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PIPELINE SAFETY

Better Data and Guidance Could Improve Operators' Responses to Incidents

Statement of Susan A. Fleming, Director
Physical Infrastructure Issues

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Chairman Rockefeller and Members of the Committee:

Thank you for the opportunity to participate in this hearing on pipeline safety. As you know, pipelines are a relatively safe means of transporting natural gas and hazardous liquids; however, catastrophic incidents can and do occur.[1] We are here today because such an incident occurred on December 11, 2012, near Sissonville, West Virginia, when a rupture of a natural gas transmission pipeline destroyed or damaged 9 homes and badly damaged a section of Interstate 77. Large-diameter transmission pipelines such as these that carry products over long distances from processing facilities to communities and large-volume users make up more than 400,000 miles of the 2.5 million mile natural gas and hazardous liquid pipeline network in the United States.[2] The Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA), working in conjunction with state pipeline safety offices, oversees this network, which transports about 65 percent of the energy we consume.

The best way to ensure the safety of pipelines, and their surrounding communities, is to minimize the possibility of an incident occurring. PHMSA's regulations require pipeline operators to take appropriate preventive measures such as corrosion control and periodic assessments of pipeline integrity. To mitigate the consequences if an incident occurs, operators are also required to develop leak detection and emergency response plans. One mitigation measure operators can take is to install automated valves that, in the event of an incident, close automatically or can be closed remotely by operators in a control room.[3] Such valves have been the topic of several National Transportation Safety Board (NTSB)

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[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 statement refers to both as "incidents."

[2]This statement uses the term "transmission pipeline" to refer to both onshore hazardous liquid and natural gas pipelines carrying product over long distances to users.

[3]For the purposes of this statement, the term "install an automated valve" refers 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.

recommendations since 1971 and a PHMSA report issued in October 2012.[4]

As mandated in the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, we issued a January 2013 report on the ability of transmission pipeline operators to respond to a hazardous liquid or natural gas release from an existing pipeline segment.[5] My statement today is based on this report and addresses (1) variables that influence the ability of transmission pipeline operators to respond to incidents and (2) opportunities to improve these operators' responses to incidents. My statement also provides information from two other recent GAO reports on pipeline safety (see app. I). For our January 2013 report, we examined incident data, conducted a literature review, and interviewed selected operators, industry stakeholders, state pipeline safety offices, and PHMSA officials. Our work on each pipeline safety report was conducted 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.

Summary

Numerous variables—some of which are under operators' control—influence the ability of transmission pipeline operators to respond to incidents. For example, the location of response personnel and the use of manual or automated valves can affect the amount of time it takes for operators to respond to incidents. However, because the advantages and disadvantages of installing an automated valve are closely related to the specifics of the valve's location, it is appropriate that operators decide whether to install automated valves on a case-by-case basis. Several

[4]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). The study was conducted pursuant to the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which 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).

[5]GAO, *Pipeline Safety: Better Data and Guidance Needed to Improve Pipeline Operator Incident Response*, GAO-13-168 (Washington, D.C.: Jan. 23, 2013).

operators we spoke with have developed approaches to evaluate the advantages and disadvantages of installing automated valves, such as using spill-modeling software to estimate the potential amount of product released and extent of damage that would occur in the event of an incident.

One method PHMSA could use to improve operator response to incidents is to develop a performance-based approach for incident response times. 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). First, though, PHMSA must improve the data it collects on incident response times. These data are not reliable 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. Furthermore, 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, and not all operators we spoke with were aware of existing PHMSA guidance designed to assist operators in making these decisions. We recommended that PHMSA should: (1) improve incident response data and use those data to explore the feasibility of developing a performance-based approach for improving operators' responses to pipeline incidents and (2) assist operators in deciding whether to install automated valves by formally collecting and sharing evaluation approaches and ensuring operators are aware of existing guidance. PHMSA agreed to consider these recommendations.

Background

Three main types of pipelines—gathering, transmission, and distribution—carry hazardous liquid and natural gas from producing wells to end users (residences and businesses) and are managed by about 3,000 operators. Transmission pipelines carry these products, 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.

PHMSA administers two general sets of pipeline safety requirements and works with state pipeline safety offices to inspect pipelines and enforce the requirements. The first set of requirements is minimum safety standards that cover specifications for the design, construction, testing, inspection, operation, and maintenance of pipelines. The second set is part of a supplemental risk-based regulatory program termed “integrity management.” Under transmission pipeline integrity management programs, operators are required to systematically identify and mitigate risks to pipeline segments that are located in highly populated or environmentally sensitive areas (called “high-consequence areas”).[6]

According to PHMSA, industry, and state officials, responding to either a hazardous liquid or natural gas pipeline incident typically includes detecting that an incident has occurred, coordinating with emergency responders, and shutting down the affected pipeline segment. 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. 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.[7] Operators must also conduct an investigation to identify the root cause and lessons learned, and report to PHMSA. Federal and state authorities may use their discretion to investigate some incidents, which can involve working with operators to determine the cause of the incident.[8]

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

[6]“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.

[7]The National Response Center, managed by the United States Coast Guard, is the sole federal point of contact for reporting oil and chemical spills.

[8]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.

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 at the valve's location (referred to as "automated valves") include 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.[9] 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,[10] while integrity management regulations require that transmission pipeline operators conduct a risk assessment for pipelines in high-consequence areas that includes the consideration of automated valves.

Incident Response Time Depends on Multiple Variables, Including the Use of Automated Valves

Multiple variables—some controllable by transmission pipeline operators—can influence the ability of operators to respond quickly to an incident, according to PHMSA officials, pipeline safety officials, and industry stakeholders and operators. 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 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 are within an operator's control, and four other variables that influence a pipeline operator's ability to respond to an incident but are beyond an operator's control. The effect a given variable

[9]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). We refer to all of these valves as automated valves.

[10]49 C.F.R. §§ 192.179, 195.260.

has on a particular incident response will vary according to the specifics of the situation. The five variables within an operator's control are:

- leak detection capabilities,
- location of qualified operator response personnel,
- type of valve,
- control room management, and
- relationships with local first responders.

The four factors beyond an operator's control are:

- type of release,
- time of day,
- weather conditions, and
- other operators' pipelines in the same area.

(See table 1 for further detail.) Appendix II provides several examples of response time in past incidents; response time varied from several minutes to days depending on the presence and interaction of the variables just mentioned.

Table 1: Variables Influencing Pipeline Operator Incident Response Times

Variables within an operator's control	Variables beyond an operator's control
• *Leak detection capabilities.* Pipeline operators perform a variety of leak detection activities to monitor their systems and identify leaks, including 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 in the pipeline. • *Location of qualified operator response personnel.* 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. • *Type of valves.* 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. • *Control room management.* Clear operating policies and shutdown protocols for control room personnel can influence response time to incidents. 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. • *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.	• *Type of release (leak vs. rupture).* 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 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. • *Weather conditions*. Weather—such as storms, winter conditions, and wind—can affect how quickly an operator can detect and respond to pipeline incidents. • *Other operators' pipelines in the same area.* If two or more operators own pipeline in a shared right of way determining whose system is affected can increase incident response time.

Source: GAO analysis of information from PHMSA officials, pipeline safety officials, and industry stakeholders and operators.

As noted, one variable that influences operators' response times to incidents is the type of valve installed on the pipeline. Research and industry stakeholders indicate that the primary advantage of installing automated valves—as opposed to other safety measures—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 an initial blast, quickly isolating the pipeline segment through automated valves can reduce subsequent damage by reducing the amount of hazardous liquid and natural gas released.

Research and industry stakeholders also identified two disadvantages operators should consider when determining whether to install automated 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. In addition, according to operators, vendors and contractors, the monetary costs of installing automated valves can range from tens of thousands to a million dollars per valve,[11] which may be significant expenditures for some pipeline operators. 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 officials stated that they generally support the idea that pipeline operators be given some flexibility to target spending where the operator believes it will have the most safety benefit.

Research and industry stakeholders also indicate the importance of determining whether to install valves on a case-by-case basis because 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's location, the likelihood of an ignition, type of product being transported, operating pressure, topography, and pipeline diameter, among other factors, all play a role in determining the extent to which an automated valve would be advantageous.

Operators we met with are using a variety of methods for determining whether to install automated valves that consider—on a case-by-case basis—whether these valves will improve response time, the potential for accidental closure, and monetary costs. 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 hazardous liquid pipeline 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.

[11]The cost of installing an automated valve ranges depending on the location and size of the pipeline and the type of equipment being installed, among other things.

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

In our report, we note that PHMSA has not developed a performance-based framework for incident response times, although some organizations in the pipeline industry have done so.[12] 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.[13] According to our past work, 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 toward goals. While PHMSA has established a national goal for incident response times, it has not linked performance measures or targets to this goal. Specifically, PHMSA directs operators to respond to certain incidents—emergencies that require an immediate response[14]—in a "prompt and effective" manner, 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 and track their performance over time. PHMSA officials told us that because pipeline incidents often have unique characteristics, developing a performance measure and associated target for incident response time

[12]For example, 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. 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 pipelines in highly populated areas. 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.

[13]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.

[14]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.

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. In addition, officials stated it would be difficult to identify a single response time target for all incidents, as pipeline operators likely should respond to some incidents more quickly than others.

Defining performance measures and targets for incident response can be challenging, but one possible 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 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. However, we found that PHMSA does not have the reliable nationwide data on incident response time data it would need to conduct such analyses. Specifically, the response time data PHMSA currently collects are unreliable 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. Our report recommended that PHMSA improve incident response data and use these data to evaluate whether to implement a performance-based framework for incident response times. PHMSA agreed to consider this recommendation.

We also found that PHMSA needs to do a better job of sharing information on ways operators can make decisions to install automated valves. For example, many of the operators we spoke with were unaware of existing PHMSA enforcement and inspection guidance that could be useful for operators in determining whether to install automated valves on transmission pipelines. In addition, while PHMSA inspectors see examples of how operators make decisions to install automated valves during integrity management inspections, they do not formally collect this information or share it with other operators. Given the variety of risk-based methods for making decisions about automated valves across the operators we spoke with, we believe that both operators and inspectors would benefit from exposure to some of the methods used by other operators to make decisions on whether to install automated valves. Our report recommended that PHMSA share guidance and information on operators' decision-making approaches to assist operators with these determinations. PHMSA also agreed to consider this recommendation.

Chairman Rockefeller this concludes my prepared remarks. I am happy to respond to any questions that you or other Members of the Committee may have at this time.

GAO Contact and Staff Acknowledgments

For questions about this statement, please contact Susan Fleming, Director, Physical Infrastructure, at (202) 512-3824 or flemings@gao.gov. In addition, contact points for our Offices of Congressional Relations and Public Affairs may be found on the last page of this statement. Individuals who made key contributions to this statement include Sara Vermillion (Assistant Director), Sarah Arnett, Melissa Bodeau, Russ Burnett, Matthew Cook, Colin Fallon, Robert Heilman, David Hooper, and Josh Ormond.

Appendix I: Summary of Recent GAO Reports on Gathering Pipelines and Low-stress Transmission Pipelines

GAO recently issued two reports related to the safety of certain types of pipelines. The first, GAO-12-388, reported on the safety of gathering pipelines, which currently are largely unregulated by the federal government. The second, GAO-12-389R, reported on the potential safety effects of applying less prescriptive requirements, currently levied on distribution pipelines, to low-stress natural gas transmission pipelines. Further detail on each report is provided below. For the full report text, go to www.gao.gov.

GAO-12-388: Collecting Data and Sharing Information on Federally Unregulated Gathering Pipelines Could Help Enhance Safety

Included in the nation's pipeline network are an estimated 200,000 or more miles of onshore gathering pipelines, which transport products to processing facilities and larger pipelines. Many of these pipelines have not been subject to federal regulation because they are considered less risky due to their generally rural location and low operating pressures. For example, out of the more than 200,000 estimated miles of natural gas gathering pipelines, the Pipeline and Hazardous Materials Safety Administration (PHMSA) regulates roughly 20,000 miles. Similarly, of the 30,000 to 40,000 estimated miles of hazardous liquid gathering pipelines, PHMSA regulates about 4,000 miles.[1]

While the safety risks of onshore gathering pipelines that are not regulated by PHMSA are generally considered to be lower than for other types of pipelines, PHMSA does not collect comprehensive data to identify the safety risks of unregulated gathering pipelines. Without data on potential risk factors—such as information on construction quality, maintenance practices, location, and pipeline integrity—pipeline safety officials are unable to assess and manage safety risks associated with gathering pipelines. Further, some types of changes in pipeline operational environments could also increase safety risks for federally unregulated gathering pipelines. Specifically, land-use changes are resulting in development encroaching on existing pipelines, and the increased extraction of oil and natural gas from shale deposits is resulting in the construction of new gathering pipelines, some of which are larger in diameter and operate at higher pressure than older pipelines. As a result, PHMSA is considering collecting data on federally unregulated gathering

[1]According to PHMSA officials, Alaska, California, Louisiana, and Oklahoma have the majority of federally unregulated gathering pipeline mileage in the United States.

pipelines. However, the agency's plans are preliminary, and the extent to which PHMSA will collect data sufficient to evaluate the potential safety risks associated with these pipelines is uncertain.

In addition, we found that the amount of sharing of information to ensure the safety of federally unregulated pipelines among state and federal pipeline safety agencies appeared limited. For example, some state and PHMSA officials we interviewed had limited awareness of safety practices used by other states. Increased communication and information sharing about pipeline safety practices could boost the use of such practices for unregulated pipelines.

We recommended that PHMSA should collect data on federally unregulated onshore hazardous liquid and gas gathering pipelines, subsequent to an analysis of the benefits and industry burdens associated with such data collection. Data collected should be comparable to what PHMSA collects annually from operators of regulated gathering pipelines (e.g., fatalities, injuries, property damage, location, mileage, size, operating pressure, maintenance history, and the causes of incidents and consequences). Also, we recommended that PHMSA establish an online clearinghouse or other resource for states to share information on practices that can help ensure the safety of federally unregulated onshore hazardous liquid and gas gathering pipelines. This resource could include updates on related PHMSA and industry initiatives, guidance, related PHMSA rulemakings, and other information collected or shared by states. PHMSA concurred with our recommendations and is taking steps to implement them.

GAO-12-389R: Safety Effects of Less Prescriptive Requirements for Low-Stress Natural Gas Transmission Pipelines Are Uncertain

Gas transmission pipelines typically move natural gas across state lines and over long distances, from sources to communities. Transmission pipelines can generally operate at pressures up to 72 percent of specified minimum yield strength (SMYS).[2] By contrast, local distribution pipelines

[2]Pipelines will begin to deform at a certain level of operating pressure. As a result, pipelines operate at a percentage of the level of pressure that will cause the pipeline to deform, known as SMYS. The SMYS depends on the type of metal and is an indicator of when the metal in the pipe starts to yield, deforming in a way that does not return to its original shape. By definition, transmission pipelines operate at or above 20 percent of SMYS (49 CFR § 192.3). Some transmission pipelines operate under special permits that allow different maximum operating pressure that could exceed 72 percent of SMYS.

generally operate within state boundaries to receive gas from transmission pipelines and distribute it to commercial and residential end users. Distribution pipelines typically operate well below 20 percent of SMYS. Connecting the long-distance transmission pipelines to the local distribution pipelines are lower stress transmission pipelines that may transport natural gas for several miles at pressures between 20 and 30 percent of SMYS.

Applying PHMSA's distribution integrity management requirements to low-stress transmission pipelines would result in less prescriptive safety requirements for these pipelines. Overall, requirements for distribution pipelines are less prescriptive than requirements for transmission pipelines in part because the former operate at lower pressure and pose lower risks in general than the latter. For example, the integrity management regulations for transmission pipelines allow three types of in-depth physical inspection. In contrast, distribution pipeline operators can customize their integrity management programs to the complexity of their systems, including using a broader range of methods for physical inspection. While PHMSA officials stated that "less prescriptive" does not necessarily mean less safe, they also stated that distribution integrity management requirements for distribution pipelines can be more difficult to enforce than integrity management requirements for transmission pipelines.

In general, the effect of changing PHMSA's requirement for low-stress transmission pipelines for pipeline safety is unclear. While the consequences of a low-stress transmission pipeline failure are generally not severe because these pipelines are more likely to leak than rupture, the point at which a gas pipeline fails by rupture is uncertain and depends on a number of factors in addition to pressure, such as the size or type of defect and the materials used to conduct the pipeline. In addition, the mileage and location of pipelines that would be affected by such a regulatory change are currently unknown, although PHMSA recently changed its reporting requirements to collect such information. The concern is that because distribution pipelines are located in highly populated areas, the low-stress transmission pipelines that are connected to them could also be located in highly populated areas. As a result, we considered the current regulatory approach of applying more prescriptive transmission pipeline requirements reasonable.

Appendix II: Examples of Pipeline Incident Response Times

Operators we spoke with stated that the amount of time it takes to respond to an incident can vary depending on a number of variables (see table 2).

Table 2: 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 remotely controlled valves. About 2 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.

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