American Public Gas Association

October 25, 2012

Max Kieba
U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration
East Building, 2nd Floor
1200 New Jersey Ave., SE
Washington, DC 20590

Dear Mr. Kieba:

Re: APGA Comments on the LEAK DETECTION STUDY – DTPH56-11-D-000001,

The American Public Gas Association ("APGA") is the national, non-profit association of publicly-owned natural gas distribution systems. APGA was formed in 1961 as a non-profit, non-partisan organization, and currently has approximately 700 members in 36 states. Overall, there are nearly 1,000 municipally-owned systems in the U.S. serving more than five million customers. Publicly-owned gas systems are not-for-profit retail distribution entities that are 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.

All of APGA's members operate distribution pipelines and about 5 percent also operate lines that are classified as transmission, either because these lines operate at or above 20 % of Specific Minimum Yield Stress (SMYS) or meet the functional definition of transmission found at 49 CFR 192.3. As APGA has previously pointed out to PHMSA, "transmission" pipelines operated by distribution systems bear little or no resemblance to real transmission lines. Many are less than 4 inches diameter and may operate at less than 1 percent of SMYS. Therefore APGA is vitally interested in this draft study.

General comments:

APGA appreciates the opportunity to submit comments on the above referenced draft report. In the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 Congress mandated that the Pipeline and Hazardous Materials Safety Administration (PHMSA) write a report to Congress regarding leak detection systems. The relevant portion of the legislation states:

> **SEC. 8. LEAK DETECTION.**
> *(a) LEAK DETECTION REPORT.—*
> *(1) IN GENERAL. — Not later than 1 year after the date of enactment of this Act, the Secretary of Transportation shall submit to the Committee on Commerce, Science, and Transportation of the Senate and the Committee on Transportation and Infrastructure and the Committee on Energy and Commerce of the House of Representatives a report on leak detection systems utilized by* ***operators of hazardous liquid pipeline facilities and transportation-related flow lines.***
> *[Emphasis added]*
> *(2) CONTENTS.—The report shall include—*
> *(A) an analysis of the technical limitations of current leak detection systems, including the ability of the systems to detect ruptures and small leaks that are ongoing or intermittent, and what can be done to foster development of better technologies; and*
> *(B) an analysis of the practicability of establishing technically, operationally, and economically feasible standards for the capability of such systems to detect leaks, and the safety benefits and adverse consequences of requiring operators to use leak detection systems.*

Although not required by the legislation, PHMSA chose to expand the scope of the study to include natural gas transmission and distribution pipelines. APGA hoped that PHMSA would use this report to explain to Congress the significant differences between leak detection on the various types of pipelines that PHMSA regulates, namely:

1. Linear, long distance, high pressure pipelines transporting liquids with varying compressibility (hazardous liquid)
2. Linear, long distance, high pressure pipelines transporting compressible gases (interstate gas transmission),
3. Relatively short, linear or interconnected, high pressure pipelines transporting compressible gases (gas transmission lines operated as part of distribution networks), and
4. Relatively low pressure, interconnected natural gas distribution systems.

Unfortunately the report provides data about leak detection systems (LDS) for the first two types of pipelines but only offers unsupported speculation for LDS on distribution pipelines and transmission lines operated as part of distribution networks. Without any support, the authors offer their opinion that LDS designed for long, linear pipeline systems should also work and be cost effective on interconnected, networked transmission and distribution lines operated by distribution operators.

According to the draft report's summary:

1. Leak detection systems are a proven technology on liquid pipelines.
2. "Practically all internal LDS technologies applicable to liquids pipelines apply equally well to gas pipelines also." [page 2-10]
3. "The cost-benefit for these systems is typically very good." [page 2-11]
4. "Generally, overall full-lifecycle costs of an LDS are minor compared with other systems on the pipeline: automation and control, metering, inspection and maintenance, for example. The difficulty lies in convincing operators of their value so that they do not waste their investments." [page 2-12]
5. "Testing, Maintenance, Control Room Procedures, Training and Continual Improvement are the main operational issues that an operator must consider." [page 2-11]
6. "Gas pipelines are given very little guidance with these issues, either by the industry associations or by regulations." [page 2-11]

In other words, a reader of the summary would conclude that leak detection systems are feasible and cost-effective for natural gas distribution systems and it is only the failure of PHMSA and the American Gas Association to provide guidance on operational issues that is holding back the widespread use of this technology in the gas distribution industry.

Only if the reader continues to read the full report does he/she learn that:

1. The potential benefits of LDS are due to potentially faster response times that could result in reduced property loss. [page 6-9]
2. No reductions in deaths or injuries are projected from the use of LDS in distribution [page 6-9]

3. Distribution incidents where leak detection systems are operational have on average **slower** response times than incidents where no LDS is operational. [page 3-93].
4. Average response times for distribution incidents with no LDS was 0.2 hours (12 minutes). [page 3-93]
5. Despite the fact that incidents with LDS report a slower response time, the report assumes a 75% reduction in property loss for distribution incidents. [page 6-9]

Obviously someone reading just the summary will get a grossly distorted picture of the feasibility, potential costs and potential benefits of LDS on distribution systems.

APGA members do not own or operate hazardous liquid or interstate natural gas transmission pipelines, therefore we cannot comment on those sections of the report. APGA can state that the report's conclusions about LDS on gas distribution lines and transmission lines operated by distribution systems lack any basis in fact and are just plain wrong. To publish such a study would be a grave disservice to APGA's members and an embarrassment to PHMSA. For these reasons APGA urges PHMSA to delete all discussion of gas distribution leak detection systems from its final report to Congress.

Specific Comments:

The draft report is fatally flawed in virtually every section where LDS for distribution is discussed.

Page 2-8 of the draft states that:

> "The overall technical issues identified from the work performed on Task 3, based on data reviewed between January 1, 2010 and July 7, 2012 for natural gas transmission pipelines were:
>
> 1. The pipeline controller/control room identified a release occurred around 16% of the time.
>
> 2. Air patrols, operator ground crew and contractors were more likely to identify a release than the pipeline controller/control room.
>
> 3. An emergency responder or a member of the public was equally likely to identify a release as an air patrols, operator ground crew or contractors.

4. SCADA was the leak identifier in 21 (15%) out of 141 releases where a SCDA was functional at the time of the release.

5. For gas transmission pipelines, SCADA did not appear to respond more often than personnel on the ROW or members of the public passing by the release incident.

6. Large distances between block valves may also have been a contributory factor in the size of the release.

7. For 92 incidents along the ROW where a leak/rupture occurred in a pipe body or pipe seam, there were 22 incidents above the average volume release and 70 below the average volume of 23,078 MSCF.

8. The chances of having an above-average release volume were around 1 in 4. That is a release volume greater than around 23,078 MSCF.

9. For 40 out of 101 incidents the pipeline shut down time was between 5 minutes and 1 hour.

10. For 61 out of 101 incidents the pipeline shut down time was longer than 1 hour."

The draft does not state how many of these incidents involved long-line, linear, actual transmission pipelines and how many involved gas distribution pipelines that are classified as transmission because of the operating pressure or the function of the pipeline. As APGA has previously pointed out to PHMSA, "transmission" pipelines operated by distribution systems bear little or no resemblance to real transmission lines. Many are less than 4 inches diameter and may operate at less than 1 percent of SMYS. The report should differentiate between different types of "transmission" pipeline – those that are true transmission lines and those operated as part of distribution systems.

Page 2-9 the draft states "Releases on gas distribution lines were more likely to ignite and more likely to explode than releases on gas transmission and hazardous liquids pipelines." The report should define what they mean by "explode." An unconfined cloud of natural gas can ignite but will not detonate in what is commonly considered an explosion, e.g. generating a shock wave that will cause damage outside of the ignition area. If there is evidence natural gas distribution leaks can cause explosions that data should be presented.

Also on page 2-9, the draft states that "The pipeline controller/control room identified a release occurred less than 1% of the time." It should be noted that the vast majority of distribution operators (probably over 90%) do not have control rooms or SCADA systems.

On page 2-10 the draft states "Practically all internal LDS technologies applicable to liquids pipelines apply equally well to gas pipelines also. Because of the much greater compressibility of gas, however, their practical implementation is usually far more complex and delicate." Not one shred of evidence is presented in the report to support this statement. It is solely the opinion of the authors. APGA is not aware of any internal LDS technology applicable to networked, interconnected distribution systems or to transmission lines operated as part of a networked, interconnected distribution system. These systems typically have neither pressure sensors nor flow meters anywhere but receipt and delivery points. Few, if any, of the pressure and metering points are telemetered in real time – most customer meters are read monthly, therefore real time LDS based on input and output is impossible. Even if real-time flow measurement were available, performing a mass balance on a interconnected, network of distribution pipelines transporting a compressible fluid (natural gas) would require detailed spacial and temporal pressure, temperature and gas compositional data in order to compute local real (as opposed to ideal) gas densities. The computing power necessary for such real-time density calculations over the millions of miles of distribution piping would require a quantum leap in supercomputing.

On page 2-11 the draft states "Testing, Maintenance, Control Room Procedures, Training and Continual Improvement are the main operational issues that an operator must consider… Gas pipelines are given very little guidance with these issues, either by the industry associations or by regulations." Taken out of context this is a very misleading statement. The reason there is little guidance for LDCs from either trade associations or regulations is 1) 90% plus of LDCs have no SCADA or control room for which testing, maintenance, procedures and improvement could be applied. Furthermore, there is no feasible technology for automatic detection of leaks on interconnected, networked distribution systems. Neither is there technology for automated or remote shutdown of such systems. The authors offer not one single example of a successful application of LDS technology to networked, interconnected distribution system. Virtually every statement in the draft report regarding distribution systems lacks any factual basis, and rather relies on the opinion of the authors. This statement should be deleted.

The entire discussion of economic feasibility in chapter 2 lumps distribution in with transmission and hazardous liquid pipelines. APGA has no knowledge of hazardous liquid pipeline operations and only knowledge of gas transmission operations as it applies to transmission lines operated as part of a distribution system. The statements that the "cost-benefit for these systems is typically very good" is ludicrous and not one shred of supporting evidence is offered to support this statement. The report fails to identify any technically and economically feasible leak detection system for distribution pipelines or transmission pipelines operated as part of distribution systems. This entire section should be deleted.

The statement on page 2-12 that "**<u>In our opinion</u>** many of the leak detection regulations in 49 CFR 195 – especially expressions of principles and procedures – apply in large part equally well to gas pipelines" [emphasis added] is so absurd with respect to distribution pipelines it calls into question the credibility of the entire report. The authors fail to identify a single, successful application of LDS systems to distribution pipeline networks that lack SCADA, control rooms and internal flow measurement systems, e.g. the vast majority of the gas distribution industry. There is not one shred of evidence offered in the report to support this statement. Since this is solely the unsupported opinion of the authors, it should be deleted.

Figure 3.37 Gas Distribution Releases, Initial Identifier will be used to suggest distribution control room management rules need to be improved to improve leak detection capabilities, when, in fact, few, if any, distribution systems have SCADA systems capable of detecting leaks on networked distribution systems. However on page 3-93 the report notes that "[t]he average time to respond for those incidents where SCADA was functional **<u>is 0.4 hours</u>**… Where SCADA was not functional (most of the incidents), the average response time was **<u>0.2 hours</u>**." [emphasis added] APGA challenges the earlier statement that LDS is cost effective, when the data shows that SCADA does not increase the response time to distribution incidents. Such a contrary result ought to call into question the entire analysis of distribution LDS.

Chapter 4.7.3 Gas Distribution Pipelines clearly shows the authors unfamiliarity with distribution systems. It states:

> "All five gas distribution pipelines interviewed use SCADA on their Intermediate pressure systems and therefore Pressure/Flow monitoring was universally claimed as a form of leak detection. In contrast to high-pressure transmission, most reliable measurement on the Intermediate pressure pipelines was of flow measurement, for commercial reasons, at supply and delivery points. The leak detection is therefore actually Flow monitoring.
>
> Given that Flow rate is maintained by the supplier in Intermediate pressure operations we expect this to provide at best large rupture detection and all interviewed operators conceded this.
>
> Two of five operators used ASVs and universally the leak detection principle was Pressure monitoring.
>
> Four of the five operators use Real-Time Transient Modeling (RTTM) of their pipelines but they are used strictly for training, planning and capacity optimization via modeling. They explicitly do not use the RTTM in leak detection.
>
> One operator uses Acoustic technology in especially high-consequence areas, but describes this as a "Pilot".
>
> In summary:
>
> 1. Leak detection is universally by Flow monitoring (100%)
>
> 2. Two operators (40%) use ASVs and the leak detection principle is Pressure monitoring
>
> 3. One operator (20%) uses Acoustic sensors, but describes this as a "Pilot"."

These conclusions clearly indicate that the 5 (out of approximately 1,300) distribution systems interviewed were not representative of distribution systems in general. APGA suspects these 5 were among the 1 percent of the very largest gas distribution systems, and furthermore, that they were answering questions about monitoring capabilities of transmission pipelines that were being monitored and controlled as part of their distribution system rather than actual distribution piping. Anyone with even a basic understanding of networked, interconnected, low pressure distribution systems would immediately recognize that leak detection by flow monitoring, where no real time flow monitoring exists is impossible, that ASVs are also not technologically feasible, and neither are acoustic sensors. The report offers not one shred of evidence to support any of the statements cited above. This entire section should be deleted.

It is not appropriate to extrapolate conclusions based on interviews with 5 of the very largest distribution operators, who may have been answering for their system as a whole, bot transmission and distribution, rather than just their capabilities on piping typical to a purely distribution system.

On page 7-24 the report states that “All five gas distribution pipelines operators interviewed in task 4 use SCADA on their intermediate pressure systems and therefore Pressure/ Flow monitoring was universally claimed as a form of leak detection,” yet the analysis of reportable incidents finds that less than 1% of incidents were detected by SCADA.

Conclusion:

The draft report is seriously flawed with regard to assessing the ability of leak detection systems to detect ruptures and small leaks on natural gas distribution and transmission piping operated as part of distribution systems. The draft report substitutes unsupported opinions for facts on the practicability of establishing technically, operationally, and economically feasible standards for the capability of such systems to detect leaks on distribution piping. The draft report provides no data on the safety benefits and adverse consequences of requiring natural gas distribution operators to use leak detection systems. If released without major corrections, the report will be a disservice to the distribution industry and an embarrassment to PHMSA.

If you have questions, please feel free to contact me.

Sincerely,

John P. Erickson, PE
Vice President, Operations