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Report to Congressional Committees

January 2013

PIPELINE SAFETY

Better Data and Guidance Needed to Improve Pipeline Operator Incident Response

GAO

Accountability * Integrity * Reliability

GAO-13-168

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Highlights

Highlights of GAO-13-168, a report to congressional committees

Why GAO Did This Study

The nation's 2.5 million mile network of hazardous liquid and natural gas pipelines includes more than 400,000 miles of "transmission" pipelines, which transport products from processing facilities to communities and large-volume users. To minimize the risk of leaks and ruptures, PHMSA requires pipeline operators to develop incident response plans. Pipeline operators with pipelines in highly populated and environmentally sensitive areas ("high-consequence areas") are also required to consider installing automated valves.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 directed GAO to examine the ability of transmission pipeline operators to respond to a product release. Accordingly, GAO examined (1) opportunities to improve the ability of transmission pipeline operators to respond to incidents and (2) the advantages and disadvantages of installing automated valves in high-consequence areas and ways that PHMSA can assist operators in deciding whether to install valves in these areas. GAO examined incident data; conducted a literature review; and interviewed selected operators, industry stakeholders, state pipeline safety offices, and PHMSA officials.

What GAO Recommends

DOT should (1) improve incident response data and use these data to evaluate whether to implement a performance-based framework for incident response times and (2) share guidance and information on evaluation approaches to inform operators' decisions. DOT agreed to consider these recommendations.

View GAO-13-168. For more information, contact Susan A. Fleming at (202) 512-2834 or flemings@gao.gov.

What GAO Found

The Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) has an opportunity to improve the ability of pipeline operators to respond to incidents by developing a performance-based approach for incident response times. The ability of transmission pipeline operators to respond to incidents—such as leaks and ruptures—is affected by numerous variables, some of which are under operators' control. For example, the use of different valve types (manual valves or "automated" valves that can be closed automatically or remotely) and the location of response personnel can affect the amount of time it takes for operators to respond to incidents. Variables outside of operators' control, such as weather conditions, can also influence incident response time, which can range from minutes to days. GAO has previously reported that a performance-based approach—including goals and associated performance measures and targets—can allow those being regulated to determine the most appropriate way to achieve desired outcomes. In addition, several organizations in the pipeline industry have developed methods for quantitatively evaluating response times to incidents, including setting specific, measurable performance goals. While defining performance measures and targets for incident response can be challenging, PHMSA could move toward a performance-based approach by evaluating nationwide data to determine response times for different types of pipeline (based on location, operating pressure, and pipeline diameter, among other factors). However, PHMSA must first improve the data it collects on incident response times. These data are not reliable both because operators are not required to fill out certain time-related fields in the reporting form and because operators told us they interpret these data fields in different ways. Reliable data would improve PHMSA's ability to measure incident response and assist the agency in exploring the feasibility of developing a performance-based approach for improving operator response to pipeline incidents.

The primary advantage of installing automated valves is that operators can respond quickly to isolate the affected pipeline segment and reduce the amount of product released; however, automated valves can have disadvantages, including the potential for accidental closures—which can lead to loss of service to customers or even cause a rupture—and monetary costs. Because the advantages and disadvantages of installing an automated valve are closely related to the specifics of the valve's location, it is appropriate to decide whether to install automated valves on a case-by-case basis. Several operators we spoke with have developed approaches to evaluate the advantages and disadvantages of installing automated valves. For example, some operators of hazardous liquid pipelines use spill-modeling software to estimate the amount of product release and extent of damage that would occur in the event of an incident. While PHMSA conducts a variety of information-sharing activities, the agency does not formally collect or share evaluation approaches used by operators to decide whether to install automated valves. Furthermore, not all operators we spoke with were aware of existing PHMSA guidance designed to assist operators in making these decisions. PHMSA could assist operators in making this decision by formally collecting and sharing evaluation approaches and ensuring operators are aware of existing guidance.

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Abbreviations

DOT	Department of Transportation
NTSB	National Transportation Safety Board
PHMSA	Pipeline and Hazardous Materials Safety Administration

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Accountability * Integrity * Reliability

United States Government Accountability Office
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January 23, 2013

The Honorable John D. Rockefeller IV
Chairman
The Honorable Ranking Member
Committee on Commerce, Science, and Transportation
United States Senate

The Honorable Fred Upton
Chairman
The Honorable Henry Waxman
Ranking Member
Committee on Energy and Commerce
House of Representatives

The Honorable Bill Shuster
Chairman
The Honorable Nick J. Rahall
Ranking Member
Committee on Transportation and Infrastructure
House of Representatives

The United States has over 2.5 million miles of hazardous liquid and natural gas pipelines that transport approximately 65 percent of the energy we consume. These pipelines, which are largely regulated by the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA), are relatively safe when compared with other modes of transporting hazardous goods (e.g., highway and rail). However, when pipelines leak or rupture the results can be devastating, including fatalities, injuries, and extensive property or environmental damage. Such an "incident" occurred in September 2010 in San Bruno, California, killing 8 people and damaging or destroying over 100 homes.[1] To minimize the risk of a pipeline incident, pipeline operators are required to develop leak detection methods and emergency response plans. Operators with pipelines in highly populated or environmentally sensitive areas (called "high-consequence areas") are subject to supplemental risk-

[1]In its regulations, PHMSA refers to the release of natural gas from a pipeline as an "incident" (49 C.F.R. § 191.3) and a spill from a hazardous liquid pipeline as an "accident." (49 C.F.R. §195.50). For simplicity, this report will refer to both as "incidents."

based regulations under PHMSA's integrity management program.[2] Through this program, PHMSA requires that operators conduct a risk assessment to determine what additional measures to take to mitigate the consequences of pipeline failures. One mitigation measure operators can take based on the results of the risk assessment is to install automated valves, which in the event of an incident, close automatically or are closed remotely by operators in a control room.[3] Since 1971, the National Transportation Safety Board (NTSB) has made recommendations that DOT develop standards and requirements for automated valves. Following the San Bruno incident, NTSB recommended that DOT require natural gas pipeline operators install automated valves in all high-consequence areas.[4]

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 mandated that GAO examine the ability of transmission pipeline[5] operators to respond to a hazardous liquid or natural gas release from an

[2]"High-consequence areas" are defined differently for hazardous liquid and natural gas. For natural gas, such areas typically include highly populated or frequented areas, such as parks. For hazardous liquid, high-consequence areas include highly populated areas, other populated areas, navigable waterways, and areas unusually sensitive to environmental damage.

[3]For the purposes of this report we use the term "install an automated valve" to refer to any actions that allow the operator to remotely or automatically close a valve. Such actions do not necessarily mean an operator is installing a completely new valve. For example, operators may install an actuator and communications at an existing valve location.

[4]See NTSB, *Pipeline Accident Report: Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California*, September 9, 2010, NTSB/PAR-11/01 (Washington, D.C: Aug. 30, 2011). According to NTSB, PHMSA is in the process of responding to this recommendation. Specifically, in August 2011, PHMSA began a rulemaking process that could address the extent to which operators will be required to install automated valves. 76 Fed. Reg. 53086 (Aug. 25, 2011).

[5]For the purposes of this report, we use the term "transmission pipeline" to refer to both onshore hazardous liquid and natural gas pipelines carrying product over long distances to users.

existing pipeline segment.[6] Accordingly, this report contains information on: (1) opportunities to improve the ability of transmission pipeline operators to respond to incidents, and (2) the advantages and disadvantages of installing automated valves in high-consequence areas and ways that PHMSA can assist operators in deciding whether to install valves in these areas.

To determine what opportunities exist to improve the ability of transmission pipeline operators to respond to incidents, we identified the variables that influence operators' incident response capabilities. To do so, we spoke with selected operators about their prior incidents and variables that influenced their ability to respond. Operators were selected based on criteria, including amount and types of pipeline owned in high-consequence areas[7] and geographic diversity. We also discussed prior incidents, incident response times, and federal oversight of the pipeline industry with officials from PHMSA, state pipeline safety offices, industry associations, and safety groups. Based on our discussions and review of prior incidents, we identified variables that influence operators' ability to respond to incidents. We also examined 2007 to 2011 PHMSA incident data, including data on:

- total number of incidents;
- type of incident (leak or rupture);
- type of pipeline where the incident occurred; and
- the dates and times when an incident occurred, the operator identified the incident, the operator's resources (personnel and equipment) arrived on site, and the operator shut down a pipeline or facility.

[6] The Act also directed the Secretary of Transportation to consider additional regulations requiring the use of automated valves where economically, technically, and operationally feasible on new transmission facilities. Pub. L. No. 112-90, § 4, 125 Stat. 1904, 1906 (2012). In response, PHMSA contracted with Oak Ridge National Laboratory to draft a study, which found that automated valves were feasible under certain conditions. Oak Ridge National Laboratory, *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*, ORNL/TM-2012/411 (Oct. 31, 2012).

[7] According to 2010 PHMSA data, the eight operators we selected represented 19 percent of hazardous liquid and 10 percent of natural gas miles in these areas. There were 682 hazardous liquid and natural gas transmission pipeline operators with 98,013 pipeline miles in high-consequence areas.

We assessed the reliability of data through discussions with PHMSA officials and select operators and determined that data elements related to numbers of incidents, types of releases, and types of pipeline where incidents occurred were reliable for the purpose of providing context. However, we determined that data elements related to response time were not sufficiently reliable for the purpose of conducting a detailed analysis of relationships between response time and other factors. Finally, we reviewed federal requirements, and industry and government performance standards related to emergency response within the pipeline industry.

To determine the advantages and disadvantages of installing automated valves in high-consequence areas and ways that PHMSA can assist operators in deciding whether to install these valves, we identified the key factors that should be used in deciding whether to install automated valves in high-consequence areas. To do so, we conducted a literature review of previous research dating back to 1995 and interviewed officials from industry associations and pipeline safety groups. In addition, we collected information from selected operators on their methods for deciding whether to install automated valves, as well as specific pipeline segments and valve locations on which they made such decisions. We also discussed the regulations with officials from PHMSA, state pipeline safety offices, and pipeline operators to determine what, if any, additional guidance would help operators apply the current regulations on installing automated valves. For further details on our scope and methodology, see appendix I.

We conducted this performance audit from March 2012 to January 2013 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

Background

Three main types of pipelines carry hazardous liquid[8] and natural gas from producing wells to end users (residences and businesses) and are managed by about 2,500 operators:

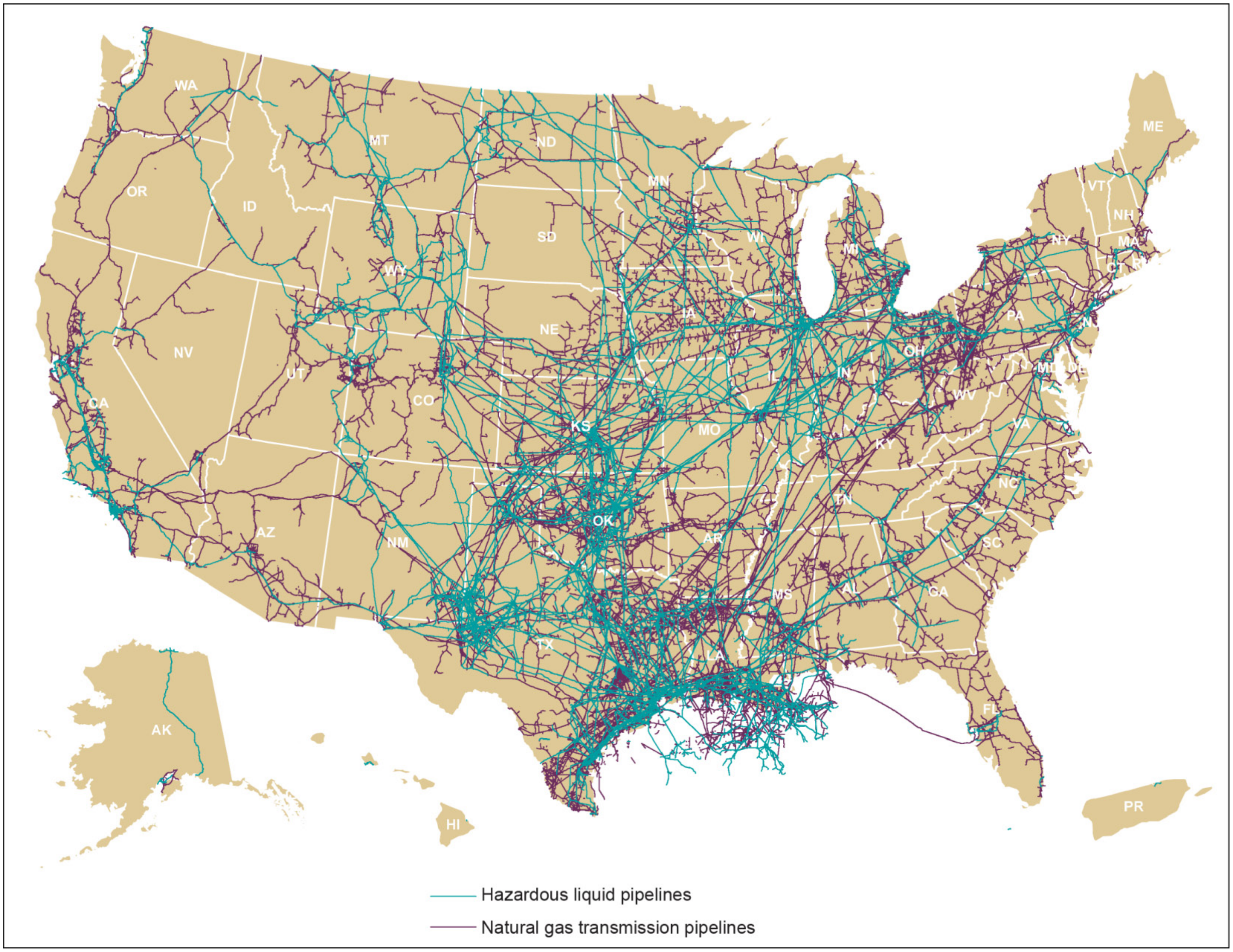
- *Gathering pipelines* collect hazardous liquid and natural gas from production areas and transport the products to processing facilities, which in turn refine and send the products to transmission pipelines. These pipelines tend to be located in rural areas but can also be located in urban areas. PHMSA estimates there are 200,000 miles of natural gas gathering pipelines and 30,000 to 40,000 miles of hazardous liquid gathering pipelines.

- *Transmission pipelines* carry hazardous liquid or natural gas, sometimes over hundreds of miles, to communities and large-volume users, such as factories. Transmission pipelines tend to have the largest diameters and operate at the highest pressures of any type of pipeline. PHMSA has estimated there are more than 400,000 miles of hazardous liquid and natural gas transmission pipelines across the United States. (See fig. 1.)

- *Distribution pipelines* then split off from transmission pipelines to transport natural gas to end users—residential, commercial, and industrial customers. There are no hazardous liquid distribution pipelines. PHMSA has estimated there are roughly 2 million miles of natural gas distribution pipelines, most of which are intrastate pipelines.

[8]Hazardous liquid products include petroleum (crude oil, condensate, natural gasoline, natural gas liquids, and liquefied petroleum gas); petroleum products (flammable, toxic, or corrosive products obtained from distilling and processing of crude oil, unfinished oils, natural gas liquids, blend stocks, and other miscellaneous hydrocarbon compounds); and anhydrous ammonia.

Figure 1: Transmission Pipeline across the United States, as of September 2012



Source: PHMSA.

PHMSA administers the national regulatory program to ensure the safe transportation of hazardous liquid and natural gas by pipeline, including developing safety requirements that all pipeline operators regulated by

PHMSA must meet.[9] In 2012, the agency's budget was $201 million, which was used, in part, to employ over 200 staff in its pipeline safety program. About half of the pipeline safety program staff inspects hazardous liquid and gas pipelines for compliance with safety regulations. Besides PHMSA, over 300 state inspectors help oversee pipelines and ensure safety. State and federal officials may also investigate specific pipeline incidents to determine the reason for the pipeline failure and to take enforcement actions, when necessary.[10]

PHMSA enforces two general sets of pipeline safety requirements. The first are minimum safety standards that cover specifications for the design, construction, testing, inspection, operation, and maintenance of pipelines. The second set of safety requirements are part of a supplemental risk-based regulatory program termed "integrity management."[11] Under transmission pipeline integrity management programs, operators are required to systematically identify and mitigate risks to pipeline segments—discrete sections of the pipeline system separated by valves that can stop the flow of product—that are located in high-consequence areas where an incident would have greater consequences for public safety or the environment. To ensure operators comply with minimum safety standards and integrity management requirements, PHMSA conducts inspections in partnership with state pipeline safety agencies. Inspections may focus on specific pipeline segments or aspects of an operator's safety program, or both. According to PHMSA, officials conduct an inspection for each operator at least once every 5 to 7 years, but may conduct additional inspections based on safety risk or at the discretion of PHMSA or state officials. PHMSA is authorized to take enforcement actions against operators, including

[9]PHMSA does not regulate all pipelines. For example, many gathering pipelines have not been subject to PHMSA regulations because they are generally located away from population centers and operate at low pressures.

[10]PHMSA may conduct an incident investigation in instances when an NTSB investigation is also under way. In such cases, PHMSA does not determine the cause of the incident; rather its review is to determine regulatory compliance.

[11]PHMSA established requirements (49 C.F.R. § 195.452) for integrity management for hazardous liquid pipeline operators with 500 or more miles of pipelines in December 2000 (65 Fed. Reg. 75378, (Dec. 1, 2000)) and for operators with less than 500 miles in January 2002 (67 Fed. Reg. 2136, (Jan.16, 2002)). In 2003, PHMSA issued integrity management regulations for all operators of gas transmission pipelines (68 Fed. Reg. 69778, (Dec.15, 2003)).

issuing warning letters, notices of probable violation, notices of amendment, notices of proposed safety order, corrective action orders, and imposing civil penalties.[12]

Transporting hazardous liquids and natural gas by pipelines is associated with far fewer fatalities and injuries than other modes of transportation. From 2007 to 2011, there was an average of about 14 fatalities per year for all pipeline incidents reported to PHMSA, including an average of about 2 fatalities per year resulting from incidents on hazardous liquid and natural gas transmission pipelines. In comparison, in 2010, 3,675 fatalities resulted from incidents involving large trucks and 730 additional fatalities resulted from railroad incidents. Yet risks to pipelines exist, such as corrosion and third party excavation, which can damage a pipeline's integrity and result in leaks and ruptures. A leak is a slow release of a product over a relatively small area. A rupture is a breach in the pipeline that may occur suddenly; the product may then ignite resulting in an explosion.[13] According to pipeline operators we met with, of the two types of pipeline incidents, leaks are more common but generally cause less damage. Ruptures are relatively rare but can have much higher consequences because of the damage that can be caused by an associated explosion.

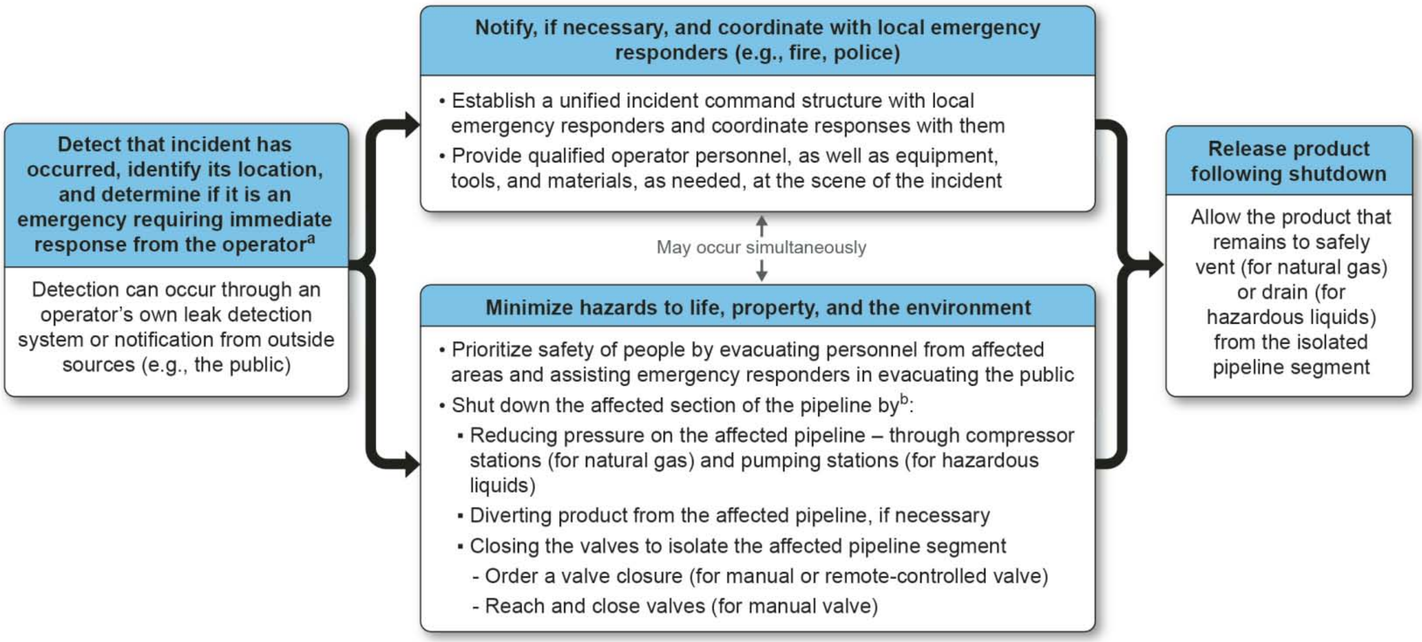
[12] *Warning letters* are issued for lower risk probable violations and program deficiencies. Through such letters PHMSA notifies the operator of the alleged violations and directs it to correct them or be subject to further enforcement action. *Notices of probable violation* allege specific regulatory violations and, where applicable, propose corrective action in a compliance order and/or civil penalties. The operator has a right to respond and request an administrative hearing. *Notices of amendment* allege that an operator's plans and procedures are inadequate and require that they be amended. The operator has a right to respond and request an administrative hearing. *Notices of proposed safety order* notify an operator that a particular pipeline facility has a condition or conditions that pose a pipeline integrity risk to public safety, property, or the environment. These notices propose measures the operator must take to address the identified risk, including inspection, testing, and repair. *Corrective action orders* are issued to operators with a pipeline that represents a serious hazard to life, property, or the environment. The order identifies actions that must be taken by the operator to assure safe operation, including the shutdown of a pipeline or operation at reduced pressure, physical inspection or testing of the pipeline, and repair or replacement of defective pipeline segments, among other actions.

[13] The risks and consequences posed by gas and hazardous liquids incidents also differ. Natural gas tends to ignite more easily, resulting in more explosions. Hazardous liquids ignite less easily, but can spill and pollute the environment.

According to PHMSA, industry, and state officials, responding to either a hazardous liquid or natural gas pipeline incident typically includes steps such as detecting that an incident has occurred, coordinating with emergency responders, and shutting down the affected pipeline segment. (See fig. 2.) Under PHMSA's minimum safety standards, operators are required to have a plan that covers these steps for all of their pipeline segments and to follow that plan during an incident. Officials from PHMSA and state pipeline safety offices perform relatively minor roles during an incident, as they rely on operators and emergency responders to take actions to mitigate the consequences of such events. Following an incident, operators must report incidents that meet certain thresholds—including incidents that involve a fatality or injury, excessive property damage or product release, or an emergency shutdown—to the federal National Response Center,[14] as well as conduct an investigation to identify the root cause and lessons learned. Federal and state authorities may also use their discretion to investigate some incidents, which can involve working with operators to determine the cause of the incident. If necessary, authorities will take steps to correct deficiencies in operator safety programs, including taking enforcement actions.

[14]The National Response Center is the sole federal point of contact for reporting oil and chemical spills.

Figure 2: Steps Operators Take When Responding to Incidents



Sources: GAO analysis, PHMSA, industry stakeholders, and pipeline operators.

[a]Some incidents, such as very small leaks, do not create a hazardous condition and may not require an immediate response from the operator. The operator can address these non-emergency incidents while maintaining normal operations.
[b]Emergency shutdown procedures can be initiated remotely by control room operators or through personnel in the field.

While prior research shows that most of the fatalities and damage from an incident occur in the first few minutes following a pipeline rupture, operators can reduce some of the consequences by taking actions that include closing valves that are spaced along the pipeline to isolate segments. The amount of time it takes to close a valve depends upon the equipment installed on the pipeline. For example, valves with manual controls (referred to as "manual valves") require a person to arrive on site and either turn a wheel crank or activate a push-button actuator. Valves that can be closed without a person located at the valve location (referred to as "automated valves") include both remote-control valves, which can be closed via a command from a control room, and automatic-shutoff valves, which can close without human intervention based on sensor readings.[15,16] (See fig. 3.) Automated valves generally take less time to close than manual valves. PHMSA's minimum safety standards dictate the spacing of all valves, regardless of type of equipment installed to close them,[17] while integrity management regulations require that transmission pipeline operators conduct a risk assessment for high-consequence areas that includes the consideration of automated valves.[18]

[15]Hazardous liquid regulations refer to emergency flow restriction devices, which include remote-control valves and "check" valves that automatically prevent product from flowing in a specific direction. See 49 C.F.R. § 195.452(i)(4). For the purposes of this report we describe all of these valves as automated valves.

[16]PHMSA does not collect data on the number of manual and automated valves. The Interstate Natural Gas Association of America—the primary industry group for natural gas transmission pipelines—has collected valve equipment information for almost half of the 300,000 miles of natural gas transmission pipeline in the United States and reports that of the 29,827 valves reported 5,013, or 17 percent, are automated. In highly populated and frequented locations 1,972, or 23 percent, of the 8,693 total valves, were automated.

[17]49 C.F.R. §§ 192.179, 195.260.

[18]Automated valves are one of several measures that operators can take to prevent and mitigate the consequences of a pipeline incident. Other measures include additional leak detection and damage prevention activities.

Figure 3: A Hand Wheel Used to Close a Manual Valve (Outlined in Red on Left) and an Actuator Used to Remotely Close an Automated Valve (Outlined in Red on Right)

Source: GAO.

A manual valve on the Northwest Pipeline system near Pocatello, Idaho

Source: GAO.

A remotely-controlled valve on an Enterprise Products hazardous liquid pipeline system near Houston, Texas

Performance-Based Approach Offers Opportunity to Improve Incident Response, but Better Data Are Needed

The ability of transmission pipeline operators to respond to incidents, such as leaks and ruptures, is affected by a number of variables—some of which are under operators' control—resulting in variances in response time; for a given incident, that time can range from minutes to days. Several states and industry organizations have developed performance-based requirements for operators to meet in responding to incidents. PHMSA has some performance-based requirements, but its current performance goal related to incident response is not well defined. More precise performance measures and targets could lead to improved response times and less damage from incidents in some cases. However, PHMSA would need better data on incidents to determine the feasibility of such an approach.

Incident Response Time Depends on Multiple Variables, Some of Which Operators Can Control

According to PHMSA officials, pipeline safety officials, and industry stakeholders and operators, multiple variables—some controllable by transmission pipeline operators—can influence the ability of operators to respond quickly to an incident. Ensuring a quick response is important because according to pipeline operators and industry stakeholders, reducing the amount of time it takes to respond to an incident can also reduce the amount of property and environmental damage stemming from an incident and, in some cases, the number of fatalities and injuries. For example, several natural gas pipeline operators noted that a faster incident response time could reduce the amount of property damage from secondary fires (after an initial pipeline rupture) by allowing fire departments to extinguish the fires sooner. In addition, hazardous liquid pipeline operators told us that a faster incident response time could result in lower costs for environmental remediation efforts and less product lost. We identified five variables that can influence incident response time and that are within an operator's control:

- *Leak detection capabilities*. How quickly a leak is detected affects how soon an operator can initiate a response. Pipeline operators must perform a variety of leak detection activities to monitor their systems and identify leaks.[19] These activities commonly include periodic external monitoring, such as aerial patrols of the pipeline, as well as continuous internal monitoring, such as measuring the intake and outtake volumes or pressure flows on the pipeline. In addition, pipeline operators must conduct public awareness programs for those living near pipeline facilities about how to recognize, respond to, and report pipeline emergencies; these programs can influence how quickly an operator becomes aware of an incident. Attempting to confirm an incident can also affect response time. Pipeline operators may prefer to have two sources of information to confirm an incident, such as data from a pipeline sensor and a visual confirmation, especially if shutting down the system is a likely response to the incident. Natural gas pipeline operators in particular generally seek to confirm an incident before a shutdown, as shutdowns interrupt the gas flow and can cut off service to their customers.

[19]Hazardous liquid pipeline operators are required to have a leak detection system on their pipeline. Natural gas pipeline operators may choose to install a leak detection system, although they are required to periodically survey their pipeline to identify leaks.

- *Location of qualified operator response personnel*. The proximity of the operator's response personnel to a facility or shutoff valve can affect the response time. Response personnel who have a greater distance to travel to the facility or valve site can take longer to establish an incident command center or to close manual valves. Along with proximity, incident response time depends on whether qualified operator response personnel—those who are trained and are authorized to take necessary action, such as closing manual valves—are dispatched.

- *Type of valves*. The type of valve an operator has installed on a pipeline segment can affect how quickly the segment can be isolated. Automated valves, which can be closed automatically or remotely, can shorten incident response time compared to manual valves, which require that personnel travel to the valve site and turn a wheel crank or activate a push-button actuator to close the valve. However, if affected valves happen to be located at or close to facilities where personnel are permanently stationed, the type of valve could be less critical in influencing incident response time.

- *Control room management*. Clear operating policies and shutdown protocols for control room personnel can influence response time to incidents.[20] For example, incident response time might be reduced if control room personnel have the authority to shut down a pipeline or facility if a leak is suspected, and are encouraged to do so. A few of the operators we met with told us that while in the past it was a common practice in the industry to avoid shutdowns unless absolutely necessary, the practice now for these operators is to shut down the line if there is any doubt about safety. An official from one natural gas pipeline operator told us that his company instructs control room personnel that they will not suffer repercussions from shutting down a line for safety reasons. Another official from a hazardous liquid pipeline operator told us that the authority to shut down is at the control room level and that even personnel in the field can make the call to shut down a line.

[20]PHMSA requires pipeline operators to develop and follow written control room management procedures that define the roles and responsibilities of control room personnel in normal, abnormal, and emergency operating situations. This requirement allows individual operators to define the specific responsibilities for control room management by considering the characteristics of the operator's pipeline and its methods of safely managing pipeline operation.

- *Relationships with local first responders*. Operators that have already established effective communications with local first responders—such as fire and police departments—may respond more quickly during emergencies.[21] For example, one natural gas pipeline operator told us that during one incident, the local first responders had turned to the operator personnel for direction on how to respond to a rupture. As a result, the operator said that one of the lessons learned was that the company needed to conduct more emergency response exercises, such as mock drills, with the local first responders so the responders would know their roles and responsibilities.

We identified four other variables that influence a pipeline operator's ability to respond to an incident, but are beyond an operator's control:

- *Type of release*. The type of release—leak or rupture—can influence how quickly an operator responds to an incident. Leaks are generally a slow release of product over a small area, which can go undetected for long periods. Once a leak is detected, it can take additional time to confirm the exact location. Ruptures, which usually produce more significant changes in the external or internal conditions of the pipeline, are typically easier to detect and locate.

- *Time of day*. The time of day when an incident occurs can affect incident response time. The operator's response personnel may be delayed in reaching facilities in urban or suburban areas during peak traffic times. Conversely, if an incident occurs during the evening or on a weekend, the operator's response personnel could be able to reach the facility more quickly, because of lighter traffic. For example, one natural gas pipeline operator told us about an incident that occurred on a Saturday afternoon, which meant that traffic did not delay response personnel traveling to the scene.

- *Weather conditions*. Weather conditions can affect how quickly an operator can respond to an incident. For example, one natural gas pipeline operator described an incident caused by a hurricane's storm

[21]PHMSA requires pipeline operators to establish and maintain communications with fire, police, and other appropriate public officials to learn the responsibility and resources of each government organization that may respond to a natural gas or hazardous liquid pipeline emergency and acquaint the officials with the operator's ability in responding to an emergency. Operators must also plan and coordinate their responses to emergency incidents with these officials.

surge that pushed debris into the pipeline at a facility, and flooding prevented the response personnel from reaching the site for several days, during which time the pipe continued to leak gas. Winter conditions can also make it more difficult for the operator's response personnel to reach a facility or to access valve sites in remote areas. As another example, windy conditions can disperse natural gas and make it hard to detect a leak.

- *Other operators' pipeline in the same area*. If two or more operators own pipeline in a shared right of way,[22] determining whose system is affected can increase incident response time. Operators may delay responding if they have not confirmed that the incident is on their pipeline. For example, one natural gas pipeline operator told us about an incident that took 2 days to repair because when their personnel first detected a leak, the personnel initially contacted another operator, whose line crossed over theirs, to make sure the leak was not the other operator's.

Operators we spoke with stated that the amount of time it takes to respond to an incident can depend on all of the variables listed above and can range from several minutes to days (see table 1).

[22]A right of way is a strip of land, usually between 25 to 150 feet wide, containing one or more pipelines.

Table 1: Examples of Response Times in Select Pipeline Incidents from 2009 to 2011

Incident response time	Description
1 minute	A rupture on a natural-gas transmission pipeline located underground in a sparsely populated area was caused when a construction company worker accidentally struck the pipeline, which then ignited and exploded. When the line broke, automatic-shutoff valves on either side of the rupture closed within one minute. Despite the fast valve closure, the explosion caused one fatality—the worker who struck the pipeline—and injured seven others. The affected pipeline segment was 20 miles long. Though the valves were closed, there was enough gas remaining in the pipeline to fuel the fire for several hours. In addition to causing a fatality and injuries, the incident cost the operator an estimated $1 million, due primarily to the value of the lost product ($740,000), as well as damage to the pipeline ($288,000).
3 minutes	A rupture on a hazardous liquid transmission pipeline, located underground near a creek in a sparsely populated area, was caused when heavy rains shifted the land which broke the pipeline, releasing over 1,700 barrels of propane. The line break was immediately picked up by the operator's computer-based leak detection system, and operator personnel on site closed manual valves to isolate the segment within 3 minutes. Because propane is a highly volatile liquid, which turns to gas when released into the atmosphere, there was no soil or water contamination or environmental cleanup costs. The incident cost the operator an estimated $128,000, due primarily to the cost of repairs ($73,000) and value of lost product ($55,000).
8 minutes	During the night, unknown individuals operating construction equipment punctured a hazardous liquid transmission pipeline located underground in an environmentally sensitive area, causing 56 barrels of crude oil to leak into the soil. The puncture caused a drop in pressure that the control room operator detected in 2 minutes. Six minutes later, the control room operator shut down the pipeline and isolated the affected segment with remote-control valves. About two hours later, the operator's response personnel arrived on site. The incident cost the operator an estimated $1.3 million, due primarily to its environmental remediation efforts ($1 million) and emergency response ($250,000).
2 hours	A crack on an above-ground portion of a hazardous liquid pipeline, located in a populated area, caused 120 barrels of crude oil to spray into the air. About 15 minutes after the incident started, a local resident reported to the fire department that crude oil was spraying into the air at a pipeline station. The fire department went to the incident site and, about 30 minutes after the initial call, notified the pipeline operator of a broken oil pipeline. About 20 minutes after receiving the fire department's call, the control room began shutting down the pipeline system and isolating the affected segment by ordering the closure of the upstream valve. Approximately 50 minutes later—about 2 hours after the incident started—response personnel arrived on site and manually closed the valve, which stopped the leak. The incident cost the operator an estimated $183,000, due primarily to its emergency response ($118,000) and environmental remediation efforts ($61,000).
7 days	A natural gas transmission pipeline, located underground in a sparsely populated area, developed a small leak as the result of a construction defect. The operator did not discover the leak on the pipeline for almost a week following initial reports due to the size of the leak in combination with wind gusts in the area that dissipated the escaping natural gas, reducing the common signs of a gas leak, such as the smell and damage to vegetation. Once the operator detected the leak during routine, periodic external monitoring of the pipeline, it took over a day to identify its exact location. The incident cost the operator an estimated $128,000 in repairs ($106,000) and lost product ($22,000).

Source: GAO presentation of information obtained during interviews with pipeline operators.

A Performance-Based Approach Could Improve Incident Response Times

We and others have recommended that the federal government move toward performance-based regulatory approaches to allow those being regulated to determine the most appropriate way to achieve desired, measurable outcomes.[23] For example, Executive Order 13563 calls for improvements to the nation's regulatory system, including the use of the best, most innovative and least burdensome tools for achieving regulatory ends.[24] We have also previously reported on the benefits of a performance-based framework,[25] which helps agencies focus on achieving outcomes.[26] Such a framework should include: 1) national goals; 2) performance measures that are linked to those national goals; and 3) appropriate performance targets that promote accountability and allow organizations to track their progress towards goals.

PHMSA has included these three elements of a performance-based framework in some aspects of its pipeline safety program, but not for incident response times. For example, PHMSA has set national goals intended to reduce the number of pipeline incidents involving fatality or major injury and the number of hazardous liquid pipeline spills with environmental consequences. Each of these national goals has associated performance measures (i.e., the number of such incidents) and specific targets (such as reducing the number of incidents involving a fatality or major injury from 39 to less than 28 per year by 2016) that allow PHMSA to track its progress toward the goals. However, while PHMSA has established a national goal for incident response times, it has not linked performance measures or targets to this goal. Specifically, PHMSA

[23]We consider performance-based regulations those that focus on desired, measurable outcomes, rather than prescriptive processes, techniques, or procedures.

[24]76 Fed. Reg. 3821, § 1 (a), (b)(4) (Jan. 21, 2011).

[25]GAO, *Statewide Transportation Planning: Opportunities Exist to Transition to Performance-Based Planning and Federal Oversight*, GAO-11-77 (Washington, D.C.: December 2010).

[26]In addition, NTSB has recommended that the Department of Transportation conduct an audit to assess the effectiveness of PHMSA's oversight of performance-based safety programs. See NTSB, *Pipeline Accident Report: Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California*, September 9, 2010, NTSB/PAR-11/01 (Washington, D.C: Aug. 30, 2011). In response to the NTSB recommendation, the Department of Transportation is currently conducting an audit, which it expects to issue in early 2013, that will evaluate the effectiveness of PHMSA's inspection and oversight of pipeline operators' integrity management programs, including expanding the use of meaningful metrics and setting goals for pipeline operators and tracking performance against those goals.

directs operators to respond to certain incidents–emergencies that require an immediate response–in a “prompt and effective” manner,[27] but neither PHMSA’s regulations nor its guidance describe ways to measure progress toward meeting this goal. Without a performance measure and target for a prompt and effective incident response, PHMSA cannot quantitatively determine whether an operator meets this goal. PHMSA officials told us that because each incident presents unique circumstances, its inspectors must determine whether an operator’s incident response was prompt and effective on a case-by-case basis. According to PHMSA, in making this determination, inspectors must use their professional judgment to balance any challenges the operator faced in responding with the operator’s obligation to the public’s safety.

Other organizations in the pipeline industry, including some state regulatory agencies, have developed methods for measuring the performance of operators responding to incidents by using specific incident response times. According to the National Association of Pipeline Safety Representatives, several state pipeline safety offices have initiatives that require natural gas pipeline operators to respond within a specified time frame to reports of pipeline leaks. For example, the New Hampshire Public Utilities Commission has established incident response time standards—ranging from 30 to 60 minutes, with performance targets—for natural gas distribution companies to meet when responding to reports of a leak.[28] In addition, members of the Interstate Natural Gas Association of America have committed to achieving a 1-hour incident response time for large diameter (greater than 12 inches) natural gas

[27]Emergencies include natural gas detected inside or near a building, accidental release of hazardous liquid or carbon dioxide from a pipeline facility, fire or explosion occurring near or directly involving a pipeline facility, operational failure causing a hazardous condition, or natural disaster affecting pipeline facilities.

[28]According to these standards, gas distribution companies have three response time targets—30 minutes, 45 minutes, and 60 minutes—which companies must meet between 76 to 97 percent of the time, depending on the response time target and the operator’s working hours when the call is received (i.e., normal business hours, after hours, and weekends/holidays). For example, gas distribution companies are expected to achieve a 30-minute response 76 percent of the time during weekends and holidays, but 82 percent of the time during normal business hours. These response time standards also apply to other events, such as odor complaints or reports of damage to the pipeline.

pipelines in highly populated areas.[29] To meet this goal, operators are planning changes to their systems, such as relocating response personnel and automating over 1,800 valves throughout the United States.

According to PHMSA officials, pipeline incidents often have unique characteristics, so developing a performance measure and associated target for incident response time similar to those used by other pipeline organizations would be difficult. In particular, it would be challenging to establish a performance measure using incident response time in a way that would always lead to the desired outcome of a prompt and effective response. Officials stated that the intention behind requiring operators to respond promptly and effectively is to make the area safe as quickly as possible. In some instances, an operator can accomplish this outcome in the time it takes to close valves and isolate pipeline segments, while in other instances, an operator might need to completely vent or drain the product from the pipeline. Likewise, it would be difficult to identify a specific target for incident response time, as pipeline operators likely should respond to some incidents more quickly than others. For example, industry officials noted that while most fatalities and injuries caused by a pipeline explosion occur in the initial blast, a faster incident response time could help reduce fatalities and injuries in cases where there are sites nearby whose occupants have limited mobility (e.g., prisons, hospitals). In these situations, operators told us they want to ensure their incident response time is faster than for more remote locations where an explosion would have less of an impact on people, property, and the environment.

Although defining performance measures and targets for incident response can be challenging, one way for PHMSA to move toward a more quantifiable, performance-based approach would be to develop strategies to improve incident response based on nationwide data. For example, performing an analysis of nationwide incident data—similar to PHMSA's current analyses of fatality and injury data—could help PHMSA

[29]According to officials from the Interstate Natural Gas Association of America, which represents natural gas transmission pipeline operators, members will conduct a risk analysis on a case-by-case basis to determine the appropriate maximum incident response time for small diameter (i.e., 12 inches or less) natural gas pipelines in highly populated areas. Prior to the 1-hour goal for large diameter pipelines, members did not have any incident response time commitment.

determine response times for different types of pipelines (based on characteristics such as location, operating pressure, and diameter); identify trends; and develop strategies to improve incident response. Furthermore, as part of this analysis of response times for various types of pipelines, PHMSA could explore the feasibility of integrating incident response performance measures and targets for individual pipelines into its integrity management program. For example, PHMSA might identify performance measures that are appropriate for various types of pipelines and allow operators to determine which measures and targets best apply to their individual pipeline segments, based on the characteristics of those segments. Such an approach would be consistent with our prior work on performance measurement, as it would allow operators the flexibility to meet response time targets in several ways, including changes to their leak detection methods, moving personnel closer to the valve location, or installing automated valves. PHMSA would then review an operator's selection of measures and targets as part of ongoing integrity management inspections; this process is similar to how inspectors review other provisions in the integrity management program.

PHMSA Data on Incident Response Time Are Limited

PHMSA would need reliable national data to implement a performance-based framework for incident response times to ensure operators are responding in a prompt and effective manner.[30] However, the data currently collected by PHMSA do not enable them to accurately determine incident response times for all recent incidents for two reasons: 1) operators are not required to fill out certain time-related fields in the PHMSA incident-reporting form and 2) when operators do provide these data, they are interpreting the intended content of the data fields in different ways. Specifically, PHMSA requires operators to report the date and time when the incident occurred. Operators are not required to report the dates and times when:

- the operator identified the incident;
- the operator's resources (personnel or equipment) arrived on site; and
- the operator shut down and restarted a pipeline or facility.

[30]We have reported on the need for comprehensive and reliable data to implement a performance-based approach. See GAO, *Surface Transportation: Restructured Federal Approach Needed for More Focused, Performance-Based, and Sustainable Programs,* GAO-08-400 (Washington, D.C.: Mar. 6, 2008).

As a result, our analysis determined that hazardous liquid pipeline operators did not report the date and time for two of these variables—when the incident was identified and when operator resources arrived on site—for 26 percent (178 out of 674) of incidents that occurred in 2010 and 2011. Also, these operators did not identify whether a shutdown took place in 16 percent (108 out 674) of incidents over the same time period.[31] In comparison, natural gas pipeline operators reported more complete data; these operators did not report data for when the operator identified the incident and resources arrived on site in only 3 percent (6 out of 191) of incidents that occurred in 2010 and 2011. Also, these operators did not identify whether a shutdown took place in only about 2 percent (3 out of 191) of incidents over the same period. PHMSA officials told us that because they have not used the time-related data to identify safety trends, the omissions have not been a problem for them, although in the future they may decide to make some of these data fields mandatory.

In addition to omitting certain incident data fields, several officials from pipeline operators told us that they interpret what to include in the time-related, incident data fields differently. For example, according to one official from a natural gas operator, some operators interpret the time when an operator identified the incident as the time when operator personnel first received a call about a potential leak, while others may interpret the time when an operator identified an incident as the time when operator personnel received an on-site confirmation of a leak. These differing interpretations occur even though guidance on PHMSA's

[31]The DOT Inspector General has also reported on significant data problems with PHMSA hazardous liquid pipeline operator data. In its 2012 audit, the DOT Inspector General identified shortcomings in PHMSA data management and quality that limit the usefulness of incident and annual report data. For example, according to the audit, PHMSA lacks a method to detect duplicate reporting of annual shipment volumes from one year to the next. PHMSA reported that it created a data quality assurance plan in 2010 and has implemented many improvements in its pipeline safety data systems, but still faces significant staffing and funding needs to make further improvements. See Office of Inspector General, U.S. Department of Transportation, *Hazardous Liquid Pipeline Operators' Integrity Management Programs Need More Rigorous PHMSA Oversight*, AV-2012-140 (Washington, D.C.: June, 2012).

website instructs operators how to complete the reporting forms, including the time-related data fields.[32]

Improved Information Sharing about Evaluating Automated Valve Advantages and Disadvantages Could Inform Operators' Decisions

The primary advantage of installing automated valves is reducing the time to shut down and isolate a pipeline segment after a leak or rupture occurs, while disadvantages include the potential for accidental closures and monetary cost. Because these advantages and disadvantages vary among valve locations, operators should make decisions about whether to install automated valves—as opposed to other safety measures—on a case-by-case basis. PHMSA has several opportunities to assist operators in making these evaluations, including communicating guidance and sharing information on some methods operators use to make these decisions.

Improved Response Times, Potential for Accidental Closures, and Costs Should be Evaluated on a Case-by-Case Basis

Research and industry stakeholders indicate that the primary advantage of installing automated valves is related to the time it takes to respond to an incident. Although automated valves cannot mitigate the fatalities, injuries, and damage that occur in the initial blast, quickly isolating the pipeline segment through automated valves can significantly reduce subsequent damage by reducing the amount of hazardous liquid and natural gas released. For example, NTSB found that automated valves would have reduced the amount of time taken to stop the flow of natural gas in the San Bruno incident and, therefore, reduced the severity of property damage and life-threatening risks to residents and emergency responders.[33] According to research and industry stakeholders, automated valves will only decrease the number of fatalities and injuries in those cases when people cannot easily evacuate the area, such as cases involving hospital patients or prison inmates.

Research and industry stakeholders identified several disadvantages operators should consider when determining whether to install automated

[32]PHMSA guidance states that when reporting on when an operator identified the incident, operators should enter the date and time when the operator became aware or first identified when the incident had occurred, and not when the operator determined that the incident met the reporting criteria.

[33]NTSB, *Pipeline Accident Report: Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California*, September 9, 2010, NTSB/PAR-11/01 (Washington, D.C: Aug. 30, 2011).

valves, related to potential accidental closures and the monetary costs of purchasing and installing the equipment. Specifically, automated valves can lead to accidental closures, which can have severe, unintended consequences, including loss of service to residences and businesses. For example, according to a pipeline operator, an accidental closure on a natural gas pipeline in New Jersey resulted in significant disruption and downstream curtailments to customers in New York City during high winter demand. In addition, the monetary costs of installing automated valves can range from tens of thousands to a million dollars per valve, which may be significant expenditures for some pipeline operators.[34] (See table 2.)

Table 2: Advantages and Disadvantages of Installing Automated Valves on Pipelines

Advantages	Improved response time	• Can reduce injuries and fatalities for some locations, such as hospitals or prisons, where people cannot evacuate quickly. • Can reduce the amount of damage by limiting the amount of fuel for secondary fire(s) and environmental cleanup. • Can allow operator personnel and emergency responders to access the affected segment more quickly and safely. • Can reduce the potential monetary cost of an incident for the operator by limiting the amount of product lost.
Disadvantages	Accidental closures	• For natural gas pipelines, accidental closures can result in the loss of service to utilities and critical customers (e.g., winter-time outages can leave people without heat). • For hazardous liquid pipelines, accidental closures can cause an incident, when a valve closes and the subsequent pressure buildup causes the pipeline to rupture.
	Monetary costs	• Requires operators to purchase equipment, including devices to remotely communicate or sense pressure drops, actuators to close the valve, and power sources for this new equipment. • Requires operators to take on installation costs, which can involve temporarily shutting down the pipeline, purging the product from the pipeline, and pulling product from the market. Operators may also have costs related to accessing the valve location (e.g., right of way, permitting, and physical space to install the new equipment) and updating their leak detection technologies. • May require operators to incur additional recurring costs to train staff, maintain the valves, increase security, and conduct inspections of the new valve.

Source: GAO analysis of research and industry stakeholder opinions.

Research and industry stakeholders also indicate the importance of determining whether to install valves on a case-by-case basis because

[34] See below and appendix III for a discussion on the costs of automated valves.

the advantages and disadvantages can vary considerably based on factors specific to a unique valve location. These sources indicated that the location of the valve, existing shutdown capabilities, proximity of personnel to the valve location, the likelihood of an ignition, type of product being transported, operating pressure, topography and pipeline diameter, among others, all play a role in determining the extent to which an automated valve would be advantageous.

Operators Have Developed Approaches to Evaluate Advantages and Disadvantages of Installing Automated Valves

Operators we met with are using a variety of methods for determining whether to install automated valves. One of the eight operators we met with had decided to install automatic-shutoff valves across its pipeline system, regardless of risk, to eliminate the need for control room staff to make judgment calls on whether or not to close valves to isolate pipeline segments. However, seven of the eight operators we met with developed their own risk-based approach for considering potential advantages and disadvantages when making these decisions on a case-by-case basis. For example, two natural gas pipeline operators told us that they applied a decision tree analysis to all pipeline segments in highly populated and frequented areas. They used the decision tree to guide a variety of yes-or-no questions on whether installing an automated valve would improve response time to less than an hour and provide advantages for locations where people might have difficulty evacuating quickly in the event of a pipeline incident. Other operators said they used computer-based spill modeling to determine whether the amount of product release would be significantly reduced by installing an automated valve. These seven operators told us that their approaches for making decisions about whether to install automated valves considered the advantages and the disadvantages we identified above.[35]

- *Improved response time*. Most operators we spoke with considered whether automated valves would lead to a faster response time. For example, the primary criterion used by two of the natural gas pipeline operators was the amount of time it would take to shut down the pipeline and isolate the segment and population along the segment. In one instance, an operator decided to install a remote-control valve in a location that would take pipeline personnel 2.5 hours to reach and 30 minutes more to close the valve. Installing the automated valve is

[35]See appendix II for more details on the methods used by each operator to determine whether or not to install automated valves.

expected to reduce the total response time to under an hour, including detecting the incident and making the decision to isolate the pipeline segment. In addition, several hazardous liquid pipeline operators used spill modeling to determine whether an automated valve would result in a reduced amount of damage from product release at individual locations. This spill modeling typically considered topography, operating pressure, and placement of existing valves. For example, one hazardous liquid pipeline operator used spill modeling to make the decision to install a remote-control valve on a pipeline segment with a large elevation change after evaluating the spill volume reduction.

- *Accidental closures*. Operators indicated that installing automated valves, especially automatic-shutoff valves, could have unintended consequences, which they considered as part of their decisions to install automated valves. For example, two natural gas pipeline operators considered whether there is the potential for accidentally cutting off service when assessing individual locations for the possible installation of an automatic-shutoff valve. As noted, one natural gas pipeline operator has made the decision to install automatic-shutoff valves across its pipeline system. The operator stated that in the past, there were concerns with relying on automatic-shutoff valves because of the possibility for accidental closures, but the operator believes it has developed a process that effectively adapts to pressure and flow change and minimizes or eliminates the risk of the valve accidentally closing. Other natural gas pipeline operators stated that relying on pressure sensing systems can be dangerous because "tuning" the pressure activation in an effort to avoid accidental closures can result in situations where the valve will not automatically close during an actual emergency. For hazardous liquid, all operators we spoke with stated that they either do not consider or do not typically install automatic-shutoff valves because an accidental closure has the potential to lead to an incident. Specifically, operators stated that an unexpected valve closure can result in decompression waves in the pipeline system, which might cause the pipeline to rupture if operators cannot reduce the flow of product promptly.

- *Monetary costs*. According to operators and other industry stakeholders, considering monetary costs is important when making decisions to install automated valves because resources spent for this purpose can take away from other pipeline safety efforts. Specifically, operators and industry stakeholders told us they often would rather focus their resources on incident prevention to minimize the risk of an incident instead of focusing resources on incident response. PHMSA stated that it generally supports the idea that pipeline operators should be given flexibility to target compliance dollars where they will have the most safety benefit when it is possible to do so. Operators we spoke with stated that they considered costs associated with purchasing and installing equipment. For example, four operators indicated that they will consider the costs related to communications equipment when determining whether to install automated valves. In addition, three operators stated that decisions to install automated valves are affected by whether the operator has or can gain access to the pipeline right of way. Other cost considerations mentioned by at least one operator included local construction costs and possible changes to leak detection systems. Finally, two natural gas pipeline operators stated that monetary cost plays a role in determining what steps they plan to take to meet a one-hour response time goal for pipelines in highly populated areas. For example, the operator might choose to move personnel closer to valves rather than installing automated valves, if that is the more cost-effective option.[36]

Opportunities Exist for PHMSA to Better Communicate Guidance and Share Best Practices Operators Use to Determine Whether to Install Automated Valves

PHMSA has developed guidance to help operators understand current regulations[37] on what operators must consider when deciding to install automated valves, but not all operators are aware of the guidance. PHMSA includes on its primary website two types of guidance that can be useful for operators in determining whether to install automated valves on transmission pipelines. First, PHMSA has developed inspection protocols for both the hazardous liquid and natural gas integrity management program. Second, PHMSA has developed guidance on the enforcement actions inspectors will take—such as a notice of proposed violation and warning letter, among others—should PHMSA discover a violation. Both of these pieces of guidance provide additional detail—not included in regulation—on the steps operators might take in considering whether to install automated valves. For example, PHMSA's inspection protocol for

[36]For a discussion of the costs of installing automated valves see appendix III.

[37]Federal regulations require hazardous liquid and natural gas pipeline operators to consider measures to prevent and mitigate the consequences of a pipeline failure that could affect a high-consequence area, including installing automated valves on individual pipeline segments if the operator determines such a valve would add protection and enhance public safety. As part of this determination, operators must consider certain factors at a minimum. These factors relate to descriptive characteristics of individual pipeline segments—such as pipeline profile and operating pressure—and consideration of the possible safety and environmental outcomes. See 49 C.F.R. §§ 192.935, 195.452(i).

natural gas operators describes several studies on the generic costs and benefits of automated valves and indicates that operators may use this research as long as they document the reasons why the study is applicable to the specific pipeline segment. However, operators we spoke with were unaware of existing guidance to varying degrees. Specifically, of the eight operators we met with, three were unaware of both the inspection and enforcement guidance, and the remaining five operators were unaware of the enforcement guidance. Operators we spoke with, including those that were unaware of the guidance, told us that having this information would be helpful in making decisions to install automated valves. According to PHMSA, the agency provides this guidance to operators to ensure operators follow it as they make decisions on whether to install automated valves, but does not re-distribute the guidance at regular intervals (e.g., annually).

According to PHMSA, inspectors see examples of how operators make decisions to install automated valves during integrity management inspections, but the inspectors do not formally collect this information or share it with other operators. Current regulations give operators a large degree of flexibility in making decisions in deciding to install automated valves. As mentioned earlier, we spoke with operators that are using a variety of risk-based methods for making decisions about automated valves. For example, some used basic yes-or-no criteria, while others applied commercially available computer software to model potential incident outcomes. According to PHMSA, officials do not formally share what they view as good methods for determining whether to install automated valves. Officials stated they do not believe it is appropriate for PHMSA to publicly share decision-making approaches from a single operator, as doing so might be seen as an endorsement of that approach. However, according to PHMSA, its inspectors may informally discuss methods used by operators for making decisions to install automated valves and suggest these approaches to other operators during inspections. While the operators we spoke with represent roughly 18 percent of the overall hazardous liquid and natural gas transmission pipelines in high-consequence areas in 2010, there are over 650 additional pipeline operators we did not speak with that may be using other methods for determining whether to install automated valves. As such, we believe that both operators and inspectors could benefit from exposure to some of the methods used by other operators to make decisions on whether to install automated valves.

We have previously reported on the value of organizations reporting and sharing information and recommended that PHMSA develop methods to share information on practices that can help ensure pipeline safety.[38] PHMSA already conducts a variety of information-sharing activities that could be used to ensure operators are aware of both existing guidance and of approaches used by other operators for making decisions to install valves. While, according to PHMSA officials, the agency will not endorse a particular operator's approach or practice, it can and does facilitate the exchange of information among operators and other stakeholders. For example, PHMSA issues advisory alerts in the Federal Register on emerging safety issues, including identified mechanical defects on pipelines, incidents that occurred under special circumstances, and reminders to correctly implement safety programs (e.g., drug and alcohol screening). In addition, PHMSA administers a website different from its primary website that, according to officials, is intended to ensure communication with pipeline safety stakeholders, including the public, emergency officials, pipeline safety advocates, regulators, and pipeline operators.[39] PHMSA also periodically conducts public workshops with pipeline stakeholders on a wide variety of topics, including one in March 2012 on automated valves.

Conclusions

While PHMSA currently requires operators to respond to incidents in a "prompt and effective manner," the agency does not define these terms or collect reliable data on incident response times to evaluate an operator's ability to respond to incidents. A more specific response time goal may not be appropriate for all pipelines. However, some organizations in the pipeline industry believe that such a performance-based goal can allow operators to identify actions that could improve their ability to respond to incidents in a timelier manner, and are taking steps to implement a performance-based approach. A performance-based goal that is more specific than "prompt and effective" could allow operators to examine the numerous variables under their control within the context of an established time frame to understand their current ability to respond and identify the most effective changes to improve response times, if needed, on individual pipeline segments. Reliable data would improve PHMSA's

[38]GAO, *Pipeline Safety: Collecting Data and Sharing Information on Federally Unregulated Gathering Pipelines Could Help Enhance Safety*, GAO-12-388 (Washington, D.C.: Mar. 22, 2012) and GAO, *Rail Transit: FTA Programs Are Helping Address Transit Agencies' Safety Challenges, but Improved Performance Goals and Measures Could Better Focus Efforts*, GAO-11-199 (Washington, D.C.: Jan. 31, 2011).

[39]See http://primis.phmsa.dot.gov/comm/.

ability to measure incident response and assist the agency in exploring the feasibility of developing a performance-based approach for improving operator response to pipeline incidents.

One of the methods operators could choose to meet a performance-based approach to incident response is installing automated valves, a measure some operators are already taking to reduce risk. Given the different characteristics among valve locations, it is important for operators to carefully weigh the potential for improved incident response times against any disadvantages, such as the potential for accidental closure and monetary costs, in deciding whether to install automated valves as opposed to other safety measures. However, not all operators we spoke with were aware of existing PHMSA guidance and PHMSA does not formally collect or share evaluation approaches used by other operators to make decisions about whether to install automated valves. Such information could assist operators in evaluating the advantages and disadvantages of these valves and help them determine whether automated valves are the best option for meeting a performance-based incident response goal.

Recommendations for Executive Action

We recommend that the Secretary of Transportation direct the PHMSA Administrator to take the following two actions:

- To improve operators' incident response times, improve the reliability of incident response data and use these data to evaluate whether to implement a performance-based framework for incident response times.

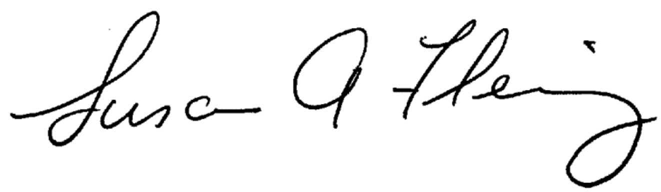
- To assist operators in determining whether to install automated valves, use PHMSA's existing information-sharing mechanisms to alert all pipeline operators of inspection and enforcement guidance that provides additional information on how to interpret regulations on automated valves, and to share approaches used by operators for making decisions on whether to install automated valves.

Agency Comments

We provided the Department of Transportation with a draft of this report for review and comment. The department had no comments and agreed to consider our recommendations.

We are sending copies of this report to relevant congressional committees, the Secretary of Transportation, and other interested parties. In addition, this report will also be available at no charge on GAO's website at http://www.gao.gov.

If you or your staff have any questions about this report, please contact me at (202) 512-3824 or flemings@gao.gov. Contact points for our Offices of Congressional Relations and Public Affairs may be found on the last page of this report. GAO staff who made key contributions to this report are listed in appendix IV.



Susan Fleming
Director, Physical Infrastructure

Appendix I: Objectives, Scope, and Methodology

The objectives of our review were to determine (1) the opportunities that exist to improve the ability of transmission pipeline operators to respond to incidents and (2) the advantages and disadvantages of installing automated valves in high-consequence areas and ways that the Pipeline and Hazardous Materials and Safety Administration (PHMSA) can assist operators in deciding whether to install valves in these areas.

To address our objectives, we reviewed regulations, National Transportation Safety Board (NTSB) incident reports, and PHMSA guidance and data on enforcement actions, pipeline operators, and incidents, related to onshore natural gas transmission and hazardous liquid pipelines. We also attended industry conferences and interviewed officials at PHMSA headquarters and regional offices (Eastern, Southwestern, and Western), state pipeline safety agencies, pipeline safety groups, and industry associations. Specifically, we interviewed officials from the American Gas Association, American Petroleum Institute, Arizona Office of Pipeline Safety, Association of Oil Pipelines, Interstate Natural Gas Association of America, National Association of Pipeline Safety Representatives, NTSB, Pipeline Research Council International, Public Utilities Commission of Ohio, and West Virginia Public Service Commission.

To address both objectives, we also conducted case studies on eight hazardous liquid and natural gas pipeline operators. We selected these operators based on our review of PHMSA data on the operators' onshore pipeline mileage, product type and prior incidents, recommendations from industry associations and PHMSA, and to ensure geographic diversity. We selected six hazardous liquid and natural gas pipeline operators with a large amount of pipeline miles in high-consequence areas that also reported recent incidents (i.e., one or more incident(s) reported from 2007 through 2011) with a range of characteristics, such as: affected a high-consequence area; resulted in an ignition/explosion; or involved an automated valve. We also selected one natural gas pipeline operator and one hazardous liquid pipeline operator with a small number of pipeline miles in high-consequence areas, to obtain the perspective of smaller pipeline operators.[1] Specifically, we interviewed officials from:

[1]According to 2010 PHMSA data, the eight operators we selected represented 19 percent of hazardous liquid and 10 percent of natural gas miles in high-consequence areas. There were 682 hazardous liquid and natural gas transmission pipeline operators with 98,013 pipeline miles in high-consequence areas.

- Belle Fourche Pipelines (Casper, Wyoming)—Hazardous Liquids;
- Buckeye Partners (Breinigsville, Pennsylvania)—Hazardous Liquids;
- Enterprise Products (Houston, Texas)—Hazardous Liquids and Natural Gas;
- Granite State Gas Transmission (Portsmouth, New Hampshire)—Natural Gas;
- Kinder Morgan-Natural Gas Pipeline Company (Houston, Texas)—Natural Gas;
- Phillips 66 (Houston, Texas)—Hazardous Liquids;
- Northwest Pipeline GP (Salt Lake City, Utah)—Natural Gas; and
- Williams-Transco (Houston, Texas)—Natural Gas.

To determine what opportunities exist to improve the ability of transmission pipeline operators to respond to incidents, we identified several factors that influence pipeline operators' incident response capabilities. To do so, we discussed prior incidents, incident response times, and federal oversight of the pipeline industry with officials from PHMSA, state pipeline safety offices, industry associations, and safety groups. We also spoke with operators about their prior incidents and the factors that influenced their ability to respond. We also examined 2007 to 2011 PHMSA incident data, including data on total number of incidents, type of incident (leak or rupture), type of pipeline where the incident occurred, and the date and time when: an incident occurred; an operator identified the incident; operator resources (personnel and equipment) arrived on site; and an operator shut down a pipeline or facility. We assessed the reliability of these data through discussions with PHMSA officials and selected operators. We determined that data elements related to numbers of incidents, types of releases, and types of pipeline where incidents occurred were reliable for the purpose of providing context, but that data elements related to response time were not sufficiently reliable for the purpose of conducting a detailed analysis of relationships between response time and other factors. We also reviewed federal requirements, prior GAO reports, and industry and government performance standards related to emergency response within the pipeline industry.

To determine the advantages and disadvantages of installing automated valves in high-consequence areas and the ways that PHMSA can assist operators in deciding whether to install these valves, we identified the key factors that should be used in deciding whether to install automated valves in high-consequence areas. We used two categories of sources to identify the key factors:

(1) *Literature review*. We conducted a literature review of previous research on pipeline incidents. Specifically, we used online research software to search through databases of scholarly and peer-reviewed materials—including articles, journals, reports, studies, and conferences dating back to 1995—which identified over 200 sources.

(2) *Interviews with industry stakeholders*. During our interviews with officials from industry associations and pipeline safety groups, we discussed the advantages and disadvantages of installing these valves.

To ensure that the literature review included just those documents that were relevant to our purpose, two analysts independently reviewed abstracts from the 200 sources identified to determine whether they were within the scope of our review. Each source had to meet specific criteria, including mentioning automated valves, pipeline incidents, and operator emergency response. We excluded sources that were overly technical for the purposes of our review. To ensure these analysts were making similar judgments, they separately examined a random sampling of each other's sources. The analysts then added sources suggested by industry stakeholders during our interviews and reviewed them using the same criteria. After excluding documents that were not publicly available, one analyst reviewed these sources to identify advantages and disadvantages operators should consider when making decisions to install automated valves. A second analyst reviewed the analysis and performed a spot check on identified advantages and disadvantages. Specifically, the second analyst picked four of the sources at random to review and compared the advantages and disadvantages he identified to those of the first analyst. As part of our case studies, we discussed these advantages and disadvantages with operators. We also collected information from operators on their methods for deciding whether to install automated valves, as well as specific pipeline segments and valve locations where operators made such decisions (see app. II). We contacted vendors (manufacturers and installers) of automated valves to identify the range of costs for purchasing and installing these valves. We also discussed the regulations with officials from PHMSA headquarters and regional offices, state pipeline safety offices, and pipeline operators to determine what, if any, additional guidance would help operators apply the current regulations on installing automated valves.

We conducted this performance audit from March 2012 to January 2013 in accordance with generally accepted government auditing standards.

Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

Appendix II: How Select Operators Determined Whether to Install Automated Valves

We conducted site visits to eight hazardous liquid and natural gas pipeline operators with different amounts of pipeline miles in or affecting high-consequence areas.[1] Seven of the eight operators we visited told us they use approaches that consider both the advantages and disadvantages of installing automated valves on a case-by-case basis as opposed to other safety measures; the eighth operator stated that it follows a corporate strategy of installing automated valves in all high-consequence areas. A brief description of the approach used by each of the eight operators, based on our discussions with them, follows.

Pipeline operator: Belle Fourche

Product type: Hazardous liquid

Number of pipeline miles: 460 (total); 135 (could affect high-consequence areas)

Decision-making approach: The operator assesses each pipeline segment[2] using spill-modeling software to determine the amount of product release and extent of damage that would occur in the event of an incident. The software considers flow rates, pressure, terrain, product type, and whether the segment is located over land or a waterway. Monetary costs are considered as part of the decision-making process, including the cost of installing communications equipment and gaining access to the valve location when the operator does not own the right of way. The operator stated that installing a remote-control valve costs between $100,000 and $500,000. Automatic-shutoff valves are not considered as the operator believes an accidental closure could lead to pipeline ruptures.

[1]Requirements for integrity management require hazardous liquid pipeline operators to determine whether an incident on their pipeline could affect a high-consequence area, while natural gas pipeline operators are required to determine whether their pipeline is in a high-consequence area. Regulations also define how to identify high-consequence areas for these two types of operators.

[2]Pipeline segments are discrete sections of the pipeline system separated by valves that can stop the flow of product. The distance between valves is dictated in federal regulations. C.F.R. §§ 192.179, 195.260.

Results to date: According to Belle Fourche officials, this approach has not resulted in any decisions to install automated valves because the advantages have not outweighed the disadvantages on any of the pipeline segments assessed.[3]

Pipeline operator: Buckeye Partners

Product type: Hazardous liquid

Number of pipeline miles: 6,400 (total); 4,179 (could affect high-consequence areas)

Decision-making approach: The operator assesses each pipeline segment using spill-modeling software to determine the amount of product release and extent of damage that would occur in the event of an incident. The operator considers installation of an automated valve when this modeling shows such a valve would 1) reduce the size of the incident by 50 percent or more and 2) significantly reduce the consequences of an incident. The operator conducts additional analysis to determine the location where the automated valve would lead to the largest reduction in spill volume and overall consequences of an incident. Monetary costs are considered as part of the decision-making process, including costs for gaining access to pipeline when the operator does already not own the right of way. The operator stated that installing a remote-control valve costs between $35,000 and $325,000. Automatic-shutoff valves are considered, but not typically installed, as the operator believes an accidental closure could lead to a pipeline rupture.

Results to date: According to Buckeye Partners officials, this approach has resulted in additional analysis of the possible installation of 25 remote-control valves along 75 pipeline segments assessed.

Pipeline operator: Phillips 66

Product type: Hazardous liquid

[3]According to the operator, several automated valves have been installed independent from this decision-making approach.

Number of pipeline miles: 11,290 (total); 3,851 (could affect high-consequence areas)

Decision-making approach: The operator assesses every 100 feet of pipeline (which covers all pipeline segments) using spill-modeling software to determine the amount of product release and extent of damage that would occur in the event of a complete rupture. The operator also uses a relative consequence index for individual pipeline segments that considers the impact to high-consequence areas. Automated valve projects are further evaluated if 1) the potential drain volume is greater than 1,000 barrels, 2) the pipeline segment exceeds a certain threshold on the consequence index, or 3) the existing automated valves are greater than 7.5 miles apart. Monetary costs are considered as part of the decision-making process, including the cost of installing communications equipment, access to power, gaining access to the valve's location when the operator does not own the right of way, and local construction costs. The operator stated that installing an automated valve costs between $250,000 and $500,000. Automatic-shutoff valves are not considered as the operator believes an accidental closure could lead to pipeline ruptures.

Results to date: According to the Phillips 66 officials, this approach has resulted in decisions to install 71 automated valves in the 508 high-consequence area locations assessed.

Pipeline operator: Enterprise Products

Product type: Hazardous liquid and natural gas

Number of pipeline miles: 23,012 (total); 8,783 (could affect or in high-consequence areas)

Decision-making approach: The operator assesses each pipeline segment using spill-modeling software to determine the amount of product release and extent of damage that would occur in the event of an incident. The software considers factors such as topography and the placement of existing valves. The operator also uses a risk algorithm to identify threats to individual pipeline segments. The operator told us that it does not have specific criteria for guiding decisions to install automated valves; rather, officials make judgment calls based on the results of spill modeling and the application of the risk algorithm. Monetary costs are considered as part of the decision-making process, including the cost of installing communications equipment and the amount of necessary infrastructure work. The operator stated that installing a remote-control valve costs between $250,000 and $500,000. Pipelines carrying gas or highly volatile liquids—which are in gas form when released into the atmosphere—are excluded from consideration, according to the operator, because industry studies have shown that automated valves do not significantly improve incident outcomes for these product types.

Results to date: According to Enterprise Products officials, this approach has not resulted in any decisions to install automated valves because the advantages have not outweighed the disadvantages on any of the pipeline segments assessed.

Pipeline operator: Granite State Gas Transmission

Product type: Natural gas

Number of pipeline miles: 86 (total); 11 (high-consequence areas)

Decision-making approach: The operator assesses individual pipeline segments in high-consequence areas using risk analysis software that considers the operator's response time to an incident, population in the area, and pipeline diameter, among other variables. Monetary costs are considered as part of the decision-making process, including the cost of installing communications equipment and costs to change or improve the existing leak detection system. The operator stated that installing an automated valve costs between $40,000 and $50,000. Automatic-shutoff valves are not considered, as officials believe that they could lead to unintended consequences, such as accidental closures.

Results to date: According to Granite State Gas Transmission officials, this approach has resulted in decisions to install remote-control valves in 30 of the 30 locations assessed.

Pipeline operator: Kinder Morgan-Natural Gas Pipeline Company of America (NGPL)

Product type: Natural gas

Number of pipeline miles: 9,800 (total); 569 (high-consequence areas)

Decision-making approach: The operator follows a long-term corporate risk management strategy for NGPL, developed in the 1960s, that calls for installing automatic-shutoff valves across its pipeline system regardless of advantages and disadvantages for individual pipeline segments. The operators told us that automatic-shutoff valves, as opposed to remote-control valves, were chosen because they reduce the potential for human error when making decisions to close valves. Officials stated that the biggest concern of using automatic-shutoff valves is the potential for accidental closures, but they believe they have developed a procedure for managing the pressure sensing system that effectively adapts to pressure and flow change and minimizes or eliminates these types of closures. Monetary costs are not considered as part of the decision-making process. The operator stated that installing automatic-shutoff valve on an existing manual valve costs between $48,000 and $100,000.

Results to date: According to Kinder Morgan officials, this approach has resulted in the installation of automated valves at 683 out of 832 locations across the pipeline system. Officials plan to automate the remaining valves over the next several years.

Pipeline operator: Northwest Pipeline GP[4]

Product type: Natural gas

Number of pipeline miles: 3,900 (total); 170 (high-consequence areas)

Decision-making approach: The operator uses a decision tree to assess individual pipeline segments based on several criteria, including the location of the valve (e.g., high-consequence area), diameter of the pipe, and the amount of time it takes for an operator to respond upon notification of an incident. The operator will install an automated valve in

[4]Williams Gas Pipeline is the parent company of two operators we visited: Northwest Pipeline GP and Williams Gas Pipeline-Transco. Northwest Pipeline GP is also referred to as WGP West. Williams Gas Pipeline-Transco is one of three pipeline systems that make up WGP East, which also includes Gulfstream Pipeline and Cardinal Pipeline.

any high-consequence, class 3, or class 4 areas[5] on large diameter pipe (i.e., above 12 inches) where personnel cannot reach and close the valve in under an hour. Monetary costs are considered as part of the decision-making process for the purposes of determining the most cost-effective way to ensure the operator can respond within one hour to incidents in high-consequence areas. The operator stated that installing an automated valve costs between $37,000 and $240,000. Automatic-shutoff valves are not installed in areas where an accidental closure could lead to customers losing service (i.e., in places where there is a single line feed servicing the entire area) or where pressure fluctuations may inadvertently activate the valve.

Results to date: According to Northwest Pipeline GP officials, this approach has resulted in decisions to install automated valves at 59 of the 730 locations assessed.

Pipeline operator: Williams Gas Pipeline-Transco[6]

Product type: Natural gas

Number of pipeline miles: 11,000 (total); 1,192 (high-consequence areas)

Description of decision-making method: The operator uses a decision tree to assess individual pipeline segments based on several criteria, including the location of the valve (e.g., high-consequence area), diameter of the pipe, and the amount of time it takes for an operator to respond upon notification of an incident. The operator will install an automated valve in any high-consequence, class 3, or class 4 areas on

[5]The Pipeline and Hazardous Materials Administration regulates natural gas pipelines based on class locations. Class 3 includes any location with more than 46 buildings intended for human occupancy within 220 yards of a pipeline, or an area where the pipeline lies within 100 yards of either a building or a small, well-defined outside area (such as a playground) that is occupied by 20 or more persons at least 5 days a week for 10 weeks in any 12-month period. Class 4 includes any location where unit buildings with four or more stories above ground are prevalent. See 49 CFR 192.5.

[6]Williams Gas Pipeline is the parent company of two operators we visited: Northwest Pipeline GP and Williams Gas Pipeline-Transco. Northwest Pipeline GP is also referred to as WGP West. Williams Gas Pipeline Transco is one of three pipeline systems that make up WGP East, which also includes Gulfstream Pipeline and Cardinal Pipeline.

large diameter pipe (i.e., above 12 inches) where personnel cannot reach and close the valve in under an hour. Monetary costs are considered as part of the decision-making process for the purposes of determining the most cost-effective way to ensure the operator can respond within one hour to incidents in high-consequence areas. The operator stated that installing an automated valve costs between $75,000 and $500,000. Automatic-shutoff valves are not installed in areas where an accidental closure could lead to customers losing service (i.e., in places where there is a single line feed servicing the entire area) or where pressure fluctuations may inadvertently activate the valve.

Results to date: According to Williams Gas Pipeline-Transco officials, this approach has resulted in decisions to install automated valves at 56 of the 2,461 locations assessed.

Appendix III: Automated Valve Costs

The eight operators we spoke with provided a range of cost estimates for installing automated valves—from as low as $35,000 to as high as $500,000 depending on the location and size of the pipeline, and the type of equipment being installed, among other things.[1] While both hazardous liquid and natural gas transmission pipeline operators estimated a similar cost range from about $35,000 to $500,000, hazardous liquid pipeline operators tended to estimate higher costs. Specifically, two of the three operators that exclusively transport hazardous liquids estimated that the minimum costs of installing an automated valve was $100,000 or higher and the maximum was $500,000. In contrast, pipeline operators that exclusively transport natural gas all estimated that the minimum cost was $75,000 or lower and three of the four operators estimated that maximum costs would be $240,000 or lower.

We also spoke with five equipment vendors and six contractors that install valves to gather additional perspective on the cost of purchasing and installing automated valve equipment.[2] According to estimates provided by these businesses, the combined equipment and labor costs range between $40,000 and $380,000. Specifically, equipment costs range from $10,000 to $75,000 while labor costs range from $30,000 to $315,000. (See table 3.) Vendors stated that the cost of installing an automated valve depends primarily on the functionality of the equipment (for example, additional controls would increase the cost), while contractors stated that these costs depend on the diameter and location of the pipeline. Vendors and contractors had varying opinions on whether the costs were greater to install an automated valve on hazardous liquid or natural gas pipeline.

[1]Several hazardous liquid operators indicated that the cost of installing an automated valve could be as high as $1 million under specific circumstances, but stated that these high costs are unusual.

[2]One pipeline contractor we spoke with had not yet installed an automated valve and did not did not provide cost estimates for doing so. Instead the contractor stated that the labor costs of installing a manual valve on an existing pipeline would be between $60,000 and $80,000.

Table 3: Range of Equipment and Labor Costs, According to Pipeline Vendors and Contractors

Equipment vendor	Range of equipment costs	Contractor	Range of labor costs
#1	$10,000 – $75,000	#1	$30,000 – $150,000
#2	$15,000 – $30,000	#2	$35,000 – $175,000
#3	$15,500 – $43,000	#3	$40,000 – $150,000
#4	$30,500 – $43,500	#4	$100,000 – $200,000
#5	$32,000 – $46,000	#5	$120,000 – $315,000
Average	**$20,600 – $47,500**	**Average**	**$65,000 – $198,000**

Source: GAO presentation of vendor and contractor information.

Appendix IV: GAO Contact and Staff Acknowledgments

GAO Contact

Susan Fleming, (202) 512-3824 or flemings@gao.gov.

Staff Acknowledgments

In addition to the contact above, Sara Vermillion (Assistant Director), Sarah Arnett, Melissa Bodeau, Russ Burnett, Matthew Cook, Colin Fallon, Robert Heilman, David Hooper, Mary Koenen, Grant Mallie, Josh Ormond, Daniel Paepke, Anne Stevens, and Adam Yu made key contributions to this report.

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