IMPLEMENTATION OF THE PIPELINE INSPECTION, PROTECTION, ENFORCEMENT AND SAFETY ACT OF 2006 AND REAUTHORIZATION OF THE PIPELINE SAFETY PROGRAM

(111–113)

HEARING

BEFORE THE

SUBCOMMITTEE ON

RAILROADS, PIPELINES, AND HAZARDOUS MATERIALS

OF THE

COMMITTEE ON TRANSPORTATION AND INFRASTRUCTURE

HOUSE OF REPRESENTATIVES

ONE HUNDRED ELEVENTH CONGRESS

SECOND SESSION

May 20, 2010

Printed for the use of the
Committee on Transportation and Infrastructure

U.S. GOVERNMENT PRINTING OFFICE

56–560 PDF WASHINGTON : 2010

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May 18, 2010

SUMMARY OF SUBJECT MATTER

TO: Members of the Subcommittee on Railroads, Pipelines, and Hazardous Materials

FROM: Subcommittee on Railroads, Pipelines, and Hazardous Materials Staff

SUBJECT: Hearing on "Implementation of the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 and Reauthorization of the Pipeline Safety Program"

PURPOSE OF THE HEARING

The Subcommittee on Railroads, Pipelines, and Hazardous Materials is scheduled to meet on Thursday, May 20, 2010, at 9:30 a.m., in room 2167 of the Rayburn House Office Building to receive testimony on Implementation of the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 and Reauthorization of the Pipeline Safety Program.

BACKGROUND

The Pipeline and Hazardous Materials Safety Administration (PHMSA) was created under the Norman Y. Mineta Research and Special Programs Improvement Act of 2004 (P.L. 108-426). Prior to enactment of the Act, the Department of Transportation's (DOT) Research and Special Programs Administration handled pipelines and hazardous materials safety. PHMSA is charged with the safe and secure movement of almost one million daily shipments of hazardous materials by all modes of transportation. The agency also oversees the safety of the nation's 2.5 million miles[1] of gas and hazardous liquid pipelines, which account for the transportation of 64 percent of the energy commodities consumed in the United States. PHMSA does not have jurisdiction over offshore production piping such as the riser pipe from an offshore well to a production platform on the surface. The U.S. Coast Guard, the Department of Interior's Minerals Management Service, and the U.S. Environmental Protection Agency regulate various aspects of offshore production facilities.

[1] There are 2,534,000 miles of pipelines under PHMSA's jurisdiction, of which 2,036,800 are for distribution of natural gas, 323,600 for transmission of natural gas, and 173,500 for hazardous materials including oil.

PHMSA does have safety jurisdiction over offshore transportation piping running across the Outer Continental Shelf.

The first statute regulating pipeline safety was the Natural Gas Pipeline Safety Act of 1968 (P.L. 90-481), which Congress amended in 1976 (P.L. 94-477). Congress added hazardous liquid pipelines to the statute in the Pipeline Safety Act of 1979 (P.L. 96-129). Subsequent bills included the Pipeline Safety Reauthorization Act of 1988 (P.L. 100-561), the Pipeline Safety Act of 1992 (P.L. 102-508), the Accountable Pipeline Safety and Partnership Act of 1996 (P.L. 104-304), the Pipeline Safety Improvement Act of 2002(P.L. 107-355), the Norman Y. Mineta Research and Special Programs Act, and the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (P.L. 109-468).

The Acts provide for Federal safety regulation of facilities used in the transportation of natural and other gases and also of hazardous liquids by pipeline. The regulatory framework promotes pipeline safety through exclusive Federal authority for regulation of interstate pipelines and facilities. States may impose additional standards for intrastate pipelines and facilities as long as they are compatible with the minimum Federal standards.

PHMSA's pipeline safety functions include developing, issuing, and enforcing regulations for the safe transportation of natural gas (including associated liquefied natural gas facilities) and hazardous liquids by pipeline. Regulatory programs are focused on ensuring safety in the design, construction, testing, operation, and maintenance of pipeline facilities, and in the citing, construction, operation, and maintenance of liquefied natural gas facilities.

In support of these regulatory responsibilities, PHMSA administers grants to aid States in conducting intrastate gas and hazardous liquid pipeline safety programs; monitors performance of those State agencies participating in the programs; collects, compiles, and analyzes pipeline safety and operating data; and conducts training programs through the Transportation Safety Institute for government and industry personnel in the application of the pipeline safety regulations. PHMSA also conducts a pipeline safety technology program with emphasis on applied research.

The pipeline safety program was strengthened and reauthorized through 2010 at the end of the 109th Congress by the Pipeline Inspection Protection, Enforcement, and Safety Act of 2006 (PIPES Act).[2]

To address concerns that arose out of two BP oil spills on the North Slope of Alaska in 2006, the PIPES Act required DOT to promulgate a rulemaking to ensure that all low-stress (i.e. low-pressure) hazardous liquid pipelines are subject to the same standards and regulations as all other hazardous liquid pipelines.[3] The first BP spill occurred on March 2, 2006, when internal corrosion on a 34 inch low-stress pipeline, which at the time was unregulated by PHMSA because it was a low-stress pipeline, caused a 5,000 barrel crude oil spill (212,252 gallons spilled) on the North Slope. The oil spill was the worst in the history of oil development on Alaska's North Slope, and went undetected for five days before a BP oilfield worker detected the scent of hydrocarbons during a drive through the area. It was later learned by Federal investigators that BP had ignored at least

[2] *Id.*

[3] 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.

four alarms on its Supervisory Control and Data Acquisition (SCADA) system – a computer system used for monitoring and controlling the pipeline – indicating there was a leak.

A second leak was discovered on August 6, 2006, while BP was inspecting the Eastern Operating Area segment of the pipeline. Field inspection of the leak site revealed multiple holes at a single location, contributing to an estimated spill of approximately 1,000 gallons of processed crude oil.

The cause of the leaks was internal corrosion. Federal investigators found that BP had not established a regular maintenance pigging (cleaning pig) or internal inspection (smart pigging) program on the pipelines. In fact, BP had never run cleaning pigs on the Eastern Operating Area pipelines since it took over operation of them in 2000. BP's predecessor, ARCO Alaska, had last cleaned and smart pigged the lines in 1992 and then suspended smart pigging of the Eastern Operating Area pipeline when residues, waxes, and calcium carbonate deposits clogged the Trans Alaska Pipeline strainers. Before the 2006 spill, an internal inspection of the Western Operating Area pipeline, which BP has always operated, was last performed in 1998 using a high-resolution magnetic flux leakage tool. According to PHMSA at the time, these should have been indications to BP that the lines needed significant cleaning and were at risk of rupturing. Once BP was forced to clean the lines after the Alaska spills, the lines were so corroded that the pigs actually got stuck during cleaning operations. In the end, PHMSA ordered BP to completely replace the lines. Replacement was completed in December 2009.

On June 3, 2008, in response to the Congressional mandate, PHMSA published a Final Rule regulating 803 miles of large diameter, low-stress pipelines. Although the BP Oil Transit Lines are now regulated by PHMSA through the low-stress rule, more than 1,300 miles of low-stress hazardous liquid pipelines across the United States remain unregulated (even though the PIPES Act required that they be regulated).

Specifically, the PIPES Act required PHMSA to issue regulations, no later than December 31, 2007, that subject low-stress hazardous liquid pipelines to the same standards and regulations as all other hazardous liquid pipelines. The law allowed PHMSA to implement the applicable standards and regulations in phases, so PHMSA split the rulemaking into two phases. In the Final Rule issued on June 3, 2008, PHMSA stated that it would come back in a second rulemaking and regulate all other applicable low-stress pipelines. It has been more than three years since the PIPES Act was signed into law and PHMSA has not issued a rule to deal with this second phase.

The PIPES Act also required PHMSA, in response to numerous National Transportation Safety Board safety recommendations, to issue regulations requiring each operator of a gas or hazardous liquid pipeline to develop, implement, and submit to the Secretary (for approval) a human factors management plan designed to reduce risks associated with human factors, including fatigue, in each control center for the pipeline. Each plan was to include a maximum limit on the hours of service established by the operator for individuals employed as controllers in a control center for the pipeline.

PHMSA issued a Final Rule on control room management in December 2009. The Final Rule requires pipeline operators to implement, by February 1, 2013, measures to prevent fatigue that could influence a controller's ability to perform as needed. Operators are required to schedule their shifts in a manner that allows each controller enough off-duty time to achieve eight hours of continuous sleep. Operators must train controllers and their supervisors to recognize the effects of fatigue and in fatigue mitigation strategies. Each operator's procedures must also establish a maximum limit on the number of hours that a controller can work.

The rule also requires operators to provide formal training programs, including computer-based or non-computer (e.g., tabletop) simulations to train controllers to recognize and deal with abnormal events. The training must also provide controllers with a working knowledge of the pipeline system, particularly as it may affect the progression of abnormal events, and their communication responsibilities under the operator's emergency response plans.

In addition, the PIPES Act strengthened enforcement at DOT by increasing the number of Federal pipeline safety inspectors from 90 to 100 in 2007, 111 in fiscal year (FY) 2008, 123 in FY 2009, and 135 in FY 2010 – a 50 percent increase in inspectors by 2010. President Obama requested funding for 135 Full Time Equivalent Personnel in the FY 2010 budget request and Congress appropriated funding for all of the requested positions. However, even though PHMSA added 18 positions in FY 2010, this brings to number of inspectors actually on-duty to about 94 – 41 inspectors short of the 135 required in the law.

PHMSA's inspection program is administered at both the Federal and State levels. Under current law, PHMSA may allow States to conduct inspections of intrastate and interstate pipelines in lieu of Federal inspection as long as the State has a PHMSA-certified pipeline safety program. Today, 48 States plus Puerto Rico and Washington DC are certified to inspect intrastate natural gas pipelines[4]; 17 States are certified to inspect intrastate hazardous liquid pipelines.[5] [6] Additionally, nine States are authorized to act as PHMSA's agent to inspect interstate natural gas pipelines[7]; six States are authorized to conduct inspections for interstate hazardous liquid pipelines.[8] [9] Those that are not under State oversight fall under Federal oversight through PHMSA; in 2009, PHMSA conducted 884 inspections of pipeline facilities (about 480 pipeline operators are under PHMSA's oversight).[10]

In addition to inspector increases, the PIPES Act strengthened PHMSA's authority to order pipeline operators to take corrective action to remedy a condition that poses a threat to public safety, property, or the environment. It strengthened the Administration's authority to help facilitate the restoration of pipeline operations during manmade or natural disasters, and it required implementation of a number of NTSB safety recommendations dealing with worker training, SCADA computer systems, and the installation of excess flow valves.

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4 Exceptions are Alaska and Hawaii.
5 These are Alabama, Arizona, California (Fire Marshal), Indiana, Kentucky, Louisiana, Maryland, Minnesota, Mississippi, New York, New Mexico, Oklahoma, Pennsylvania, Texas, Virginia, Washington, West Virginia.
6 Pipeline and Hazardous Materials Safety Administration, CY 2010 State Program Certification/Agreement Status, Revised December 2009.
7 These are New York, Connecticut, West Virginia, Ohio, Michigan, Iowa, Minnesota, Washington, and Arizona.
8 These are New York, Virginia, Minnesota, Washington, California, and Arizona.
9 Pipeline and Hazardous Materials Safety Administration, CY 2010 State Program Certification/Agreement Status, Revised December 2009.
10 Pipelines and Hazardous Materials Safety Administration, powerpoint presentation entitled "The Pipeline Inspection Program," prepared upon request of House Transportation and Infrastructure Committee Majority Staff (March 2010).

To increase accountability among pipeline operators and their senior executives, the law required the certification and signature of annual and semi-annual pipeline integrity management program performance reports by a senior executive officer of the company operating the pipeline. In addition, the PIPES Act increased transparency by requiring monthly public summaries of all gas and hazardous liquid pipeline enforcement actions taken by the DOT, and required the Secretary to review incident reporting requirements for operators of natural gas pipelines to ensure that the data collected is accurate.

The PIPES Act also required operators of natural gas distribution pipelines to implement a pipeline integrity management program with the same or similar integrity management elements as the hazardous liquid and natural gas transmission pipelines, which became effective on March 31, 2001, and February 14, 2004, respectively.

On February 1, 2000, in the wake of several pipeline ruptures in Bellingham, Washington; Simpsonville, South Carolina; Reston, Virginia; and Edison, New Jersey, PHMSA issued a Final Rule requiring pipeline operators to develop and implement an integrity management program that enabled the operator to continually evaluate the entire range of threats to each pipeline segment's integrity by analyzing all available information about the pipeline segment and consequences of a failure on a high consequence area. This includes analyzing information on the potential for damage due to excavation; data gathered through the required integrity assessment; results of other inspections, tests, surveillance and patrols required by the pipeline safety regulations, including corrosion control monitoring and cathodic protection surveys; and information about how a failure could affect the high consequence area.

The Final Rule required an operator to take prompt action to address the integrity issues raised by the assessment and analysis. This means an operator must evaluate all defects and repair those could reduce a pipeline's integrity. An operator must develop a schedule that prioritizes the defects for evaluation and repair, including time frames for promptly reviewing and analyzing the integrity assessment results and completing the repairs. An operator must also provide additional protection for these pipeline segments through other remedial actions, and preventive and mitigative measures.

The Final Rule became effective March 31, 2001. All baseline assessments for operators with more than 500 miles of pipeline were to be completed by March 31, 2008; all others were to be completed by February 15, 2002. According to PHMSA, the program revealed thousands of hazardous liquid pipeline defects as a result of the baseline assessments. More than 3,800 serious hazardous liquid pipeline defects had to be repaired immediately; another 14,000 hazardous liquid defects had to be repaired within a 60- to 180-day time period.[11] The industry repaired an additional 32,000 defects identified through the program.[12]

With respect to natural gas transmission pipelines, the Pipeline Safety Improvement Act of 2002 required DOT to issue a rulemaking to require natural gas transmission pipeline operators to also develop integrity management programs. The Final Rule became effective February 14, 2004. Operators are required to complete a baseline assessment of 50 percent of its covered segments, beginning with the highest risk segments, by December 17, 2007 and 100 percent of its covered

[11] *Id.*
[12] *Id.*

segments by December 17, 2012. Thus far, according to PHMSA, more than 900 serious pipeline defects identified through the baseline assessments were in need of immediate repair and almost 2,000 additional repairs are scheduled.[13]

In response to the 2006 congressional mandate, PHMSA issued a Final Rule establishing integrity management requirements for gas distribution pipeline systems on December 4, 2009. The rule also requires operators to install excess flow valves on new and replaced residential service lines, subject to feasibility criteria outlined in the rule. The effective date of the rule is February 12, 2010. Operators are given until August 2, 2011 to write and implement their program.

In addition to integrity management, the PIPES Act provided PHMSA with new Federal civil authority to enforce one-call laws against excavators and pipeline owners and operators in states that do not have adequate enforcement. The PIPES Act also provides guidance to States on the elements for an effective damage prevention program, and establishes a grant program to incentivize States to adopt and implement a comprehensive program that meets the guidance. One-call laws require homeowners and excavators to call before they conduct digging operations. Each year, there are more than 200,000 incidences of unintentional damage to underground utility infrastructure. There has been criticism of States issuing exemptions to one-call laws, which some witnesses will discuss at the hearing.

On the security side, the PIPES Act required the Inspector General of the Department of Transportation (DOT IG) to conduct an assessment of the actions taken to implement the annex to the memorandum of understanding between the DOT and the Department of Homeland Security (DHS) relating to pipeline security.

On May 21, 2008, the DOT IG released the results of the assessment, entitled "Actions Needed to Enhance Pipeline Security," which found that the PHMSA and Transportation Security Administration (TSA) have taken initial steps toward formulating an action plan to implement the provisions of the annex; however, further actions are needed as the current situation is far from an "end state" for enhancing the security of the Nation's pipeline system.

The DOT IG recommended that PHMSA collaborate with TSA to complete the following actions: (1) finalize the action plan for implementing the annex provisions and program elements and effectively execute the action plan; (2) amend the annex to clearly delineate the roles and responsibilities of PHMSA and TSA in overseeing and enforcing security regulations for liquid natural gas operators; and (3) maximize the strategy used to assess pipeline operators' security plans and guidance to ensure effective and timely execution of congressional mandates in the Implementing Recommendations of the 9/11 Commission Act of 2007 (P.L. 110-53).

A chart detailing the status of all the directives included in the PIPES Act is attached to this memorandum.

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[13] *Id.*

EXPECTED WITNESSES

Mr. Andrew Black
President
Association of Oil Pipe Lines

Mr. Rocco D'Alessandro
Executive Vice President, Nicor Gas (Illinois)
On behalf of
American Gas Association

Mr. Dan East
District Manager, Reynolds Inc. (Albuquerque, NM)
On behalf of
The National Utility Contractors Association

Mr. Paul J. Metro
Gas Safety Supervisor, Pennsylvania Public Utility Commission
On behalf of
The National Association of Pipeline Safety Representatives

The Honorable Cynthia Quarterman
Administrator
Pipeline and Hazardous Materials Safety Administration

Mr. Gary L. Sypolt
Chief Executive Officer, Dominion Energy (Richmond, VA)
On behalf of
The Interstate Natural Gas Association of America

Mr. Carl Weimer
Executive Director
Pipeline Safety Trust

Pipeline Inspection, Protection, Enforcement, and Safety (PIPES) Act of 2006 – Implementation Status as of May 2010

Section	Mandate	Deadline	Current Status
1 - Short Title			
2 - Damage Prevention	This section provides PHMSA with new Federal civil authority to enforce one-call laws against excavators and pipeline owners and operators in States that do not have adequate enforcement. This section also provides guidance to States on elements for an effective damage prevention program, and establishes a grant program to incentivize states to adopt and implement a comprehensive program that meets the guidance. Further, the section authorizes the Secretary to make grants to any organization or entity for the development of technologies that will facilitate the prevention of pipeline damage caused by demolition, excavation, tunneling, or construction activities, with an emphasis on wireless and global positioning technologies having potential for use in connection with notification systems and underground facility locating and marking services. The Secretary is prohibited from issuing these grants until competitive procedures for awarding the community technical assistance grants (under section 5) and criteria for selecting such grant recipients are established.	None provided	PHMSA has been educating States on PIPES Act priorities and the importance of establishing an effective damage prevention program. The grant competition to incentivize states to adopt and implement such a program has been completed. Grants were awarded as follows: FY 2008 - $1,300,000 to 15 States. FY 2009 - $1,000,000 to 12 State organizations. FY 2010 - $2,000,000 to 22 State organizations. PHMSA established criteria for the damage prevention technology grants. The grants, however, cannot be awarded until competitive procedures for awarding the community technical assistance grants (under section 5) and criteria for selecting such grant recipients are established. On October 29, 2009, PHMSA issued an Advanced Notice of Proposed Rule Making outlining the competitive procedures with a Notice of Proposed Rulemaking expected to be issued in summer 2010.
3 - Public Education and Awareness	This section authorizes $1 million for FY 2007 and 2008 for the Secretary to issue grants for promoting public education and awareness with respect to the 811 national excavation damage prevention phone number.	None provided	Grants in the amount of $1,179,164 were provided to the Common Ground Alliance from July 1, 2002, through June 30, 2007 for the start-up and funding of the national 811 advertising campaign that was launched on May 1, 2007.

Section	Mandate	Deadline	Current Status
			From July 1, 2007 through the present, an additional $629,959 has been obligated for the 811 campaign, totaling $1,809,123.
4 - Low-Stress Pipelines	This section directs the Secretary to issue regulations subjecting low-stress hazardous liquid pipelines to the same standards and regulations as other hazardous liquid pipelines 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. Implementation of the standards and regulatory requirements may be phased-in.	December 31, 2007	Failed to meet the deadline. PHMSA decided to pursue a two-phased approach to meet the Section 4 mandate: regulate rural low-stress hazardous liquid pipelines affecting Unusually Sensitive Areas (USAs) now and deal with the regulating the rest later. PHMSA claims they took this approach because they had no data on low-stress pipelines outside of USAs, so they decided to regulate the areas they had data on first and tackle the others later. The Final Rule covering low-stress hazardous liquid pipelines affecting USAs was issued on June 3, 2008. This rule, referred to by PHMSA as Phase I, covered 803 miles of large diameter, low-stress pipelines. A rule covering all other low-stress hazardous liquid pipelines as directed in the section 4 mandate has not been issued. Based on information gathered from the reporting requirement in 49 C.F.R. § 195, PHMSA estimates that the Phase II rule will cover 1,384 miles of additional low-stress pipelines not covered under the current regulations.
5 – Technical Assistance Grants	The section reauthorizes a program for making technical assistance grants to local communities relating to the safety of pipeline facilities in those communities. The section requires the Secretary to establish competitive procedures for awarding grants	Authorized through FY 2010	These technical assistance grants were first authorized in the Pipeline Safety Improvement Act of 2002; yet it took PHMSA until November 6, 2008 to publish the competitive procedures that are used in awarding grants. The Notice

Section	Mandate	Deadline	Current Status
	under this section and criteria for selecting grant recipients before issuing Damage Prevention Technology grants under section 1. The first three grants awarded under this section must be $25,000 demonstration grants for the purpose of demonstrating and evaluating the utility of grants under this section.		also details PHMSA's plans for awarding the three technical assistance program demonstration grants authorized in the PIPES Act. In 2009, 21 grants totaling $963,921 were awarded along with another four grants supporting the Pipeline Informed Planning Alliance. There are currently 48 proposals received for consideration in 2010, which are currently under peer review.
6 - Enforcement transparency	This section requires the Secretary to provide monthly updated summaries to the public of all gas and hazardous liquid pipeline enforcement actions, which must identify the operator involved in the enforcement activity, the type of alleged violation, the penalty or penalties proposed, any changes in case status since the previous summary, the final assessment amount of each penalty, and the reasons for a reduction the proposed penalty, if appropriate. This section also requires the Secretary to provide a mechanism for an operator named in an enforcement action to make information, explanations, or documents it believes are responsive to the enforcement action available to the public.	December 31, 2007	PHMSA launched a system in May 2007 for granting web-based access to enforcement documents. It can be found at: http://primis.phmsa.dot.gov/comm/reports/enforce/Enforcement.html
7 - Direct Line Sales	This section eliminated the former exception of direct sales natural gas pipelines from the definition of an interstate gas pipeline facility. As a result, direct sales pipelines are now subject to Federal pipeline safety regulations and PHMSA is responsible for their regulatory oversight and enforcement.	None provided	PHMSA published an Advisory Bulletin to operators informing them of PIPES Act changes in jurisdiction on May 13, 2008, after extensive coordination with States.
8 – Petroleum	This section requires the Secretaries of	Report due June 1,	A final report was transmitted to Congress on

Section	Mandate	Deadline	Current Status
Transportation Capacity and Regulatory Adequacy Study	Transportation and Energy to conduct periodic analyses of the domestic transport of petroleum products by pipeline and identify areas where shortages or price disruptions may be caused by a pipeline failure. The section requires the Secretaries to submit a report to Congress setting forth their recommendations to reduce the likelihood of the shortages and price disruptions.	2008	January 14, 2009.
9 – Distribution Integrity Management Program Rulemaking and Excess Flow Valves	This section requires the Secretary to prescribe minimum standards for integrity management programs for distribution pipelines. The section also requires operators of natural gas distribution systems to install excess flow valves on single family residence service lines in certain circumstances.	December 31, 2007	A Final Rule was issued on December 4, 2009. PHMSA also published an Advisory Bulletin for pipeline operators on the excess flow valve requirements contained in the PIPES Act in the Federal Register on June 5, 2008.
10 - Emergency Waivers	This section authorizes the Secretary to waive compliance with a pipeline safety regulation as long as the Secretary determines that: (1) it is in the public interest to grant the waiver; (2) the waiver is not inconsistent with pipeline safety; and (3) the waiver is necessary to address an actual or impending emergency involving pipeline transportation, including an emergency caused by a natural or manmade disaster. The waiver is good for 60 days and may be renewed upon application to the Secretary only after notice and an opportunity for a hearing.	None provided	PHMSA published an Interim Final Rule in the Federal Register on March 28, 2008, which established the procedures PHMSA will follow in issuing safety orders and handling waivers, including emergency waivers. PHMSA published a Final Rule in the Federal Register on January 16, 2009.
11 - Restoration of Operations	This section allows the Secretary to advise, assist, and cooperate with heads of other departments and agencies to facilitate the restoration of pipeline operations that have been or are anticipated to become disrupted by manmade or natural disasters.	None provided	This section was self executing.
12 – Pipeline Control	This section requires operators of gas and hazardous	June 1, 2008	A Final Rule was issued on December 3, 2009.

Section	Mandate	Deadline	Current Status
Room Management	liquid pipelines to develop, implement, and submit to the Secretary (for approval) a human factors management plan designed to reduce risks associated with human factors, including fatigue, in each control center for the pipeline. Each plan must include a maximum limit on the hours of service established by the operator for individuals employed as controllers in a control center for the pipeline.		
13 - Safety Orders	This section requires the Secretary to issue regulations providing that if the Secretary determines that a pipeline facility has a condition that poses a pipeline integrity risk to public safety, property, or the environment, the Secretary may order the operator of the facility to take necessary corrective action, including physical inspection, testing, repair, or other appropriate action, to remedy that condition.	December 31, 2007	PHMSA published an Interim Final Rule in the Federal Register on March 28, 2008, which established the procedures PHMSA will follow in issuing safety orders and handling waivers, including emergency waivers. PHMSA published a Final Rule in the Federal Register on January 16, 2009.
14 - Integrity Program Enforcement	This section authorizes the Secretary to conduct enforcement proceedings if the Secretary determines that a risk analysis or integrity management program does not comply with pipeline safety regulations, has not been adequately implemented, or is inadequate for the safe operation of a pipeline facility.	None provided	This was a technical clarification to the statute. No rule change was required.
15 - Incident Reporting	This section requires the Secretary to review incident reporting requirements for gas pipeline operators and modify the reporting criteria as appropriate to ensure that the incident data gathered accurately reflects incident trends over time.	December 31, 2007	PHMSA modified the incident reporting criteria to ensure that the incident data gathered accurately reflects incident trends over time. PHMSA published a Federal Register notice on September 4, 2008, subsequently extending the comment period to December 12, 2008 in another Federal Register notice published on October 30, 2008. PHMSA responded to comments in a Federal Register notice published on August 17, 2009 and after receiving

Section	Mandate	Deadline	Current Status
			comments back revised the incident reporting forms, as applicable. Office of Management and Budget (OMB) approval to use the new form was granted on January 13, 2010 and PHMSA issued an Advisory Bulletin on January 25, 2010 servicing notice that the new forms should be used for all incidents occurring after January 1, 2010. PHMSA began collecting the additional information on January 1, 2010.
16 – Senior Executive Signature of Integrity Mgmt Program Performance Reports	This section directs the Secretary to establish procedures requiring certification of annual and semiannual pipeline integrity management program performance reports by a senior executive officer of the pipeline operator.	None provided	An Advisory Notice to operators was issued on April 23, 2007.
17 - Cost Recovery for Design Reviews	This section allows the Secretary to charge fees for facility design safety reviews in connection with a proposal to construct, expand, or operate a liquefied natural gas pipeline facility.	None provided	PHMSA requested the authority to spend funds collected from the design safety reviews in the President's FY 2009 budget request. To date, PHMSA has not collected any fees from design safety reviews and does not anticipate doing so in the near future. Liquefied Natural Gas projects have not materialized at the rate anticipated and a very small number of projects are only now being considered.
18 – Authorization of Appropriations/ emergency response training grants/inspector staffing requirements	This section authorizes appropriations for the pipeline safety program. It also authorizes the Secretary to establish a program for making grants to State, county, and local governments in high consequence areas for emergency response management, training, and technical assistance. The bill authorizes $10 million for the program for each	Authorized through FY 2010	$500,000 in grants is provided on an annual basis to the National Association of Fire Marshalls for emergency response training. PHMSA also conducts training workshops in every state. With respect to inspector staffing, President Obama requested funding for 135 Full Time

Section	Mandate	Deadline	Current Status
	of FY 2007 through FY 2010. Further, this section requires the Secretary to ensure that the number of positions for pipeline inspection and enforcement personnel at PHMSA does not fall below 100 for FY 2007, 111 for FY 2008, 123 for FY 2009, and 135 for FY 2010.		Equivalent Personnel in the FY 2010 budget request and Congress appropriated funding for all of the requested positions. However, even though PHMSA added 18 positions in FY 2010, this brings to number of inspectors actually on-duty to about 94 – 41 inspectors short of the 135 required in the law.
19 - Implementation of NTSB Recommendations	This section requires the Secretary to issue standards that implement the following recommendations contained in the National Transportation Safety Board's (NTSB) report entitled "Supervisory Control and Data Acquisition (SCADA) in Liquid Pipelines" and adopted November 29, 2005: (1) Implementation of the American Petroleum Institute's Recommended Practice 165 for the use of graphics on the supervisory control and data acquisition screens; (2) Implementation of a standard for pipeline companies to review and audit alarms on monitoring equipment; and (3) implementation of standards for pipeline controller training that include simulator or noncomputerized simulations for controller recognition of abnormal pipeline operating conditions, in particular, leak events.	June 1, 2008	PHMSA issued a Final Rule on control room management on December 3, 2009.
20 - Accident Reporting Form	This section directs the Secretary to modify accident reporting forms to require gas and hazardous liquid operators to provide data related to controller fatigue.	December 31, 2007	PHMSA modified the accident reporting forms to require gas and hazardous liquid operators to provide data related to controller fatigue. Forms did not receive Office of Management and Budget (OMB) approval until January 13, 2010, thirteen days after the regulation requiring the

Section	Mandate	Deadline	Current Status
			new forms be used, went into effect.
21 - Leak Detection Technology Study	This section requires the Secretary to submit to Congress a report on the effectiveness of leak detection systems utilized by operators of hazardous liquid pipelines.	December 31, 2007	The final report was transmitted to Congress on June 23, 2008.
22 - Corrosion Control Regulations	This section requires the Secretary to review the adequacy of part 195 internal corrosion control regulations and report to Congress.	Report due December 31, 2007	PHMSA discussed this issue with the Advisory Committee in July 2007 and then published a notice in the Federal Register seeking comments on identified risks and approaches to controlling them. The comments were incorporated into a study transmitted to Congress on December 31, 2007. In that study, PHMSA found that existing regulations provide for the opportunity to require pipeline operators to establish adequate corrosion control programs.
23 - Inspector General Report	This section requires the DOT IG to conduct an assessment of the actions the DOT has taken in implementing the annex to the memorandum of understanding between the DOT and the DHS relating to pipeline security, and to transmit a report to Congress.	December 31, 2007	The DOT IG issued the final report, entitled "Actions Needed to Enhance Pipeline Security, on May 21, 2008. The DOT IG found that PHMSA and TSA have taken initial steps toward formulating an action plan to implement the provisions of the annex; however, the report noted that further actions are needed as the current situation is far from an "end state" for enhancing the security of the Nation's pipeline system. PHMSA has acknowledged that TSA has the lead role in transportation security in a Memorandum of Understanding, while continuing to contribute the core competencies of its staff to protect the public.
24 - Technical Assistance Program	This section authorizes the Secretary to award grants to universities with expertise in pipeline safety and security to establish a collaborative program to	March 31, 2009 for the universities to submit reports	This program has not been funded by Congress.

Section	Mandate	Deadline	Current Status
	conduct pipeline safety and technical assistance programs. Reports to Congress on the programs are required if the grants are made.	to the Secretary on the programs October 1, 2009 for the Secretary to transmit findings and recommendations to Congress	
25 – Natural Gas Pipelines	This section requires the Secretary to review and comment on a Government Accountability Office (GAO) report issued under section 14(d)(1) of the Pipeline Safety Improvement Act of 2002 and transmit to Congress any appropriate legislative recommendations necessary to implement the conclusions of that report.	60 days after enactment	The Secretary sent a letter to Congress on November 29, 2007 recommending that Congress amend 49 U.S.C. § 60109(c)(3)(B) in the manner set forth in the Administration's 2006 pipeline reauthorization proposal to implement the conclusions of the GAO report on risk-based standards for pipeline reassessments.
26 - Corrosion Technology	This section allows the Secretary to conduct research, development, demonstration, and standardization activities related to corrosion detection.	None	This is an ongoing effort.

HEARING ON IMPLEMENTATION OF THE PIPELINE INSPECTION, PROTECTION, ENFORCEMENT AND SAFETY ACT OF 2006 AND REAUTHORIZATION OF THE PIPELINE SAFETY PROGRAM

Thursday, May 20, 2010

HOUSE OF REPRESENTATIVES,
SUBCOMMITTEE ON RAILROADS, PIPELINES, AND HAZARDOUS MATERIALS,
COMMITTEE ON TRANSPORTATION AND INFRASTRUCTURE,
Washington, DC.

The Subcommittee met, pursuant to call, at 9:30 a.m., in room 2167, Rayburn House Office Building, Hon. Corrine Brown [Chairman of the Subcommittee] presiding.

Ms. BROWN OF FLORIDA. Good morning.

Will the Subcommittee on Railroads, Pipelines, and Hazardous Materials come to order.

The Subcommittee is meeting today to hear testimony on the Implementation of the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, and Reauthorization of the Pipeline Safety Program.

We planned this hearing long before the Deepwater Horizon oil disaster. In fact, we planned this months ago, but it offers a perfect opportunity to examine the progress the Department of Transportation has made in implementing the PIPES Act as well as the safety performance of gas and hazardous liquid pipeline operators. Pipeline accidents are rare, but as we are seeing from the oil spill in the Gulf, they can be totally devastating to the economy and to the environment. The National Pipeline Safety Program was strengthened and reauthorized through 2010 through the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006.

The act requires DOT and certain pipeline operators to develop and implement an integrity management program for distributing pipelines, installing excess-flow valves and ensuring that all low-stress pipelines are subject to the same standards and regulations and other hazardous liquid pipelines. It strengthened DOT's authority to ensure corrective action from pipeline operators and to help restore pipeline operators during disasters.

The legislation also increased inspectors by 50 percent and reported improvement in the program but one that the DOT is still struggling to meet. I don't know why. I just had a job fair. I had 12,000 people there, so we have lots of people who want jobs.

What is so disturbing to me is that a main mandate in the legislation regarding low-stress pipelines was included to address concerns that arose out of two BP oil spills on the North Slope of Alaska in 2006. This is the same company responsible for the Deepwater Horizon spill we are dealing with today. The same company that was responsible for the explosion in Texas that killed 15 oil workers and injured 170 others and was fined by the Occupational Safety and Health Administration as having organizational and safety deficiencies in all levels of the corporation. As a result, BP received the largest fine in OSHA's history—$87 million.

This is also the same company that was found guilty of one of the felony counts for illegal disposal of hazardous waste in 1999 and that as recently as May 5 was fined by the State of Washington for 13 serious safety violations. DOT also found, just prior to enactment of the PIPES Act of 2006, that BP had failed to properly maintain and inspect their pipelines in Alaska's North Slope. Eventually, BP was forced to replace those lines because of so much corrosion.

This behavior is unacceptable. Let me repeat, this behavior is unacceptable. We need to change the mindset of corporate boardrooms and ensure that all pipeline operators are putting safety before profit.

I want to also know what DOT is doing to ensure that the second phase of rulemaking for low-stress pipelines is fully implemented as Congress intended in the 2006 Act.

Finally, we as a Committee need to hear what is working and what isn't working as DOT continues to implement this legislation.

With that, I want the welcome today's panelists and thank them for joining us. I am looking forward to their testimony.

Before I yield to Mr. Shuster, I ask that Members be given 14 days to revise and extend their remarks and to permit the submission of additional statements and material by Members and witnesses.

Without objection, so ordered.

I yield to Mr. Shuster for his opening statement.

Mr. SHUSTER. Thank you, Chairwoman Brown, for holding the hearing, and thank you for yielding to me.

Welcome, Administrator Quarterman. Thank you for being here.

In our last hearing on pipeline safety, which was held in June of 2008 we highlighted DOT's failure to meet key deadlines that were set in the Pipeline Safety Reauthorization bill passed by Congress in 2006. Today, we will revisit DOT's progress in implementing key provisions in the 2006 bills, and we will hear from industry groups and pipeline safety advocates on their thoughts for reauthorizing the pipeline safety programs.

The Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 expires on September 30 of this year. That leaves us only 4 months to move a pipeline safety reauthorization bill through the House and the Senate. Today's hearing will serve as a jumping-off point for us to begin the reauthorization process.

I am happy to say that, after a slow start, DOT is well on its way to fully implementing the 2006 pipeline safety bill. The Department has recently completed a key rulemaking that addresses fatigue in pipelines, control rooms and the Secretary's prescribed minimum standards for pipeline Integrity Management Programs, and issued guidance on the installation of excess-flow valves.

Overall, most people in the pipeline community feel that we are moving in the right direction on pipeline safety. The 2006 bill made some significant changes as to how the Department of Transportation oversees the pipeline industry and to how pipeline companies operate their facilities.

I expect that the next pipeline safety reauthorization bill will build on the successes of the 2006 bill. Many of the provisions from the bill were only implemented in the last year or two, so it does not make sense to rewrite those provisions until we have had a chance to evaluate their effectiveness. We should address the parts of the law that we know to be flawed, but for the most part I expect we will continue down the path the 2006 bill put us on.

Again, I want to thank the Chairwoman for holding the hearing today, and I look forward to hearing our witnesses today.

I yield back.

Ms. BROWN OF FLORIDA. I want to welcome Ms. Quarterman, who is the Administrator for the Pipeline and Hazardous Materials Safety Administration.

Ms. Quarterman, just to remind you, your oral statement must be limited to 5 minutes. We have a Joint Session of Congress starting at 11 o'clock, so we want to allow enough time for Members to make their opening statements and for the second panel of witnesses to testify, but your entire written statement will appear in the record, so please proceed, and Members will get an opportunity when they ask their questions to give their opening statements, if that is OK.

All right, Ms. Quarterman.

TESTIMONY OF THE HON. CYNTHIA QUARTERMAN, ADMINISTRATOR, PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

Ms. QUARTERMAN. Thank you. Good morning.

Chairwoman Brown, Ranking Member Shuster, Members of the Subcommittee, 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 at the Pipeline and Hazardous Materials Safety Administration. The lessons learned from past tragedies have significantly influenced the safety policies underlying the laws and regulations related to pipeline safety.

Thanks to Congress and especially this Subcommittee, the Department has made tremendous strides in improving its pipeline safety program. I am pleased to update you on PHMSA's progress in implementing the mandates from the PIPES Act of 2006 and its role in maintaining a safe and reliable pipeline transportation network.

Thanks to your help, PHMSA has developed a forward-leading Pipeline Safety Program. A reauthorized program in 2010 promises to build on that progress. PHMSA has worked aggressively to respond to congressional interests 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 recommendations to today's low of nine open recommendations, having closed seven since the beginning of this year. Of the nine remaining open recommendations, none are classified as unacceptable. Several recommendations should close before the year's end. There are no outstanding IG recommendations for the pipeline program, and the two outstanding GAO recommendations should also be closed later this year. PHMSA has made great progress in strengthening its industry oversight program and increasing the transparency of its enforcement processes.

PHMSA's pipeline staff has been growing and continues to grow. By the end of fiscal year 2010, we expect to have 206 Federal pipeline safety personnel on hand, an increase of 65 over 2006. PHMSA has instituted a new, more aggressive recruitment strategy to promptly seal vacant inspection and enforcement positions, with incentives that will assist us in overcoming obstacles in obtaining the most qualified candidates possessing specialized skills.

PHMSA has taken advantage of higher penalty authority by imposing and collecting larger penalties where appropriate. PHMSA has set records in its enforcement program, processing $19 million in civil penalties since 2006, on average $183,000 per proposed civil penalty, compared with $57,000 before 2006.

PHMSA has added integrity management requirements to natural gas distribution networks, similar to those required of gas transmission pipelines, to address pipelines where safety risk most impacts citizens.

PHMSA has also worked to improve the internal operation of pipeline companies' control rooms. Operators are now required to establish human factors, management plans and implement new requirements on graphic displays, alarm systems and controller training. These actions remove the pipeline program's control room standards from the NTSB's top 10 list and replaces it with NTSB praise. PHMSA has modified its Web site and databases to provide on-the-spot information to its stakeholders.

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 State pipeline safety programs' cost, totaling $40.5 million, compared with 45 percent coverage in 2006. We project a further increase to 65 percent in 2011.

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

All of these accomplishments the agency is proud of. We are looking forward to working with Congress to address these issues and to reauthorize the pipeline safety program.

Thank you.

Ms. BROWN OF FLORIDA. Let me just say that, if we don't finish the questions and your statements in the hour and a half that we have, we will come back after the 11:00 to 12:00 that we have to officially break for the Joint Session.

Let me just begin by saying that, in 2007, the Bush administration submitted a proposal to Congress to eliminate a requirement included in the Pipeline Safety Act of 2002 for gas transmission operators to reinspect their pipelines every 7 years. It seems that the Obama administration agrees with that.

Given the devastation that has occurred, what is the administration's position on the elimination of the 7-year inspection?

Ms. QUARTERMAN. The current standard, Lady Chairman, is 7 years, and that is the period that the Obama administration has been enforcing and plans to continue to enforce. At this point in time, we do not have a position on whether that period should be changed.

I recognize in our testimony there is an indication referring to the report. That was something that has not been reviewed in any detail at this point. If someone were to propose in legislation a change in the period, we would take a position at that time. At this point, we have no position on that.

Ms. BROWN OF FLORIDA. Change it from the 7-year——

Ms. QUARTERMAN. Correct.

Ms. BROWN OF FLORIDA. —to maybe increasing it to 5 years? I mean it goes both ways.

Ms. QUARTERMAN. Right. My staff has said that there might be reason to shorten the time period for some companies, and my take on that is the 7-year is a maximum, not a minimum, so we are fully able to do that within the existing law.

Ms. BROWN OF FLORIDA. So you have the authority to do that——

Ms. QUARTERMAN. Uh-huh.

Ms. BROWN OF FLORIDA. —if you had someone who was constantly violating the intent?

Ms. QUARTERMAN. Right. If their Integrity Management Program required a shorter period because of the integrity of their pipeline, they certainly could do it more frequently.

Ms. BROWN OF FLORIDA. Mr. Shuster.

Mr. SHUSTER. Thank you.

My question deals with the number of inspectors. There is authorized to have 135. You have less than 100, I believe. Why are there so many vacancies? Can we do with 100 and not go to the 135 number and save some money if we can still do it effectively and efficiently?

Ms. QUARTERMAN. At present, there are 104 inspectors on board, and we recognize there has been a problem filling vacancies within the pipeline program.

One of the things the Deputy Secretary said to me, upon accepting this position, was the fact that those vacancies were there and we needed to ensure that they were filled as quickly as possible. As a result of that, I have been having monthly meetings with the staff on both the pipeline and the HAZMAT sides of the agency to bird-dog what is happening with the openings, and we are seeing many people come in, and we have a plan going forward. It is part of the executive management performance measures that they fill those vacancies before the end of the year.

Mr. SHUSTER. With 104, are we hitting our goal of doing the inspections that are necessary? I guess my question is: Do we need 135? I mean a lot of times you try to figure out in an operation 135 seems like the right number. Then, lo and behold, you find out, ah, we don't need that many. That is my question.

Ms. QUARTERMAN. I believe that we do need—I think the number may be 136.

Mr. SHUSTER. It is 135. OK.

Ms. BROWN OF FLORIDA. It is 135, but keeping in mind, if you don't mind me interjecting, they only inspect 15 percent of the lines. Given the problems that we have, maybe they need to be doing more.

Do you all have the authority to inspect additional segments?

Ms. QUARTERMAN. We certainly have the authority to inspect the pipelines that are subject to our jurisdiction, yes.

Mr. SHUSTER. Recently, you issued a final rule on control room management. Do you feel that that rulemaking will adequately address the issue of fatigue in the pipeline control rooms?

Ms. QUARTERMAN. Well, we certainly hope that it does.

The issue of fatigue is a difficult one and one which not just PHMSA but many organizations within the Department of Transportation are dealing with, and we are sitting on a number of internal panels to address those issues.

The current rulemaking requires a company to set a maximum hour of service, which we think is appropriate, and it also importantly requires that a company allow for 8 hours of sleep by a person who is working there, but it allows each company to tailor its particular operations with respect to that. It is something, when we visited with the NTSB, they were very—they thought it was forward-looking and forward-thinking. They were very positive about that approach. I think the devil is in the details, as it is with anything, and we have the opportunity to inspect companies and see exactly what they do with that requirement, and we will be looking at it closely.

Mr. SHUSTER. It is my understanding that a lot of these control room operators are working 12-hour shifts, 3 days on, 4 days off. They have put in treadmills and machines in there, you know, to allow them to get a little blood flow going, and there are quiet rooms so they can take naps if they need to. So it seems to me they are doing a lot of the right things, and from what we are hearing from the workers, they like the 3 days on/12 hours. That seems to be, you know—make a happy workforce, which a happy workforce seems to do a better job. So, anyway, I just wanted to point that out.

The other question I had was—I know now it is 7 years we are testing pipelines, and I know, in speaking to some folks in the industry, there was some thought to go to a risk-based testing program in high-population areas, in sensitive environmental areas,you know, how old the pipeline is and what is flowing through it; instead of doing 7 years, go to a risk-based system where some places are going to be tested even more frequently than 7 years and some maybe less when there is not considered to be high risk.

What are your thoughts on that?

Ms. QUARTERMAN. Well, I understand that is the position of the prior administration, that they did file a report with this Committee, along with, I think, similar recommendations from the GAO, suggesting that a risk-based system should be adopted. It is not something that I have had an opportunity to review at this point.

Mr. SHUSTER. OK. Well, I hope you take a look because that is something that, I think, we really ought to—it is one of the sophisticated tools we have today to determine risk, to determine, you know, the various criteria to testing. I hope it is something we will consider because I think it would be—again, 7 years seems like an arbitrary number when you have higher risk areas that may need it more frequently.

Finally, how successful do you believe the 811 "Call Before You Dig" campaign has been? Do you have any numbers on that?

Ms. QUARTERMAN. I am sorry?

Mr. SHUSTER. The 811 "Call Before You Dig," was that a success?

Ms. QUARTERMAN. Oh, it is absolutely a success.

In my opening statement, I mentioned the drastic decrease in the number of incidents of excavation damage associated with serious incidents, and it is really something that PHMSA developed and has been working with all stakeholders to move forward, and it is absolutely a 100 percent success. Hopefully, we can find other initiatives like that to go forward with.

Mr. SHUSTER. That is great to hear. I am living proof. I called 811 before I did digging in my yard, and no utilities were damaged, no telephone lines. So if I can do it, anybody can do it.

Thank you very much for being here. I appreciate your testimony.

I yield back.

Ms. BROWN OF FLORIDA. Mr. Teague.

Mr. TEAGUE. Thank you, Madam Chairwoman, for hosting this meeting this morning and for allowing me to be here.

Also, thanks to all of the witnesses for showing up today and for taking the time to visit with us and to give us the information that we want.

As everyone knows, pipelines are critical to delivering energy to people all across the United States, whether it is natural gas or gasoline or whatever the commodity may be, and without the pipeline system that we have, operating the way it does, we wouldn't be able to enjoy the quality of life that we enjoy.

As we are going to have an increase in the usage of natural gas, hopefully for fuel and things, then the pipelines are going to play a much bigger role and become much more important in getting the natural gas to the sites that we need; but at the same time, you know, we need to be sure that safety is first and foremost in everything that we do, and I think that this hearing today is critical to provide the effective oversight for pipeline safety regulation that we need to do.

The 2006 reauthorization was a comprehensive bill that actually resulted in the development of a lot of new safety regulations. Most of those have been implemented or are in the process of being implemented, I guess, now, and I hope that where these safety regulations are working that we allow time for them to continue to work for us to see how they are working before we change them.

I did have a couple of questions, and one of them is about the Integrity Management Program. You know, I know that the current program mandates 7 years, and I think, in 2006, when they came up with that number, it was an arbitrary number because the House recommended 5 and the Senate 10.

But do you think that—should it be on a set time frame or, with the things like the intelligent PIGs that we have now to run through the pipelines, should we just use that information rather than have a time frame and take into consideration population density and things like that?

Ms. QUARTERMAN. Well, a few years ago, the administration submitted a report, suggesting, along with the GAO, that a risk-based system should be put in place. At this point in time, I have not had the opportunity to review in any detail what is in that report, and the administration, therefore, has no position on whether it should be 7 years or risk-based. I will take an opportunity to do that if it is something that the Committee would like us to do.

It seems to me that now may be a better time than earlier to do a more thorough review since we are beyond sort of the first series of tests to see what the results have been and what the current integrity is of the gas pipeline system, but it is not something that I am prepared to commit to one way or the other here today.

Mr. TEAGUE. OK. I appreciate that answer, but I would like for you to—you know, while we are giving the system that we are operating in now an opportunity to work, if we could check, you know, about the data that they are able to compile rather than intelligent PIGs through the line and everything, and maybe if we did go to a risk-based, if we are able to truly constantly access the risk-based, then I think that, you know, it would be better because we are going to have more lines as we go toward making natural gas a transportation.

Are there a lot of discrepancies as you go across the country, a patchwork type of regulation from State to State, or have most of the States come in line with Federal regulations?

Ms. QUARTERMAN. Well, all of the States are required to adopt the baseline regulations from the Federal Government with respect to pipeline safety. There are differences in some issues from State to State. For example, with respect to damage prevention issues, not all States have adopted full bore enforcement requirements as we might like, but we are working with them to assist them to do that.

Mr. TEAGUE. OK, because I do think that that is important. You know, it is kind of like pumping your PIG down the line and different sizes of lines all along the place. It creates a lot of problems, and if we have different regulations as we go from State to State, that creates a lot of problems. At the same time, I understand States have the right to protect their citizens in the way that they deem best, but do you see particular economic challenges coming to the gas utilities?

Ms. QUARTERMAN. I'm sorry. What was that?

Mr. TEAGUE. Do you see any particular economic challenges coming to the gas utilities as they implement these additional lines and things so that we can have the natural gas available at fuel stops?

Ms. QUARTERMAN. Well, we are working closely with members of industry and the natural gas industry in terms of adopting some of these new requirements; for example, the distribution integrity management plan as well as the new control room requirements, to assist them in ensuring that they are able to adopt these requirements without a huge economic impact.

Probably the biggest impact on natural gas economy at this point is the increase in the Marcellus and other shale plays throughout the country where we are seeing much more gas coming into the natural gas system than was previously expected.

Mr. TEAGUE. You know, another question that I have—and I think it might be better to get it from the industry—but you know, I think a lot of people don't realize how many pipelines we have, because they are hidden and we don't have to look at them like we do other things, but you know, if we could have some information for our Committee and for the public in general about, you know, how much it costs to transport a barrel of oil in a truck, on a train or down a pipeline, say, from Houston to Chicago or something like that, if we had an apple-to-apple comparison about, you know, the benefits of the pipeline versus the railroad or the highways, I think that would be pretty beneficial, not just to our Committee but for the general population as well.

Ms. QUARTERMAN. Well, I am sure the industry can supply you with financial information. I can tell you that the pipeline is far cheaper.

Mr. TEAGUE. Hopefully, some of them sitting behind you picked up on that, and we are going to have the information pretty soon. Thank you for your testimony today.

Madam Chairwoman, thank you.

Ms. BROWN OF FLORIDA. Thank you.

Mr. Cao.

Mr. CAO. Thank you very much, Madam Chair.

I have a question concerning the pipelines along the coasts. As you know, many of the pipelines that run from some of the offshore rigs to some of the refineries in Louisiana run through the delicate marshes and the wetlands.

I just want to know what procedures have you implemented since the oil spill in the Gulf to better monitor. What procedures have you implemented in order to more expediently address any kind of leaks that would come out from these pipelines to prevent disasters from happening?

What I have seen so far with our response to the oil spill in the Gulf and how the devastation has impacted the people of New Orleans and the Second District, it seems to me that we as the Federal Government seem to have a position where we are saying our role is not involved in trying to fix the leak, in trying to address the spill, that it is the private sector's duty, and therefore, we minimally get involved. I am not sure whether or not that is a position that we should be taking. So my question to you is:

What procedures have you implemented? What problem areas do you see that you need to address with respect to the pipelines that run through the marshes and the wetlands to prevent future disasters?

Ms. QUARTERMAN. Well, let me begin by saying that the incident in the Gulf is an absolute tragedy, and my heart goes out to the families of those people who have lost their lives there and to those whose livelihoods continue to be affected. As to pipeline safety in the Gulf of Mexico, PHMSA is responsible for those pipelines that are considered transportation pipelines coming off of the Gulf of Mexico.

The difference between a pipeline and a drilling facility is very large. A pipeline, a lot like a garden hose, can be shut off and on. It has valves throughout it that can stop any oil problem——

Mr. CAO. That is what we are saying with the blowout preventer. There are mechanisms to shut off the valves. There are methods to shut the oil flow, and as we saw in this incident, everything has failed. So do you have a plan of action for a worst case scenario in which all of those safety mechanisms that you have along the pipelines fail?

Ms. QUARTERMAN. We obviously do many drills for oil spill containment, but again, a pipeline has a limited quantity of oil within it. It is not a reservoir full of oil. It has a limited—there is a known quantity of oil within it, and there are valves throughout it. If one fails, the next one can close, so at some point it can be shut off completely; but, yes, we do have plans in place to address a spill.

Mr. CAO. And do you have plans in place to address expedient cleanup of a spill?

Ms. QUARTERMAN. Yes.

Mr. CAO. OK. Those are all the questions that I have. Thank you very much.

Ms. BROWN OF FLORIDA. Thank you.

Maybe I can help clarify a little of his question because, basically, it was not your agency's responsibility at that very moment. It would have been if the pipeline was finished and the oil was being transported back to shore, it would have been our responsibility.

Ms. QUARTERMAN. Correct.

Ms. BROWN OF FLORIDA. But at the point it is right now, what agency's responsibility was it to make sure that the problems that incurred did not happen?

Ms. QUARTERMAN. The Department of Interior is responsible for the oversight of offshore oil and gas production and development.

Ms. BROWN OF FLORIDA. OK.

Ms. QUARTERMAN. Exploration as well, which was this instance.

Ms. BROWN OF FLORIDA. Who had the responsibility for ensuring that the safety mechanism—it was not the Coast Guard. Was it just——

Ms. QUARTERMAN. For the oversight, it is the Department of Interior. For the cleanup, it is the Coast Guard. The actual responsibility to ensure that safety mechanisms were in place rests with the operator.

Ms. BROWN OF FLORIDA. Well, I am going to Mr. Walz, but what we need to do is to—as we look at this issue—and no one at this point is trying to blame anyone but to make sure we have a handle over how we can work better together to ensure that this problem does not happen that would devastate Florida and the entire East Coast.

Mr. Walz.

Mr. WALZ. Thank you, Madam Chair and Ranking Member, and thank you, Ms. Quarterman, for being here today.

Nothing we talk about today can be outside of that frame of Deepwater Horizon—that is obvious—of looking at where responsibilities lie. Yesterday, a very interesting point was brought up—I think we all knew it—but to hear it and watch it yesterday, as Mr. McKay was sitting down there, this idea of industry self-certification and MMS's procedure on that to listen to the folks say, We carried out all inspections under the watchful eye of BP, there was silence in here. That is not demonizing, but the fact of the matter is: Where was our watchful eye?

I would like you to explain to me, if you could, what is PHMSA's integrity management process? How do you know this is getting done, and how do you know it is happening? It is one thing to have it on paper, but I don't really care what is on paper. I care that that pipeline is safe. How do we know for certain that the paper is matching up with the reality of the inspections?

Ms. QUARTERMAN. Absolutely, and I agree with you 100 percent.

Let me say first that the first responsibility is on the operator. They have to be responsible and take ownership for the pipeline safety. It is the responsibility of PHMSA to ensure that they take that requirement seriously. We have more than 100 inspectors who go out and review the integrity management plan that they have put in place and ensure that they have been, for example, filling places in the line where they should be, because there have been holidays in the line, that they are going and doing that.

We, of course, look at the Integrity Management Program itself, but we have maybe six or seven different kinds of inspections that we do. If a pipeline is being constructed, we go out during the construction phase and ensure that the construction is being handled well.

Mr. WALZ. So there is physically someone on the ground? It is not just somebody checking to see if the box has been checked. There is somebody to see if the pipeline has been installed correctly?

Ms. QUARTERMAN. Yes, there is.

Mr. WALZ. How many violations have you found with your inspectors? During the integrity management process, how many violations have there been or reprimands?

Ms. QUARTERMAN. I would have to go and provide that for you in the record. I don't know the answer to that question. There have been many.

Mr. WALZ. OK. Then is there follow-up on that——

Ms. QUARTERMAN. Absolutely.

Mr. WALZ. —to correct them?

Ms. QUARTERMAN. Absolutely.

Mr. WALZ. Then we would know the numbers of how long it takes to correct them and whether they have been corrected and brought up to standard?

Ms. QUARTERMAN. Absolutely.

Mr. WALZ. So you're comfortable that the process is working?

Ms. QUARTERMAN. I believe it is.

Mr. WALZ. How many miles do we inspect of the total miles?

Ms. QUARTERMAN. There are about 2 million-plus miles of pipeline in the United States. Much of that is inspected by our State partners. Our State partners inspect the intrastate lines and many of the gathering lines within their States. PHMSA's oversight, or inspection, miles are a fraction of those.

Mr. WALZ. Do you know if these State partners are feeling any pinch from State budgeting as we see 49 of 50 States experiencing pretty serious troubles? Are they being cut or impacted by that?

Ms. QUARTERMAN. They are absolutely feeling the pain.

Under the Pipeline Safety Act, we do have a series of grants that we can use to help the States fulfill their pipeline safety requirements. Very recently, we suspended a requirement in that law so that, at least for 2009, they would be able to get more money from the grants that are available, but we are watching that very closely and trying to give them as much money as we can. Right now, we are funding more than 50 percent of the State pipeline programs through the grants.

Mr. WALZ. So, if this gets worse and the States go and we are not able to authorize on this site, there will be a gap then in inspection on this? That potential lies there?

Ms. QUARTERMAN. There is a potential that State programs could be cut, and we could not fund enough to fill in the gap. Ultimately, if the State programs are not able to do what they should, we are here to backstop them.

Mr. WALZ. Do you have a contingency plan to do that?

Ms. QUARTERMAN. Well, when States step out from the program, we do. We step in.

Mr. WALZ. OK, because my State alone is facing $9 billion next year, and I don't know where they are going to find that.

So, with that, I yield back, and I thank you again for being here.

Ms. QUARTERMAN. Thank you.

Ms. BROWN OF FLORIDA. Would you put up the picture of Florida as I call on Mr. Buchanan from Florida? That is Mr. Buchanan's great State there.

Mr. BUCHANAN. Thank you, Madam Chair.

Ms. Quarterman, in terms of PHMSA's responsibility regarding construction on new pipelines, what is your exact role? Are you involved from the beginning to the end or can you give me some sense of that?

Ms. QUARTERMAN. We are responsible for the oversight of construction, making sure that the materials are in line with the requirements in our act, making sure—I mean we don't determine the siting of a particular pipeline. We are there only with relation to the construction of the pipeline and the oversight of that.

Mr. BUCHANAN. In terms of your work with the FERC on the construction of a new pipeline, how do you coordinate? What is your working relationship with that organization?

Ms. QUARTERMAN. I think it can be improved. We are not usually involved as a coordinator when FERC does it—coordinating agency when FERC does some of its work on the gas side. On the oil side, there is no requirement that FERC be involved in the siting of a new pipeline.

Mr. BUCHANAN. In terms of improvement, what is your thought? I mean what would you do to improve it, the relationship? What do you think the improvement needs to be? Where does it need to be addressed?

Ms. QUARTERMAN. Well, the first step, which has not happened yet, is I would like to sit down and meet with the Chair of the Commission to talk about current working relations. It is something that is on my agenda, but it has not happened yet. I think we would like to be more involved in the decisions that get made there. Often, we just have the results, and then we have to go with it from there, so——

Mr. BUCHANAN. Yes. I think if you want to improve the relationship, you have got to get that first meeting and get that going.

Ms. QUARTERMAN. Yes.

Mr. BUCHANAN. I yield back, Madam Chair.

Ms. BROWN OF FLORIDA. Thank you.

Mr. Arcuri from New York. You can take down that Florida picture.

Mr. ARCURI. Thank you, Madam Chair, for conducting this hearing.

Ms. Quarterman, thank you very much for being here.

Yesterday's hearing was, I think, very enlightening to many of us. It certainly opened up some issues that I am very concerned with. One of the things that we saw and learned yesterday is that the MMS requires an oil spill response plan for drilling.

Do you have a similar type of response plan for each particular pipeline in case there is a leak?

Ms. QUARTERMAN. We do.

Mr. ARCURI. So, if there were a natural gas pipeline—for instance, in my area, we have the Millenium Pipeline.

Are they required to have a response plan on file with you?

Ms. QUARTERMAN. Natural gas is different from oil. There is no natural gas response plan requirement that I am aware of.

Mr. ARCURI. OK. So, if there were a leak in a pipe—let's say a natural gas pipeline—what would the response be? How would we determine whether or not, you know, there were problems that were going to result to the environment or to the water table as a result?

Ms. QUARTERMAN. Well, the operator does have to have a notion of how to respond to that as part of his operating procedures, but it is not within the context of the oil spill response requirement.

Mr. ARCURI. So, do you review the plan that is on file for the pipeline?

Ms. QUARTERMAN. We do.

Mr. ARCURI. All right. Do you make a determination whether or not that is adequate?

Ms. QUARTERMAN. Yes.

Mr. ARCURI. All right. What happens if you make a determination that it is not adequate?

Ms. QUARTERMAN. Then it has to be redone.

Mr. ARCURI. OK. Do you set specifications in terms of what the criteria are to make it satisfactory?

Ms. QUARTERMAN. Yes, we do.

Mr. ARCURI. Now, one of the concerns that I had yesterday from comments is, you know, we constantly practice fire drills. We constantly practice HAZMAT cleanups for different teams.

Is there a process or a procedure that you require or that you in some way lay out for practicing a response to different possible catastrophes, and can you tell us about that?

Ms. QUARTERMAN. Absolutely.

In fact, there was a tabletop exercise going on with respect to an oil spill someplace in the country, almost simultaneous with this spill in the Gulf of Mexico, and it is just that. It is an exercise where all the parties who would be responsible for responding get together and say, this is what happened. There was a spill in North Dakota, and here is how much was released. Then they coordinate how they should respond to that given that situation.

Mr. ARCURI. Are you comfortable with the process that you have in place to respond to a potential catastrophe, as they were calling it yesterday, a catastrophic situation?

Ms. QUARTERMAN. Well, I don't think it is possible to in advance of a catastrophe really be 100 percent prepared. I think we are doing a lot to be prepared. I think we should probably take a second look at it given the event in the Gulf, but we certainly are trying to be prepared.

Mr. ARCURI. I have just one more question.

One of the other things that concerned me is this whole idea of worst case scenario. What I may contemplate as a worst case scenario may not be the same as what you contemplate as a worst case scenario, and what the operator of a particular facility may contemplate as a worst case scenario may be significantly less because they want it to be significantly less.

So who makes the determination as to what the worst possible case scenario is? You know, how do you oversee that to make sure that the worst case scenario is truly the worst case scenario?

Ms. QUARTERMAN. This is getting deeper than I can go in this area, but I believe the answer is that the agency—well, the operator may propose a worst case scenario, and the agency has an opportunity to say that is not adequate, but I will have to get back to you on that particular question.

Mr. ARCURI. OK. If you could, I would appreciate that very much. Thank you very much for your cooperation.

I yield back the balance of my time.

Ms. BROWN OF FLORIDA. Thank you.

Mr. Brown.

OK.

Does the Chairman of the Full Committee want to say something at this time or do you want me to?

Yes, sir.

Mr. Carney.

Mr. CARNEY. Thank you, Madam Chair.

Thank you for being here, Ms. Quarterman. I have a number of questions along the lines of my colleagues'.

Mr. Arcuri, Mr. Shuster and I are in the Marcellus Shale formation area ourselves. You know, Pennsylvania is a little more aggressive in developing than New York right now, but I think that is probably going to change at some point, right, Mr. Arcuri?

How many more miles of pipeline do you anticipate being created because of the new discoveries in the shale region, in the Marcellus Shale region?

Ms. QUARTERMAN. Perhaps someone from industry could address that. I am not sure how many more—we expect quite a few more miles of pipeline as a result of those plays, absolutely, especially in Pennsylvania.

Mr. CARNEY. So, if it is quite a few, I will say, maybe, 50 percent more-ish?

Ms. QUARTERMAN. In Pennsylvania or across the board?

Mr. CARNEY. Well, across the board. You know, whatever. The point is——

Ms. QUARTERMAN. Some huge amount, yes.

Mr. CARNEY. Some huge amount, and we are already understaffed in inspection. What are we doing to ramp up for the increased miles that we all anticipate, that we all know are coming?

Go ahead.

Ms. QUARTERMAN. I was going to say the State of Pennsylvania does have a program where they would be the ones responsible for being the primary inspector within Pennsylvania except with respect to gathering lines. We have been working with the State of Pennsylvania to expand their authority so that they might be responsible for what we expect, primarily in Pennsylvania, to be gathering lines associated with this new play. One would hope that, as a result of that, they would also be asking for additional personnel. Certainly, at the Federal level, we have been requesting additional people going forward.

Mr. CARNEY. Well, if you are working in Pennsylvania, then you know that Pennsylvania is almost like every other State in the Union—you know, broke. It doesn't have the resources. You said that you backstop States that are broke and that don't have the resources, but it appears that you, too, don't have adequate resources. I mean you are not even fully staffed for what you are required to do now, and then going forward to backstop States that don't—you know, and you have got a lot of States. You have got 49 States that are in arrears with inspectors who are probably dropping off, you know, and we are making all kinds of concessions now.

I think industry is going to get a pass on this somehow, and the problem is we rely on them. We rely on their self-certification. We saw what happened, obviously, and we know what is going on in the Gulf. You know, we can talk about that all the livelong day.

I want to talk for a minute about high-consequence areas and who gets to define a high-consequence area.

Can you answer that?

Ms. QUARTERMAN. There is a rule that defines the high-consequence area in terms of how many people live there, what kind of environment they are in, that kind of thing, so that is specified.

Mr. CARNEY. OK. How many people live in an area—I mean when is it not high consequence? Because I represent a rural area.

Ms. QUARTERMAN. On the gas side, a rural area would be less than 10 households, probably.

Mr. CARNEY. Less than 10 households. OK.

So we are making some determination that 11 households is high consequence, and 10 isn't. Because I live in a village with, maybe, 12 or 14 houses. So am I high consequence or low consequence or moderate consequence?

Ms. QUARTERMAN. Well, if you are 12, you are probably high consequence, or you are covered.

Mr. CARNEY. OK. So my neighbors down the road who are in the nine-house area are low consequence?

Ms. QUARTERMAN. Well, I don't want to use the words "high consequence," really, but you are covered by the rulemaking——

Mr. CARNEY. It is an unofficial term, I think.

Ms. QUARTERMAN. Yes.

You are covered by the rule that relates to the gathering pipelines in rural areas. I don't think the language is "high consequence" for that particular rulemaking.

Mr. CARNEY. Who helps define them? Is it the industry working with PHMSA or who makes this determination? Who defines nine or 10 houses? Is it the industry? Is it PHMSA? Is it the government? Who is making this determination?

Ms. QUARTERMAN. It is a combination of the two.

Mr. CARNEY. OK. All right.

Now, Homeland Security, DHS, has a role to play in this, too, as I understand. You know, PHMSA is in charge of safety. Homeland Security is in charge of security.

Ms. QUARTERMAN. Correct.

Mr. CARNEY. I was at a hearing—we conducted a hearing from the Homeland Security side a few weeks ago in Florida. That distinction, according to the first responders on the ground, who had to respond to a natural gas pipeline leak, said it caused confusion; it caused a lack of adequate reaction time. You know, we had a pipeline spill that went on for 44 hours, I think they said, because there were no clear lines of communication between PHMSA, DHS, and the first responders on the ground.

How do we address that?

Ms. QUARTERMAN. Well, TSA has the primary responsibility for security issues with respect to pipelines.

Having said that, I have to say that we work very closely with them on pipeline issues, and we often go with them to inspect facilities, and we are in daily contact with TSA on pipeline issues. Whenever there is a spill of any consequence, we are talking to them.

Mr. CARNEY. That is not according to the first responders. I mean, in a real-world scenario, you talk about tabletop exercises, which, respectfully—you know, they are OK, but they don't necessarily shake out the lines of command on the ground. When we had a real-world example, we didn't have a chance. You know, the report was bad. I mean the first responders said that this was a distinction without a difference as far as they were concerned.

How do we address that? You know, what are your recommendations to address that?

Ms. QUARTERMAN. Well, obviously, we need to find out what the circumstances are of the particular instance that you are referring to and try to assign someone as the lead. I don't believe that

PHMSA was the lead in this particular instance, but there needs to be clear demarcation of who is the lead.

Mr. CARNEY. The guys on the grounds don't care.

Ms. QUARTERMAN. I understand that, but on the ground there needs to be a standard so that everybody knows that, when something like this happens, X is the lead, whoever that may be, and that is the person who is in charge. I mean it sounds like it was not well-coordinated, because nobody knew who should be the individual or the organization in charge.

Mr. CARNEY. That is right.

I am sorry. Thank you for the indulgence, Madam Chair.

Ms. BROWN OF FLORIDA. Thank you.

Let's see if we can clear this up.

The National Association of Pipeline Safety Representatives asked the Secretary of Transportation to grant the Pipeline Act to provide the States with more grant funding, and I understand in the past it was like 80–20.

What is the status of that? Because, back to his question, you know, the States don't have any money, and we need our partners fully engaged, and at this time, you say you waived it for, what, 2009?

Ms. QUARTERMAN. 2009, yes.

Ms. BROWN OF FLORIDA. Well, this is 2010. What is the status of that request?

Ms. QUARTERMAN. Well, we are sort of a year behind in terms of how it works, so the 2010 request has not come forward yet so.

Ms. BROWN OF FLORIDA. Does the 2009 request——

Ms. QUARTERMAN. The 2009, the request affects the 2009 periodic because of the way it is funded forward; 2010 is not yet up for funding, our request for suspension is not yet ripe for that period.

Ms. BROWN OF FLORIDA. OK. But what is the status of it? Are we going to grant this waiver to get our partners busy?

Ms. QUARTERMAN. I don't think we have a request for a waiver for that next year. When the next year comes, then we will, we will consider that, yeah.

Ms. BROWN OF FLORIDA. OK, I guess I am confused. My understanding, you waivedfor what year? How many grants have you granted, for example Pennsylvania and other States?

Ms. QUARTERMAN. There are 50, I believe, State partners who get funding, and this year, in 2010, they are being funded for 2009, so, in this year, 2010, we have waived or suspended the requirement. Now next year, they can ask again to be suspended.

Ms. BROWN OF FLORIDA. OK. Ms. Markey.

Ms. MARKEY. Thank you, Madam Chair.

Thank you for being here. You mentioned that there is over 2 million miles of pipeline that you are responsible for regulating. What percentage would you say that you are able to actually inspect that are not in high consequence areas?

Ms. QUARTERMAN. I don't have the actual breakdown of what percentage is in high consequence areas versus not. There are about 173,000 miles that are hazardous liquid and a large percentage of those are in high consequence areas. The remaining distribution pipelines are about 2 million miles, and most of those are high consequence areas. Transmission pipelines, about 323,000 miles, and it is a much smaller percentage. I don't know what for transmission pipelines.

Ms. MARKEY. I also want to ask you a little bit about your waiver policy. TransCanada has asked recently for a waiver for its proposed pipeline. It is going to run 2,000 miles from central Alberta into the Gulf of Mexico. And I know that they have asked for a waiver to have thinner pipes.

What is—the concern being, we heard extensively that MMS has used industry standards as they are developing their regulations, meaning industry essentially writing their own regulations. So this is a concern when industry, when companies come in and ask for waivers. So can you talk a little bit about the criteria you look at when you are looking at waivers to existing policy? And what standards do you use?

Ms. QUARTERMAN. Certainly. There are special permits that have, or waivers, as you call them, that may be requested. Back in 2009, there were published procedures for how waivers might be granted. At current, there are about 85 active special permits. About 31 are pending before us. These are, in our view, they have to meet an extremely high standard in that they have to meet or exceed the pipeline safety requirements. They take about 8 months to 2 years for us to review these permits. They are filed in the Federal Register, so that there is public comment on them. And when they are granted, there are a number of conditions and requirements that are added that are beyond those that are in the current regulations. We analyze the request.

There are things that are obviously completely off the table that are not acceptable. We do a review of the fitness of the operator who is making a request. We look at the pipeline segment that is at issue and its history of failure. We look at the enforcement history of the company and whether or not they have any outstanding actions, what their safety profile is. It requires concurrence of all the regional directors in the field, the inspector fields. It requires concurrence of the engineering group, the regs group, the legal department, and certain subject matter experts.

The special permits are not usual. I don't know the details of the TransCanada request that you referred to. But I would be happy to look into it if you would like.

Ms. MARKEY. Yes if you could look into it.

Do you also have a public comment at all from the area's landowners that are affected, for instance?

Ms. QUARTERMAN. Of course, yes.

Ms. MARKEY. If you could get back with me specifically on that issue I would appreciate it, and I yield back my time Madam Chair.

Thank you.

Ms. BROWN OF FLORIDA. Thank you. Mr. Larsen.

Mr. LARSEN. Thank you, Madam Chair.

And thank you for holding this hearing.

Before I start, I want to recognize Carl Weimer from the Pipeline Safety Trust. He is going to be on the second panel. He is from Whatcom County in my district, the City of Bellingham area, where there was obviously a major tragedy about 11 years ago next month. And Carl will be on the next panel. I look forward to hearing from him, the Pipeline Safety Trust.

Administrator Quarterman, the agency, in your testimony, says you finished phase one on low stress. And in the fall of '1992, PHMSA testified that you would be in the rulemaking process for phase 2 , the low stress pipeline rule, but that rulemaking does not seem to have begun a year and a half later. Can you explain why that is and what your plans are for phase 2 and low stress? Phase 2?

Ms. QUARTERMAN. Absolutely. There was a rulemaking on low stress one, as you are aware of. When I started at the agency, which has not been very long now, the issue arose about whether or not to proceed with low stress 2. I believe that a cost-benefit analysis had been done in prior years that suggested that the rule might not be cost-beneficial. We convened a group of the rulemaking team to review the current cost-benefit analysis and have determined that the numbers now support going forward with the rule. It is in the process of being drafted and should be out this summer.

Mr. LARSEN. So some time in June or July?

Ms. QUARTERMAN. Right.

Mr. LARSEN. Also in the outstanding work that you have left to do, why has it taken over 3 years for PHMSA to begin the rulemaking process for proposing regs to establish a criteria for State enforcement for pipeline damage prevention laws, and will that rule address the issue that several of our witnesses on the next panel will raise, which is whether States should exempt municipalities or State departments of transportation and railroads from their Damage Prevention One Call rules?

Ms. QUARTERMAN. That rulemaking just went out for an ANPRM, or an Advanced Notice of Proposed Rulemaking last year where it asked a number of questions. I don't believe the questions include the question of an exemption, which is something that I firmly believe there should not be exemptions to the One Call rule, and I support that. I don't believe that ANPRM includes that.

That doesn't mean that the notice of proposed rulemaking will not address that issue. My understanding of the reason for why it has taken so long is that we have a very good—and the agency has had a longstanding working relationship with the States, and they have been trying to encourage them to make changes to the State laws dealing with enforcement without having the hammer of having a requirement in the law that says, or in the regs that says, you have to do these things. So they have been doing what I would call a softer approach to get the States to come along to change their laws.

At this point, we think we have gone as far as we can with that approach and need to go forward with the rulemaking. I don't think the program would like to be in a position where they have to say that a State's program is inadequate, and therefore, the Federal Government is stepping in. We prefer that the States come along without having to do that.

Mr. LARSEN. Just to change subjects a little bit on Technical Assistance to Communities Grant program. I know you are receiving applications from a variety of folks, and I understand you might be receiving applications from pipeline operators. Does PHMSA think that pipeline operators are eligible for these grants? I think you might find community folks would say they are not.

Ms. QUARTERMAN. Yes, I am not familiar with the applicants for that. I know that we are in the process of reviewing it, and I don't believe that was the initial intent of it so——

Mr. LARSEN. I am not sure either that it is.

The question came up on the 7-year versus the risk assessment, and it is disappointing to me that the administration does not seem to be providing us any guidance on the administration's position on that. We have been debating this issue well probably longer than I have been here, but I was here when we wrote the 2002 bill, and we have been debating firm timeline versus a risk assessment since then and probably before that.

And it seems to me that if we are just going to move forward on a straight authorization, we could just change the dates in the PIPES act and move on. I don't know that we are going to do that. I am not sure if the Chairman's intent is on that. But it does seem one of these outstanding issues that we keep coming back to and coming back to and now coming back to, is a firm timeline on inspections versus using some level of flexibility on risk-assessment. And I say that, I don't try to say that with any weight towards one or the other. I am saying that it is an issue that we go around and around and around on with the communities, with the industry, amongst ourselves, and to hear the administration yet does not have some guidance on that particular point is, again, it is disappointing. It is sort of like waiting for Godot; it just never shows up.

Ms. QUARTERMAN. Let me clarify a little bit. The current requirements in the law is 7 years, and that is what we are enforcing, and that is what we are proposing to enforce going forward. The administration has no plans that I am aware of to change that.

Mr. LARSEN. OK.

Madam Chair, thank you for the opportunity to have some questions. And I will be back after the Mr. Calderon speaks, and of course, I will submit my opening statement for the record. Thank you.

Ms. BROWN OF FLORIDA. Mr. Cohen.

Mr. COHEN. Thank you, Madam Chair.

And I also will submit an opening statement as we go along.

And I thank the witness, Ms. Quarterman.

I appreciate your coming before us today.

I have got two statements I would like to enter into the record, and I would like to ask the Chair if it would be so permitted. One is a letter signed by more than 1,100 organizations nationwide concerning our environment and the potential call for leadership on clean energy and climate, and the other is an article by Mr. Friedman in yesterday's New York Times that also addresses the oil spill and the need for the administration to use this as an opportunity to look at more alternative forms of energy and an energy policy that will get us clean of fossil fuels and move forward.

With permission, I would like to enter those in the record.

Without objection.

Mr. OBERSTAR. Madam Chair, my suggestion is that the letter should be accepted for the hearing record, but the staff should review to see how voluminous the accompanying material is that may be more appropriate for the Committee file.

So, I would not object to the Chair's accepting, but my practice has been to be careful about the volume of material we have in the hearing record. The letter probably is brief enough, but I don't know about the 1,100 signatories to it.

Mr. COHEN. There are only about six pages. They are small type.

Mr. OBERSTAR. With that caveat, I would not object.

Mr. COHEN. Thank you, Mr. Chairman, and Madam Chairman.

I would like to ask the witness, there has been an issue, which I know Ms. Markey kind of referred to, concerning the proposed Keystone XL Pipeline, stretching 2,000 miles from Canada to the Gulf Coast, which would bring tar sands oil to the Gulf refineries. What stage or is there a stage that you are involved in or that you know of that we could review or have any kind of look at this process to see whether or not we should permit such a pipeline to bring in this material that is even worse for our environment than the present oil that we are using?

Ms. QUARTERMAN. Well, we are not in a position at PHMSA to make any, have any impact on whether or not the pipeline should go forward. We review the safety of the pipeline, the construction of the pipeline.

With respect to their request for a special permit, that has—should at this point have been published I think in the Federal Register, but we welcome comments beyond that and would be happy to take those. But we can't influence whether or not the pipeline goes forward.

Mr. COHEN. Who can influence that? Who can determine whether or not we permit this?

Ms. QUARTERMAN. This is an oil—is it an oil or gas pipeline? I am sorry.

Mr. COHEN. It is some kind of tar sands oil pipelines.

Ms. QUARTERMAN. Oil pipelines do not require any sort of permitting through the FERC, so it is the siting requirement are on a State by State basis, so each individual State has the opportunity to weigh in on whether or not right-of-way should be given to that pipeline.

Mr. COHEN. How about the safety, you look at the safety?

Ms. QUARTERMAN. We look at the safety, correct.

Mr. COHEN. Has there been final, do you feel comfortable that the safety is, that they are secure enough and safe enough to carry this material?

Ms. QUARTERMAN. We don't really have an approval process. We can't approve; we don't approve or disapprove a pipeline. We can look at the construction requirements and ensure that it meets the requirements of the Pipeline Safety Act. So we really don't have any authority to stop or start a pipeline unless it has a safety-related issue that could then be met.

Mr. COHEN. Let me ask you if you would look at the safety issues and see that they are met, and do you think our standards are strong enough, our safety standards for pipelines, oil pipelines?

Ms. QUARTERMAN. I believe that they are. We are always constantly looking at them and changing them to address the best practices available.

Mr. COHEN. You have seen what has happened in the Gulf, and we heard from Mr. McKay, head of BP Oil, the president, that they had all the safety that they could possibly need, and therefore, they had no reason to think that they would need anything else. Do you think maybe we all should reexamine everything that we are looking at that has possible effects on our environment?

Ms. QUARTERMAN. Absolutely.

Mr. COHEN. Would you might look at this again?

Ms. QUARTERMAN. Sure.

Mr. COHEN. I may send you a letter about it, and appreciate you looking at it.

Ms. QUARTERMAN. We will. Thank you.

Mr. COHEN. Thank you very much.

I yield back the balance of my time.

Ms. BROWN OF FLORIDA. Ms. Richardson.

Ms. RICHARDSON. Thank you, Madam Chairwoman.

At what point were you notified of the spill in the Gulf?

Ms. QUARTERMAN. I probably became aware of it shortly after it happened. We do have an internal national response team.

Ms. RICHARDSON. Was it hours? Was it days?

Ms. QUARTERMAN. Looking back on it, I can't tell you exactly whether it was hours or days. I am sure it was more likely hours than it was days.

Ms. RICHARDSON. And you don't know whether you were advised the same day as when the spill occurred?

Ms. QUARTERMAN. I don't recall. It is not within our jurisdiction, and I don't remember. It was probably shortly thereafter.

Ms. RICHARDSON. Have you been asked to do anything regarding the spill?

Ms. QUARTERMAN. No. We have not.

Ms. RICHARDSON. It is my understanding that you are responsible for the construction, to ensure that the construction of the pipelines are being done properly.

Ms. QUARTERMAN. Correct.

Ms. RICHARDSON. Whose jurisdiction is it to ensure that there are safety, proper safety options if—in the event a pipeline does not work?

Ms. QUARTERMAN. We are.

Ms. RICHARDSON. So then, when I came in earlier, someone asked something about responsibility, and you referenced the Department of the Interior.

Ms. QUARTERMAN. That is with respect to the spill in the Gulf of Mexico, which is, it is a drilling rig which is overseen by the Department of the Interior. It has nothing to do with pipelines whatsoever.

Ms. RICHARDSON. Now, one of my questions is, it is my understanding that you verified that pipeline companies properly identify all the pipelines segments that could affect a high consequence area.

Ms. QUARTERMAN. Correct.

Ms. RICHARDSON. Properly identify the risks associated with each pipeline segment.

Ms. QUARTERMAN. Correct.

Ms. RICHARDSON. And properly evaluate and rank those risks, is that correct?

Ms. QUARTERMAN. Correct.

Ms. RICHARDSON. And use the most appropriate tools for conducting the inspections.

Ms. QUARTERMAN. Correct.

Ms. RICHARDSON. So is there a reason why your two Departments don't work together or talk or share information, or do you?

Ms. QUARTERMAN. Oh, we certainly do, yes.

Ms. RICHARDSON. So if you do, what would be in your thought of the reason of why we have failed in these areas regarding the spill in the Gulf?

Ms. QUARTERMAN. Our coordination with the Department of the Interior is limited to pipeline safety issues. There are pipelines in the Gulf of Mexico. And the Department is responsible for those that are leading up to the production facilities, and PHMSA is responsible for them once they leave. But we are, we have no role in terms of the drilling of a particular well.

Ms. RICHARDSON. But your two areas don't talk and learn from one another best practices, share the different things that you are doing?

Ms. QUARTERMAN. Oh, certainly, with respect to pipeline safety, yes.

Ms. RICHARDSON. It seems clear now that BP wasn't really prepared to respond to a worst-case scenario in the Gulf, as they stated. I realize that offshore drilling and the operation poses a very different challenge than the transportation of the project, which is what you are saying. But what I do need to understand is whether you evaluate the pipeline companies and whether you feel that they are prepared to deal with their own worst-case scenarios?

Ms. QUARTERMAN. We do evaluate the pipeline companies, and part of the criteria that that is considered is whether or not they are able to deal with worst-case scenarios.

Ms. RICHARDSON. And to what extent do you require them to demonstrate that?

Ms. QUARTERMAN. They have to have a plan, an oil spill response plan, and we do have drills for oil spill response which does involve not just the Federal agents but also companies.

Ms. RICHARDSON. So but I am sure also with drilling in the ocean we also have plans. So what confidence should the public have that if those plans failed in that scenario, why your plans would not fail, is my question?

Ms. QUARTERMAN. Well, part of the catastrophic scope of the spill in the Gulf of Mexico is a result of the inability to reach for human beings, for a human being to reach that item because it is located a mile or more at the bottom of the ocean. And the oil spill response, therefore, is compromised.

In the instance of pipelines, they are, as I said earlier, perhaps like a garden hose, where they can be turned off and on. There are several valves along the way that can be shut down. No more oil can go into the pipeline. You can stop it from going in or out. There might be a spill but you won't see a spill where it is just an open well spewing forth oil.

Ms. RICHARDSON. Let me say this, because my time has expired, I would just urge you that I think many of us thought, as Members who are responsible ultimately of oversight of the various agencies, I think many of us thought in that scenario that certain things wouldn't happen, that the blow factors and protectors would work and all of that, but I think the day of what we think will work, the public isn't going to allow that anymore. So we may have to reconsider other items to make sure, so if that means we have two and three things in line or whatever new items need to be considered, I would just urge that we consider all of those. Because I don't think we can afford continued mistakes in these areas.

Thank you, Madam Chairwoman.

Ms. BROWN OF FLORIDA. Thank you.

And Mr. Cummings.

Mr. CUMMINGS. Thank you very much, Madam Chair.

And Administrator, I have just one subject matter I want to address here.

We hear a lot about problems with regard to excavation. But we also know that the second leading cause of problems is corrosion. And I just want you to talk about that for a moment and how you deal with that and how we, it seems like every city, particularly my city, which we seem to have all kinds of problems with old pipes and all kinds of things are getting older. And I am just trying to figure out exactly how do you all address corrosion at a time when we have seen all kinds of infrastructure fall apart? I am just curious.

Ms. QUARTERMAN. Thank you.

Corrosion is a leading cause, as well as pipeline failure, and it is one that can be addressed, at least in part, through the Integrity Management Program that is in place by in-line inspections to see if there is a loss in the thickness of a pipe.

In addition to those requirements, there are requirements for cathodic protection, and this is something where essentially electronic currents can cause on the outside of the pipe a less likelihood of corrosion, and companies are required to have a cathodic protection system in place and to look at the results of interval surveys where they check for corrosion. But it is, as you say, quite a problematic issue.

Another thing the Integrity Management Program is meant to do is that an operator is supposed to be looking at its pipeline and identifying locations along the pipeline where corrosion might be a particular problem, for instance, where there is a change in environment, for example you go from a rocky area to one where there is a lot of water, or just a change in the environment where there might be the conditions necessary to promote corrosion.

We are also working very closely with NACE, which is the National Association of Corrosion Engineers to identify leading technologies to help us on the issue of corrosion. But it is one that we spend a lot of time on and will continue to spend a lot of time on going forward because we recognize it is a huge issue for pipelines.

Mr. CUMMINGS. As I am listening to you I am wondering how much of this is on the honor system. As I listened to Congresswoman Richardson, it reminded me of something that I often say that so often people are telling each other that things are going to be fine if something goes wrong, nothing is going to go wrong. They say, when the rubber meets the road, everything is going to be fine. And then when the rubber comes to meet the road, we discover there is no road.

So I am trying to figure out, when we talk about integrity, are we talking about an honor system to some degree? Because one of the things that I have discovered is that a lot of folks, when you put them on the honor system, they are not always honest. And so, I just want to know what, how do you, assuming some of it is the honor system, I am sure all of it can't be, but how do you double check that? Because I have noticed that, and we have noticed in this Subcommittee, when we were talking—when we talk about various things like drains and putting in certain kinds of windows and things of that nature, when it comes to safety, a lot of times, folks will pinch pennies and give up safety.

And so I am just wondering, how do we, how you make sure that integrity is truly being honored?

Ms. QUARTERMAN. Right. That is a great question. You are right that, in the first instance, it is a question of honor because companies put together Integrity Management Plans that say they are going to do certain things.

Now, thanks to the law that was put in place by this Committee, nowadays the chief executive has to sign off on that plan to say, yes, this is, in fact, a plan that I back and I am supporting.

But then we have inspectors that go in and look at the plan. They look at the results from a smart pig, an inline inspection tool, that might show that there is a certain amount of loss in the pipeline thickness, and then they look at the record to see if that was repaired or not.

A company can say, we repaired all these, but in fact, they did not. And that is the job of the inspector, to go behind them to make sure that in fact those things have happened.

Now can we deal with 100 inspectors 100 percent of pipelines? No, we can't. But we are doing many of them, and we are trying to go to a new method of inspection where we really look at where the risks are for a particular company and drill down into those risks rather than doing just a checklist and inspection program.

Mr. CUMMINGS. Thank you very much.

I see my time is up. Thank you, Madam Chair.

Ms. BROWN OF FLORIDA. Now, to hear from the Chair of the Committee, Mr. Oberstar, who was here late last night. I left him here after 7:00 o'clock on a similar subject.

Mr. Oberstar.

Mr. OBERSTAR. Thank you very much, Madam Chair.

This is a very, very important follow-up hearing to yesterday's hearing, but also on the work of pipeline safety that this Committee has been engaged in for well over 22, 23 years, when I held the first hearing on the failure of a gasoline pipeline in Mounds View, Minnesota, which is symbolic of and showed evidence of widespread failure within the agency to do its work properly.

Now, at the hearing yesterday, I confronted Mr. McKay, the CEO of BP, with the results of the Texas refinery failure, the pipeline failure in Alaska, that spilled 5,000 barrels of oil on the North Slope, the largest pipeline failure in the history of oil extraction from the North Slope, and several other subsequent failures of that company that required the Department of Transportation to change the administrator of PHMSA, bring in a retired Coast Guard admiral, put the agency back on a sound safety mindset footing, and result in fines, including a misdemeanor fine on the company, a misdemeanor citing of the company, and a $12 million penalty for failure to maintain their system properly and a number of other failures of that company over a period of years.

Have you done a follow-up review of BP's pipeline system?

Ms. QUARTERMAN. BP is scheduled for an integrated inspection this year, and I have requested of my staff that they compile a performance review of BP, in particular, their history of violations, how good they are doing, how good they are not doing.

Mr. OBERSTAR. When will that take place?

Ms. QUARTERMAN. Which one, the inspection?

Mr. OBERSTAR. Yes.

Ms. QUARTERMAN. The date of the inspection, I don't know. The documentation review should be ready in the next couple of weeks.

Mr. OBERSTAR. Will you provide for the Committee the guideline review?

Ms. QUARTERMAN. Absolutely.

Mr. OBERSTAR. We would like to, I would like to put my hands on it and review it, and of course, it will be available for majority and minority as well.

There are 3,800 drill rigs in the Gulf of Mexico. That is 660,000 square miles of ocean, and hundreds and hundreds of pipelines. They were disrupted during Katrina and Rita, had to be repositioned, relocated. We are coming up on hurricane season. Shouldn't there be a review of pipeline safety and standards? Shouldn't you have inspectors ready to go out in the Gulf to take a look at, particularly at any of the pipelines that BP might be operating?

Ms. QUARTERMAN. We are ready. We can do it.

Mr. OBERSTAR. Will you do it this year? Will you direct an overview of pipeline safety in the Gulf to ensure that there is system integrity, that there are, that wherever pigging has been required to be done, whether cleaning pigs are required to go through the pipelines that has been done, whether there are other safety precautions under your rules and regulations, that they have been followed?

Ms. QUARTERMAN. Yes. We are already going to do the BP review. We can make it Gulf-wide.

Mr. OBERSTAR. I think it is only prudent and precautionary in light of what has happened here, should there be a pipeline break. Pipeline safety is just one break around the corner from being unsafe as we know all too well.

We have also seen in the hearing yesterday, but not just yesterday's hearing, the cozy relationship between government and industry. Here is a drill rig built in Korea, registered in the great maritime nation of the Republican of the Marianas, whose certification was done by a contracted entity located in Reston, Virginia, not certified by an independent organizations, built to—and a blowout preventer built to American Petroleum Industry Standards or

Institute standards, certified by industry, operated by industry, not reviewed by Minerals Management Service agency. And we found a similar pattern in the Coast Guard hearings that we held, that Mr. Cummings conducted 2, 3, years ago, on the failure to have independent review of industry design, engineering, and manufacturing.

We found a similar problem in the FAA, which I hold up always as the highest standard of safety. But there, again, there was a customer service initiative, directed by Office of Management and Budget to be done by the FAA, in which FAA was directed to treat airlines as their customers. That is an arm's-length relationship. They are not supposed to be subject to the pleasure of the industry. If the FAA, if Southwest Airlines is FAA's customer, and the customer is unhappy with the service they are getting, they can request a change, and they did. And they got the principal maintenance inspector shifted from the Southwest ticket to someplace else until whistle-blowers brought it to our attention, and we held hearings, and we found that some 200,000 passengers were flown in unsafe aircraft.

So here is this, the Coast Guard culture is being changed. The standards for safety at the Coast Guard are being changed. The standards for safety are being upgraded in the FAA. We need the same thing to happen in the pipeline administration, and I see evidence of that happening under your leadership. But I want you to be aggressive and assertive.

And I want you to assure that there is independent—no, in the pipeline corrosion 2008 pipeline corrosion report, which PHMSA ordered, "PHMSA often incorporates standards in whole or in part developed by various industry consensus organizations in their regulations." The Michael Baker Raymond Fessler report, it lists all those standards by national association of this, American association of that, among them the American Petroleum Institute. Shouldn't there be an independent review with certification? Why should PHMSA be accepting industry standards?

Fine, they know what they are doing. They know their business. But that needs to be subjected to independent review. Are you going to do that?

Ms. QUARTERMAN. With respect to the safety culture, let me just say that one of the first things that I said to my staff in our first all-hands meeting was that they needed to be clear, as I was, that our customer is the American public. And is it is our responsibility to ensure that hazardous materials by pipeline or any other mode is safe and that there is a tendency in government to think of your customer as being someone other than the American public because industry or other constituents come in and speak a lot. If there is not somebody balancing out on the other side, if you only hear from industry representatives, you tend to believe or go native, I guess, you begin to think that that is your constituent and forget about the American public.

That may have been the case in the past with the pipeline program. I think that has changed, thanks to your help, and now they are very much involved with the States and with the Pipeline Safety Trust and the other constituents. They have, they really tried to speak to all, all parties, all stakeholders.

As to the question of industry standards, yes, they are adopted into the existing pipeline standards. Many of those organizations are not necessarily industry organizations. They are professional organizations with respect to corrosion——

Ms. BROWN OF FLORIDA. Excuse me. According to the Rules of the House, we are going to have to stand at adjournment until after the session that is starting at this time. We are going to have to stand in recess, and we are going to come back at 12 o'clock or as soon as the session is over.

I was trying to finish up with you. But I don't think we are there yet.

You think we are? OK.

OK, then we will start with panel two.

And so any additional comments you can submit to the record, I have got to say that, follow up with what the Chairman said, if you found BP or any other company in violations, what is your recourse? I would be interested in seeing that in writing. And we are going to put the question in writing.

Ms. QUARTERMAN. Thank you.

Ms. BROWN OF FLORIDA. So thank you very much for your testimony, and any additional questions the Committee will give to you in writing.

And at 12 o'clock, or directly after the session is over, we will come back, and we are going to stand in recess at this time according to the Rules of the House.

Thank you.

[11:12 a.m.]

[Recess.]

Ms. BROWN OF FLORIDA. Thank you. I would like to welcome and introduce our second panel of witnesses.

TESTIMONY OF CARL WEIMER, EXECUTIVE DIRECTOR, PIPELINE SAFETY TRUST; PAUL METRO, GAS SAFETY SUPERVISOR, PENNSYLVANIA PUBLIC UTILITY COMMISSION, ON BEHALF OF THE NATIONAL ASSOCIATION OF PIPELINE SAFETY REPRESENTATIVES; ANDREW BLACK, PRESIDENT AND CEO, ASSOCIATION OF OIL PIPE LINES; ROCCO D'ALESSANDRO, EXECUTIVE VICE PRESIDENT, NICOR GAS, NAPERVILLE, ILLINOIS, ON BEHALF OF AMERICAN GAS ASSOCIATION; GARY L. SYPOLT, CHIEF EXECUTIVE OFFICER, DOMINION ENERGY, RICHMOND, VIRGINIA, ON BEHALF OF THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA; AND DAN EAST, REGIONAL MANAGER, REYNOLDS, INC., ALBUQUERQUE, NEW MEXICO, ON BEHALF OF NATIONAL UTILITY CONTRACTORS ASSOCIATION

Ms. BROWN OF FLORIDA. We have with us Mr. Carl Weimer, who is executive director of the Pipeline Safety Trust; Mr. Paul Metro, who is the secretary of the National Association of Pipeline Safety Representatives; Mr. Edward Black, president and executive officer of the Association of Oil Pipe Lines; and Mr. D'Alessandro, on behalf of the American Gas Association; and Gary L. Sypolt, chief executive officer of Dominion Energy, on behalf of the Interstate Natural Gas Association; and Mr. Dan East, on behalf of the National Utility Contractors Association.

We can begin with Mr. Weimer.

Mr. WEIMER. Chairwoman Brown, Ranking Member Shuster and Members of the Subcommittee, thank you for inviting me to speak today on the important subject of pipeline safety.

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 today here today to speak for the relatives of the 56 people who have been killed, the 209 people who have been injured, and for those that have been burdened by over $900 million in property damage in pipeline incidents that have occurred since we last spoke to this Subcommittee in March 2006.

We provide many ideas for improvements in our written testimony but would like to concentrate on just a few of them here today.

Our priority for this year's reauthorization is the expansion of the Integrity Management Rules for more miles of pipeline. The 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 is what requires that once pipelines are put in the ground, they are 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. And of all the deaths caused by these type 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 the 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 the 12 people died.

What this means to people who live around these pipelines in rural areas is that their lives are not worth protecting with the important Integrity Management rules.

When Integrity Management was first conceived, inspections were limited to high-consequence areas because this was a huge undertaking for the 90,000 miles of pipelines that were included. At that time, leaders within Congress and PHMSA stated that the future of these types of inspection requirements would be expanded. We believe the future is now and that the industry now has the experience and equipment necessary to begin similar inspections of the over 300,000 miles of pipelines that currently have no such requirements.

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 the current management rules.

In the PIPES Act of 2006, Congress made clear its desire that States move forward with pipeline damage prevention programs. We hope Congress will encourage PHMSA to move forward with its recent proposed rulemaking regarding damage prevention and make sure that States understand that exemptions to railroads, State transportation departments, and municipal governments are dangerous and unwarranted.

The results of a huge lack of valid data regarding excavation damage to pipelines make it nearly impossible to implement programs strategically and cost effectively. We hope Congress will require PHMSA to initiate a valid mandatory reporting requirement for excavation damage.

Also, after 2 years of work by a multi-stakeholder group of more than 150, the Pipeline Informed Planning Alliance is about to release a report that makes recommendations for actions that local governments can take to protect people and pipelines with 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, just as was authorized in PIPES for the successful promotion of the 811 one-call number, $500,000 per year to promote, disseminate, and provide technical assistance regarding the PIPA recommendations so local governments are aware of them.

Finally, there is still a good deal of work for PHMSA to do 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 local communities need to be authorized and funded, and PHMSA needs to have the resources necessary to ensure that many miles of new pipelines being constructed are adequately inspected during construction.

Thank you again for this opportunity to testify today. We hope that you will consider some of the ideas we have brought forward. If you have any questions now or at any time in the future, I would be glad to try to answer them.

Thank you.

Ms. BROWN OF FLORIDA. Thank you.

Mr. Shuster.

Mr. SHUSTER. Thank you, Madam Chair.

I just wanted to take an opportunity to welcome Mr. Paul Metro, who is here today. He is the Secretary of the National Association of Pipeline Safety Representatives. His day job is at the Gas Safety Division of Pennsylvania at the Public Utilities Commission.

I want to thank you for being here today. We know that you regulate, inspect and enforce State and Federal regulations in the State of Pennsylvania dealing with natural gas and hazardous pipelines. So welcome today.

Thank you.

Ms. BROWN OF FLORIDA. Mr. Metro, please.

Mr. METRO. Chairwoman Brown, Ranking Member Shuster, Members of the Committee, thank you for the opportunity to appear today on behalf of the National Association of Pipeline Safety Representatives, commonly referred to as NAPSR. NAPSR is a nonprofit organization of State pipeline safety personnel.

My name is Paul Metro. I am the national Secretary of NAPSR, and I am also the Gas Safety Program Manager for the Commonwealth of Pennsylvania. NAPSR members are partners with the U.S. DOT in pipeline safety, and we provide inspection enforcement of the Federal and State pipeline safety regulations in the country.

Since the Pipeline Safety Act was signed into law in 1968, States have been serving as stewards of pipeline safety by acting as certified agents for implementing and enforcing Federal safety regulations. 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 with regard to gaseous and liquid pipeline systems.

I have submitted written testimony for the record describing the role of the States in maintaining or enhancing pipeline safety. The testimony explains a State's focus in providing pipeline safety and makes recommendations as to Federal assistance that is needed by State programs to implement the Federal mandates. The testimony highlights NAPSR's view with regard the two key points.

First, NAPSR recommends that new mandates only be imposed by this reauthorization process if it is proven that existing mandates do not work. The last three reauthorizations have created several mandates in the natural gas and hazardous liquid industries and regulatory bodies. The States and the industry need more time to fully assess and evaluate the effects of the mandates. NAPSR inspects almost 2.3 million miles of pipelines and over 9,000 system operators. The imposition of additional mandates now would only exacerbate the hardships that State pipeline safety programs are currently under, which brings me to my second point:

Because of current revenue shortfalls in their economies, many States are having trouble meeting the means test provided for in the 2006 Pipeline Safety Act. As a condition for awarding Federal pipeline safety grants, the Secretary of Transportation is authorized to waive the means test in the PIPES Act. However, the condition for such a waiver to be granted has not been identified or defined. Facilitating State access to Federal grant funds under special circumstances is within the purview of Congress.

As partners with the U.S. DOT and given the regulatory priorities recognized in the PIPES Act, the State programs are focusing on four major safety elements: performing ongoing inspections of pipeline facilities to verify operator compliance, supporting excavation damage prevention, ensuring pipeline system integrity, and practicing fiscal responsibility through the management of risk and pipeline safety.

Part of fiscal responsibility also lies with the Federal Government living up to its original promise made in 1968, which provided for 50 percent funding of State expenditures for pipeline safety. Most recently, the PIPES Act of 2006 authorized a thorough funding goal of up to 80 percent of the State's program costs. Still, during the calendar year, it can be shown that the State's gas consumers funded more than 68 percent of the State program costs. Adding funding was appropriated by Congress in fiscal year 2009 and 2010, but the previous mentioned means test and the pipeline safety law threatens the availability of future grants funded to

States that are not able to collect sufficient revenue from their residences and businesses.

In other words, many of the State's pipeline safety budgets have been reduced due to severe economic budgetary conditions, and the States cannot continue to fund 68 percent of the program costs.

NAPSR recommends a modification to the 2006 PIPES Act, which would define specific conditions for which a waiver could be granted to a State without significant delay and without affecting pipeline safety. The current reauthorization process could mitigate the unintended consequences of section 60107(b) by changing the requirements of utilizing a rolling average of the previous fiscal year's State expenditures to a 3-year average of State expenditures computed on the basis of fiscal years 2004, 2005, and 2006.

It is now up to the congressional Committee to adjust authorized funding for State pipeline safety grants over the next 4 years and to facilitate State access to such funding so the States can continue to carry out their programs and fulfill the congressional mandated expanded safety programs even during times of economic stress.

Thank you, Madam Chairwoman, and I will be glad to answer any questions.

Ms. BROWN OF FLORIDA. Mr. Black.

Mr. BLACK. Thank you, Madam Chairman, Ranking Member Shuster, Members of the Subcommittee.

I am Andy Black, President and CEO of the Association of Oil Pipelines. I appreciate the opportunity to appear on behalf of AOPL and API, the American Petroleum Institute.

I will discuss the oil pipeline industry's commitment to safety, our improved safety record and why we believe pipeline safety reauthorization should be narrowly focused on existing programs, specifically damage prevention.

Pipelines are the safest, most reliable, economical, and environmentally favorable way to transport oil and petroleum products to the Nation's refineries and communities, including all grades of gasoline, diesel, jet fuel, home heating oil, and propane. Transportation rates are low, regulated by FERC, generally stable and predictable, and do not fluctuate with changes in commodity fuel prices.

Pipelines have every incentive to invest in safety. The most important is the potential for injury to members of the public, our employees and our contractors. We could also incur costly repairs, cleanups, litigation, and fines, and the pipeline may not be able to accommodate its customers.

On many pipelines, operators use automated systems that detect releases or other abnormal operating conditions. Controllers are trained to identify signs of leaks and to respond quickly to shut off product-flow to isolate an incident. Pipeline operators are required to have response plans in place, conduct regular 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. Pipeline companies perform visual inspections along rights-of-way, including from the air, 26 times a year, for signs of damage, leakage and encroachment.

Operators are required to develop an integrity management plan for segments of pipelines that could affect high-consequence areas near population centers or sensitive environmental areas. Liquid pipeline operators conducted baseline assessments prior to March 2008, identifying threats to their pipelines and applying technologies to address identified threats. This includes inline inspection by so-called "smart pigs." Full reassessments that are underway for liquid pipelines must be done within 5 years and are required into the future.

Pipelines have the best safety record of any transportation mode. Still, we 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. Pipelines have spent billions of dollars on integrity management, far exceeding earlier estimates. More than $1 billion has been spent by companies representing just 15 percent of DOT-regulated pipelines over just the past 5 years. We expect this upward trend in compliance costs to continue.

As a result, liquid pipeline spills along rights-of-way have decreased over the past decade in both volume of releases and number of releases. We are proud of this improved record, but we are not content. We still strive for zero releases.

What could be done to make pipelines even safer?

We need help preventing excavation damage, which is less frequent today but still accounts for 31 percent of all significant pipeline incidents on the liquid side.

Our members helped establish and support one-call centers, which serve as the clearinghouse for excavation activities, using the 811 national "call before you dig" number that Congressman Shuster mentioned, but in some cases State laws requiring the use of 811 do not exist, are weak or incomplete or are not adequately enforced. In many States, State agencies, municipalities and other local entities are exempted from requirements to use the one-call system. These exemptions create a gap in enforcement and safety because the threat of pipeline damage is the same regardless of who the excavator is.

We believe the Office of Pipeline Safety is headed in the right direction with its proposal of last year, which draws on authority from Congress 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.

OPS finalized a control room management rule last year. The NTSB read it, and removed the issue of pipeline controller fatigue from its "most wanted" list of transportation safety improvements. The industry is hard at work developing implementation plans. In 2008, OPS issued regulation for low-stress pipelines within a half mile of an unusually sensitive area. We believe focusing on these areas was the right approach.

Congress has provided OPS with a thorough set of tools to regulate pipeline safety. We see no reason for Congress to greatly expand the pipeline safety program or impose significant new mandates upon OPS or industry. We do believe Congress should encourage OPS to complete its rule on damage prevention, disallowing any exemptions to one-call requirements.

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

Ms. BROWN OF FLORIDA. Mr. D'Alessandro.

Mr. D'ALESSANDRO. Good afternoon, Madam Chairwoman and Members of the Committee. I am pleased to appear before you today.

Ms. BROWN OF FLORIDA. Pronounce your name.

Mr. D'ALESSANDRO. My name is Rocco D'Alessandro.

Pipeline safety is a critically important issue, and I thank you for not only holding this hearing but for all of 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.

I am testifying today on behalf of 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.

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

Safety is our top priority. We spend an estimated $7 billion each year in safety-related activities. I want to assure the Committee that the natural gas industry has worked vigorously to implement these provisions that relate to our sector. From a regulatory perspective, the past 10 years have easily included far more major pipeline safety rulemakings than any other decade since the creation of the Federal pipe code in 1971.

Specifically, there are four core provisions of the PIPES Act of 2006 that are key to enhancing the safety of distribution pipeline—excavation damage prevention, distribution integrity management programs, 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 through State legislative changes and regulatory actions.

The 2006 PIPES Act required DOT to establish a regulation prescribing standards for integrity management programs for distribution pipeline operators. They published the final rule on December 4 of last year. The effective date of the rule was just February 12 of this year. Operators are given until August 2 of 2011 to write and implement the program. It will impact more than 1,300 operators, 2.1 million miles of pipe, and 70 million customers.

The final rule effectively takes into consideration the wide differences that exist between natural gas distribution operators. It allows operators to develop a DIMP plan that is appropriate for the operating characteristics of their distribution delivery system and the customers they serve. Operators are aggressively implementing DIMP.

The 2006 PIPES Act mandated that DOT require natural gas distribution utilities to install an excess-flow valve, EFV, on new and replacement service lines for single-family residences. Operators have installed an estimated 950,000 EFVs since the June 1, 2008 date.

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

In summary, many of the mandates within the 2006 PIPES Act have just become regulation, and the government and industry are working to implement these regulations. AGA believes that the 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. Thank you.

Ms. BROWN OF FLORIDA. Mr. Sypolt.

Mr. SYPOLT. Madam Chair, Members of the Subcommittee, thank you for having me testify today on the safety of the Nation's energy pipeline network.

I am Gary Sypolt, CEO of Dominion Energy. I am responsible for Dominion's natural gas businesses.

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 pipelines, 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 analogous 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 power and transportation sectors. Many of you might also have heard about the recent boom in new domestic natural gas supply development, particularly from the shale deposits. This all has a safety dimension.

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 those 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 do happen, 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 the 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 at the same time we are finishing baseline work. My written testimony includes some data on the results of the work done thus far. There are two important takeaways from this work that I would like to share with the Subcommittee.

First, the data strongly suggests that, in reassessments, the numbers 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 time frame, these periodic reassessments are able to catch corrosion precursors before they manifest themselves into failures.

With all that said, the other takeaway is the technology for conducting these assessments, primarily internal inspection devices known as "smart pigs," which continue to develop and improve over time. A new generation of these devices is currently being employed, and it is giving us a clearer, more granular view of the condition of our pipeline systems.

In the last 4 years, there have also been several additional improvements in pipeline safety, including a new rule on pipeline controller fatigue mitigation. INGAA worked with the other pipeline associations and with PHMSA in developing a new standard for controller fatigue that meets the recommendations made by the NTSB in 2001.

My written testimony includes some other safety initiatives that have been completed in recent years as well. This leads to my main point.

The pipeline safety program, at least with respect to natural gas transmission pipelines, is working well to reduce accidents and protect the public. PHMSA has the authority it needs to improve standards over time. INGAA believes that, given this level of performance and in addition to the short amount of time remaining in this Congress, the simple reauthorization of the Pipeline Safety Act is a logical step for Congress to make. We support a straightforward authorization that leaves the current programs in place. It will be a pleasure to work with you in enacting such a bill. However, if you choose to broaden the bill, we would offer the following suggestions:

Damage prevention is critical to our industry. State one-call programs are essential to avoiding accidents and to preventing fatalities and injuries. I am pleased to say that our home State of Virginia serves as a model for the Nation. However, some States still exempt some of the most significant excavators from their programs, such as State highway departments and their contractors, municipal governments, and railroads. All excavators should have to call before they dig.

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

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

Madam Chair, we are proud of the safety improvements our industry has made over the last decade. We hope that you agree that much has been improved. Thank you again for inviting me to testify today.

Ms. BROWN OF FLORIDA. Thank you.

Mr. East.

Mr. EAST. Thank you, Madam Chair, Ranking Member Shuster, and Members of the Subcommittee.

My name is Dan East. I am a district manager for Reynolds, Incorporated, and I am based out of Albuquerque, New Mexico. I also serve as the NUCA, or the National Utility Contractors Association, Chairman. NUCA represents the contractors, manufacturers, and suppliers that rebuild and build America's infrastructure.

We appreciate the opportunity to provide comments to the implementation of the Pipeline Inspection, Protection, and Enforcement Act of 2006. The PIPES Act will result in the evaluation of State one-call and damage prevention laws that may be inadequate if and when Federal intervention may be required.

As I have stated, NUCA members work to repair and build America's aging underground infrastructure. Ladies and gentlemen, we are digging around the clock, but so many times we have dealt with underground facility owners and operators who mismark or do not mark their facilities. This happens more times than not. We understand that the PIPES Act authorizes Federal enforcement of State one-call and damage prevention laws. We just want to make sure that we hold all parties accountable. Now, it might come as a surprise to some of you, but we as excavators want to see quality enforcement. We see the lack of enforcement all the time.

Now, what do I mean by "quality enforcement"?

One, we have laws in place today that when we, the excavator, hit a properly marked utility, we are required to make restitution for that utility, but today there are no means for the excavator to recoup losses resulting from a mismarked utility. What I mean by that is that we can spend hours and hours and hours looking for a utility that has been mismarked, and we are not able to recoup those downtime costs. After we have spent those hours looking for this utility and we move on with our excavation for another 5, 10, 15 feet and we hit that utility, now we have a serious safety issue, one where people can get hurt, and we must spend months defending ourselves against that utility.

For instance, right now I am dealing with year-old mismarked utilities in a project in Taos, New Mexico, and it is a continual fight to prove ourselves that we were in the right.

We understand, as excavators, we have to call the one-call notification centers, we have to wait the required time for the utility to mark their services, and we dig carefully around those utilities. We do this day in and day out. What we are wanting to see is effective and balanced enforcement, but please remember it needs to be balanced.

NUCA has also been involved with the Common Ground Alliance since its inception in 2000. As many of you know, the CGA came out of a 1999 Common Ground Study, which proved to be a true testament to the spirit of shared responsibility in damage prevention among all stakeholders. It is a shared responsibility that makes damage prevention truly possible. We have represented the excavation community ever since, and we are proud to say that we have been a part of its success for the last 10 years.

We see a lot out there, ladies and gentlemen, but I would like for you to understand that we need a balanced enforcement so that both the utility and the excavator meet their responsibilities.

Again, I thank you for the opportunity to testify before you today, and I look forward to any questions that you might have. Thank you.

Ms. BROWN OF FLORIDA. Thank you all for your testimony.

Mr. Shuster, do you want to go first?

Mr. SHUSTER. Sure. Thank you very much.

From what I hear from Messrs. Black, D'Alessandro, Sypolt, and East—and any one of the four of you can correct me—the PIPES Act is—you are pleased with where it is today. It hasn't been in place long enough. You haven't been able to implement for a long enough period of time to determine whether it is very good or good—or maybe there are some things we have tweaked in it—and as we move forward on the authorization, you want to stay along the same path with some changes here and there.

Is that a fair assessment, Mr. Black?

Mr. BLACK. Yes, sir, although we encourage attention to damage prevention, as I mentioned.

Mr. SHUSTER. Right.

Mr. D'Alessandro.

Mr. D'ALESSANDRO. We would just like the chance to keep implementing the 2002 and finish up, and the 2006 DIMP plans are just being written right now.

Mr. SHUSTER. OK.

Mr. SYPOLT. We believe, Congressman, that the rule works, and we believe that what we have really seen from the data is that it is working very, very well, and the amount of issues that we have are certainly declining, and we expect them to further decline.

Mr. SHUSTER. Mr. East.

Mr. EAST. I would also sentiment that agreement, along with the other three parties here, that, yes, it is working. However, it is at this point a little bit unbalanced toward the utility and not the contractor, and that is where we need to see some adjustments.

Mr. SHUSTER. You would like to see that the exemptions that exist today should not exist for railroads, State DOTs, and everybody should have to call before they dig?

Mr. EAST. That is correct. Yes, sir.

Mr. SHUSTER. That is your main bone of contention with it?

Mr. EAST. Yes.

Mr. SHUSTER. Mr. Metro, I think I heard you say that it hasn't been in place long enough to really get a good feel to be able to measure it. So you are in somewhat of agreement with the rest of the panel?

Mr. METRO. That is correct. The States would like to see some extended time to see if these mandates work.

Mr. SHUSTER. Right.

Mr. Weimer, in fairness, to be fair and balanced, I understand you don't see it quite the way the rest of them do, so I will give you 30 seconds to just give me a synopsis of the major points that you want to see changed.

Mr. WEIMER. We actually agree that the law has done a very good job and is moving forward. We just see that it can be built upon, and more miles of pipeline can be included so people that aren't included under those protections do fall under those protections.

Mr. SHUSTER. OK. Thank you.

As far as the control room management rule that DOT released, are there any aspects of it you and industry would like to see changed? Are you pleased with that?

I have got an understanding of how the folks work in a control room. For most of you, is it fair to say that a lot of folks who are working the 3 days/12-hour shifts are happy and you are putting some things in place that are keeping them alert and not run down?

Mr. Black, why don't we start with you and go down the table.

Mr. BLACK. We think it is a good rule. We largely support it. We are busy at work implementing it. We would like to iron out one issue of a definition of how it is applied to a control room and a controller. We think this can be done in upcoming workshops.

Mr. D'ALESSANDRO. Almost the same content. We are in the process of writing it. We are happy with the way it is coming across. Again, I think our people, the controllers, are happy with the hours and satisfied.

Mr. SYPOLT. We would echo that. Certainly, our controllers love the schedule. They come back to work well rested and can concentrate well on their jobs.

Mr. SHUSTER. Mr. East, you don't have control rooms. You build them. You build the control rooms.

Mr. EAST. Exactly.

Mr. SHUSTER. Mr. Weimer, do you have any thoughts on what has happened?

Mr. WEIMER. We think it was a good rule, and we are glad to see that it is being implemented.

Mr. SHUSTER. OK. Mr. Metro, as far as the Marcellus gas find and the pipelines, I think Mr. Carney started asking questions about this. Do we have any idea what percentage increase in Pennsylvania we are going to see in pipeline construction?

Mr. METRO. It is going to be a tremendous increase. In 2009, Pennsylvania DEP issued 1,854 well permits. So, just based on that, we know there are going to be a tremendous amount of pipelines being built.

Mr. SHUSTER. And you are equipped to handle the inspection and all that is going to come with those pipelines coming?

Mr. METRO. Not at this time.

Mr. SHUSTER. Right, and that is what you talked about as the shortfall in the State budgets.

What is the major—is it not enough personnel or the mandates you have to go out and——

Mr. METRO. Pennsylvania has a little bit of a unique problem. We are the only State in the Union that does not have the extended authority to regulate pipelines that are not utilities, so we are working on the process of getting that extension with the Pennsylvania legislature. If we can get that extension, then we can get full jurisdiction over the non-utility pipelines, and then we will beef up our personnel as we go through; but as you are well aware, Pennsylvania has budgetary issues, and we will do the best we can with the people that we have, and we use a risk assessment model to do those type of inspections.

Mr. SHUSTER. I understand that 80 percent of the inspectors out there are employed by the States. As I was talking to the Administrator earlier, the number is 135 on the Federal level. Is 135 the right number? Should it be 185 or should it be 105? Your interaction with the Federal Government, how does that go?

Mr. METRO. Well, from Pennsylvania's perspective and from the other States' perspectives, it would be nice to see additional Federal safety inspectors in the field. Pennsylvania has one inspector that resides within Pennsylvania, a Federal inspector, so it would be nice to see additional people.

Mr. SHUSTER. GAO has come out and said that a risk-based focus on pipeline testing would be a better way to go than just the 7 years.

What are your thoughts on that?

Mr. METRO. Well, we haven't seen enough data yet to see if the 7-year is sufficient. However, I would note that many of the States use risk analysis when they perform their inspections. So risk analysis definitely would be an issue that we would like to look at.

Mr. SHUSTER. Right.

Mr. Weimer, your view on the risk-based?

Mr. WEIMER. Yes, we also think there has not been enough data. Congress gave the natural gas industry 10 years to do the first set. We are not through that whole 10-year period yet, so we think we need to get through a couple of cycles——

Mr. SHUSTER. How far along are we, do you know?

Mr. WEIMER. Oh, I think we are into—well, it was passed in 2002 and then kicked off in 2004, so we are really about 6 years into the whole cycle.

Mr. SHUSTER. And industry, Mr. Black and Mr. D'Alessandro, your thoughts on the risk-based. How confident are you that that is the way to go?

Mr. BLACK. Liquid pipelines are a little farther along. We have completed our first baseline assessments. We are in the reassessments now. This was not in our testimony, but it is an intriguing idea. It sounds like one for the regulator to consider well.

Mr. D'ALESSANDRO. We have completed our first round on our transmission, and we have always had a risk-based model system. We have also always used a risk-based model system for the distribution pipes, which now the DIMP follows a risk-based system.

Mr. SYPOLT. We certainly believe the risk-based assessment is a better way to go than the 7-year period.

Basically, we have started reassessments already as we complete our baselines, and we find less and less significant issues in the reassessment—in fact, less than 10 percent of what we found in the baseline, which says the corrective action we are taking has been working. So we are very pleased with that, and we did get a tremendous amount of data that we looked at to help us decide how to determine what risk we really have and what period of time we should have.

Some pipelines actually would be more frequent than 7 years. Some would be maybe less than that depending on the information that we find. What it allows us to really do, though, is to take the resources that we have and use them to their best benefit so that we can address those pipelines that we feel are of higher risk than others.

Thank you.

Mr. SHUSTER. Mr. East, do you have any view on that? Though you are probably not going to be testing them. You are going to be fixing them.

Mr. EAST. We are into fixing them, that is correct; but in listening to the testimony, risk-based does make more sense than a fixed 7-year time period.

Mr. SHUSTER. Right. OK. Well, I don't have any further questions, so I yield back to the Chairwoman.

Ms. BROWN OF FLORIDA. Thank you.

I have a series of questions. Mr. Weimer, I will start with you because we just finished talking, and I want to get you on the record.

Do you oppose a prior Bush, now Obama administration, proposal to eliminate this 7-year reinspection requirement for gas operators? How do you feel about that?

Mr. WEIMER. Yes, we oppose it. At this point, we think we need to get through the whole 10-year period and see a couple of the second-year reassessments. It would be nice if the data were shared with the public so the public could see, company by company, what the real reassessments are.

We think, in reality, there may be a time in the future when such risk-based is a good idea, but that puts more emphasis on the regulators then to be able to keep track of what the industry is doing, where an automatic reinspection interval kind of is better for the public, in our view.

Ms. BROWN OF FLORIDA. What percentage do we inspect?

Mr. WEIMER. Well, on the natural gas side, only about 7 percent of the natural gas transmission pipelines fall within the integrity management rules. Now more lines than that are being inspected, but those results aren't totally shared with the public.

Ms. BROWN OF FLORIDA. Mr. Metro, I have a question. I asked earlier about the grant program. We are talking about the legal mandate that we get up to 134 Federal inspectors, but with the grant program, I was asking about the waiver because basically we work with the State partners. How does that program work for you?

Mr. METRO. In Pennsylvania, which I can give you an example of, we receive about 60 percent currently for funding through the State grant. That number has increased over the last couple of years. Previously, it has been hovering around 40 percent, anywhere from 40 to 50 percent.

With our States' budgets and the economic situation that we are in, more States are looking toward the Federal Government to aid them in their budgetary problems. Now, this year, the States and the National Association of Pipeline Safety Representatives went to PHMSA and asked for a waiver because of the economic situation, and PHMSA granted it. We need some help on that in the reauthorization. That waiver needs to be made easier for the States. The process needs to be made easier.

Ms. BROWN OF FLORIDA. OK. I think that that is one way to— it is all the same money. It is all the taxpayers' money, and that is one way to stretch it and make sure we give them the safety standards if the State is doing the inspections.

Mr. METRO. I agree.

Ms. BROWN OF FLORIDA. So you are saying that we need to look at how we can work with the Department to make sure the waiver program works better.

Mr. METRO. Yes. NAPSR would work closely with PHMSA to try to develop some type of program to make this waiver process better.

Ms. BROWN OF FLORIDA. Mr. Black, you indicated, because of the program, that the industry has had to spend about $1 billion. However, it seems to me that you have identified about 32,000 repairs that were made, and out of those 32,000 repairs, 6,800 of them were serious. It seems to me that maybe you all have saved billions of dollars, because if the system had not worked you could have been faced with the situation that we are facing in another category.

Mr. BLACK. Yes, absolutely, Madam Chair. We think money spent on safety pays off.

Ms. BROWN OF FLORIDA. OK.

Mr. Sypolt, in your testimony, you indicated that you would like for us to eliminate the 7-year.

Mr. SYPOLT. Yes, ma'am.

Ms. BROWN OF FLORIDA. Would you like us to go to a 5-year? I know that is not what you are recommending.

What are you recommending?

Mr. SYPOLT. What we recommended, Madam Chair, is that we look at the reassessment period based upon a risk-based analysis rather than a defined period of time, and there may be some pipelines based on that risk analysis that you would do more often than 7 years and some less often than 7 years. By being able to look at the data, to look at the prior information from the baseline pig run, you know, we would have a better view of where we could get the most benefit from spending our resources so that we actually concentrate on those lines that may be of higher risk than others.

Mr. SHUSTER. Madam Chair, could I just ask a quick follow-up?

Ms. BROWN OF FLORIDA. Go ahead.

Mr. SHUSTER. Could you give us a picture of what that looks like, risk-based? Is that high population areas? Is that environmentally sensitive areas?

Mr. SYPOLT. It would take both of those into consideration. It would take into consideration, Mr. Congressman, many other things as well—soil conditions. In fact, I think you heard Ms. Quarterman this morning talk more about leaving rocky areas and going into water or different soil conditions. We look at soil conditions. We look at the make of the pipe. We look at the wall thickness of the pipe and the pressure at which it operates—clearly, what we have seen with regard to the prior corrosion on the pipeline system. So it takes into consideration a great deal of information. It is not just something where we say, Well, we would like to do A at this and B at that.

Mr. SHUSTER. Thank you.

Ms. BROWN OF FLORIDA. What do you think about the fact that we are only inspecting from 7 percent to 15 percent? What is the possibility of expanding that pool of inspections if we go to a less frequent time period?

Mr. SYPOLT. I think, Madam Chair, that is an excellent question and one I am glad you asked me.

The 7 percent really only applies to the regulation in those HCA areas. It doesn't mean that is all that our industry is doing. You know, the pipeline industry, with regard to natural gas transmission lines, actually, through today, has actually run smart pigs in about 49 percent of the transmission systems in the U.S., and we expect by 2012 to have run between 60 and 65 percent of that even though only 7 percent is required.

Ms. BROWN OF FLORIDA. You know, one of the things that we are finding—we have got to trust our stakeholders. You trust, but you verify, as Ronald Reagan said. What are the best ways that we can verify that we are protecting the public?

I would like to hear from some of the other participants on that, because, when I look at this report, what we are talking about is British Petroleum. The part of the legislation came out of their 2006 spill, but yet they have been fined over and over again, and there has been noncompliance. So what is it we can do when we find someone in the industry not complying with the regulations?

Mr. SYPOLT. Actually, I have found that PHMSA certainly does a very thorough job of auditing the natural gas transmission pipelines. In fact, I might even think, at times, they have been somewhat heavy handed in those audits, but they do work very hard to verify the information that we collect in the audits that we do, which are lined out, Madam Chair, in great detail.

You know, a pipeline may be required to do, by regulation, more than a million investigations set on a certain time frame. We have software packages where we set out the schedules for when those are to be done. We get notices to our employees so that they actually know by when they are supposed to have that done. If they get within 2 weeks of it and they still haven't completed that investigation, we get a printout that goes to their supervisors so that they see that they have not completed that investigation.

Then the dates on which those are there show up on printouts that the PHMSA auditors and State auditors have an opportunity to come in and review, and they do. Believe me, they do review those in great detail. They may come to our offices and spend 3 days on an audit, going through that information that is laid out in great detail to them. Unfortunately, at times they do find a few things. There are very few. We strive to comply absolutely with all of those, but occasionally they do find things, and they do fine pipelines.

Ms. BROWN OF FLORIDA. Well, would anyone else like to respond to that?

Mr. Black.

Mr. BLACK. Well, I would just like to agree that the Congress has given the Office of Pipeline Safety a lot of tools. They have shown they are not hesitant to use them. They do inspections. They have enforcement. They do fines. There are special permit requests that are denied by the agency. They are pretty active in this.

Ms. BROWN OF FLORIDA. Mr. Weimer.

Mr. WEIMER. Yes. One of the things that we think that could help increase the trust but also allow people to verify is a better way for the public to be able to verify that inspections have occurred.

Congress has done a very good job of helping transparency as far as incidents. There is a whole incident database now that the public can look at. There is an enforcement database so you know if a pipeline company has had a problem and has been fined, but there is no way that the public can look and see if a company has had inspections, what the outcomes of those inspections have been or how that has been followed up on. So one of the ways transparency could grow would be to put up some kind of an inspection database so the public could review that.

I think, overall, if the public looked at that, they would find out that the vast majority of pipelines are being run very safely, so it would increase the trust in pipelines, but at this point the public can't look at that information.

Ms. BROWN OF FLORIDA. Mr. East, you mentioned the one-call centers. Do you want to expand on that? You say all of the States don't have that, but I thought we had a uniform 811 number.

Mr. EAST. We do have an 811 number, and it is working quite well, but not all the States have encompassed the 411 or the 811 for contractors, homeowners—whomever—to make that call to get into the utilities, to have their utilities located, but it is something that the CGA and everybody is working towards. It has been very effective. We are slowly getting there. As part of that, though, we also need to make sure we get all stakeholders signed up to that 811 or their 411 calls to where the municipalities of the utilities—everybody—is a member of that one-call system so that we get all utilities located.

Ms. BROWN OF FLORIDA. All right. Thank you.

Mr. Larsen.

Mr. LARSEN. Thank you, Madam Chair. Again, thank you for having this oversight hearing as we are considering what to do next with the PIPES Act or with the pipeline safety laws. A couple questions for Mr. Weimer.

In your testimony, you pointed out that PHMSA's incident database lists only 70 excavation-related incidents. I apologize if you mentioned this and I wasn't here, but you also noted that the Common Ground Alliance records showed 60,000 incidents in the same time period.

Can you explain the discrepancy here?

Mr. WEIMER. I think that discrepancy is explained by the PHMSA's database. Companies are only required to report incidents if there has been a death, an injury that causes hospitalization, or $50,000 worth of property damage, and that is $50,000 in 1984 dollars, so it is really more like $90,000-plus today. A lot of damage caused by excavation probably doesn't hit that cost range, so that is probably why there are only 70 reported under PHMSA. The Common Ground Alliance captures many more because it is voluntary, and they keep their results secret. They are saying 60,000, although it is a very hit-and-miss system that a lot of regions haven't plugged into totally. So there is a big disconnect there if we want to move forward with damage prevention programs in a strategic sort of way.

Mr. LARSEN. Yes.

I understand this is a sticking point, perhaps, between the opinions of the Pipeline Safety Trust, and maybe others on the panel, and I will give others on the panel an opportunity to respond to it.

You brought up a point regarding the idea to extend PHMSA oversight to the siting of pipelines. Can you talk a little bit about what that would look like and why you think that is important?

Mr. WEIMER. Yes. I don't think I recommended that they have oversight over siting, but it needs to be integrated better with siting—the safety and the siting.

Right now, depending on whether it is a natural gas or a liquid pipeline, FERC might be involved with natural gas. It is the States or even the U.S. State Department with liquid pipelines, and there is kind of this disconnect when the U.S. State Department is doing an EIS on the siting of a pipeline, but PHMSA is doing other processes like spill plans that are required, the special waivers or permits. Even the high-consequence areas kind of fall outside of that

EIS process. So, with the public's trying to be part of that whole process, there is this disconnect.

There are also some concerns. PHMSA did a number of inspections about a year ago and held a workshop where they went in and inspected 35 sites and found a wide range of problems on construction of new pipelines. They found coating damage. They found pipes that were bought that were not the correct pipes being put in the ground incorrectly, welded incorrectly.

What it really brought to mind was that we need to make sure that PHMSA has the resources so they are on site when they are building these thousands and thousands of miles of new pipeline, and I don't think that is how it has happened in the past.

Mr. LARSEN. Mr. D'Alessandro or Mr. Black?

Mr. D'Alessandro, you have been pleasantly, you know, patient, so I will give you a chance to maybe respond to that.

Mr. D'ALESSANDRO. From our industry point of view, I am not—you know, from the distribution point of view, I think I would defer to the bigger sized pipes.

Mr. LARSEN. OK. Mr. Sypolt.

Mr. SYPOLT. Mr. Congressman, I was waiting for Mr. D'Alessandro to respond. Would you please repeat the question?

Mr. LARSEN. It was basically to respond to Mr. Weimer's comments about what role PHMSA would play in the siting of pipelines and that there is maybe a disconnect between the safety aspects and the siting aspects.

Mr. SYPOLT. I guess I haven't seen PHMSA's role in siting. I have seen that more in FERC, in the FERC process. You know, public meetings are held where the public can come and find out about and learn about the activities of the pipeline construction as well as the risks of the pipelines.

PHMSA, though, does come out and audit the construction activity, and I think that is, you know, beneficial for them to do that. Certainly, they have the regulation in place that allows them to do that today.

Mr. LARSEN. Madam Chair, the clock didn't start, so I am not quite sure how much time I have got. OK.

Just generally, you know, we are considering the reauthorization that is up this year. As I said to the first panel, we could just change the dates on this thing and move on. That is one end of the spectrum. The other end of the spectrum would be some level of changes made, probably more major changes, but I guess I sense we are not looking at a full overhaul, but we are looking at maybe some changes to the act.

Generally, are the guardrails on this reauthorization kind of defined fairly well?

Mr. Weimer.

Mr. WEIMER. I think that is true. I think, in the last two reauthorization cycles we have dealt with a lot of the low-hanging fruit, and now we are looking at things that are already existing, maybe pushing the edges of those and expanding those slightly but nothing—no new major initiatives.

Mr. LARSEN. Mr. Black.

Mr. BLACK. There is a lot that this agency has done recently, and there is a lot that we are implementing. We think that is working.

The safety record is coming down on liquid and gas pipelines. I don't think there is a lot that we ask you to do. Pardon me for being repetitive.

We do encourage you to look at damage prevention. It is an interesting policy issue to have the State enforcement of damage prevention but have the Federal authority to step in when a State doesn't have an adequate plan. That is what the Office of Pipeline Safety is working on right now. I hope that you all will encourage them to move forward to do that. One, but not all, of the issues in there is of the one-call exemption. We hope that, of the 41 States that have some type of exemptions for one-call, they will either step up themselves or find the Federal Government doing it for them.

Mr. D'ALESSANDRO. We believe we need a chance to get DIMP implemented. The plans aren't due until August. Our TIMP, the Transmission Integrity Management Plan, we have gone through. We are on our second reassessment. We feel we have got enough data, that we have got everything we need to move forward. Damage prevention numbers are getting better. They are showing improvement. So I think we are fine in moving straight forward.

Mr. LARSEN. Yes.

Mr. SYPOLT. Mr. Congressman, we believe that a simple reauthorization would actually be beneficial to move forward with. We did comment on three things that we might change, should the Congress choose to open up the bill, and we have basically talked about all those.

The only one that we haven't mentioned—again, you know, it may have been for PHMSA to look at some legacy-type regulations that we believe may have been supplanted by the integrity management programs of today.

Mr. LARSEN. Right. Yes.

Mr. East.

Mr. EAST. We would concur. However, we do believe that damage prevention is going down, but if there is an area to tweak in damage prevention we need a little help.

We would like to see the other States get involved with one-call systems so that all stakeholders are involved with this. We have worked very hard on the contracting side to work with the municipalities and the stakeholders, and if we can all come to terms and get all of this put together, I believe our damage prevention will be much greater.

Mr. LARSEN. Mr. Metro, I am sorry, I sort of skipped over you.

Mr. METRO. That is fine.

The States agree pretty much that we would like to see a simplified reauthorization process. It is just that the States would like to make sure that the revenues and the funds are going to them appropriately.

Mr. LARSEN. I also noted from someone's testimony to maybe authorize it for a longer period of time rather than for 4 years. I don't know. It might be helpful for us to start, maybe, if we get this done, doing oversight hearings next year so we are building up to the next 4 years or whatever time frame so that if, in fact, we do a 4-year, by year four, we will have gotten that list of things, and we are just ready to go.

Mr. LARSEN. We will start negotiating the next reauthorization today as opposed to the tail end of the reauthorization period. It just seems to me after we did this in 2002 in 1998 or 1996, maybe jumping on this a little sooner, for the next round because we are going to have about 10 years of experience or 12 years of experience, that we should be able to say, OK, what would the next iteration look like? This might be better timing for that.

Thank you all.

Ms. BROWN OF FLORIDA. Thank you. I want to thank the witnesses for their testimony and the Members for their questions. Again the Members of this Subcommittee may have additional questions for the witness, and we will ask you to respond in writing. The hearing record will be held over for 14 days for Members wishing to make additional statements or to ask further questions.

Unless there is further business before the Subcommittee, we are adjourned.

[Whereupon, at 1:15 p.m., the Subcommittee was adjourned.]

OPENING STATEMENT OF REP. STEVE COHEN

Subcommittee on Railroads, Pipelines, and Hazardous Materials

"Implementation of the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 and Reauthorization of the Pipeline Safety Program"

May 20, 2010

I am pleased to be here today to receive testimony from the Administrator of the Pipeline and Hazardous Materials Safety Administration as well as our other distinguished guests regarding the PIPES Act and the Reauthorization of the Pipeline Safety Program.

Mr. Chairman, I would like to introduce for the record two documents. One is a letter signed by more than 1100 organizations nationwide, and the other is the latest column by Thomas Friedman that appeared in the New York Times on May 18. Both address the same, extremely important issue. Why, Mr. Chairman, as we witness a historically-disastrous oil spill in the Gulf of Mexico, as this chamber has already passed historic climate change legislation and the Senate is considering the same, as we meet here today to talk about the safety of oil pipelines, why is the US government turning a blind eye to a proposed project that is one of the worst instances of destruction of the environment yet conceived? I am speaking of the proposed Keystone XL pipeline stretching more than 2000 miles from Canada to the Gulf Coast that would bring filthy tar sands oil to the Gulf refineries. Oil from the tar sands of Alberta has 15% more carbon than even the worst crude oil. As we consider historic climate change legislation, construction of this proposed pipeline would nullify that step by introducing more carbon-intensive oil into this country. It is unsafe, it is dirty, it is a massive step backwards, and it makes no sense. I would plan to ask those testifying today why the government is not paying more attention to this critical issue.

I would like to thank the witnesses for attending this important hearing today and look forward to hearing their response to this pivotal question.

REP. RICK LARSEN OPENING STATEMENT –
T&I Rails Subcommittee Hearing on "Implementation of the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 and Reauthorization of the Pipeline Safety Program"
May 20, 2010

Madam Chairwoman, thank you for holding this important hearing.

I would like to recognize Carl Weimer, who is here testifying on behalf of the Pipeline Safety Trust. Carl is from Whatcom County in my district, where a deadly pipeline explosion occurred nearly 11 years ago.

Pipeline safety is of great importance to me and my constituents. On June 10, 1999, a pipeline explosion claimed the lives of two 10-year-old boys and an 18-year-old young man in my district in Bellingham, Washington.

In response to this tragedy and several other pipeline explosions across the country, Congress passed legislation to strengthen our pipeline safety regulations. The 2002 Pipeline Safety Improvement Act increased penalty fines, improved pipeline testing timelines, provided whistleblower protection, and allowed for state oversight. In 2006, Congress reauthorized the 2002 law by passing the Pipeline Inspection, Protection, Enforcement and Safety (PIPES) Act.

Since that day in June, we have made significant progress in ensuring the safety of our nation's pipelines. The frequency of "high consequence events" to pipelines has diminished almost 35 percent over the last ten years. Due to the integrity management program required by the new law, pipeline operators have made extensive repairs to their pipelines that otherwise would have led to future accidents.

The 811 One Call program provides a number people can call before they dig to make sure that they won't hit a pipeline. And Congress has significantly increased the number of pipeline inspectors in the field.

However, we must remain vigilant, and that's why today's hearing is so important.

In preparing for today's hearing, my staff and I have spoke with several of our witnesses. The implementation of the 2006 law seems to be going very well, with one notable exception.

PHMSA has not begun the rulemaking process for Phase II of the low-stress rule, and has not indicated when it will do so. I look forward to hearing PHMSA's plans for initiating this rulemaking and their explanation for why it has taken so long to begin this process.

PHMSA is also still in the process of implementing federal enforcement of third party excavation damage to pipelines.

And although I commend President Obama for requesting Fiscal Year 2010 funding for all 135 authorized inspectors, I am concerned that PHMSA only has about 94 inspectors currently on-duty.

The PIPES Act is due for reauthorization this year. I hope this hearing will spark a robust discussion about what reauthorization might look like and if there are any pressing issues that need to be addressed.

From reading the testimony, it appears as if nearly all of our witnesses agree that Congress and PHMSA should clarify that states should not exempt municipalities, state transportation departments and railroads from their damage prevention "one call" rules.

And some of our witnesses, including PHMSA, believe that Congress should permit risk-based reassessment intervals for natural gas transmission pipelines.

Other issues, such as expanding the miles of pipelines that fall under Integrity Management rules, PHMSA's data reporting requirements, and expanding the use of excess flow valves are also covered by the testimony.

I look forward to delving into these issues with our witnesses.

Whether or not Congress decides to pursue a simple reauthorization of existing programs or creates new pipeline safety mandates and programs, I believe it is important that Congress reauthorize the PIPES Act this year and does not let it lapse. It is also critical for Congress to adequately fund important programs such as the Technical Assistance to Communities grant program, the 811 One Call Program, state damage prevention grants, and federal pipeline safety inspectors.

Again Madam Chairwoman, thank you for holding this hearing, and I look forward to discussing these issues with my colleagues and our witnesses.

Congresswoman Laura Richardson

Statement at Committee on Transportation and Infrastructure, Subcommittee on Railroads, Pipelines, and Hazardous Materials

Laura Richardson

"IMPLEMENTATION OF THE PIPELINE INSPECTION, PROTECTION, ENFORCEMENT AND SAFETY ACT OF 2006 AND REAUTHORIZATION OF THE PIPELINE SAFETY PROGRAM""

2167 Rayburn House Office Building

Thursday, May 20th, 2010

10:00A.M.

Madam Chairwoman, I'd like to thank you for calling this hearing to look at issues related to the Reauthorization of the Pipeline Safety Program. The timing could not be better; following on the heels of the hearing we had yesterday examining the disaster in the Gulf Coast. Many of these issues are similar, and lessons can be learned from this disaster which can help prevent a similar incident in the pipeline area.

The committee has already, on several occasions, taken affirmative action to ensure the adequacy of the pipes transporting these materials. And while often unnoticed by the general public, these pipelines transport 64 percent of the energy commodities consumed in the United States over a network of 2.5 million miles. And as the DOT IG reported two years ago, further actions are needed as the current situation is far from an "end state" for enhancing the security of the Nation's pipelines.

One important action was attempting to ensure the safety of this network was to provide an adequate number of inspectors. In the FY2010 budget, President Obama requested funding for 135 full-time pipeline inspectors for PHMSA (Pipeline and Hazardous Materials Safety Administration), in compliance with law passed by this committee. Congress appropriated funding for all of the requested positions. However, PHMSA only added 18 positions in FY 2010, bringing the total number of inspectors actually on-duty today to about 94 – 41 inspectors short of the 135 required in the law. It is very troubling that the administration has failed to utilize the funding we provided, and is leaving vacant positions that are crucial to ensuring the adequate maintenance of these pipelines that certainly have not been immune to incidents over the past several years.

I'm also concerned about PHMSA's pace of rule making. In June 2008, PHMSA issued a Final Rule that regulated 803 miles of low-stress pipelines, but more than 1,300 miles remain unregulated. At our last pipeline safety hearing in June 2008, former Administrator Carl Johnson said the second rule would be on the streets in Fall 2008. It's been two years since that hearing and we are still waiting for the second rulemaking. I hope that the witnesses shed some light on this rule making process and that we can get this rule out as quickly as possible.

If we learned anything in yesterday's hearing related to the Gulf Coast oil spill disaster, we learned about the importance of adequate preparations for a disaster. It seems clear now that BP, the industry, and Government were not prepared to respond to a worst case scenario in the Gulf. Not having adequate technology or engineering solutions ready to go is the fault of many in this case. I hope that in this related area we can learn from this disaster and make sure we are prepared for a worst case scenario disaster.

I'd like to thank the Chairwoman again for calling this timely hearing and thank the witnesses for appearing before us today and I look forward to hearing their statements.

Thank you, Madam Chairman

Testimony of
Andrew J. Black
on Behalf of the
Association of Oil Pipe Lines (AOPL) and the American Petroleum Institute (API)

Before the House Committee on Transportation and Infrastructure
Subcommittee on Railroads, Pipelines, and Hazardous Materials

May 20, 2010

Introduction
I am Andy Black, President and CEO of the Association of Oil Pipe Lines (AOPL). I appreciate this opportunity to appear before the subcommittee today on behalf of AOPL and the American Petroleum Institute (API).

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, our 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 be narrowly 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 important petroleum products to our communities, including all grades of gasoline, diesel, jet fuel, home heating oil, kerosene, and propane. Some of our members transport or may soon 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 more than 168,000 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 the 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

Pipelines are the safest method of transporting fuels, as demonstrated by the lowest number and volume of releases of any transportation mode. 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.

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.

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[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.

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, using a combination of practices I will discuss shortly. 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[4]. 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, 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.

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 Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) Office of Pipeline Safety

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[4] These figures are from the Industry's Pipeline Performance Tracking System, a voluntary reporting system that tracks pipeline system spills.

(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 statute (Title 49 C.F.R., 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
- Environmentally 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 five years, and review assessment results to make mitigation and repair decisions. 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 plan that identifies threats to the pipeline and subsequently applies technologies to mitigate each threat. Assessments include in-line inspection by "smart pigs", which detect abnormalities in the pipe that need to be addressed, such as corrosion, pipeline deformation, cracking and other abnormal features. 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.

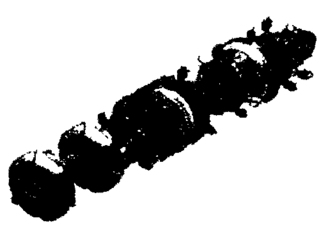

Diagram of a smart pig

Operators must also document the completion of baseline assessment plans or revisions, integrity management results, excavation and repair schedules, repair and mitigation efforts, and additional preventative and mitigation actions to protect HCAs. Liquid pipeline baseline assessments were completed for existing pipelines by March 2008. As previously noted, reassessments must be done at intervals of no more than five years per the current regulations. A risk-based approach establishes the appropriate assessment interval within the five-year period. Many operators use these same techniques beyond pipeline segments which could affect HCAs.

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.

Operators conduct risk assessments for potential impacts to HCAs as part of an IMP. The risk analysis uses data gathered from a variety of sources, including the following sources:

- Internal and external corrosion assessments
- Operations management reviews
- Third-party damage surveys
- Weather and natural forces
- Visual and mechanical inspections
- Historical data and USGS mapping
- Cathodic protection surveys
- Digital elevation models

As a part of the IMP process, each pipeline operator must determine the capability of various automation systems to detect leaks. The results of this analysis are incorporated into the risk analysis for each pipeline segment. Pipeline automation and SCADA system 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 supervisory control and data acquisition (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. A protective

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[5] 49 CFR Part 195.452.

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. Companies also employ a cathodic protection system to control the corrosion of steel by applying a small electric current on the pipeline. Since corrosion is an electro-chemical process, this electrical charge inhibits corrosion even if the protective coating has been damaged.

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 five years these pipelines alone exceeded by nearly four times DOT's estimate 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.

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 can have 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

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

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 direct 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 can mark and protect underground infrastructure from digging and other excavation projects.

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 damage prevention. 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 do not exist, 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.

Eliminating exemptions for state and local governments
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. This exemption creates 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.

AOPL and API support fundamental requirements that should apply to all excavators, including state agencies and municipalities:

- Use state One-Call systems prior to excavation by dialing the national 811 Call Before You Dig number;
- Follow location information or markings established by pipeline operators and other utility owners and operators;
- Report any and all excavation damage to pipeline operators; and
- Immediately notify emergency responders when excavation damage results in a release of pipeline products.

The importance of eliminating One-Call exemptions is included in the OPS damage prevention ANPRM as a factor in evaluating state programs. We are thankful for PHMSA Administrator Quarterman's consistent support for One-Call and the concerns she has expressed with One-Call exemptions and inconsistent enforcement.
She has rightly seized on this important issue.

The PIPES Act granted OPS the authority to grant funds for damage prevention programs to states adhering to the nine damage prevention principles included in the bill. Such grants are limited and are not enough to incentivize strong state damage prevention programs.

PIPES Act implementation
The Pipeline Safety Inspection, Protection, and Enforcement (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 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 10, 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, and hopes to resolve implementation issues in upcoming workshops.

- 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 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 low stress pipelines of 8 5/8" diameter or more within ½ mile of an Unusually Sensitive Area. All low-stress lines are required to submit an annual infrastructure report under this rule, as well. We believe this was generally the right approach. We know some have suggested OPS should undertake a second phase of regulation for the low-stress lines not addressed by this rule, but we question whether the benefits of such regulation would outweigh the costs.

Pipeline safety reauthorization
AOPL and API believe OPS is doing an admirable job with the authorities granted in the 2006 PIPES Act 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 now could disrupt further delay programs underway to improve the safety of our nation's critical pipeline infrastructure.

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 narrowly focused on addressing existing OPS programs. We also suggest the reauthorization should be for a longer period than four 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.

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.

Testimony of Rocco D'Alessandro
Executive Vice President of Operations

Nicor Gas

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Before the U.S. House Subcommittee on
Railroads, Pipelines, and Hazardous Materials

May 20, 2010

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 transport and store gas for 129,000 commercial and industrial customers using 29,000 miles of gas mains and service pipes.

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.

Mr. Chairman and members of the committee, our message today is a simple one – AGA believes that the current pipeline safety law is working well and that it should be reauthorized this year. The 2006 PIPES Act included significant mandates that the industry is in the process of implementing. The work that the Pipeline and Hazardous Materials Safety Administration (PHMSA) has completed, and the initiatives taken by industry on its own, has combined to produce significant improvement in pipeline safety over the last several years. Given this, we do not believe there is a need for changes in the pipeline safety statutes at this time – but rather urge the committee to reauthorize the current law.

DISTRIBUTION PIPELINES

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.

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 U.S. Department of Transportation. The states may also choose to adopt standards that are more stringent than the federal ones, and many have done so. LDCs are in close 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 2006 PIPES Act. I want to assure the committee that the natural gas distribution industry has worked vigorously to implement those provisions that related to our sector. We have also finalized the implementation of major initiatives from the 2002 Pipeline Safety Act. From a regulatory perspective, the past ten 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 piping are covered under the recently promulgated Distribution Integrity Management regulation;

• 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 test 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 distribution pipeline -- Excavation Damage Prevention, Distribution Integrity Management Programs (DIMP), Excess Flow Valves, 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 prevent 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 Department of Transportation (DOT) to establish a regulation prescribing standards for integrity management programs for distribution pipeline operators. The DOT published the final rule establishing natural gas distribution integrity management program (DIMP) requirements on December 4, 2009. The effective date of the rule was February 12, 2010. Operators are given until August 2, 2011 to write and implement their program.

PHMSA previously implemented integrity management regulations for hazardous liquid and gas transmission pipelines. Because there are significant differences between gas distribution pipelines and gas transmission or hazardous liquid pipelines, it would have been impractical to apply the existing regulations to distribution pipelines. The proposed rule incorporated the same basic principles as transmission integrity management regulations, but with a slightly different approach to accommodate differences between transmission and distribution systems. The DIMP final rule requires operators to develop and follow individualized integrity management (IM) 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 implemented 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 1,300 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 conference 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 implement the DIMP regulation. I am pleased to inform the committee that all affected stakeholders are working to make this an effective regulation.

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 they automatically close 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).

However, due to the inherent uncertainties and complexities associated with service lines to multiple-family dwellings, commercial and industrial customers, 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 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 eight 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

Beyond the significant requirements of the 2006 PIPES Act, the Pipeline Safety Improvement 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 awareness.

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.

Reply to Questions from Congresswoman Corrine Brown
On the May 20, 2010 Pipeline Safety Oversight Hearing
to
AGA Witness Rocco D'Alessandro
Before the U.S. House Transportation and Infrastructure committee
Subcommittee on
Railroads, Pipelines, and Hazardous Materials

The American Gas Association (AGA) appreciated the opportunity to testify before the committee regarding gas utility industry efforts to safely and reliably deliver natural gas to more than 70 million Americans. To supplement the record for the hearing, we have provided answers to your questions on excess flow valves, excavation damage prevention and the Distribution Integrity Management Program (DIMP). As discussed in more detail below, the safety performance of all three issues largely depends upon the performance of state damage prevention programs. Excess flows valves are designed to engage only if an outside force, primarily improper excavation, occurs on the pipeline and results in a significant release of natural gas. Operator DIMP programs will evaluate, rank and address risks to the distribution pipeline systems. Improving excavation damage prevention will be one of the primary elements of DIMP because excavation damage is the leading cause of distribution pipeline incidents.

AGA believes all of the legislative elements necessary to improve pipeline safety are in place. Time is needed to evaluate improvements that have been implemented over the last seven years and regulatory refinements need to be made by PHMSA to improve excavation damage prevention programs.

Question 1
In 1994, at the Gross Towers Apartment retirement complex in Allentown, Pa., a natural gas explosion occurred that killed one person, injured 66 persons and caused more than $5 million in property damage. The National Transportation Safety Board stated that had an excess flow valve been installed at the eight-storey apartment building the consequences of the accident could have been substantially reduced and the likely result would have been no injuries or deaths. The NTSB, in its final report noted that they have been recommending excess flow valves be installed since 1971.

In your testimony and in many of the position papers issued by the American Gas Association, you note the difficulty in installing excess flow valves in apartment buildings and for industrial applications because of the fluctuation in demand. Has excess flow valve technology improved to the point where the issues of unintended shut-off, previously cited by the American Gas Association as a major problem, have now been overcome?

AGA Response

No. Since 1994, excess flow valves (EFV) technology for single family homes has improved and the reliability of EFV installations has been demonstrated. However, EFV technology for multifamily, industrial or commercial applications has not evolved to the point where the issue of unintended shut-off has been overcome. Furthermore, EFVs have rarely been used in multi-family, commercial or industrial applications due to the many technical problems extending beyond just unintended shut-offs.

The 1994 incident at the Gross Towers Apartment was tragic. We agree with the National Transportation Safety Board (NTSB) that the probable cause of the incident "was the failure of the management of Environmental Preservation Associates, Inc., to ensure compliance with OSHA's and its own excavation requirements through project oversight. Contributing to the accident was the failure of the workmen from Environmental Preservation Associates, Inc., to notify UGI Utilities, Inc., that the line had been damaged and was unsupported."

The NTSB cited the absence of an excess flow valve as a factor that may have contributed to the severity of the 1994 incident -- but an EFV would not have prevented the incident. The concerns with inadvertent closure of excess flow valves installed on small diameter, uniform gas load piping that serves a single family home has essentially been eliminated as a result of the improvements in single family EFV technology and subsequent operator experience. However, due to the inherent uncertainties and complexities associated with service lines to multiple-family dwellings, commercial and industrial customers, it was, and continues to be, unreasonable to mandate nationwide installation of EFVs beyond the single-family residential class.

AGA has developed a one-page issue paper, attachment 1, which provides the background and status of EFVs. More detailed information is provided below to present a comprehensive Congressional record.

EFVs for Single Family Residential Services

AGA supported the 2006 Congressional mandate for EFVs. In fact, natural gas distribution utility operators had begun voluntarily installing EFVs before the June 2008 Congressional deadline. The Distribution Integrity Management Program (DIMP) final rule codified the Congressional mandate to install EFVs in new or fully replaced services to single-family residences. <u>Congress was correct in limiting the EFV mandate to single-family residential dwellings.</u> EFVs designed for single family resident applications are devices with relatively simple operating characteristics that a utility can readily install. Conversely, attempting to install EFVs in multi-family, commercial or industrial facilities involves a complexity far beyond the inadvertent cut-off problems AGA previously presented.

The EFV is primarily intended to shut off gas flow when service line damage occurs resulting in gas escaping at a rate that exceeds the design flow of the EFV. Gas operators generally install EFVs that have a capacity of approximately 50 to 100 percent more than the normal connected load to the customer's premises. This means that not all leaks in the gas line will cause the EFV to shut-off. Small gas leaks from corrosion or a small excavation puncture will not release enough gas to result in an

EFV closure. A typical 3,000 square foot single family residence will have a gas range, water heater, clothes dryer, and furnace that will draw from 0 to 275 standard cubic feet per hour (SCFH) at 10 psi. The EFV will generally be designed to trip only if the gas flow exceeds 475 SCFH at 10 psi. The capacity of a typical residential EFV will range from 475 SCFH at 10 psi to 840 SCFH at 60 psi. The typical single family residential service is a 1/2 to 3/4 inch polyethylene plastic line that operates up to 60 psi. There are still instances of inadvertent closures on single family residence facilities, but the uniformity of single family residences makes the installation of EFVs practical and diminishes the instances of inadvertent closures.

Industrial Services

Industrial facility EFVs represent an extreme engineering challenge. EFV manufacturers stated that they can count on one hand the number of EFVs that they have custom designed, per the request of industrial facility owners. AGA believes that attempting to mandate excess flow valves for industrial facilities like chemical plants, oil refineries, or computer chip manufacturing plants is a bad idea that will have unintended consequences that actually undermine safety. The service lines to large industrial facilities can be as large as 12 inches in diameter and operate at more than 200 psi. Gas loads from these facilities can vary dramatically throughout the day. Many industrial facilities have Environmental Protection Agency permits that require them to continuously operate flares or vapor incinerators that use natural gas to burn toxic pollutants[1]. Shutting off the gas supply with an EFV could create greater safety hazards than the release of gas the EFV was attempting to prevent. Industrial service lines are usually made of steel rather than plastic. They are more susceptible to corrosion than plastic, but less susceptible to excavation damage that could cause a rupture that would trip an EFV. If excavation damage releases gas from an industrial plant service line, it would be more appropriate to seek timely manual gas shut-off of the damaged line, after ensuring that the plant has an alternative gas supply for its safe operation.

Commercial Services

A commercial facility can range from a ten story hospital with more than a million square feet of space to heat to a 1,000 square foot dentist office. A "commercial facility" is a financial term that has no technical meaning in the pipeline safety regulatory context. As stated earlier, EFVs are designed to operate if there is a rupture to the gas service line that results in a release of gas that exceeds the capacity of the EFV, generally 50 to 100 percent more gas that the maximum connected calculated loads in the facility. It is difficult to envision excavation damage that would produce a rupture on a steel service line to a large commercial facility that would release enough gas to exceed the maximum by 100 percent. Thus, AGA believes that EFVs are not appropriate for most commercial facilities.

In addition, commercial facilities are very inclined to make significant changes to gas equipment and related gas loads without consulting the natural gas operator. These changes in gas equipment could result in the inadvertent closure of a natural gas supply for multiple days until the operator can obtain

[1] EPA has issued rules covering over 96 categories of major industrial sources, such as chemical plants and oil refineries, as well as commercial facilities like dry cleaners, http://www.epa.gov/ttn/atw/allabout.html#progress

the necessary permit to excavate the street and replace the undersized EFV. Very common examples of this are commercial strip malls. One year a commercial space can be a hair salon with a very low natural gas load. The next year the same space could be a pizza parlor with gas oven that draws a gas load many times higher than the previous tenant. This inadvertent closure would result in considerable financial impact to the customer due to loss of business. More importantly, it causes unnecessary excavation to locate the undersized EFV; and excavation is a major source of pipeline incidents and injuries.

Multi-family Dwellings

There are inherent uncertainties and complexities associated with service lines to multiple-family dwellings, such as apartment complexes, that prevent installation of EFVs beyond the single-family residential class. Multi-family apartment complexes have gas loads that can swing dramatically during the day. When you factor in the additional changes in gas load that occur from season to season, the complexity associated with the multi-family dwellings is obvious.

It should be noted that the Gas Piping Technology Committee's DIMP guidance document includes expanding the use of EFVs beyond single family residences as an additional and accelerated action that an operator may choose to mitigate the consequences of damages to distribution service lines caused by natural forces, excavation and other outside forces. This element of DIMP may go beyond single family residence facilities when the operator determines that the conditions are appropriate. This allows state regulators to review the expanded use of EFVs for operators under their jurisdiction.

The National Association of Pipeline Safety Representatives (NAPSR) has the following position on using EFVs in services other than single family homes:

- Installation of EFVs for commercial, multi-family, master meter and industrial customers must be carefully considered because of the variability in loads that can occur at such establishments. Sources of variability:
    - Commercial establishments: expansion or contraction of the business or change in commercial operation type.
    - Multi-family buildings: load peaks occurring in the mornings and evenings.
    - Master meters: either or both of the above could occur.
    - Industrial plants: very large variations likely due to high-fire on startup, low-fire during normal production and pilot when production ebbs. It is commonly believed that industrial customers will be difficult to protect using EFVs.
- A drastic change in gas load downward can cause the EFV to become oversized and, therefore, compromise the EFVs ability to provide protection; a change in gas load upward can result in an unplanned shutoff which would be intolerable for many commercial and industrial establishments.

In summary, AGA believes there are fundamental technical problems that prevent the safe and reliable installation of EFVs in most multiple-family dwellings, commercial and industrial facilities. It is unreasonable to attempt mandatory nationwide installation of EFVs beyond the single-family residential class. Technical studies need to be completed before it is reasonable to rely upon automatic devices, like EFVs, to shut off unintended gas releases from service lines to these type of facilities. Additionally, there are opportunities to thoughtfully install EFVs on a case-by-case basis in services beyond single family homes through the DIMP program.

Question 2

In your testimony, you cite that a significant cause for the reduction of pipeline incidents was the reduction in excavation incidents due to the implementation and promotion of "one call" or 811 systems. Specifically, you note that, "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. Will you elaborate on this?

AGA Response

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 few states have recently made positive changes to their one call law such as Utah, Indiana, Florida and Maryland.

Enforcement - 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 believes that consistent and effective enforcement must be designed so that all stakeholder entities are held accountable for pipeline safety.

Exemptions - AGA's position is that exemptions are detrimental to the one call process and should be eliminated at the state level in the interest of safety. It is not uncommon for states, cities, and counties to be exempt from notifying one call when they excavate and to be granted an exemption from having to mark their underground facilities. Twenty-one states currently have exemptions for their state Department of Transportation[2].

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[2] Source: One Call Systems International, a CGA committee

Mandatory Reporting of Damages - According to the 2009 One Call Systems International Resource Guide, half the states have no law requiring an excavator to notify an underground facility owner of damage made to a line. It is critical for all utilities to know when their facilities have been damaged so they can make the proper repair and avoid a leak or rupture from occurring in the future. AGA wishes to commend Congress for incorporating language in the 2006 PIPES Act requiring excavators to notify underground facility owners of damage to the facility.

AGA also commends DOT's Pipeline & Hazardous Materials Safety Administration (PHMSA) for publishing an advance notice of proposed rulemaking in 2009, which poses several important questions on how it should structure the process for federal enforcement of excavators in those states with inadequate damage prevention programs. Simply issuing this notice has resulted in discussions throughout the pipeline community to determine what actions states can take in improving their programs.

In summary, the identification of the nine elements in the 2006 PIPES Act and the implementation of 811 are significant milestones in helping pipeline operators reduce their damages from 3rd party excavators. But there is still much more work left to accomplish at the state level, in strengthening the state one call laws.

Question 3

On December 4, 2009, DOT published a final rule establishing Natural Gas Distribution Integrity Management Program requirements. The effective date of the rule was February 12, 2010 with all operators required to write and implement their programs by August 2, 2011. Can you tell the committee what percentage of your members have already implemented their programs and can you also advise what percentage of your members will meet the target deadline of August 2, 2011. (If there are difficulties meeting the deadline, what is the cause of the difficulty?)

AGA Response

The Pipeline and Hazardous Materials Safety Administration issued a final rule Distribution Integrity Management Program on December 4, 2009. The main tenets of DIMP are: know the pipeline system; identify threats; rank risks; act on the risks. Operators have been doing this as a matter of course for years. The DIMP regulation adds an overarching formality and additional requirements upon the many standards and regulations operators already implement to maintain the industry's excellent safety record. 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 1300 operators, 2.1 million miles of piping, and 70 million customers. Consequently, at the present time, few if any operators have reached the point of implementing a fully DIMP-compliant program.

AGA believes many gas utilities have already taken the preliminary steps to develop a plan to implement the final DIMP regulation. AGA is confident that all operators will develop a plan and implement the regulation by the August 2, 2011 deadline. The following information supports AGA expectations.

1. The Gas Piping Technology Committee (GPTC) has already published a guidance document to help operators implement the regulation. The document is the *Guide for Gas Transmission and Distribution Piping Systems, Distribution Integrity Management Program - Appendix G-192-8*. The GPTC is an American National Standards Institute (ANSI) accredited standards committee authorized to develop and disseminate the Guide under the designation ANSI / GPTC Z380.1. In order to fulfill its responsibilities, the GPTC established and maintains liaison with the DOT, Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety and the National Transportation Safety Board. The GPTC is comprised of federal and state regulators, pipeline operators, manufacturers, and the public.

2. AGA coordinated DIMP workshops in January 2010, less than 60 days after promulgation of the final rule, in which operators gave presentations to their peers to help other utilities implement the regulation. More than 275 people attended the workshops. State and federal regulators participated in the program to give their views on the DIMP final rule and observed how some operators plan to, or have already implemented, portions of the DIMP regulation.

3. The American Public Gas Association (APGA) Security and Integrity Foundation (SIF) developed the on-line tool, the "Simple, Handy, Risk-based Integrity Management Plan" (SHRIMP) program, to help smaller operators create a written Distribution Integrity Management Plan. The program was developed with the assistance of an advisory group that included one state pipeline safety manager from each of the five regions of the National Association of Pipeline Safety Representatives (NAPSR). The APGA Security and Integrity Foundation is a non-profit 501(c)(3) corporation dedicated to promoting the security and operational integrity and safety of small natural gas distribution and utilization facilities.

4. More than two dozen members of the Southern Gas Association and Northeast Gas Association formed a collaborative effort to develop a framework document which would provide a foundation and the guidelines for a distribution integrity management plan. The framework document is being finalized and will be available to help any gas utility build customized distribution integrity management plans that comply with the final rule.

In summary, operators are aggressively developing programs to implement this rule. Workshops have been conducted throughout the nation. Webinars and audio conferences have also been held. Software programs have been developed specifically for distribution integrity management. Guidance documents have been developed to implement the DIMP regulation. AGA is pleased to inform the committee that all affected stakeholders are working to make this an effective regulation.

2010 Pipeline Safety Act Reauthorization
Issue Paper
Large Volume Excess Flow Valves

Background: 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 they automatically close 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.

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 the Department of Transportation require natural gas distribution utilities to install an EFV on new and replacement service lines for single family residences, wherever operating conditions allow, beginning on June 1, 2008. Since this date, approximately 85 percent of new or fully replaced services in single family residential dwellings have been installed with EFVs.

Update: AGA supported the 2006 Congressional mandate for EFVs. Operators voluntarily installed EFVs before the June 2008 Congressional deadline. The Distribution Integrity Management Program (DIMP) final rule codified the Congressional mandate to install EFVs in services to single-family residences. Congress was 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 would 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, it was, and continues to be unreasonable 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.

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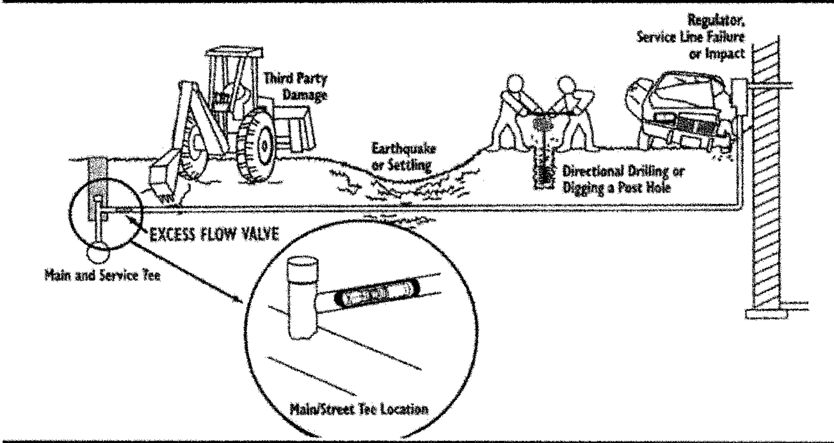
EFV Installation Location



Written Testimony
by

Dan East

Chairman
National Utility Contractors Association

before the

House Subcommittee on Railroads, Pipelines,
and Hazardous Materials

addressing

"Reauthorization of the Federal Pipeline Safety Program"

May 20, 2010

Madam Chairman, Ranking Member Shuster, and members of the subcommittee, my name is Dan East, Regional Manager for Reynolds, Inc., in Albuquerque, New Mexico. I also serve as Chairman of the National Utility Contractors Association. NUCA represents thousands of underground utility contractors, manufacturers, and suppliers who provide the materials and workforce to build and maintain our nation's network of water, sewer, natural gas, telecommunications, and construction site development industries. NUCA appreciates the opportunity to appear before you to discuss the today to discuss the reauthorization of the federal pipeline safety program.

"PIPES" Act of 2006

A primary focus of the Pipeline, Inspection, Protection, Enforcement and Safety (PIPES) Act of 2006 addressed enforcement of state pipeline one-call and damage prevention laws. The Act authorized federal dollars to improve the quality and effectiveness of state programs, and by authorizing expanded federal enforcement authority. Specifically, the ANPRM states that the PIPES Act provides PHMSA with "authority to conduct civil enforcement proceedings against excavators who damage pipelines in a state that has failed to adequately enforce its damage prevention laws."

NUCA is grateful to have participated on a task team to review annual state damage prevention grant applications for these federal dollars since the PIPES Act was enacted. Providing additional federal resources to improve state damage prevention programs, and enforcement of them, is an effective and proactive way to assist states to provide a safer work environment and enhance damage prevention of underground facilities.

Establishing a federal role in enforcement of damage prevention laws is another matter entirely. NUCA agrees with many of the stakeholders in the damage prevention community that enforcement of damage prevention laws is entirely inadequate in many states. However, often overlooked in the debate is that enforcement of *all* parties responsible for preventing damage is often inadequate, not just enforcement of excavation requirements.

Damage prevention is a two-way street – the responsibilities of those locating and marking underground facilities are equally important as those performing excavation activities. Consistent with the enforcement provisions in the PIPES Act, PHMSA's final rulemaking should ensure for a balanced approach to damage prevention enforcement.

Additionally, any damage prevention organization worth its salt recognizes the importance of "shared responsibility", as advocated by PHMSA and the highly-acclaimed Common Ground Alliance (CGA).

NUCA has been a proud member of the CGA since it was established, representing the "Excavator" stakeholder group on the CGA Board of Directors and on all working committees.

"Prohibitions" in the PIPES Act

The PIPES Act includes "Prohibitions" language that restricts persons from engaging in demolition, excavation, tunneling, or construction "without first using that system to establish the location of underground facilities," or "in disregard of location information or markings established by a pipeline facility." The legislation also requires that excavators promptly report any damage to the owner or operator caused by excavation, and to call the "911" emergency number if "the damage results in the escape of any flammable, toxic, or corrosive gas or liquid..."

The "Prohibitions" also address the locating and marking responsibilities of the pipeline operator, stating that "[a]ny owner or operator of a pipeline facility who fails to respond to a location request in order to prevent damage to the pipeline facility or who fails to take reasonable steps, in response to such a request, to ensure accurate marking of the location of the pipeline facility on order to prevent damage to the pipeline facility shall be subject to a civil action under section 60120 or assessment of a civil penalty under section 60122."

In other words, the PIPES Act requires excavators to call the appropriate one-call center, respect the markings provided by the pipeline operator, report any damage and call 911 in hazardous situations as described above. Comparably, pipeline owners and/or operators must respond to locate requests and provide accurate locating and marking of their facilities in a timely fashion (according to state law). NUCA believes that these primary responsibilities are imperative to achieving damage prevention, and that if either side fails to do its part, safety is compromised.

Federal Enforcement Only if States Neglect Enforcement Responsibilities
The "Limitation" provision in the PIPES Act restricts PHMSA from interfering with state enforcement unless PHMSA determines that the state's enforcement is inadequate to protect safety. Further, a federal rule must be promulgated that describes the criteria and procedures PHMSA will employ to determine what will be considered inadequate enforcement.

Additionally, PHMSA has publicly indicated that the agency's intent is *not* to dictate or control state enforcement practices, but will reserve the authority to enforce damage prevention laws in states deemed to have inadequate enforcement.

NUCA believes that the best place for development and enforcement of damage prevention programs is at the state level. The federal government should encourage states to adopt efficient policies, educational activities, and enforcement procedures that promote effective damage prevention programs. We do not support a permanent federal role in enforcing state damage prevention laws.

Encourage Balanced Enforcement
NUCA was pleased to see the "Prohibitions" (enforcement) section of the PIPES Act include provisions to address the responsibilities of both excavators and underground pipeline operators. We believe PHMSA should follow the approach in the proposed rule. When evaluating determining the adequacy of a state's enforcement program, PHMSA should hold enforcement of facility operators' locating and marking responsibilities in the same regard as the responsibilities of the excavator, and the proposed rule should reflect that.

Although the pipeline safety regulations already require pipeline operators to locate and mark their facilities in response to locate requests by excavators, states that evaluate their damage prevention laws and enforcement practices in response to the PIPES Act should be remind that there are two sides to the damage prevention coin. A *balanced* approach to damage prevention is fundamental to its effectiveness – excavators as well as facility operators must meet their responsibilities for successful damage prevention.

When evaluating "excavation" damage, it's important to look at who is doing the excavating. PHMSA should look at "in house" excavators employed by the pipeline company as well as "third party," or contract, excavators. "First party" and "second party" damages, although often unreported, carry the same consequences as damages caused by landscapers, home owners, and contract excavators. The PHMSA rulemaking should address this to ensure that state authorities look at the big picture.

Encourage Comprehensive Enforcement
NUCA understands that PHMSA's jurisdiction is limited to gas and hazardous liquid pipelines. However, PHMSA should encourage states to evaluate and enhance their enforcement practices for *all* underground facilities to the extent possible. State authorities responding to this regulatory initiative will certainly consider all underground facilities under their jurisdiction.

Addressing enforcement in a balanced and comprehensive manner in the proposed rule will facilitate the entire process.

Role of "Nine Elements" of the PIPES Act
The PIPES Act describes what has become widely known as the "Nine Elements of an effective damage prevention program." The Nine Elements include enhanced communication and partnership, performance measures for locators, effective training and public education, fair and consistent enforcement, efficient use of technology, and data analysis to improve performance. Although the PIPES Act focuses on enforcement, NUCA suggests that PHMSA look at the state damage prevention program as a whole. Even if thorough enforcement exists in a particular state, if the program itself does not adequately address the Nine Elements, we submit that the program itself may be inadequate.

Exemptions
"Participation" in damage prevention includes both calling the center before excavating as well as underground facility operators *belonging* to the appropriate one-call center. Membership of underground facility operators is fundamental to the damage prevention process. Exemptions currently exist in several state damage prevention laws, including for some state highway departments, railroad companies, municipalities and other stakeholders. NUCA believes that exemptions only increase the likelihood of facility damages.

Damage Reporting.
While extensive damage reporting requirements are subject to excavators in most state laws, NUCA believes that data on what are often referred to as "near misses" is absent. When underground facility operators fail to locate and mark their lines accurately, that data should be captured regardless if the facility was not hit. Even if reporting of "near misses" is required by state law, it is our understanding that these requirements are rarely enforced.

NUCA believes that damages incurred by the excavator should be collected as well. In cases where a facility is hit because of a failure to accurately locate and mark facilities in a timely fashion, that information should be collected, including any damage to the excavator's equipment or property, and any downtime incurred by the excavator while the true location of underground facilities is determined.

NUCA submits that the locating and marking requirements are too often neglected or performed inadequately by underground facility operators and/or the contract locators retained by them, and that enforcement of these requirements is rarely practiced by state authorities.

The effectiveness of any state damage prevention program is contingent on how each stakeholder meets its responsibility in the process. Effective planning and design, efficient practices by one-call centers, excavator compliance with all damage prevention requirements, accurate and timely locating and marking practices by *all* facility operators, and educated and prudent oversight and enforcement by all levels of government are needed to fully achieve damage prevention.

NUCA appreciates the opportunity to appear before the subcommittee today, and I look forward to answering any questions you may have.

BEFORE THE TRANSPORTATION AND INFRASTRUCTURE COMMITTEE
SUBCOMMITTEE ON RAILROADS, PIPELINES & HAZARDOUS MATERIALS
U.S. HOUSE OF REPRESENTATIVES

NATIONAL ASSOCIATION OF PIPELINE SAFETY REPRESENTATIVES

TESTIMONY OF PAUL J. METRO

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May 20, 2010

NATIONAL ASSOCIATION OF PIPELINE SAFETY REPRESENTATIVES

TESTIMONY OF PAUL J. METRO

BEFORE THE TRANSPORTATION AND INFRASTRUCTURE COMMITTEE
SUBCOMMITTEE ON RAILROADS, PIPELINES & HAZARDOUS MATERIALS
U.S. HOUSE OF REPRESENTATIVES

May 20, 2010

Introduction

Chairman Brown, Ranking Member Shuster, 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 Secretary 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 testify 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% of 1.9 million miles of gas distribution piping in the nation, 29% of 300,000 miles of gas transmission and 32% 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. We 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 program.

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 2 million miles of distribution pipelines under state jurisdiction. This 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 best practices developed in this area. However, new Federal requirements have significantly increased the states' compliance verification workload, particularly in the area of written procedures, implementation processes, on-going 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 50% funding of state expenditures for pipeline safety. Most recently, the PIPES Act of 2006 authorized a maximum federal funding goal of 80% of the states' program costs. Still, it can be shown that in 2009, State gas users have paid for more than 68% 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. More "test time" is needed and it seems to us, added legislative mandates on the PHMSA pipeline safety program are not warranted during this period. They may 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 both their 50% cost share and a portion of Federal share 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 towards fulfilling the goals established by Congress in the 2006 Pipes Act (49 USC Chapter 601) for PHMSA to provide grants for up to 80% of the states' yearly expenditures. FY 2010 appropriations further increased funding toward that goal.

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 three 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. PHMSA has even suggested 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 a state's 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 while the remainder is taking other measures, but 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 program entirely. PHMSA 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.

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 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 less protracted process for a decision by the Secretary to grant a waiver to a state.

It is 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 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 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% of the costs of providing the safety and compliance activities necessary. The states have 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% of the cost of the personnel, equipment, and activities for pipeline safety in that state, provided that state met the means test of its funding.

This last condition is difficult to satisfy due to the magnitude of the financial crisis that befell on most states. A waiver to individual states is being carefully considered by PHMSA to provide financial aid via federal grant funding, but the process has taken about 8 months.

It is now up to this Congressional committee to adjust the authorized funding for state pipeline safety grants over the next four 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 times of economic distress. Adequate funding authorized for state programs will directly lead to more inspectors in the field, more jobs, more frequent inspections of pipeline operators 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.

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NAPSR
06/09/10

Paul Metro's Reply to Congresswoman Corrine Brown's May 27, 2010 Letter

Question 1:

Since, as you noted in your statement, state employees make up 80% of the engineering staff involved in pipeline inspection, how do the states manage to ensure that their responsibilities to the program are upheld in a budget crisis such as the one faced in the previous year? Can you elaborate briefly on the consequences of the economic distress in the states, with examples of the impact of state cuts on pipeline safety programs?

Answer:

Every State program subscribes to the basic tenet that it is responsible to the citizens in the state to oversee and assure that all pipelines within its jurisdiction are being designed, constructed, operated and maintained in a safe manner and in accordance with all federal regulations, and for many programs, additional State regulations. For their part, state program personnel have been and are committed to doing what is necessary with less resources. The level to which this can occur varies form state to state, depending on state government policies, priorities and resource constraints. Limitations may entail legally mandated furlough days; an executive order for a statewide budget cut without exceptions; the lack of sufficient personnel due to a hiring freeze; or a moratorium on the purchase or replacement of state vehicles. Exhibit A attached here shows a few examples illustrating the details of budget cuts and impacts on the programs of the states shown.

We are seeing the impact of state budget cuts that took place during the first year of major financial woes in the states. More is yet to come. One state manager recently noted that like in a few other states, although this year his program was exempted from the cuts ordered statewide, public officials will be hard pressed to keep the exemption in place when funds for education, health and crime-fighting are being drastically cut. Although most states have fulfilled their pipeline safety obligations to date, the ability to sustain the level of effort and especially to verify compliance with the more complex mandates (such as transmission integrity management, operator qualification, public awareness communications, excavation damage prevention, distribution integrity management and control room management/human factors), is uncertain once the existing state resource limit is reached. As a bottom line, it will result in less oversight through fewer state inspections. With this scenario, we can easily see how regulations without oversight could quickly become only suggestions.

Question 2:

How important are the funding waivers now being considered by PHMSA, to the continuation of State Pipeline programs at their present level and what would be the impact if PHMSA didn't grant such a waiver?

Answer:

As stated in my written testimony document, 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 in some states, discontinuance of the entire program. For many years the states have carried the lion's share of the costs for providing pipeline safety programs within their states, and as it stands right now, state pipeline safety programs are being cut due to lack of sufficient revenue. The law appears to prohibit PHMSA from granting any federal funds if a state program is being cut to where the state's share of the cost is not maintained or grown compared to the rolling average of state funding over the previous 3 years. If a waiver is not granted, it would leave the state pipeline safety program relying only on state resources to carry out its compliance verification and enforcement. With a deficit of at least 40% in funding in a program that has already been cut, there would be a definite shortage of inspectors in the field inspecting the operators' systems, a much lower frequency of inspections, or perhaps a combination of these two scenarios. In short, the level of system risk to public, property or the environment could increase.

At this time and into the future, it is critical that the funding waivers continue to be available to a state in a timely manner until the state is able to collect sufficient annual revenue to carry its share of the cost of the pipeline safety program.

Question 3:
In your testimony, you note that "We are now undertaking projects each year that help promote "One Call" programs and other initiatives. Others have noted that not all states have "One Call" programs and that this hinders further prevention of excavation accidents.

Will some of the projects being undertaken by the "National Association" seek to ensure that "One Call" programs cover those states which do not have "One Call" or similar programs which reduce excavation incidents?

Answer:
NAPSR data indicate all 50 states have One-Call systems, although in six states, the corresponding systems' coverage is not statewide. Thanks to One-Call grants authorized by Congress, most states have applied for funding of projects that help promote use of the One-Call system in their state to further aid in preventing excavation damage incidents.

Since each One-Call project is state-specific, and due to its mission to ensure such projects are effective in carrying out damage prevention, NAPSR works with PHMSA to evaluate yearly project applications submitted by state pipeline safety program offices. These projects must fall into one or more of the categories listed in Exhibit B attached here. NAPSR members also work with the various stakeholders in the Common Ground Alliance, a national non-profit organization committed to helping further develop best practices and seeking advanced methods, techniques and equipment for the prevention of damage to underground facilities.

On a national level, NAPSR serves as a conduit to communicate best practices and lessons learned between the states to help increase the effectiveness of all state damage prevention programs. This would include such efforts as legislative activities necessary for modifying existing One-Call laws and securing enforcement authority with the most effective agency within each state.

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Exhibit A

Examples of Added Details on State Budget Cuts

Summary

Needless to say, state program budget cuts in effect today, next year and possibly beyond, will affect safety levels right now and in the future. There is also a cumulative effect in succeeding years as fewer inspections are carried out and the risk of something going wrong increases.

Starting last year, 18 state agencies have imposed work furloughs without pay, with some states mandating as many as 21 days.

A survey of state pipeline safety agencies conducted by NAPSR shows that at least half of the states are experiencing budget cuts from 2% to 25% for 1 to 4 years. This comes at a time when regulations such as

- Transmission Integrity Management, Operator Qualification, Public Awareness, are in the process of having their effectiveness verified and
- Distribution Integrity Management, Control Room Management/Human Factors and excavation damage prevention are in the beginning stages of implementation.

This will likely delay verification of the effectiveness of these rules and possibly full coverage by years, because it will involve less state inspections in the field and less interactions with the operators of gas and liquid fuel delivery systems to ensure all requirements are being met.

Details of cuts in individual states can be exemplified by what is happening in GA, OK, AZ and NY.

Examples of Individual States

GA

Change in Revenue (2008 to 2009)[*]	-19.1%	Budget Gap for 2009	23.8%
U.S. Average[†]	- 11.7%	U S. Average	17.7%

- 4-day workweek -- will affect field inspections and related office work
- 25% budget cut
- Wage freeze
- No travel or restricted travel e.g. to educational seminars
- Of the 8 inspectors on staff, 4 were given incentives for early retirement – combined 70 years experience will be lost
- Hiring freeze, so no replacement for people lost
- No replacement of vehicles used for field inspections of pipeline facilities in the state – now running high-mileage vehicles subject to breakdown and lost productive time

[*] State data reference PEW Center on The States, "Beyond California -- States in Fiscal Peril", November 2009
[†] *Ibid*

- 2,300 excavation damages/year -- depending on the situation, many of these may have to be investigated, which can be hampered because of the constraints imposed on the pipeline safety program

With these restrictions, state funded expenditures for pipeline safety are reduced below levels of previous years and the job of ensuring pipeline safety is affected.

OK

Change in Revenue (2008 to 2009)	-12.6%	Budget Gap for 2009	13.6%
U.S. Average	- 11.7%	U.S. Average	17.7%

- 8 furlough days this "Fiscal Year" till June – 8 more from July 2010 till next June
- 10% budget cut
- Overnight stays restricted for
    - Trips associated with training of inspectors
    - Conducting actual inspections
- Of 10 inspectors on staff, one retired – won't be replaced – 22 years experience lost
- 10% reduction in allowed miles per driver on field inspection duty
- No new equipment purchases (includes vehicles, computers)
- State vehicle mileage before decommissioning increased to 120,000-140,000 miles

Impact on ability to inspect the system in the state in a 3-year time frame: ¼ of system will be missed per year because of the above restrictions.

With these reduced expenditures, there is a reduction in the state program and in the absence of a funding waiver from PHMSA, federal funding would likely be unavailable.

Because of the shortage of human resources, the pipeline safety program office is unable to take on new roles in connection with added mandates that are in the beginning stages of implementation by way of the regulatory process (e.g. Distribution Integrity Management).

AZ

Change in Revenue (2008 to 2009)	-16.5%	Budget Gap for 2009	41.1%
U.S. Average	- 11.7%	U.S. Average	17.7%

- 15% budget cut
- Travel restricted to only mandatory purposes such as field inspections or required training
- Out of 12 inspectors on staff, lost 2 inspector positions
- Due to hiring freeze, the program is now staffed at its 1996 level
- There is w age freeze and
- Any salary incentives for performance have been cancelled
- No new equipment purchases
- Have 30 % of vehicle fleet due for replacement but not allowed to replace

NY

Change in Revenue (2008 to 2009)	-17.0%	Budget Gap for 2009	32.3%
U.S. Average	- 11.7%	U.S. Average	17.7%

- 10% cut
- Travel restrictions: any out-of-state travel that costs $500 or more has to have waiver issued
- Out of a staff of 26 inspectors, has lost 2 positions (in NYC inspector staff)
- Hiring freeze
- Wage freeze
- No new equipment purchases
- Aging vehicle fleet cannot be replaced

With these cutbacks, there will be a reduction in number of safety aspects inspected during field inspections of operator facilities.

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Exhibit B

One-Call Project Priority List

A. PRIORITY 1

1. Compliance Enforcement
    - Legal assistance with enforcement actions
    - Cost of enforcement and/or complaint investigations
    - Cost of enforcement actions
2. State agency collection and analysis of data
    - One Call center statistics
    - One Call center membership
    - Compliance/Noncompliance statistics
    - Causes of noncompliance
    - Frequency, cause, and consequences of dig-ins
    - Identification of problem areas or individuals
    - Incorporation of excavation damage data tools (such as DIRT, etc.) into state monitoring and compliance program *new
    - Submission of state-collected excavation damage data to other data collection systems (such as DIRT) *new
3. State Legislation and Rulemaking
    - Obtaining input from affected interests
    - Assistance drafting language
    - Testimony before legislative/rulemaking bodies
    - Studies to identify legislative needs
4. Implementation of One Call Laws and Regulations**
    - Start-up costs for the state agency only, mandated by new law or rules
    - Equipment (including computer programming and software)
    - Records systems and databases
    - Procedures
    - First-year information campaign on new/changed law or rules

** A state cannot request grant funds to implement proposed legislation - the legislation must have already been passed.

B. PRIORITY 2

1. One Call Membership Initiatives for Operators, such as:
    - Initial membership fees
    - Fax machines
    - Computer equipment
    - Communication improvements
    - E-mail access
    - Dedicated phone line
    - Locating equipment and training
2. Consolidation of Multiple One Call Centers (only costs incurred by the state agency)
    - State agency expense to encourage consolidation
    - One Call Center consolidation expenses
    - First year promotion of new one-call center and phone number

3. Training of state inspection or enforcement personnel in -
   Facility locating methods and technology
   Provisions of state One Call law or regulations
4. Equipment to support on-going enforcement program (including computer programming and software.)
5. Location Capabilities
   Development and/or conduct of training for locators
   Field trials or demonstrations of new technology locating equipment
6. Efforts to encourage operators to contribute to data collection systems such as DIRT

C. PRIORITY 3

1. Development and/or conduct of state-provided training programs for excavators
2. Development and/or conduct of state-provided training programs for operators
3. Development and/or distribution of promotional items or materials
4. Development and/or conduct of damage prevention awareness campaigns, such as:
   Public service announcements
   Informational mailings
   Advertisements
   One Call center promotions
   Booths/exhibits
   811 awareness campaigns

5. Record retention and recording capabilities for one-call notification systems; and making the data available to the state...

NON-ALLOWABLE COSTS

Lobbying
Travel to conferences
Costs billed to state pipeline safety or other grants
Reimbursed costs
Equipment for One Call centers
Mapping or map enhancement by operators
Subsidizing usual and ordinary One Call center functions or activities

UNITED STATES DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

Hearing on
Implementation of the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 and Reauthorization of the Pipeline Safety Program

Before the
Committee on Transportation and Infrastructure
Subcommittee on Railroads, Pipelines, and Hazardous Materials
United States House of Representatives

Written Statement of Cynthia L. Quarterman
Administrator
Pipeline and Hazardous Materials Safety Administration
U.S. Department Of Transportation

Expected Delivery 10:00 a.m.
May 20, 2010

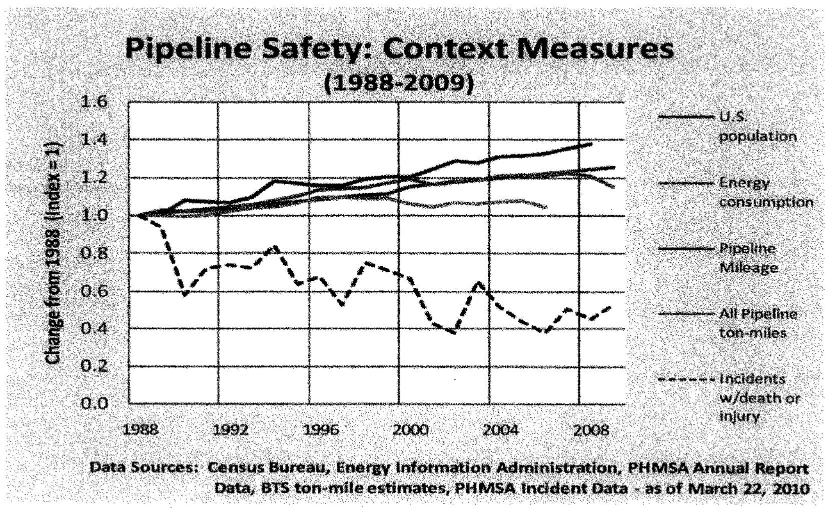
Chairwoman Brown, Ranking Member Shuster, members of the subcommittee, thank you for the opportunity to appear today. Safety is Secretary LaHood's top priority and it is my top priority as well. Our employees are also committed to reducing risks in pipeline transportation as their highest priority. We want our employees to bring up new and creative ideas and to challenge each other and supervisors so that the best safety solutions are put forward. As our nation's reliance on the safe and environmentally sound transportation of energy fuels and 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.

We continue our work with many governmental partners to promote safety. The National Transportation Safety Board (NTSB), the Department's Office of Inspector General (OIG) and the Government Accountability Office (GAO) all have a vested interest in the safe and reliable operation of the nation's pipeline infrastructure. For years we have worked aggressively to be responsive to all of their recommendations. We have taken seriously each and every recommendation that they have made to PHMSA. Indeed, we implemented a deliberate approach to responding to their recommendations. Accomplishments include closing the three OIG recommendations; significant progress on GAO recommendations on incident reporting with the last action due out this summer; and making 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 these recommendations and we are currently working to address the remaining and additional recommendations. We do not have any open unacceptable recommendations.

I am pleased to discuss the PHMSA Pipeline Safety Program and to brief you on the significant progress made since the passage of the PIPES Act in December, 2006. We also look 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 that has resulted in safer communities today. The pipeline safety record is good. Over the past 20 years, all the traditional measures of risk exposure have been rising – population, energy consumption, pipeline ton-miles. At the same time, the number of serious pipeline incidents – those involving death or injury – has declined by 50% over the last twenty years. As indicated in the chart below we aim to continue this long-term trend.



The following is 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.

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 human factors 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 increasing results from our effective systems risk management approach, which this Subcommittee helped devise.

1. PHMSA Has Increased Enforcement, Increased Transparency, and Improved 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 the number of federal inspectors, as well as state inspectors. In 2006, PHMSA had 141 pipeline staff. That increased to 173 by the end of 2009, including a significant increase in inspection and enforcement staff, and we expect to have 206 pipeline staff by the end of 2010.

Also, PHMSA has embraced enforcement transparency by leveraging its website and databases to provide on-the-spot information to stakeholders. Within months after the Act was signed into law, we launched our enforcement transparency website. As we reported in our 2008 testimony before this Subcommittee, PHMSA has made tremendous strides in improving the transparency of its enforcement process. The enforcement transparency web site 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 web site 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 economic resources, the PIPES Act also gave PHMSA a much needed enforcement tool – the Safety Order. On January 16, 2009, PHMSA published a final rule establishing the process by which PHMSA will conduct 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 we had hoped, the certification requirement has placed an increased emphasis on management's accountability and the importance and 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 in the summer of 2010. 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 that ultimately resulted 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. PHMSA took that direction and acted comprehensively.

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

Pursuant to the authority granted in the PIPES Act, PHMSA issued a final rule on December 4, 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 extent 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. That said, the rule establishes simpler requirements for master meter and small liquefied petroleum gas operators, reflecting the relative risk of these smaller pipeline systems.

PHMSA made tremendous efforts getting ready for the establishment of DIMP. We have consensus standards, guidance, training, IT systems, and data to increase our understanding of risk and provide effective oversight. 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 for 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.

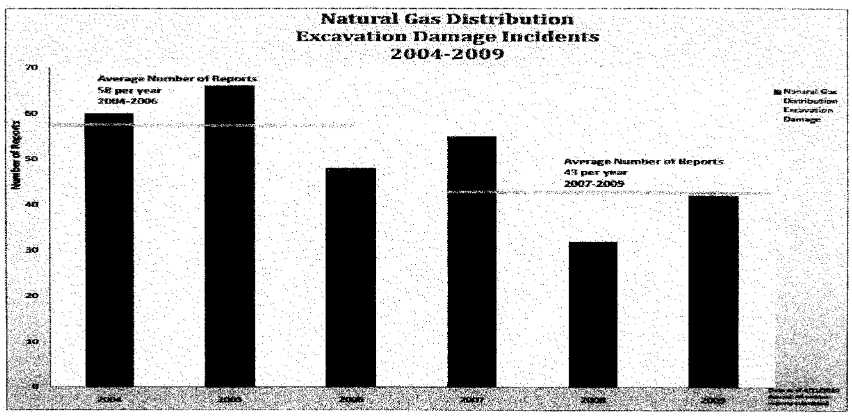
1. PHMSA Has Strengthened Its Assistance to States.

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% of intrastate hazardous materials liquid pipelines and 20% of the interstate gas pipelines. PHMSA maintains primary responsibility for the remaining pipelines, including all interstate hazardous liquid pipelines and 80% of the interstate gas pipelines. States employ approximately 63% of the inspector workforce. The expansion of the Federal pipeline safety initiatives has increased the cost of and 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, increasing 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% 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% funding of the state pipeline safety programs. These partnerships have proven to be one of PHMSA's strongest assets in helping to strengthen 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 accidental breaches and failures by third-party excavators. While excavation damage is 100% 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 dollars 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 has also used 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 $1.5 million funding assistance for CGA's 811 advertising campaign.

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." 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 Addressed the Additional Regulatory Enhancements and Undertook 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 took action to regulate rural low-stress hazardous liquid pipelines to the same standards as other hazardous liquid pipelines. Low stress pipelines operate at or below 20% 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 stressed that PHMSA needed 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 8 5/8 inches or greater in diameter and located in or within a ½-mile of an unusually sensitive area. With Phase I accomplished, PHMSA is now working on issuing a notice of proposed rulemaking for Low Stress II. Low Stress II will bring the remainder of the unregulated low stress pipelines under our safety regulation.

Emergency Waiver of Pipeline Safety Requirements. The PIPES Act provided authority allowing 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 provided 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 and that PHMSA is now responsible for regulatory oversight and enforcement of these lines.

OIG Recommendations Regarding Pipeline Security Annex. After the OIG completed its statutorily required report to Congress on DOT actions to implement the pipeline security annex between DOT and the DHS, PHMSA addressed all three recommendations in the report. 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. On June 23, 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. In our report to Congress, we found that existing regulations are generally sufficient to achieve safety and environmental protection goals but that 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 and sent Congress legislative recommendations necessary to implement the conclusions of that report. PHMSA reviewed its experience with gas transmission operators' implementation of integrity management and the GAO report on this subject. We recommended that Congress amend the law to provide us the authority to promulgate risk based standards for determining pipeline reassessment intervals. As a risk-based, data-driven organization, we continue to believe that a scientific basis is the best way to determine safety decisions and the allocation of resources. We have demonstrated that PHMSA and its state agency partners have the ability, experience, and training to review the adequacy of engineering justification that would be presented to us by operators seeking to vary the reassessment interval. In January 2008, we held a public meeting on the technical basis for making decisions on assessment intervals. The bottom line is that we believe these decisions should be made on a case-by-case basis, one operator at a time, and segment by segment, so that relevant operating characteristics can be considered along with individual operator performance.

II. BUILDING ON A SOLID FOUNDATION

As we continue to advance pipeline safety, we believe we have a solid foundation to build on. We have accomplished a great deal, but much remains to be done to implement the promise of the PIPES Act. 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.

We have accomplished many goals with our state partners; however, we need to make sure that our state partners continue to receive the resources they need to implement not only damage prevention initiatives but the distribution integrity management program. We hope that the grant programs to states and communities supported and funded in the PIPES Act receive continued support.

PHMSA also intends to update its enforcement strategy and penalties to deter future non-compliance and incentivize better performance. We continue to make full use of the increased 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 its proposed pipeline safety civil penalties, and the average per case has more than tripled. Specifically, between 2004 and 2006, we proposed $10 million in civil penalties, with an average proposed civil penalty of $57,000; and, between 2007 and 2009, we proposed $19 million in civil penalties and an average proposed civil penalty of $183,000. Furthermore, the average penalty proposed per individual violation[1] has increased from approximately $16,000 in 2002 to an average of approximately $100,000 today. As a result, in major cases we are now limited by the cap of $100,000 per violation/$1,000,000 series in our penalty provisions. As integrity management programs take hold, we intend to ensure operator accountability through strong, effective enforcement.

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 more, and better, data will help us make risk based informed decisions along the way as we look to see what other regulatory gaps need to be strengthened or closed. We will also continue to monitor the effectiveness of integrity management programs and the need for additional regulatory enhancements.

With the anticipated increase in transportation of new products with properties 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 will 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

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

federal agencies to forecast the transportation implications from the inception of marketing new fuels, as part of a systemic 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 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.

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.

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Questions from Chairwoman Brown
May 20, 2010 Hearing on
"Implementation of the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 and Reauthorization of the Pipeline Safety Program"
(Responses as of June 4, 2010)

Q1: We recently learned that the Minerals Management Service has a policy to inspect an oil rig at least once per month. How many staff are responsible for inspecting pipelines at PHMSA? Does PHMSA have an inspection policy similar to MMS? How often does an inspector get to the same operator?

A: PHMSA periodically reports to Congress staffing levels for Inspection and Enforcement positions. In fiscal years 2009 and 2010, Congress authorized new pipeline safety Inspection and Enforcement positions for PHMSA. The influx of new positions combined with resignations, retirements, and promotions results in vacancies for some of the positions. Each of the vacancies in our Inspection and Enforcement Program is currently either being advertised, applications are being reviewed, or are in the process of being filled. The table below shows the number of positions whose primary responsibility is conducting pipeline safety inspections (does not include enforcement staffing at PHMSA/HQ):

Office	Positions	Filled as of 6-3-2010
Central Region	27	18
Eastern Region	15	13
Southern Region	15	11
Southwest Region	29	23
Western Region	27	23
Total	113	88

No, PHMSA does not have an inspection policy similar to MMS. PHMSA employs a risk-ranking algorithm to schedule pipeline safety inspections. The primary risk factor in the algorithm is "time since last inspection." Hence, there is no consistent frequency for the inspections. Risk factors other than "time since last inspection" increase the inspection frequency for some pipelines and decrease it for others. However, PHMSA has inspected 85 percent of all operators within the past three years, and is continuing to ensure the remainder are inspected.

Q2: In the FY 2010 budget, President Obama requested funding for 135 full-time pipeline inspectors for PHMSA (in compliance with our law). Congress appropriated funding for all of the requested positions. However, PHMSA only added 18 positions in FY 2010, bringing the total number of inspectors actually on-duty today to about 88 – 47 inspectors short of the 135 required in the law. Why hasn't PHMSA hired the full 135 inspectors? What happened to that funding?

A: The Pipes Act authorized 135 inspection and enforcement full time positions beginning in FY2010. PHMSA currently has 103 inspection and enforcement staff on board. We are aggressively recruiting to fill the remaining 33 positions and hope to fill many by year's end. The FY 2010 Appropriations Act provided the additional funding that PHMSA requested for the 18 new positions authorized in FY 2010. PHMSA is increasing its Federal pipeline safety inspection and enforcement (I&E) personnel to 136 full-time positions, one (1) position above the 135 required by the PIPES Act.

Q3: My understanding is that PHMSA has safety jurisdiction over offshore transportation pipelines running across the Outer Continental Shelf. What sort of inspections are conducted on these pipelines? How often do your inspectors inspect these lines? How many of your inspectors are fully qualified to inspect these lines?

A: PHMSA inspections are generally classified as Programmatic or Unit inspections. Programmatic Inspections evaluate the written procedures required by PHMSA regulations. Operators generally create these procedures to apply to both onshore and offshore pipelines. Unit Inspections focus on evaluating records demonstrating operator compliance with the written procedures. Unit Inspections generally include an inspection of some portion of the infrastructure associated with the Unit to ensure that the written procedures are effectively implemented in the field. Offshore pipelines have also been included in pilot tests of the Integrated Inspection process, which uses a risk analysis to determine the appropriate combination of programmatic and field inspections.

PHMSA's risk ranking algorithm for inspection scheduling results in varying inspection frequencies for offshore pipelines. More than three quarters of all offshore pipeline units have been inspected since 2008 with more planned during the rest of FY2010.

Over the past nine years, the percentage of PHMSA Unit Inspections on offshore pipelines has been at least twice the rate of corresponding onshore mileage. For hazardous liquid pipelines, offshore mileage is 3% of the total mileage, but 6% of hazardous liquid Unit Inspections were on offshore lines. For gas transmission, offshore mileage is 2% of the total, but 7% of gas transmission Unit Inspections were on offshore lines.

As requested by the Committee I am ensuring that we are taking all reasonable measures to ensure the safety of offshore transportation pipelines running across the Outer Continental Shelf.

PHMSA pipeline safety inspectors are simultaneously qualified to conduct safety inspections of both onshore and offshore pipelines. Qualification as a PHMSA pipeline safety inspector generally takes three years to complete, and only fully qualified inspectors can lead an inspection.

Q4: In yesterday's hearing, we learned that MMS relies heavily on industry certifications. I understand that PHMSA has established an integrity management process for gas and hazardous liquid pipeline operators to evaluate the condition of their pipelines.

- **Can you describe in detail this process, tell us how many hazardous liquid and natural gas pipeline miles are covered (compared to total pipeline mileage) under the integrity management requirements, and tell us how often the companies have to conduct these integrity management assessments?** ***[Note: A witness on the second panel says the program only covers 44% of all hazardous liquid pipelines and 7% of all natural gas transmission pipelines.]***

- **How specifically does PHMSA verify that the pipeline companies have: (1) properly identified all the pipeline segments that could affect a high-consequence area; (2) properly identified the risks associated with each pipeline segment; (3) properly evaluated and ranked those risks; and (4) used the most appropriate tools for conducting the inspections? Please provide as much detail as possible. Also, if there are reports, what specific information is provided in the report to PHMSA? Please provide a sample of what PHMSA receives.**

- **According to your website, PHMSA must be informed and the pipeline companies must document the condition of their pipe. Specifically, how does PHMSA verify the accuracy of what the companies submit to the agency? And then how does PHMSA verify that the appropriate repairs have been conducted? Has PHMSA verified – beyond just reviewing written reports developed by the pipeline companies – that the companies actually made the 6,800 immediate repairs and 25,000 other repairs that they reported to PHMSA?**

A: *This question was subdivided into 3 separate parts. Responses for each part are provided separately.*

Bullet 1 Response

In 2000 and 2002 PHMSA promulgated the integrity management rules that establish requirements for managing pipeline integrity in high consequence areas (HCAs) for hazardous liquid pipelines. In 2003, integrity management requirements for natural gas transmission lines were established. The rules require that the company put in place formal integrity management programs to manage pipeline integrity. Key program elements of these integrity management programs are established in these rules. These program elements include:

- Identifying pipeline segments that could affect HCAs in the event of a release;
- Developing and implementing a Baseline Assessment Plan to conduct integrity assessments on these HCA-affecting pipeline segments;
- Reviewing the results of the integrity assessments, including the integration of other data sources to better understand pipeline conditions;
- Remediating potentially injurious pipeline anomalies identified through assessments;
- Integrating assessment results with other information in a risk analysis that fully characterizes the risks to safe pipeline operation;
- Identifying and implementing additional preventive and mitigative measures to address the highest risks identified through risk analysis;
- Continually evaluating pipeline risks and periodically conducting re-assessments of pipeline segments that could affect HCAs on an on-going basis; and
- Measuring integrity management program performance and making improvements as necessary.

A key element of these integrity management programs is a requirement to regularly conduct integrity assessments on pipelines where a failure might impact people, property, or the environment in an HCA. Assessments can be performed through the use of intelligent in-line inspection tools (aka "smart pigs"), hydrostatic pressure testing, or other PHMSA-approved techniques. The integrity management rules require operators to assess the portions of their pipelines that could affect HCAs at regular intervals and repair any potentially injurious anomalies. For hazardous liquid pipelines, operators have already completed the baseline assessments required by the regulations and are now conducting re-assessments of these pipeline segments. Operators must determine the assessment interval based on the risk represented by the pipe segment. However, in no case can the assessment interval exceed five years.

For natural gas transmission pipelines, operators have until December 17, 2012 to complete their initial baseline assessments. Subsequent reassessment intervals must be risk-based; however, in no case can the assessment interval exceed seven years. Many operators have already completed their initial baseline assessment and have begun conducting reassessments.

There are approximately 76,000[1] miles of hazardous liquid pipelines that can affect high consequence areas should a failure occur. This represents 44% of the total hazardous liquid pipeline mileage.

There are approximately 19,000[2] miles of gas transmission pipelines that can affect high consequence areas should a failure occur. This represents 6.4% of the total gas transmission pipeline mileage. [3]

As a result of the integrity assessments required by the regulations, not only are these most sensitive sections of pipelines now more secure, but the assessments required by the regulations are providing additional protection beyond HCAs. While operators are only required to assess the pipeline segments that can affect HCAs on a fixed schedule, they have in fact smart pigged, pressure tested, or otherwise assessed significantly greater portions of the pipeline infrastructure, thus increasing safety in locations beyond the originally designated HCAs.[4]

Bullet 2 Response

PHMSA conducts rigorous, comprehensive inspections of operator integrity management programs to assure they have complied with all regulatory requirements including the identification of segments that could affect HCAs, the identification, evaluation, and ranking of risks associated with these segments, and the selection of the appropriate integrity assessment methods. These inspections are conducted using a comprehensive set of protocols that support an in-depth review of all operator program elements. The protocols for hazardous liquid and natural gas transmission integrity management inspections are available on PHMSA's web site. These protocols not only check for compliance with the regulation's prescriptive requirements, but also support a detailed audit of an operator's management and analytical systems, processes, and practices to manage pipeline integrity. Comprehensive guidance material is provided to federal and state inspectors to assist in the application of the protocols and in the evaluation of operator integrity management programs. All federal and state inspectors conducting integrity management inspectors receive advance training to foster rigor and consistency.

To date PHMSA has inspected the integrity management programs of all the operators it regulates at least once. PHMSA has inspected all major hazardous liquid pipeline operators a second time to assure they are continuing to manage pipeline integrity and making progress in building the robust integrity management programs PHMSA expects. To date, more than 73 hazardous liquid operators have received a second comprehensive integrity management program inspection, and 13 operators have received a third such inspection. All major natural gas transmission pipeline operators have received an initial inspection and three have already received a second comprehensive program inspection. [5]

Operators are required to submit integrity management program performance measures to PHMSA. Hazardous liquid pipeline operators submit annual reports that include the number of pipeline miles assessed during the year, the number and type of repairs made, and other information about the assets they

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[1] 2008 Annual Report Data from PHMSA's Liquid IM Performance Measures Report· 173, 546 total miles, and 76, 203 miles that could affect HCAs. (May 28, 2010)

[2] 19,098 could affect miles based on reports through December 31, 2009 from PHMSA's Gas Integrity Management Performance Reporting (May 28, 2010). Total onshore gas transmission mileage is 297,325 from PHMSA 2008 annual reports. Offshore gas transmission does not contain population areas, therefore no HCAs.

[3] It may be helpful to note here as validated by GAO, that approximately two thirds of the US population theoretically affected by a natural gas transmission pipeline failure live in these HCA's [3]

[4] In 2008, it was estimated that some 86% of the hazardous liquid pipeline mileage has been actually been assessed. This number was determined by estimating the miles assessed from miles "inspected" data reported in the Annual Reports. This figure was included in the Hazardous Liquid Integrity Management Status Report· Conclusion of Baseline Assessment Period for Major Liquid Operators Because it is an estimate, it is not included in this response A comparable estimate for gas transmission lines has not been made.

[5] IM Inspection data from the integrity management database, June 1, 2010.

operate. Gas transmission pipeline operators are required to submit integrity management performance measures semi-annually as well as an annual report providing data on their pipeline infrastructure. Copies of the hazardous liquid and gas transmission annual report forms are attached. The actual reports submitted by individual hazardous liquid operators and individual gas transmission operators can be viewed on PHMSA's web site.

Bullet 3 Response

Both the hazardous liquid and gas transmission integrity management rules require periodic reporting of operator performance measures on the integrity assessments they conduct and the repairs that are made. Company executives are required to certify the accuracy of the performance measure reports to PHMSA. However, PHMSA does not rely solely on the company's statement. PHMSA's inspectors also review the integrity management performance measures submitted by the operators during integrity management inspections. PHMSA's inspection protocols contain explicit direction to validate the operator's approach for reporting assessment and repair-related data when conducting integrity management program inspections.

While inspector resources preclude conducting a comprehensive verification of all operator-submitted data (e.g., typically dozens and sometimes hundreds of repair records), checking selected data elements for conformance with the reporting guidance is performed. For example, inspectors are now checking repair records for all immediate repair conditions (the most serious anomalies), and selected other actionable anomalies. Inspectors record on the protocol form any problems or concerns identified with the integrity management performance measure information. When discrepancies or problems are found, operators are directed to amend their performance measure report submissions to correct these deficiencies.

Since the beginning of the integrity management inspections in late 2002, PHMSA inspectors have taken a systematic, disciplined approach to assuring that operators identify and repair pipeline anomalies in a timely manner. Using the inspection protocols, PHMSA inspectors assure operators:

- Perform a thorough and effective review of integrity assessment results to identify actionable anomalies.
- Perform a timely assessment results review to assure anomalies are identified promptly after an assessment is performed and within the time limits established in the integrity management regulations.
- Remediate anomalies in a timely manner to assure they are repaired as soon as practical and within the time limits established in the regulations.
- Use appropriate remediation methods for addressing the specific types of anomalies identified.

To assure repairs are made, inspectors review:

- Pipeline repair procedures;
- Pipe excavation and remediation records that specify the repair or remediation actions taken by the operator to return the pipe to a safe operating condition;
- Non-destructive examination results and other evidence and data characterizing the pipeline condition;
- Photographs taken during the pipeline repair and excavation work; and
- Documentation of the repair method in compliance with the regulations and applicable industry standards.

Finally, PHMSA also conducts integrity management field verification inspections. These inspections are performed to witness first-hand integrity management activities in the field. These field verification inspections involve observing first-hand pipeline repairs whenever practical. Inspectors verify that operators are following their procedures for locating and exposing the anomaly, measuring the anomaly and characterizing the pipeline condition, and performing the pipeline repair. Inspectors assure that the appropriate repair methods are used, that repairs are completed within the time frame required and appropriately documented. More than 120 field verification inspections[6] have been performed since 2006. In addition to these field verification inspections, inspectors also observe operator pipeline repair activities during the routine standard inspections if the opportunity is available. Both DOT's OIG and the GAO have reviewed PHMSA's integrity management oversight program.

Q5: A witness on the second panel testified that pipeline operators are not required to conduct integrity management inspections on 56% of their hazardous liquid pipelines and 93% of their natural gas transmission pipelines (representing over 365,00 miles of pipelines) because those pipelines are not in a High consequence Area (HCA) as PHMSA has defined an HCA. Do you agree with that? If not, what is your assessment?

- **In 2002, there was a serious accident in Carlsbad, New Mexico, where a gas pipeline ruptured and burned for 55 minutes, killing 12 people that were camping near the pipeline. Under existing integrity management regulations, would the operator be required to conduct integrity management assessments of this pipe? [The answer is no because they don't live in a High Consequence Area.] How many pipeline deaths since 2000 have occurred outside of High Consequence Areas?**

- **As a follow-up, a witness on the second panel proposes to increase the pipeline miles (beyond just those that affect HCA's) that the pipeline operators have to assess. Do you agree with that or disagree with that proposal?**

A: The observation by the panelist is technically correct. Pipeline operators are required to conduct integrity assessments on portions of their pipelines that could affect HCAs. For hazardous liquid pipelines, this is approximately 44% of the total liquid line mileage. For gas transmission pipelines, approximately 6.4% of the total pipeline mileage could affect HCAs.

While operators are only required to assess pipelines that could affect HCAs, in practice operators evaluate a much greater percentage of pipelines when they conduct these assessments. This is due largely to the practical constraints associated with running in-line inspection tools (aka "smart pigs"). Because of the location of the launchers and receivers used to insert and remove smart pigs from the pipeline, relatively long sections of pipeline are inspected when these tools are used. These sections generally contain portions of the pipeline that can affect HCAs and portions of the pipeline that do not affect HCAs. Thus while conducting assessments of the portions of their lines that affect HCAs, operators running smart pigs also obtain data on the condition of their pipelines in other areas and take action to assure the integrity of those sections outside of HCAs.

The location where the Carlsbad accident occurred would not be identified solely on the basis of adjacent population as a high consequence area under the gas integrity management rule requirements. However, it would have been classified as an HCA "identified site" where people were known to congregate. Operators first began to identify their high consequence areas and report whether accidents occurred in these areas in 2002. In the eight year period from 2002 through 2009, seven fatalities have occurred outside of high consequence areas for gas transmission pipelines. Four of these fatalities were pipeline operator employees or contractors involved in work-related activities, and three of these fatalities were members of the public. For hazardous liquid pipelines, there have been eleven fatalities outside of high

[6] 124 IMP Field Verification Inspections recorded in SMART Inspection data as of May 30, 2010. IMP Field Verifications were first performed in 2006.

consequence areas over this same period. All but two of these fatalities involved pipeline operator employees or contractor personnel involved in work-related activities.

PHMSA believes that the risk-focused approach employed in establishing priority assessment and repair in High Consequence Areas was prudent, and that the integrity management investments it drove were clearly needed. We believe these investments have provided important public and environmental benefits. We also believe that a lot of work has been done by pipeline operators outside of the HCA's due to the over testing they have done. Nonetheless, PHMSA believes that more needs to be done beyond HCA's, but not at the expense of people and environmental resources in the HCA's currently covered by our integrity management regulations. We believe this topic merits additional consideration and technical study, and we plan to do this over the next few years.

Q6: It seems clear now that BP wasn't really prepared to respond to a worst case scenario in the Gulf as they stated. I realize that an offshore drilling operation poses different challenges than transportation of product, but what I want to know is: Does PHMSA evaluate whether pipeline companies are prepared to deal with worst case scenario spills? If so, how? And how do the pipeline companies demonstrate that to PHMSA?

A: PHMSA evaluates hazardous liquid pipelines under the Oil Pollution Act of 1990, section 4202, National Planning and Response System. PHMSA has promulgated its related regulatory requirements in 49 CFR Part 194. In accordance with the enabling legislation, PHMSA requires operators of onshore[7] oil pipelines that could discharge into a navigable waterway[8] or adjoining shoreline to submit facility response plans to PHMSA for responding to worst case discharges of oil. If applicable, PHMSA approves facility response plans before pipeline operators (subject to the Oil Pollution Act of 1990) may operate pipelines. If a new or different operating condition or information would substantially affect the implementation of a response plan, the operator must immediately modify its response plan to address such a change and, within 30 days of making such a change, submit the change to PHMSA. Pipeline operators must review and resubmit their plans every five years, and amend facility response plans as necessary. PHMSA must approve the amendments when significant changes are made to the facility response plans.

Facility response plans must: (1) be consistent with the National Contingency Plan and Area Contingency Plans; (2) name the qualified individual with full authority to implement removal actions and require immediate communications between the qualified individual, the Federal official, and spill responders; (3) name and ensure by contract (or other means that PHMSA approves) private personnel and equipment necessary to remove a worst case discharge (including a discharge resulting from a fire or explosion) and to mitigate or prevent a substantial threat of such a discharge; (4) describe the training, equipment testing, periodic unannounced drills, and response actions of persons at the facility, to be carried out under the plan to ensure the safety of the facility and to mitigate or prevent the discharge or the substantial threat of the discharge; (5) be updated periodically; and (6) be resubmitted for approval of each significant change. PHMSA reviews the facility response plans and determines whether they meet the Oil Pollution Act of 1990 requirements. When the facility response plan meets the Oil Pollution Act of 1990 requirements, PHMSA approves the facility response plan. Subsequent to their approval, PHMSA inspectors verify that the plans are maintained and that required exercises of the plan are conducted.

[7] As defined in 49 CFR 194 5, *Onshore oil pipeline facilities* means new and existing pipe, rights-of-way and any equipment, facility, or building used in the transportation of oil located in, on, or under, any land within the United States other than submerged land

[8] As defined in 49 CFR 194.5, "*Navigable waters* means the waters of the United States, including the territorial sea and such waters as lakes, rivers, streams; waters which are used for recreation, and waters from which fish or shellfish are taken and sold in interstate or foreign commerce."

PHMSA helps lead the National Preparedness for Response Exercise Program. The Exercise Program is designed to strengthen oil spill prevention and response. PHMSA was one of the designers, hosts, and evaluators of the Spill of National Significance 2010 Exercise. In addition, operators of pipelines subject to the Oil Pollution Act of 1990 must conduct annual table top exercises. Under section 7001 of the Oil Pollution Act of 1990, PHMSA is one of thirteen Federal Departments and Agencies that serve on the Interagency Coordinating Committee on Oil Pollution Research. The Interagency Committee's two purposes are (1) to prepare a comprehensive, coordinated Federal oil pollution research and development plan; and (2) to promote cooperation with universities, research institutions, State Governments, other nations, and industry through information sharing, coordinated planning, and joint funding projects. Preventing, mitigating, and responding to worst case discharges and learning lessons from the Deepwater Horizon incident was one of the key topics addressed at the May 19, 2010 Interagency Committee Public Meeting.

Lastly, in light of the Deepwater Horizon spill, PHMSA is taking steps to direct hazardous liquid pipeline operators to reevaluate the adequacy of their current oil spill preparedness and response capabilities and to step up efforts to exercise their contingency plans with affected emergency responders.

Q7: One of the key mandates we included in the PIPES Act as a result of the two BP oil spills in 2006 was a requirement that all low-stress hazardous liquid pipelines be regulated in the same manner as other hazardous liquid pipelines. In June 2008, PHMSA issued a Final Rule that regulated 803 miles of low-stress pipelines, but more than 1,300 miles remain unregulated. At our last pipeline safety hearing in June 2008, former Administrator Carl Johnson said the second rule would be on the streets in Fall 2008. It's been two years since that hearing and we are still waiting for the second rulemaking. When is PHMSA going to issue this rule?

A: PHMSA anticipates publishing a notice of proposed rulemaking proposing to subject the remaining 1,300 miles of rural low stress pipelines to the Pipeline Safety Regulations in or before July 2010, and we plan to publish a final rule early next year.

Q8: We learned from last week's hearing that MMS has extensively "incorporated by reference" standards that are developed by industry organizations in their regulations. Meaning, industry is essentially writing its own regulations.

According to your agency, corrosion is the second leading cause of pipeline incidents. A November 2008 report entitled "Pipeline Corrosion," which was conducted at PHMSA's request, stated: "PHMSA often incorporates standards in whole or in part that are developed by various industry consensus organizations in their regulations." The authors of the report – Michael Baker and Raymond Fessler – provide a list of those "standard development organizations" whose standards are often incorporated in PHMSA regulations by reference:

- **National Association of Corrosion Engineers**
- **American Society of Mechanical Engineers**
- **American Petroleum Institute**
- **American Society of Testing and Materials**
- **American Society for Nondestructive Testing**
- **American National Standards Institute**
- **International Organization for Standardization**
- **Det Norske Veritas**
- **British Standards Institute**

How many private sector consensus standards have been incorporated by reference in your regulations - both pipelines and hazmat? Follow-up:

- **Can you describe the process by which these "private sector consensus standards" are developed in general terms, including the makeup and expertise of the individual participants in the process? Do the industry groups include non-industry safety professionals? Does PHMSA actively participate in the process? Further, how does PHMSA evaluate the adequacy and scope of any particular "private sector consensus standard"?**

- **If PHMSA chooses to incorporate by reference in their regulations any particular industry-developed standard, is the regulation limited to that specific version of the industry standard? Meaning, what happens with your regulation when the industry changes the standard? Does it go back out for notice and comment?**

A: PHMSA has incorporated by reference all or sections of 69 separate standards into the Pipeline Safety Regulations and 151 separate standards into the Hazardous Materials Safety Regulations. The process we use to incorporate standards is explained in more detail below, but we point out that when PHMSA believes some aspect of a standard does not meet PHMSA's directive, it will not incorporate the new edition. In the most recent periodic update to technical standards rulemaking PHMSA did not propose to incorporate seven revised editions due to objections of PHMSA technical committee members. PHMSA explains why the revised version was rejected in the rulemaking.
The National Technology Transfer and Advancement Act of 1995 (Pub. L. 104-113) directs Federal agencies to use technical standards and design specifications developed by voluntary consensus standard bodies instead of government-developed technical standards, when practicable. The Office of Management and Budget (OMB) Circular A-119: "Federal Participation in the Development and Use of Voluntary Consensus Standards," sets the policies on the Federal use of voluntary consensus standards. As defined in OMB Circular A-119, voluntary consensus standards are technical standards developed or adopted by voluntary consensus standards bodies, both domestic and international. PHMSA's procedures follow the requirements of OMB A-119.

The following list shows the standard-setting bodies that are incorporated by reference (IBR) in 49 CFR part 192, Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards; 49 CFR part 193, Liquefied Natural Gas Facilities: Federal Safety Standards; and 49 CFR part 195, Transportation of Hazardous Liquids by Pipeline:

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

PHMSA has over 40 technical committee members who participate in over 25 voluntary consensus standards committees whose standards PHMSA incorporates by reference. These committees are API, ASTM, ASME , NACE , and NFPA. Additionally, PHMSA has fourteen representatives on ten committees where the standards are not currently IBR. Some of these standards are being considered for future IBR. PHMSA determines the appropriate level of involvement in each selected committee based on the level of risk represented by the topics being addressed by the committee. Active committee membership by PHMSA and our state regulatory partners allows us to prevent undesirable changes to standards (requirements in conflict with the regulations or those not in the best interest of public safety) and to work with committees to produce new, improved provisions in the standards. PHMSA reviews standards identified as low risk when new editions are updated to determine if they should be adopted.

Voluntary consensus standards are generally developed or modified in response to an identified need to strengthen existing provisions, to incorporate new technology, or to address a new or existing regulatory requirement. There is a formal process for requesting development of a new standard or improving an existing standard; the process begins with a request from a member of the organization or from the public. Finalization of a new or modified standard involves an approval process including balloting that involves the main body of the standards organization.

AGA, API, ASCE, ASME, ASTM, MSS, NACE, and NFPA are American National Standards Institute (ANSI) accredited standards development organizations and operate with approved standards development procedures. ANSI accreditation as a standards development organization signifies that the procedures used by standards body meet the ANSI's rigorous requirements for openness, balance of interest, due process, appeals process, and consensus. Each of these organizations has developed and received ANSI approval for its standards development process. Some standards IBR are administered by ANSI accredited standards development organizations but are not American National Standards (ANS) standards. Their approval process may follow procedures that are similar to their ANSI accredited procedures.

Depending on the standards development organizations, participation may be limited to members of the organization. Consensus standards development organizations typically allow any person (organization, company, government agency, individual, etc.) with a direct and material interest in the product, operation, or practice described in the standard to participate. Some committees require members to submit an application and may limit the number of members from a single organization. The expertise of the members varies depending on who is participating in the committee at a given time. Usually the organization seeks members who have experience in the specific topic being addressed by the standard. If the committee does not have the technical expertise to write the standard, an organization may contract with technical experts to write a draft of the standard.

PHMSA periodically updates the pipeline safety regulations to IBR all or parts of new editions of voluntary consensus standards. PHMSA evaluates the adequacy and scope of all standards being considered for IBR using a thorough process involving review by agency experts, public notice and comment, and review and acceptance by our Technical Advisory Committees (TAC) prior to a final rule. Every document IBR is referenced by its full title and specific edition. The PHMSA technical committee member or a staff member with necessary expertise reviews each new edition to determine whether it should be incorporated in whole or in part into the pipeline safety regulation or if the revised edition should be rejected.

Q9: I understand that you are focusing more on "integrated inspections" rather than "traditional inspection methods." What does that mean? If they are driven by risk, how does PHMSA determine which pipelines are most at risk?

A: PHMSA has employed a data driven and risk based planning algorithm for many years. This algorithm uses the data from many sources: inspection history, enforcement history and accident history for example. This algorithm is used to rank order those operators and which of their pipeline units present a greater risk and therefore should be inspected more frequently.

PHMSA is a reevaluating our current algorithm to improve its output. One change is a result of the Integrated Inspection (II) program. The II program inspects pipeline systems. This is to say, the inspection activity will include several units of the operator and these unit's risks need to be combined to present the system's risk. PHMSA has also improved its data quality and is finding better ways to use previously untapped data.

PHMSA has utilized several types of inspections to address all of an operator's compliance requirements. These were distinct activities that addressed specific regulatory requirements. The II program combines these distinct inspection types into one overall inspection process. The II process allows the inspection team to assess the overall compliance and safety program of the operator. This new process better utilizes the existing data we have on the operator to focus efforts on the areas that pose the greatest risks. The planning algorithm identifies which systems we should inspect but the II process specifically focuses the actual inspection on the operator's unique risks of the system.

Even though PHMSA is employing this II process we are continuing to utilize other inspection programs. For example, PHMSA continues to oversee the construction of new pipelines through specific inspections of these projects. Should an operator have an accident, dedicated PHMSA staff investigate these events independently to identify regulatory compliance and ensure actions are taken to reduce the likelihood of reoccurrence.

Q10: In 2007, PHMSA chartered a data team to improve the quality of pipeline safety data and has invested considerable resources and efforts to document and address known data quality issues. Yet, an internal PHMSA report circulated in November 2009 found:

"Most of our data collection relies on third-party reporting from regulated companies. This is convenient, and it goes directly to the source. It also introduces *serious biases and gaps* in the data we collect. Despite the best intentions and professionalism, the regulated industry has an institutional bias (and probably a liability aversion) in determining the causes, circumstances, and consequences of failures. *Accident investigations–the limited number that we do–have shown* some *significant differences between what a company reports and an objective view of these events.* Reports from companies also reflect large numbers of blanks and "unknown" data, particularly in the most serious cases–exactly where it is most critical that we have good data. An alternative approach–collecting much of the data ourselves in the course of our inspections or investigations—has been discussed but never evaluated fully. *We have ample authority to collect data directly as part of our inspections or accident investigations, but many in the organization see data collection as a distraction from more important safety oversight activities.* There is also an ownership issue with the data ..."

There is a historical understanding that the data we get from industry is "their" data. *Even when we believe (or know) data to be wrong, we don't modify our data until we get revised reports from the company. Even now, as we recognize the need for more accurate information, we generally augment the data with our own information rather than modifying the basic data in our system.* This practice, however, creates ambiguity in the data that analysts might use, expand the opportunity for misinterpretation, and doesn't really solve the problem.

"Our own independent accident investigations are very limited in number and scope. We have completed 19 investigations (about 3%) of the 664 reported pipeline incidents in 2008. The information we get from our investigations is not converted *into* data that could be used for statistical analysis or engineering reference. *We often collect more data during the course of an investigation than we require in the incident report from an operator, but this information does not get entered into any data base.* It appears to be collected primarily for enforcement purposes related to individual companies, not to build our knowledge base.

"Our processes do not effectively reconcile discrepancies between our investigation reports and the accident reports submitted by operators. The discrepancies can be significant. In one case, a pipeline operator reported $0 damage (and that is what we showed in our data); the investigator reported lost product, a fire, and an estimated $588,000 in property damage, but the data base was not updated or corrected until 9 months after the incident. In other cases, the data base was not updated to reflect design pressure, operating pressure at the time of the accident, or year of installation–from the more detailed investigation reports. These discrepancies are just from a cursory review of the 10 most recently closed cases."

What is PHMSA doing to address these concerns?

A: We'd like to offer a clarification regarding the independent accident investigations mentioned in the text leading up to the question. PHMSA's Office of Pipeline Safety (OPS) conducts a review of *all* gas transmission, gathering, and distribution incidents and telephonic reports, as well as all hazardous liquid incidents greater than 5 barrels and those hazardous liquid incidents less than 5 barrels but which meet other reporting criteria. The number (19) quoted in the internal PHMSA report referred to in the question represents only those incident investigations that had been selected for an in-depth post-incident investigation. For example, OPS received 667 incident reports in 2008. 376 were hazardous liquid reports, 151 were gas distribution reports, and 140 were gas transmission and gathering line reports. Of these 667 reports, about 72% - or 475 reports - were reviewed by OPS's Regional Review Team and some were sent to our State partners for their follow-up. Of the 376 hazardous liquid reports, about 50% or 190 were "small spills" ranging from 5 gallons to less than 5 barrels. OPS use these "small spill" reports for inspection planning and analysis purposes but do not conduct thorough reviews or investigations on these "small spills." OPS conducted in-depth post-incident investigation on 28 incidents in 2008.

OPS recognizes – and has already put in place a plan to address – the issues identified in the internal PHMSA report referred to in the question. Beginning with the OPS data team chartered in 2007, OPS has made significant and thoughtful progress to improve the quality of its data, enhance its analytical capabilities, and improve the way it uses data to drive management and operational decisions. This has included recent efforts by OPS to significantly modify and enhance our primary forms for operator reporting. These forms are designed to capture information and data pertaining to both incidents as well as to the facility infrastructure being regulated. The objective of these modifications and enhancements is to selectively identify those pieces of information and data that – upon internal analysis - will be most meaningful and revealing in terms of both guiding OPS in the pursuit of its mission and providing more valuable metrics by which to gauge its effectiveness. The old forms and their questions were found to be incomplete in this regard, and OPS responded by thoroughly modifying and enhancing each of these forms and adding new forms where needed. Additionally, OPS has already developed a Data Quality and Analysis Improvement Plan (DQAIP) that identified many of the same issues as were identified in the referenced internal PHMSA report, and further, has recently reorganized its data-related functions to support the implementation of the DQAIP. The DQAIP will ensure that sound data management practices can be successfully institutionalized and sustained. This Plan involves: more rigorous data quality and completeness checks; a new process for the review and augmentation of operator-reported data; enhanced follow-up incident investigations based on the severity of the incident and on the potential for learning opportunities; steps to validate the timeliness of report submissions, changes, and supplements; and, a more structured process for conducting analyses and sharing of results.

What was not made clear in the internal PHMSA report mentioned above is that much of the data that remained un-updated or that was left blank in original report submissions was not always critical to the more in-depth incident investigation. Nonetheless, OPS recognizes that a structured approach is needed to ensure that certain critical data *is* provided *and* that certain critical data does indeed get updated when appropriate. OPS also recognizes the need for capturing data from the in-depth failure investigations OPS conducts in a centralized database. OPS has chartered an Incident Investigation Process Improvement Team to establish a more formal, and more consistently applied investigation process for *all* incidents.

Q11: The same report (noted above) states that PHMSA has several "invisible risks" within your statutory authority but not necessarily regulated and where you have little or no risk data. The list of "invisible risks" includes LNG (liquefied natural gas) facilities. What is PHMSA doing about this?

A: Currently, operators of LNG facilities are not subject to incident or annual reporting requirements. On July 2, 2009, PHMSA published a notice of proposed rulemaking proposing to subject operators of LNG facilities to the same incident and annual reporting requirements as other pipeline facilities. PHMSA anticipates publishing the final rule by September 2010.

Q12: A witness on the second panel stated that there is a vast difference between the incident database of PHMSA and the incident database of the Common Ground Alliance largely due to reporting requirements. The witness also notes that this "data gap" inhibits PHMSA from determining whether its programs are truly affecting excavation damage. What is your response to that?

A: The two databases were designed for different purposes but should be considered complementary. PHMSA's incident database includes information about pipeline incidents and accidents in which the terms "incident" and "accident" have been defined in our regulations for many years and include events that involve a fatality, injury with hospitalization, $50,000 or more in damages or releases of hazardous liquids that meet specific thresholds. Because our requirements for reporting incidents and accidents have been standardized for many years, PHMSA can analyze data as far back as 1986 to determine the most common causes of pipeline accidents/incidents over time and by location. For this response, we'll refer to all hazardous liquid incidents and gas accidents as incidents. PHMSA's historical database does allow for analysis that can demonstrate trends in the rate of excavation damage to regulated pipelines that result in incidents, in addition to and as compared to other causes, such as corrosion, material/equipment failure or incorrect operation. In January, 2010 PHMSA modified the incident reporting forms to adopt the same mandatory data collection requirements as the CGA database for reportable incidents caused by excavation damage. These changes to the reporting form will allow PHMSA to conduct a more detailed analysis of incidents caused by excavation damage.

The CGA Damage Information Reporting Tool (DIRT) was launched with substantial financial and staff support from PHMSA in November, 2003. DIRT is a database that captures detailed information about excavation damage to all underground facilities on a national scale. The DIRT tool was specifically designed to capture information about excavation damages only; incidents caused by anything other than excavation damage are not captured in DIRT. Data submission is voluntary and anonymous, and PHMSA does not have access to the underlying DIRT data. Using the data submitted, the CGA annually publishes a report that describes national and regional trends as they relate to excavation damage. This report provides a more complete picture of excavation damage trends across the nation (as compared to PHMSA's database) because it includes data pertaining to all underground utilities. However, because the data in DIRT is submitted voluntarily, the report cannot be considered a comprehensive source of all underground facility damages. In particular to pipelines and PHMSA's analytical needs, the DIRT data is incomplete and is examined only on a nationwide or regional basis in the CGA's annual report.

PHMSA supports the continued development and evolution of the DIRT database and encourages pipeline operators to submit their data. As more states begin to implement reporting requirements for damages, there is increasing interest among stakeholders to adopt the DIRT tool as the standard for reporting damages. The CGA has recently developed optional modifications to DIRT that will allow states or company-level organizations to collect and analyze their desired data and will permit submitting entities to reveal their identities, rather than submitting anonymously. These new features will assist states that are working to improve and strengthen their damage prevention laws and programs and will provide for more granular analysis of damage data.

Also, PHMSA's data collection efforts as they relate to the new Distribution Integrity Management Program rule require operators to annually submit the number of excavation damages and the number of locate tickets received. Comparing the number of locate tickets received by an operator to the number of excavation damages the operator incurs is a common method of measuring the effectiveness of damage prevention programs and will provide standardized data for analysis over time as the data is captured.

Q13: In December, PHMSA issued a Final Rule to address human factors and other aspects of control room management; including requiring operators to implement hours of service requirements for control room personnel (which Chairman Oberstar spearheaded in tile PIPES Act). The rule required certain pipeline operators to define the roles and responsibilities of controllers and provide them with the necessary information, training, and processes to fulfill them. Operators must also implement methods to prevent controller fatigue. The Final Rule requires pipeline operators to develop control room management procedures by August 1, 2011, and implement the procedures by February 1, 2013. Why so long? Seems like this is commonsense and should have been in place earlier. Also, are LNG (Liquefied Natural Gas) facilities subject to this rule? If not, why not? What will PHMSA do to address control room management and LNG's in the future?

A: Based on comments received on the proposed rule and recommendations of our Technical Advisory Committees, PHMSA promulgated regulations allowing 18 months for operators to develop their written plans and procedures. PHMSA will develop new training and guidance for our inspectors as well as guidance for the regulated community. PHMSA will host a control room management (CRM) public workshop in November 2010 in anticipation of starting inspections of operators' plans and procedures in summer 2011. Operators requested an additional 18 months to take extra steps to comply with the rule, such as renegotiate union contracts to accommodate new rules for working hours; upgrade SCADA equipment and capabilities; including re-program training simulators to mimic new SCADA equipment functions and user interfaces; and train controllers on new SCADA equipment, alarm management plans, etc. PHMSA's Technical Advisory Committee approved that additional time. PHMSA will evaluate the reasonableness of these timeframes as they relate to fatigue management.

The CRM regulations are not specifically adopted in Part 193—the regulations applicable to LNG facilities. It should be noted, however, that LNG controllers who perform dual roles by remotely monitoring and controlling transportation pipelines associated with the LNG plant may meet the definition of a controller under the new CRM rule and therefore be subject to the CRM regulations (under Part 192), with respect to duties associated with controlling the pipeline. PHMSA considered adopting the CRM regulations into Part 193, but based on comments received on the NPRM and recommendations of the Technical Advisory Committee, the agency determined that it was necessary to collect more information and data regarding how CRM concepts would be warranted for LNG facilities. For example, LNG facilities exist on a single site, rather than dispersed over hundreds or thousands of miles. LNG controllers walk to field equipment within minutes to monitor conditions, including possible failure modes, whereas pipeline controllers frequently interact with field equipment via their SCADA systems. PHMSA has recently expanded data collection efforts that will facilitate the agency's future determination about the appropriateness of applying CRM concepts on LNG facilities.

Q14: You talked about increased enforcement in your written testimony. Your website shows that the amount of civil penalties proposed against operators that violate Federal pipeline safety standards have increased significantly from about $1.7 million proposed in 2002 to $6.4 million proposed in 2009 - the second highest level since 2001. First, what do you attribute the increase in proposed civil penalties to? More inspections? Less compliance by pipeline companies? A combination of both? Second, while the penalties proposed have increased the number of cases actually closed have decreased significantly. For example, in 2008, out of the 24 cases that were opened, only 1 case was closed? In 2009, out of the 38 cases that were opened, only six cases were closed. Already in 2010, 12 cases have been opened and none of them have been closed.

A: In the Pipeline Safety Improvement Act of 2002, Congress significantly increased the maximum civil penalties PHMSA is able to propose for violations that occurred after December 17, 2002.[9] The limits increased from $25,000 per violation per day (up to a maximum of $500,000 for a related series of violations), to $100,000 per violation per day (to a maximum of $1,000,000 for a related series of violations). In the years since, we have worked hard to achieve a mature penalty structure that more effectively applies this increased penalty authority while rigorously generating risk-based and consistent penalties that are tough but fair. We have proposed and assessed higher civil penalties when operators commit violations that either contributed to pipeline accidents or increase their risk. Our enforcement procedures provide detailed risk-based criteria for selecting enforcement actions, and we document risks, aligned with our penalty structure, for each civil penalty violation. When penalties are warranted, the average penalty proposed per individual violation has increased from approximately $16,000 in 2002 to an average of approximately $100,000 today.[10] Higher individual penalties have resulted in higher yearly totals. In 2009, we proposed a total of $6.4 million in civil penalties, the second highest yearly total in agency history.[11]

Many of our civil penalty cases take significant time from the date the case is opened until the case is closed. Our enforcement process allows for "due process" where the operator is given an opportunity to respond to the allegations in our enforcement notice letters. As permitted by our regulations, operators sometimes request hearings to defend their actions and present their case. Subsequent to hearings, operators are often provided additional time to submit further written material supporting their case. Furthermore, even after we have rendered a decision in a Final Order, many of our Final Orders not only require payment of a civil penalty, they also include a Compliance Order. Compliance Orders require the operator to take certain actions – often over a period of months or, in some cases, years – to bring its facilities and programs back into compliance. Once the operator has completed these actions, our inspectors must verify that they have been accomplished satisfactorily before a case can then be closed. Civil penalty cases, which are the ones most likely to be contested and involve hearings, often take significant time to proceed through this process and be closed. Only the simplest and most straightforward cases where the operator does not contest the allegations, and where there are no continuing compliance enforcement requirements, are able to be closed within a year of being opened.

[9] Enforcement cases initiated after December 17, 2002, could apply this higher civil penalty authority only if the actual documented violations occurred after December 17, 2002. Thus, many enforcement cases initiated in 2003 could only apply the lower penalty authority

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

[11] In 2008, we proposed a total $8.7 million in civil penalties, the highest yearly total in agency history

Q15: I see PHMSA talk a lot about excavation damage and that is a serious issue but I haven't seen a lot of talk about corrosion which is the second leading cause of all pipeline accidents. What is PHMSA doing to address corrosion?

A: PHMSA continues to promote new standards for corrosion detection and remediation on pipelines through new inspection standards, industry standards and code revisions, continuing research, and is addressing new corrosion threats such as Stress Corrosion Cracking coming from biofuels.

PHMSA has continued to periodically inspect operators for compliance with corrosion control regulations. The hazardous liquid and gas transmission integrity management rules issued in 2001 and 2004 require operators to (1) evaluate the risk of corrosion and other threats, (2) perform assessments of pipelines to detect potentially injurious conditions, and (3) remediate anomalies, defects, and other conditions that could be deleterious to pipeline integrity. The integrity management rules also require that the operator study, identify, and implement (as appropriate) additional preventive and mitigative measures to manage pipeline risks, including corrosion. These programs are responsible for finding and removing approximately 35,000 anomalies in High Consequence Areas (HCAs) that could have led to future failures. The hazardous liquid integrity management program alone illustrates roughly 46% of the anomalies found were corrosion related. The natural gas transmission program numbers won't be available until the industry reports after the 2012 deadline to complete baseline assessments.

PHMSA has participated with standards developing organizations such as NACE International in developing new standards. When appropriate, these new standards are incorporated into pipeline safety regulations by reference. PHMSA has recently completed a review of recently published consensus industry standards developed by NACE International and is planning to issue a notice of proposed rulemaking to incorporate by reference three NACE standards that have been reviewed by PHMSA. This proposed rule would propose to incorporate by reference consensus standards governing the conduct of assessments of the physical condition of in-service pipelines (to identify corrosion and other defects) using in-line inspection, internal corrosion direct assessment, and stress corrosion cracking direct assessment. Periodic assessment of the condition of gas transmission pipelines is required by integrity management regulations under §192.921and §192.937. Periodic assessment of hazardous liquid pipelines is required by integrity management regulations under §195.452. These sections of the federal regulations allow use of the inspection techniques addressed in these standards.

The PHMSA Pipeline Safety Research and Development Program is co-funding projects with the pipeline industry that are developing technology solutions for addressing corrosion threats. These solutions were developed then deployed via our program, creating additional tools for industry to better manage corrosion. Examples are internal corrosion sensors to identify pooled water locations in gas systems; a handheld tool to inspect for external corrosion through thick pipeline coatings; separate software and hardware improvements to expand the use of guided wave, a key tool for assessing difficult to inspect areas such as cased crossings; and an in-line inspection tool to internally map current demand for identifying unprotected areas along the pipeline.

Section 22 of the PIPES Act required PHMSA to conduct a review of the internal corrosion control regulations set forth in subpart H of part 195 to determine if the regulations are currently adequate to ensure that the pipeline facilities subject to such regulations will not present a hazard to public safety or the environment. This review was completed and submitted to Congress in a report dated June 23, 2008, *Internal Corrosion Control: A Regulatory Requirements Adequacy Review*. As a result of this review, PHMSA issued Advisory Bulletin ADB-08-08, dated November 24, 2008 (73 FR 71089) to advise and remind operators of PHMSA's regulatory position with respect to the management of internal corrosion. On March 26, 2009, PHMSA held a public workshop to highlight the results of this review, the advisory bulletin, and to provide a forum for the pipeline industry to share best practices in the management of internal corrosion.

In 2009, PHMSA promulgated new rules to address operation of gas pipelines at an alternative Maximum Allowable Operating Pressure (MAOP). Incorporated into this new rule were more stringent corrosion control requirements. For pipelines operating at an alternative MAOP, operators must conduct in-place coating surveys prior to operation to find damaged coating, conduct additional close interval surveys, and interference surveys. These additional tests provide greater assurance that coating systems and cathodic protection systems are undamaged and functioning properly to protect the pipeline from external corrosion. In addition, periodic integrity assessments must be conducted over the entire pipeline (both inside and outside HCAs) operating at an alternative MAOP, in order to find and repair corrosion metal loss defects and other injurious pipeline defects. PHMSA will continually monitor the effectiveness of these measures with a view toward continually improving regulations and corrosion management programs.

Questions for House Transportation & Infrastructure
Subcommittee on Railroads, Pipelines and Hazardous Materials
May 20, 2010 – 10:00 a.m. – Hearing on Pipeline Safety Act of 2006
(PHMSA Responses as of June 4, 2010)

Ongoing Issues Related to Safety and Integrity of Imported Large Diameter Line Pipe Products
For the PHMSA Panel

The U.S. is home to a number of companies which manufacture large diameter steel line pipe (LDLP) used in pipelines to transport gas. This pipe is made in a number of states which include Alabama, Arkansas, California, Florida, Louisiana, Mississippi, Oregon and Texas. Over the past five years, the domestic industry has expanded operations and made significant investments in new facilities to meet increased demand for the product.

The U.S. LDLP industry works closely with its customers to ensure that product quality and specifications for the product are attained. The domestic industry has had extensive experience in production and research and development on the product and today manufactures safe and high quality product for its customers. Over the past few years there have been reports of inferior product being used in pipelines which has resulted in safety and integrity problems for these projects. As a result, Federal authorities including PHMSA responded by contacting U.S. producers over the past 18 months to inquire about the LDLP production process and to tour their facilities. The U.S. companies not only complied, but provided a number of employees to be available for these meetings and tours.

Question:

1. Recognizing the oversight role of PHMSA and its authority to ensure that products meet safety guidelines that benefit the pipeline infrastructure, why has the agency limited these inquiries to U.S. producers instead of surveying the producers of the imported product? Does PHMSA have the authority to conduct on site visits abroad at the plants of the foreign producers? If not, which federal agency has the authority to conduct a safety and quality audit of the process used abroad?

PHMSA Answer:

PHMSA has authority over domestic transportation of natural gas and hazardous liquid, pipeline facilities and the owners and operators of those facilities, and through them their contractors, pursuant to 49 USC 60101 *et seq*. It is true that due to our concerns regarding issues discovered in our oversight of new pipeline construction projects that we expanded our investigations to include several domestic steel pipe providers. As expected, these providers were quite helpful and cooperative and volunteered their services.

PHMSA does not have authority to inspect foreign plants directly. However, PHMSA can enforce compliance with code-referenced standards on pipe strength that we have incorporated by reference into our regulatory requirements. Pipeline operators must maintain and make available for our inspection valid documentation of pipe mechanical and chemical composition properties to validate pipe strength.

PHMSA and State regulators already inspect operator pipe records for compliance with safety standards under existing authorities. We are now spending additional time working with operators who contract with foreign pipe mills to review the basis for their confidence in material quality control for line pipe regardless of which country it is acquired from.

Further, PHMSA is working with API to update the 5L national consensus standard for steel making and pipe rolling. This updated standard for high strength micro-alloyed steel pipe will include more rigorous requirements designed to reduce the incidence of low-strength pipe. API has already circulated these new pipe steel manufacturing and pipe rolling standards for membership approval.

PHMSA is not aware of other Federal agencies with jurisdiction over foreign steel pipe mills that make pipe for usage in natural gas and hazardous liquid pipelines in the United States. We are aware, however, that the U.S. pipeline industry has been working to identify and address quality control problems in those foreign mills where they acquired problem pipe.

2. What if any additional authority might PHMSA require to conduct international sight visits to ensure that imported LDLP meets the safety and quality standards as required by API standards established for the global industry?

PHMSA Answer:

Under current statute, PHMSA does not have the authority to inspect foreign pipe mills. However, PHMSA can enforce compliance with code-referenced standards on pipe strength that we have incorporated by reference into our regulatory requirements. Quality control over all aspects of pipeline construction, from material manufacture and fabrication, to transportation, and finally installation and pre-operational integrity testing, is critically important to the integrity of all pipelines.

3. Has PHMSA discussed the import integrity issues with API and other groups which establish standards in the industry? If so, what conclusions have been reached?

PHMSA Answer:

PHMSA published an Advisory Bulletin in the Federal Register that provided pipeline operators with guidance on low strength pipe. PHMSA also held a construction workshop in April of 2009, in concert with our State regulatory partners, as well as in partnership with the Federal Energy Regulatory Commission and the Canadian National Energy Board, that reviewed the low strength pipe issues. During 2009, PHMSA meet with API executives in Washington, DC, to discuss remedial actions by that group, and has reviewed low strength pipe issues at API conferences in Denver in early June, 2009 and in New Orleans in late January, 2010.

PHMSA has also met several times with the INGAA Foundation following our April 2009 Construction Workshop. The INGAA Foundation has established an action plan in response to our challenges that is staffed by several task work groups. These work groups are developing procedures for use by the U.S. pipeline industry to recognize and implement improved steel acquisition procedures, quality assurance procedures, and manufacturing inspections. PHMSA has been very transparent with the public and collaborative with our regulatory partners domestically and in Canada in addressing needed improvements in construction of new pipelines. We have made our actions and presentations publicly available through the PHMSA website: http://primis.phmsa.dot.gov/construction/index.htm.

TESTIMONY OF
GARY L. SYPOLT
CHIEF EXECUTIVE OFFICER
DOMINION ENERGY

ON BEHALF OF
THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

BEFORE THE
SUBCOMMITTEE ON RAILROADS, PIPELINES AND HAZARDOUS MATERIALS
COMMITTEE ON TRANSPORTATION AND INFRASTRUCTURE
U.S. HOUSE OF REPRESENTATIVES

REGARDING
REAUTHORIZATION OF THE PIPELINE SAFETY ACT

MAY 20, 2010

Interstate Natural Gas Association of America
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Madam Chair and Members of the Subcommittee:

Good morning. 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 natural "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 United States 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 United States 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

Madam Chairwoman, 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.

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
- 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%	$1, 058 012	5%
2006	1	33%	2	66%	1	33%	2	66%	$31,020 029	$2,869,452	9%	$20 882,094	67%	$7 266 481	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-public 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, 2005-2009, there were thirteen 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 this 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 primarily due to a tornado destroying a pipeline compressor station ($85 million).

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[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

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 re-assessment 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	1285	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 assessment 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 undertaken in 2005 by the Pipeline Research Council International (PRCI)[5], 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

[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

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 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 United States 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 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 towards 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 four years without any new regulatory programs or mandates. Given the success of the program over the last four 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.

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 seven 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 consensus standard organizations.

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.

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

One of the benefits of the Integrity Management Program (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 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

Madam Chairwoman, 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

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

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.

Pipeline Safety TRUST

Credible.
Independent.
In the public interest.

Testimony of
THE PIPELINE SAFETY TRUST

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Presented by

Carl Weimer, Executive Director

BEFORE THE

SUBCOMMITTEE ON RAILROADS, PIPELINES, AND HAZARDOUS MATERIALS
TRANSPORTATION AND INFRASTRUCTURE COMMITEE
U.S. HOUSE OF REPRESENTATIVES

HEARING ON

Implementation of the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 and Reauthorization of the Pipeline Safety Program

MAY 20, 2010

Good morning, Chairwoman Brown, Ranking Member Shuster 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 ten 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 from our opinion PHMSA learned those hard lessons and has changed for the better. While there is always room for improvement, 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 56 people who have been killed by pipeline incidents since we last spoke to this committee on March 16, 2006. We are speaking for the 209 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 four 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**

Expanding the miles of pipelines that fall under the Integrity Management rules

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.

One of our major concerns is that the Integrity Management rules that require hazardous liquid and gas transmission pipeline operators to more carefully assess their pipelines only apply to limited sections of pipelines that fall in High Consequence Areas (HCAs). These assessments are most frequently accomplished by internal inspection of the pipelines with smart pigs. Due to these important new pipeline safety regulations, pipeline operators found, excavated and repaired more that 34,000 anomalies on pipelines between 2002 -2008. This represents a significant improvement in the future safety of our nation's important transportation infrastructure.

Currently 44% of hazardous liquid pipelines and only 7% of natural gas transmission pipelines fall under these important integrity management rules, requiring that they *ever* do these inspections. Yet despite Congressional action, 56% of hazardous liquid pipelines and 93% of natural gas transmission pipelines still are not required to comply with these important regulations.

To illustrate why this is a problem consider that we are approaching the ten-year anniversary of the Carlsbad, New Mexico pipeline explosion that killed twelve people. In response, Congress passed the Pipeline Safety Improvement Act of 2002, which required Integrity Management of natural gas transmission pipelines within High Consequence Areas (HCAs). Yet HCAs are defined so narrowly that they don't even include the Carlsbad pipeline area despite the fact that twelve people died there in one pipeline incident. What this means to people who live around these pipelines is that if you live near a pipeline in a more rural area, your life is not worth protecting with these important integrity management rules. As Jim Hall, Chairman of the National Transportation Safety Board at the time of the Carlsbad incident said "No American would want to use any transportation vehicle that would not be properly inspected for 48 years, nor should we have pipelines traveling through any of our communities in this condition." Chairman Hall's words are as true today as they were in 2000. With the upcoming ten year anniversary of the Carlsbad pipeline incident, and in memory of the twelve men, women and children who died there as the result of an uninspected pipeline, the Trust asks Congress to expand Integrity Management to all pipelines so that their deaths might not have been in vain.

When Integrity Management was first conceived and implementation began, inspections were limited to High Consequence Areas (HCAs) because this represented a huge undertaking on the more than 90,000 miles of pipelines that are included within these HCAs. At that time, leaders within Congress and PHMSA stated that in the future these types of inspection requirements would be expanded to additional miles of pipeline outside of the HCAs. The future is now, and we believe the industry now has the experience and equipment necessary to begin similar inspection on the over 365,000 miles of pipelines that currently have no such regulatory requirements. This is extremely important when you consider that of all the deaths caused by these types of pipelines since 2002 over 75% of them have occurred along pipelines that are outside of HCAs, so currently are not required to meet the Integrity Management rules. 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.

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 five 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 transportations 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—can not 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 correcting the "reportable incident" requirements for excavation damage to ensure that the effort and money being spent is well targeted and effective. The solution may be as easy as PHMSA requiring incidents to pipelines be reported to the Common Ground Alliance's DIRT database, and that the part of the database that falls under these requirements be made publicly available. If the pipeline industry wants everyone else to be a partner in preventing damage to their pipelines, then it seems the industry should provide the data regarding excavation damage to their lines so we can all see how well we are doing.

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.

After more than two 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..."***

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. Just as Congress required PHMSA to institute Enforcement Transparency in the PIPES Act of 2006, The Trust hopes you will require similar Inspection Transparency this year.

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.

• **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.

• **Emergency Response Plans.** These plans are required for onshore oil pipelines, yet they are not easily publicly available. Easy access to these plans would allow local government, citizens and academic institutions to review the adequacy of their plans and suggest needed improvements.

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 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 d 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 standards 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 five 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 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 where the gas demand on the service lines would be predictable and similar to the demand curve on a single family residential application. After attending PHMSA sponsored workshops on this issue, the Trust agrees with the NTSB that the technology exists and the path forward to define such applications is quite clear. We ask that you set a date certain for PHMSA to move forward on a rulemaking to expand the use of EFVs in these types of applications.

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 ten 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.

Pipeline Safety TRUST CREDIBLE. INDEPENDENT. IN THE PUBLIC INTEREST.

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Responses to Chairwoman Brown's additional questions from the May 20, 2010 hearing on the Implementation of the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 and Reauthorization of the Pipeline Safety Program.

1. In your testimony you advocate requiring pipeline operators to expand their integrity management programs to an additional 365,000 miles of pipeline outside of High Consequence Areas. Why do you believe that it is important to go beyond just High Consequence Areas?

In response to horrific pipeline tragedies, Congress required integrity management in High Consequence Areas 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% of natural gas transmission pipelines and 44% 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 ten year ago this summer.

- 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% of all the deaths caused by these types of pipelines have occurred in areas that fall outside of the current integrity management requirements. In summary, it is not credible to tell the American people that the pipelines in their communities are safe when the integrity of these pipelines may not have been assessed in over half a century.

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 ten 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 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.

2. In your testimony, you note that there is a vast difference between the incident database of PHMSA and the incident database of the Common Ground Alliance largely due to the reporting requirements. You also note that this "data gap" inhibits PHMSA from determining whether its programs are truly affecting excavation damage.

Do you believe that mandating structured reporting requirements through the "Common Ground Alliance's DIRT Database" will help identify the root cause of excavation damage and prevent such damages in the future or should the reporting requirements be maintained within PHMSA so data can be studied and uniform reporting requirements be maintained? If not, how should Congress address this issue?

The key to any valid, usable data is to ensure that the data is accurate, being reported in a consistent manner by everyone, and provides a true picture of what is actually occurring. Currently the reporting systems of both PHMSA and the Common Ground Alliance (CGA) have "flaws" that need to be corrected.

The primary problem with PHMSA's system is the vast majority of excavation damage incidents are never reported because the level of damage that must occur before reporting is required is too high; this is especially true for natural gas pipelines. This could easily be corrected by requiring the operator to report any excavation damage. Since this would dramatically increase the number of reports that PHMSA would have to process, and that companies would have to file, it would probably make sense to streamline or reduce other parts of the reporting requirements for these incidents that fall below the current reporting threshold to decrease the burden. These types of incidents would also have to be flagged so they can be easily separated from the rest of the incident database so the ability to track historical trends is not disrupted. None of this seems complicated as long as PHMSA has the staff resources necessary.

The CGA system would probably take more effort to make its database useful for analyzing excavation damage. The current CGA system has the following problems that would need to be overcome:

- It is a voluntary system, which leads to inconsistent and spotty reporting
- It includes all underground utilities, not just pipelines, so getting buy-in from other users may be difficult
- Its data is closed to outside review and verification, and confidentiality is guaranteed
- Reports are submitted from a variety of stakeholder groups which appears to create some overlap in reporting and perhaps some selective reporting.
- Over 20 separate "virtual DIRT" systems have been set up in different states, each with differing reporting requirements. These would all need to be integrated.

The inconsistency in reporting was brought home again this week when three workers were killed in two pipeline incidents caused by excavation damage in Texas. A review of the PHMSA database from 2007 – 2009 shows that excavation damage causes an average of 10 pipeline incidents each year in Texas. Yet in responding to press inquiries about the recent excavation tragedies in Texas, Texas Railroad Commissioner Michael Williams said "there are roughly 18,000 line punctures or mishaps in Texas each year."

Texas' understanding of its excavation damage may point to a third possible solution, to require that states have reporting requirements and databases in place to ensure adequate knowledge and improvement of their damage prevention programs. 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 adequate information to target its 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

Because most states have taken on the responsibility of operating state-based damage prevention programs it may well be easiest to just require states to adopt reporting requirements similar to Texas. This 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 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.

3. In your testimony, you indicate that pipelines bringing natural gas service to multi-unit apartment dwellings should be equipped with "excess flow valves". Those valves close the pipeline off in the event of a catastrophic failure or other accident which would cause an uncontrolled release of natural gas which could result in fire or explosion. According to various industry organizations, these devices may cause more problems by shutting off vital gas services to apartments, hospitals and industrial facilities. Do you believe that the current technology utilized in "excess flow valves" operates effectively so that these types of unintended consequences will not occur?

The Pipeline Safety Trust believes the key point to this discussion is covered in the 2001 recommendation from the National Transportation Safety Board (see highlighted portion below):

> "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."

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.

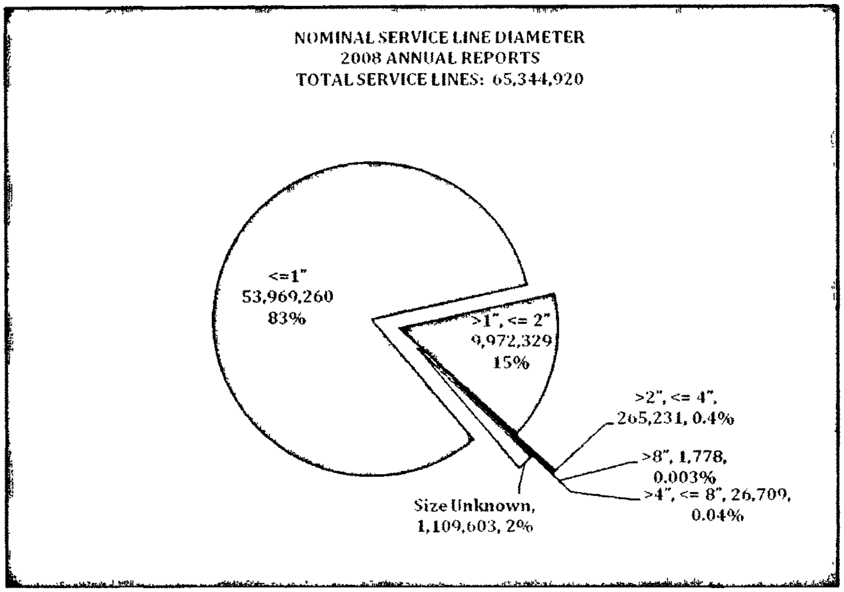

Figure 1 (Source – PHMSA's – Interim Evaluation: Response To NTSB Recommendation P-01-2)

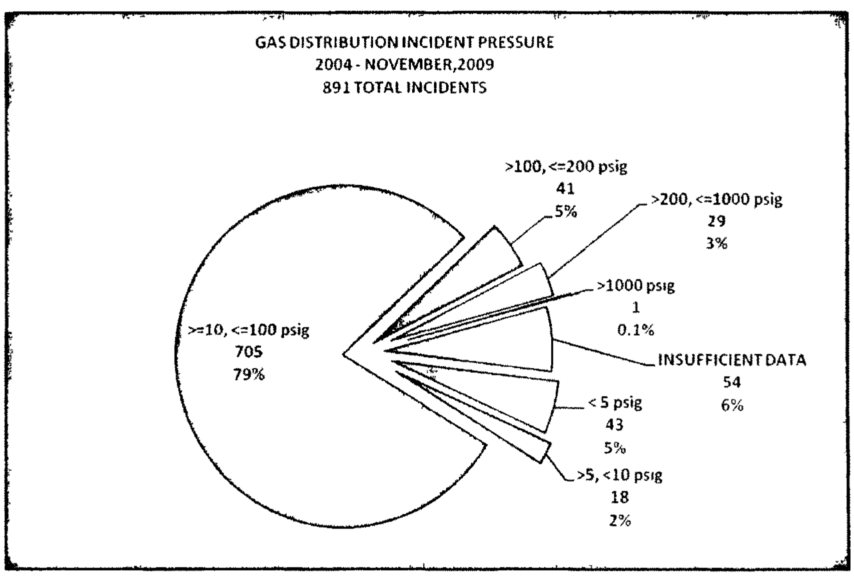

Figure 2 (Source – PHMSA's – Interim Evaluation: Response To NTSB Recommendation P-01-2)

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 include the many types of structures where "**operating conditions are compatible with readily available valves.**

4. In your testimony, you note that "It may also be necessary for Congress to clarify important parts of good damage prevention program." Can you elaborate on what needs to be clarified?

The two issues with damage prevention programs that we think need more specific clarification relate to exemptions from the "One Call" laws that many states provide, and the need as discussed earlier to provide a clearly defined system for data collection related to damage to pipelines from excavation.

Last time we surveyed state damage prevention programs there were 13 states that exempted their Departments of Transportation, and 11 states that exempted railroads from important parts of their damage prevention rules. Other states also exempt municipal road and utility departments as well. We think such exemptions provide an unneeded gap in damage prevention programs since excavation by anyone has the same risk of damaging underground pipelines. PHMSA's recent Advanced Notice of Proposed Rulemaking mentioned the need to eliminate exemptions, but we think it would be helpful if during the reauthorization process Congress reiterates this point by specifically asking for these types of exemptions to be removed from damage prevention programs.

We have already provided additional information above about the need for data collection requirements relating to excavation damage to pipelines. Without such data it is impossible to strategically target educational materials and enforcement.

5. It seems clear now that BP wasn't really prepared to respond to a worst case scenario in the Gulf as they stated. I realize that an offshore drilling operation poses different challenges than transportation of product, but do you think that PHMSA should evaluate whether pipeline companies within their jurisdiction are prepared to deal with worst case scenario spills?

This is an area of pipeline safety that the Pipeline Safety Trust has not really analyzed. We have always tried to put our efforts in areas that will help prevent product from being released to begin with, or limit the immediate damage done if a release occurs.

One reason we have not spent time analyzing spill response readiness is that 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. 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. We urge Congress to increase this transparency by requiring the development and review of spill response plans goes through a public comment process, and the spill response plans to be posted on the PHMSA website.

6. One of the key mandates we included in the PIPES Act as a result of the two BP oil spills in 2006 was a requirement that all low-stress hazardous liquid pipelines be regulated in the same manner as other hazardous liquid pipelines. In June 2008 PHMSA issued a Final Rule that regulated 803 miles of low-stress pipelines, but more than 1300 miles remain unregulated. At our last pipeline safety hearing in June 2008, former Administrator Carl Johnson said the second rule would be on the streets in Fall 2008. It's been two years since that hearing and we are still waiting for the second rulemaking. Do you have concerns that PHMSA hasn't issued this rule?

The Pipeline Safety Trust certainly shares your concern about the delay in this promised rulemaking. We have contacted PHMSA about this issue and have been told that the second phase of the low-stress rulemaking will start later this year. While we have no reason to doubt the schedule that has been communicated to us, we certainly think it would be valuable for Congress to reiterate these requirements.

One other area in need of similar review is a rulemaking to provide greater clarity and perhaps expansion of regulations on natural gas pipelines. With the huge increase in domestic natural gas drilling across many parts of the country pipelines to connect these thousands of wells are encroaching on more urbanized areas. Many of these pipelines fall outside of the jurisdiction of the federal minimum safety regulations because of arcane definitions (developed as an industry standard that was incorporated by reference into the federal regulations) that allow pipeline companies to design production systems to avoid regulation. As more and more of these unregulated pipelines are added to populated areas this may well be the next "emergency pipeline issue" that Congress is forced to issue mandates for. We hope that instead of responding to some future tragedy Congress will direct PHMSA to undertake a rulemaking to fix the definitions designed by industry (49 CFR §192.8) so it is clear which pipelines are regulated gathering lines versus production lines versus flow lines. The huge amounts of natural gas coming from these new productions areas are providing the nation with a valuable domestic energy supply. Let's make sure these supplies are developed safely.

7. We learned from yesterday's hearing that MMS has extensively "incorporated by reference standards that are developed by industry organizations in their regulations. Meaning, industry is essentially writing its own regulations. Is this something that concerns you as a safety advocate?

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 lists the following 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

In addition to the practice of incorporating by reference industry developed standards, many regulations require implementation of the regulations based on individual operator's "risk based" analysis. This essentially allows individual pipeline companies to draft their own customized regulations without going through any public review process. One example would be the current push by the natural gas industry to remove the seven-year re-inspection interval that Congress mandated. Instead of a standard re-inspection interval that would allow all companies' results to be compared, each company, based on its own internal findings, would design its own re-inspection program for each individual segment of its pipelines. This engineered, risk-based approach may be feasible. However, 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. This system also totally removes the public from any review and comment on the proposed engineered risk-based approach. For these reasons, we continue to oppose any change to the seven-year re-inspection intervals.

TESTIMONYOF THE AMERICAN PUBLIC GAS ASSOCIATION

BEFORE THE HOUSE TRANSPORTATION AND INFRASTRUCTURE

SUBCOMMITTEE ON RAILROADS, PIPELINES AND HAZARDOUS MATERIALS

HEARING ON IMPLEMENTATION OF THE PIPELINE INSPECTION,

PROTECTION, ENFORCEMENT AND SAFETY ACT OF 2006 AND

REAUTHORIZATION OF THE PIPELINE SAFETY PROGRAM

MAY 20, 2010

Ms. Chairwoman 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 1/2 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).

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 5 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 towards 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 towards 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 three 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 (EFV's)

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 flowrates 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 towards 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 % 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 3rd 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 towards reauthorization of the Pipeline Safety Act.

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