expand those inclusions.

Senator LAUTENBERG. Is there technology to do something to make these valves more effective where the demand for gas is great? So, even if something happens, that the direct flow to one user of part of the structure still requires energy?

Mr. WEIMER. Right. I think it's obvious from the work group that PHMSA has conducted that for the vast majority of the size of pipelines and for the load demands, there are already excess flow valves available to deal with that. It's just a matter of clarifying and defining where that line is, where you cross into different types that have load demands that vary so much that at this point excess flow valves don't make much sense.

Senator LAUTENBERG. Mr. D'Alessandro, what do you think? The industry has voiced concern, and you've expressed it, at the expanding use of excess flow valves. However, NTSB and safety advocates across the country have called for them, to be repetitive, to be required in these structures. Given what you've said and what you've heard today, can you commit to working with us, with the Committee, to find a practical solution on this issue?

Mr. D'ALESSANDRO. We look forward to doing that. Our issue is the mandatory installation of EFVs on all of the facilities. We think for some of them they might fit the occasion to do it, but I think in some of the testimony you've seen the words "operating conditions justify." In my testimony I talked about the service line and the fluctuation in pressures that happen within the facilities could kick off EFVs. But we'd love to work on EFVs and find some type of solution.

Senator LAUTENBERG. I wonder—this question can be answered by any one of you—whether or not in those types of buildings there ought to be something internal, not unlike a fire safety cannister or something like that—more than a cannister, but a unit that could be used. There is a significant extra risk in those buildings where there are multiple dwellings.

Anybody volunteer a response to that? We have to do something to protect the people who are in those buildings. Their lives are no less valuable. Their families are no less of concern. What can we suggest as an alternative to not being able to provide excess flow valves?

No volunteers?

Mr. D'ALESSANDRO. I'll give it a shot. The excess flow valve really protects the customer from an external or a hit before the meter set. That would protect them. If anything would happen within their own internal piping—and I'm not sure if that's where you're headed with your question—the excess flow valve would not protect that. It would not kick itself off if it's inside the home.

Safety—in the public awareness program that we've got going on, all of us participate in educating our consumers about natural gas, about the smell of natural gas, what to do in case they smell natural gas. Our response record of responding when there are gas emergencies in the gas distribution pipeline, we take it very serious and we all strive to have high standards on that.

Senator LAUTENBERG. Mr. Felt, a quick question here. BP's oil spill in the Gulf has shown that the company's response plan was completely inadequate. How can we be confident that oil companies operating offshore or onshore pipelines have the right response plans in place so that they're adequately prepared for a worst case scenario?

Mr. FELT. Well, sir, I think that if you look at what's expected today, response plans are developed by the pipeline companies, by the operators, submitted to the OPS for review and approval. Our experience, my experience, has been that when they are submitted we'll get some feedback, either on areas where they're not adequate or some clarification that's needed.

Just looking from our own personal company's standpoint, those plans are unique to each facility. They do look at worst case scenarios. They look at the worst case conditions in those worst case scenarios. PHMSA I believe is getting ready to come out—we saw a draft announcement just recently where they're going to ask for another review in light of what's happened in the Gulf, just to make sure that there are adequate resources to respond and if there are any changes please respond within the next 30 days. I hope I'm not jumping ahead of OPS, but we did see that announcement coming out.

Senator LAUTENBERG. Well, certainly this tragedy, this calamity that has taken place, puts us all on alert and we have to be much more careful about the exposure that something like that happens.

Mr. FELT. I agree.

Senator LAUTENBERG. Senator Thune.

Senator THUNE. Thank you, Mr. Chairman.

Gentlemen, thank you for your testimony today. Let me ask you a question about new technologies. What role do you see new technologies playing to improve the safety of pipelines?

Mr. SYPOLT. Senator, I'll take a shot at that to start with. Actually, we've seen technology improve over time, that basically has been used in our integrity management programs, like in new evolutions or new generations of smart pigs, and those continue to improve. I think that is a very key thing to help us in our integrity management programs. So I do think that continued research is a very valuable tool.

Senator THUNE. I think one of the greatest threats to pipeline safety and integrity—and it has been talked about at some length today—comes from accidental damage due to digging and excavation. I commend PHMSA and the states for developing the One-Call program, which allows excavators to dial 811 anywhere in the country and learn the location of pipelines and other utilities before digging.

However, recent accidents demonstrate that we may need to do more in this area, and I'm interested in what recommendations you might have for improving the One-Call program to prevent excavation damage. Anybody?

Mr. SYPOLT. I'll be happy to start it off for you, Senator. I do believe that, with regard to One-Call systems, they are our first line of attack to protect the public. Clearly I believe there should be no exceptions to One-Call. I think every party should have to call. No one should be excepted from safety.

Second, I think that there has to be a very clear communication between the parties with regard to where the activity is being done, and then there has to be a thorough follow up and marking of the pipelines. Fourthly, the group who's doing the excavation has to work very cautiously around those facilities.

If all four of those things do not work, I don't believe there's more regulation that could take care of it. I think regulation is in place to do those things, except for the part where certain parties are excepted from One-Call systems.

Mr. FELT. Sir, I'd like to add just one other point to that, and that's the enforceability. There are cases where there's no consequence for not following the One-Call rules, either for the excavator or the person doing the proper marking. I believe that's something that needs to be addressed as well.

Mr. WEIMER. One other point, if I could, and I certainly agree with everything that Mr. Sypolt and Mr. Felt said. Back to our issue of reporting requirements, recently in the two incidents in Texas, when we looked at those, the PHMSA database showed that on average there are ten incidents a year from damage in the State of Texas. The Texas Railroad Commission shows that there are 18,000 incidents a year from damage. So there's a big disconnect on whose data you're looking at.

When we looked at the State of Texas, they have an excellent reporting system that requires both excavators and operators to report any damage to pipelines. That's why they know they have 18,000 incidents a year, and it's available to the public to look at. You can scroll through it and organize it by excavator, by pipeline company, by city, and look. So you can come up with A–1 Excavators has hit pipelines in Fort Worth, Texas, 10 times in the last 6 months and make some conclusions from those types of things.

I think that's an excellent system that could be adopted in other states.

Senator THUNE. You've noted that state authorities have primary responsibility over gas distribution pipelines and that many states have chosen to adopt regulatory standards that are more stringent than Federal ones. Could you describe some of the State regulations that are more stringent and how many states have adopted standards that are more stringent, and then perhaps, to follow up, are there more stringent state standards or best practices that PHMSA could or should consider adopting? I think you just mentioned the State of Texas as an example. But are there some states that have more stringent standards and can you give me some examples of those, and are there some things that perhaps the feds ought to be adopting that states are already doing?

Mr. SYPOLT. I believe that the State of Virginia, Senator, has probably one of the very best One-Call systems out there. I think it serves as a model. One, there's high participation in it, high-profile participation in it. In the event there are parties who actually cause damage, there's a group that actually assess penalties on what they think that group should pay. I think that peer pressure has served very well in the State of Virginia, and we've been extremely pleased with that One-Call system.

Senator THUNE. You don't have to confine it to One-Call. It's sort of a broad question about things the states are doing in terms of regulation.

Mr. WEIMER. One of the other things that has been brought to our attention a lot is the difficulty getting hold of PHMSA's spill response plans for liquid and oil pipelines. There are some groups even in the Midwest from your own state, I believe, that had to use the FOIA to actually get their hands on a spill response program so they could review it to see if it adequately protected their area.

In the state I'm from, the State of Washington, Washington has adopted regulations that once a complete spill response program is submitted to the State of Washington it opens up a 30-day comment period where the public, universities, interested local governments, have a chance to review and comment on that spill response plan. There's nothing within the Federal regulations that opens up spill response plans for any public review or comment.

Senator THUNE. Thank you.

Thank you, Mr. Chairman.

Senator LAUTENBERG. I now call on Senator Udall, and sitting next to him is Senator Begich. These are very mountainous states, a lot higher than New Jersey's 1,200-foot highest mountain.

Senator BEGICH. That's a mountain?

Senator LAUTENBERG. But I don't know whether the problems are more difficult. But Senator Udall.

STATEMENT OF HON. TOM UDALL, U.S. SENATOR FROM NEW MEXICO

Senator UDALL. Thank you, Chairman Lautenberg. I'd like to put my opening statement in the record and proceed from there.

Thank you for doing this hearing. I think the issue of pipeline safety is a very important one. As you say, we have mountains, but we also have flat areas and desert areas and a variety of problems. That's one of the things I wanted to focus on with the Committee today.

Mr. Weimer emphasized this. We're almost on the 10-year anniversary of the Carlsbad explosion, where a family of 12 was camping and through no fault of their own they were wiped out in an explosion.

I'm wondering, for our first three witnesses, how do you respond to the recommendation by Mr. Weimer that integrity management plans be expanded to rural areas, like the area outside Carlsbad where the accident occurred 10 years ago? What do you think of that?

Mr. SYPOLT. Senator, I believe that—well, let me start with a few facts here. When you look at the natural gas transmission system today as it stands, about 49 percent of the transmission system has been smart pigged, as opposed to the requirement of only 7 percent in HCA areas. So pipelines are already doing much more than just the HCA areas.

We expect, based on surveys from particularly the INGAA membership, that by the end of 2012 we will have pigged 65 percent of those pipelines. That being said, we should make sure, though, that we do not lose focus on those areas which we believe have the greatest impact, where there is the most population and pipelines are closest to those. So I think that we already are doing much more than just the HCA areas and pipelines basically treat—when they find something outside of those HCA areas, they take the same corrective actions as they do inside the HCA areas. So I believe much more is being done than the 7 percent required today by PHMSA.

Mr. FELT. Sir, on the liquid side 44 percent are covered already under the integrity management plan rules, because 44 percent occur within HCAs or affect HCAs. But, like the gas side, much more is done than just the minimum 44 percent. In fact, earlier estimates were that the integrity management plan would require somewhere in the neighborhood of a couple of hundred million dollars. The industry has spent billions of dollars, and I think that's a reflection of how much more work is being done beyond the minimum requirement.

I think the danger with requiring all pipelines or all miles of pipelines to be treated the same is that you take away the flexibility or the ability to place your dollars where there's greater emphasis. It's that flexibility, I think, that we need. The pipeline companies are already doing more than the minimum, but to require every mile to be treated the same I think would not be the most effective way to manage the system. That's why the rules were developed with emphasis on HCAs.

Mr. D'ALESSANDRO. From a distribution point of view, a lot of our transmission pipelines that are covered are not piggable. So we have to do some type of other assessment. Most of the time it only can be direct assessment because we cannot pressurize them or hydrotest them because then we put water in our system and we create another issue of corrosion within our system.

We believe—in my testimony I talked about the assessment of low-stress transmission pipelines being moved from TIMP over to DIMP. That would assist us, that now all pipeline, all mileage, would be covered underneath the DIMP robust plan and have a risk-based program looking at that. So that is one recommendation from a distribution point of view.

Senator UDALL. Mr. Weimer, would you like to comment on those?

Mr. WEIMER. We certainly agree that the industry has done more. There are some companies that almost smart pig 100 percent of their pipelines. We commend those companies. The main difference we see is what's required versus what's done voluntarily is who you have to report that to and who knows that information. For the natural gas transmission industry, what's found outside of high consequence areas doesn't need to be reported to PHMSA and what's found—anomalies found in the pipelines aren't required to be treated the same way they are if they are under the regulations. So there's a big difference between whether you're doing it voluntarily or whether it's under the regulation.

Senator UDALL. Thank you, Chairman Lautenberg, and thank you to the panelists.

[The prepared statement of Senator Udall follows:]

PREPARED STATEMENT OF HON. TOM UDALL, U.S. SENATOR FROM NEW MEXICO

Mr. Chairman, thank you for holding this hearing today on ensuring the safety and security of our Nation's pipeline infrastructure.

Almost 10 years ago, in August 2000, New Mexico experienced one of the most tragic pipeline accidents in recent memory.

Twelve members of the same extended family, camping outdoors near Carlsbad, New Mexico, were killed in a horrific explosion of a natural gas pipeline early in morning.

The National Transportation Safety Board investigation found the explosion the result of corrosion, and that both industry and government attention to pipeline safety needed improvement.

Following that incident, Congress took action, passing the Pipeline Safety Improvement Act of 2002. Congress reauthorized that Act in 2006 and it is time for us to get to work again on pipeline safety.

Pipelines may be the safest form of transportation, compared to trucking or railroads, but that fact is no consolation to the family and friends left behind after fatal pipeline accidents.

That fact also does no cleanup of the environment following pipeline accidents that leak hazardous liquids like oil and gasoline into the environment.

As a result, we must remain vigilant. As recent fatal accidents in Texas have shown, including one earlier this month, our work is not complete.

I look forward to hearing how the pipeline safety programs Congress put in place are working and how they can be improved.

In particular, we must ensure that existing regulations are being enforced and be skeptical of waivers and self-regulation.

Senator LAUTENBERG. Senator Vitter.

Senator VITTER. Mr. Chairman, I'm going to pass right now. I really want to hear more discussion from the panelists.

Senator LAUTENBERG. Senator Begich.

STATEMENT OF HON. MARK BEGICH, U.S. SENATOR FROM ALASKA

Senator BEGICH. Thank you, Mr. Chairman.

Let me, if I can, follow up on Senator Thune's questions on the One-Call. I'm not as familiar with—I understand what they do on ground, but do they have a similar situation for offshore? Why I ask that is, as you know, pipelines come offshore moving product to land facilities, and there is stuff we're starting to hear about where people might be anchoring, for example, might be interfering with some of the lines.

Can you help me understand that a little bit better from your own industry? Is that an issue that's starting to become a problem? We've heard just a couple indications that as we have more and more lines coming in offshore onto land-based facilities and then ships who are then also laying anchor, how that all connects—or actually, we don't want them to connect.

Tell me, is there a One-Call center for that, where there are zones that you cannot be anchoring in? And then, if not, what recommendations might you have on this area? For anyone who wants to step up on that?

Mr. SYPOLT. My understanding, Senator, is for offshore, obviously it's more difficult than onshore, where pipelines are mapped very well, GPS coordinates are taken. My understanding is the State of Texas is actually looking at a system to really approach those offshore pipelines by having them mapped with GPS systems and then having ships equipped with those type systems where they can either look at their system and see the map of the pipelines or contact the Coast Guard to actually get some feedback as to whether or not they're looking at laying anchor somewhere close to a pipeline system.

But offshore is not as far advanced as we are onshore with One-Call type systems, Senator.

Senator BEGICH. If I can just interrupt before someone else answers, based on obviously the larger issue, which is the blowout and the spill, which is a whole different set of circumstances, is this something you think we should accelerate, some more discussion, or is it not that big of a problem that you've heard within your own associations?

Mr. FELT. Well, sir, I've not heard of it being as much of a problem. But before I would comment one way or the other, I think it would be more appropriate to talk to the Office of Pipeline Safety, because I think there is that transition period between close to the shoreline versus further offshore. I think I heard Ms. Quarterman talk about the fact that there is a transition area, and probably understanding more what they're regulating would be helpful.

Senator BEGICH. Any other comments from folks on that one?

[No response.]

Senator BEGICH. Let me, if I could take another step. As we talk about pipelines, we have a big one in Alaska and we'll have, hopefully soon, maybe, a bigger one moving gas. Do you think PHMSA has the capacity, staffing, and authority to deal with these large projects in a timely manner, and making sure that they don't become a bottleneck in the delay of a project of that magnitude? It's a big project for us as we think of the gas line, and as we think about this we're thinking of all the Federal agencies that will be touching this line in some form of regulatory process. On big projects like this, my instincts tell me that a lot of agencies are never geared up to deal with large projects. I may be wrong about that, but I want to get some feedback from you of how you see that, or their capacity to deal with large projects.

Mr. SYPOLT. Obviously, Senator, the Alaska pipeline is a huge project. It's outside of the norm. I believe that PHMSA has looked at other large projects, similar to the Rockies Express Pipeline that was built across the majority of the United States. So they have taken on large projects before and watched over those.

But clearly the Alaska project would be a huge one that would require several resources that they probably would be directing in that direction for a period of time.

Senator BEGICH. Do you think they have the—and again, this may be an unfair question for you, but do you think they have the authority to do whatever kind of reimbursable contracting or anything of that nature to bring those resources to bear as they need them for a project of that magnitude?

Mr. SYPOLT. Senator, I'm not sure that I know that answer.

Senator BEGICH. That's fine.

Anyone else want to comment on that, on their ability? Yes?

Mr. WEIMER. That's one concern that we've had with a lot of the new pipelines. We've heard some discussion today of the Keystone pipelines and some of those, and the ones in Alaska would be even larger. My understanding—and this is something that it probably would make sense to question PHMSA about a little more—is there's somewhat of a disincentive built into their fee structure, because their fee structure is based on user fees that they don't start to collect until there's actually product going through those pipelines.

So to inspect pipelines that are not yet working, they're taking money that's coming from other things and trying to divert resources. So there has been some discussion about whether you need actual fees for inspections of proposed new pipelines so existing pipelines aren't subsidizing the new operators.

Senator BEGICH. Let me ask—that's an interesting question. People hate this when I bring this up at these meetings, but I used to be a mayor. When we had building inspections, you always had fees to inspect those buildings in the construction phase, as well as obviously if you were a commercial building on your annualized inspections.

Let me ask other people to comment. Do you think there should be a fee structure for prior to and during construction of projects, say of that size?

Mr. WEIMER. I think I'm coming at it with my same—because I'm an elected county council member, too.

Senator BEGICH. Oh, good.

Mr. WEIMER. So to a degree we always try to get fees to cover the fees so other people aren't subsidizing that. So it makes sense to us and it's a way to make sure that they have the resources to pay for those things without spreading themselves too thin. Now, whether that's the case or not, that would be questions that you'd have to ask PHMSA.

Senator BEGICH. Anyone else want to comment on that? I know industry folks don't like to always talk about fee issues, but this is an opportunity for you.

[Pause.]

Senator BEGICH. I knew someone would take the bait.

Mr. FELT. I agree that you probably have to ask PHMSA about the super-large projects. But it hasn't deterred them so far from inspecting, say, more moderate sized projects. Currently our company is involved with a relocation project to accommodate, in the State of New Jersey, where the New Jersey Turnpike is widening. We're going to spend well over $100 million on construction in that particular project, and we're just the relocating part of that project. We've already been notified that PHMSA inspectors will be out there and we're prepared for that.

So maybe something of a larger nature has to be discussed separately, but I think for the day-to-day type of work that's happening it appears to me that PHMSA is——

Senator BEGICH. Is OK.

Mr. FELT.—is okay. They're there, they're showing up.

The other thing is that the fees that we'll be paying down the road—if they're inspecting, I think the approach they're taking, if they're inspecting up front, they probably won't have as much need to inspect later on. So they'll be collecting fees, yes, after the fact, but it'll probably more than reimburse the effort they put in up front. Now, that's not for maybe the super-large projects, but probably for all other ones.

Senator BEGICH. Because we estimate this is probably a 30, 40, 50, depending on what day it is, billion dollar project.

One last comment. I know I've exceeded my time.

Mr. D'ALESSANDRO. The only thing I was going to add was, when Rocky Express came through Illinois not only was PHMSA inspecting it, but your state OPS was also out there inspecting. So there's more pressure, I think, maybe at the state level because of their funding and their staffing. But they're also out there inspecting those large projects.

Senator BEGICH. Very good.

Thank you all very much for your time and answers.

Thank you, Mr. Chairman.

Senator LAUTENBERG. Senator Vitter, are you still patient?

Senator VITTER. Yes.

Senator LAUTENBERG. We're joined by Senator Pryor and I would now ask you to ask any questions that you might have.

STATEMENT OF HON. MARK PRYOR, U.S. SENATOR FROM ARKANSAS

Senator PRYOR. Thank you. Thank you, Mr. Chairman. I do have just a small number. Thank you for your leadership here, and I appreciate the panel being here today, too.

Let's see. Mr. Felt, I would like to ask you a question about the TransCanada Pipeline. In the approval process, as I understand it, because it's Canada and U.S. there has to be an approval process through the State Department; is that right?

Mr. FELT. That is correct. You're talking about the gas line——

Senator PRYOR. Yes.

Mr. FELT—coming through? That would probably be more appropriate for one of the other gentlemen.

Senator PRYOR. OK.

Mr. FELT. Oh, the oil line you're talking about? Oh, yes. I'm sorry. There is a NEPA process for that, for that pipeline, that's correct.

Senator PRYOR. And how is that approval process going? Is the State Department moving that through or doing the proper due diligence they need to do?

Mr. FELT. I'm really not familiar with the details. I do know that it's going through the process. I heard that it is making progress. But that's really third- or fourth-hand information.

Senator PRYOR. OK. I know as part of the Gulf oil spill there has been some allegations or concerns about MMS being too close to the oil industry. I would like to ask about the relationship with PHMSA and your industry. So I don't know who this should be best directed to, but if you could tell us about the relationship between PHMSA and your industry and how hard they look at things, how difficult the inspections and the approval process are, etcetera. So who wants to take that?

Mr. SYPOLT. I'll be happy to, Senator. I believe that the PHMSA regulations are based on sound engineering practices, so the regulations that they enforce make great sense to the industry. The industry does millions and millions of inspections. Many of those are based on certain timeframes and have to be completed within certain timeframes. PHMSA or their agents come out very regularly and audit our records. The records are very, very open as far as PHMSA or their agents' ability to look for any particular violations, such as being 3 days late on an inspection.

When you're doing millions of inspections and you have 1 or 2 of them that are 3 days late and you end up fined for that, some pipeline operators will believe that to be heavy-handed regulation. So I think PHMSA is aggressive in their audits and in their enforcement practices.

Mr. FELT. Sir, I'd like to add a couple points on that. I would say that we have a respectful relationship with PHMSA. In addition to just auditing records, it has been my experience that they'll actually go out into the field, and not just the field locations, but the remote locations, and look at corrosion readings out in the middle of a cornfield somewhere. They'll look at valves just to make sure that they've been properly maintained.

Interestingly enough, the pipeline records, the safety record, has been improving over the years, but it seems to me that the number of inspections have been increasing, the detailed level of the inspections have been increasing. Unfortunately, the number of fines have been increasing, both number and size. To me, that's a reflection of what I believe is PHMSA raising the bar even while the safety performance is improving.

So I think that's what the public wants and I'd have to commend PHMSA for doing it, even though it's at the expense of the pipeline industry. But I think we all win.

Senator PRYOR. Did you want to?

Mr. D'ALESSANDRO. When you look at the PIPES Act and the impact it had on the distribution companies, PHMSA's been straightforward and fair with us, but they do enforce what they have there. From a distribution point of view, they utilize the state agencies on inspections and enforcements and follow-ups.

But we appreciate PHMSA—they've been straightforward. They're strict on their rules, but they share them and they're knowledgeable, so we understand what we're walking into and what needs to be corrected.

Senator PRYOR. One last question on that, and that is that, again, with some regulators there's not a real clear revolving door rule or law. Do you know what the rule or law is with PHMSA in terms of when someone can leave the agency and go to work for a company that has business before the agency? Do you know what the rule is on that?

[No response.]

Senator PRYOR. Do people in the industry routinely hire ex-employees of PHMSA?

Mr. FELT. I wouldn't say routinely. I am aware that it's happened. I think—and it's just anecdotal, but I think it's just as easily seen where they hire people with experience in the industry to help them better assess and inspect, and that has been the experience I've seen. A lot of the people that are working at the inspector level have got prior first-hand experience in the industry.

Mr. SYPOLT. Senator, I would agree with Mr. Felt. It typically goes that they hire people from the industry rather than the industry hires people from PHMSA.

Senator PRYOR. Thank you, Mr. Chairman.

Senator LAUTENBERG. Senator Vitter.

STATEMENT OF HON. DAVID VITTER, U.S. SENATOR FROM LOUISIANA

Senator VITTER. Thank you, Mr. Chairman.

A couple of questions. For the whole panel: If you look at serious incidents, particularly those that cause injury or death, what are the top categories of causes related to those serious incidents? I assume corrosion is on that short list. I know that was a factor in an explosion that caused a death in Louisiana several years ago. Is that on the short list? What else would be on the short list?

Mr. SYPOLT. Outside excavation, Senator, is the largest impact. Corrosion is on that list, but it's pretty far down, down the list. But outside excavation would be the greatest impact.

Senator VITTER. What else would be high on the list? Anybody?

Mr. FELT. I believe equipment failure is probably high on the list, too. But I would have to say that the third party or excavation damage, the reason it's so high on the list is because you probably—first of all, you're not prepared for it. That's why it occurs. There's no warning when it happens. And you've probably got an operating piece of equipment involved. So it's not so much that you have the release of gas or gasoline; it's that you have an ignition source right there at the time. I think that's what contributes to the severity of the incidents.

Mr. D'ALESSANDRO. The key in excavation damage, it's pretty broad. The number one issue on excavation damage is people not using 811 and making that first call. The second thing is, once the lines are marked, there's proper construction that still has to be done around the pipes to secure them. That's the number two issue.

The number third issue on excavation damage is really mislocating, the locate is not within the 18 inches and it's mismarked.

Senator VITTER. Then the second question is about offshore pipelines in particular, which are obviously significant off Louisiana. What role does PHMSA play in regulating offshore pipelines, first of all, generally speaking?

Mr. FELT. Sir, I think that PHMSA would be the best people to ask. I don't have offshore pipelines, but I did hear Ms. Quarterman talk about the fact that they do have some authority within—I can't remember how many miles of the shoreline. So there's probably some transition between OPS or PHMSA and MMS, and they'd probably be better able to answer that.

Senator VITTER. Maybe I'll go back to them with the question.

Anyone have any direct perspective on that? Do any of you have offshore pipelines?

[No response.]

Senator VITTER. Thank you, Mr. Chairman.

Senator LAUTENBERG. Thank you, Senator Vitter.

You know, I respect so much the fact that safety has been improved over these years, but nevertheless we have a question here about the number of accidents since 2006. Not a question, but there still were 58 deaths since 2006, $900 million in damages. So the mission is to get that down to an even lower level, and I'm sure all of you agree with me. I just bring that to your attention so that we can continue to look at the possibilities and—this is not intended to be a threat, but at regulation perhaps, or rules that can make it even safer. I know that all of you would like that to occur.

The number of inspectors. Mr. Weimer, we've had an increase from 2007 of about 40 inspectors. With that, do you have knowledge or an idea as to whether or not we have enough people out there to look at these things? I hear of going to the cornfields and other very difficult places to find the location. Do we have enough people out there to do the job, do you think?

Mr. WEIMER. Probably a good question for PHMSA. From our perspective, there has been significant progress made because of the PIPES Act to hire more inspectors. They've had some problems actually getting those inspectors hired and out in the field. I was glad to hear Ms. Quarterman talk about their expedited efforts to get those inspectors actually hired and fill those positions.

In the State of Washington, after the pipeline explosion in Bellingham that killed three children, the State of Washington looked at that and decided that the number of inspectors that were available from the Western Region of OPS was not adequate for what they wanted to do in the State of Washington. So they got the authority to do their own inspections in Washington and hired I think eight inspectors just for the State of Washington, which was far more than PHMSA could provide, to provide better inspections. Other states have made those same decisions.

Senator LAUTENBERG. We'll have to look at that, because again safety being the primary issue of today's hearing. The fact is we want to make sure that we have the tools on the government side to do what we have to do to ensure as much protection as possible.

PHMSA and the Federal Energy Regulatory Commission both bear responsibility for regulating the development of new natural gas pipelines. How can this cooperation be improved to make sure that the public has the necessary information on the impact of a pipeline to their community and the impact—there will be those proposing what the economic result might be, but the fact of the matter is that the safety factor being what it is—who is principally responsible in your view, and how can that collaboration be improved—between these two agencies?

Mr. SYPOLT. Mr. Chairman, PHMSA does certainly come out on the construction of new pipelines. How does the public—I believe that was your question, how do they find out about these pipelines and the safety of them? FERC actually holds public awareness meetings or public meetings on projects in various communities along the pipeline route, where those type discussions do occur. The pipelines are there present, FERC is there present, and there's a ton of information given regarding the construction process, and there are—on INGAA websites there are many slides that actually explain the construction process as well.

So people have access to that. But during the construction process itself, PHMSA comes out for inspection during the construction, sir.

Senator LAUTENBERG. So the responsibility lies primarily there.

One of the things that I've worked on since I've pretty much been in the Senate, and that is guaranteeing that the public has a right to know about what's in their area in terms of chemicals or emissions, etcetera. I wonder how we can improve the public's awareness of what's in their area and raise their consciousness to a level so that they an submit questions if they have any to make sure that they're appropriately protected.

Mr. WEIMER. Well, Mr. Chairman, if I can take a crack at that one. That's certainly one of our large issues, too, to make sure as much information is available as possible, because I think that makes everything safer. Even talking about the issue you just raised the question about during siting, for gas pipelines you have FERC and PHMSA working together. With liquid pipelines, it's even more complicated because you may have the Department of State or you may have states trying to do it, and there seems to be a disconnect between the safety issues and the siting issues, especially when it comes to information available for people that are trying to decide if a pipeline through their area is safe, because often PHMSA grants special waivers or special permits for things to do with pipelines. They have spill response plan responsibilities.

They designate high consequence areas in places. Lots of those processes are either somewhat secret from even local governments, like high consequence areas, or they're done after the fact as the EIS is moving through for the siting.

So somehow to better coordinate so those processes that PHMSA is in charge of are actually integrated into the EIS's that the states or that the Department of State or FERC are doing would be one way.

There are lots of other things. One of the things that we're really looking for and we understand that PHMSA is working on now is inspection transparency, so people in communities can look to see specific companies, what have they been inspected for, what was found, what was done. My understanding is you'll see PHMSA coming out with a website that will let individuals and communities be able to do that. We think that would be a great step forward.

Senator LAUTENBERG. One of the things that happened in my State of New Jersey, that big accident took place in 1994 and that raised the recognition. I think that those of you who have cause to put down new pipelines in the State of New Jersey know that there's a very interested public in what you're about to do. So we have an inspection team out there of citizens who are concerned about themselves, their families, and their community.

I want to thank you each, all of you who testified here on this panel, for a degree of consciousness that you bring to the problem and how you hold safety as a principle factor. Please continue to do that.

We'll keep the record open for a bit so that any questions that may not have been asked and want to be asked will be submitted, and we would ask your prompt response, hopefully within a week of the time that you get the questions.

Thank you, and this hearing is adjourned.

[Whereupon, at 4:19 p.m., the hearing was adjourned.]

APPENDIX

RESPONSE TO WRITTEN QUESTIONS SUBMITTED BY HON. JOHN D. ROCKEFELLER IV TO HON. CYNTHIA L. QUARTERMAN

Question 1. What has PHMSA found in its evaluations of companies' oil spill response plans and what additional enforcement mechanisms does PHMSA need to make sure companies develop adequate plans? Are companies' response plans available to the public?

Answer. PHMSA ensures that oil response plans meet all applicable regulatory requirements of 49 CFR Part 194 before it approves them. After an operator submits a proposed plan, PHMSA reviews it fully. If a plan does not meet all the applicable regulatory requirements, PHMSA works with the operator to revise the plan and correct any deficiencies. PHMSA has reviewed approximately 450 response plans and has ensured that they all meet regulatory requirements. Response plans generally include:

- Procedures and a list of resources for responding, to the maximum extent practicable, to a worst case discharge and to a substantial threat of such a discharge;
- Certification that the response plan is consistent with the National Contingency Plan and specific elements of each applicable Area Contingency Plan;
- A core plan with:
  - An information summary,
  - Immediate notification procedures,
  - Spill detection and mitigation procedures,
  - Contact information for the oil spill response organization (OSRO),
  - Contact information for Federal, State, and local agencies that the operator expects to have pollution control responsibilities or support,
  - Training procedures,
  - Equipment testing,
  - A drill plan that satisfies, or is equivalent to provisions of, the National Preparedness for Response Exercise Program (PREP), and
  - Plan review and revision procedures;
- An appendix for each response zone included in the plan. If the plan only covers one response zone, then this section is a single summary of specific information from the core plan; and
- A detailed description of the operator's response management system that includes a clearly defined chain of command and identifies sufficient trained personnel to fill each position.

To date, PHMSA has not received reports from response agencies (*e.g.,* USCG or EPA) indicating that PHMSA-approved plans have been inadequate during actual pipeline incidents and releases. On June 30, 2010, PHMSA issued an Advisory Bulletin reminding operators of onshore oil pipeline facilities that they must conduct a review of their oil spill response plans and submit any updates to their oil spill response plans as set forth in § 194.121 within 30 days.

PHMSA will continue to work with other Federal approving agencies to strengthen the standards and processes for its response plan review to ensure that plans adequately address spill risk. PHMSA is planning an oil spill response plan benchmark study with other Federal agencies. The study will review how other Federal agencies administer oil spill planning, preparedness and recovery operations.

PHMSA, through the Secretary of Transportation, needs to have the authority to enforce Part 194 of the regulations through civil penalties. PHMSA urges Congress to amend 33 U.S.C. 1321(b)(6)(A) to provide it with this authority by indicating that agencies who issue regulations pursuant to 33 U.S.C. 1321 have authority to enforce those regulations.

Facility oil spill response plans submitted to PHMSA are available to the public through Freedom of Information Act (FOIA) requests. Individual operators may also make these plans available on their websites or as requested by the public.

Question 2. In light of the catastrophic consequences from the recent oil spill in the Gulf of Mexico, what steps is PHMSA taking to make sure it is providing sufficient oversight of the offshore pipelines under its jurisdiction? What additional requirements does PHMSA apply to offshore pipes than it does for onshore pipes to prevent such environmental disasters?

Answer. Since the *Deepwater Horizon* oil spill, PHMSA has reviewed its inspection records for operators of offshore transportation pipelines subject to PHMSA's jurisdiction. It has verified that the facilities of all such operators have been inspected within the past 3 years or are scheduled for inspection this calendar year. PHMSA has reviewed accident and incident report data to identify risks that may be unique to offshore pipelines. This review indicates that the offshore accident rate for offshore liquid pipelines is below the per-mile average for onshore liquid pipelines. In addition, PHMSA has identified certain regulatory actions that should be taken, and that it intends to take, to improve its oversight of offshore facilities.

PHMSA applies the same corrosion control and integrity management requirements to both onshore and offshore pipelines. Offshore gas pipelines, however, have a higher rate of corrosion failure than onshore pipelines. PHMSA regulations include additional inspection and reburial requirements for pipelines located in shallow waters of the Gulf of Mexico that could pose a hazard to navigation. Finally, PHMSA is considering whether additional or different regulatory requirements should be made for offshore pipelines.

Question 3. Integrity Management Plans are currently only required for High Consequence Areas, which cover a limited amount of pipeline mileage. Is this requirement sufficient, or should Integrity Management Plans be expanded to cover a wider portion of pipelines?

Answer. Integrity Management (IM) programs have significantly increased safety in High Consequence Areas (HCAs) by ensuring that operators identify potentially dangerous anomalies and by increasing operators' knowledge about the condition of their pipelines.

IM programs help focus operator resources on the areas of greatest risk to the public and the environment. The IM regulations complement and are in addition to PHMSA's baseline prescriptive safety requirements. All operators must comply with PHMSA's prescriptive regulations for any pipelines that fall within PHMSA's jurisdiction. In addition to these baseline regulations, operators must maintain IM programs uniquely suited to address the risks confronting the HCAs on each of their pipelines.

The current IM requirements provide protection that extends beyond just HCAs. While operators are only required to assess the pipeline segments that can affect HCAs (approximately 44 percent of the Nation's pipeline mileage), they have actually "smart pigged," pressure tested, or otherwise assessed a far greater proportion (approximately 86 percent) of the total hazardous liquid pipeline mileage. This has increased pipeline safety in locations well beyond the HCAs.

PHMSA intends to review the current rules to determine whether IM requirements should be applied beyond HCAs and, if so, to what extent.

Question 4. Please describe the process PHMSA uses to inspect the integrity and safety of pipe used for pipeline construction. Is this process the same for domestic and imported pipe?

Answer. PHMSA ensures pipe quality through constructionsite inspections during pipeline installation. Inspections evaluate installation practices including welding, materials documentation, and leak and strength tests of the pipe at the conclusion of pipeline installation. The final documentation of pipe serviceability prior to placing a pipeline into service is the PHMSA-mandated hydrostatic test, during which the pipeline is tested at a pressure higher than it will ever experience during its service life.

PHMSA regulations reference the professional standard for line pipe, American Petroleum Institute (API) standard 5L. API standard 5L provides manufacturing standards for pipe used in the oil and natural gas industry. PHMSA inspections include reviews of pipe testing data and certifications that document pipe conformity with the manufacturing standards. Any pipe, whether domestic or imported, used in a pipeline system under PHMSA's jurisdiction must comply with these provisions.

PHMSA takes a proactive approach when it learns of material quality issues, including line pipe issues. In late 2008, in the course of field inspections, PHMSA discovered a potential issue with steel pipe quality when isolated failures occurred in the field during hydrostatic testing. PHMSA immediately implemented requirements for determining the extent of the problem with the operator involved and for removing low strength pipe from the pipeline system. When PHMSA discovered a second operator with similar issues, PHMSA issued a safety Advisory Bulletin to the public in May 2009, alerting all pipeline operators to the potential issue and recommending practices to ensure that purchased pipe met PHMSA requirements. PHMSA also later published interim guidelines providing specific steps operators may take to check for pipe quality issues. In taking action on the pipe quality issue, PHMSA acknowledged that although the issue appeared to be isolated to high grade steels (X70 and X80), action needed to be taken to prevent a recurrence or a more widespread problem.

Question 5. When a company submits a waiver to construct a pipeline using pipe that does not meet regulatory requirements, what steps does PHMSA take to ensure the integrity and safety of the pipe?

Answer. The Federal Pipeline Safety Statute (49 U.S.C. § 60118) permits the Office of Pipeline Safety to waive regulatory requirements by issuing special permits. PHMSA issues a special permit only after completing a review that shows that waiver of the regulations will not compromise public safety. Typically, an operator that requests a special permit must take measures to mitigate any adverse consequences of non-compliance with the regulations. Such measures may include but are not limited to:

- Operating pipelines at reduced pressures;
- Providing additional cathodic and corrosion protection;
- Monitoring pipelines more frequently (*e.g.,* by aerial or foot patrols);
- Installing pipeline instruments that continuously monitor pipeline pressures;
- Installing high and low pressure alarms and automatic shutdown devices to prevent pipeline failure; and
- Carrying out detection and monitoring activities designed to discover the release of oil.

RESPONSE TO WRITTEN QUESTION SUBMITTED BY HON. FRANK R. LAUTENBERG TO HON. CYNTHIA L. QUARTERMAN

Question. The BP oil spill in the Gulf of Mexico showed the disastrous consequences that can occur when a Federal oversight agency fails to do its job. Are you confident that PHMSA's inspectors are performing unbiased inspections and that the agency is performing the necessary level of oversight of our Nation's pipelines?

Answer. PHMSA is confident that its inspections are unbiased and adequate, and that PHMSA is using all the necessary tools to oversee the Nation's pipelines. Most PHMSA inspectors are engineers or have obtained technical college or graduate degrees. All pipeline inspectors also receive extensive formal and informal training prior to performing inspections. PHMSA requires all its inspectors to be certified via a three-year training course. PHMSA inspects pipelines at all phases of construction and operation. PHMSA inspects new pipeline construction. These inspections are typically highly resource intensive over a short time span. PHMSA inspectors examine everything from the design to construction to initial operation. PHMSA regularly inspects the operating pipelines under its jurisdiction. PHMSA inspects each pipeline operator once every 3 years on average. State partners also assist PHMSA to oversee the Nation's pipelines. PHMSA has a detailed program to verify that its State partners are performing adequately. PHMSA conducts targeted inspections to ensure that operators who are granted special permits are complying with them. PHMSA's enforcement record demonstrates the success of its inspection program. PHMSA issue on average 230 enforcement actions per year, and its collection rate on assessed penalties is 99 percent.

To ensure that PHMSA's inspectors carry out unbiased inspections, PHMSA requires every inspector to file a financial disclosure report listing all financial interests and outside activities that could create a conflict of interest, or the appearance of a conflict of interest, with the inspector's job responsibilities. This way, PHMSA ensures that its inspectors are free from any potential conflicts of interest. In addition, PHMSA provides ethics training to all new hires as well as annual refresher training for all inspectors. PHMSA also sends out periodic informational bulletins on relevant topics such as gift restrictions, avoiding appearances of impropriety, and how to ensure impartiality and integrity when performing one's job. One such ethics bulletin specifically addressed the allegations related to the Federal oversight agency relating to the BP spill.

RESPONSE TO WRITTEN QUESTIONS SUBMITTED BY HON. MARK PRYOR TO HON. CYNTHIA L. QUARTERMAN

Question 1. What is the approval process for new trans-national oil pipeline like the Keystone XL pipeline project from Alberta, Canada to Houston and Port Arthur?

Answer. Executive Order 13337 authorizes the U.S. Department of State (DOS) to receive applications and issue Presidential permits for the construction, connection, operation, or maintenance of certain facilities (including oil pipelines) at the national borders. Presidential permit applications require a DOS project assessment pursuant to the National Environmental Policy Act (NEPA) and Section 106 of the National Historic Preservation Act (NHPA), as well as an interagency National Interest Determination review. DOS typically requests relevant Federal agencies, including the Department of Transportation (DOT), to submit their opinions during this process. PHMSA has provided assistance to the DOS on technical pipeline matters with respect to the Keystone XL project. DOS may also coordinate with affected state and local agencies. Additional applications and approvals may be needed depending on state and local laws. Approvals through The National Energy Board (NEB) of Canada are required to construct and operate the Canadian portion of these lines.

Keystone XL has requested a special permit from PHMSA to deviate from the design factors in the regulations (49 CFR § 195.106). As part of PHMSA's review of the special permit request, PHMSA is conducting its own environmental assessment (EA) in accordance with DOT Order 5610.1C; the National Environmental Policy Act (NEPA), 42 U.S.C. §§ 4321–4375; and the Council on Environmental Quality regulations, 40 CFR §§ 1500–1508. The purpose of the EA is to assess whether granting a special permit would have a significant impact on the environment.

Other agencies with which Keystone XL filed applications include:

- The U.S. Bureau of Land Management, for a grant of right-of-way and temporary use permit allowing construction and operation of the pipeline project across certain Federal lands;
- The Montana Department of Environmental Quality, for a certificate under the Montana Major Facilities Siting Act; and
- The South Dakota Public Utilities Commission, for a permit under the South Dakota Energy Conversion and Transmission Facility Act.

Question 2. Do you know the status of the Keystone XL pipeline project at the Department of State and other relevant agencies?

Answer. The DOS environmental review of the project under NEPA is ongoing. On April 16, 2010, a draft Environmental Impact Statement (DEIS) was published for public comment. The comment period for the DEIS ended July 2. DOS is currently compiling and responding to the comments, which will inform the Final Environmental Impact Statement (FEIS). The DOS inter-agency National Interest Determination review is underway for 90 days beginning June 16. At the end of the formal EIS and National Interest periods, DOS will decide whether to issue the permit and will inform the agencies by Executive Secretariat memo of that decision.

PHMSA's review of the special permit request and related EA is also ongoing. PHMSA intends to publish draft versions of the special permit analysis and findings as well as the EA, and to provide a 30-day public comment period prior to making a final decision.

With respect to other agencies, TransCanada filed its section 52 application with the National Energy Board and received approval on March 11, 2010 to construct and operate the Canadian portion of the Keystone XL.

TransCanada filed an application with the U.S. Bureau of Land Management for a grant of right-of-way and temporary use permit that would allow construction and operation of the pipeline across certain Federal lands. The application is currently under review by the agency.

TransCanada filed an application with the Montana Department of Environmental Quality for a certificate under the Montana Major Facilities Siting Act. The application is currently under review by the agency.

TransCanada filed an application for with the South Dakota Public Utilities Commission for a permit under the South Dakota Energy Conversion and Transmission Facility Act and received approval on March 11, 2010.

Question 3. What regulatory authority will PHMSA have during its construction and through the life of its use?

Answer. Once the State Department has approved the siting, PHMSA will have the statutory authority to regulate the design, construction, operation, and maintenance of the Keystone XL pipeline to protect public safety and the environment. PHMSA's regulations cover the full pipeline life cycle, and PHMSA engineers will conduct inspections to carry out its responsibilities.

49 CFR Part 195 prescribes safety standards and reporting requirements for pipeline facilities used in the transportation of hazardous liquids. 49 CFR Part 195, Subpart C prescribes minimum design requirements for new pipeline systems constructed with steel pipe. 49 CFR Part 195, Subpart D prescribes minimum requirements for constructing new pipeline systems with steel pipe.

PHMSA's responsibility in pipeline construction is to ensure that the pipeline will operate safely once it is placed in service. PHMSA inspects pipeline construction to ensure compliance with these requirements. Inspectors review operator-prepared construction procedures to verify that they conform to regulatory requirements. Inspectors then observe construction activities in the field to ensure that they are conducted in accordance with the procedures. Additional inspections occur once a pipeline is in service and throughout its lifetime to confirm that it is being operated and maintained in accordance with 49 CFR Subpart F. Additional Subparts of Part 195 that subject operators to inspection and enforcement include Subpart B (Annual, Accident, and Safety Related Condition Reporting), Subpart E (Pressure Testing), Subpart G (Qualification of Pipeline Personnel), and Subpart H (Corrosion Control).

Question 4. How would you describe the relationship between PHMSA and the oil and gas industry? Do you believe there is a revolving door problem between PHMSA and the oil and gas industry that needs to be addressed?

Answer. As a safety oversight and enforcement agency, PHMSA maintains a professional relationship with the oil and gas industry. PHMSA does not have a revolving door. Some of PHMSA's personnel do have experience in the oil and gas industry. PHMSA has found that their experience enables them to identify safety and compliance issues. As inspectors and accident investigators, PHMSA's personnel see first-hand the tragic results of safety shortcuts and non-compliance and have little patience for operators who endanger the public and the environment.

Question 5. Does PHMSA have adequate resources (inspectors) to carry out its authorized goals?

Answer. Yes. The additional inspection and enforcement positions that Congress authorized in Fiscal Years 2009 and 2010 provide PHMSA with an adequate number of pipeline safety inspectors. These positions have enabled PHMSA to conduct a wider range of pipeline inspections.

Question 6. Do exemption requirements for one-call systems in states weaken the effectiveness of these programs?

Answer. Yes. Effective damage prevention programs involve active participation and accountability for all stakeholders. However, limited exemptions based on the type of excavation activities, such as agricultural tilling or gardening to a minimal depth with hand tools, are often included in state one-call laws, and do not generally represent a threat to safety. The risks to public safety and the pipeline infrastructure are greater when groups of stakeholders, such as municipalities or state DOTs, have blanket exemptions from participating in the one-call process. PHMSA strongly supports the elimination of such exemptions and continues to work with the states to help them strengthen laws and promote fair, balanced, and inclusive one-call programs.

Question 7. Are existing penalties for safety violations adequate for pushing industry to focus on safety over revenue?

Answer. Existing penalty levels have largely been effective. That said, PHMSA has been issuing penalties at the top limit of its authority. Increased civil penalty levels would be helpful in certain situations for additional deterrent effect.

Question 8. Should PHMSA have more authority to regulate offshore pipelines?

Answer. No. PHMSA's authority to regulate offshore transportation pipelines is complemented by the Bureau of Ocean Energy Management's authority over production on the Outer Continental Shelf and State agencies' authority over production in State waters.

Question 9. How is PHMSA prepared to respond to a major pipeline failure caused by a natural disaster, manmade disaster, or terrorist attack? (New Madrid)

Answer. When a significant interstate pipeline incident occurs, PHMSA inspectors are dispatched from their respective Regional Office to investigate the cause of the failure. They monitor effects of response operations on pipelines that may be involved or near to the incident. They determine if there were violations of the Pipeline Safety Regulations that contributed to the incident. They ensure that an operator's repair procedures provide an adequate level of safety as they restore the line to service. In some cases, investigators from Headquarters or other Regional Offices are deployed to assist if their specific expertise is necessary. PHMSA has a highly trained and experienced inspector force of over 100, most of whom are engineers.

When incidents occur in natural gas distribution systems, PHMSA's State partners usually lead the pipeline safety investigation. PHMSA will, in some situations, assist in those investigations. PHMSA supports State-level pipeline safety programs in 48 states and the District of Columbia through Grants-in-Aid. PHMSA's State partners generally enforce State laws concerning intrastate natural gas distribution and master meter systems. In a limited number of cases, State partner agencies also inspect interstate hazardous liquid pipeline systems, such as those that transport crude and refined oil products, as part of their grant agreement. When a pipeline incident involves a spill of either crude or refined oil, PHMSA works with the Federal On-Scene Coordinator (usually an official from the U.S. Environmental Protection Agency or the U.S. Coast Guard) to ensure that the operator mounts a rapid, efficient spill response operation, even as PHMSA oversees the operator as it works to repair and restore its pipeline to service.

When an event involves many Federal, State, and local agencies, PHMSA provides technical support through Emergency Support Function (ESF) #1 (Transportation) and ESF #12 (Energy), consistent with the conduct of operations under the National Response Framework. If the event or significant consequences of the event are pipeline-related, PHMSA provides direct assistance to the Incident Commander, as the Pipeline Operations Branch of the Operations Division. PHMSA's representatives participate as technical experts concerning pipeline operations, response options, and consequence management within the Integrated Command Structure of the incident.

In addition to incidents in which PHMSA directly oversees a pipeline operator's response to an incident, repair procedures, and eventual restoration of services, PHMSA has successfully operated in a wide range of incidents, including those of caused by criminal acts. PHMSA has routinely participated as a party in incident investigations under primary NTSB jurisdiction in coordination with the Chemical Safety and Hazard Analysis Board and others.

PHMSA worked closely with the Transportation Security Administration for the past 2 years to develop protocols involving the FBI, TSA and other DHS elements, and the Department of Energy on coordinating the Federal response to threats to pipelines.

Question 10. What do you believe should be the top priorities for PHMSA in light of the recent BP disaster?

Answer. One of PHMSA's top priorities is to recruit and retain America's brightest individuals to help oversee the Nation's pipeline energy supply systems and help safeguard the public and the environment. PHMSA must continue to work with all stakeholders to address the causes of pipeline failure, including excavation damage and corrosion. PHMSA must continue to support PHMSA's State partners, who make up a significant portion of the pipeline safety workforce and who can focus on local needs and concerns. PHMSA must promote research and development into better ways to assess and assure pipeline safety. In addition to those priorities, PHMSA will ensure the adequacy of its oversight of offshore pipelines and oil spill response plans.

RESPONSE TO WRITTEN QUESTION SUBMITTED BY HON. MARK BEGICH TO HON. CYNTHIA L. QUARTERMAN

Question. Alaska and Hawaii are the only two states in the Nation that do not have approved state pipeline safety programs. Pipelines play a key role in safely transporting the oil and gas produced on Alaska's North Slope, Cook Inlet, and hopefully soon the National Petroleum Reserve-Alaska and the Chukchi and Beaufort Seas. The Trans-Alaska Pipeline system falls under PHMSA jurisdiction as a partner agency of the Joint Pipeline Office. Although cooperation with Alaska appears to be improving, the lack of a strong state pipeline program is still a problem because all these systems connect. It also paces unusual resource burdens on PHMSA in Alaska. The low stress pipeline spill on the North Slope in 2006 is one example of the outcomes of inadequate oversight. It is my understanding that PHMSA assists states with cost-sharing grants for pipeline safety programs. What steps is PHMSA taking to encourage the State of Alaska to get an approved Pipeline Safety program in place?

Answer. PHMSA has a long history of encouraging Alaska to enter the pipeline safety program and has met repeatedly with various stakeholders in Alaska to discuss the benefits of a state program. PHMSA executives, as well as regional personnel, have met with Alaskan stakeholders to highlight how such a program would help ensure public and environmental safety and provide for an increased focus on local issues and concerns.

PHMSA has developed a good working relationship with all of its State and Federal partners in Alaska and has made a deliberate effort to consistently share information on pipeline issues with them. Although the relationship is good, PHMSA seeks a more formal arrangement for the safety oversight of Alaska's pipelines, especially the intrastate gas distribution pipelines that directly serve the local public. Alaska's Governor will have to determine whether to enter into the Federal pipeline safety program.

PHMSA notes that Alaska does currently regulate some pipelines such as flowlines, which are also subject to certain regulatory requirements of the EPA. PHMSA is always willing to assist Alaska with inspector training and/or technical assistance.

RESPONSE TO WRITTEN QUESTIONS SUBMITTED BY HON. KAY BAILEY HUTCHISON TO HON. CYNTHIA L. QUARTERMAN

Question 1. What recommendations do you have for the Committee with respect to reauthorizing the pipeline safety program? When can we expect to see a formal proposal from the Administration?

Answer. The Administration's reauthorization proposal is being reviewed and will be transmitted in due course.

Question 2. Pipeline operators are working to design and build pipelines to make transportation of ethanol and ethanol blended fuels by pipeline feasible. PHMSA has indicated that its research shows that it is safe to move gasoline blends with ethanol up to 10 percent, but that at higher blend levels, questions remain because of stress corrosion cracking. Why does a higher concentration of ethanol cause more safety problems?

Answer. High concentrations of ethanol threaten the integrity of storage tanks, line pipe, and valves because ethanol is highly oxygenated, and oxygen causes corrosion. The use of higher ethanol fuel mixtures (*e.g.,* 85 percent ethanol (E85) and Fuel Grade Ethanol (95 percent ethanol, or E95)) causes ethanol stress corrosion cracking. Non-metallic pipeline components such as seals and other elastomers swell in the presence of ethanol. If there is an ethanol fuel fire, alcohol resistant foams are needed to suppress the fire. PHMSA has a comprehensive and collaborative research strategy to address ethanol pipeline challenges.

Question 3. What more can be done to prevent pipeline damage caused by hurricane damage? Is any additional Federal authority needed to allow such damage to be addressed quickly by pipeline operators?

Answer. PHMSA supports H.R. 5629, the Oil Spill Accountability and Environmental Protection Act of 2010, which would require pipeline operators to notify the Secretary of Transportation of any changes in the operational status of their facilities following a hurricane or other manmade or natural disaster. The proposed bill would also require operators to submit damage assessments to the Secretary of Transportation within 30 days after the end of a hurricane or other manmade or natural disaster. Otherwise, PHMSA believes its regulations adequately address damage to pipelines caused by hurricanes by ensuring proper design, materials selection, operations, and regular maintenance. Facilities designed and operated in accordance with PHMSA regulations are expected to survive those forces and conditions likely to be posed by most storms and to be able to resume operations after conditions return to normal.

Question 4. Under the Oil Pollution Act of 1990, PHMSA has been delegated authority over onshore oil spill response plans, but does not have enforcement authority regarding compliance. Instead, PHMSA must refer non-compliance cases to the Coast Guard for appropriate enforcement. Does it make sense to you that the Coast Guard, rather than PHMSA, has enforcement authority over onshore pipelines? Do you recommend that Congress shift that authority to PHMSA?

Answer. At the time that the Oil Pollution Act was passed, the U.S. Coast Guard was part of the Department of Transportation, which meant regulation and enforcement were both delegated to the Secretary of Transportation. Now that the U.S. Coast Guard is part of the Department of Homeland Security, enforcement is more difficult to coordinate.

PHMSA, through the Secretary of Transportation, needs to have the authority to enforce Part 194 of the regulations through civil penalties. PHMSA urges Congress to amend 33 U.S.C. 1321(b)(6)(A) to provide it with this authority, as proposed by H.R. 5629, the Oil Spill Accountability and Environmental Protection Act of 2010.

Question 5. According to PHMSA, Texas is the only state that regulates off-shore production pipelines. Do you believe other States should be more pro-active in this area?

Answer. PHMSA has traditionally allowed the states to regulate offshore production pipelines in state waters. States, including Texas, California, Alabama, and Mississippi, regulate some pipelines in their waters. Those regulations vary from jurisdiction to jurisdiction. The interpretation and application of those regulations are matters of state and local law. That said, PHMSA reserves the right to regulate offshore production lines in state waters as a matter of Federal law. PHMSA is currently reviewing the extent to which states are regulating pipelines in their waters.

Question 6. What impact does the spill in the Gulf have on PHMSA's safety priorities? Has it prompted your agency to conduct a review of the safety of off-shore pipelines?

Answer. Since the *Deepwater Horizon* oil spill, PHMSA has reviewed its inspection records for operators of offshore transportation pipelines subject to PHMSA's jurisdiction. It has verified that the facilities of all such operators have been inspected within the past 3 years or are scheduled for inspection this calendar year. PHMSA has reviewed accident and incident report data to identify risks that may be unique to offshore pipelines. This review indicates that the offshore accident rate for offshore liquid pipelines is below the per-mile average for onshore liquid pipelines. In addition, PHMSA has identified certain regulatory actions that should be taken, and that it intends to take, to improve its oversight of offshore facilities.

PHMSA has conducted a review of its offshore pipeline safety inspection program and is considering whether additional or different regulatory requirements should be made for offshore transportation pipelines and related facilities. PHMSA has identified the need to promulgate regulations for design, construction, operation, and maintenance of transportation regulated platforms and transportation pipeline risers connected to offshore floating facilities. Consensus standards are currently under revision to strengthen the design, construction, and maintenance requirements. PHMSA is participating on the Committees revising the standard and expects to incorporate the standard by reference after a thorough internal review is complete. We anticipate this initiative to update regulations will take 2 years.

PHMSA will be studying the safety oversight of offshore transportation platforms by working with the Department of the Interior through the 1996 Memorandum of Understanding. In addition, in the next year, PHMSA will examine the regulations implemented by State agencies with regulatory authority for offshore production and transportation pipelines.

Question 7. How is integrity management applied to off-shore pipelines? Are there special requirements?

Answer. Offshore hazardous liquid pipelines must be covered by an integrity management program if the pipelines are in, or could affect, a commercially navigable waterway or an unusually sensitive area, but there are no special requirements for offshore pipelines.

Offshore gas transmission pipelines are generally not covered by integrity management programs.

Question 8. As you know, in 2006 the U.S. Government Accountability Office (GAO) recommended that Congress consider replacing the 7-year fixed interval for reassessments of gas transmission pipelines with a variable schedule based on risk. What is the Administration's position on GAO's recommendation? When can we expect to have your recommendation?

Answer. The current law requires a periodic reassessment of facilities subject to Integrity Management rules. The longest permitted interval between reassessments is once every 7 years. The Administration is enforcing the current law.

RESPONSE TO WRITTEN QUESTIONS SUBMITTED BY HON. JOHN THUNE TO HON. CYNTHIA L. QUARTERMAN

Question 1. There seem to be different views on the need to regulate production and gathering lines that connect wells together and then transport product to a transmission line. I have two questions: Which of these lines are regulated, and by whom (Federal or State)? Should all of these lines be subject to safety regulation and, if not, why not?

Answer. *Hazardous Liquid and Gas Production Lines*: By statute, the Federal pipeline safety regulations cannot apply to hazardous liquid pipelines involved with onshore production, refining, or manufacturing facilities, and any storage or in-plant piping associated with those facilities.[1] These facilities and associated piping are considered non-transportation-related pursuant to Executive Order 12777 and are regulated by the Environmental Protection Agency (EPA).[2]

Offshore production pipelines on the OCS are regulated by the Department of the Interior under the terms of a Memorandum of Understanding with PHMSA. Offshore hazardous production pipelines in state waters are reserved for regulation by the states as a matter of policy.

Hazardous Liquid Gathering Lines: The Federal pipeline safety regulations apply to all hazardous liquid gathering lines in non-rural areas and to any pipeline segment, including a hazardous liquid gathering line of any diameter, which crosses a commercially-navigable waterway. However, by statute those regulations cannot apply to onshore crude oil hazardous liquid gathering lines that are: (1) 6 inches or less in nominal diameter, (2) operated at low pressure, and (3) located in a rural area which is not unusually sensitive to environmental damage.[3]

Consistent with that statutory exclusion, the Federal pipeline safety regulations only apply to certain "regulated rural gathering lines." Those lines are onshore gathering lines in rural areas that (1) have a nominal diameter of between 6⅝ inches and 8⅝ inches; (2) are located within ¼ mile of an unusually sensitive areas; and (3) operate at a stress level greater than 20 percent of specified minimum yield strength (SMYS).

Offshore hazardous liquid gathering lines on the OCS are either regulated by the Department of the Interior (producer-operated lines) or PHMSA (transporter-operated lines). Offshore hazardous liquid gathering lines in state waters are reserved for regulation by the states as a matter of policy.

Gas Gathering Lines: PHMSA regulates most gas gathering lines. Congress authorized Federal regulation of gas gathering lines based largely on the physical and functional characteristics of those lines, including their location, distance from the wellhead, operating pressure, throughput, and composition of the transported gas. Consistent with those requirements, the Federal pipeline safety regulations do not apply to the onshore gathering of gas: (1) through a pipeline that operates by gravity, (2) through a pipeline that does not meet the definition of a "regulated onshore gathering line," and (3) within the inlets of the Gulf of Mexico, except for certain underwater inspection and reburial requirements.

There are two categories of "regulated onshore gathering lines" for purposes of the Federal pipeline safety regulations. The first are Type A regulated onshore gathering lines, *i.e.,* metallic lines whose maximum allowable operating pressure (MAOP) is 20 percent or more of specified minimum yield strength (SMYS) and nonmetallic lines with an MAOP of more than 125 psig that are in a Class 2, Class 3, or Class 4 location. The second are Type B gathering lines, *i.e.,* metallic lines whose MAOP is less than 20 percent of SMYS and nonmetallic lines with an MAOP of 125 psig or less, which are in a Class 2 location (as determined under one of three formulas) or in a Class 3 or 4 location. These two categories of gathering lines are subject to different requirements as specified further in the pipeline safety regulations. Onshore gas gathering lines in Class 1 locations are not subject to the requirements for "regulated onshore gas gathering lines."

Offshore gas gathering lines on the OCS are either regulated by the Department of the Interior (producer-operated) or PHMSA (transporter-operated).

Offshore gas gathering lines in state waters are reserved for regulation by the states as a matter of policy.

Further Regulation: PHMSA believes that the production and gathering of hazardous liquids and gas by pipeline should be subject to effective safety regulations. The agency has sought to achieve that objective in a manner consistent with the pipeline safety laws and is currently reviewing whether additional or more stringent regulation of these activities is appropriate. However, PHMSA cannot regulate a pipeline that is excluded from the scope of its authority by statute, and the agency is willing to work Congress in determining whether any of these restrictions should be repealed or modified.

Question 2. At the recent pipeline safety hearing before the House Transportation and Infrastructure Committee, you mentioned that oil pipelines must have an oil spill response program, but that there is no similar requirement for natural gas pipelines. What other significant differences exist between oil and gas pipeline regulations?

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[1] 49 U.S.C. § 60101(a)(22).
[2] *See* 40 CFR § 112.
[3] *See* 49 CFR § 195.

Answer. PHMSA is currently completing a comprehensive assessment of the differences between the regulations for gas and oil pipelines, and evaluating whether any of these differences suggest significant opportunities to improve current regulations.

While this study has not been completed, early results suggest that major differences in the regulations are a result of differences in the properties of the materials being transported. For example, natural gas is lighter than air and therefore disperses in the atmosphere following release from a pipeline, alleviating the need for a "spill response plan" in addition to the required emergency response plan.

Other differences (not all of which are significant) between oil and gas regulations that PHMSA is examining include:

- Numerous differences in integrity management program regulations. Most derive from differences in the properties of the materials being transported (*e.g.,* the definition of High Consequence Area), though some do not (*e.g.,* differences in the required timeframe for remediation of defects identified by required assessments). For integrity management inspections, the maximum time interval allowed between pipeline segment inspections is 5 years for hazardous liquid pipelines and 7 years for gas pipelines.
- Gas pipeline pressure design factors are based on Class Location, while liquid pipeline design factors are based on physical location: onshore vs. navigable waterways and offshore platform.
- Differences in corrosion control requirements.
- Differences in hydrotest requirements for oil and gas pipelines.
- Gas regulations address threaded fittings, and liquid regulations do not.
- Differences in the regulations for shut-off valves.
- For burial of pipeline, the liquid regulations lack backfill requirements.

Question 3. Can you explain for the Committee where your agency's jurisdiction begins and where it ends?

Answer. Congress has given PHMSA jurisdiction over hazardous liquid and gas pipeline systems. That jurisdiction includes authority over gas and liquid transmission pipelines, certain gas and liquid gathering lines, gas distribution pipeline systems, and liquefied natural gas (LNG) facilities. PHMSA does not have jurisdiction over gas or liquid production pipeline systems or hazardous liquid refining or manufacturing facilities and any storage or in-plant pipeline associated with these facilities.

Congress has directed PHMSA to delegate its authority to regulate certain pipelines to State agencies that are interested and qualified to assume that responsibility. A part of the delegated responsibility is to assure state regulations are at least as stringent as Federal regulations.

PHMSA has jurisdiction over onshore pipeline systems as well as certain parts of offshore systems. Other jurisdictional agencies sharing offshore authority include DOI, the Coast Guard, and states with ocean or gulf borders. PHMSA has developed Memoranda of Understanding (MOU) with individual agencies to clarify offshore responsibilities. Under a 1996 MOU with DOI, DOI inspects the structural integrity of offshore platforms.

Question 4. In addition to safety concerns, we must also ensure the security of our Nation's pipelines. Please tell the Committee how PHMSA coordinates with TSA in regards to pipeline security.

Answer. PHMSA and DHS have agreed that TSA is the lead agency in pipeline security. PHMSA supports TSA by providing technical expertise and access to existing intergovernmental relationships, such as PHMSA's State pipeline safety partner agencies. PHMSA communicates frequently with its counterparts at the TSA Transportation Sector Network Management's Pipeline Security Division (PSD) concerning pipeline incidents, threats to pipelines, and suspicious activities at pipeline and energy facilities. PHMSA Inspectors have participated in TSA Pipeline Corporate Security Reviews and Critical Facility Inspections and in DHS' sponsored Security Reviews of Liquefied Natural Gas facilities. PHMSA and TSA have cooperated on numerous projects including revision of pipeline security guidelines, and more recently, development of Security Incident Protocols that extend to the Department of Justice, Department of the Interior, and Department of Energy. We meet regularly in accordance with an action plan developed in 2006 and are actively working on our joint participation in Sector Coordinating Councils and Government Coordinating Councils in support of the National Infrastructure Protection Plan.

RESPONSE TO WRITTEN QUESTIONS SUBMITTED BY HON. MIKE JOHANNS TO HON. CYNTHIA L. QUARTERMAN

Question 1. How has your agency been involved with the development of the Environmental Impact Statement (EIS) applicable to the Keystone XL pipeline project?

Answer. PHMSA is acting as a cooperating agency during the development of the EIS. Through that role PHMSA has:

- Reviewed and provided comments to the State Department's pre-draft EIS. Comments from PHMSA were primarily in the area of pipeline safety, including description of the special permit request and examples of draft conditions that could be imposed if the special permit request were granted.
- Shared Supplemental Information received from the operator with the State Department.
- Attended State Department Public Meetings following issuance of the Draft EIS. For those meetings with a Q&A format, PHMSA helped respond to questions related to pipeline safety.
- Provided additional information to the State Department as needed via e-mail, phone calls, and in-person meetings.

Question 2. Is the State Department required to involve you?

Answer. Yes. Executive Order 13337 of April 30, 2004, requires the State Department to refer any application for a Presidential permit for a cross-border oil pipeline to the Secretary of Transportation. The Executive Order also requires the Secretary of State to send pertinent information to the Secretary of Transportation and to request the Secretary's views. Typically such communications are referred to PHMSA.

Question 3. To your knowledge, were state pipeline safety inspection authorities involved in the Keystone XL EIS? If so, how?

Answer. Under Executive Order 13337, the Secretary of State may consult with such State, tribal, and local government officials and foreign governments as she deems appropriate. PHMSA is unaware of whether state pipeline safety inspection authorities were involved. It is PHMSA's understanding that the operator was required to file a separate application with the South Dakota Public Utilities Commission for a permit under the South Dakota Energy Conversion and Transmission Facility Act and received approval on March 11, 2010. Two of the States along the currently proposed route, Oklahoma and Texas, have authority to regulate, inspect, and enforce liquid pipeline safety requirements over intrastate liquid pipelines through certification by PHMSA's Office of Pipeline Safety. In Montana, South Dakota, Nebraska, and Kansas, PHMSA regulates, inspects, and enforces intrastate liquid pipeline safety requirements. PHMSA has the authority to inspect, regulate and enforce interstate liquid pipelines such as Keystone XL in all states.

Question 4. The State Department's EIS for the Keystone XL project lists the Department of Transportation's Office of Pipeline Safety as an "Assisting Agency," and not as a "Cooperating Agency." What does that distinction mean in terms of how the Department of State completes its work on the EIS, and what does that distinction mean for your involvement in the project? What activities did your office undertake, if any, that would have differed had you been listed as a "cooperating agency"?

Answer. PHMSA is actually a cooperating agency on Keystone XL and has been working with the Department of State to address the project's pipeline safety issues. The role of a cooperating agency, as established by the National Environmental Policy Act (NEPA) of 1969, is to engage its staff, skills, and resources to help the lead agency with environmental analysis, including any portions of the environmental impact statement concerning which the cooperating agency has special expertise. PHMSA has cooperated on those analyses for which it has jurisdiction or special expertise with respect to the Keystone pipeline project.

RESPONSE TO WRITTEN QUESTIONS SUBMITTED BY HON. MARK PRYOR TO HON. DEBORAH A.P. HERSMAN

Question 1. What are the most important NTSB recommendations currently unaddressed?

Answer. Installation of excess flow valves (EFV) in natural gas distribution pipeline systems has been a recommendation of the Board for nearly 10 years (P–01–2). EFVs are installed in service lines and mitigate gas leaks from the service line by detecting an abnormally high flow rate. When an excess flow is detected, an EFV automatically closes a valve, thus shutting off the flow of gas from the distribution line to the service line.

Pipeline Hazardous Material Safety Administration's (PHMSA) current mandate requires excess flow valves on new or replacement service lines to single family residences only. The NTSB recommends that PHMSA require that excess flow valves be installed in all new and renewed gas service lines, regardless of a customer's classification, when the operating conditions are compatible with readily available valves.

The NTSB believes that apartment buildings, other multifamily dwellings, and commercial properties are susceptible to the same risks from leaking gas lines as single-family residences, and we believe this gap in the law and the regulations should be eliminated.

While the NTSB has not issued recommendations specifically addressing either the effective oversight of risk-based assessments in pipeline safety regulation or the regulation of low-stress pipelines, these two areas are critical to safeguarding the integrity of our Nation's pipeline systems.

Effective Oversight

Over the past decade or more, PHMSA has used a risk-based assessment for regulating the DOT pipeline safety program. PHMSA has successfully built a partnership with various facets of the pipeline industry to develop, implement and execute a multi-part pipeline safety program. In the NTSB's view, all stakeholders, including PHMSA, have come to rely heavily upon this approach. The NTSB believes a risk-based approach can work *if* effective oversight is exercised by PHMSA and the pipeline operators.

The Safety Board also believes that with the risk-based assessment come increased responsibilities for both the individual pipeline operators and PHMSA. Operators must diligently and objectively scrutinize the effectiveness of their programs, identify areas for improvement, and implement corrective measures. PHMSA, as the regulator, must also do the same in its audits of the operators' programs and in self-assessments of its own programs. In short, both operator and regulator need to verify whether risk-based assessments are being executed as planned, and more importantly, whether these programs are effective. Unfortunately, NTSB has investigated several accidents in which ineffective oversight contributed to the pipeline accident.

Low-Stress Pipelines Regulation Equality

At the time the PIPES Act was enacted, Federal pipeline safety regulations only applied to low-stress pipelines that were located in populated areas, crossed navigable waterways, or carried highly volatile liquids, such as compressed liquefied propane. In a final rulemaking, "Pipeline Safety: Protecting Unusually Sensitive Areas from Rural Onshore Hazardous Liquid Gathering Lines and Low-Stress Lines," published on June 3, 2008, PHMSA issued regulations for rural onshore low-stress pipelines that have a diameter of at least 8⅝ inches and that are within ½ mile of an area defined as unusually sensitive. Low-stress pipelines meeting these criteria will be required to meet 49 CFR Part 195, for hazardous liquid pipelines in its entirety by July 2012.

The final rule also included regulations for rural onshore gathering lines that operate at stress levels greater than 20 percent of the pipe strength, have a diameter between 6⅝ and 8⅝ inches and are within ¼ mile of an area defined as unusually sensitive. (A "gathering line" is defined as a pipeline with a diameter of 8⅝ inches or less that transports petroleum from a production facility.) Under the final rule, rural onshore gathering lines will be required to meet Part 195 in part by July 2011. The safety requirements of Part 195 that will eventually apply to the rural onshore gathering lines include annual and accident reporting requirements, establishment of maximum operating pressure, installation of line markers, public education programs, damage prevention programs, corrosion control, and operator qualification programs.

On June 22, 2010, PHMSA published a follow-up Notice of Proposed Rulemaking (NPRM) addressing the regulation of all rural onshore hazardous liquid low-stress pipelines. This NPRM represents phase two of PHMSA's implementation of its mandate in the PIPES Act. In this NPRM, PHMSA proposes safety requirements for all rural low-stress pipelines not included under the phase one final rule. This latest NPRM does not include any new proposed requirements for onshore rural gathering lines.

The low-stress pipelines captured under the new NPRM include: (1) rural low-stress pipelines of a diameter less than 8⅝ inches located in or within one-half mile of an unusually sensitive area and (2) all other rural low-stress pipelines that were not included under phase one. PHMSA estimates that the NPRM will apply to 1,384 miles of low-stress pipelines not covered by the previous rule. However, the NPRM does not broaden the regulation of rural on-shore gathering lines. The NTSB believes that the key to the success of these regulations will be effective oversight exercised by the pipeline operators and PHMSA.

Question 2. What should Congress do to improve pipeline safety?

Answer. Over the past decade or more, PHMSA has used a risk-based assessment for regulating pipeline safety. The pipeline safety regulations provide the structure, content, and scope for many aspects of the overall pipeline safety program. Within this regulatory framework, pipeline operators have the flexibility and responsibility to develop their individual programs and plans, determine the specific performance standards, implement their plans and programs, and conduct periodic self-evaluations that best fit their particular pipeline systems. PHMSA likewise has the responsibility to review pipeline operators' plans and programs for regulatory compliance and effectiveness.

The NTSB believes that with the risk-based assessment approach come important responsibilities for both the individual pipeline operators and PHMSA. The operator and regulator need to verify whether risk-based assessments are being executed as planned, and more importantly, whether these programs are effective. Unfortunately, there have been some recent pipeline investigations in which the NTSB discovered that PHMSA and operator oversight of risk-based assessment programs, specifically integrity management programs and public education efforts, have been lacking and have failed to detect flaws and weaknesses in such programs.

NTSB is concerned that the level of self-evaluation and oversight currently being exercised is not uniformly applied by some pipeline operators and PHMSA to ensure that the risk-based safety programs are effective. The NTSB believes that PHMSA must establish an aggressive oversight program that thoroughly examines each operator's decision-making process for each element of its integrity management program.

Congress can ensure that PHMSA has the needed funding and resources to implement an aggressive oversight program, and require that PHMSA provide periodic analyses of its oversight program.

Question 2a. Should PHMSA have more authority to regulate offshore pipelines?

Answer. The NTSB believes that PHMSA should have more authority to regulate all types and categories of offshore pipelines. The regulation of offshore pipeline systems has not been addressed in recent legislation or regulatory action. Jurisdiction over offshore pipelines of all types is complex and currently involves coastal states, PHMSA, and the Department of the Interior. The jurisdictional responsibilities are based on the location and function of a pipeline (*e.g.,* production versus transportation) rather than on the threat to public safety and the environment from the petroleum and/or natural gas transported. These jurisdictional complexities can easily lead to gaps in the regulations and inconsistencies in pipeline safety standards, which could be minimized if a more seamless approach to regulating offshore pipelines is taken by giving PHMSA sole jurisdiction over all pipeline systems located wholly or partially on the Outer Continental Shelf.

Currently, PHMSA has the most expertise at the Federal level on pipeline safety issues, and would be best suited to work with existing stakeholders to develop and implement a simplified and more consistent regulatory program for offshore pipelines. PHMSA would also need the resources to assume such expanded responsibilities.

The tragedy in the Gulf of Mexico involving the *Deepwater Horizon* drilling platform is a grim reminder of the damage that a major oil spill can cause. While the magnitude of the *Deepwater Horizon* spill is far greater than any known pipeline failure, the events in the Gulf should remind those involved in the pipeline industry that all pipelines, offshore and onshore, must be sufficiently safeguarded and regulated in order to protect the public and the environment.

Question 2b. What would be NTSB's role in responding to a major pipeline failure caused by a natural disaster, manmade disaster, or terrorist attack?

Answer. Under the NTSB's operating statute (49 U.S.C. 1131), the NTSB is required to investigate or have investigated a pipeline accident in which there is a fatality or substantial property damage, or significant injury to the environment. The NTSB can also investigate any accident that the Board decides is catastrophic or involves problems of a recurring nature.

Major catastrophic pipeline failures caused by natural disasters do not occur often, but can and have been investigated by the NTSB. In September 1996 the NTSB adopted a Pipeline Special Investigation Report—*Evaluation of Pipeline Failures during Flooding and of Spill Response Actions, San Jacinto River near Houston, Texas, October 1994*, excerpts of which are attached for your reference. The NTSB report addressed: (1) the adequacy of Federal and industry standards on designing pipelines in flood plains, (2) the preparedness of pipeline operators to respond to threats to their pipelines from flooding and to minimize the potential for product releases, and (3) the preparedness of the Nation to minimize the consequences of petroleum releases. More often, however, acts of nature, such as the washouts of creek and river beds, floods, frost heaves, or lightning strikes, cause less than catastrophic incidents. Most NTSB pipeline investigations involve failures of designs, materials, operations, maintenance, human error and other factors that could be identified as manmade disasters, or attributed to some form of human interaction.

NTSB has established multi-tiered evaluation criteria that can be applied for any pipeline accident in order to determine whether an NTSB response is needed, and the level of response to be provided. The criteria are based on the danger to the public (fatalities and injuries, evacuations, etc.), property damage, and environmental damage.

According to 49 U.S.C. 1131, the NTSB's investigation has priority over any other investigation by another department, agency, or instrumentality of the Federal Government with a key exception. The NTSB must relinquish its investigative priority to the Federal Bureau of Investigation if the Attorney General, in consultation with the Chairman of the NTSB, determines that circumstances indicate that the accident may have been caused by a criminal act. The NTSB may provide technical support to the FBI, while continuing its investigation of safety issues resulting from the accident.

EVALUATION OF PIPELINE FAILURES DURING FLOODING AND OF SPILL RESPONSE ACTIONS, SAN JACINTO RIVER NEAR HOUSTON, TEXAS, OCTOBER 1994

Pipeline Special Investigation Report—Adopted: September 6, 1996—Notation 6734

NATIONAL TRANSPORTATION SAFETY BOARD
Washington, DC

Executive Summary

Between October 14 and October 21, 1994, some 15 to 20 inches of rain fell on the San Jacinto River flood plain near Houston, Texas, resulting in dangerous flooding that far surpassed past flooding experience in the region. The floods forced over 14,000 people to evacuate their homes and resulted in 20 deaths.

Due to the flooding, 8 pipelines ruptured and 29 others were undermined both at river crossings and new channels created in the flood plain. More than 35,000 barrels (1.47 million gallons) of petroleum and petroleum products were released into the river. Ignition of the released products within flooded residential areas resulted in 547 people receiving (mostly minor) burn and inhalation injuries. The spill response costs were in excess of $7 million and estimated property damage losses were about $16 million.

With respect to this accident, the Safety Board undertook a special investigation that focused on the following safety issues: (1) the adequacy of Federal and industry standards on designing pipelines in flood plains, (2) the preparedness of pipeline operators to respond to threats to their pipelines from flooding and to minimize the potential for product releases, and (3) the preparedness of the Nation to minimize the consequences of petroleum releases. The report also addresses the need for effective operational monitoring of pipelines and for the use of remote- or automatic-operated valves to allow for prompt detection of product releases and rapid shutdown of failed pipe segments.

As a result of its investigation, the Safety Board makes nine safety recommendations: one to the Research and Special Programs Administration, five to the National Response Team, and one each to the American Petroleum Institute, the Association of Oil Pipe Lines, and the Interstate Natural Gas Association of America.

Introduction

Serious flooding in the San Jacinto River flood plain near Houston, Texas, in October 1994 caused 8 pipelines to rupture and 29 others to be undermined both at river crossings and new channels created in the flood plain.

The high number of pipelines ruptured and damaged during this incident, and the magnitude of the petroleum releases and spill response efforts emphasized the threats posed to public safety and the environment by petroleum transportation by pipeline. Although pipeline transportation is one of the safest .means for transporting petroleum, it poses great risk potential to the environment because of the large volumes of hazardous liquids that can be released when a rupture occurs.

In a pipeline transport situation, as opposed to other transport options, there is greater likelihood of releasing petroleum into environmentally sensitive areas. Concerns about the environmental consequences of releases from pipelines have been expressed by the Congress, the States, and local interests.

Because so many pipelines were damaged during this flood and such large volumes of petroleum and petroleum products were released—requiring a massive environmental response in terms of personnel and equipment—the Safety Board undertook this special investigation to assess the adequacy of Federal and industry standards on designing pipelines in flood plains, the preparedness of pipeline operators to respond to threats to their pipelines from flooding and to minimize the potential for product releases, and the preparedness of the Nation to minimize the consequences of petroleum releases.

In the course of the investigation, the Safety Board also discovered evidence reinforcing the need for effective operational monitoring of pipelines and for the use of remote- or automatic-operated valves to allow for prompt detection of product releases and rapid shutdown of failed pipe segments.

Conclusions

1. The design bases of most pipelines undermined or ruptured during the flood did not include study of the flood plain to identify potential threats; rather, operators used only general design criteria applicable at the time the pipelines were installed.

2. Standards for designing pipelines across flood plains are needed to define the multiple threats posed to pipelines and to address the research, study, and future considerations that must be used for designing pipelines and periodically reevaluating the integrity of their designs during their operating life.

3. Most operators of pipelines crossing the San Jacinto River flood plain continued operations without evaluating the capability of the pipeline design to withstand the threats presented by the flood.

4. Few pipeline operators took effective response actions during the San Jacinto flood to minimize the potential for product releases.

5. Pipeline operators would have been more likely to have implemented early shutdown and/or purging of products from pipe segments crossing the San Jacinto flood plain had the Research and Special Programs Administration required them to develop plans for responding to substantial threats of a pipeline failure and product discharge.

6. The response by local, State, and Federal Government agencies to the flood emergency was well-managed and effective.

7. Failed liquid pipelines continue to release excessive volumes of petroleum and liquid products into the environment because the Research and Special Programs Administration has not established requirements for rapid detection and shutdown of failed pipe segments, and the liquid pipeline industry has not incorporated means for rapidly detecting, locating, and shutting down failed pipe segments.

8. Risks to workers and the public were increased significantly when the unified command conducted an in-situ bum without having in place appropriate checks and balances to ensure that approved procedures and requirements were followed explicitly.

9. Spill management personnel responding from other regions of the country and trained on different incident command procedures created communications, command, and control difficulties because they were not familiar with the incident command structure and procedures in use in the Galveston Bay area.

10. Implementation of the unified incident command structure and operational principles in the National Response Team's Technical Assistance Document *Incident Command System/Unified Command* will enhance the overall preparedness for responding to petroleum spills.

11. Some lessons on improving the area's spill response preparedness were not learned primarily because a comprehensive after-action critique was not conducted.

Recommendations

As a result of its investigation, the National Transportation Safety Board makes the following recommendations:

—to the Research and Special Programs Administration:

Require operators of liquid pipelines to address, in their Oil Pollution Act of 1990 spill response plans, identifying and responding to events that can pose a substantial threat of a worst-case product release. (Class II, Priority Action) (P–96–21)

—to the National Response Team:

Make your membership aware of the circumstances and nature of the events in the October 1994 environmental response at Houston, Texas, specifically in regard to the need for coordinating all planning and operational activities prior to conducting in-situ burn countermeasures. (Class II, Priority Action) (I–96–1)

Motivate National Response Team agencies to integrate into their area contingency plans the command and control principles contained in Technical Assistance Document *Incident Command System/Unified Command* and encourage them to train all personnel assigned management responsibilities in those principles. (Class II, Priority Action) (I–96–2)

Include procedures for implementing your Unified Command/Incident Command System that will ensure that all safety-critical operations are coordinated with parties at risk. (Class II, Priority Action) (I–96–3)

Establish guidance calling for Federal On-Scene Coordinators to conduct a comprehensive after-action critique of each spill response to incorporate the observations of all participating agencies to identify improvements needed in equipment, communications procedures, guidance, techniques, and management. (Class II, Priority Action) (I–96–4)

Request that Federal On-Scene Coordinators document and forward to National Response Team headquarters all "lessons learned" developed from after-action critiques for review and implementation nationwide as appropriate. (Class II, Priority Action) (I–96–5)

—to the American Petroleum Institute:

Take the lead to develop, in cooperation with the Association of Oil Pipe Lines and the Interstate Natural Gas Association of America, design and construction standards adequate for pipelines to safely cross flood plains and streambeds, including the development of recommended practices for periodically reassessing crossing designs in light of changes that have occurred in the flood plain or streambed. (Class II, Priority Action) (P–96–22)

—to the Association of Oil Pipe Lines:

Develop, in cooperation with the American Petroleum Institute and the Interstate Natural Gas Association of America, design and construction standards adequate for pipelines to safely cross flood plains and streambeds, including the development of recommended practices for periodically reassessing crossing designs in light of changes that have occurred in the flood plain or streambed. (Class II, Priority Action) (P–96–23)

—to the Interstate Natural Gas Association of America:

Develop, in cooperation with the American Petroleum Institute and the Association of Oil Pipe Lines, design and construction standards adequate for pipelines to safely cross flood plains and streambeds, including the development of recommended practices for periodically reassessing crossing designs in light of changes that have occurred in the flood plain or streambed. (Class II, Priority Action) (P–96–24)

By the National Transportation Safety Board

JAMES E. HALL,
Chairman.
ROBERT T. FRANCIS II,
Vice Chairman.
JOHN A. HAMMERSCHMIDT,
Member.
JOHN J. GOGLIA,
Member.
GEORGE W. BLACK, JR.,
Member.

September 6, 1996

§ *1131. General authority*

(a) General.——

(1) The National Transportation Safety Board shall investigate or have investigated (in detail the Board prescribes) and establish the facts, circumstances, and cause or probable cause of——

(A) an aircraft accident the Board has authority to investigate under section 1132 of this title or an aircraft accident involving a public aircraft as defined by section 40102(a)(37) of this title other than an aircraft operated by the Armed Forces or by an intelligence agency of the United States;

(B) a highway accident, including a railroad grade crossing accident, the Board selects in cooperation with a State;

(C) a railroad accident in which there is a fatality or substantial property damage, or that involves a passenger train;

(D) a pipeline accident in which there is a fatality, substantial property damage, or significant injury to the environment;

(E) a major marine casualty (except a casualty involving only public vessels) occurring on the navigable waters or territorial sea of the United States, or involving a vessel of the United States, under regulations prescribed jointly by the Board and the head of the department in which the Coast Guard is operating; and

(F) any other accident related to the transportation of individuals or property when the Board decides——

(i) the accident is catastrophic;

(ii) the accident involves problems of a recurring character; or

(iii) the investigation of the accident would carry out this chapter.

(2)(A) Subject to the requirements of this paragraph, an investigation by the Board under paragraph (1)(A)–(D) or (F) of this subsection has priority over any investigation by another department, agency, or instrumentality of the U.S. Government. The Board shall provide for appropriate participation by other departments, agencies, or instrumentalities in the investigation. However, those departments, agencies, or instrumentalities may not participate in the decision of the Board about the probable cause of the accident.

(B) If the Attorney General, in consultation with the Chairman of the Board, determines and notifies the Board that circumstances reasonably indicate that the accident may have been caused by an intentional criminal act, the Board shall relinquish investigative priority to the Federal Bureau of Investigation. The relinquishment of investigative priority by the Board shall not otherwise affect the authority of the Board to continue its investigation under this section.

(C) If a Federal law enforcement agency suspects and notifies the Board that an accident being investigated by the Board under subparagraph (A), (B), (C), or (D) of paragraph (1) may have been caused by an intentional criminal act, the Board, in consultation with the law enforcement agency, shall take necessary actions to ensure that evidence of the criminal act is preserved.

(3) This section and sections 1113, 1116(b), 1133, and 1134(a) and (c)–(e) of this title do not affect the authority of another department, agency, or instrumentality of the Government to investigate an accident under applicable law or to obtain information directly from the parties involved in, and witnesses to, the accident. The Board and other departments, agencies, and instrumentalities shall ensure that appropriate information developed about the accident is exchanged in a timely manner.

(b) Accidents Involving Public Vessels.——

(1) The Board or the head of the department in which the Coast Guard is operating shall investigate and establish the facts, circumstances, and cause or probable cause of a marine accident involving a public vessel and any other vessel. The results of the investigation shall be made available to the public.

(2) Paragraph (1) of this subsection and subsection (a)(1)(E) of this section do not affect the responsibility, under another law of the United States, of the head of the department in which the Coast Guard is operating.

(e) Accidents Not Involving Government Misfeasance or Nonfeasance.——

(1) When asked by the Board, the Secretary of Transportation may——

(A) investigate an accident described under subsection (a) or (b) of this section in which misfeasance or nonfeasance by the Government has not been alleged; and

(B) report the facts and circumstances of the accident to the Board.

(2) The Board shall use the report in establishing cause or probable cause of an accident described under subsection (a) or (b) of this section.

(d) Accidents Involving Public Aircraft.—The Board, in furtherance of its investigative duties with respect to public aircraft accidents under subsection (a)(1)(A) of this section, shall have the same duties and powers as are specified for civil aircraft accidents under sections 1132(a), 1132(b), and 1134(a), (b), (d), and (f) of this title.

RESPONSE TO WRITTEN QUESTION SUBMITTED BY HON. KAY BAILEY HUTCHISON TO HON. DEBORAH A.P. HERSMAN

Question. What recommendations do you have for the Committee with respect to reauthorizing the pipeline safety program?

Answer. NTSB concerns can be grouped into three general areas: excess flow valves (EFVs), safety oversight, and low-stress pipeline regulation equality. NTSB has recommended the use of EFVs in gas distribution pipeline systems for many years. While the NTSB has not issued recommendations specifically addressing either the effective oversight of risk-based assessments in pipeline safety regulation or the regulation of low-stress pipelines, these two areas are critical to safeguarding the integrity of our Nation's pipeline systems.

Apply Excess Flow Valves (EFVs) Equally

EFVs are installed in natural gas service lines where they connect to the distribution line. EFVs are designed to mitigate gas leaks from the service line by detecting an abnormally high flow rate. When an excess flow is detected, an EFV automatically closes, thus shutting off the flow of gas from the distribution line to the service line.

The Pipeline and Hazardous Material Safety Administration's (PHMSA) current mandate under the PIPES Act requires excess flow valves only on new or replacement service lines to single family residences. The NTS13 recommended nearly 10 years ago (P–01–2) that PHMSA require that excess flow valves be installed in all new and replacement gas service lines, regardless of a customer's classification, when the operating conditions are compatible with readily available valves.

The NTSB believes that apartment buildings, other multifamily dwellings, and commercial properties are susceptible to the same risks from leaking gas lines as single-family residences, and we believe this gap in the law and the regulations should be eliminated.

Effective Safety Oversight

Over the past decade or more, PHMSA has used a risk-based assessment for regulating the DOT pipeline safety program. PHMSA has successfully built a partnership with various facets of the pipeline industry to develop, implement and execute a multi-part pipeline safety program. In the NTSB's view, all stakeholders, including PHMSA, have come to rely heavily upon this approach. The NTSB believes a risk-based approach can work if effective oversight is exercised by PHMSA and the pipeline operators.

The NTSB also believes that with the risk-based assessment come increased responsibilities for both the individual pipeline operators and PHMSA. Operators must diligently and objectively scrutinize the effectiveness of their programs, identify areas for improvement, and implement corrective measures. PHMSA, as the regulator, must also do the same in its audits of the operators' programs and in self-assessments of its own programs. In short, both operator and regulator need to verify whether risk-based assessments are being executed as planned, and more importantly, whether these programs are effective. Unfortunately, there have been some recent pipeline investigations in which the NTSB discovered indications that PHMSA and operator oversight of risk-based assessment programs, specifically integrity management programs and public education programs, has been lacking and has failed to detect flaws and weaknesses in such programs.

Low-Stress Pipelines Regulation Equality

At the time the PIPES Act was enacted, Federal pipeline safety regulations only applied to low-stress pipelines that were located in populated areas, crossed navigable waterways, or carried highly volatile liquids, such as compressed liquefied propane. In a final rulemaking, "Pipeline Safety: Protecting Unusually Sensitive Areas from Rural Onshore Hazardous Liquid Gathering Lines and Low-Stress Lines," published on June 3, 2008, PHMSA issued regulations for rural onshore low-stress pipelines that have a diameter of at least 8⅝ inches and that are within ½ mile of an area defined as unusually sensitive. Low-stress pipelines meeting these criteria will be required to meet 49 CFR Part 195, for hazardous liquid pipelines in its entirety by July 2012.

The final rule also included provisions for rural onshore gathering lines that operate at stress levels greater than 20 percent of the pipe strength, have a diameter between 6⅝ and 8⅝ inches and are within ¼ mile of an area defined as unusually sensitive. (A "gathering line" is defined as a pipeline with a diameter of 8⅝ inches or less that transports petroleum from a production facility.) Under the final rule, rural onshore gathering lines will be required to meet Part 195 in part by July 2011. The safety requirements of Part 195 that will eventually apply to the rural onshore gathering lines include annual and accident reporting requirements, establishment of maximum operating pressure, installation of line markers, public education programs, damage prevention programs, corrosion control, and operator qualification programs.

On June 22, 2010, PHMSA published a follow-up Notice of Proposed Rulemaking (NPRM) addressing the regulation of all rural onshore hazardous liquid low-stress pipelines. This NPRM represents phase two of PHMSA's implementation of its mandate in the PIPES Act.

In this NPRM, PHMSA proposes safety requirements for all rural low-stress pipelines not included under the phase one final rule. This latest NPRM does not include any new proposed requirements for onshore rural gathering lines.

The low-stress pipelines captured under the new NPRM include: (1) rural low-stress pipelines of a diameter less than 8⅝ inches located in or within one-half mile of an unusually sensitive area and (2) all other rural low-stress pipelines that were not included under phase one. PHMSA estimates that the NPRM will apply to 1,384 miles of low-stress pipelines not covered by the previous rule. However, the NPRM does not broaden the regulation of rural on-shore gathering lines. The NTSB believes that the key to the success of these regulations will be effective oversight exercised by the pipeline operators and PHMSA.

The NTSB believes that PHMSA should have more authority to regulate all types and categories of offshore pipelines. The regulation of offshore pipeline systems has not been addressed in recent legislation or regulatory action. Jurisdiction over offshore pipelines of all types is complex and currently involves coastal states, PHMSA, and the Department of the Interior. The jurisdictional responsibilities are based on the location and function of a pipeline (*e.g.,* production versus transportation) rather than on the threat to public safety and the environment from the petroleum and/or natural gas transported. These jurisdictional complexities can easily lead to gaps in the regulations and inconsistencies in pipeline safety standards, which could be minimized if a more seamless approach to regulating offshore pipelines is taken by giving PHMSA sole jurisdiction over all pipeline systems located wholly or partially on the Outer Continental Shelf.

Currently, PHMSA has the most expertise at the Federal level on pipeline safety issues, and would be best suited to work with existing stakeholders to develop and implement a simplified and more consistent regulatory program for offshore pipelines. PHMSA would also need the resources to assume such expanded responsibilities.

The tragedy in the Gulf of Mexico involving the *Deepwater Horizon* drilling platform is a grim reminder of the damage that a major oil spill can cause. While the magnitude of the *Deepwater Horizon* spill is far greater than any known pipeline failure, the events in the Gulf should remind those involved in the pipeline industry that all pipelines, offshore and onshore, must be sufficiently safeguarded and regulated in order to protect the public and the environment.

Response to Written Questions Submitted by Hon. John Thune to Hon. Deborah A.P. Hersman

Question 1. Today, ethanol and fuel blended with ethanol usually move by truck or rail due to technological challenges in moving these products by pipeline. Yet, the ability to move ethanol and other biofuels by rail would be safety and less expensive. What recommendations do you have for encouraging the development of ethanol pipelines?

Answer. Ethanol or ethyl alcohol is a volatile flammable liquid with a significant flammability range (concentration in air of 3 percent to 19 percent) and poses a significant fire risk, but ethanol is not corrosive, particularly toxic, or a severe pollutant. (Pure ethanol is found in alcoholic beverages.) Today, ethanol is primarily used as a feedstock for the production of various chemical products and as an additive in gasoline. Ethanol used for such commercial purposes is denatured, meaning a substance is added to the ethanol to deter people from consuming it as an alcoholic beverage.

The commercial demand for ethanol has dramatically risen in recent years because of its use in gasoline. Automotive gasoline containing ethanol is commonly transported by hazardous liquid pipelines. Although the NTSB is not aware of any existing pipelines dedicated to the transportation of ethanol, the NTSB does not see any properties of ethanol that would make it uniquely hazardous to transport by pipeline with existing regulations to safeguard people and the environment applied to these pipelines.

Biofuels would likewise be flammable. It is conceivable that a particular biofuel, depending on its source and composition, may potentially have corrosive or environmentally harmful properties that a pipeline operator would have to consider in light of current regulations.

Question 2. You note in your written testimony that partnerships between the industry and PHMSA have led to a number of joint initiatives. What lessons can be learned from the cooperative relationship between PHMSA, the States, and the oil and gas industry that could be beneficial for other industries?

Answer. Over the past decade or more, PHMSA has used a risk-based assessment for regulating pipeline safety. Within this regulatory framework, pipeline operators have the flexibility and responsibility to develop their individual programs and plans, determine the specific performance standards, implement their plans and programs, and conduct periodic self-evaluations that best fit their particular pipeline systems. PHMSA likewise has the responsibility to review pipeline operators' plans and programs for regulatory compliance and effectiveness.

The NTSB believes that with the risk-based assessment approach come important responsibilities for both the individual pipeline operators and PHMSA, and these programs can be effective when both parties are fulfilling their responsibilities. Unfortunately, there have been some recent pipeline investigations in which the NTSB discovered that PHMSA and operator oversight of risk-based assessment programs, specifically integrity management programs and public education efforts, have been lacking and have failed to detect flaws and weaknesses in such programs.

Congress can ensure that PHMSA has the needed funding and resources to implement an aggressive oversight program, and require that PHMSA provide periodic analyses of its oversight program.

RESPONSE TO WRITTEN QUESTIONS SUBMITTED BY HON. MARK PRYOR TO ROCCO D'ALESSANDRO

Question 1. Do you oppose expanding integrity management inspections?

Answer. AGA opposes expanding the high consequence area (HCA) definition in the Transmission Integrity Management Program (TIMP). Some reasons for not expanding the integrity management HCA definition are: (1) the risk-based integrity management inspection philosophy in the pipeline safety statute has proven to be effective and is still being implemented, (2) treating all pipeline segments as if they posed the same risks is not consistent with the risk-based engineering principles built into the pipeline safety Federal code of regulations, 49 CFR 192, and the (3) AGA believes there are potential unintended consequences in eliminating risk prioritization that could stretch operator safety resources and not allocate them to the most critical areas.

Congress required DOT to establish criteria for operators to identify transmission pipelines in densely populated areas, conduct risk analyses, and adopt and implement integrity management programs. To accomplish these tasks, the DOT created the HCA concept, which went beyond densely populated areas and included places where people are known to congregate on a regular basis. (*i.e.,* churches, playgrounds, recreational areas, etc.) The intent of establishing HCAs was for the natural gas industry to devote its resources toward protecting those areas which represent the greatest risk for the public. Operators were given 10 years to complete these assessments and begin reassessments. Baseline assessments will be complete by the December 2012 deadline. It should be noted that HCAs for hazardous liquid pipelines used a vastly different technical basis from gas transmission pipelines because of the properties transported. These HCAs include unusually sensitive drinking water and ecological resources, high population areas and other populated areas, and commercially navigable waterways.

Some define risk management as the identification, assessment, and prioritization of risks followed by coordinated and economical application of resources to minimize, monitor, and control the probability and/or impact of unfortunate events. Pipeline safety regulations have incorporated risk management principles into regulation for decades. The regulations treat pipeline segments differently based upon various factors. Since 1970, natural gas transmission pipelines have used risk-based Class 1, 2, 3 or 4 locations, which are based upon the concentration of buildings near pipeline corridors, for design, construction, operation and maintenance requirements. The transmission integrity management program HCA concept is an enhancement to existing risk-based pipeline safety regulations.

Treating most or all pipeline segments with the assessment requirements applied in HCAs would dramatically increase the resources needed for safety without a commensurate improvement in safety. The expansion could have the unintended consequence of adversely affecting safety if the focus on higher risk areas is diluted by a one-size-fits-all approach.

Question 2. How often do most companies conduct internal integrity assessments?

Answer. The Transmission Integrity Management Program (TIMP) regulation requires a specific type of integrity assessment every 7 years in HCAs, but operators conduct some type of safety assessment on all pipeline segments on a continual basis.

The TIMP regulation requires operators to conduct a prescriptive integrity management assessment every 7 years (49 CFR 192 Subpart O). The integrity assessment interval recommended by the American Society of Mechanical Engineers, ASME B31.8S, Managing System Integrity of Gas Pipelines, consensus standard does not give a fixed interval for an integrity assessment. Instead it gives a range of years based upon historical technical national pipeline performance data and current data on the specific pipeline being analyzed.

There are many safety assessment intervals built into the pipeline safety code separate from the TIMP assessments. For example, there is external corrosion control monitoring annually, leakage surveys from one to four times per year, and patrols from one to four times per year. Importantly, section 192.613 Continuing Surveillance, requires operators to have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions.

Question 3. In light of the recent BP spill and leak events, do you believe there is more that industry, Congress, or PHMSA should do to enhance pipeline safety?

Answer. The BP spill and leak event is not related in any way to pipeline safety. Pipeline incidents are rare because of the extensive regulatory structure and operator commitment to safety. PHMSA requires operators to analyzing pipeline accidents and failures, for the purpose of determining the causes of the failure and minimizing the possibility of a recurrence.

One area of pipeline safety that could be enhanced is excavation damage prevention. Although the nine elements in the 2006 PIPES Act were an important achievement for reducing pipeline damages, the greatest impact will actually occur when states open up their one-call laws and revise the language so that it adheres to the nine elements to create a robust and effective state damage prevention program. This may take several years due to the unique timing of state legislative sessions and the existence of special interest groups that have no desire in overhauling their state damage prevention laws. Still, a handful of states have recently made positive changes to their one-call law such as Utah, Indiana and Maryland.

Many state one-call laws are antiquated and fail to effectively address difficult issues, such as enforcement of excavators who fail to follow the one-call process or fail to abide by safe digging practices. Without consistent and effective enforcement from a recognized authority at the state level, it is impossible to develop an effective damage prevention program. Most states either have no agency to enforce the damage prevention laws, or the agency simply does not have the funding to execute its responsibilities. Many states give enforcement authority to the attorney general and pipeline safety enforcement is neglected because of more pressing priorities by state justice departments. AGA is of the position that consistent and effective enforcement must be designed so it can hold all entities accountable for pipeline safety.

Question 4. What do you believe should be the top priorities for PHMSA in light of the recent BP disaster?

Answer. AGA cannot speak on behalf of PHMSA regarding priorities. However, over the last 7 months PHMSA has issues two major regulations that must be implemented—Distribution Integrity Management (DIMP) and Control Room Management (CRM). These were priorities set forth by Congress in the Pipeline Improvement, Protection, and Enforcement Act of 2006. The DIMP program requires operators to develop comprehensive integrity management plans that will identify risks and implement corrective actions for all piping an operators' system. The plans will facilitate better regulatory oversight. The CRM regulation is a comprehensive control system rule which includes human factors, fatigue management and emergency response requirements. These are top priorities for AGA members.

Question 5. Do you believe PHMSA currently provides enough oversight of our Nation's oil and gas pipelines?

Answer. Most AGA member companies are under the jurisdiction and oversight of state regulators. AGA believes there is sufficient Federal and state oversight of pipelines to ensure safety.

RESPONSE TO WRITTEN QUESTIONS SUBMITTED BY HON. MARK PRYOR TO TIMOTHY C. FELT

Question 1. What do you believe should be the top priorities for PHMSA in light of the recent BP disaster?

Answer. The liquid pipeline industry remains at a continued state of readiness to properly maintain and operate our systems. We are certainly aware of the increased focus that the *Deepwater Horizon* incident will place on our industry. On June 28, 2010, PHMSA issued an Advisory Bulletin to all operators of liquid pipeline facilities required to develop and submit spill response plans under 49 CFR Part 194. The Advisory Bulletin requires all covered operators to review and update, as necessary, their spill response plans to calculate and envision worst-case scenario planning. Operators must examine available resources required to respond to worst-case scenarios, and conduct their review (including any updates) within 30 days. Operators were also asked to confirm that drills have been performed at the frequency specified in their plans and maintain on-going training with first responders. Pipeline operators already have significant obligations under current regulation to maintain up-to-date response plans that are specifically tailored for each site and also include frequent drills and training. We would request that as the Federal Government continues its important oversight work, in light of the Deepwater incident, that it provide clear and consistent compliance guidance to affected pipeline operators.

We do believe there are some constructive steps PHMSA and the Office of Pipeline Safety (OPS) could make to remove gaps in pipeline safety regulation. First, PHMSA should encourage states to enhance their damage prevention laws or move quickly to improve damage prevention programs in the states that have weak or ineffective laws. Most importantly, PHMSA should remove exemptions for state and municipal governments from One-Call requirements. Such exemptions create unnecessary opportunities for third-party damage to pipelines. As I mentioned in my testimony, incidents from excavation damage by third parties accounted for only 7 percent of release incidents from 1999 to 2008. However, 31 percent of all significant incidents (those that result in spills of 50 barrels or more, fire, explosion, evacuation, injury or death) came from excavation damage by third parties. AOPL and API believe Congress should encourage OPS to move forward to issue a final rule on damage prevention based on the October 2009 Advanced Notice of Proposed Rulemaking (ANPRM), disallowing any exemptions to One-Call requirements.

Question 1a. Do you believe PHMSA currently provides enough oversight of our Nation's oil and gas pipelines?

Answer. The liquids pipeline industry believes that PHMSA is a fair but tough regulator with several significant oversight tools, including: random and regular inspections of equipment and facilities, enforcement authority, and fines. PHMSA has a set of prescriptive safety regulations and standards that require a diligent focus by our industry to remain in compliance. Recently, critics of our industry have unfairly distorted and misconstrued the industry's constructive working relationship with PHMSA, especially on the issue of setting consensus standards. Pipeline operators have every interest in developing best practices that help maintain the integrity of their systems, which pushes the industry to achieve operational excellence. It should be recognized that PHMSA can require, as well as reject, modifications to industry standards before incorporating them by reference. Further, all consensus industry standards involve public input under guidelines established by the American National Standards Institute (ANSI), whose Board of Directors are currently comprised of individuals from several Federal agencies, including DOE, NIST, CPSC, EPA, and DoD. In addition, PHMSA's Technical Advisory Committee has direct representation from those in the advocacy community to incorporate all points of view in the regulatory process. We take issue with those that unfairly criticize and malign the reputation of organizations like the American Society of Mechanical Engineers (ASME) International and the American Society for Testing and Materials (ASTM) that were involved in setting consensus standards that have been adopted by PHMSA. These and other professional organizations provide real-world technical expertise and important insight to the regulatory process. The notion that the pipeline industry regulates itself is false. The role of Federal safety regulator is clearly and strongly performed by PHMSA.

RESPONSE TO WRITTEN QUESTIONS SUBMITTED BY HON. MARK PRYOR TO GARY L. SYPOLT

Question 1. Do you oppose expanding integrity management inspections?

Answer. We *do oppose expanding the High Consequence Area (HCA) definition* in the legislation to include more pipeline mileage. Currently, these HCAs are defined (for natural gas transmission lines) as those pipeline segments located within populated areas. If a pipeline is in an HCA, it is subject to an extra layer of protection beyond the existing pipeline safety regulations; in other words, it is subject to the Integrity Management Program (IMP) with its accompanying procedural and administrative requirements. The existing safety regulations, which have continually been updated since 1970, govern the design, materials, construction, operation and maintenance of *all natural gas transmission pipelines* and have contributed significantly to the safety record of natural gas transmission systems both within HCAs and outside HCAs. The focus of the mandated IMP on reducing risk in populated areas continues to make sense to us in that it allows the pipeline operators to focus its resources on those areas of the pipeline that are more densely populated.

The mandated IMP program specifically allows three types of inspection technology: hydrostatic pressure testing, direct assessment and internal inspection using "smart pigs." The legislation does allow the use of any new technology for inspections, but at this time *no new viable inspection technology has been accepted by PHMSA*.

Hydrostatic pressure testing involves isolating a section of pipeline and filling it with water and pressuring it far beyond the maximum operating pressure to see if the pipe ruptures or leaks. During the process, the pipeline segment must be taken out of service for several weeks. The pipeline operator must collect, handle and dispose of large volumes of water used in the testing. Finally, residual water or sediment could present operational problems once the pipeline segment is returned to service.

Direct assessment involves excavating segments of pipeline and physically inspecting them (externally) every time it is inspected. This requires significant excavation work, including tearing up private property and roads, and potentially damaging the pipeline with excavation equipment every time the assessment is done.

Within the last two decades, smart pig technology has been the "solution of choice" for integrity assessments because the alternatives—hydrostatic testing and direct assessment—present the aforementioned problems. Smart pigs can be a useful tool for managing corrosion where they are practical to use. However, many natural gas pipelines were constructed in an era before smart pigs were invented. These pipelines were engineered to transport natural gas—a highly compressible substance—rather than solid devices such as smart pigs. This means that pipeline segments with tight bends, telescoping segments, or valves which do not open completely, limit the passage of smart pigs and require extensive excavation and modifications to allow the insertion, passage and retrieval of smart pigs for inspections. These pipeline modifications are by far the most costly component of the IMP program.

As I noted in my testimony, however, we have invested heavily and are already inspecting and repairing pipelines- via smart pigs—in much more than just the defined HCAs. For natural gas transmission pipelines, HCAs account for about *7 percent of total mileage*, but we expect to actually perform internal inspections and repairs on about *65 percent of total mileage* by the end of the baseline Integrity Management Program (IMP) assessments which will be completed in December of 2012.

Based on this level of performance, I do not believe that integrity management inspections should be expanded by legislative mandate.

Question 2. How often do most companies conduct internal integrity assessments?

Answer. The Pipeline Safety Improvement Act of 2002 requires that natural gas transmission pipelines in HCAs undertake an initial integrity assessment by December 2012, and reassessments every 7 years thereafter. As mentioned previously, most of this work is being completed via internal inspections using smart pig devices.

A consensus standard developed by the American Society of Mechanical Engineers (ASME) about a decade ago suggested a reassessment interval of 10 years for most high-pressure natural gas transmission pipelines. We believe the ASME standard is a logically and technically superior basis for setting reassessment intervals, and we hope Congress ultimately permits PHMSA to incorporate such a standard into the regulations, rather than the current seven-year mandate. In a report to Congress on this question in 2006, the GAO agreed with this position.

Question 3. In light of the recent BP spill and leak events, do you believe there is more that industry, Congress or PHMSA should do to enhance pipeline safety?

Answer. First, it should be said that PHMSA and the pipeline safety program generally are not comparable to MMS and the events that led to the BP spill. For at least the last decade, the pipeline safety program at PHMSA has been characterized by action in the development of new safety standards for a variety of pipeline systems. Congress has added a number of mandates to PHMSA in terms of directing pipeline safety efforts. The occurrence of pipeline accidents is low, and serious accidents are very rare. The main reason is that industry, the regulator, and the public have worked together to put better safety programs and technologies in place.

Still, more can be done. My testimony covered several ideas, including the implementation of a "safety culture" across the pipeline industry, including our contractors. This culture assists in reducing the workplace accidents which are a significant portion of the serious pipeline incidents still occurring. It is also an area where the BP experience is instructive. "Safety culture" can be defined as an environment in which employees engage in best safety practices whether they are supervised or not. In other words, employees are empowered to take the safest path, and are rewarded for doing so. This type of culture creates the best environment for avoiding accidents.

Another area of additional focus, and the largest cause of serious incidents, is excavation damage prevention. This is also a "safety culture" issue but involves many stakeholders. Much has been done on this issue in the last 10 years, but more can be done. I would like to discuss this further in my answer to the next question.

The final area of continuing focus is the ongoing development of new materials, equipment, and best practices for such items as employee training or equipment maintenance. All of these things are important to making continued improvement to safety. In my testimony, I included the example of improved smart pig technology. Better standards and technology will ultimately lead to fewer accidents.

Question 4. What do you believe should be the top priorities for PHMSA in light of the recent BP disaster?

Answer. The top priority for PHMSA, given the BP disaster and the public response, should be maintaining public credibility and trust by focusing on those causes of accidents which have the most impact on the public. INGAA believes more should be done with respect to excavation damage prevention. Accidental hits to pipelines from, for example, construction equipment, tend to be the leading cause of deaths and/or injuries associated with our pipelines. While these state-run damage prevention programs have improved significantly over the last decade, more needs to be done. The recent accidents in Texas, profiled in my testimony, point to this conclusion. Again, a credible damage prevention effort is about more than just making the first call to a one-call center. An effective program includes full participation by all excavators and all underground utility operators, accurate and timely marking of facilities by utility operators, procedures for due caution by excavators working around marked facilities, and effective enforcement of the state regulations.

Question 5. Do you believe PHMSA currently provides enough oversight of our Nation's oil and gas pipelines?

Answer. Yes. The safety record of the pipeline industry is testament to this conclusion.

RESPONSE TO WRITTEN QUESTIONS SUBMITTED BY HON. MARK PRYOR TO CARL WEIMER

Question 1. What in your view would be the best way to conduct Integrity Management reviews by industry and PHMSA?

Answer. The Pipeline Safety Trust believes that the basic theory and implementation of the reviews required by Integrity Management programs for Hazardous Liquid and Natural Gas Transmission pipelines is sound, and has led to the detection and correction of thousands of potential safety problems.

Our concern is not so much in the way that Integrity Management reviews are conducted, but the limited miles of pipelines that are required to conduct such valuable safety reviews. Currently only 7 percent of natural gas transmission pipelines and only 44 percent of hazardous liquid pipelines are required to do these reviews. We believe that it is time to require that all of these types of pipelines fall under Integrity Management rules so people living in more rural neighborhoods have equal safety protection.

If the Integrity Management program is not to be expanded to all of these types of pipelines then there are a couple of things that would at least help increase the safety under the existing limited mileage. These include:

- Many operators inspect many more miles of pipeline than is required, which is a good thing. These operators should be required to report their findings to PHMSA on the mileage of pipelines outside of the required areas, and how they responded to those findings, in the same way they report findings in the required areas.
- The definition for determining High Consequence Areas for natural gas transmission pipelines in 49 CFR 192.903 should be changed as follows to significantly increase safety:

High consequence area means an area established by one of the methods described in paragraphs (1) or (2) as follows:

(1) An area defined as——

(iii) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy

- It should be made clear that at a minimum during the normal reinspection intervals operators should reassess their entire pipelines to determine if there have been any changes in circumstances (such as increase population near the pipeline) that would require additional areas to be added to High Consequence Area status.

Question 2. Should PHMSA have more authority to regulate offshore pipelines?

Answer. PHMSA already has significant authority in the offshore areas within the control of the states. While it is clear from the Gulf of Mexico disaster that a comprehensive review of offshore regulations and authority needs to be completed, the Pipeline Safety Trust has not considered this to the degree necessary to make a recommendation about whether authority needs to shift from MMS to PHMSA.

We would suggest that a study be undertaken to compare both the regulations and performance under both agencies, and then a good comparison of what needs to be strengthened where would be relatively easy.

One further point that should be addressed regardless of which agency is in charge is the implementation of a mandatory damage prevention notification system in the offshore waters. Onshore Congress, PHMSA and the pipeline industry have all spent significant effort to ensure the implementation of the national 811 "call before you dig" number and associated damage prevention awareness. No similar system is required in the offshore areas of the Gulf where increasing activities are occurring putting underwater pipelines at risk. One such offshore damage prevention system that has been developed that should be studied for possible mandatory implementation is GulfSafe. More information about it can be found on their website at: *http://www.gulfsafe.com/*.

RESPONSE TO WRITTEN QUESTIONS SUBMITTED BY HON. JOHN THUNE TO CARL WEIMER

Question 1. There seems to he some inconsistency in the treatment of oil pipelines compared to gas pipelines in terms of regulation and emergency response requirements. What recommendations do you have for addressing these?

Answer. I am not sure I understand the question, so would need more information regarding what "inconsistency" is being referred to.

The main inconsistency that we are currently concerned about is the difference in attention being spent addressing production, gathering, and flow lines. For oil pipelines Congress has asked, and PHMSA is now working toward a rulemaking, to implement new regulations on these low-stress oil pipelines. This is important work and we support it! Natural gas pipelines have similar production lines, many of which are unregulated, or the point where regulations begin is unclear. With a huge increase in domestic drilling for natural gas, much of it occurring in more populated areas in places like Texas, New York, and Pennsylvania, there is a need to ensure adequate regulation of these types of natural gas pipelines, especially in populated areas.

We believe that much of our concern about unregulated natural gas pipeline could be addressed by the following two changes:

- Implement a rulemaking to clarify the point where onshore regulated gas gathering lines begin (49 CFR Part 192.8). That point should be defined to ensure there are no unregulated gas pipelines off of well pads in class 2, 3, or 4 areas, or other "identified sites" where large groups may gather.

- Implement a rulemaking to include all Type A gathering lines (49 CFR Part 192.9) under the full requirements of the Integrity Management program (49 CFR Part 192 Subpart O) that currently only applies to transmission pipelines.

Question 2. Do you consider integrity management a success?

Answer. We do consider Integrity Management of transmission pipelines a success. For both liquid pipelines and natural gas pipelines integrity Management was a huge step up in regulations ensuring that transmission pipelines in more populated areas, and areas that could affect sensitive environments, were inspected on a regular basis. These required inspections found nearly 35,000 anomalies in need of repair on pipelines in the first round of inspections. These are anomalies that may not have been found and repaired until leaks, ruptures, or explosions occurred under the previous regulations.

While Integrity Management has been a success it is still limited to only 7 percent of natural gas pipelines and 44 percent of liquid pipelines. It is time to expand this successful program to all transmission pipelines to ensure that those in more rural areas have these same safety benefits, and that our critical fuel transportation network remains viable.

RESPONSE TO WRITTEN QUESTIONS SUBMITTED BY HON. JOHANNS TO CARL WEIMER

Question 1. Your testimony recommends that the pipeline safety system be changed to correct the "pipeline siting vs safety disconnect" which separates the safety function of PHMSA from the siting process. In light of this recommendation, what is your view of how PHMSA has been involved in the permitting process for the Keystone XL pipeline in Nebraska?

Answer. We have not been actively involved in the Keystone permitting process, but our understanding is that it has proceeded like most other new pipeline permitting processes across the country. In all of those permitting processes, whether being overseen by FERC, the Department of State or the states, there is a disconnect between PHMSA's review and approval of pipeline safety issues (special permits, High Consequence Areas, spill response plans, etc.) and the official environmental review that is part of the permitting. These two now separate processes need to be integrated into a single process. That way things like spill response plans and High Consequence Areas can be developed and publicly reviewed as part of the permitting—not in the separate processes that PHMSA now uses many of which are closed to the public. It makes little sense for the Department of State to do an environmental review is such critical things as Spill Response plans (under PHMSA's authority) have not yet been developed or made public.

One way to better integrate these separate processes would be to require PHMSA to be a cooperating agency for all interstate pipeline siting processes, and that all parts of a new pipeline's safety review be a part of that siting review as well.

Question 2. What specific recommendations would you make for the regulatory process that governs the issuance of a Presidential permit? Do these recommendations differ as compared to recommendations for the regulatory process that governs pipeline siting for exclusively domestic transport of crude oil?

Answer. We don't really see that there should be any real difference in the permitting process between purely domestic pipelines and ones that cross an international border. The recommendations we made above to better integrate permitting and pipeline safety would apply to both.

Question 3. What comments would you offer, if any, concerning the role that state authorities play in the regulatory process governing the issuance of Presidential permits for the international transport of crude oil?

Answer. Unlike the siting of interstate natural gas pipelines, which is controlled by FERC, states do have the ability to create pipeline siting agencies for interstate hazardous liquid pipelines. We think states should exercise this ability to give them control over the siting process, but in reality some states do and some states don't. In the states that do not create such siting agencies the routing and permitting decisions are left up to the pipeline companies and local government.

It is unclear to us whether a Presidential Permit granted by the State Department preempts the normal state siting authority, or whether those two processes can run in parallel to each other. This should be clarified, and at a minimum such state agencies should be made cooperating partners in the review by the State Department.

PREPARED STATEMENT OF MICHAEL THOMPSON, CHIEF, PIPELINE SAFETY, OREGON PUBLIC UTILITY COMMISSION AND CHAIRMAN, NATIONAL ASSOCIATION OF PIPELINE SAFETY REPRESENTATIVES (NAPSR)

Introduction

Chairman Lautenberg, Ranking Member Thune, members of the Committee, thank you for the opportunity to discuss our role in support of pipeline safety as related to reauthorization of the pipeline safety law. This law contains necessary protections that our Nation depends on to maintain safety in its energy pipeline network. I am the Chairman of the National Association of Pipeline Safety Representatives (NAPSR) which is a non-profit organization of state pipeline safety personnel who serve to support, encourage, develop and enhance pipeline safety in the country. I am pleased to submit this statement for the record on behalf of NAPSR and in support of our member states' efforts, as well as in support of the partnership with the Secretary of Transportation to fulfill the mandates of the Pipeline Safety Act.

I will briefly describe the role of the states in maintaining or enhancing pipeline safety, where our efforts are currently focused, and what it takes for State programs to implement the Federal mandates.

The States as Stewards of Pipeline Safety

Since the Pipeline Safety Act was signed into law in 1968, states have been very active as stewards of pipeline safety in assisting the U.S. DOT Secretary in carrying out the Nation's pipeline safety program. States act as certified agents for implementing, ensuring and enforcing Federal safety regulations, working in partnership with the Secretary. State pipeline safety program personnel are classified as state employees providing oversight of state and local safety regulations which in all cases are either equivalent or stricter than Federal regulations. This arrangement between the Federal and State government has mutually benefited both State and Federal regulators, while ultimately benefiting the local citizens and consumers in providing a safe, reliable energy supply and distribution infrastructure. The current arrangement, from a Federal perspective, has distinct advantages because state employees are generally less expensive than Federal employees or private contractors, have lower travel, maintenance and operating costs, and typically yield the economies of scale that state governments inherently possess. This also allows for greater safety oversight because it uses knowledge of local conditions, considerations of local concerns, relationships with local first responders and the ability to provide direct and immediate feedback to the public. This is indeed a fiscal "bargain" for the Federal agency but more importantly, provides the prerequisite detailed knowledge required for thorough scrutinizing of pipeline operations that the public and this committee demand.

One other distinct advantage that state programs have over comparable Federal oversight is the ability to incorporate and leverage state pipeline safety initiatives into a multitude of other existing state review processes that blend safety, reliability and rate-making authorities over energy providers, rather than distinct "silos" with separate government agencies.

State pipeline safety personnel represent more than 80 percent of the state/Federal inspection workforce. State inspectors are the "first line of defense" at the community level to promote pipeline safety, underground utility damage prevention, and public awareness regarding gaseous and liquid fuel pipelines.

The responsibility for state pipeline safety programs is carried out by approximately 325 qualified engineers and inspectors in the lower 48 states, District of Columbia and Puerto Rico. Recent statistics indicate that states are responsible for pipeline safety covering over 92 percent of 1.9 million miles of gas distribution piping in the nation, 29 percent of 300,000 miles of gas transmission and 32 percent of 166,000 miles of hazardous liquid pipelines. State personnel in 11 states act as "interstate agents" also inspecting interstate gas and liquids pipelines that would otherwise be inspected by PHMSA. Based on these percentages, every state inspector is responsible for overseeing/inspecting, more than 5,500 miles of pipeline. That's further than twice the distance from Miami to Seattle.

Enhancing Pipeline Safety

Beginning in 1968, when the Pipeline Safety Act was signed into law and now, since the passage of the PIPES Act in 2006, states have been working with PHMSA in fulfilling the mandates of the resulting law. This is being accomplished in a two-pronged approach: (1) on mandates that are simple to carry out, processes are put in place that can yield immediate safety benefits (*e.g.,* increased levels of enforcement); and (2) on multi-faceted mandates (*e.g.,* excavation damage prevention) states work with the Federal Government, and where appropriate, with private stakeholders, to concentrate on developing practical, effective and affordable solutions to implement the various aspects of such mandates. Although such efforts take more time, the result is a carefully crafted, sensible approach that is more likely to achieve the stated goal of the legislative mandate.

Essential to the Federal-state partnership in this area are the pipeline safety program managers in each of 52 state agencies which are members of NAPSR. In addition to their intensive inspection oversight work schedules, many take extra time to address areas of concern in meeting the existing challenges or with new initiatives and proposals for recommended improvements to pipeline safety. NAPSR currently has members on 27 task groups, with representatives from 33 states working with PHMSA on key safety elements of the pipeline safety program. These include, but are not limited to, excavation damage prevention, gas distribution integrity management, gas transmission and hazardous liquids integrity management, public awareness communications, control room management, safety performance data collection and analysis, national consensus standards development, risk-based and integrated inspections, and planning for pipeline right-of-way encroachment. With their knowledge and experience about conditions in their states, NAPSR members provide unique and valuable expertise to these task groups.

Four Key Elements in Ensuring Pipeline Safety

The focus of state efforts is concentrated onto four major elements:

> Comprising the first and basic element in pipeline safety are on-going state inspection efforts of jurisdictional pipeline facilities to verify operator compliance with long-standing Federal standards that cover design, installation, initial testing, corrosion control and many operating and maintenance functions. While new sets of regulations have been developed to address recently identified needs, the on-going enforcement of the original code requirements is essential to maintaining the basic levels of safety in our pipeline systems. Oversight of properly installed new facilities for example, should minimize future integrity issues.
>
> The second element in pipeline safety is minimizing excavation damage to pipelines. NAPSR members worked with PHMSA in developing the necessary implementation steps for the 9 elements specified in the PIPES Act for excavation damage prevention. Our members are now undertaking projects each year that help promote One-Call programs and other initiatives to put into practice the various components of the 9-element damage prevention program specified in the Act.
>
> The third key element of pipeline safety is pipeline system integrity resulting from the last two pipeline safety reauthorizations. Through NAPSR, states worked in the recent past with a stakeholder group to develop the foundation of the Distribution Integrity Management Program rule. We are now working with PHMSA to ensure proper implementation of this rule which adds formalized integrity management coverage of over 1.8 million miles of distribution pipelines strictly under state jurisdiction. State programs will be 100 percent responsible for this, which is about to undergo the test of time to verify the effectiveness of the corresponding legislative mandate and its regulatory offspring.
>
> It must be remembered that many states have long had successful integrity management programs in the form of additional and accelerated operating and maintenance activities, as well as planned pipe replacement programs. These programs have been very effective in addressing the local needs of the individual distribution systems throughout the country, and are based on the actual circumstances affecting the individual systems. We are the source of many of the pipeline safety best practices developed in this area. New Federal requirements have significantly increased the states' compliance verification workload, particularly in the area of written procedures, implementation processes, ongoing data collection and analysis, and recordkeeping.
>
> Finally, a fourth and critical key element in dealing with pipeline safety is the practice of fiscal responsibility through the management of risk. This may include risk-based approaches to pipeline safety to allow the operators under state jurisdiction to apply their resources to the areas where they are most needed, while enhancing or maintaining safety. Through forums at National Association of Regulatory Utility Commissioners (NARUC) and the efforts of NAPSR, we work with our Federal partner, PHMSA, to identify such areas. This requires ensuring that proper data is collected by our operators and compiled by our program offices, so that risks can be properly identified, assessed and mitigated.

Here, our NAPSR members are engaged in an on-going effort with PHMSA to collect reliable, high quality, relevant data on the characteristics and safety performance of the Nation's gaseous and hazardous liquid fuel delivery systems. The associated costs of all these programs are mostly covered by in-state user fees and cost-of-service fees, which are augmented by Federal grant funds derived from Federal user fees—part of which is also paid by intrastate pipelines. Our regulatory commissions are directly accountable to the states' ratepayers and are the fiscal guardians responsible for prudent funding decisions balanced by the goal of ensuring pipeline safety.

Part of fiscal responsibility also lies with the Federal Government living up to its original promise from the Pipeline Safety Act of 1968 which provided for up to 50 percent funding of state expenditures for pipeline-safety. Most recently, the PIPES Act of 2006 authorized a maximum Federal funding goal of 80 percent of the states' program costs. Still, it can be shown that in 2009, State gas users have paid for more than 68 percent of the total pipeline safety program costs. Final FY 2010 figures are not yet available.

Grant funding of the states through the Federal Pipeline Safety Program is vital to enabling the states to ensure the safety of existing pipeline facilities and of new pipeline construction projects through state inspection activities. These funds form the foundation of the Federal-state partnership that makes it possible to carry out the necessary inspection and enforcement work involving pipeline systems of more than 9,000 gas distribution, transmission and hazardous liquid companies in the U.S.

The Need to Allow Current Mandates to Work

Amendments in 1996, 2002, and 2006, to Title 49 USC Chapter 601 have set in place additional mandates for pipeline safety in the law. As a result of those amendments, new regulations, technical standards, inspection protocols and training requirements have been or are being adopted. In accordance with Federal certification requirements, each state must incorporate these changes into their pipeline safety programs, giving rise to an increasing need for accompanying resources in maintaining such programs. Furthermore, it takes time for the more complex mandates of the last three pipeline safety reauthorizations to achieve maturity. At this point, we do not have conclusive proof that all these mandates are effective in ensuring safety of pipeline facilities, but positive effects are becoming noticeable. We feel more "test time" is needed, and it seems to us, that added legislative mandates on the PHMSA pipeline safety program are not warranted during this period. They may even exacerbate the hardship many state pipeline programs are currently under, as shown below.

Due to prior insufficient appropriations, states have had to grow their programs to fulfill the new unfunded mandates and have thus been forced to cover with state funds a larger share of the program costs white the Federal share has fallen short of the amount authorized by Congress.

Despite this shortfall in appropriated Federal funding, states have continued to improve safety, as is evident from the reduction in serious pipeline incident data collected by PHMSA over the past 10 years. The record also clearly demonstrates that states in association with PHMSA have made steady progress in implementing the many mandates over the past years.

The PHMSA FY 2009 budget request and ensuing appropriation was a first step directed toward fulfilling the goals established by Congress in the 2006 Pipes Act (49 U.S.C. Chapter 601) for PHMSA to provide grants for up to 80 percent of the states' yearly expenditures. FY 2010 appropriations further increased funding toward that goal.

However, Federal grant funds are not just passed along to the states. There is a means test for eligibility for such grant funds in the pipeline safety law. Section 60107(b) requires that state spending (excluding the Federal contribution) on its natural gas and hazardous liquid safety programs must at least equal the average amount spent in the previous 3 years. This condition has led to an unintended consequence. Fortunately, there is a provision by which the Secretary of Transportation is authorized to waive this requirement.

Unintended Consequence

It has become apparent that in the absence of such a waiver, this provision could have unanticipated negative impacts on state pipeline safety programs and the Federal/state partnership. At one point, PHMSA has even suggested that a legal interpretation of the language indicates that if a state does not maintain its three-year average spending level, it could lose eligibility for any grant funds. At the present time, states are almost universally experiencing severe economic distress, with reduced revenues and massive budget shortfalls leading to across-the-board budget cuts, hiring and travel restrictions, deferred equipment purchases, and other often draconian measures to control state expenditures. For example, in 18 states pipeline safety program employees have been furloughed without pay, some for as many as 21 days. In this environment, it is inevitable that many states will be forced to reduce expenditures for pipeline safety. This is not a reflection of the states' commitment to pipeline safety, but the reality of the current economic crisis.

A survey of state pipeline safety agencies conducted by NAPSR shows that more than half of the states are experiencing budget cuts with the remainder taking other measures and expecting possible budget cuts over the next few years. Not only is growth in state programs during these times very unlikely, some cutbacks in state expenditures are certain.

Penalizing states under such circumstances undermines state programs at a time when Federal support for their mission is more important than ever. The availability of grant funds to reach adequate funding at the state program level is a very important factor in protecting state programs from further cutbacks, and even from calls to discontinue the programs entirely. PHMSA has realized this and after about 8 months of deliberations, waiver requests by states are being carefully considered on a state-by-state basis.

How Reauthorization Can Help

The currently contemplated reauthorization process could mitigate the unintended consequence of Section 60107(b) by specifying that rather than a rolling average of the previous Fiscal Years, the *3-year average of state expenditures would be computed on the basis of FY 2004, 2005 and 2006*. The rationale for this is that with the passage of the PIPES Act in 2006, state programs were given a significant number of added unfunded mandates, that is, mandates whose state funding was not matched by increased Federal grant appropriations until FY 2009. An example of such a mandate with a potentially huge impact is the requirement for gas Distribution Integrity Management Programs.

Ideally, the modification to the existing law would further specify that the DOT Secretary may grant a waiver of this requirement to a state *in the event of special circumstances, for reasons that may include a state's inability to collect sufficient revenue to maintain or increase the state's share of its safety program as required by the above-named section of the law*. The precedent for this approach was set during passage of the Pipeline Safety improvement Act of 2002 which included provisions in the law for pipeline facility risk analysis and integrity management programs. Paragraph 60109(c)(5) of the law states that "the Secretary may waive or modify any requirement for reassessment of a facility under paragraph (3)(B) *for reasons that may include the need to maintain local product supply or the lack of internal inspection devices* if the Secretary determines that such waiver is not inconsistent with pipeline safety." This would allow a faster process for a decision by the Secretary to grant a waiver to a state.

It is also important to note that even with waivers in place, states will continue to be subject to a thorough performance assessment conducted by PHMSA using certification and evaluation criteria that tie such performance to the grant amount provided to the states.

Conclusions

Programs mandated by the last three pipeline safety reauthorizations have required and continue to require extensive additional state efforts to address safety in areas that include but are not limited to operator qualification requirements, gas transmission and liquids pipeline integrity, public awareness communications, excess flow valve installation, pipeline control room management, distribution system integrity, and excavation damage prevention. These mandates still need a number of years to prove their worth. A hiatus in added legislative mandates would be beneficial by allowing the regulators to focus on the effectiveness of existing mandates without detriment to safety.

As state programs have had to grow to administer and enforce the new requirements, Federal grant monies have not been adequate to fund even 50 percent of the costs of providing the safety and compliance activities necessary. The states have gradually had to assume a gradually larger share of the costs of providing for the majority of the Nation's pipeline safety programs. This was recognized in the PIPES Act, which authorized PHMSA to reimburse a State with up to 80 percent of the cost of the personnel, equipment, and activities for pipeline safety in that state, provided that the state met the means test of its funding. This last condition is difficult to satisfy due to the magnitude of the financial crisis that has befallen most states.

A revision to the language in Section 60107(b) would provide timely financial relief via easier state access to grant funding.

It is now up to this Congressional committee to adjust the authorized funding for state pipeline safety grants over the next 4 years and to facilitate state access to such funding, so that states can continue to carry out the Congressionally-mandated expanded safety programs even during these times of economic distress. Adequate funding authorized for state programs will directly lead to more inspectors in the field, more frequent inspections of pipeline operators, more thorough inspections and fewer pipeline accidents.

Like you, we understand the importance of our mission to the safety of our citizens, energy reliability and continued economic growth of our Nation.

Thank you.

PREPARED STATEMENT OF THE AMERICAN PUBLIC GAS ASSOCIATION

Mr. Chairman and members of the Committee, the American Pubic Gas Association (APGA) appreciates this opportunity to submit testimony on behalf of public gas systems to the Committee for this important hearing on pipeline safety. APGA also wants to commend the Committee for all the work it has done over the years to ensure that America has the safest, most reliable pipeline system in the world.

APGA is the national association for publicly-owned natural gas distribution systems. There are currently approximately 1,000 public gas systems located in 36 states. Publicly-owned gas systems are not-for-profit, retail distribution entities owned by, and accountable to, the citizens they serve. They include municipal gas distribution systems, public utility districts, county districts, and other public agencies that have natural gas distribution facilities. Public gas systems range in size from the Philadelphia Gas Works which serves approximately 500,000 customers to the City of Freedom, Oklahoma which serves 12 customers.

Overview

Safety is the number one issue for public gas systems. No other issue rises to the level of safety for the local distribution company (LDC) that provides natural gas service to its consumers. Gas utilities are the final step in taking natural gas from the production field to the homeowner or business. As such, our members' commitment to safety is second to none and they keep focused on providing safe and reliable service to their customers.

Our members receive their natural gas from interstate transmission pipelines. Transmission pipelines usually consist of long and straight lines of pipe that have a large diameter and are operated at high volumes and high pressures. By contrast, the distribution pipelines in LDC's are generally smaller in diameter (as small as ½ inch), and are constructed of several kinds of materials including cast-iron, steel and plastic. Distribution pipelines also operate at much lower pressures and always carry odorized gas that can be readily detected by smell.

Public gas systems are an important part of their community. Our members' employees live in the community they serve and are accountable to local officials (and their friends and neighbors). Public gas systems are generally regulated by their consumer-owners through locally elected governing boards or appointed officials. However, when it comes to pipeline safety, nearly all of our members are regulated by an individual State's pipeline safety office. All of our members must comply in the same manner as investor- and privately-owned utilities with pipeline safety regulations issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA). This includes belonging to the State ONE-CALL system, marking the location of gas lines when notified of an excavation and notifying other utilities in advance of the utility planning to excavate. Municipal gas utilities are subject to the same excavation damage prevention requirements as their investor- and privately-owned utility counterparts.

While the manner of safety regulation may be the same, one major difference between the average investor-owned utility and the average public gas system is size: in the number of both customers served and employees. Approximately half of the 1,000 public gas systems have five employees or less. As a result, regulations and rules do have a significantly different impact upon a small public gas system than they do upon a larger system serving hundreds of thousands or millions of customers with several hundred or even thousands of employees and an in-house engineering staff.

Implementation of the PIPES Act

The Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (PIPES Act) contained several provisions that addressed safety issues at the LDC level, including excavation damage prevention. Excavation damage is the leading cause of natural gas distribution pipeline incidents and APGA strongly supports efforts to reduce excavation damage. The PIPES Act established an incentive program for states to adopt stronger damage prevention programs. Specifically, the Act outlined nine elements of effective damage prevention programs. In order to obtain damage prevention program grants from the U.S. Department of Transportation, a state must demonstrate, or have made substantial progress toward demonstrating, that its damage prevention program has incorporated these nine elements. This flexible approach has allowed states to implement the nine elements in a manner that meets their individual needs.

These elements, along with the 811 national "Call Before You Dig" number, which began in May, 2007, have helped address excavation damage. APGA strongly supports this approach to limiting excavation damage which recognizes that government has a responsibility to adopt and enforce effective damage prevention programs. APGA commends Congress and PHMSA for these efforts toward addressing excavation damage.

Distribution Integrity Management

Another critical component of the PIPES Act was the requirement that LDC's establish Distribution Integrity Management Programs (DIMP). Even before the PIPES Act passed, PHMSA had convened a working group of Federal and state regulators, industry and the public to advise PHMSA on how to approach DIMP. The group met over a 12 month period. APGA and its members actively participated in the group. In December 2009, PHMSA issued a final regulation on DIMP. APGA would also like to commend PHMSA for its leadership and work toward the development of a final rule that will significantly enhance safety.

The final rule requires all distribution pipeline operators, regardless of size, to implement a risk based integrity management program that addresses seven key elements:

1. Develop and implement a written integrity management plan.
2. Know the infrastructure performance.
3. Identify threats, both existing and of potential future importance.
4. Assess and prioritize risks.
5. Identify and implement appropriate measures to mitigate risks.
6. Measure performance, monitor results, and evaluate the effectiveness of its programs, making changes where needed.
7. Periodically report performance measures to its regulator.

Basically, a gas distribution system must have a written plan in place and the plan must demonstrate an understanding of the gas distribution system, including the characteristics of the system and the environmental factors that are necessary to assess the applicable threats and risks to the gas distribution system. The operator must also identify additional information needed and provide a plan for gaining that information over time through normal activities. The plan must consider eight categories of threats to the pipeline system. An operator must consider incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history and excavation damage experience to identify existing and potential threats.

A key component of this rule, and one strongly supported by APGA, is that the rule was designed to be flexible. The rule allows each LDC to manage its system with the goal of improving safety based on the system's unique performance characteristics, as opposed to following prescriptive rules that could divert resources away from the most significant threats for that particular utility. For example, the transmission integrity management rules imposed a fixed, interval, inspection-intensive program aimed primarily at detecting corrosion and mechanical damage. A review of PHMSA's annual and incident report data for the 3-year period 2005–2007, found that failures on distribution systems due to corrosion was the least likely of the eight threats listed in the DIMP rule to result in fatalities, injuries or significant property loss. On the other hand, a failure due to excavation damage is eleven times more likely to result in a reportable incident than a corrosion-caused failure. Under the DIMP rule, each operator must still assess the risk of corrosion, but only take additional actions above and beyond current regulations if indicated by its risk assessment.

The DIMP rule also requires operators to file annual reports with PHMSA listing the number of excavation damages that occurred during each calendar year. PHMSA adopted the Common Ground Alliance's Damage Information Reporting Tool (DIRT) definition of "damage" which includes "any impact that results in the need to repair or replace an underground facility due to a weakening, or the partial or complete destruction, of the facility, including, but not limited to, the protective coating, lateral support, cathodic protection or the housing for the line device or facility." In the past, only excavation damage that resulted in a leak was reported on the annual reports, so PHMSA will be receiving significantly more damage reports than it collected in the past. This annual report data is available to the public on PHMSA's website allowing PHMSA, the industry, state regulators and the public to evaluate trends in excavation damage.

"SHRIMP"

"SHRIMP," short for "Simple, Handy, Risk-based Integrity Management Plan," is a DIMP plan development tool developed by the APGA Security and Integrity Foundation (SIF). The SIF is a non-profit 501(c)(3) corporation created by APGA in 2004. The SIF is dedicated to promoting the security and operational integrity and safety of small natural gas distribution and utilization facilities. The SIF focuses its resources on enhancing the abilities of gas utility operators to prevent, mitigate and repair damage to the Nation's small gas distribution infrastructure. The SIF delivers programs and services to the industry through a cooperative agreement with PHMSA while working closely with the National Association of Pipeline Safety Representatives (NAPSR) and other state pipeline safety organizations.

SHRIMP is a web-based tool that walks the user through the steps of developing a Distribution Integrity Management Plan, similar to how tax preparation software walks users through preparing income tax returns. It asks questions about the material of construction of the distribution system; the results of required inspections and tests; the number and causes of leaks on the system and other information relevant to assessing the eight threats in the DIMP rule. Where any threat is elevated, SHRIMP offers suggestions for additional actions the user could implement to reduce that threat as well as performance measures to determine whether the additional action chosen is effective at reducing the threat. The output is a complete, written DIMP plan customized for the user's system that meets all the requirements of the regulation. SHRIMP is available to all distribution operators (investor owned, municipal, master meter, etc) and it is free to the small systems with fewer than one thousand customers.

Control Room Management

The PIPES ACT also required PHMSA to regulate fatigue and other human factors in pipeline control rooms. PHMSA issued control room management rules in December 2009. While these rules may be reasonable when applied to transmission pipeline controllers, unfortunately PHMSA's definition of a controller has the unintended consequences of classifying hundreds of public gas system employees as pipeline controllers. PHMSA's rule fails to differentiate between Supervisory Control and Data Acquisition (SCADA) systems and telemetry systems that simply transmit data to a central office. All SCADA systems include telemetry, but all telemetry is not SCADA if it provides no means to control the operation of the pipeline. By PHMSA's definition, however, anyone who can display telemetered data on a computer is a controller.

Distribution systems typically monitor the pressure and flow at the gate stations where they receive gas from their transmission pipeline supplier. They may also record pressures at various points around the distribution system to ensure there is adequate pressure to deliver gas to customers at the extreme ends of the system. For years these data were recorded on paper charts, manually collected each day. Increasingly utilities are installing telemetry to transmit these data back to the office where it can be periodically reviewed throughout the day by utility managers. This allows faster response to low flow/low pressure situations and frees up the personnel who collected pressure charts for other inspection and maintenance activities. Some systems allow telemetry to be viewed remotely via the Internet. This telemetry is for business purposes, not public safety.

Because distribution systems operate at relatively low pressures and are an interconnected network rather than a straight line pipeline, a complete rupture of a distribution line would be unlikely to cause a flow surge or pressure drop detectable by the telemetry system. Even were a pressure drop to be detected, all these "controllers" can do is send other personnel to investigate—they have little or no actual control over the system and no ability to isolate a suspected leak.

For years distribution systems operated safety without the ability to monitor these data in real time. Even today, many of these "SCADA systems" are left unattended at night and over weekends and holidays. Yet PHMSA's rules would require utilities to implement a fatigue management program for individuals and their supervisors who have access to a SCADA monitor that can safely go unattended over nights and weekends. This rule adds significant costs to a utility's decision to automate the transmission of operational data back to offices and thus stifles the use of telemetry to gas distribution operations.

APGA's concerns could be easily addressed were PHMSA to simply adhere to the unambiguous language in its controller definition that states a controller is one who both monitors *AND controls via a SCADA system*. Instead, PHMSA stated in the preamble to the rule that it believes "control via a SCADA system" actually means control via means other than a SCADA system, resulting in the unintended consequences described above.

Reauthorization

APGA supports reasonable regulations to ensure that individuals who control the Nation's network of distribution pipelines are provided the training and tools necessary to safely operate those systems. In this regard, over the past several years the industry has had numerous additional requirements placed on it, *e.g.,* DIMP, excess flow valves, control room management, operator qualification, public awareness and more. Many of our members are in the process of working to comply with the administrative burdens of these additional regulations. Given that our members are non-profit systems in many cases with limited resources, these additional regulations, while important, do impose an additional operational burden upon them. For this reason, APGA strongly supports a clean reauthorization of the Act.

Should the Committee consider revisions to the Act, there are a number of issues APGA would ask the Committee to consider. We urge the Committee to give great consideration before imposing any additional regulatory burdens upon LDC's through this reauthorization effort. In terms of reauthorization, APGA is specifically concerned about an expansion in the requirements for excess flow valves and potential changes in the funding mechanism for PHMSA.

Excess Flow Valves (EFVs)

The PIPES Act included a provision requiring operators to install excess flow valves on new and replaced single residential service that operate year around at or above 10 pound-force per square inch gauge. Exceptions are provided if EFVs are not available, if it is known there are contaminants in the system that would cause the EFV to fail or if it is known there are liquids in the system. Prior to this installation requirement, there was a customer notification rule in place that required gas systems to make their customers aware of the availability of EFVs and install an EFV if the customer was willing to pay installation costs. It was limited to new and renewed services because EFVs are installed underground where the "service line" to a residence connects to the gas main. If a hole is already open and a new connection to the main is being installed, adding an EFV at that time costs just a fraction of what it would cost to install or replace an EFV when no other work is planned at the main-service connection.

Each EFV has a preset closure flow rate. Once installed on a service line it will prevent gas from flowing at any flow rate higher than its preset closure flow rate. There is no way short of replacing the EFV to change its closure flow rate. This is typically not an issue with EFVs on residential service lines since the gas demand to a residence does not typically change drastically. A residence will have a relatively constant and predictable gas demand over its lifetime so the EFV can be sized accordingly.

However, APGA is greatly concerned about an expansion of the EFV requirements to commercial and industrial businesses and multifamily residences. A commercial building, unlike a residential unit, may see huge changes in gas demand as tenants in the space move in and out. For example, a space in a strip mall that today is occupied by a shoe store could be converted to a restaurant or bakery tomorrow. The gas demand could double or triple. That could require replacing the meter, regulator and EFV. Since the first two items are above ground, replacement is relatively inexpensive. However, the EFV is buried and replacing it would be very costly, often hundreds of times the initial cost of the EFV. To address this problem, an operator could install a grossly oversized EFV with closure flow at or near the free flow limits of the service line. However, a valve so oversized would probably not close even if the line were ruptured, defeating the purpose of having an EFV on the line in the first place.

The same and additional issues apply to installing EFVs on service lines to industrial customers. The flow rates and operating pressures to many industrial customers exceed the capacity of commercially available EFVs.

The potential costs of a false closure of the EFV can be significantly greater for a commercial or industrial customer than a residence. Both would suffer business losses in addition to the inconvenience of no heat or hot water. An evening's loss of business to a restaurant could run into the thousands of dollars, however some industries such as microprocessor chip manufacturers could see millions of dollars of product ruined by the loss of temperature control required by their processes.

The industry has experience with EFVs designed for typical flow rates to single-family residences, but has little or no experience with EFVs designed for larger flows.

PHMSA has established a working group of government, industry and public experts to study the issues related to installing large volume EFVs on other than single residential services. We encourage Congress to allow this stakeholder working group to proceed toward making specific recommendations on this issue.

Funding of User Fees

Under the current formula, user fees for funding PHMSA are collected by natural gas transmission operators from their downstream customers. User fees are mandatory costs a natural gas transmission operator can pass through to customers in its cost-of-service. This allowable pass-through treatment is similar to other mandatory safety program costs. As a result, it is natural gas distribution operators that pay the user fees to transportation operators in their transportation rates, and it is the natural gas transmission operators that, after collecting the user fees from its customers, pass those fees to PHMSA in the annual pipeline safety user fee assessment.

APGA supports this current formula and we believe it has worked well over the years. APGA is strongly opposed to any changes in the current formula that would shift the user fees to the LDC's. The pipelines currently build these fees into their costs and if they believe they are not recovering the costs, they have an option provided to them under Section 4 of the Natural Gas Act to file for a rate increase with the Federal Energy Regulatory Commission. Since the Federal Energy Regulatory Commission has never turned down a request to include pipeline safety user fees in transportation rates charged by interstate pipelines, the decision whether or not to pass through all or a portion of the user fees to its customers is completely within the pipeline's discretion. If for business reasons a natural gas transmission operator makes a business decision not to pass this safety cost through to one or more of its customers (*e.g.,* it wishes to discount rates to certain customers, avoid filing a rate case, etc.), any consequence arising from that decision should be borne by that natural gas transmission operator.

Shifting fees to distribution would mean that LDC customers would pay both the user fees assessed to the LDC *and* the fees passed on in transportation rates charged by their pipeline supplier. Gas customers served directly from a transmission line would pay a lesser amount of user fees per unit of gas than if the same customer were served through the LDC. The current user fee system also greatly simplifies fee collection as there are fewer transmission pipeline operators than there are LDCs. The current system of user fee collection has worked well for over 20 years.

Integrity Management of Low Stress Transmission Lines

Currently, low stress transmission lines (a line operating below 30 percent of the specified minimum yield stress) operated by distribution systems are regulated under the Transmission Integrity Management Program (TIMP). It is APGA's position that those pipelines should be regulated under the Distribution Integrity Management Program (DIMP). The benefit of handling this under DIMP is that TIMP focuses on finding mainly corrosion problems. The DIMP rule addresses corrosion but also requires distribution operators to consider other threats to integrity including excavation, natural forces, incorrect operations and more. When a high stress line corrodes it can suddenly rupture, whereas a low stress line would just start leaking, and the leak would get progressively worse over time. The utility has time to find it through ongoing leak surveys and patrols and fix it before it threatens public safety. Since the big issue with distribution is third-party damage, all the inspections for corrosion are of questionable benefit.

Conclusion

Natural gas is critical to our economy, and millions of consumers depend on natural gas every day to meet their daily needs. It is critical that they receive their natural gas through a safe, affordable and reliable delivery by their LDC. We look forward to working with the Committee toward reauthorization of the Pipeline Safety Act.

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