American Gas Association

October 26, 2012

Patrick Landon
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. Landon:

Re: AGA Comments on the *Studies for the Requirements of Automatic and Remotely Controlled Shutoff Valves on Hazardous Liquids and Natural Gas Pipelines with Respect to Public and Environmental Safety,* Oak Ridge National Laboratory, 2012

I. Introduction

The American Gas Association, founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 71 million residential, commercial and industrial natural gas customers in the U.S., of which 92 percent — more than 65 million customers — receive their gas from AGA members. AGA is an advocate for natural gas utility companies and their customers and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international natural gas companies and industry associates. Today, natural gas meets almost one-fourth of the United States' energy needs.

AGA appreciates the opportunity to submit comments on the above referenced draft report. PHMSA only provided a few days to review and develop comments on this very comprehensive 336 page report. Therefore, AGA will limit its comments to highlighting a few issues contained in the report necessary to place its conclusions in a proper perspective and to properly apply the report's concepts to natural gas transmission pipelines operated by local distribution companies (LDCs).

AGA agrees with the central conclusion of the authors, that remote control valves (RCVs) and automatic shut-off valves (ACVs) can be an effective strategy to mitigate potential fire damages from a rupture of a natural gas transmission pipeline, only if very exacting response times by operator personnel and fire fighters are attainable. The report states:

> *For natural gas pipelines, installing ASVs and RCVs can be an effective strategy for mitigating potential fire consequences resulting from a release and subsequent ignition provided all of the following conditions are satisfied.*
>
> *The leak is detected and the appropriate ASVs and RCVs close completely so that the damaged pipeline segment is isolated within 10 minutes or less after the break, and fire fighting activities within the area of potentially severe damage can begin soon after the fire fighters arrive on the scene.*
>
> *Fire fighters arrive on the scene and are ready to begin fire fighting activities within 10 minutes or less after the break.*
>
> *Fire hydrants are accessible in the vicinity of the potentially severe damage radius.*
>
> *Block valves close in time to reduce the heat flux at the potentially severe damage radius (1.5times the PIR) to 2.5 kW/m2 (800 Btu/hr ft2) or less within 10 to 20 minutes after the break.*[1]

There will be many cases where it will be difficult for pipeline control room operators to detect and initiate closure of control valves within the 10 minutes required by the theoretical analysis in this report. For local distribution companies without a control room, the 10 minute response time will be virtually impossible to achieve. There will be many situations where it will be difficult for firefighters to receive communications from emergency dispatchers, determine the location of the incident, navigate through traffic and initiate fire fighting activities within 10 minutes of a pipeline rupture. It is impossible to determine where a rupture will occur in advance; therefore the requirement in the hypothetical for fire hydrants to be readily available is not achievable in the real world. AGA believes the hypothetical 8 to 13 minute time period the report uses in its cost benefit analysis for detection, closure of valves and initiation of firefighting action is not realistic.

[1] *Executive Draft, Page xxviii, Page 177*

Given the extreme conditions required in report to make installing RCVs and ASVs effective, AGA believes the conclusions in the report are consistent with other studies that concluded that the installation of RCVs and ASVs were not cost beneficial or had limited cost benefit. There have been numerous studies conducted by various parties to assess the impact of remote control valves (RCVs) and automatic shut-off valves (ASVs) and block valve spacing on consequences in the event of a pipeline incident. For example, a study was conducted by the U.S. Department of Transportation, Research and Special Programs Administration in September 1999 to evaluate the feasibility of RCVs. The report, *"REMOTELY CONTROLLED VALVES ON INTERSTATE NATURAL GAS PIPELINES (Feasibility Determination Mandated by the Accountable Pipeline Safety and Partnership Act of 1996)"* found that while RCVs are technically feasible, they are not economically feasible; *"the quantifiable costs far outweigh the quantifiable benefits".* Further, the report also found that *"there is a small benefit from reduced casualties because virtually all casualties from a rupture occur before an RCV could be activated."*

In July 2010, Robert J. Eiber Consultant Inc. and Kiefner and Associates issued a report "Review of Safety Considerations for Natural Gas Pipeline Block Valve Spacing" to ASME Standards Technology, LLC. The study concluded that *"the only quantifiable impact on the type of valve operator, which controls the time to close a valve after an incident, is the economic impact of gas loss, but this does not produce a safety impact. The most severe consequences to the public occur in the first moments after incident initiation, thus valve spacing, valve location and valve closure time (valve operator type) do not affect public safety. This review found that all of the prior research studies, the examination of the PHMSA incident database, and examination of NTSB gas transmission pipeline incidents indicate that main line block valve spacing on natural gas transmission pipelines is not related to public safety. Valves are useful for maintenance and line modification, but they do not control or affect public safety as the injuries and fatalities on natural gas transmission pipelines generally occur during the first 30 seconds after gas has been released from a pipeline."*

In March, 2011 AGA prepared a white paper, "Automatic Shut-off Valves (ASV) and Remote Control Valves (RCVs) On Natural Gas Transmission Pipelines", to provide information related to the relative benefits, challenges, issues, feasibility, costs and performance expectations associated with the installation of ASVs and RCVs. The white paper notes that "*there are potential benefits associated with the use of ASVs and RCVs. Operators should note that the presence of an ASV or RCV on a transmission* *pipeline will not prevent an incident from occurring and may not lessen any related injury to persons or damage to property."* In October 2012, AGA issued a report, *Design Guidelines for Installation of Automatic Shut-off Valve (ASV) and Remote Control Valve (RCV) Systems in Gas Transmission Pipelines.*

The primary difference between the Oakridge report and previous reports is that Oakridge works to develop a theoretical breakeven point where the installation of valves would be cost effective. As the report clearly states, how new or fully replaced transmission pipelines would meet this criteria is not known because of the many variables that must be considered for each individual installation. Essentially, each installation requires an individualized risk assessment that considers the unique features in each pipeline system and the unique features of the installation location.

AGA supports the installation of remote or automatic control valves in new or fully replaced transmission lines where the valves would be technically feasible, operational and cost beneficial[2]. Each pipeline system is unique and the operator must conduct a risk assessment to determine the technical, operational, and cost benefit of installing RCVs and ASVs. Rapid, indiscriminate, mandatory installation of RCVs and ASVs will not improve safety. Existing regulations in 49 CFR 192.935 require operators of natural gas pipelines to conduct a risk analysis of its pipeline in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S, Section 5 (ASME, 2010)[3] and to consider the benefit of installing ASV or RCV. Any regulatory change should be consistent with this risk-based approach.

The remaining comments highlight the following aspects of the report which are essential to a proper understanding of the high-level conclusions.

1. The complexity of the risk assessments for valves requires case-by-case analysis
2. There is a concern with disruption of gas service on gas distribution systems.
3. Risk assessments already required.
4. Not all transmission pipeline ruptures result in catastrophic events.
5. The report is limited to worst case scenarios
6. There are three phases involved in the. The report proposes time limits for response; detection, valve closure and blowdown.

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[2] AGA Commitment to Enhancing Safety
[3] Report page 165

7. The report concludes that valve installation is not cost-beneficial without first responder intervention.

II. Detailed Comments

1. The complexity of the risk assessments for valves requires case-by-case analysis

The vast majority of products moved by pipeline are used to provide energy in various forms - energy to run automobiles, to heat and brighten homes, and to power industries. Together petroleum and natural gas supply over 62% of total U.S. energy needs. There is a network of 300,000 miles of natural gas transmission pipeline in the nation. Approximately 240,000 miles are interstate transmission pipeline and 45,000 miles are intrastate transmission pipelines, i.e. pipelines interwoven into the gas distribution system. The report does not discuss, but recognizes the complexity of the pipeline network and the necessity of its continuous operation. The diversity of pipeline systems means that it is impossible to establish a one-size fits all approach to evaluating and deciding to install RCVs or ASVs. Relevant portions of the report acknowledge that the potential installation of RCVs and ASVs must be evaluated on a case-by-case basis.

> Consideration of site-specific variables is essential in determining whether the cost benefit is positive or negative and whether installation of ASVs or RCVs in newly constructed or fully replaced pipelines is economically feasible.[4]

> These release scenarios do not model the unique features of a particular pipeline facility or it's site-specific design features and operating conditions. These unique features and conditions can invalidate the underlying assumptions in this study and, therefore, reduce or eliminate the positive cost benefits attributed to block valve closure swiftness.[5]

This complexity is particularly an issue on local distribution company systems. Due to the service obligations of LDCs, their systems are highly networked with many locations having multiple supply points. This provides both opportunities and challenges as the use of RCVs and ASVs are considered.

[4] Executive draft, Page xxviii
[5] Executive draft, Page xxviii

The Oakridge report did a very good job in making a generic hypothetical pipeline system for its analysis. Even with the factors listed below the reality of evaluating the installation of RCVs or ASVs is more complicated, especially in gas distribution systems which often are a sole source support to customers.

2. There is a concern with disruption of gas service on gas distribution systems

It is important to minimize the time for the uncontrolled release of gas from a pipeline rupture. However, there are situations, especially with smaller diameter, lower pressure, sole source transmission pipelines where it is prudent to allow the gas to be released until alternative delivery methods are provided to critical customers like hospitals or power generation plants whilst avoiding potential ignition sources. These additional minutes can prevent other safety events unrelated to the pipeline rupture. The report recognizes these considerations and states:

> Operational feasibility evaluations also need to consider factors such as the remoteness and accessibility of the valve location; effects of service disruptions for valve maintenance, repair and testing; and possible travel delays caused by severe weather or traffic congestion. In addition, there may be limited times during the year that pipelines serving critical customers can be shutdown due to service reliability considerations. Therefore, operators must consider downstream system demands when scheduling maintenance.[6]
>
> Although ASVs and RCVs are capable of isolating damaged pipeline segments more quickly than MCVs, their use introduces the possibility of unintended or unnecessary block valve closure and the associated consequences for the operator and the public. For example, human error could be the cause for unnecessary or unwanted RCV closure or an ASV could inadvertently close due to a plausible, but infrequent, event such as a decrease in pipeline pressure caused by changes in demand resulting from extremely cold or hot weather. The resulting service disruption could adversely affect thousands of customers including residences, hospitals, schools, nursing homes, chemical plants, and power plants for days or weeks (AGA, 2011).

3. Risk assessments already required

PHMSA and operators have already been prudent in their evaluation and use of RCVs and ASVs. The existing regulation requires operators to evaluate the value of installing RCVs and ASVs in HCAs. Limited resources and the complexity of these case-by-case risk assessments does not allow for

[6] *Executive draft, Page xxvii*

wide spread evaluation and use outside of HCAs. Many interstate transmission pipelines in rural areas with looped lines utilized RCVs and ASVs because the engineering analysis and potential for unintended consequences is small. The report recognizes the prudence in existing regulation.

> *Pipeline operators are required to conduct risk assessments of their pipelines and take additional measures to mitigate the consequences of a pipeline failure in a HCA. Such additional measures may include, but are not limited to, installing ASVs or RCVs.*[7]
>
> *IM regulations require that an operator must install an automatic or remotely operated valve if the operator determines, based on a risk analysis, that these would be an efficient means of adding protection to a HCA in the event of a gas release (49 CFR 192.935(c)).*[8]
>
> *An operator must conduct a risk analysis of its pipeline in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S, Section 5 (ASME, 2010) to identify additional measures to protect the HCA and enhance public safety.*[9]

AGA believes no amendments are necessary to 49 CFR 192.935. PHMSA should consider amendments to the design requirements for transmission pipelines to ensure that operators perform a risk assessment during the design of new or fully replaced transmission pipelines. AGA offers this regulatory language for a new section in Subpart D–Design of Pipeline Components.

§192.179 Transmission line valves.
(Underlined text is new)

(a) Each transmission line, other than offshore segments, must have sectionalizing block valves spaced as follows, unless in a particular case the Administrator finds that alternative spacing would provide an equivalent level of safety:

(1) Each point on the pipeline in a Class 4 location must be within 2½ miles (4 kilometers) of a valve.

(2) Each point on the pipeline in a Class 3 location must be within 4 miles (6.4 kilometers) of a valve.

(3) Each point on the pipeline in a Class 2 location must be within 7½ miles (12 kilometers) of a valve.

(4) Each point on the pipeline in a Class 1 location must be within 10 miles (16 kilometers) of a valve.

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[7] Executive Draft, Page xxi

[8] Executive Draft, Page 2

[9] Executive draft, *Page 165*

(b) Each sectionalizing block valve on a transmission line, other than offshore segments, must comply with the following:

(1) The valve and the operating device to open or close the valve must be readily accessible and protected from tampering and damage.

(2) The valve must be supported to prevent settling of the valve or movement of the pipe to which it is attached.

(c) Each section of a transmission line, other than offshore segments, between main line valves must have a blowdown valve with enough capacity to allow the transmission line to be blown down as rapidly as practicable. Each blowdown discharge must be located so the gas can be blown to the atmosphere without hazard and, if the transmission line is adjacent to an overhead electric line, so that the gas is directed away from the electrical conductors.

(d) Offshore segments of transmission lines must be equipped with valves or other components to shut off the flow of gas to an offshore platform in an emergency.

(e) Each transmission line constructed or entirely replaced shall incorporate the use of automatic or remote-controlled shut-off valves, or equivalent technology, on sectionalized block valves, where economically, technically, and operationally feasible. Such automatic or remote-controlled valves shall be installed in locations where the operator's ability to shut-down the pipeline in a timely manner in the event of an emergency will be improved, after consideration of the swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, and location of nearest response personnel.

4. Not all transmission pipeline ruptures result in catastrophic events

Operators strive for zero incidents. It is important to note that not all transmission pipeline ruptures result in catastrophic events. Many ruptures do not find an ignition source and the gas release is dissipated into the atmosphere. The report shows that releases from smaller diameter lower pressure pipelines, even if ignited, do not create a potential impact radius (PIR) that is large enough to likely result in injuries or significant damages. Pipelines safety regulations acknowledge these features and provide that these low stress small diameter pipelines comply with a less stringent set of integrity management regulations than large diameter, higher pressure pipe. Any new provisions on installation of ASVs or RCVs should likewise acknowledge this fact and allow for these lesser potential consequences to reduce the potential benefit assessment related to such installations on low stress small diameter pipelines.

Table 3.3. Design features and operating conditions for hypothetical natural gas pipelines considered in the risk analysis

Design Feature	Nominal Line Pipe Diameter, in.	
	42	12
MAOP, psig	1,480	300
PIR, ft	1,115	143
Overall length of pipeline, mi.	100	100
Block valve closure time, minutes after break	8 and 13	8 and 13
Compressor inflow after break, ft/s	0 and 15	0 and 15
Block valve spacing, mi.		
Class 1	20	20
Class 2	15	15
Class 3	8	8
Class 4	5	5

Note: The break occurs adjacent to a block valve rendering the block valve inoperable.

Table 3.3 of the report shows that the PIR for a 12-inch diameter pipe at 300 psig is only 143 ft.

5. The report is limited to worst case scenarios

The report is limited to worst case scenarios for two pipe designs. This of course, provides a conservative analysis for the purpose of calculating the cost-benefit of installing RCVs or ASVs. AGA believes that the authors of the study were forthright in their discussion of the conservative assumptions used in the study. They acknowledge that different cost benefit results will be calculated, positive or negative, on a case-by-case basis.

The scope of the study is further limited by considering only worst case releases of these products resulting from a guillotine-type break in the pipeline… this study will only consider release scenarios that result in immediate ignition of the released product at the break location.[10]

The risk analyses described in Sections. 3.1, 3.2, and 3.3 use various methodologies to quantify the effectiveness of block valve closure swiftness in mitigating damage to the human and natural environments by evaluating a series of case studies for a limited number of hypothetical natural gas and hazardous liquid pipeline release scenarios….. However, these release scenarios do not model any particular or unique pipeline configurations or site-specific conditions that could invalidate the underlying assumptions or reduce consequence severity. In addition, the risk analyses are based on theoretical models that approximate actual pipeline release behavior, but do not account for natural phenomena such as weather conditions at the

[10] Executive draft, *Page 6*

time of the release and physical barriers such as terrain features and vegetation that can also affect reduce consequence severity.[11]

Consequently, economic feasibility assessments for specific pipeline segments need to be based on avoided damage costs and valve automation costs that reflect the actual pipeline design features and operating conditions and the site-specific parameters appropriate for the area where the pipeline segment is located….. Consideration of site-specific variables in the risk analysis is essential in determining whether the cost benefit is positive or negative and whether installation of ASVs or RCVs in newly constructed or fully replaced pipelines is economically feasible.

6. There are three phases involved in the response; detection, valve closure and blowdown. The report incorporates unrealistic time limits for each phase.

The report presents a thorough hypothetical analysis of the response times necessary to make the installation of RCVs and ASVs effective in mitigating fire damage after the release and ignition of natural gas from a transmission pipe rupture. AGA does not believe the response times in the hypothetical are realistic in any of the three stages. It is not considered a common practice to place ASVs in transmission pipelines in distribution systems, because of the unintended consequences of false closure. Human intervention is required to identify a pipeline event, evaluate the situation and make the decision to close the correct isolation valve(s) due to the need to analyze multiple data points and resolve potentially conflicting information. In addition, RCVs require some type of back-up electric power source at the site, and also require communications from the site to the designated control location(s). RCV operation relies on the ability of RTUs to communicate information to the SCADA system, and the gas controller to be able to communicate a command to close the valve back to the local RTU. In practice, the controller has to decide if a drop in pressure from 300 psig to zero is actually a pipeline rupture or a false zero signal because a wire or line in a pressure sensor was cut. Typically, RCVs will not be closed until some type of field confirmation is completed. The 8 to 13 minutes for leak detection and valve closure is not realistic. A gas controller will not shutdown the gas flowing to Manhattan or Capitol Hill because of a single information point that showed low pressure. Therefore, the report acknowledges the limitations of RCVs.

After detecting a signal deviation that exceeds established limits, an analysis is initiated to determine the cause for the deviation and to determine if the deviation is: (1) consistent with

[11] Executive draft, *Page 179*

acceptable system performance, or (2) an indication of a system failure such as a leak or rupture. In the event of a system failure, the signals are used to identify the type and possible causes for the failure, locate the point of failure, and determine the proper course of action to limit the potential consequences of the failure and to minimize impacts on the remainder of the system. Without positive evidence of a leak or failure based on field observations, the decision by control room operators to close block valves to isolate a line segment only occurs after analysis confirms a critical emergency situation. However, pipeline operators use different decision-making processes because every pipeline has unique design features, control schemes, and operating requirements that affect the decision to initiate block valve closure.[12]

7. **The report concludes that without timely first responder intervention the valve installation is not cost-beneficial.**

AGA agrees with the central conclusion of the authors, that remote and automatic control valves can be an effective strategy to mitigate potential fire damages from a rupture of a natural gas transmission pipeline, only if very exacting response times by operator personnel and fire fighters. The report states:

Risk analysis results discussed in Section 3.1.4 show that without fire fighter intervention following natural gas pipeline releases, the swiftness of block valve closure has no effect on mitigating potential fire damage to buildings and personal property in HCAs. Block valve closure swiftness also has no effect on reducing building and personal property damage costs because thermal radiation is most intense immediately following the break. Consequently, without fire fighter intervention, there is no quantifiable benefit in terms of cost avoidance for damage to buildings and personal property attributed to block valve closure swiftness in natural gas pipelines. However, when combined with fire fighter intervention the swiftness of block valve closure has a potentially beneficial effect on mitigating fire damage to buildings and personal property in HCAs. Closing block valves sooner decreases the natural gas release rate which n turn reduces the thermal radiation intensity at a specific location and point in time. After the heat flux at a particular location decreases to an acceptable level, fire fighters can safely initiate fire fighting activities.[13]

The report speaks indirectly to the need by operator personnel and fire fighters to develop and maintain strong emergency response processes and contacts. Actions or activities that can improve arrival time of fire fighters to the incident would also be beneficial to both safety and cost. AGA supports this as a continued need for pipeline safety.[14]

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[12] *Executive draft, Page 163*

[13] Executive draft, *Page 173*

[14] AGA Commitment to Enhancing Safety

Finally, AGA notes that page 5 of the report draft says, "Completion of these objectives will facilitate a favorable closure of NTSB Recommendation (P-11-11) and will enable PHMSA to successfully report the status of transmission pipeline facility operator to respond to a hazardous liquid or gas release from a pipeline segment." It is unclear from review of the report how this facilitation will occur, as the report notes only theoretical scenarios of valve closures and their effects. More importantly, it is not the responsibility of the consultant to speculate what actions are sufficient to address NTSB recommendations. It is recommended that this section be removed from this report.

III. Conclusion

AGA appreciates the opportunity to submit comments on the above referenced draft *Studies for the Requirements of Automatic and Remotely Controlled Shutoff Valves on Hazardous Liquids and Natural Gas Pipelines with Respect to Public and Environmental Safety,* Oak Ridge National Laboratory, 2012. AGA decided to suggest few recommended changes to the study. AGA believes that PHMSA should acknowledge in its report to Congress that the conclusions in the Oakridge report are consistent with other studies that concluded that the installation of RCVs and ASVs in natural gas transmission pipelines were not cost beneficial or had limited cost benefit.

Even with this limited cost benefit industry supports the installation of remote or automatic control valves in new or fully replaced transmission lines where the valves would be technically feasible, operational and cost beneficial[15]. Each pipeline system is unique and operator must conduct its own risk assessment to determine the technical feasibility, operational, and cost benefit of installing RCVs and ASVs. Wide spread, mandatory installation of RCVs and ASVs will not improve safety. Regulations defined in 49 CFR 192.935 require operators of natural gas pipelines to conduct a risk analysis of its pipeline in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S, Section 5 (ASME, 2010).[16] Any regulatory change should be consistent with this risk-based approach.

If you need additional information, please feel free to contact me.

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[15] AGA Commitment to Enhancing Safety
[16] Report page 165

Respectfully submitted,

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