TESTIMONYOF THE AMERICAN PUBLIC GAS ASSOCIATION

SUBMITTED TO THE SENATE COMMERCE, SCIENCE AND TRANSPORTATION SUBCOMMITTEE ON SURFACE TRANSPORTATION AND MERCHANT MARINE INFRASTRUCTURE, SAFETY, AND SECURITY HEARING ON PIPELINE SAFETY: ASSESSING THE SAN BRUNO, CALIFORNIA EXPLOSION AND OTHER RECENT ACCIDENTS

SEPTEMBER 28, 2010

Mr. Chairman and members of the Committee, the American Pubic Gas Association (APGA) appreciates this opportunity to submit testimony on behalf of public gas systems to the Committee for this important hearing on pipeline safety.

APGA is the national association for publicly-owned natural gas distribution systems. There are 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 concern of public gas systems. No other issue rises to the level of safety for the local distribution company (LDC) that provides retail 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 large interstate and intrastate transmission pipelines. Transmission pipelines usually consist of long and straight lines of steel pipe that have a large diameter and are operated at relatively high pressures and stress. By contrast, the distribution pipelines in LDC's are 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 stress 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 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. As with small business, the burdens of regulation on these tiny utilities can be unbearable if not tailored to the realities of the community.

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 safely 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 telemetry 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 distract them from important operations, inspection and maintenance tasks. 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.

<u>Excess Flow Valves (EFV's)</u>

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 <u>AND</u> 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.

<u>San Bruno Accident</u>

On September 9 a 30 inch diameter, high pressure, natural gas transmission pipeline ruptured and the escaping gas ignited killing 4 people, destroying many houses and disrupting the lives of many San Bruno residents. Our thoughts and prayers are with the residents and families affected by the recent natural gas transmission line incident in San Bruno, CA. We are deeply saddened by the tragedy.

APGA and its members recognize the importance of operating and maintaining a safe pipeline system. The National Transportation Safety Board (NTSB) is currently investigating the cause of the accident. When all the facts are known, the lessons learned will be applied by the industry to ensure such accidents never happen again.

There are over 2 million miles of gas transmission and distribution pipelines in the United States. The San Bruno pipeline was a transmission line. Transmission lines tend to be large diameter and operate at high pressures in order to efficiently transport large quantities of gas over long distances. Distribution lines are smaller and much lower pressure than transmission lines. The kind of rupture that occurred in San Bruno could not occur on a distribution line because the pressures are much lower than that in transmission pipelines. Ruptures on distribution typically only occur when the line is damaged by an outside force such as excavation equipment. A distribution line rupture places the excavator and people and property in the immediate vicinity at risk, but could not result in the widespread damage seen in the San Bruno accident.

In addition much attention has been placed on the age of the pipeline involved in the San Bruno accident. Reportedly the steel pipe was over 50 years' old, however contrary to what many have insinuated, steel does not lose strength with age. All of the skyscrapers in the world are steel-framed buildings and many, including the Empire State Building, are well over 50-years' old, yet no one has suggested that these buildings should be replaced because the steel frame is aging. Unless steel is damaged by corrosion or by mechanical damage steel pipelines can be safely operated longer than 50-years. Federal regulations and industry practices require monitoring for corrosion and damage prevention programs to prevent mechanical damage.

The close proximity of the houses to the pipeline no doubt contributed to the severity of the accident. The issue of development near pipelines has been addressed by two Transportation Research Board studies and the ongoing Pipelines and Informed Planning Alliance initiative by PHMSA. Those reports contain useful information about what government and communities can do to address this issue.

As Congress, federal and state pipeline safety regulators and industry assess the causes and consider actions to address safety issues raised by the San Bruno accident APGA urges everyone to wait until the facts are known before legislating specific solutions.

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.