Interstate Natural Gas Association of America

INGAA FOUNDATION

# Framework for Geohazard Management

*Prepared for*

**INGAA, The INGAA Foundation, and a Group of Sponsors**

*Prepared by*


**Center for Reliable Energy Systems, LLC (CRES)**
**Geosyntec Consultants, Inc.**



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## Abstract

Geohazards are a major contributor to pipeline incidents. Geohazards can affect the integrity of a pipeline and ultimately result in pipeline failures by progressing through the following three stages:

1. An existing or potential geohazard feature or condition exists along or near a pipeline,
2. The geohazard "engages" the pipeline, creating a demand on the pipeline, and
3. The demand exceeds the capacity of the pipeline, resulting in a pipeline failure.

Geohazard management is intended to minimize the likelihood of geohazards impacting a pipeline to the point of potentially causing undesirable consequences, such as a leak, rupture, or impaired serviceability. This document covers processes and procedures that may be used to manage geohazards that have progressed to any one of the three stages.

While some elements of geohazard management are similar to the management of other integrity threats, the following unique features of geohazard management should be considered:

- Geohazards range from slowly developing processes with movement rates of inches per year or less to processes that occur essentially instantaneously with little warning.
- Geohazards range from those that currently intersect a pipeline and have been affecting the pipe for years to those that do not yet intersect a pipeline, but could impact the pipe in a single event.
- Geohazards typically induce additional demand beyond that which exists in pipelines without geohazards. The magnitude of the longitudinal stress induced can be greater than the hoop stress, which is the main focus of most operators' Integrity Management Program (IMP). The high longitudinal stress can increase the likelihood of certain failure modes, such as girth weld leaks or ruptures, and influence the behavior of other common threats, such as corrosion and mechanical damage.
- Most pipelines are not specifically designed to resist the load imposed by geohazards. The integrity of a pipeline affected by geohazards should be assessed by considering modes and magnitudes of loading appropriate to the geohazards.

Geohazard assessment can be conducted using a three-level framework, progressing from an initial assessment (i.e., Level 1) to a highly detailed, site-specific assessment (i.e., Level 3). Each level is progressed through as needed to make a response decision. The degree of geohazard characterization increases with each level of assessment. Typically, but not necessarily in all

cases, the length of pipeline or number of sites being assessed decreases with each increasing level of assessment.

The three-level framework has two interrelated and mutually supported components: (1) geohazard-focused assessment and (2) pipeline integrity-focused assessment. The outcome of one component can help to make decisions about the need for and the required level of refinement of the other component. The integration and order of geohazard- and integrity-focused assessments can be selected based on geohazard and pipeline characteristics. It is not necessary to go through the entire process for either type of assessment.

Geohazard threat management is intended to reduce the likelihood of an undesirable event, such as a leak or rupture, from the impact of a geohazard. This threat management consists of:

- Physical measures that are designed to reduce the likelihood of a geohazard impacting a pipeline or further impacting a pipeline,
- Measures that reduce the uncertainty in the capacity of a pipeline, such as NDE (non-destructive evaluation) of girth welds and/or enhance the capacity, such as reinforcing girth welds, and
- Measures that provide ongoing reassessment of geohazard or pipeline conditions to allow for an intervention prior to the geohazard impacting the pipeline and/or to reduce the likelihood of an undesirable event.

The selection and implementation of appropriate threat management measures should be performed and documented using a classification and decision-making (CDM) system.

A few key recommendations for improving the current practice are:

- Establishing a standardized framework for geohazard management,
- Providing guidance and standardization of fitness-for-service assessment, particularly strain-based assessment, for pipelines subjected to geohazards, and
- Improving incident tracking to facilitate incident analysis and prioritization of resources.

As more accurate data on geohazards and pipeline characteristics become available through the application of new technologies and data collection and analysis, geohazard management can move towards a quantitative decision process based on safety margins similar to processes of managing other threats to pipeline integrity, such as corrosion, mechanical damage, and cracks. Appropriate data collection, analysis, and applications are key to optimized geohazard management.

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# 1 Introduction

## 1.1 Problem Statement

Geohazards are a subset of natural hazards caused by Earth processes, including meteorological and geological processes. Geohazards can be divided into two large groups: (1) geotechnical hazards that impose a load through displacement of soil or rock, and (2) hydrotechnical hazards that impose a load by the action of flowing water (including debris transported by the water).

Geohazards are a major contributor to pipeline incidents, as evident by the listed incidents attributable to early movement, i.e., geotechnical hazards, in the advisory bulletins from US DOT PHMSA [1,2]. Earlier advisory bulletins covered the potential damage to pipeline facilities from severe flooding, i.e., hydrotechnical hazards [3,4]. For any given area, the likelihood of a pipeline's exposure to geohazards is determined by the geologic, topographic, and hydrologic characteristics of that area, as well as construction activities that might alter those characteristics. The likelihood of damage to, and the potential failure of, a pipeline due to a geohazard is affected by the pipeline characteristics such as pipe diameter, wall thickness, pipe material, welding methods, and imperfections/flaws resulting from pipe construction or developed while a pipeline is in service. Some of the characteristics, such as pipe material, welding methods, and weld inspection practice, are related to the time and method of pipeline construction.

Geohazards can exist both as discrete features (e.g., a landslide) or as broad locations or areas that are susceptible to the occurrence of a geohazard such as areas prone to earthquakes. In addition, geohazard formation and/or movement can range from ongoing and slow-moving features to nearly instantaneous and fast-moving features. In the case of geotechnical hazards, the load imposed can range from gradual displacement of the ground surface over years or decades, such as from slow-moving landslides or subsidence, to essentially instantaneous displacement, such as from faulting associated with an earthquake or from a rapidly moving landslide. Hydrotechnical hazards are typically associated with transitory loads during flood events where a pipeline is exposed and subjected to loading during the flood but can also be associated with slower-developing hazards, such as channel migration.

Due to the inherent variability in the behavior of geohazards over time and the variability in pipeline characteristics and conditions, the specific processes to manage (i.e., identify, assess, mitigate, and monitor) each hazard type varies. The variations among hazard types, the unique characteristics of an operator's pipeline systems, and an operator's risk tolerance can influence the most effective approaches for geohazard management. Despite these differences, the general approach to managing geohazards for pipeline systems can be similar.

The overall process of geohazard management follows the holistic approach of “Plan-Do-Check-Act” in API RP 1173. However, in contrast to other threats to pipeline integrity, such as corrosion and mechanical damage, there is no generally accepted practice for managing geohazards and their implications on pipeline integrity. This document is intended to help fill this gap by providing a high-level framework for the management of geohazards and their impact on pipeline integrity.

The framework outlined in this document is significantly inspired and influenced by ISO 20074, API RP 1160, API RP 1173 and ASME B31.8S, and in some cases, language provided herein is directly taken from those standards.

### 1.2 Sources of Information

The principal sources of information for the development of this document are:

- An INGAA 2020 JIP (Joint Industry Project) which represents the state of the art practice for the management of landslides [5],
- A 2017 JIP which provides a comprehensive treatment of hazards characterization and FFS (Fitness-for-Service) assessment for the management of land movements [6],
- Internal documents provided by JIP members,
- Interviews with JIP members,
- Reviews of open-source industry incident data,
- Relevant standards and RPs, and
- The experience of JIP members and authors of this document.

### 1.3 Scope and Limitations

The focus of this document is geohazard management of operating pipelines, ranging from pipelines that have been in operation for decades to those that have been recently constructed. Data retention and transfer from the design, construction, and commissioning of new pipelines for the purpose of managing operating pipelines is a part of this document. In addition, Annex D briefly discusses linepipe specifications and girth welding practice that are relevant to building new pipelines, including pipe replacement projects in areas prone to geohazards. Annex D is created in response to well-documented girth weld failures of newly constructed pipelines. The conditions contributing to those failures, if not mitigated proactively, could reduce the strain capacity of newly constructed pipelines and negatively affect the success of a geohazard management program.

This document is applicable to onshore pipelines transporting natural gas or liquids, including $CO_2$. Pipelines transporting hydrogen blended with natural gas or pure hydrogen are excluded, although many of the principles could be applied to these types of pipelines.

Much of the data and experience supporting this document was derived from pipelines in North America. The primary target of this document is pipelines operating in North America, although the principles of this document can be applicable to pipelines in other parts of the world.

The document covers the following hazards:

- Geotechnical hazards, including:
  - Landslides,
  - Subsidence associated with discrete locations, such as from sinkholes,
  - Seismic fault ruptures, ground shaking, liquefaction, and tsunamis[1], and
  - Volcanic eruptions, including lava flows and lahars.
- Hydrotechnical hazards, including:
  - River scour and channel migration.

This document does not cover other natural hazards, except to the extent that they can cause or trigger the hazards listed above. Examples of natural hazards not covered in this document include (not an exhaustive list):

- Weather- or climate- related hazards, such as hurricanes, tornados, high winds, lightning, hail, sea level rise, heat or cold,
- Frost heave,
- Expansive/Collapsible soils,
- Volcanic ashfall, and
- Overland erosion.

[1] Tsunamis can be caused by non-seismic hazards, such as volcanoes and submarine landslides. However, in most instances, tsunamis are managed under a seismic hazard program, because seismic events are generally responsible for the largest and most destructive tsunamis.

## 1.4 Interpretation and Use of This Document

### 1.4.1 Definition and Harmonization of Terms

It is recognized that harmonizing terms in this document and those in other industry standards and RPs which cover geohazards is desirable. It is also recognized that the same terms may have different meanings in different documents, depending on the context with which said terms are used. The first priority in this document is the consistent use of terms within the context of this document. If this document, in whole or in part, were to become a part of a larger program, e.g., become a part of an integrity management program, the definition and scope of terms should be checked for consistency within the larger program.

### 1.4.2 Use of "Mandatory-Sounding" Words and Phrases

This document provides a framework for geohazard management. It is not the intent of this document to provide minimum or optional requirements from the perspective of a standard or recommended practice (RP). When "mandatory-sounding" words or phrases such as "should" or "at minimum" are used, they should be interpreted as recommendations. The implementation of those recommendations is at the discretion of the users of this document.

## 1.5 Structure of This Document

Section 1 of this document provides a high-level overview of the intent and scope of this document. Section 2 covers terms and definitions related to geohazard and pipeline integrity assessment as a part of geohazard management. Section 3 is the central part of this document. It lays out a framework for geohazard management and geohazard assessment. It is worthwhile to note that the geohazard assessment in this section includes hazard characterization and assessment, similar to most current geohazard management programs, and FFS assessment of pipeline impacted by geohazards. The Annexes provide supporting information or further expand on the content of the main body of this document.

# 2 Terms, Definitions, and Abbreviations

## 2.1 Scope and Structure

This section is broadly broken into two groups: (1) terms and definitions and (2) abbreviations. They are provided for consistency and clarity within this document. Some of the definitions may not be the same as those in other documents.

## 2.2 Terms and Definitions

### 2.2.1 Terms and Definitions Related to Hazards

| | |
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| 2.2.1.1 Avulsion | Abrupt or gradual process in which flow is diverted out of an established river channel into a new course within the floodplain. |
| 2.2.1.2 Earthquake | Shaking of the surface of the Earth resulting from a sudden release of energy in the Earth's crust that creates seismic waves. |
| 2.2.1.3 Erosion | Wearing away or removal of soil or other material by the action of flowing water or other agents. |
| 2.2.1.4 Fault | A fracture or zone of parallel fractures in the Earth’s crust between two blocks of rock. Faults allow the blocks to move differentially along the fault plane relative to each other. |
| 2.2.1.5 Frost Heave | An upward swelling of soil during freezing conditions caused by an increasing presence of ice as it grows towards the surface. |
| 2.2.1.6 Geohazards | Geotechnical or hydrotechnical hazards that occur at discrete locations and may threaten the integrity of a pipeline or associated facility. |
| 2.2.1.7 Geotechnical Hazard | Threat to a pipeline that results from displacement of soil or rock. This group of hazard includes landslide, subsidence, seismic, and volcanic. |

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| 2.2.1.8 Hydrotechnical Hazard | Threat to a pipeline that results from changes in a waterway or body of water. This hazard includes scouring, channel migration, avulsion, and other threats related to the movement of water. |
| 2.2.1.9 Karst | Topography formed from the dissolution of soluble rocks such as limestone, dolomite, and gypsum. |
| 2.2.1.10 Landslide | Naturally occurring or human-caused downslope movement of a soil or rock material. Typically occurs either as translational slides or as rotational slides. The term “landslide” encompasses a wide variety of processes including falling, toppling, sliding, spreading, or flowing. |
| 2.2.1.11 Natural Hazard | Hazard resulting from natural Earth processes. Geohazards are a subset of natural hazards. |
| 2.2.1.12 Seismic Hazard | Threat to a pipeline resulting from earthquakes. |
| 2.2.1.13 Subsidence | A gradual settling or sudden sinking of the Earth's surface due to removal or displacement of subsurface earth materials. The principal causes of surface subsidence are both naturally occurring (e.g., karst) and human-triggered (e.g., underground mining). A sinkhole (closed depression or hole) is a common surface expression of subsidence. |
| 2.2.1.14 Tsunami | An ocean wave or series of waves, usually caused by significant bathymetric displacement along a submarine fault, a submarine or coastal landslide, or a volcanic eruption. |

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| 2.2.1.15 Volcanic Eruption | Expulsion of gases, rock fragments, and/or molten lava from within the Earth through a vent (volcano) onto the Earth's surface or into the atmosphere. |
| 2.2.1.16 Waterway | Natural or man-made stream channel through which water flows. Waterway and watercourse are equivalent terms. |

### 2.2.2 Terms and Definitions Related to Pipeline Integrity

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| 2.2.2.1 Bending Strain | Bending strain, in the context of inertial measurement unit (IMU) reported strain, is the longitudinal strain in the pipe caused by bending. |
| 2.2.2.2 Capacity | Maximum amount of loading that a pipeline can withstand prior to a negative consequence, such as a leak, rupture, or change in the physical characteristics of the pipeline (e.g., deformation of the pipe cross-section) that may negatively affect its operation. May be expressed as load, stress, or strain. |
| 2.2.2.3 Compressive Strain Capacity (CSC) | Strain capacity in compression. |
| 2.2.2.4 CSC at Maximum Load ($CSC_{ML}$) | CSC at the point of maximum load or maximum bending moment. |
| 2.2.2.5 CSC Post Maximum Load ($CSC_{PML}$) | CSC corresponding to a limit state (e.g., a fatigue limit) after attainment of maximum load or maximum bending moment. |
| 2.2.2.6 Demand | Loading imposed on a pipeline by its operational and environmental conditions. May be expressed as load, stress, or strain. |
| 2.2.2.7 Displacement-Controlled Loading | Loading in which the amount of deformation is not affected by the load-carrying capacity of the |

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| | component/structure being subjected to the loading. Examples of displacement loading are bending a pipe on a mandrel and reeling-on a pipe string in spool-based installation. |
| 2.2.2.8 Fitness-for-Service Assessment (FFS Assessment) | Quantitative engineering evaluation performed to assess a structure's suitability for its intended use. FFS assessment is often performed against possible limit states. |
| 2.2.2.9 Limit States | Acceptable limits beyond which undesirable consequences may occur. The frequently cited limit states for pipelines are the ultimate limit state, such as a leak or rupture, and the serviceability limit state, such as wrinkles and buckles that do not result in loss of containment. |
| 2.2.2.10 Load-Controlled Loading | A loading is considered load-controlled if the magnitude of such a loading is not affected by the amount of deformation or displacement. Examples of a load-controlled loading are dead-weight loading, soil load on a span, and internal pressure. |
| 2.2.2.11 Longitudinal Strain (Axial Strain) | Strain in the longitudinal (axial) direction of a pipe. |
| 2.2.2.12 Strain | Change in length per unit length. |
| 2.2.2.13 Strain-Based Assessment (SBA) | Fitness-for-service assessment using strain as a measure of demand (strain demand) and capacity (strain capacity). |
| 2.2.2.14 Strain-Based Design (SBD) | Design with a focus on the integrity of a pipeline subjected to moderate to high levels of longitudinal strain. SBD can be applied when the strain level is low, but is usually not utilized at |

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| | low strain levels as conventional stress-based design is typically sufficient. |
| 2.2.2.15 Strain Capacity (SC) | Strain level beyond which there would be a negative consequence, such as a leak, rupture, or change in the physical characteristics of the pipeline (e.g., deformation of the pipe cross-section) that may negatively affect its operation. |
| 2.2.2.16 Strain Demand (SD) | Total strain imposed on a pipeline by its operational and environmental conditions. |
| 2.2.2.17 Strain Demand Limit (SDL) | The strain level that is selected as the acceptable strain limit. |
| 2.2.2.18 Tensile Strain Capacity (TSC) | Strain capacity in tension. |
| 2.2.2.19 Total Strain | The strain caused by all sources, including external, internal, mechanical, thermal, and other sources. |

### 2.2.3 Terms and Definitions Related to Geohazard Management at Program Level

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| 2.2.3.1 Geohazard Assessment | Process of identifying, characterizing, evaluating, threat-classifying, and evaluating the integrity implications of geohazards. |
| 2.2.3.2 Geotechnical Evaluation | Evaluation of geotechnical conditions using geologic, geotechnical, and hydrotechnical engineering investigation techniques. |
| 2.2.3.3 Geohazards Inventory | List of all geohazards that have been identified, including their characteristics. |
| 2.2.3.4 Mitigation | Physical modification of a site or pipeline aimed at reducing the probability of a landslide negatively impacting a pipeline. |
| 2.2.3.5 Monitoring | Collection of data from either the environment surrounding or near a pipeline |

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| | or from the pipeline itself for the continued assessment of the conditions surrounding the pipeline or the pipeline itself. |
| 2.2.3.6 Pipeline Geohazard Management Program (PGMP) | A set of practices and procedures used to systematically identify, assess, and manage geohazards, with the intention of reducing the likelihood of pipeline damage and failures. |
| 2.2.3.7 Pipeline System | Single or multiple pipe segments that have defined starting and stopping points. |
| 2.2.3.8 Qualification | Demonstration and documentation of knowledge, skills, abilities, and/or experience required for personnel to properly perform the duties of a specific job or task. |
| 2.2.3.9 Region | A geographic area with similar topographic, geological, or hydrological characteristics which may contain an entire pipeline system or segments of a pipeline. |
| 2.2.3.10 Right-of-Way (ROW) | Corridor of land within which the pipeline operator has the right to conduct activities in accordance with the agreement with the landowner. |
| 2.2.3.11 Segment (line section) | A length of a pipeline or a part of a pipeline system having common characteristics. |
| 2.2.3.12 Subject Matter Expert (SME) | Professional expert in a subject area with demonstrated training and experience. |
| 2.2.3.13 Survey | The establishment of horizontal and vertical measurements of the Earth's surfaces and the position of a pipeline and geologic features relative to the surface. |

## 2.3 Abbreviations

| | |
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| API | American Petroleum Institute |
| ASCE | American Society of Civil Engineers |
| ASME | American Society of Mechanical Engineers |
| CDM | Classification and Decision-Making |
| CSC | Compressive Strain Capacity |
| EGIG | European Gas Pipeline Incident Data Group |
| GIS | Geographic Information System |
| ILI | In-Line Inspection |
| IMP | Integrity Management Program |
| IMU | Inertial Measurement Unit |
| INGAA | Interstate Natural Gas Association of America |
| InSAR | Interferometric Synthetic-Aperture Radar |
| LiDAR | Light Detection and Ranging |
| MTR | Mill Test Report |
| PGMP | Pipeline Geohazard Management Program |
| PHMSA | Pipeline and Hazardous Material Safety Administration |
| PQR | Procedure Qualification Record |
| PRCI | Pipeline Research Council International |
| ROW | Right of Way |
| SBA | Strain-Based Assessment |
| SBD | Strain-Based Design |
| SC | Strain Capacity |
| SD | Strain Demand |
| SDL | Strain Demand Limit |

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| SME | Subject Matter Expert |
| TSC | Tensile Strain Capacity |
| USGS | United States Geological Survey |
| WPS | Welding Procedure Specification |

# 3 Framework for Geohazard Management

This section provides a high-level framework for the management of geohazards that could potentially affect a pipeline or associated facilities. This framework accounts for the physical nature of geohazards and the response of a pipeline to the hazards.

## 3.1 Key Principles and Structure of the Framework

Geohazards can affect the integrity of a pipeline and ultimately result in pipeline failures by progressing through the following three stages:

1. A current or potential geohazard feature or condition exists along or near a pipeline,
2. The geohazard "engages" the pipeline, creating a demand on the pipeline, and
3. The demand exceeds the capacity of the pipeline, resulting in a pipeline failure.

This document covers processes and procedures that may be used to manage geohazards that have progressed to any one of the three stages. Geohazard management is intended to minimize the likelihood of geohazards impacting a pipeline to the point of potentially causing undesirable consequences, such as a leak, rupture, or impaired serviceability.

## 3.2 Key Concepts and Elements

A pipeline geohazard management program (PGMP) is a set of practices and procedures used to systematically identify, assess, and manage geohazards, with the intention of reducing the likelihood of pipeline damage and failure.

Depending on the work being performed, a PGMP may be implemented by multiple groups, both internal and external to the operator. The operator should designate a group to administer the PGMP, either a group within the operator or a qualified third party designated by the operator. A PGMP should be administered under the umbrella of an integrity management plan (IMP) or an equivalent plan/program implemented by the operator.

Once an operator has determined the types of geohazards that pose a threat to their pipelines, this information can be used to iteratively further develop its PGMP. The PGMP can range from a very simplistic program (e.g., in the case of managing few to no geohazard threats) to a very complex program (e.g., in the case of managing numerous geohazard types and locations).

When developing a PGMP, the following factors may be considered:

1. Scope and size of pipeline systems,
2. Regions in which the pipelines operate,
3. Type of geohazards present along the pipelines, and

4. Resilience of the pipelines, which may be influenced by the time and method of construction (e.g., girth welding processes and inspection practice) and time-dependent threats (e.g., cracks, corrosion, mechanical damage, etc.)

A PGMP should have a component to reassess geohazards that are likely to evolve over time. In addition, time-dependent anomalies in the pipe body and welds that can affect the resilience of pipelines potentially subjected to geohazards, such as corrosion or stress corrosion cracking (SCC), should also be reassessed at some time interval. Reassessment may vary by region, segment, and individual site in terms of the time interval for completion and approach. Reassessment may also involve performing an assessment in an area that was previously assessed.

A PGMP should incorporate aspects of continuous improvement. Updates to the program documentation should be made over time as more information is collected and/or as hazards are addressed. Commonly implemented plans and processes should be documented to establish consistency of execution within the program.

### 3.2.1 Key Elements and Implementation of a PGMP

The PGMP contains the following elements:

- Documentation of the types of geohazards being managed,
- Methods for identification of geohazards,
- Methods for assessing the threat posed by geohazards,
- Methods for assessing the integrity of the pipeline being impacted by geohazards,
- Methods or criteria used to manage geohazard threats,
- Threat management actions (i.e., monitoring and mitigative measures),
- Mechanism(s) by which relevant data are stored, and
- Personnel qualifications.

These elements are broadly in accordance with the IMP requirements specified in CFR § 192.911 and § 195.452.

The implementation of a PGMP is an iterative and evolving process consisting of the following steps (modified from INGAA 2020 [5]):

1. Identify an individual or group responsible for the PGMP.
2. Establish a preliminary process for initial geohazard identification and assessment, i.e., Level 1 Assessment, as described in Section 3.3.4.

3. Establish a data management system, if a suitable system does not already exist. This system should be used to record data and support analysis and decision-making.

4. Conduct a pilot of the PGMP on a pipe segment or system likely to have geohazards.

5. Refine the assessment processes and establish a classification and decision-making (CDM) approach (see Section 3.5.1) based on conditions encountered, company risk tolerance, and resource availability.

6. Continue with the assessment until Level 1 Assessment has been completed on all segments. Further refine these processes and CDM approaches as needed.

7. Establish threat management approaches based on the results of the screening and assessment.

8. Implement mitigation and monitoring actions to manage threats from geohazards.

At this point, the geohazard management processes can transition to a continuous cycle of monitoring, reassessment, and response. Additional assets that are acquired or constructed should be subjected to this process.

### 3.2.2 General Considerations for Geohazard Management

While most elements of geohazard management are similar to the management of other integrity threats, the following unique elements relevant to geohazard management should be considered:

- Geohazards range from slowly developing processes with movement rates less than inches per year (such as certain landslides, tectonic creeping faults, and non-tectonic growth faults) to processes that occur essentially instantaneously without prior warning (such as fault rupture in earthquakes). Consequently, the effects on a pipeline can range from gradual strain accumulation over years to effectively instantaneous straining.

- Geohazard threats result from ongoing dynamic natural processes, and as such, geohazard threats can develop and change over time in ways that can be challenging to predict or forecast.

- Geohazards range from those that currently intersect a pipeline and have been affecting the pipe for years to those that do not yet intersect a pipeline, but in a single event could impact the pipe. As such, geohazard management requires assessment of areas outside of the pipeline right-of-way (ROW).

- Geohazards can be caused or triggered by natural processes and by human activities, e.g., subsidence caused by underground mining or landslides triggered by the undermining of slopes.

- Geohazards typically induce additional demand beyond that which exists in pipelines not subjected to geohazards[2]. The magnitude of the longitudinal stress induced can be greater than the hoop stress, which is the main focus of most operators' IMP. The high longitudinal stress can increase the likelihood of certain failure modes, such as girth weld leaks or ruptures, and influence the behavior of other common threats, such as corrosion and mechanical damage.
- Most pipelines are not specifically designed with the consideration of the loading imposed by geohazards. The integrity of a pipeline affected by geohazards should be assessed by considering modes and magnitudes of loading appropriate to the geohazards.

### 3.3 A Three-Level Framework for Geohazard Assessment

Geohazard assessment can be conducted using a three-level framework, progressing from an initial assessment (i.e., Level 1) to a highly detailed, site-specific assessment (i.e., Level 3). Each level is progressed through as needed to make a response decision. The degree of geohazard characterization increases with each level of assessment. Typically, but not necessarily in all cases, the length of pipeline or number of sites being assessed decreases with each increasing level of assessment.

The three-level framework has two interrelated and mutually supported components: (1) geohazard-focused assessment and (2) pipeline integrity-focused assessment. The outcome of one component can help to make decisions about the need for and the refinement of the other component. The integration and order of geohazard- and integrity-focused assessments can be selected based on geohazard and pipeline characteristics. It is not necessary to go through the entire process for either type of assessment.

There are some differences in the targeted outcomes and processes when executing the two components. The primary objective of the geohazard-focused assessment is understanding the characteristics of the geohazards and their impact on a pipeline. The primary objective of the integrity-focused assessment is determining the safety margin expressed as a difference between capacity and demand. The process of performing the assessment is the FFS assessment. The geohazard-focused assessment is similar to the phased approach in other geohazard management documents [5, 6]. As the level increases, the uncertainty related to geohazards generally decreases.

[2] For instance, strain demand can be imposed by construction and post-construction settlement. This demand is typically stable after a period from the completion of the construction.

The precision of geohazard-focused assessments and pipeline integrity-focused assessments depends on the availability and quality of input data. As more data pertaining to geohazards and pipeline characteristics become available, the precision and certainty about the outcome increases.

### 3.3.1 Features of the Geohazard-Focused Assessment

A Level 1 Assessment is an initial assessment intended to identify potential geohazards and perform preliminary evaluation of their threats to the subject pipeline(s). The Level 1 Assessment is similar to the screening level assessment in ISO 20074.

A Level 1 Assessment is recommended when:

- A new pipeline system is acquired,
- At the completion of the construction of a new pipeline system[3], and
- Upon the initiation of a PGMP.

A Level 1 Assessment should include all types of geohazard threats that could impact pipelines in the region in which a pipeline is located. A Level 1 Assessment can be the most important component of a PGMP. The results of the Level 1 Assessment establish locations of likely geohazard occurrence or pipelines/segments vulnerable to geohazards, which are then targeted for further assessment.

Level 2 and 3 Assessments are performed to further characterize selected sites or areas identified during the Level 1 Assessment, when additional information is desired. Level 2 typically consists of a more detailed desktop assessment or a non-intrusive field assessment. Level 3 typically consists of site-specific subsurface investigations, site modeling, etc. The methods for conducting each level of assessment may vary by geohazard type and site conditions.

Uncertainties regarding the characteristics of the hazard and the associated threat typically decrease with each level of assessment. As details for a site or an area become more certain with each progressing level, the decision for how best to manage a site or an area becomes more informed. The progression of assessment levels should reflect an appropriate balance among the level of assessment, uncertainty, and responses to manage the threat.

[3] This may involve (1) reviewing considerations of geohazards and mitigation actions taken during route selection, design, and construction phases and (2) adding/modifying geohazard management approaches to meet the expectations of a Level 1 assessment.

Typically, a PGMP involves progressing through the three levels to the degree necessary to decide on how to manage a site or an area, which may vary by geohazard type, region, and site. A PGMP should define strategies and criteria for when and why an area or site needs to progress to a higher assessment level for each identified geohazard type, or why a higher assessment level is not necessary. Section 3.5.1 describes the need for and process of developing a Classification and Decision-Making system, which can be used to aid in the determination of an appropriate level of assessment.

If a decision is made to not progress to a higher-level assessment, the information collected or analyses performed during the highest level of assessment should be incorporated with other available information, such as that from prior assessments or ILI analysis, to select and design appropriate threat-management measures if deemed necessary. Threat-management measures may include installation of mitigative measures and/or development and implementation of monitoring plans.

### 3.3.2 Features of the Integrity-Focused Assessment

Many PGMPs start with a focus on geohazard assessment, i.e., characterization of strain demand, then move to FFS assessment of the pipeline. Scenarios for applying FFS assessment in geohazard management are given in Section 3.4.2.2. One of the most common applications of FFS is establishing thresholds for strain demand in conjunction with monitoring, such as inertial measurement unit (IMU) runs and pipe strain gauges. The thresholds can be used as an alert for in-depth investigations or implementation of mitigation measures. The other common use is site- or girth-weld-specific integrity assessment. The outcomes can be used to make operational decisions, such as implementing an operational restriction, and for selecting mitigation approaches.

FFS can be applied at any level of the geohazard assessment process; as such, the decision to implement a FFS assessment and the objectives of a FFS assessment can vary by site, depending on the characteristics of the geohazards and the pipeline segment. For instance, if a geohazard and its impact on a pipeline are well characterized, a FFS assessment may be used to support decision-making around implementing operational restrictions and/or performing mitigation, along with determining the desired timeline for such activities.

### 3.3.3 Role of ILI in Geohazard Assessment

In-line-inspection (ILI) tools can provide information on pipe conditions not ascertainable from geotechnical evaluation alone. At the time of the publication of this document, the primary

ILI tool used for geohazard assessment purposes is IMU bending strain[4], but this does not preclude the use of other ILI tools for geohazard assessment and analysis.

For locations where indications of geohazard activity are not easily observable from the ground surface, due to geomorphic changes, mitigation activities, or visual obstruction, ILI tools can, with some inherent limitations, provide evidence of possible locations where geohazards may have impacted the pipeline that may otherwise have gone undetected. Assuming the pipeline system is piggable, the information from ILI can be incorporated into any level of geohazard assessment. A PGMP should document the methods by which ILI tools are incorporated into the analysis of geohazard threats.

Considerations for the usage of ILI tools are as follows:

- IMU bending strain analysis may be performed as a supplementary analysis whenever IMU data is collected. The resulting bending strain analysis can be used to identify locations with indications of past pipe displacement, some of which may have been caused by a geohazard.
- Operators should consider performing an ILI analysis for pipeline segments suspected of being affected by geohazards to confirm if the pipeline segments are impacted. Typically, such an analysis would primarily consist of determining IMU bending strain, but it can be supplemented by other ILI data.
- Repeat ILI runs can also be used as a monitoring method. This usage of ILI data is discussed further in Section 3.5.3.

### 3.3.4 Level 1 Assessment

A Level 1 Assessment is aimed at achieving the following main objectives:

1. Identifying the types of potential geohazards that could be present,
2. Developing a geohazards inventory of the potential sites along the pipeline,
3. Performing an initial assessment of the potential threat(s) posed to the pipeline by the identified hazards, and

[4] IMU bending strain analysis provides an estimate of strains resulting from the lateral bending of a pipe. Depending on the characteristics of a geohazard and the manner of the interaction between the geohazard and a pipe segment, uniform strain in the longitudinal direction can be generated without or with limited lateral bending. In such cases, IMU bending strain analysis may under-represent the total strain imposed on the pipe segment. Other limitations of IMU exist as described in Reference [5].

4. Performing an initial assessment of the resilience of the pipeline, such as by determining tensile strain capacity.

A Level 1 Assessment typically focuses on identifying geohazards with the potential to impact the pipeline(s) being assessed and initially classifying their potential threats to the pipeline(s). All pipeline segments should have a Level 1 Assessment. Data on strain demand, such as available bending strain from IMU runs, may be used to supplement other methods in the identification of likely geohazard features.

If completing the initial Level 1 Assessment for an entire pipeline system as a single effort is not practical (e.g., due to limited resources or the need to acquire data such as LiDAR), a Level 1 Assessment can be broken up into regions or segments such that assessment of an entire system can be spread over several years. If a pipeline system is assessed over multiple years, segment assessment priorities and the timeline to complete each separate assessment should be established at the start of the process. The prioritization methodology may vary but could be developed based on the severity of expected geohazard conditions and/or other risk factors (e.g., HCAs, criticality, and/or strain capacity). For example, for landslides (unstable slopes), regions known to be landslide prone (as shown on USGS or state agency maps) and hilly/mountainous regions should generally be prioritized during the initial assessment, followed by assessment of the remaining areas of the system[5].

A baseline TSC analysis may be conducted at TSC-L1 or TSC-L2, as described in Section 3.4.2.5. Understanding the strain tolerance level (strain capacity) can help to determine the threat level and the need for additional assessment.

The methods used for the Level 1 Assessment vary by geohazard type and region. At a minimum, the methods should be sufficient to systematically identify hazards and produce an inventory of geohazard locations. The recommended methods for a Level 1 Assessment by common geohazard types are as follows:

- *Landslide Hazards:* Review of LiDAR digital elevation model (DEM) data, typically viewed in hillshade or slope percent format. In sparsely vegetated areas where the ground surface is clearly observable, a review of high-resolution aerial photographs or overflight by a helicopter or a low-flying fixed-wing airplane can substitute for LiDAR data review. The review can be supplemented by additional remote-sensing data (e.g., InSAR

[5] At the publication time of this document, identification of potentially landslide-prone areas using slope steepness and/or through review of landslide maps published by public agencies does not provide a sufficient level of detail to evaluate potential landslide hazards.

[Interferometric Synthetic Aperture Radar]), available landslide mapping, and/or readily available existing landslide information.

- *Hydrotechnical Hazards:* Review and compilation of government hydrography datasets by state and Federal agencies, as described in API RP 1133.
- *Seismic Hazards*: Review of published geologic maps and seismic hazard mapping by the USGS, states or equivalent agencies in other countries. This should include review of data showing the locations of faults active in the Pleistocene or Holocene epochs, potential ground shaking, and areas of potential liquefaction.
- *Subsidence Hazards:* Review of geologic maps and prior mapping of naturally occurring (e.g., karst) and anthropogenic (e.g., mining) subsidence hazard areas maintained by state and Federal agencies. Alternatively, subsidence hazards can be defined using LiDAR data, aerial photographs or aircraft overflight, as discussed above under landslide hazards. Satellite based InSAR could be a useful method for subsidence identification.
- *Volcanic Hazards:* Review of mapping by the USGS and state/provincial agencies.

### 3.3.5 Level 2 Assessment

The main objectives of a Level 2 Assessment are:

- Confirming whether possible geohazard threats identified during a Level 1 Assessment are actual geohazard threats,
- Improving geohazard characterization and classifying potential threats to a pipeline for confirmed geohazard threats, and
- Improving understanding of a pipeline's safety margin, i.e., the difference between capacity and demand.

A Level 2 Assessment focuses on specific sites or pipeline segments. Locations selected for a Level 2 Assessment can be based on the outcomes of a Level 1 Assessment, the results of monitoring (e.g., repeat LiDAR), or potential geohazards identified through other processes (e.g., third party). This level of assessment is typically non-intrusive (i.e., no subsurface drilling or excavation is conducted).

The specific form of a Level 2 Assessment varies by hazard type, but generally includes a field reconnaissance and evaluation by an SME or individuals under the supervision of an SME. Landslides, subsidence, and hydrotechnical hazards are usually evaluated through a field reconnaissance. In addition to, or in lieu of the field reconnaissance, the Level 2 Assessment may involve detailed records review or other detailed desktop assessment, such as a review of underground mine maps for evaluation of anthropogenic subsidence hazards.

To quantify the threat of a potential failure and determine if a Level 3 Assessment is necessary, segment or site-specific FFS assessment may be conducted. For instance, if the loading is primarily displacement-controlled, SBA may be conducted with the strain demand at SD-L1 level and the tensile strain capacity at TSC-L2 or TSC-L3 levels, as discussed in Section 3.4.2.5.

### 3.3.6 Level 3 Assessment

A Level 3 Assessment is a detailed site-specific assessment intended to resolve uncertainties remaining from prior assessments and/or to acquire the additional information or analysis results needed to make a decision, such as the desired type of threat-management measures to implement. A Level 3 Assessment is usually conducted for a relatively small subset of sites assessed in Level 1 and 2 Assessments. A Level 3 Assessment is the final and most detailed level of assessment.

The specific methods used to conduct a Level 3 Assessment should be fit for purpose, i.e., they should meet the intentions and needs for conducting the assessment. The methods can vary based on hazard type, location, and site-specific constraints, and may include one or more of the following:

- Conducting a detailed assessment of the subsurface geologic conditions through measures such as
  - Geophysical investigations, and
  - Intrusive, subsurface geotechnical investigations (e.g., drilling, test pits, dynamic cone penetration tests, installation of inclinometers).
- Conducting a site-specific FFS assessment, such as SBA if the loading is primarily displacement-controlled, e.g., SD-L2 (Section 3.4.2.4) and TSC-L3 (Section 3.4.2.5).

## 3.4 Fitness-for-Service (FFS) Assessment

### 3.4.1 Considerations for Selecting an Appropriate FFS Assessment

An appropriate scope and approach to a FFS assessment depends on loading modes imposed by geohazards, possible modes of failure, time-dependence of anomalies, and applicable ranges of FFS procedures.

- Broadly speaking, there are two loading modes: (1) displacement-controlled loading, and (2) load-controlled loading. Most loading modes involving geohazards are neither fully displacement-controlled or load-controlled. Loading on a buried onshore pipeline in a slow-moving landslide event is primarily displacement-controlled. The stability of a span in a scouring situation is primarily load-controlled.

- The possible modes of failures are: (1) tensile leak or rupture, (2) compressive buckling, which may or may not cause either an immediate or delayed leak, in addition to possible impairment of serviceability, and (3) burst.
- Anomalies, including volumetric features and planar flaws, are often associated with failures involving geohazards. Some of the anomalies, such as planar girth weld flaws on the inside diameter (ID) side of the pipe, are created during pipe construction. There is little evidence of in-service growth of girth weld flaws from construction. Other anomalies, such as corrosion and stress-corrosion cracking (SCC), may initiate and grow over time. Cyclic loading can initiate and grow flaws at geometric discontinuities, such as at wrinkles and buckles.
- Most FFS assessment procedures developed to date, such as API 579 and BS 7910, are primarily stress-based. They are most suitable for integrity assessment under load-controlled loading when the applied stress is less than yield strength of the materials. Stress-based methods tend to be conservative when the applied stress is greater than approximately 90% of yield strength, or when the total longitudinal strain is greater than 0.15-0.20%. There are no rigid connections between the type of hazards and the appropriate FFS assessment procedure. For instance, buried onshore pipelines affected by landslides are best assessed by strain-based procedures. Spanning caused by a sinkhole should be assessed by stress-based procedures. More information on loading modes imposed by geohazards, possible modes of failure, and appropriate FFS procedures can be found in Wang et al. [6] and API 1133.

Stress-based assessment procedures, such as API 579 and BS 7910, are well-recognized and documented. The following section covers strain-based assessment.

### 3.4.2 Strain-Based Assessment

#### 3.4.2.1 Concepts and Basic Elements of SBA

Strain-based assessment (SBA) is a process of integrity assessment that uses longitudinal (axial) strain to represent the condition of a pipeline. The effects of internal pressure are incorporated into the assessment process as it can affect the assessment outcome.

SBA encompasses at least two limit states: tensile rupture/leak and compressive buckling. Tensile rupture/leak is an ultimate limit state, which is related to the breach of the pressure boundary. Compressive buckling is usually a service limit state but can be an ultimate limit state in some cases.

SBA follows the same engineering process as a generic FFS assessment. An acceptable condition is when the strain demand is less than the strain demand limit (SDL). Such a condition can be the current state of a pipeline, or a state of pipeline projected into the future.

An acceptable condition from SBA is given as,

$$\varepsilon_D < \varepsilon_{DL}$$

$$\varepsilon_{DL} = \frac{\varepsilon_C}{S_F}$$

where $\varepsilon_D$ is strain demand, $\varepsilon_{DL}$ is the strain demand limit, $\varepsilon_C$ is strain capacity, and $S_F$ is a safety factor that is greater than 1.0.

3.4.2.2 Difference between Uncertainty and Conservatism

Uncertainty and conservatism are two related but distinct concepts. Uncertainty describes confidence that measured or calculated quantities represent reality. Less uncertainty indicates more confidence that measured or calculated quantities accurately represent reality, while more uncertainty indicates the inverse. Conservatism measures how a result may change if an assumed quantity differs from reality. An increase in conservatism generally means a reduction in the likelihood a quantity would get "worse" in that particular context.

For example, when starting an SBA, uncertainty can be high due to the limited availability of information related to the determination of strain demand (SD) and strain capacity (SC). Because of this, lower-bound SC and upper-bound SD values may be chosen to perform the assessment, which leads to an underrepresentation of the safety margin (the difference between SDL and SD). This initial result can be considered conservative, as the safety margin should not get worse if the SC or SD are different from the assumed values. As more relevant information is collected and assessments move to higher levels, uncertainty tends to decrease. This may justify increasing the SC and/or decreasing the SD, reducing the underrepresentation of the safety margin, which reduces conservatism.

3.4.2.3 Scenarios of Applying SBA

A few possible scenarios for applying SBA are given below:

(1) *Setting a segment-wide threshold for further actions*. The basis of the threshold is the SC of the target segment and a selected safety factor. The threshold is typically used in the screening of the output of strain demand tools, such as IMU or strain gauges.

(2) *Site- or girth weld-specific assessment to assist operational and mitigation decisions*. The assessment involves the determination of safety margins between the SD and SDL. The outcome can be used to make operational decisions, such as operational restrictions, or site mitigation decisions, such as timing and method of mitigation.

(3) *Setting girth weld flaw acceptance criteria*. SBA can be used to set maximum allowable flaw size for a given SD and pipe/weld mechanical properties. This information can be used to determine if a weld repair, reinforcement, or cutout is required.

(4) *Supporting the specifications or selection of linepipes*. In a pipe replacement project, SBA can be used for the selection of linepipe (e.g., from distributors) that would produce strain-resistant girth welds to achieve an acceptable pipeline strain capacity. In a new construction project, SBA can help to set linepipe specifications that would result in strain-resistant pipelines.

(5) *Supporting the selection and specifications of girth welding procedures.* Concurrent to considerations of linepipe properties/specifications, girth welding procedures can be selected to produce strain-resistant pipelines to achieve an acceptable pipeline strain capacity.

For geohazard management of existing pipelines, Scenario Nos. 1 and 2 are most commonly used. Scenario No. 3 can be used if there are reliable way(s) to characterize girth weld flaws either with in-line tools or in-ditch tools. Nos. 4 and 5 are useful in pipe replacement and new construction projects.

#### 3.4.2.4 Determination of Strain Demand

Strain demand (SD) relevant to pipeline integrity is the total strain demand, which includes the SD prior to a geohazard event and additional strain demand imposed on a pipeline segment by a geohazard event. SD can be caused by operational conditions, such as internal pressure or temperature differentials, and external conditions, such as geohazards.

Broadly speaking, there are two categories of approaches to determine/estimate SD:

(1) Strains measured on the pipe or from the pipe, including strain gauges, IMU, and strain computed from the surveyed pipe profile, and

(2) Strains computed from the interaction between a geohazard and a pipeline segment.

The second method for SD determination consists of characterizing the geohazard and estimating SD by modeling the interaction between a geohazard and a pipeline. The second method usually consists of pipe-soil interaction modeling with various levels of assumptions about the characteristics of the geohazard and mechanisms of interaction.

Public domain information on the relative accuracy of SD determination methods is scarce. Furthermore, the outcomes of some methods, such as the second method, are significantly affected by the quality of the input data and assumptions made by analysts. Therefore, it is not prudent to have a predetermined association between the accuracy of SD and a SD method unless certain evidence or justifications can be provided. Two levels of SD determination are organized, with Level 2 expected to have lower uncertainty:

- SD-L1: SD from any single method, e.g., strain gauge, IMU, pipe-soil interaction modeling without corroboration with one or more other methods, and,
- SD-L2: SD from corroboration of two or more methods.

#### 3.4.2.5 Determination of Tensile Strain Capacity (TSC)

The TSC of a pipeline is often controlled by the behavior of its girth welds. The TSC of a pipeline is often referred to as "girth weld TSC" for this reason. It should be noted that the TSC of a girth weld is not the strain value measured across a girth weld at the instant of failure (rupture or leak). The TSC of a pipeline, even when referred to as "girth weld TSC", is the nominal strain or remote strain measured away from the local area of a girth weld at the instant of a failure.

The magnitude or value of factors known to affect the TSC may not be available to pipeline operators, especially at the start of an PGMP. A multi-level approach, in approximate order of increasing accuracy and precision, can be taken for the TSC determination.

##### 3.4.2.5.1 TSC – L1 Reasonable Lower-Bound TSC

As described in Annex E, there can be large variance in TSC among the girth welds in a pipeline segment. For instance, some vintage pipelines have a highly varying level of girth weld anomalies, which can directly result in large variations in TSC.

For initial screening of a pipeline, or determining the priority of timing and implementation of the PGMP elements, having a reasonable lower-bound TSC is useful. This can be established based on the vintage of pipeline, construction practice (particularly girth welding and inspection practices), history of past failures, if any, and mechanical testing and anomaly inspections.

##### 3.4.2.5.2 TSC - L2 Segment-Specific TSC

At this level, some knowledge about the major factors affecting TSC is necessary. Typically, knowledge of the pipe and weld characteristics, including pipeline alignment sheets, mill test reports, welding procedure specifications, and non-destructive testing practices for field welds, is required to execute this level. Characteristic distributions of pipe and weld mechanical properties from available records are used to derive a plausible TSC range. A reasonable lower-bound TSC may be derived from the plausible range to facilitate initial integrity assessments.

An appropriately validated software/tool or case-specific analysis can be used to determine TSC at Level 2.

3.4.2.5.3 TSC – L3 Site/Girth Weld-Specific TSC

The type of information necessary for this level is similar to that of Level 2, except that the information is specific to a site or weld. For instance, pipe-specific tensile properties from MTRs could be used to represent the pipe properties instead of a statistical distribution of an entire pipeline or segment. Information on weld flaws could be from site- or girth weld-specific in-ditch non-destructive testing instead of using the generic workmanship flaw acceptance criteria.

An appropriately validated software/tool or case-specific analysis can be used to determine TSC at Level 3.

3.4.2.6 Determination of Compressive Strain Capacity

Compressive strain capacity associated with maximum load, $CSC_{ML}$, is often determined from equations published in various standards or RPs. There is no broadly accepted method to determine the compressive strain capacity associated with post-maximum-load CSC, $CSC_{PML}$. Methods for determining $CSC_{PML}$ have been published [7].

$CSC_{ML}$ is appropriate for primarily load-controlled loading. $CSC_{PML}$ is appropriate for primarily displacement-controlled loading.

3.4.2.7 Determination of Safety Factor for SBA

The appropriate value of an SBA safety factor (SF) depends on a number of considerations. There is no single SF that is suitable for all conditions. At a minimum, the following aspects should be considered when determining an appropriate SF

1. Level of bias built into the determination/estimation of SD and SC, which in turn depends on the availability and reliability of the required input data for SD and SC determination,
2. Geohazard characteristics and timeframe for response, and
3. Consequence and risk tolerance level.

In most cases, both the strain demand analysis and the TSC analysis should be biased toward conservative assessment outcomes. The level of conservatism varies with the analysis approach and available data. If both the strain demand analysis and the TSC analysis included significant conservatism, a SF close to 1.0 is justifiable. A greater SF should be considered if a failure event could have high consequences for life, property, environment, and economics. The selection of a SF should also consider uncertainties in the required input data.

## 3.5 Geohazard Threat Management

Threat management measures are actions that reduce the potential of a geohazard to negatively impact a pipeline. The threat in the context of this section refers to the likelihood of a geohazard impacting a pipeline and causing an undesirable event, such as a leak or rupture.

Threat management measures consist of:

- Physical measures that are designed to reduce the likelihood of a geohazard impacting a pipeline or further impacting a pipeline,
- Measures that reduce the uncertainty in and/or enhance the capacity of a pipeline, such as NDE (non-destructive evaluation) of girth welds and reinforcement of girth welds, and
- Measures that provide ongoing reassessment of geohazard or pipeline conditions to allow for intervention prior to impacting a pipeline and/or to reduce the likelihood of an undesirable event.

These measures, when implemented systematically, reduce the potential of geohazard impacts and incidents. The selection and implementation of appropriate threat-management measures should be performed using a classification and decision-making (CDM) system.

### 3.5.1 Classification and Decision-Making

The purpose of a CDM system is to standardize the implementation of threat management measures, i.e., to determine the nature of the threat-management measures and the timing or order of conducting those actions. ISO 20074 and the INGAA 2020 report [5] contain discussions of the various approaches to generating CDM systems (referred to as “assessment methods” in ISO 20074). The selected approach should consider an operator’s risk tolerance, the nature of the geohazard being managed, the data collected during prior assessments, and the practicality of implementation of the identified threat-management measures.

Each CDM system should contain the following elements:

- Requirements for the types of data needed to determine the threat classification. Data necessary for geohazard assessment, particularly Level 1 and 2 Assessments, should be included, such that data collected during the assessments can be integrated into the CDM system without additional work.
- A means to classify the perceived threat to a pipeline from the identified geohazards.
- A means to classify the resilience of pipelines against the impact of geohazards, such as strain capacity.

- A set of requirements or guidelines for whether to perform additional actions and, if so, the type of action and the time frame in which to conduct that action (i.e., the decision-making component of the CDM system), based on the classification.

### 3.5.2 Mitigation Measures

Mitigation measures are a means to manage geohazard threats through the implementation of physical means to reduce the likelihood of an impact. These measures use one or more of the following strategies:

- Avoiding the geohazard (such as through rerouting or spanning the hazard).
- Increasing the resilience of the pipeline, such as by enhancing the strain capacity of the pipeline.
- Reducing or eliminating the likelihood of the geohazard occurring, such as through landslide stabilization.

There is a large variety of options that can be implemented [5,6,8,9]. Considerations for the selection of the options typically include:

- Geologic, geotechnical, and topographic conditions
- Surface hydrologic and groundwater conditions
- Climatic conditions, including short- and long-term variability over the anticipated lifetime of the pipeline system
- Geohazard characteristics (e.g., type, movement rate, footprint, geohazard-pipeline interaction)
- Site objectives and goals (e.g., elimination of landslide hazard or reduction of potential effects)
- Site location and access
- Anticipated lifetime of mitigation (i.e., short-term versus long-term)
- Proximity to human and environmental receptors
- Environmental and regulatory considerations
- Ongoing site monitoring
- Landowner restrictions
- Pipeline operating conditions (current and future)

- Pipeline characteristics (strain capacity)
- Pipeline strain conditions (strain demand)
- Cost of implementing measures, including installation, maintenance, and future site management

Documenting and standardizing mitigation measures in a PGMP are encouraged for consistency.

#### 3.5.3 Monitoring Measures

Monitoring measures are a means of threat-management that allows for preemptive response prior to a geohazard impacting a pipeline and/or consequence minimization after an impact has occurred. The selection and usage of monitoring measures should be fit for purpose, i.e., the monitoring measures and monitoring interval should be appropriate to meet the monitoring objectives and characteristics of the hazard being monitored. As an example, use of repeat LiDAR data may be an appropriate means of identifying changes to existing landslides or the formation of new landslides but would not be an appropriate means of acting as an early warning system for seismic hazards. There are three general categories of geohazard monitoring:

- Regional monitoring, where monitoring is typically performed over large areas (such as entire pipeline systems or segments). In most cases, this type of monitoring is conducted to monitor multiple known geohazards or areas where new geohazards are likely to form. Regional monitoring is generally focused on ground or water conditions, but ILI IMU could be applied to large sections of pipeline as well. Examples of this type of monitoring include:
    - Aerial patrol/reconnaissance
    - Ground patrol/reconnaissance
    - Repeat remote sensing, such as LiDAR, aerial imagery or InSAR
    - ILI IMU runs
    - Seismometers (usually maintained by public agencies)
    - Stream gauges (usually maintained by public agencies)
    - Weather monitoring
    - Wildfire monitoring
- Site-specific ground and stream monitoring, where the monitoring is for an individual geohazard site, typically through the installation of instrumentation. This type of

monitoring is usually performed because it either provides information not available from regional monitoring or at a higher frequency or increased accuracy compared to that available from regional monitoring. Examples of this type of monitoring include:

- Survey monitoring points
- Inclinometers
- Piezometers
- Repeat ground survey, such as LiDAR or bathymetry
- Stream gauges

- Site-specific pipeline monitoring, where the installed pipe monitoring sensors are used to characterize location or strain changes that may occur to the pipeline. This type of monitoring allows for data collection at higher frequencies and may complement other monitoring methods. Examples of this type of monitoring include:
    - Pipe positional survey
    - Strain gauges
    - Strain sensing cable

It is recommended that the PGMP document considerations for selection and usage of appropriate monitoring measures. The methods for installation, data collection, and analysis for frequently used monitoring measures should also be documented. Considerations for selection and usage of monitoring measures include:

- Objectives of the monitoring. These should be defined and understood prior to establishing a monitoring approach.
- The characteristics of the geohazard(s) being monitored, such as whether occurrence of the geohazard is gradual (such as a slow-moving landslide) or occurs essentially instantaneously (such as an earthquake).
- The number of geohazards being monitored
- The needed resolution of the monitoring data
- The needed frequency of measurement, and reporting frequency of the monitoring results
- The anticipated duration for monitoring

- External constraints that could affect the selection of monitoring measures, such as topography, vegetation, and site access.

### 3.5.4 Consideration of Uncertainties in the Decision-Making Process

With the current level of technology and scientific/engineering understanding, there can be a considerable level of uncertainty in geohazard processes, geologic materials, demand imposed on a pipeline, and strain capacity. These uncertainties vary by hazard type, topographic and geologic setting, and the characteristics of a pipeline, such as the time and method of construction. For instance, even with a detailed assessment (e.g., a Level 3 Assessment), there may be considerable uncertainties in predicting the timing and amount of landslide movement, or the depth and extent of scour at a river crossing. Similarly, there may be considerable uncertainties in the total strain demand imposed on a pipeline constructed many decades ago as there is no continuous strain monitoring from a time of zero strain. The tensile strain capacity of vintage girth welds can have a large range due to lack of reliable ILI methods to reliably detect and characterize potentially injurious weld flaws.

The framework presented in this document can assist operators in reducing these uncertainties to enable decision-making, but it does not eliminate the uncertainties. Such uncertainties should be accounted for in the operator’s CDM, and appropriate steps should be taken to manage these uncertainties. Some uncertainties can be managed using frequent monitoring or implementation of mitigative measures. Other uncertainties, such as those related to tensile strain capacity, can be reduced through opportunistic NDT (non-destructive testing) mechanical testing, and collecting and managing relevant data.

## 3.6 Data Management

A PGMP should document how geohazard data are managed and maintained. Data management is an essential process for the long-term management of geohazards and should be integrated with the previously discussed processes. Data management is used to consistently inventory potential geohazards (e.g., location, type, threat level) and to track and document changes over time (e.g., changing hazard conditions or site activities, such as assessments or mitigations that may be completed over time). In general, there are two broad types of data that need to be managed: spatial (i.e., map-based) and nonspatial (i.e., non-map-based) data. Operators are recommended to have a GIS-based component for management of spatial data (e.g., Google Earth, ESRI ArcGIS), along with an approach to managing non-spatial data. There should be a clear linkage between spatial and non-spatial data components (i.e., a way to link reports, photographs, monitoring results, etc. to map locations).

The data management system should contain, at a minimum, the following elements for each identified geohazard site, if available:

- A unique identifier
- The location of the geohazard in latitude and longitude
- The footprint of the geohazard, as mapped in GIS (e.g., polygon boundary of a landslide, line trace of a fault, or point location of a stream where it intersects a pipe)
- The geohazard type, including a summary of key characteristics of the geohazard
- Key characteristics of the geohazard as they relate to threat, threat classification, and/or threat ranking
- The date(s) of activities at the site, including identification, assessment(s), mitigation, and monitoring
- The types of threat-management measures implemented for the geohazard, including intervals for monitoring and action thresholds

Additionally, the data management system should document the following for each segment managed under the PGMP:

- The date(s) of assessment(s)
- The segments covered by these assessments
- Geohazard type(s) considered under these assessments
- The intervals at which non-hazard specific monitoring is conducted (such as repeat ILI or remote monitoring)
- The scheduled date of the next assessment

### 3.6.1 Retaining Data from New Construction and Pipe Replacement

Retaining data collected during pipeline design and construction for speedy retrieval during operation can positively impact geohazard management after the pipeline is commissioned. The type of data that should be retained for future use are summarized in

Table 3-1.

Table 3-1 Data from new construction that are useful for PGMP

| Data Type | Description of the Data | Potential Use of Data |
|---|---|---|
| Pipe as-built | Alignment sheets, field bend data, surveyed position of girth welds, unique girth weld identifier, and water crossing profiles with depth of cover. | Determine if a pipe has moved. Determine the location of girth welds relative to the geohazard. Facilitate the determination of strain demand. |
| Construction method and trench condition | Construction methods: e.g., open cut, conventional bore, HDD, etc. Rock vs. soil, soil type, images of the trench, depth of cover. | Assist the determination of the cause for a movement and local strain. Facilitate the determination of strain demand. |
| Inventory of geohazards | Characteristics of geohazards along or near the ROW, any mitigation actions taken, existence/disturbance of nearby buried utilities. | Determine the history of geohazards and project possible future impact. |
| Linepipe MTRs | MTRs from pipe manufacturers. Searchable database formats are preferred over scanned images. | Facilitate the determination of strain capacity and strain demand. |
| WPS and PQR of girth welds | Welding procedure specification (WPS) and procedure qualification records (PQR). Association of any given girth weld with a WPS and possibly a PQR. | Facilitate the determination of tensile strain capacity. |
| Girth weld inspection records | Inspection methods, acceptance criteria, contractor(s) for the inspection, "raw" NDE records which has all identified indications. | Facilitate the determination of tensile strain capacity. |
| IMU immediately after construction | IMU report and raw data. | Determine the initial position and profile before post-construction events would affect the pipeline. Allow accurate determination of future movements. |

## 3.7 Treatment of Other Threats Interacting with Geohazards

A pipeline subjected to geohazards may also be exposed to other threats to pipeline integrity, such as circumferential stress corrosion cracking (C-SCC), corrosion, and mechanical damage. The threats interacting with the geohazard threats are called interacting threats. The impact of interacting threats can manifest in two ways [10,11,12]:

(1) Reduction of strain capacity, and/or

(2) Reduction of ability to contain internal pressure.

Possible impacts are briefly summarized as follows:

- Corrosion, especially corrosion with a large circumferential extent in the pipe body or near girth welds, can reduce the TSC.
- Dents without gouges can reduce the CSC but have little impact on TSC.
- Dents with gouges can reduce both CSC and TSC.
- Compressive longitudinal stresses that can be caused by geohazards reduce the burst pressure of pipes with corrosion anomalies compared to pipes with similarly-sized corrosion subjected to tensile longitudinal stresses.
- Wrinkles or buckles can cause high local hoop strain, potentially causing leaks in weak seam welds.

Among all interacting threats, those that negatively impact TSC are particularly concerning, due to the potentially greater likelihood of a leak or rupture.

### 3.8 Applicable Standards and RPs

The following standards and RPs are most relevant to this document:

- ISO 20074:2019 Petroleum and Natural Gas Industry – Pipeline Transportation Systems – Geological Hazard Risk Management for Onshore Pipeline.
- ASME B31.8S Managing System Integrity of Gas Pipelines, 2020.
- API RP 1160 Managing System Integrity for Hazardous Liquid Pipelines, Third Edition, 2019.
- API RP 1173 Pipeline Safety Management System, First Edition, July 2015.
- API RP 1133 Managing Hydrotechnical Hazards for Pipelines Located Onshore or Within Coastal Zone Areas, Second Edition, December 2017.
- API RP 1176 Recommended Practice for Assessment and Management of Cracking in Pipelines, First Edition, 2016.

# 4 References


1 Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards, 87 Fed. Reg. 33,576 (June 2, 2022).

2 Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards, 84 Fed. Reg. 18,919 (May 2, 2019).

3 Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding, River Scour, and River Channel Migration, 84 Fed. Reg. 14,715 (April 11, 2019).

4 Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding, River Scour, and River Channel Migration, 81 Fed. Reg. 2,943 (January 19,2016).

5 McKenzie-Johnson, A., Theriault, B., Wang, Y., Yu D., West, D. Ebrahimi, A., Derby, M., Greene, A., "Guidelines for Management of Landslide Hazards for Pipelines," INGAA Foundation, August 17, 2020.

6 Wang, Y.-Y., et al., "Management of Ground Movement Hazards for Pipelines," CRES Project No. CRES-2012-M03-01, final report, February 28, 2017.

7 Liu, M., Wang, Y.-Y., Sen, M., and Song, P., "Integrity Assessment of Post-Peak-Moment Wrinkles," Proceedings of the 11th International Pipeline Conference, Paper No. IPC2016-64654, September 26-September 30, 2016, Calgary, Alberta, Canada.

8 Honegger et al., "Guidelines for Constructing Natural Gas and Hydrocarbon Pipelines Through Areas Prone to Landslide and Subsidence Hazards," ENV-1, Final Report submitted to Pipeline Research Council International, Inc., L52292, January 15, 2009.

9 Golder Associates et al., "Mitigation of Land Movement in Steep and Rugged Terrain for Pipeline Projects: Lessons Learned from Constructing Pipelines in West Virginia." Final Report No. 2015-03, Submitted to INGAA Foundation, April 2016.

10 Zhou, H., Wang, Y.-Y., Bergman, J., Stephens, M., and Nanney, S., 2018, "Tensile and Compressive Strain Capacity in the Presence of Corrosion Anomalies," Proceedings of the 12th International Pipeline Conference, Paper No. IPC2018-78802, September 24-28, 2018, Calgary, AB, Canada.

11 Zhou, H., Wang, Y.-Y., Bergman, J., Stephens, M., and Nanney, S., 2018, "Burst Pressure of Pipelines with Corrosion Anomalies under High Longitudinal Strains," Proceedings of the 12th International Pipeline Conference, Paper No. IPC2018-78803, September 24-28, 2018, Calgary, AB, Canada.

12 Zhou, H., Wang, Y.-Y., and Nanney, S., 2018, "Burst Pressure of Wrinkles under High Longitudinal Strain," Proceedings of the 12th International Pipeline Conference, Paper No. IPC2018-78804, September 24-28, 2018, Calgary, AB, Canada.

# Annex A Review of Historical Geohazards Impact on Pipelines

## A.1 Introduction

As indicated in Section 1.1, the primary objective of this document is the development of a high-level framework for the management of geohazards and their structural integrity implications on pipeline integrity. This framework is intended to cover multiple types of geohazards, as discussed in Section 1.3. More in-depth guidance beyond this framework document is likely to be necessary for some geohazards, to outline additional details specific to those hazard types. To guide the development of such in-depth guidance, it is necessary to understand the relative impact of each hazard type. The review summarized in this Annex is intended to meet this need.

This Annex summarizes the review of data and information aimed at identifying the relative prevalence of different types of geohazards and the level of impact each has had historically on pipelines. The conclusions of this review provide one of the criteria considered in developing a prioritized list for in-depth guidance, which is presented in Annex C.

## A.2 Data Sources

The reviewed data were collected from the following sources:

- Incident data gathered and collated by the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA). The PHMSA data consist of required reporting from hazardous liquid and natural gas transmission and gathering operators from January 1st, 2002, to June 30th, 2022 [1].
- The 11$^{th}$ Report [2] of the European Gas Pipeline Incident Data Group (EGIG), which summarizes natural gas incidents between 1970 and 2019.

## A.3 Review of PHMSA Reportable Incidents

### A.3.1 Overview of the Reportable Incidents and Method for Data Analysis

#### A.3.1.1 Reportable Incidents for Overall Pipeline Systems

Four data files were downloaded from the PHMSA Distribution, Transmission & Gathering, LNG, and Liquid Accident and Incident Data website. A total of 9,787 incidents were in the downloaded database, including 7,716 and 2,071 incidents from hazardous liquid and natural gas pipelines, respectively, over the period of January 1st, 2002, to June 30th, 2022.

The definition of a reportable incident [3,4] varies, depending on the type of regulated pipelines, i.e., natural gas vs. hazardous liquids.

#### A.3.1.2 Incident Criteria – Natural Gas Pipelines

For an incident in a natural gas pipeline to become "reportable", the incident must consist of one of the following (from 49 CFR 191.3):

*(1) An event that involves a release of gas from a pipeline, gas from an underground natural gas storage facility (UNGSF), liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:*

*(i) A death, or personal injury necessitating in-patient hospitalization;*

*(ii) Estimated property damage of $122,000 or more, including loss to the operator and others, or both, but excluding the cost of gas lost. For adjustments for inflation observed in calendar year 2021 onwards, changes to the reporting threshold will be posted on PHMSA's website. These changes will be determined in accordance with the procedures in appendix A to part 191.*

*(iii) Unintentional estimated gas loss of three million cubic feet or more.*

*(2) An event that results in an emergency shutdown of an LNG facility or a UNGSF. Activation of an emergency shutdown system for reasons other than an actual emergency within the facility does not constitute an incident.*

*(3) An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraph (1) or (2) of this definition.*

#### A.3.1.3 Accident Criteria – Hazardous Liquids and CO2

For hazardous liquids and CO2 pipelines, the accident criteria are (from 49 CFR 195.50):

*(a) Explosion or fire not intentionally set by the operator.*

*(b) Release of 5 gallons (19 liters) or more of hazardous liquid or carbon dioxide, except that no report is required for a release of less than 5 barrels (0.8 cubic meters) resulting from a pipeline maintenance activity if the release is:*

*(1) Not otherwise reportable under this section;*

*(2) Not one described in § 195.52(a)(4);*

*(3) Confined to company property or pipeline right-of-way; and*

*(4) Cleaned up promptly;*

*(c) Death of any person;*

*(d) Personal injury necessitating hospitalization;*

*(e) Estimated property damage, including cost of clean-up and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000.*

#### A.3.1.4 Identifying Geohazard Incidents

The incident data used to populate the PHMSA database consists of self-reported summaries submitted to PHMSA by pipeline operators. Due to PHMSA reporting requirements, the incidents may have been submitted before a full failure analysis was completed. There was diversity in the data fields from required and optional fields, from standardized selection to free-form text fields. The free-form text data fields had diverse language that included different styles of technical and informal pipeline terminology. To the knowledge of the authors, there is no independent review conducted by PHMSA or others to confirm the correctness or consistency of the incident summaries prior to submittal.

When operators report incidents, PHMSA limits each incident to one causal factor. PHMSA categorizes natural hazard incidents by natural force casual factor. However, geohazard incidents are often related to multiple causal factors. Due to the data entry practices allowed by PHMSA the project team had to review each data entry and interpret the data fields to understand the incident and contributing factor.

The downloaded data files were converted into Microsoft® Excel® files for analysis. The analysis involved sorting and filtering the data to identify incidents for categorization. The filtering process occurred on each dataset separately, but in the same sequence.

The first filtering step was to remove offshore incidents, which were out of scope. This filter removed 588 incidents from the 4 datasets. Each PHMSA dataset had a different format and used slightly different terminology. When the data is summarized below as causal factors, the terminology is simplified for brevity and the actual terminology used in each dataset may be slightly different. For the purposes of this document, incidents and accidents are called incidents.

The second filtering step was to identify incidents with the causes listed as either (1) natural force, (2) material and/or weld failures, (3) other outside force damage, or (4) other. These incidents often had causal factors related to geohazards and were specifically selected due to the data entry practices. This second filtering yielded 2,255 incidents for further review.

The written narratives with one of the four causal factors listed above were reviewed to determine whether the incident was related to a natural hazard. The narrative descriptions of the incidents varied widely depending on the person doing the data entry, when the data entry was completed in the incident repair/investigation, and whether the data entry was revised when more information became available. Other data fields related to natural force incidents were reviewed to confirm the narrative. When necessary, the GPS location was checked using Google Earth® to verify the location and terrain, and to review historic imagery near the incident date. These checks were used to ensure the interpretation from the narrative aligned with this project's scope.

There was a variety of terminology used to describe each event in the narrative. Some of the terminology conflicted with the data fields selected. The project team used Google Earth® and available data fields to verify the hazard that was applicable to each incident. For example, terms used to describe landslides included landslide, slide, slip, earth movement, land movement, ground movement, soil movement, down-slope movement, movement, flow, downhill soil settlement, external stress, displacement, and subsidence.

Due to the variety of terms in the narrative used to describe geohazard incidents, the project team searched for other key words related to geohazards in incidents with causal factors other than the original four factors considered. These new terms related to external force damage or descriptions of geohazards, such as soil movement, waterway, river, and frost, and yielded 1,940 incidents. The narratives of these candidate incidents were reviewed to determine if they had a causal factor related to natural hazards. This ultimately yielded 11 incidents with causal factors other than the original four from the second filtering step but had descriptions of geohazard related in the narrative.

A total of 4,195 incidents were reviewed during the filtering and keyword review process for an indication of a causal factor related to geohazards. These were reviewed in limited detail using the narrative and incident causal factors. This initial review of the incidents yielded 2,266 incidents that were labeled as a potential geohazard and were reviewed in greater detail. Each of the 2,266 incidents was reviewed to determine the type of geohazard or natural hazard and were grouped into six categories, composed of geotechnical hazards (landslide, subsidence, and seismic), hydrotechnical (waterway), natural hazards (frost heave and weather related).

During the detailed review some of the incidents were found to be caused by operational issues (e.g. emergency shut down, uncontrolled venting, loss of communication, etc.) or equipment issues (e.g. sump tank, above ground storage tank, etc.). Operational incidents (e.g., lightning causing an emergency shutdown event, flooding causing the sump to overfill, or freezing of water inside the pipe/appurtenance causing the incident) were not a geohazard threat within the scope of the project and were labeled as operations related. These operations related incidents were removed from further review.

Of the 2,266 incidents reviewed in detail, a total of 266 reported incidents were identified as likely related to geohazards or natural hazards. All incidents that were reviewed in detail fit into these categories and there were no outlier incidents that were related to other natural hazards such as volcanic, tsunami, expansive soils, etc. Table A-1 provides a summary of incidents identified (based on the description review) as having been caused by a natural hazard by the causal factors listed in the PHMSA data. Of the 266 incidents examined, 110 were related to liquid pipelines and 156 were related to natural gas pipelines.

Table A-1 Incidents related to geohazards or natural hazards by hazards type and PHMSA causal factors

| | Incident Count | | | | | | |
|---|---|---|---|---|---|---|---|
| **PHMSA Causal Factor[6]** | **Total** | **Landslide** | **Subsidence** | **Seismic** | **Waterway** | **Frost Heave** | **Weather Related** |
| Corrosion | 8 | 2 | 0 | 0 | 5 | 0 | 1 |
| Equipment Failure | 2 | 0 | 0 | 0 | 0 | 2 | 0 |
| Excavation Damage | 1 | 0 | 0 | 0 | 1 | 0 | 0 |
| Material/Weld Failure | 29 | 20 | 6 | 0 | 3 | 0 | 0 |
| Natural Force | 205 | 39 | 12 | 3 | 36 | 23 | 92 |
| Other | 21 | 5 | 2 | 0 | 11 | 0 | 3 |

The 266 incidents were reviewed to determine if the incident was a rupture or leak. Most incidents were labeled in the PHMSA data as a rupture or leak. For incidents labeled as other, N/A, or left blank, the leak type data fields and narrative were reviewed to determine if the incident was related to a rupture or leak. The narrative described incidents ranging from fires, lighting strike leaks, instrument connection storm damage, cracked buckle, coupling separation, or circumferential separation in incidents classified under the other or N/A leak categories. For the purposes of this project, a leak is defined as a loss of product due to a crack, small hole, or appurtenance, and a rupture is defined as a loss of product related to a separation of a pipe or a hole that would take the majority of the flow from the pipeline. There were 186 incidents related to leaks and 80 related to ruptures.

### A.3.2 Incidents by Geohazard Type

Identified incidents were categorized into six hazard categories, aligning closely with PHMSA criteria, including (1) landslide, (2) waterway, (3) subsidence, (4) seismic, (5) frost heave and (6) weather related. Each incident was further categorized as a leak or a rupture.

A total of 266 reported incidents were identified as related to geohazards or natural hazards. Of the 266 incidents examined (averaging 13.0 incidents/year), 110 were related to liquid

[6] These causal factors were simplified. Each dataset has slightly different wording for causal factors.

pipelines and 156 were related to natural gas pipelines. Landslides (43) were the most prevalent source of ruptures, followed by waterway (24) and subsidence (12). Although weather related incidents were the largest number of incidents, all but one was a leak, and many were inside facilities.

Figure A-1 shows the number of leak and rupture incidents in the six categories of geohazards and natural hazards. Figure A-2 is similar but further divides each category into gas or liquid pipelines. Figure A-3 shows the incidents recorded by state. Louisiana and Texas have the most incidents by state, the most miles of transmission pipelines, and the highest pipeline density.

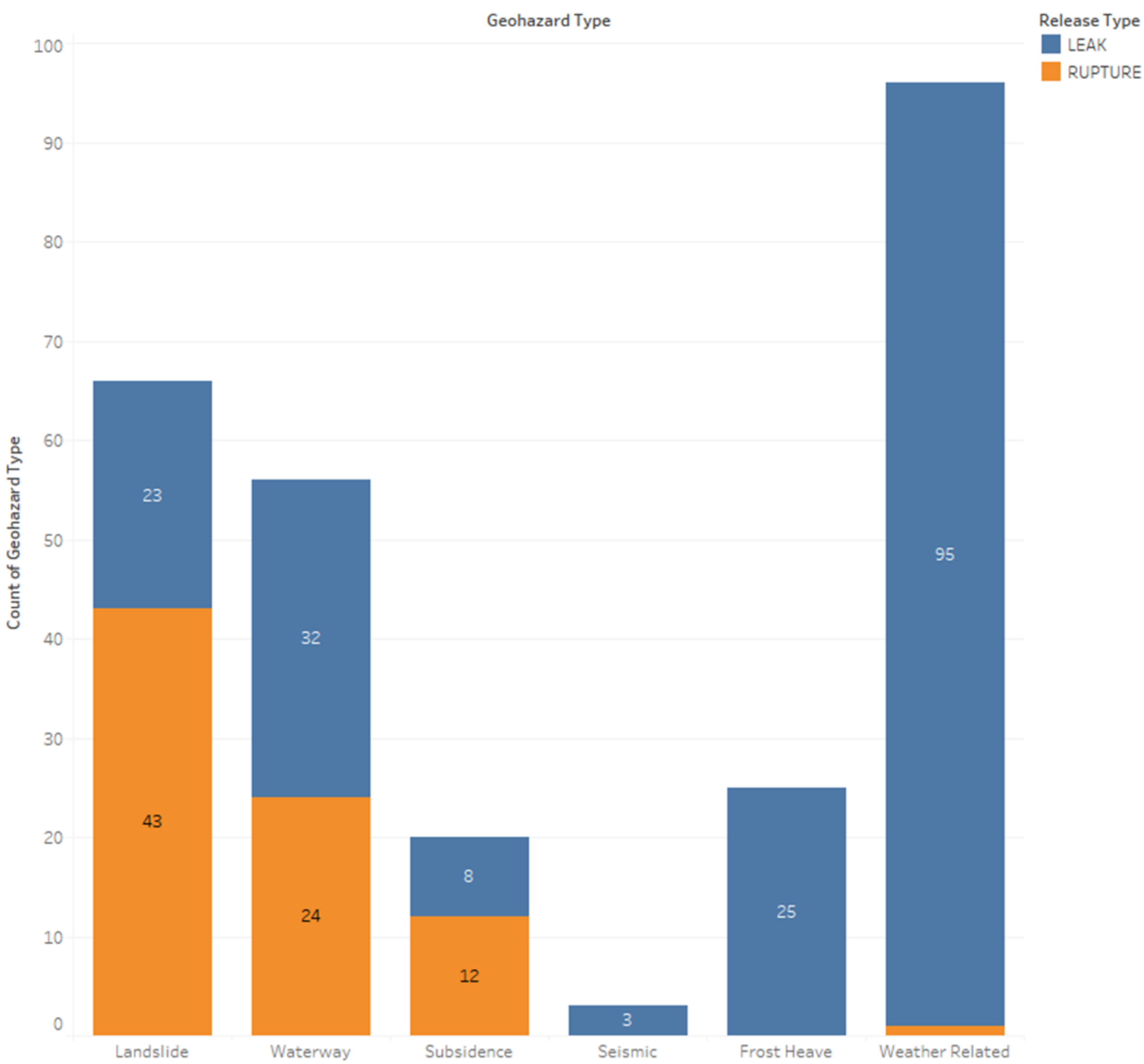



Figure A-1 Incidents by hazards type and leak vs. rupture (over a 20.5-year period)

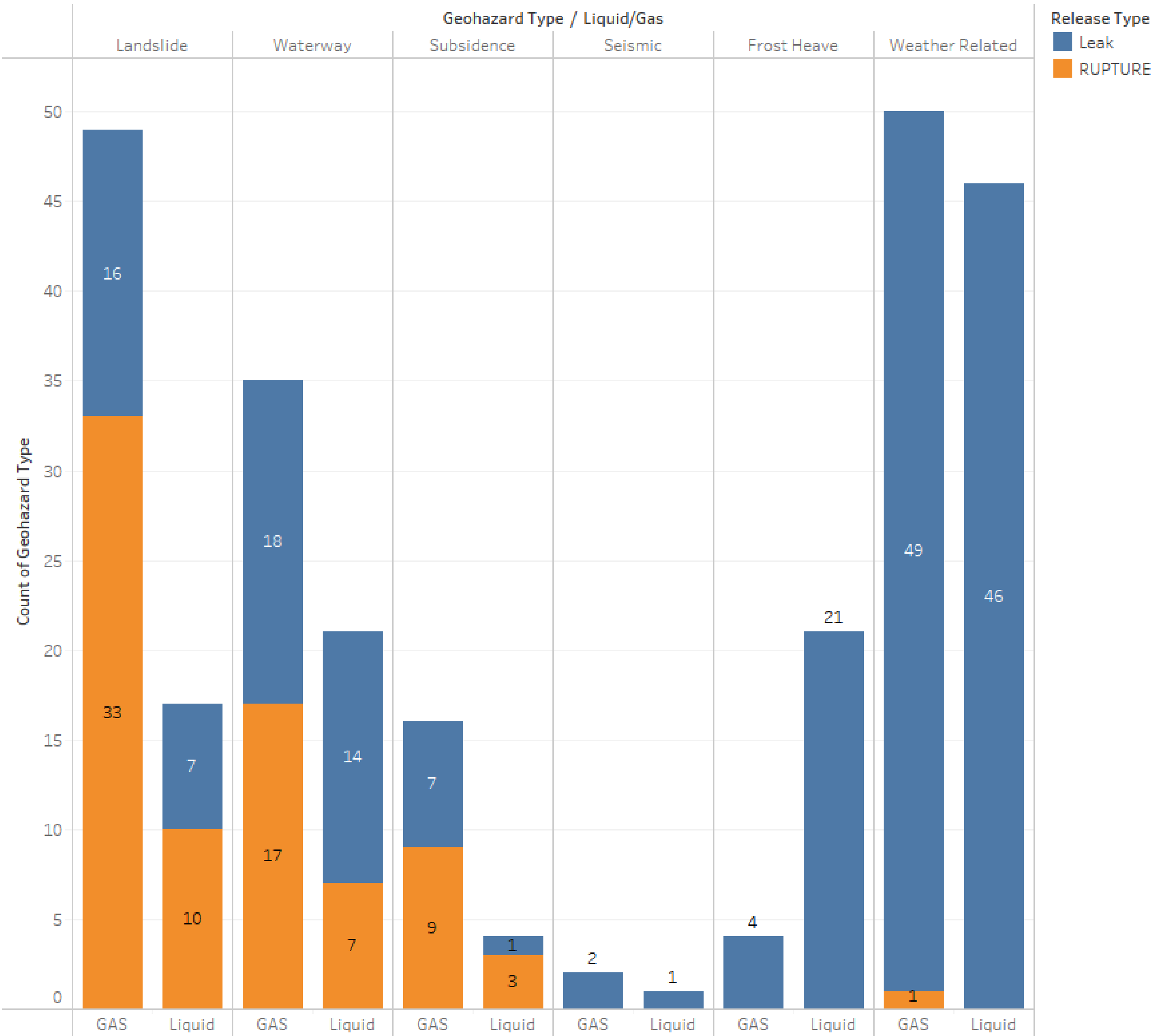



Figure A-2 Incidents by types of pipeline and hazards (over a 20.5-year period)

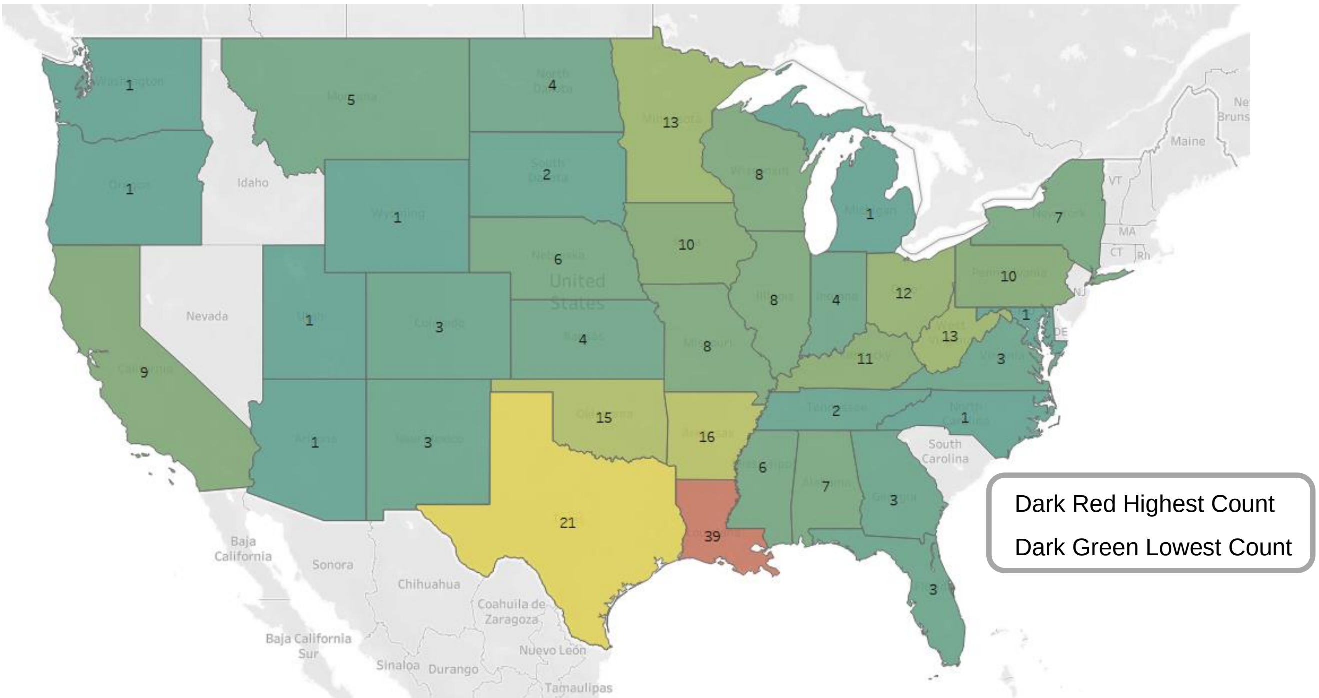



Figure A-3 Incidents by state [AK and PR not shown]

Table A-2 summarizes the PHMSA incident frequencies for geohazards and natural hazards for the entire 20.5-year period. The frequency was calculated using the total PHMSA incident count and rupture incident count for geohazards and natural hazards, divided by the 20.5-year period of record and further divided by the average miles of pipeline over the period of 2010-2021. The average mileage of pipelines during the PHMSA reporting period of 2010 - 2021 was approximately 320,000 miles for natural gas transmission and gathering and 207,000 miles for liquid pipelines [5]. The frequency was also separated by the type of pipeline to compare the rates for natural gas and liquid pipelines.

Table A-2 PHMSA incident frequency per 1000 miles per year

| | Incident Frequency | | Rupture Incident Frequency | |
|---|---|---|---|---|
| **Reporting Years** | **Natural Gas** | **Liquid** | **Natural Gas** | **Liquid** |
| 2002-2009 | 0.026 | 0.016 | 0.011 | 0.004 |
| 2010-2022 | 0.023 | 0.029 | 0.008 | 0.005 |
| 2002-2022 | 0.024 | 0.024 | 0.009 | 0.004 |
| | 0.024 / (1000 mi/yr) | | 0.007 / (1000 mi/yr) | |

Figure A-4 shows a PHMSA-produced map of the gas transmission and hazardous liquid pipelines in the United States as of August 2016 [6]. Texas and Louisiana have the most pipeline miles per state, with Texas having over double the pipeline miles of Louisiana. The top five states by mileage are Texas, Louisiana, Kansas, Oklahoma, and California, respectively. Louisiana and Texas have the highest pipeline density (miles of pipeline per square mile) with Texas having about half the pipeline density of Louisiana. The top five states by pipeline density are Louisiana, Texas, Oklahoma, Ohio, and Mississippi, respectively. The majority of the pipeline mileage in the United States is between the Appalachian Mountains and the Rocky Mountains. Large numbers of incidents in states with less mileage or density may indicate an elevated geohazard threat to pipelines. Geographic regions with high pipeline density have greater representation in the data.

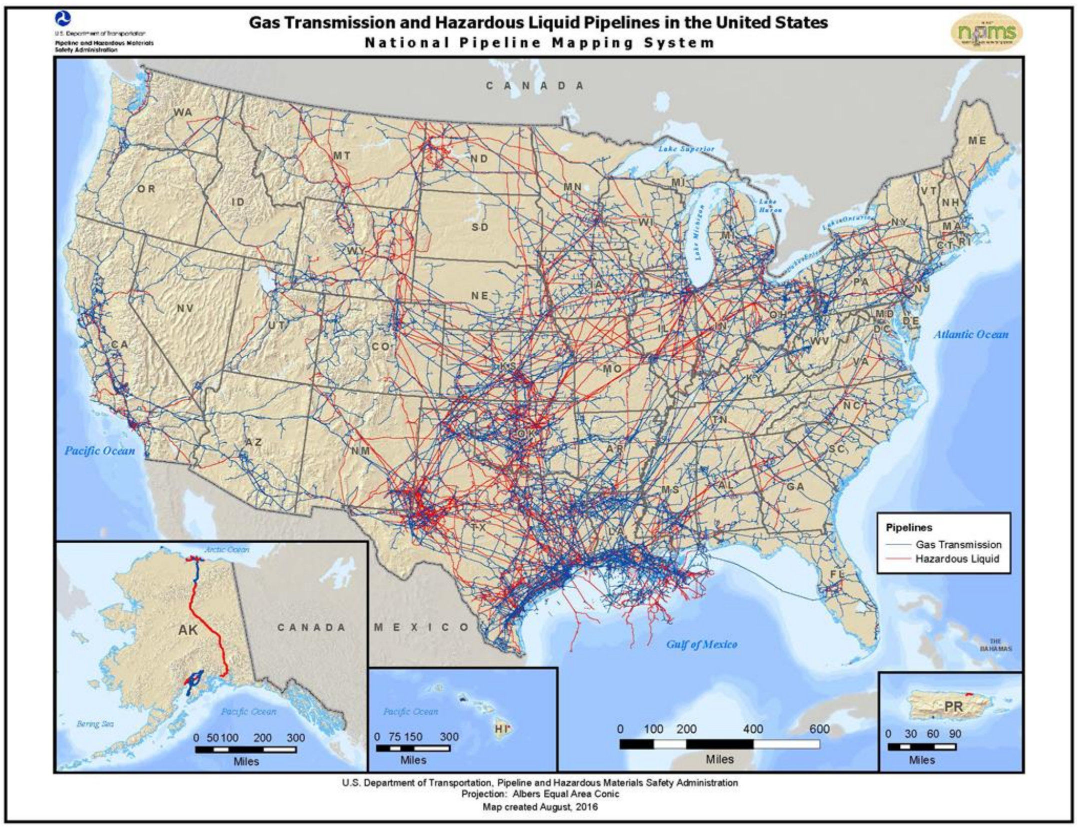



Figure A-4 Gas transmission and hazardous liquid pipelines in the United States [6]

### A.3.3 Landslide Incidents

Figure A-5 and Figure A-6 show the total landslide incident count and the landslide incident resulting in ruptures by state. West Virginia, California, Kentucky, and Ohio had a large number of incidents and multiple ruptures. West Virginia (0.093), Kentucky (0.046), and Ohio (0.022) have the highest landslide incident frequency per 1000 miles of pipeline per year. Based on the data reviewed, West Virginia was 1st in the number of landslide incidents, 14th in pipeline density, and 31st in pipeline mileage by state

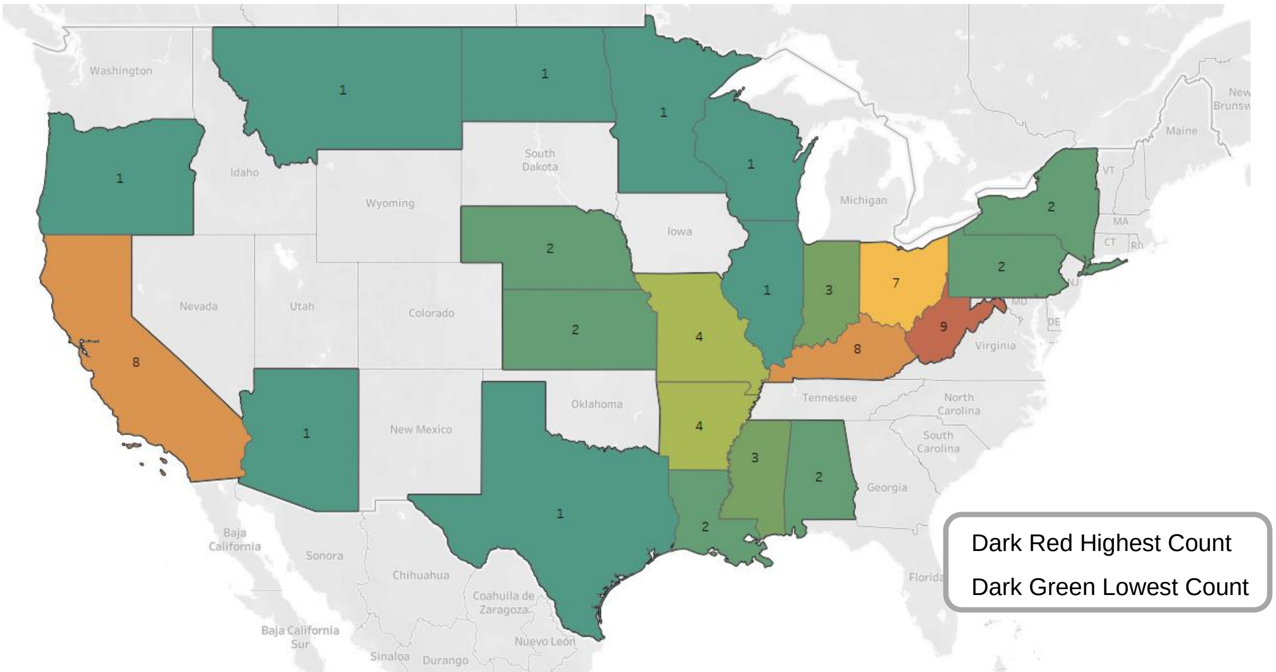



Figure A-5 Total landslide incidents by state

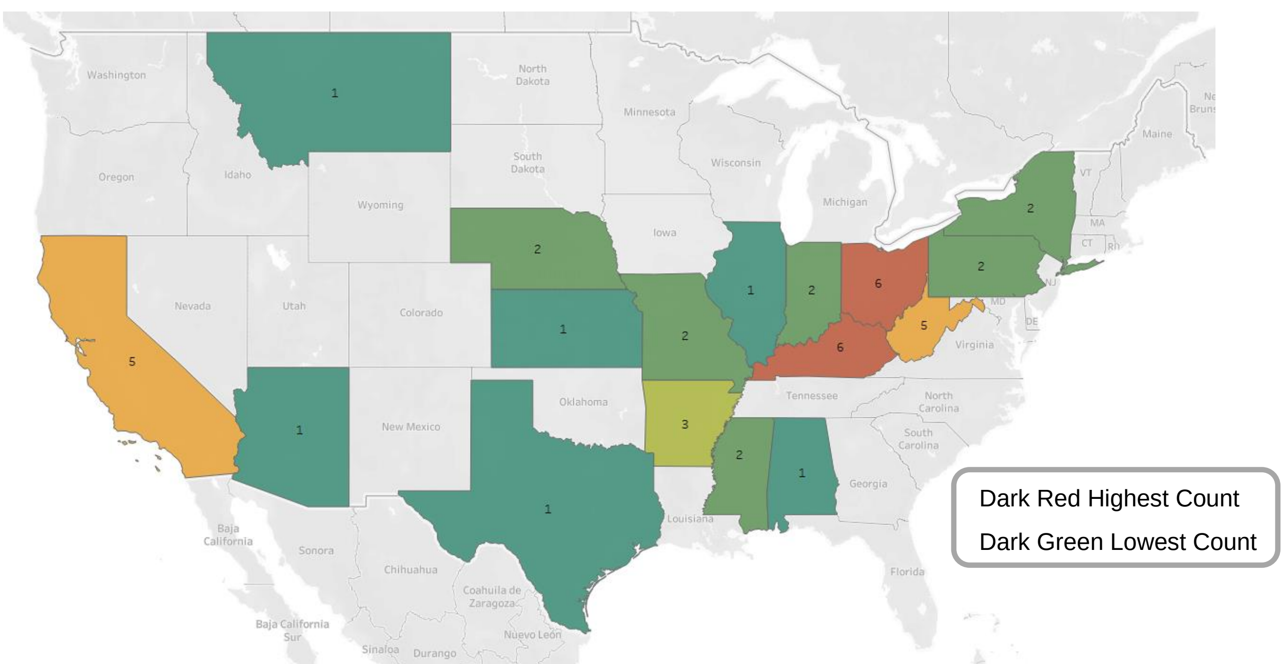



Figure A-6 Landslide incidents resulting in ruptures by state

### A.3.4 Waterway Incidents

Figure A-7 shows the number of waterway incidents per state. Waterway incidents were the second highest source of rupture incidents. The highest number of incidents occurred in Louisiana and many of those were related to hurricanes.

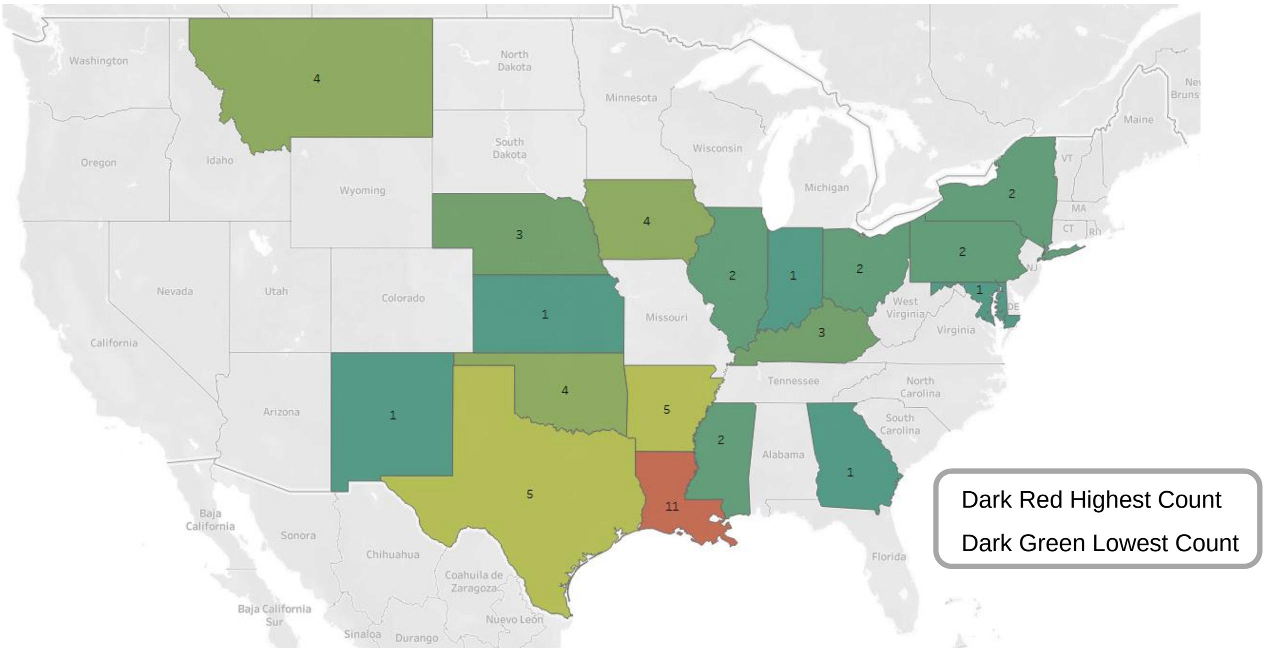



Figure A-7 Waterway incidents by state [PR not shown]

### A.3.5 Subsidence Incidents

Figure A-8 shows the numbers of subsidence incidents per state. Subsidence incidents were the third-highest source of rupture incidents. Mining and underground fluid extraction were the main factors reported for locations related to subsidence. The states where the highest rates of incidents occurred have a large occurrence of current and historic mining and extraction activities.

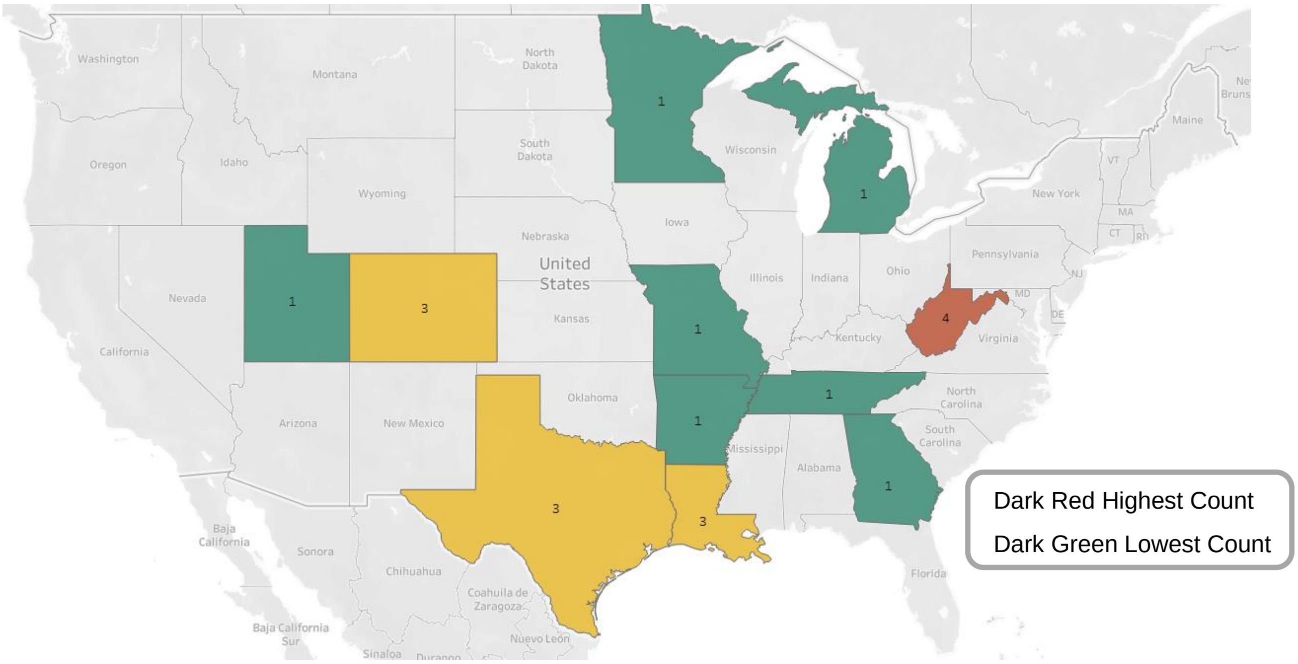



Figure A-8 Subsidence incidents by state

### A.3.6 Seismic Incidents

Seismic hazard-related incidents were very limited in the reviewed data. They were all leaks and located in areas where recent earthquakes occurred. A total of three leak events were represented in the data: two leak incidents on natural gas pipelines (one in California and one in Virginia), and one liquid pipeline leak (in Alaska). There were few major earthquake events in the United States within the timeframe of the data reviewed for this project.

### A.3.7 Weather Related Incidents

Figure A-9 shows the number of weather-related incidents per state. Approximately half of the weather-related incidents occurred in states with high hurricane occurrence in the Gulf of Mexico. The incidents caused by weather related hazards had many leaks and only one rupture reported. The rupture incident was within a flooded facility where a natural gas pipeline floated and separated at a coupling connection. The weather-related incidents were mostly attributed to lightning strikes or flying debris damage from tornadoes or hurricanes.

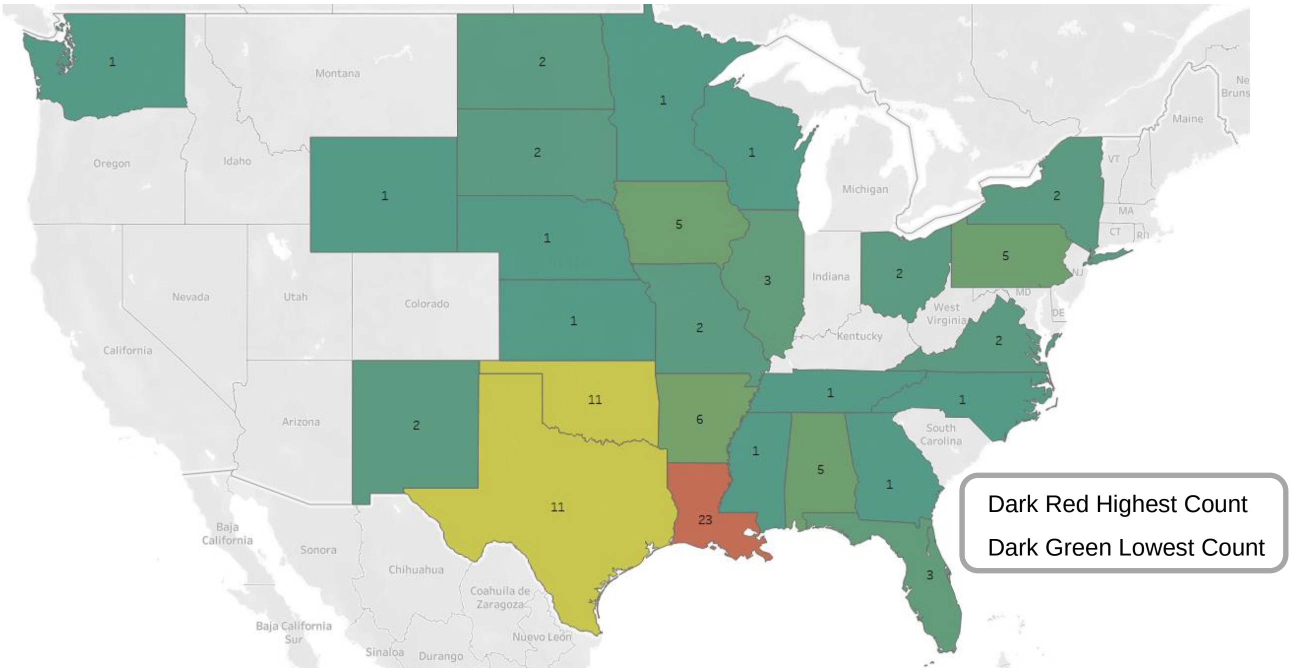



Figure A-9 Weather related Incidents by state

### A.3.8 Frost Heave Incidents

Figure A-10 shows the number of frost heave incidents per state. Over half of the incidents occurred in Minnesota and Wisconsin. The incidents caused by frost heave consisted of leaks, most related to damaged ancillary piping around valves and within facilities.

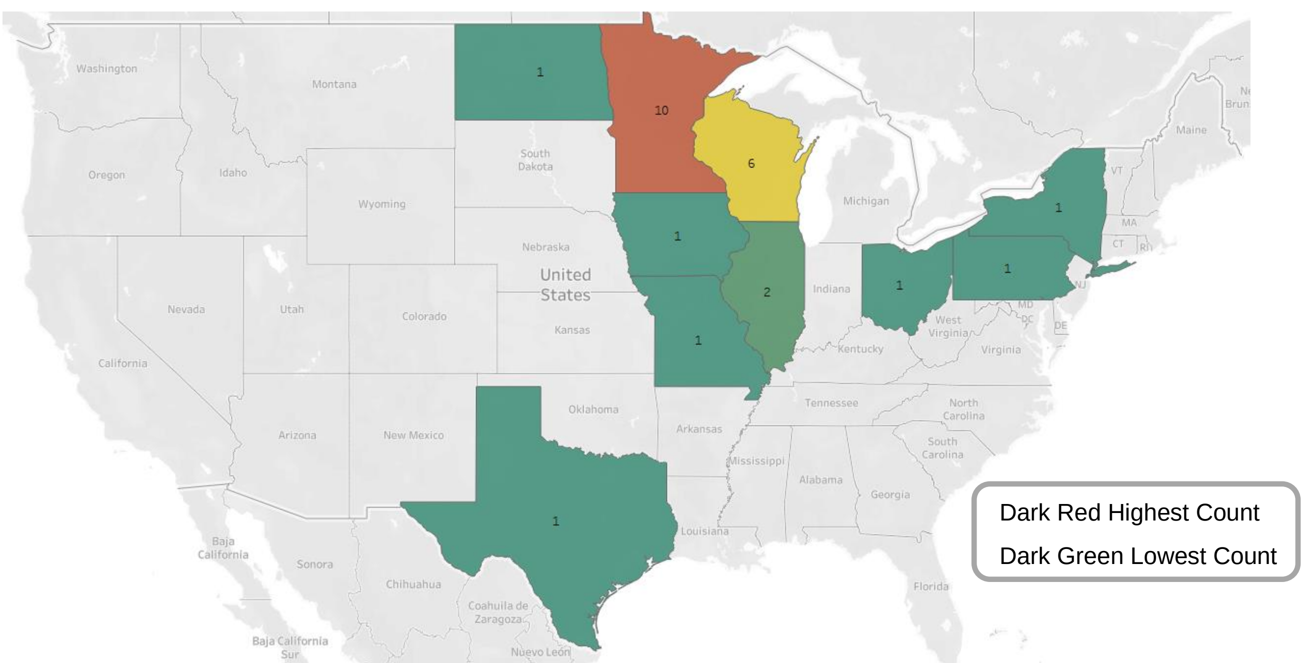



Figure A-10 Frost heave incidents by state

### A.4 Review of European Incidents

EGIG is a cooperative group of seventeen major gas transmission system operators in Europe. Their mission is to gather data on the unintentional releases of gas in their pipeline transmission systems. This group does not cover all natural gas operators or any liquid pipeline operators. EGIG collects data for onshore steel pipelines designed to operate at 15 bar or greater. They do not collect data on equipment-related releases. The pipelines included in the report may not represent all geographic areas of Europe. EGIG's scope is similar to PHMSA but only includes natural gas transmission operators who join the group and thus does not represent all European pipeline operators.

EGIG issues a report periodically and the 11$^{th}$ report was issued in December 2020. Data from the 11$^{th}$ EGIG report covers the period from 1970 to 2019. The report details statistics on releases meeting the criteria for reporting from the seventeen operators. The intent is to create a data source with the best available failure data on gas pipelines and to demonstrate the high level of safety of European gas transmission pipelines.

The release sizes were divided into three categories: pinhole/crack, hole, and rupture. The incident causes were categorized into external interference (1$^{st}$ ,2$^{nd}$, 3$^{rd}$ party damage), corrosion, construction defect/material failure, hot tap made by error, ground movement, other, and unknown. The ground movement category was divided into sub-causes of dike break, erosion, flood, landslide, mining, erosion of riverbed, erosion of the riverbank, or unknown. The EGIG report does not explicitly state if multiple categories could be assigned to each incident.

The EGIG report summarizes the frequency of incidents. EGIG calculates failure frequency by the number of incidents divided by the exposure. Exposure is the length of the pipeline system multiplied by the exposure duration, expressed in km-yrs. A primary frequency (i.e., major categories), and then subdivides the primary frequencies into secondary frequencies (i.e., per diameter class, depth of cover class, or pressure class). The primary failure frequency of ground movement was considered for this INGAA project. An example of a primary failure frequency is an incident rate caused by ground movement. A secondary failure frequency would be ground movement incident rates per diameter class or release size category.

The report includes natural gas pipelines with an average age of 35 years. Figure A-11 shows that the primary failure frequency of all release incidents has been trending down since 1970. Table A-3 shows the primary failure frequency for ground movement incidents has been relatively stable over the dataset with a slight dip in the most recent 5-year period. The failure frequency in the 20-year period between 2000-2019 was 0.032 incidents per 1000 miles per year when converting from kilometers. This failure frequency was similar to that from PHMSA data.

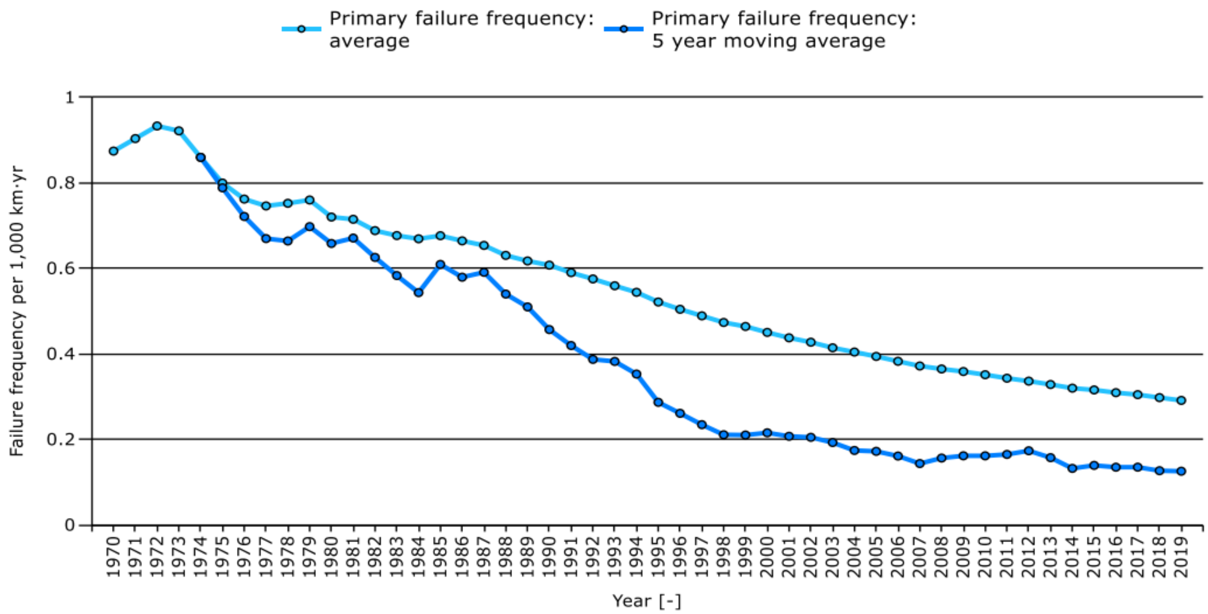



Figure A-11 EGIG primary failure frequency [2]

Table A-3 EGIG primary failure frequency per cause [2]

| Cause | Primary failure frequency | | | |
|---|---|---|---|---|
| | 1970-2019 per 1,000km·yr | 2000-2019 per 1,000km·yr | 2010-2019 per 1,000km·yr | 2015-2019 per 1,000km·yr |
| External interference | 0.134 | 0.054 | 0.035 | 0.036 |
| Corrosion | 0.05 | 0.033 | 0.034 | 0.032 |
| Construction defect/Material failure | 0.048 | 0.02 | 0.05 | 0.015 |
| Hot tap made by error | 0.013 | 0.005 | 0.002 | 0.001 |
| Ground movement | 0.025 | 0.02 | 0.02 | 0.014 |
| Other and unknown | 0.022 | 0.015 | 0.017 | 0.024 |

Figure A-12 shows that for the 2010-2019 period, 15.76% of the incidents were related to ground movement. During the same period, Figure A-13, Figure A-14, and Figure A-15 show ground movement was responsible for 9%, 22%, and 48% of pinhole/crack-, hole-, and rupture-sized incidents, respectively. Ground movement was the largest category of rupture-sized-incidents during the 2010-2019 period.

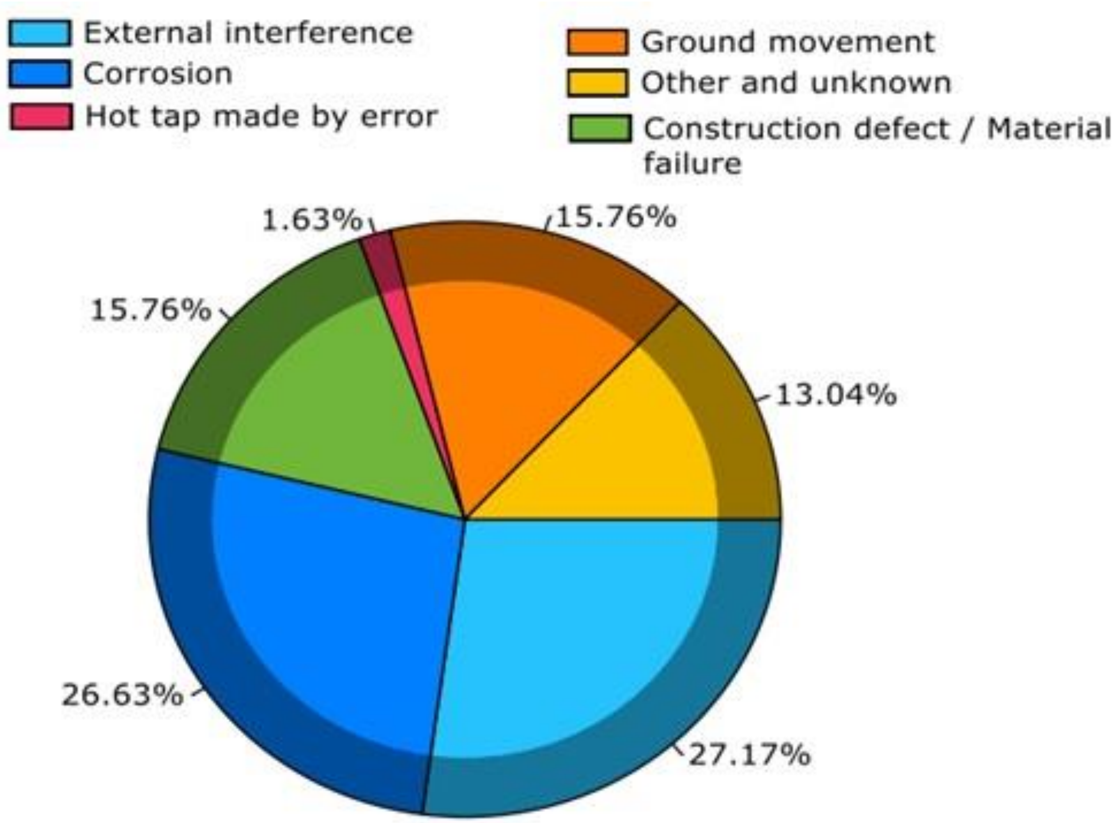



Figure A-12 EGIG distribution of incidents from 2010-2019 [2]

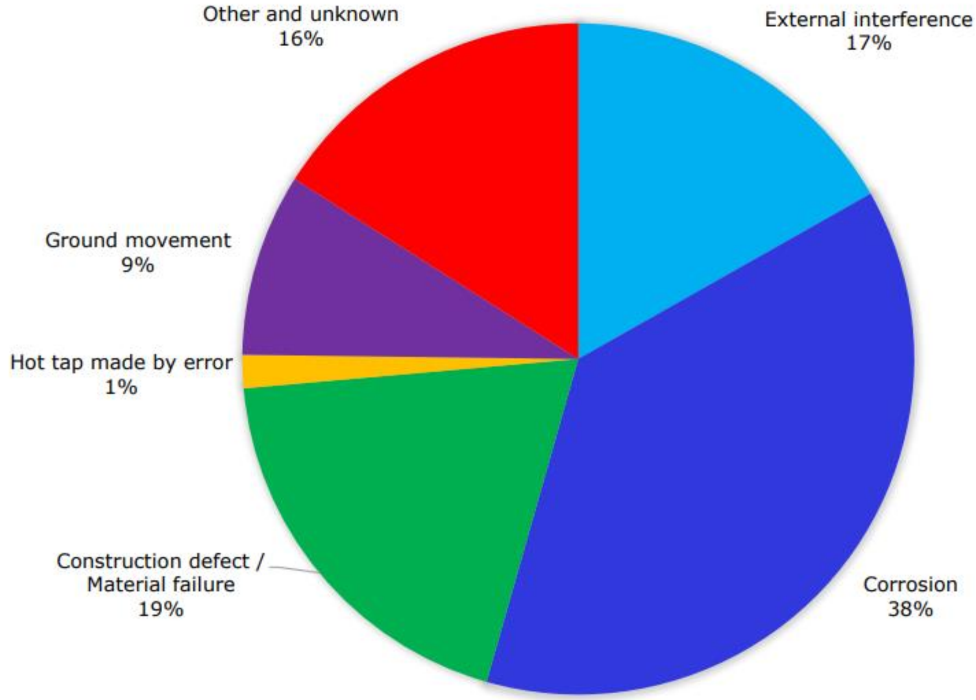



Figure A-13 EGIG distribution of incidents with pinhole/crack leak size from 2010-2019 [2]

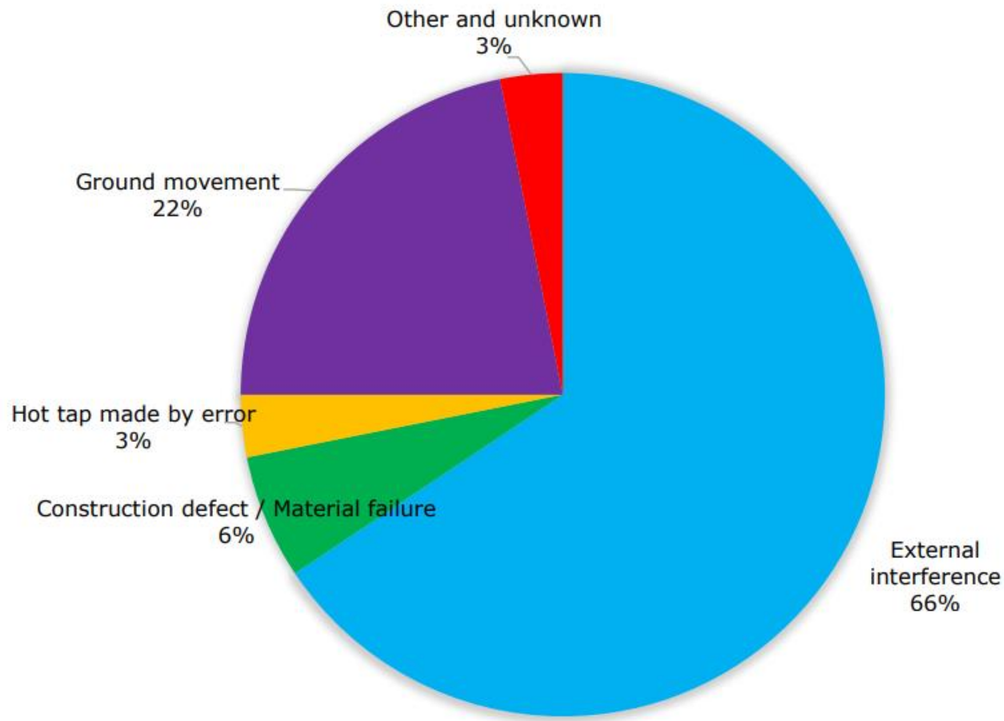



Figure A-14 EGIG distribution of incidents with hole leak size from 2010-2019 [2]

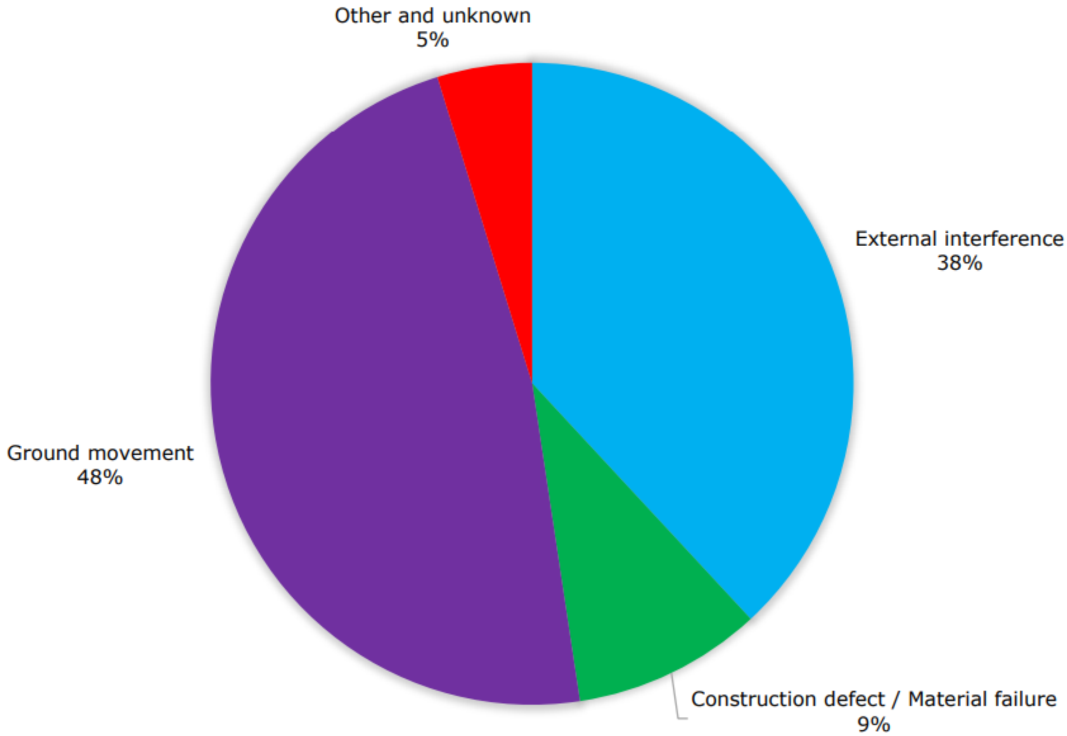



Figure A-15 EGIG distribution of incidents with rupture leak size from 2010-2019 [2]

Table A-4 shows that ground movement had the highest frequency of rupture incidents during the period 2010-2019. Figure A-16 shows that ground movement has the second highest frequency, after external interference, for rupture incidents for the period 1970-2019. Figure A-17 shows that the number of rupture incidents attributed to ground movement is larger than any other causes of ruptures during the 2010-2019 period.

Table A-4 EGIG primary failure frequency, cause, and size of leak from 2010-2019 [2]

| Cause | Failure frequency per 1,000km·yr | | | | | |
|---|---|---|---|---|---|---|
| | External interference | Corrosion | Construction defect/Material failure | Hot tap made by error | Ground movement | Other and unknown |
| Rupture | 0.060 | 0.000 | 0.001 | 0.000 | 0.007 | 0.001 |
| Hole | 0.015 | 0.000 | 0.001 | 0.001 | 0.005 | 0.001 |
| Pinhole/Crack | 0.015 | 0.033 | 0.017 | 0.001 | 0.008 | 0.014 |
| Unknown | 0.000 | 0.001 | 0.001 | 0.000 | 0.001 | 0.001 |

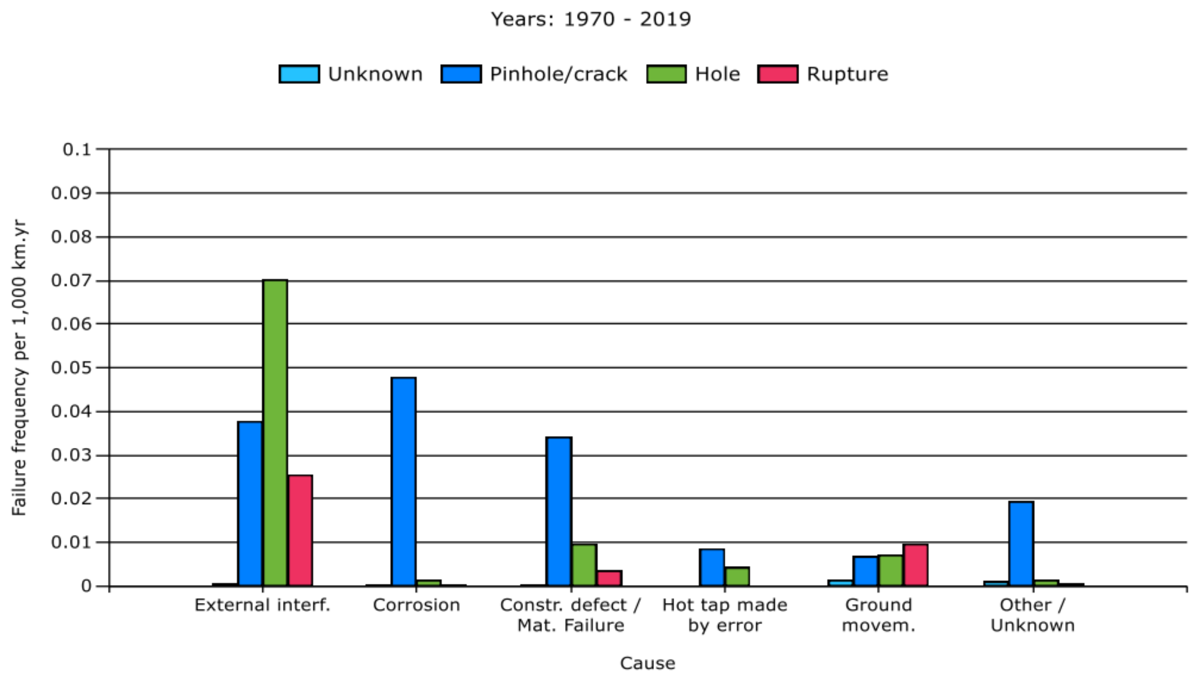



Figure A-16 EGIG primary failure frequency, cause, and size from 1970-2019 [2]

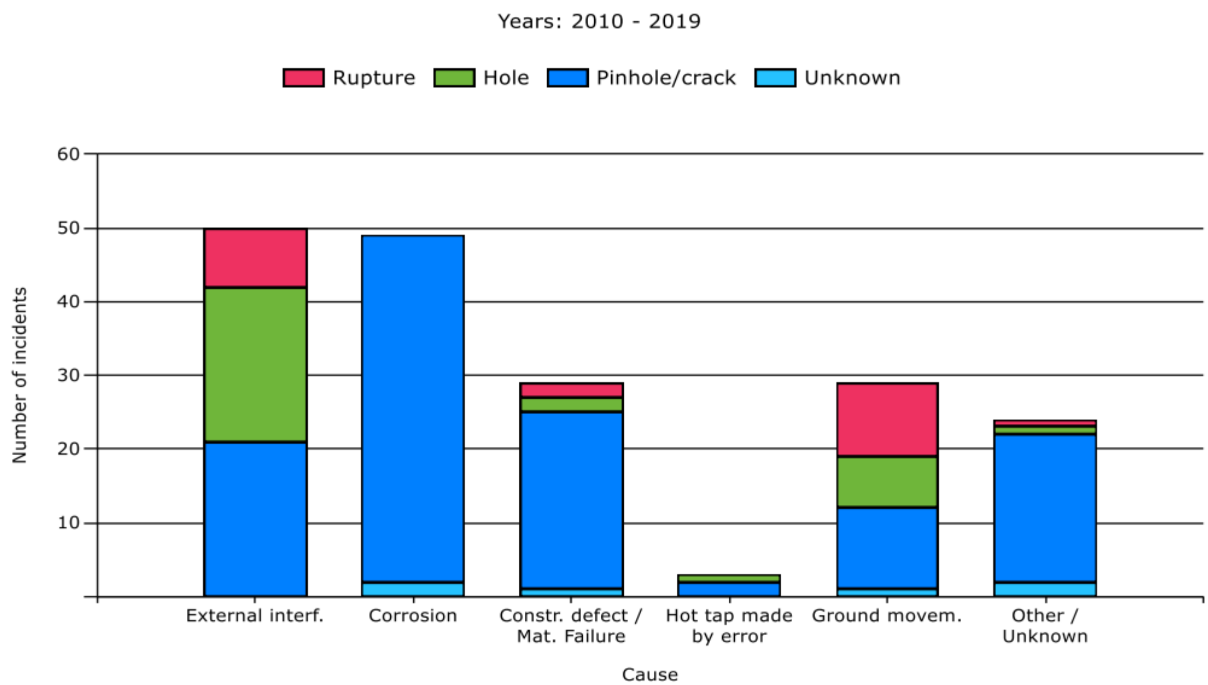



Figure A-17 EGIG number of incidents per cause from 2010-2019 [2]

Figure A-18 and Figure A-19 divided the ground movement incident data into sub-categories. The largest sub-category for ground movement incidents for the periods of 1970-

2019 (65.83%) and 2010-2019 (96.55%) was landslide. The next largest category was related to flooding in both time periods. The prevalence of these geohazards align with that of the PHMSA data.

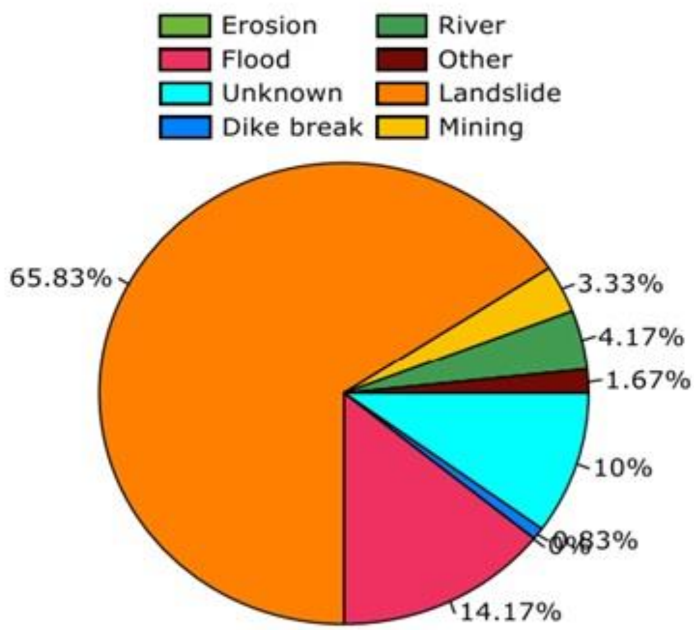



Figure A-18 EGIG distribution of sub-causes of ground movement incidents (period 1970-2019) [2]

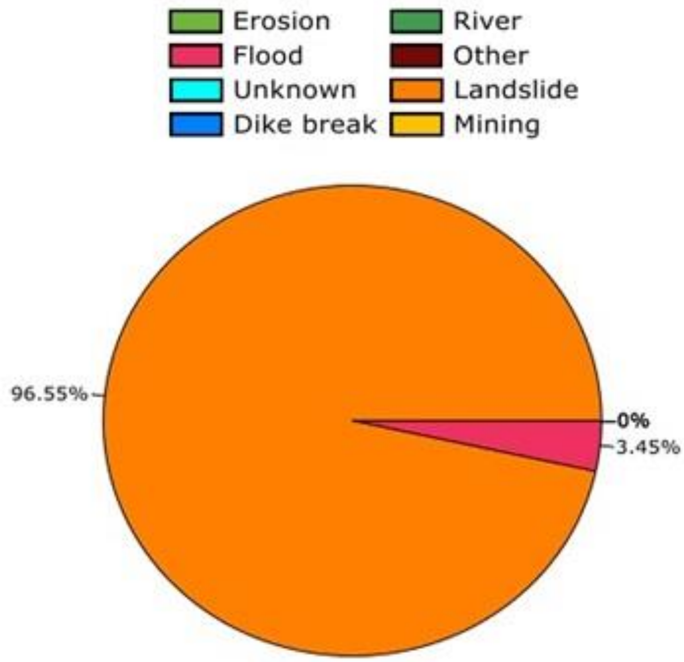



Figure A-19 EGIG distribution of sub-causes of ground movement (period 2010-2019) [2]

### A.5 Experience of Authors

The experience of the authors that prepared this document are consistent with the statistical summary presented above. During the authors' careers, some spanning back to the 1970s, the predominant cause of geohazard-related ruptures has been landslides, with hydrotechnical events being the most common secondary source of geohazard-related ruptures. The authors have not been involved with any ruptures that were definitively caused by earthquakes. However, the lack of involvement with seismic-related ruptures does not mean that these hazards should not be addressed in a geohazard management program.

The authors are aware of several ruptures in the United States (landslides and waterway related) that are not captured in the PHMSA data, either because the incidents occurred before 2002, they occurred on pipelines not regulated at the time by PHMSA, or because the incidents were not recorded as external force or geohazards in the PHMSA data by the operator.

The relative distribution of geohazard-related incidents from the PHMSA data is consistent with the authors' experiences. Many geohazard incidents that result in negative impacts to pipeline operators do not result in leaks or ruptures and thus may not be reported because they are not interpreted to meet PHMSA criteria for reporting. For example, significant landslide deformation on a pipeline that causes a pipeline operator to halt operation of the pipeline until the issue is resolved creates a negative impact to the operator, and potentially the operator's customers, but does not meet the criteria for PHMSA reporting. Operators are cautioned that

PHMSA data do not capture the absolute number of geohazard impacts, and that the actual frequency of geohazard impact to pipelines is higher than recorded. Unfortunately, the PHMSA data represent the best available historical source for tracking pipeline impacts in the United States, and thus the absolute number of historical geohazard-related impacts and their causes are likely to remain unknown.

### A.6 Major Findings

- The frequency of incidents attributable to geohazards is significant. PHMSA (0.024 incidents per 1000 miles per year for natural gas) and EGIG (0.032 incidents per 1000 miles per year) data have similar incident rates.
- The frequency of incidents attributable to geohazards has not improved significantly over the last 20-40 years, as opposed to other threats.
- There are minimal differences in the rates of geohazard incidents between natural gas and liquid pipeline systems.
- EGIG data supported that the leading cause of ruptures comes from geohazard-related incidents in the last 10 years and the second leading cause of ruptures since 1970.
- Landslide hazards are the largest source of ruptures for pipelines. The PHMSA data show hydrotechnical hazards are the second largest source of ruptures, followed by subsidence hazards. PHMSA-reportable landslide incidents are more likely to result in a rupture than a leak.
- Natural hazards (weather-related and frost heave incidents) do not have a large impact on pipeline integrity. Incidents reviewed were mostly leaks and occurred during specific weather events.

# Annex B Pipeline Operator Experience

JIP members were sent a questionnaire to gather information about their geohazard management programs and practices. The questionnaire included the following topics: program management, susceptibility, assessments, integrity analysis, mitigation, data management, and new construction. Eleven follow-up interviews were conducted to clarify members' responses and let members expand on their responses.

The purpose of the questionnaire form and interviews with JIP members was to understand their geohazard management processes, procedures, experience, and hazard priorities. This was intended to assess the state of practice, identify gaps, and commonality among operators. The summary of each section was meant to describe the breadth of what is being done and where there is consensus or divergent practices.

The following subsections cover the outcomes of the listed topics above.

## B.1 Geohazard Management Programs

The operators universally stated that geohazard management was part of their integrity management program (IMP) as hazards can impact pipeline integrity. The management of the ROW and geohazards was reported to be an important part of an IMP. Most operators had a management structure where the program was run within integrity management organization or in an organization that was reporting to integrity management.

The majority of the members have a high level of concern for landslide, waterway, and seismic hazards and have programs to manage those threats.

Operators considered hydrotechnical and geotechnical threats with similar approaches, but there were no consistent approaches toward meteorological hazards such as lightning strike and severe weather. The approach used by the operators involves identifying sites to manage and then assessing those sites for potential threat to pipeline integrity. Methods to implement this approach varied.

The complexity of each operator's geohazard program generally corresponded to the size of the organization and experience with certain hazards. Small and large operators focused on certain threats when the region in which they operated had a high level of those threats, and those programs were generally more developed and complex. For instance, operators exposed to landslide threats in Appalachia and that had previously experienced impacts from landslides tended to have more developed and complex programs to manage landslides than operators that did not have the same exposure. Other operators with more exposure to hydrotechnical threats than geotechnical threats, had developed programs focused on hydrotechnical processes.

Management practices varied based on region specific-geohazard threats, such as seismic threats in California and landslide threats in the Appalachian Mountains. Smaller operators tended to have less specific geohazard management practices or procedures to govern their actions.

Training for geohazard management varied by operators. Some had formal training for geohazard identification; however, most only had limited geohazard identification training for aerial patrol and field operations personnel. Training or qualification for engineers and construction contractors was not required or detailed by the operators through the interview responses. Some operators stated that they felt like they had inadequate knowledge regarding strain assessment techniques and would need to rely on contract engineers and service providers.

## B.2 Susceptibility to Geohazards

Many operators had a susceptibility assessment process. Sometimes, this was used to establish susceptible geohazard systems and sites and other times it was used to create a relative ranking score to determine a segment's susceptibility to certain hazards. Some operators reported using their risk assessment process to integrate different threats, like metal loss or deformations from ILI to prioritize site assessment and mitigation actions. Many operators prioritized assessing geohazard threats by relying on their past experience within the regions where they operate their pipelines.

The threats listed by operators are landslides (translational, rotational, debris flow), subsidence (karst, mining, fluid withdraw), expansive soils, waterways, erosion, seismic (faulting and liquefaction), wildfires, tsunami, weather (frost heave, lightening, flooding, storm damage, etc.), and volcanos. The top three hazards of primary interest were reported to be landslide, waterway, and seismic. Operators ranked their geotechnical hazards based on their experience. The majority of operators found landslides and seismic concerns to be the most significant geotechnical hazard. Operators tended to have varying approaches to waterway hazards that did not cross the ROW, such as avulsion or bend migration concerns.

## B.3 Geohazard Assessment

Several operators reported using a phased approach to identify and characterize specific geohazard threats. Many operators would use desktop studies, LiDAR, InSAR, and ILI IMU bending strain to identify sites where there are indications of geohazards along their pipeline segments. After operators identify sites, they progress to more detailed geotechnical, hydrotechnical, and FFS assessment.

Among the operators, there were few consistent approaches for site assessment, and approaches varied depending on the geohazard type. The variation was mainly due to the different nature of each geohazard threat and the criticality of the pipeline, but there were other operator-specific factors involved. More detailed assessments were often triggered by a risk analysis that operators performed. Some operators used a standardized approach while others used a site-specific approach.

## B.4 Pipeline Integrity Analysis

Operators' approaches to pipeline integrity analysis varied widely. Their approach appeared to correspond to their experience and risk tolerance level. Many operators make baseline assumptions (pipeline strain capacity, existing strain level, etc.) which guided actions they would take regarding ILI bending strain. Operators' actions were not always tied to the actual pipe and weld properties of the segment. There was no clear trend among operators on what methodologies were used to determine the strain capacity or strain demand. Some operators felt that they lacked the experience and training to adequately conduct strain-based assessment for FFS analysis. Most members referenced API 1133 for integrity analysis for hydrotechnical hazards, citing vortex induced vibration fatigue and stress limited span lengths.

## B.5 Monitoring and Mitigation

Some operators had specifications on mitigation efforts and others would perform unique mitigation based on geohazard site assessment. Others would combine mitigation and monitoring to reduce likelihood of impact from geohazards. The level of effort to perform geotechnical analysis varied based on criticality of the pipeline and size of the geohazard. Operators tended to take conservative mitigative actions rather than performing a formal geotechnical analysis. All operators consider the geohazard characteristics at the site and tailor their mitigation response to the specific hazard.

Most operators monitor for seismic and flooding events. Some operators had more sophisticated monitoring dashboards and monitor weather events and other potential triggers for geohazard events. Many were using instrumentation installed in the field to monitor pipeline sites. Common field monitoring techniques were reported to include survey points, strain gauges, and satellite based InSAR. Many operators used short reassessment intervals to monitor their segments with ILI or LiDAR (e.g. annual, biannual assessments).

## B.6 Data Management

Most operators are using spatial databases and GIS type tools to track geohazard sites and store data associated with assessments. Different internal tools are used to track inspection scheduling and actions (e.g., GIS-based, databases, 3rd party software). There were no consistent data models specifically for geohazard management. Two popular pipeline data models cited were created by PODS [7] and Esri [8].

Integrity data for strain-based assessment are not consistently stored by operators. Pipeline strain capacity and strain demand limits are not consistently documented as pipe data, like other pipe characteristics (yield strength, wall thickness, etc.). Many operators noted one-off strain assessments, but there was no consistent approach between the members. Pipe related data were typically managed using databases and alignment sheets.

## B.7 New Construction

Most operators were considering geohazards for new construction, but many expressed concerns on how consistently geohazards were accounted for in the design and construction process. Many operators had a process to review projects with their integrity teams to check for geohazards. Pipeline design and routing was often contracted out to meet ASME specifications and PHMSA regulations. Many operators expressed that their geohazard management approach was different for the early life of a newly constructed pipeline, where landslide incidents tended to occur more frequently in their experience.

# Annex C Priorities for Developing In-Depth Guidance

## C.1 Scope and Methodology

This Annex provides recommendations on priority for in-depth guidance by geohazard types for North American pipeline assets. In the context of this document, an "in-depth guidance" means formalization of identification, assessment, and management methodologies into a recommended practice or a standard recognized by standard-setting organizations such as API or ASME.

The criteria used to develop the priority list, in the general order of importance for assigning prioritization, include the following:

- The number of historically recorded incidents that resulted in a loss of containment event or could have resulted in a loss of containment without intervention, as summarized in Annex A.
- Perceived needs of the authors and contributing Operators (i.e., through interviews summarized in Annex B) to this document.
- Existence of meaningful guidance for the individual hazard type at the time of this document.

## C.2 Recommended Priority for Developing In-Depth Guidance

Based on the above criteria, the priority for in-depth guidance by geohazard type is:

1. Landslide
2. Hydrotechnical
3. Subsidence
4. Seismic
5. Volcanic

## C.3 Commentary on Priority Recommendations

### C.3.1 Landslides

Statistical analysis, as summarized in Annex A, and the experience of the authors and contributing operators collectively indicate that landslides are the predominant cause of geohazard-related ruptures. While guidance documents have been previously developed, such as the INGAA guidelines [9], there are no ASME standards, API recommended practices, or regulations (in the United States), that define minimum requirements for landslide hazard management. With the maturation and commercialization of newer technologies, particularly LiDAR and IMU bending strain that assist in the identification, characterization, and monitoring of areas of landslide threats, landslides can be proactively identified and managed. Effective identification and management of landslides is possible with present-day technology; as such, implementing and adopting in-depth guidance and requirements around landslide management is likely to result in the greatest reduction of geohazard-related ruptures relative to any of the other primary geohazard types.

### C.3.2 Hydrotechnical

During the period of record reviewed for this project, hydrotechnical threats were the second most common cause of geohazard-related ruptures, as summarized in Annex A. In addition, based on the experience of the authors and contributing Operators, hydrotechnical hazards are generally considered the next biggest threat to pipelines after landslides. Hydrotechnical threats predominantly occur at stream crossings, and thus the process to identify these hazards is relatively straight-forward.

In contrast to landslides, there is more existing guidance around managing hydrotechnical threats, such as API RP 1133 [10] (most recently revised in 2017). Additionally, at the time of this document, there was an ongoing PRCI effort to improve assessment and management of hydrotechnical threats, Project ENV-4-1A [11] Modernize the Assessment of Pipeline Water Crossings. It is recommended that a possible future revision or enhancement of API RP 1133 be completed to reflect the lessons learned and compiled from the PRCI effort.

### C.3.3 Subsidence

During the period of record reviewed for this project, subsidence was the third most common cause of geohazard-related ruptures, as summarized in Annex A. Guidance focused on management of subsidence hazards for pipeline operators is sparse, and typically is included with guidance for landslides, such as a 2009 PRCI report [12].

Subsidence generally occurs when underground voids condense or collapse, and as such, can have limited or subtle evidence of change to the ground surface prior to incident occurrence. This makes it a more difficult type of geohazard to pre-emptively identify and manage than landslides and hydrotechnical hazards. Maturation of technologies such as satellite-based synthetic aperture radar (SAR) that can provide frequent monitoring of subtle ground changes (in the centimeter to millimeter level) may enhance the ability to effectively manage subsidence hazards. In-depth guidance may need to wait until these technologies commercially mature in order to provide a practical approach to management of subsidence hazards.

### C.3.4 Seismic

During the period of record reviewed, no ruptures directly attributed to seismic hazards were recorded, as summarized in Annex A. This may be a function of the relatively limited exposure of pipelines in the United States and Europe to meaningful seismic hazards (in North America, hazards are concentrated along the west coast and the New Madrid Seismic Zone), and the few large earthquakes that occurred during this period. It may also indicate that pipeline operators with pipelines in seismically active areas often implement pre-emptive measures to mitigate potential seismic-related impact to their pipeline. For example, in 2002, the Trans-Alaska Pipeline successfully survived surface fault displacement of about 2.3 meters strike-slip and 0.8 meters vertically resulting from the M 7.9 Denali Earthquake, while it was designed for 6 meters lateral displacement and 1.5 meters vertical displacement (Sorensen and Myer 2003). Seismic hazards are addressed in existing pipeline literature, such as a 2017 PRCI report [13]. Due to the limited geographic extent of seismic hazards, the existing common practices for design and installations of pipelines in seismically active areas, and the existing published guidance, the priority to develop an industry-wide standard or recommended practice is lower than for the previously discussed hazard types.

### C.3.5 Volcanic

Exposure to volcanic hazards in North America is largely confined to the Cascade volcanoes of California, Oregon, Washington, and British Columbia, and the active volcanic areas of Alaska and Hawaii. During the period of record reviewed for this project and based on the experience of the authors and contributing operators, no known pipeline-related ruptures are directly attributable to volcanoes in North America. This could be due to the amount of pipeline miles exposed to the threat and frequency of significant volcanic events.

There are three known instances where pipelines were threatened by volcanic activity. In the first and second instances, the Drift River Terminal and associated pipeline in Alaska were threatened during the Mt. Redoubt eruption in 1989/1990 and again in 2009. During the 2009 eruption, the dikes built to protect the terminal saved the tanks from being washed away from extreme flooding. The flood water flow, combined with ash and debris, caused the river to change course around the Drift River Terminal. In the third instance, two pipelines within the Northwest Pipeline system in Washington were exposed by a lahar that was triggered by the Mt. St. Helens eruption in 1980.

It is recommended that those operators with potential exposure to volcanic hazards develop and maintain internal guidance to manage these hazards. At this time, the priority to develop industry-wide standards or a recommended practice for volcanic hazards is low, due to the limited geographic extent of volcanic hazards, the low frequency of events, and the need for operators exposed to such threats to develop internal guidance.

# Annex D Strain-Resistant Design and Construction for Pipe Replacement and New Construction

## D.1 Background and Problem Statement

There have been at least 30 documented girth weld failures in newly constructed pipelines in North America, South America, and Asia [14,15,16,17]. These failures include in-service leaks and ruptures, as well as hydrostatic test leaks. A review of records and post-incident testing indicated that the minimum requirements in relevant industry standards have been met. Based on historical experience, these failures were not expected. The number of incidents indicates that the recent failures are not one-of-a-kind events. Geohazards were one of the contributing factors in some of the incidents. However, most of the incidents did not involve identifiable geohazards. The loads from normal construction and post-construction settlement were sufficient to cause some of the failures.

Girth welds similar to the failed welds can exist in areas with geohazards. Clearly, girth welds that could fail without geohazards are unlikely to fare well under loads imposed by geohazards. Furthermore, some of the failures occurred within weeks or months after the pipelines were put in service. Transitioning into a geohazard management program after the commissioning of the pipelines would not likely be effective to prevent such incidents due to the low tolerance to longitudinal loading of the pipelines.

This section provides high-level guidance on building strain-resistant pipelines which are relevant to both new construction and pipe replacement projects.

## D.2 Major Contributing Factors to Girth Weld Failures

Historically, the primary causes of girth weld failures have been weld flaws and low toughness. These two factors have been the primary focus of welding standards. Large weld flaws have been largely eliminated through the widespread and mandatory use of NDT (non-destructive testing) such as radiography during construction. New pipe steel manufacturing practice and improved welding processes have improved weld toughness and reduce the propensity for hydrogen cracking during welding.

Unfortunately, new factors that negatively affect girth weld performance have emerged. Two major factors that contributed to the low strain resistance of the failed girth welds are weld strength undermatching and heat-affected zone (HAZ) softening. Weld strength undermatching has always been allowed in girth welding standards, but it has not been a major factor in actual girth welds when pipelines were constructed using lower grade pipes, such as X52. The widespread use of high-strength linepipes in new construction, particularly X70 pipes with spiral or ERW seam welds, has pushed this issue to the front. At the same time, pipe steel making, for the sake of high toughness, high strength, and low cost, has evolved. One of the consequences of the change is steels having greater propensity for HAZ softening due to the thermal cycles of field girth welding.

Weld strength undermatching and HAZ softening effectively make the weld region weaker than the rest of the pipe. When a pipe segment is subjected to longitudinal loading, much of the deformation is concentrated in the girth weld region. Since the weld region has a limited width, this deformation causes very high local strain in the girth weld region and an eventual leak or rupture.

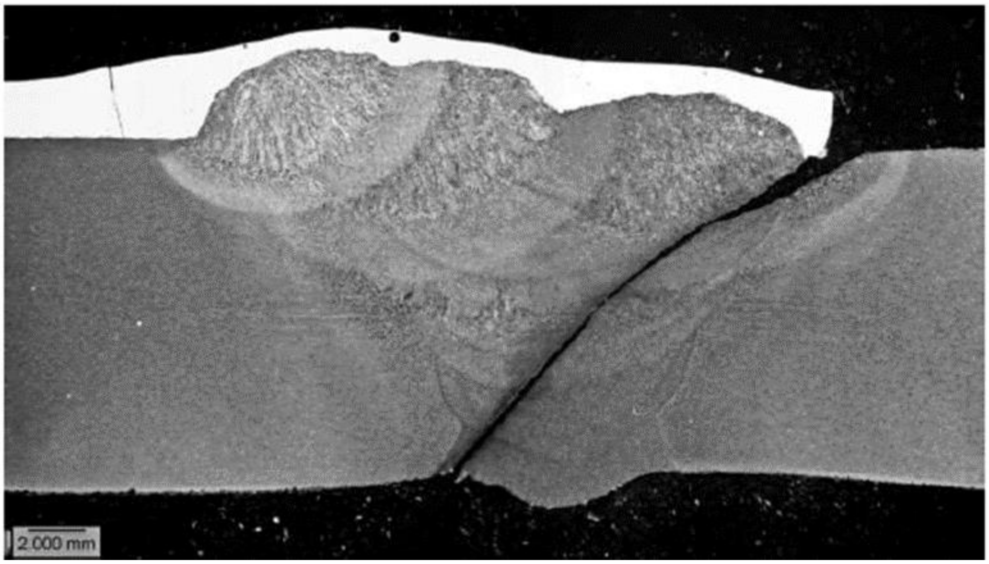



Figure D-1 Example of a failed girth weld with weld strength undermatching

## D.3 Overall Approach to Strain-Resistant Pipelines

In addition to the conventional approach to girth weld quality control by preventing, detecting, and mitigating the potential negative impact of weld flaws, preventing strain concentration at the girth welds is necessary to ensure good strain tolerance in a pipeline. This can be done by reducing weld strength undermatching and HAZ softening.

## D.4 Enhanced Linepipe Specifications

Linepipe of the same grade are allowed to have large yield strength (YS) and ultimate tensile strength (UTS) ranges, as shown in Figure D-1. For linepipes with grades X52 and above, the yield strength has a range of 22 ksi or greater, and the permitted UTS range is nearly 30 ksi or greater.

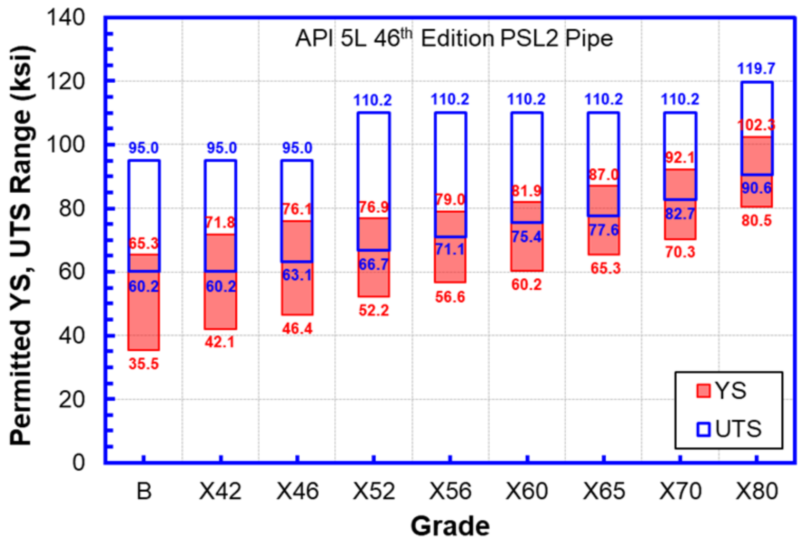



Figure D-2 Permitted ranges of yield strength and UTS for PSL2 pipes in API 5L

To reduce the level of weld strength undermatching, the upper-bound pipe strength for a grade should be limited to a reasonable value that does not unduly affect the practicality of the pipe steel making process. To reduce the level of HAZ softening, it's necessary to require steels to have a minimum level of hardenability. The recommended specifications for linepipe steels for producing strain-resistant girth welds are given in a PRCI technical bulletin [18] and in the final report of PRCI project MATH-5-3B [19].

## D.5 Improving Girth Welding Practice

The improvements to welding practices include two principal components: (1) increasing weld metal strength to reduce the level of weld strength undermatching, and (2) minimizing HAZ softening through welding process selection and control. The selection of welding options for the reduction of weld strength undermatching and HAZ is provided in a PRCI technical bulletin [18]. Recommendations are made for improved welding procedure qualifications, including selecting pipes for making qualification welds, selection of cross-weld tensile tests, and requirements for such tests [18,19].

## D.6 Construction Quality Control

In addition to specifying or selecting the right pipes and using improved field girth welding processes, having rigorous and actionable inspection criteria and enforcing such criteria in pipeline construction are necessary to ensure the quality of construction.

# Annex E Concepts, Procedures, and Tools for the Determination of TSC

## E.1 Problem Statement

Among possible failure modes affected by geohazards, a potential leak or rupture by tensile loading is generally a high priority concern. Understanding the tensile strain capacity (TSC) of a pipeline segment is critical to avoid such failures.

## E.2 Essential Concepts

TSC is the strain level in tension beyond which there would be a negative consequence, such as a leak, a rupture, or change in the physical characteristics of the pipeline (e.g., deformation of the pipe cross-section) that may negatively affect its operation. A few essential concepts about TSC are given below.

- The tolerance to tensile loading/stress/strain of a pipe segment is largely influenced by how the necessary extension or bending caused by geohazards is distributed over the segment. For instance, if girth welds are stronger than the surrounding pipes, the elongation of the segment is distributed over the length of pipe body, leading to higher strain tolerance for the overall segment.. If the girth welds are weaker than the pipe, the elongation of the segment would be concentrated more in these girth welds than the rest of the segment, leading to low strain tolerance for the overall segment.
- The TSC of a pipeline is often controlled by the behavior of its girth welds. Three groups of factors contribute to girth welds often being the controlling location: (1) existence of weld flaws, (2) weld strength undermatching, i.e., weld strength being lower than the actual strength of the pipe, and (3) geometric profiles of a weld, e.g., high-low misalignment.
- Flaws or anomalies in the pipe body, such as circumferential SCC or corrosion with a large circumferential dimension, could become a controlling location, although historically such occasions have been rare. In general, it is very difficult to have a failure in the pipe body under longitudinal/axial loading before other failure modes are initiated.
- The TSC of a pipeline is frequently referred to as "girth weld TSC" for the reasons stated above. It should be noted that the TSC of a girth weld is NOT the strain value measured across a girth weld at the instant of a failure (rupture or leak). The TSC of a pipeline, even when referred to as "girth weld TSC," is the nominal strain or remote strain in the pipe body measured away from the local area of a girth weld at the instant of a failure.
- The current definition of TSC does not make a distinction between a leak or a rupture, nor is it possible to make such a distinction on the basis of TSC alone. Reaching a TSC

indicates an imminent failure that would lead to a loss of containment (leak or rupture). Other factors, such as the rate and duration of loading exerted on the pipe segment and the material's resistance to flaw propagation in the hoop direction of a pipe, can affect whether a breach of pipe wall would be a leak or rupture.

### E.3 Understanding Dominant Factors Affecting TSC

Historical failure incidents and root cause analysis, including metallurgical and fracture mechanics analysis, indicate that the majority of tensile failures that occur in pipeline girth welds are driven by two dominant factors: (1) existence of weld flaws and (2) weld strength undermatching, including heat-affected zone (HAZ) softening. The second-tier factors are toughness and weld profiles[7]. The impact of the dominant factors is further explained below.

#### E.3.1 Weld Flaws

For vintage pipelines, before the widespread use of X-ray for girth weld inspections and acceptance during construction, weld flaws are typically the predominant factor affecting the TSC. Figure  shows exposed flaws after the fracture of a test specimen that contributed to low strain tolerance. Figure E-2 shows an in-service failure of a girth weld of a vintage pipeline containing weld flaws.

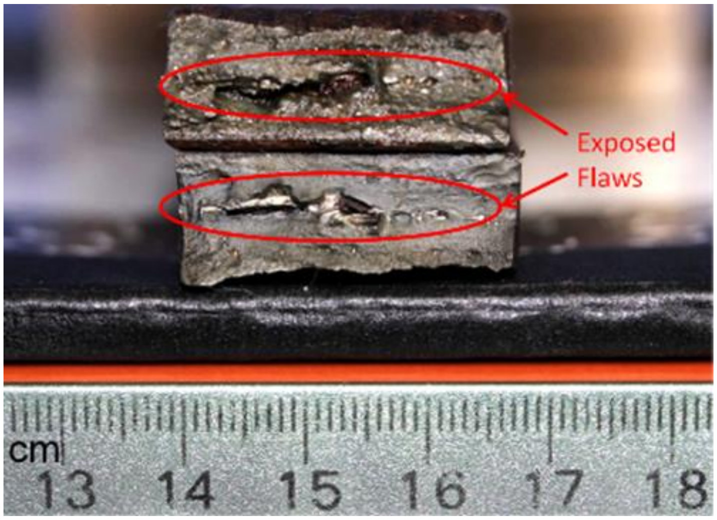



Figure E-1 Exposed flaws at the fracture surface of a girth weld after a cross-weld tensile test

[7] For girth welds fabricated with certain old welding techniques, such oxy-acetylene welds, both weld toughness and weld profiles, in addition to weld flaws, could be major factors that could negatively contribute to low TSC.

Figure E-2 Failure of a girth weld of a vintage pipeline at low strain due to weld flaws

Figure  shows the distribution of individual flaw lengths from 16 girth welds as reported by radiographic testing (RT) and phased array ultrasonic testing (PAUT). Although most of the flaws have a length of 4.0 inches or less, there is still a fair number of flaws with a length greater than 4.0 inches.

Given the dominant effect of girth weld flaws on the TSC in vintage girth welds, the TSC of those welds tend to have a very large range, from as low as 0.2% to well over 2.0%.

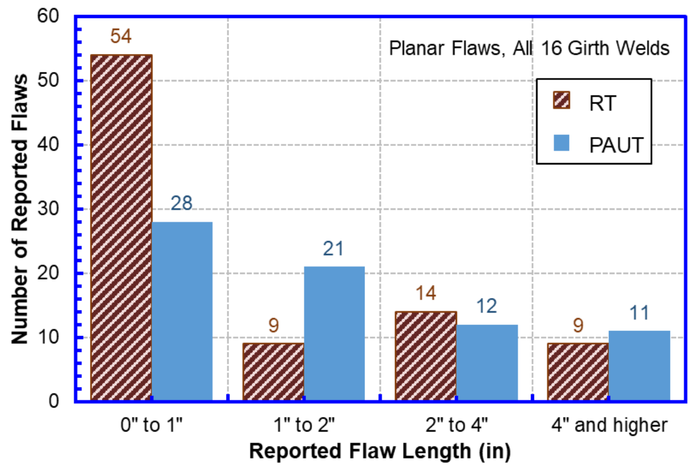



Figure E-3 Distribution of individual flaw length reported by RT and PAUT of 16 vintage girth welds [20]

### E.3.2 Weld Strength Undermatching

For modern welds inspected and accepted by radiographic workmanship criteria during construction, the TSC of girth welds is predominantly affected by weld strength mismatch. Weld strength undermatching, which is permitted by relevant codes and standards, can lead to low strain tolerance as explained in Annex D. Figure  shows a failure of a girth weld with undermatching weld strength in the absence of weld flaws. Figure  shows an in-service failure of a girth weld with undermatching weld strength.

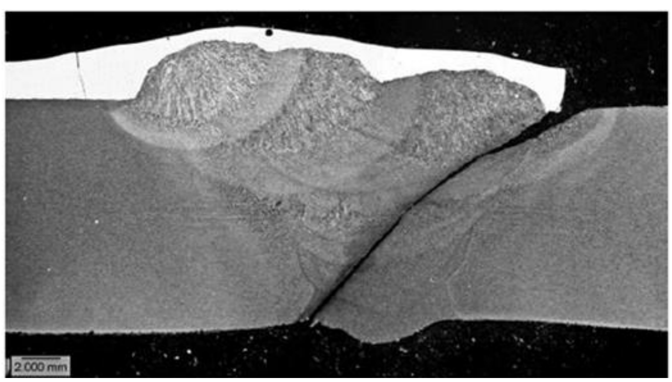


Figure E-4 Failure of a girth weld with weld strength undermatching in the absence of weld flaws

Figure E-5 In-service failure of a girth weld with weld strength undermatching

Figure  shows the evolution of the cross-weld strain in a girth weld (representing the averaged strain in the weld metal and the HAZ) and the strain in the pipe body (representing the nominal strain in the body of the pipe away from the girth weld) as a function of amount of lateral displacement over a 200-ft span of landslide. For a lateral movement of up to about 4 feet, the materials stay elastic. The cross-weld strain and the strain in the pipe body are the same. As the lateral displacement increases further, more strain goes into the weld area, as shown by the increased level of cross-weld strain compared to the strain in the pipe body, leading to a very high level of strain in the weld at a lateral displacement of 8-9 feet. Had the weld had the same strength as the pipe, the cross-weld strain would have stayed at the level of the pipe strain, much lower than the strain with the weld strength undermatching. The high strain concentration in undermatching girth welds leads to low strain tolerance.

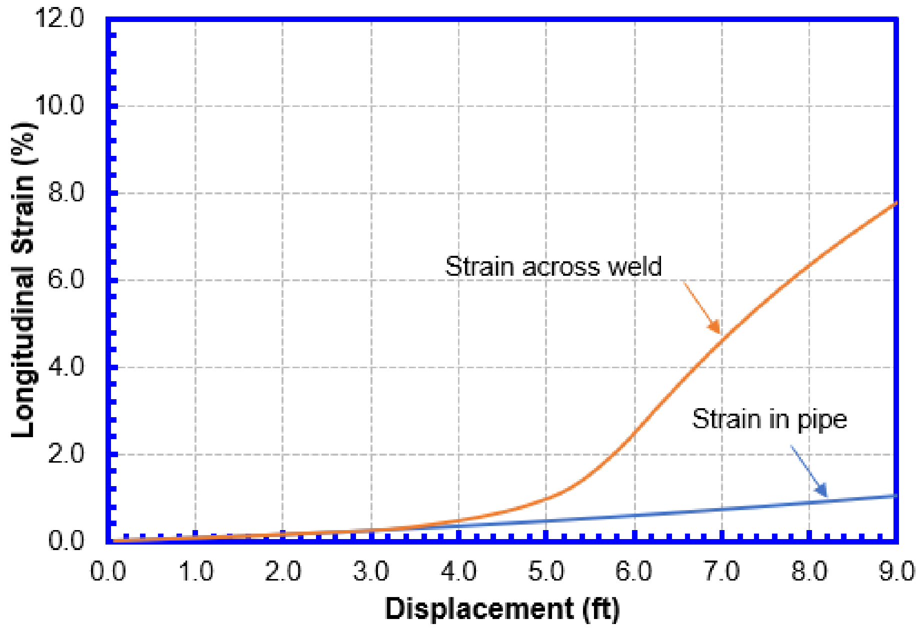
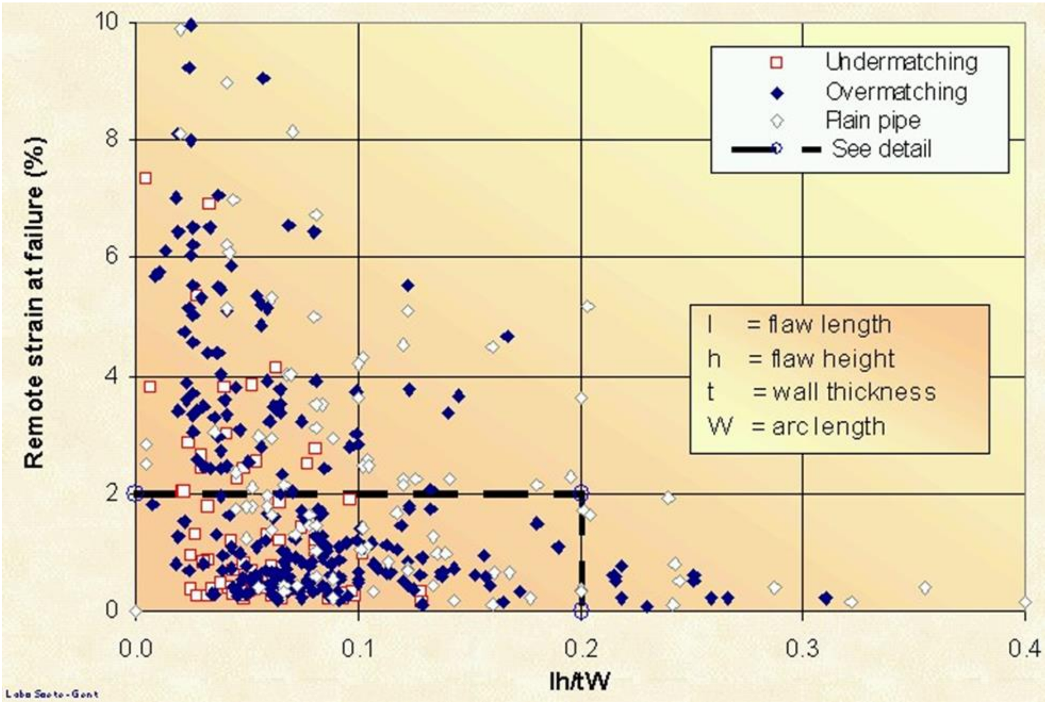



Figure E-6 Comparison of strain across a girth weld and strain in the pipe body in a weld joint with weld strength undermatching

### E.3.3 Combination of Dominant Factors

Girth welds could have a wide variety of combinations of conditions between weld strength mismatch and weld flaws, in addition to other less dominant factors. This can lead to a wide range of TSC. Figure E-7 shows possible TSC from curved wide plate tests (no internal pressure) [21]. The strain at failure ranges from as low as 0.2% to well over 2.0%.

For a girth weld or multiple girth welds of similar vintage and construction methods, the possible range of TSC can be narrowed down from the large range shown in Figure E-7 to an acceptable accuracy for making mitigation decisions. Examples of TSC predictions are given in Section E.4.1.




(a)

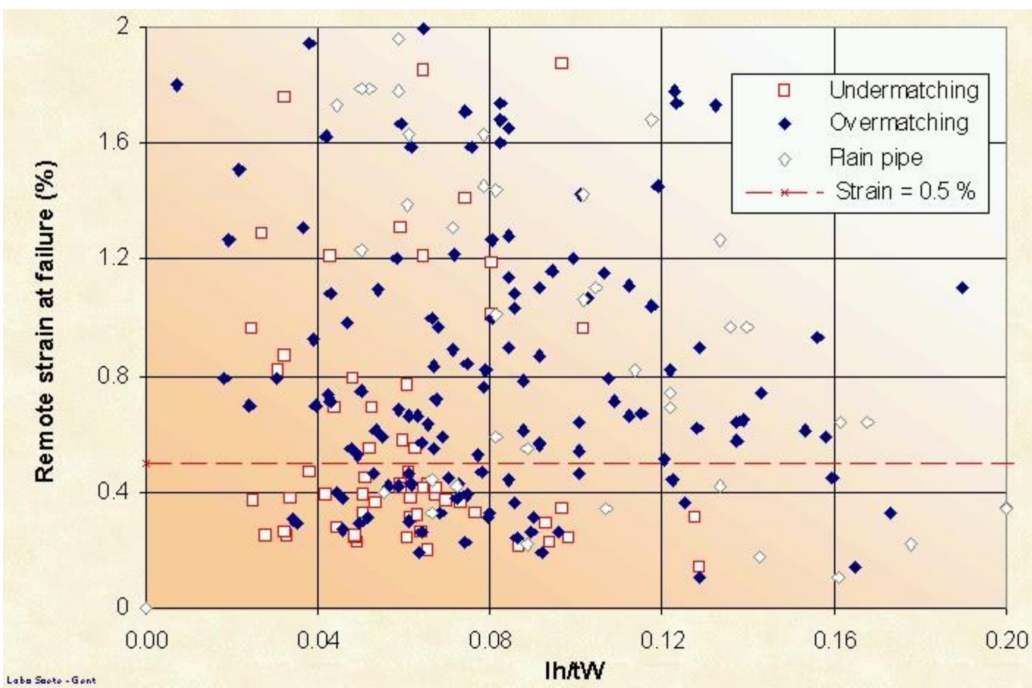



Figure E-7 Remote strain measured at failure of curved-wide plate (CWP) test specimens with planar flaws with height *h* and length *l*. The CWP has an overall gauge width of *W* and wall thickness of *t*. (a) full range of strain, (b) strain range up to 2.0%.

### E.4 Determination of TSC

The determination of TSC may involve the following steps:

1. Collect information on pipeline characteristics.
2. Determine the most appropriate TSC procedure/models to use, guided by the requirements of TSC procedures/models, such as those shown in Tables E-1 and E-2 below.
3. Collect available information on necessary parameters to exercise the TSC procedures/models. Frequently, not all information on necessary parameters is available. It may be necessary to obtain or estimate the information from pipelines with similar characteristics, such as vintage and construction methods, by consulting either internal or external SMEs.
4. Estimate TSC using the selected procedures/models.
5. Conduct confirmation tests if possible. If not, consult internal or external SMEs about likely soundness of the TSC values.

It is highly recommended that opportunistic NDT and mechanical testing of girth welds be conducted when the material becomes available. The mechanical testing must be organized to extract values for parameters that have major impacts on TSC. Customary testing meant to show code compliance is often insufficient.

#### E.4.1 Procedures and Tools for Determination of TSC

A number of procedures and tools are available for the determination of TSC. A comprehensive review of these procedures and their limitations are available [22, 23]. The most versatile and validated procedures are the four-level PRCI-CRES tensile strain models (alternatively termed ABD-1 models after the PRCI project code ABD-1[8]) [24, 25, 26]. A special subset of the PRCI-CRES models is the TSC tool built for vintage girth welds with a limited appliable range under the PRCI project SIA-1-7 (thus the tool is often referred to as SIA-1-7 model/tool) [27]. A summary of the PRCI-CRES tensile strain models with their features and

[8] It should be noted that the PRCI-CRES tensile strain models have 4 levels. Levels 2 and 3 are in closed-form equation format. Many people refer those equations as the PRCI-CRES models or ABD-1 models. This notion is not complete as the formats of Level 1 and Level 4 are different from those of Levels 2 and 3. Level 4 is particularly versatile. It has been used to determine TSC for a wide variety of linepipe and HAZ properties and girth weld configurations.

intended applications is given in Table E-1. Further descriptions of the available models, including the CSA equations [28,29], is given in Table E-2.

Table E-1 Features and intended use of the 4-level PRCI-CRES tensile strain models and a special subset of the models (SIA-1-7)

| Level of PRCI-CRES Models | Name of Subset Model | Format of the Model | Intended Application | Target Strain Demand | Range of Applicability | | |
|---|---|---|---|---|---|---|---|
| | | | | | Linepipe | Girth Welding Process | Wall Thickness (inch) |
| 1 | N/A | Tabular (available in a report) | New pipeline construction (strain-based design) | ≥ 0.5% | Modern | GMAW/FCAW/SMAW | ≥ 0.5 |
| 2 | N/A | Equations (available with a software tool) | New pipeline construction (strain-based design) | ≥ 0.5% | Modern | GMAW/FCAW/SMAW | ≥ 0.5 |
| 3 | N/A | Equations (available with a software tool) | New pipeline construction (strain-based design) | ≥ 0.5% | Modern | GMAW/FCAW/SMAW | ≥ 0.5 |
| 4 | N/A | Case-specific FEA | New pipeline construction (strain-based design) and existing pipelines (strain-based assessment) | ≥ 0.15% | Modern and vintage | All | All |
| 4 | PRCI SIA-1-7 | Software with limited range | Existing vintage pipelines (strain-based assessment) | ≥ 0.15% | Vintage | SMAW | ≤ 0.5 |

It is important to select the right tensile strain models for the determination of TSC. Tensile strain models developed for strain-based design pipelines for new constructions have a set of assumed conditions that are different from those of most existing pipelines built without strain-based design considerations. For instance, strain-based designs usually start with more stringent specifications on linepipe properties than typical specifications without strain-based design considerations. The requirements on girth welding and inspection practice are also more stringent than typical requirements in most welding standards. One example is that girth weld strength undermatching is generally not permitted for strain-based design pipelines. Therefore, it is necessary to check whether the requisite conditions for using the tensile strain models developed for strain-based design are met if they are to be applied to existing pipelines built without strain-based design considerations.

Table E-2 Features, intended use, and required input parameters of a few widely used tensile strain models

| TSC Models/Procedures | | CSA Equations | PRCI-CRES Tensile Strain Models | PRCI SIA-1-7 |
|---|---|---|---|---|
| Publication Year | | 2005-2007 | 2011-2012 | 2019-2020 |
| Target Application | | TSC estimation of existing pipelines | Levels 1-3:<br>(1) New construction,<br>(2) strain-based design, and<br>(3) linepipes made of modern microalloyed steels<br>Level 4:<br>(1) New construction and existing pipelines<br>(2) strain-based design and assessment, and<br>(3) all pipeline steels and welding processes | Assessment of existing vintage pipelines (prior to the use of microalloyed TMCP steels) with girth welds fabricated using SMAW processes and cellulosic electrodes |
| Permission for weld strength undermatching | | No | No for Levels 1-3, Yes for Level 4 | Yes |
| Parameters Incorporated in the model | Pipe diameter | User-selectable | User-selectable | User-selectable |
| | Pipe wall thickness | User-selectable | User-selectable | User-selectable |
| | Internal pressure | Not user-selectable, implicitly considered by setting limit on the maximum value of toughness | User selectable | User selectable |
| | Pipe Y/T ratio | User-selectable | User-selectable | User-selectable |
| | Girth weld strength mismatch | Not user-selectable | User-selectable | User-selectable |
| | HAZ softening or hardening | Not user-selectable | User-selectable (Level 4) | Not user-selectable |
| | Toughness | User-selectable | User-selectable | User-selectable |
| | Flaw height | User-selectable | User-selectable | User-selectable |
| | Flaw length | User-selectable | User-selectable | User-selectable |
| | High-low misalignment | Not user-selectable | User-selectable | User-selectable |
| | Girth weld bevel geometry | Not user-selectable | User-selectable | Not user-selectable |
| | Girth weld cap reinforcement | Not user-selectable | User-selectable (Level 4) | Not user-selectable |

With sufficient data support and the use of appropriate procedures/tools, the TSC of girth welds of interest can be predicted with reasonable accuracy, as shown in Figure E-8 and Figure E-9.

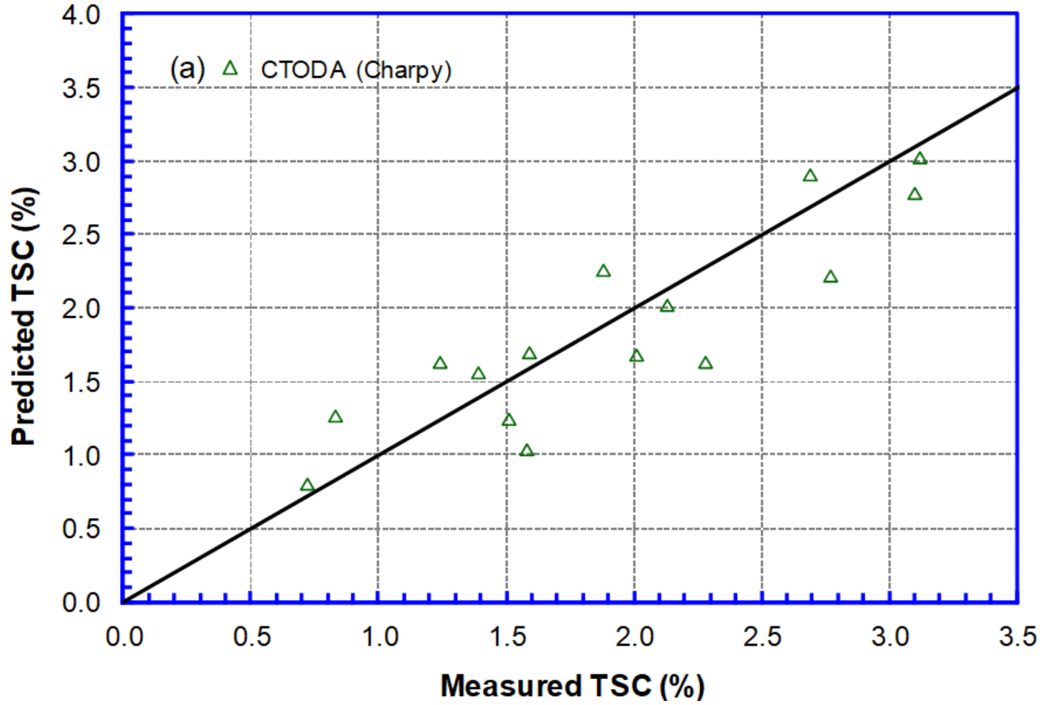



Figure E-8 TSC predicted by the Level 2 procedure of PRCI-CRES tensile strain model vs. TSC measured from full-scale tests of mechanized girth welds [26]

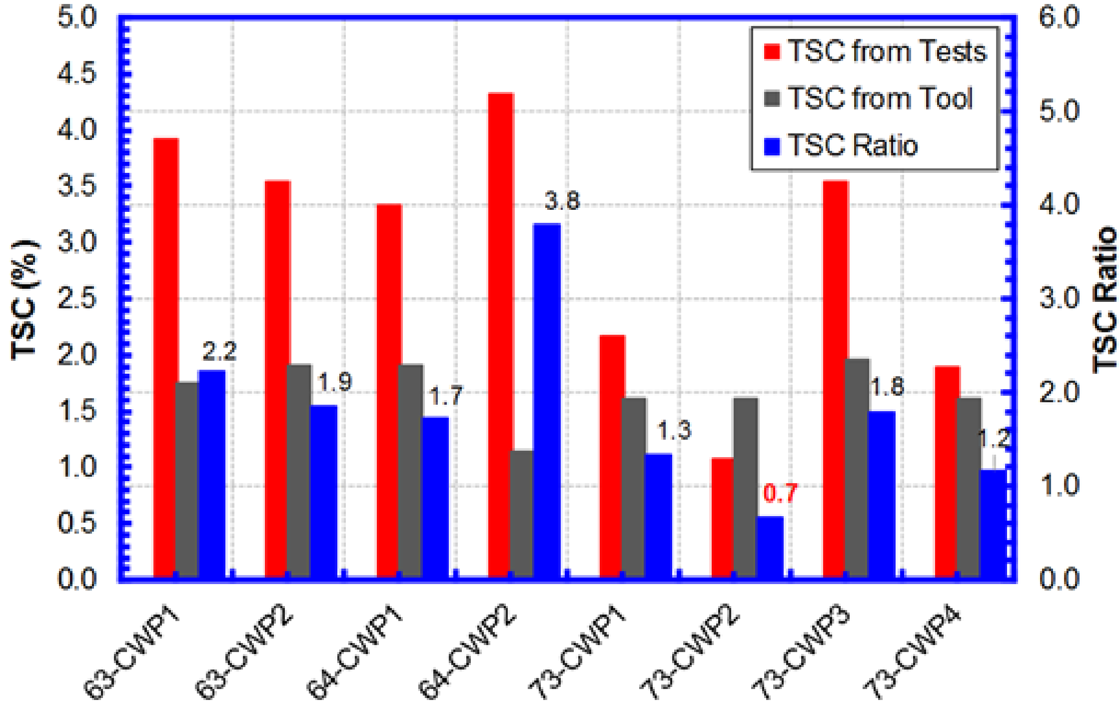



Figure E-9 Comparison of measured TSC from curved wide plate (CWP) tests of vintage girth welds and predicted TSC from the PRCI SIA-1-7 tool [27]. Specimen 73-CWP2 had a large pre-existing flaw that was not identified prior to the test. This flaw led to the unexpected low TSC.

### E.4.2 Proper Interpretation and Use of TSC

Given the wide range of possible TSCs, it's often difficult to choose a value for integrity assessment. A typical TSC value for a pipeline can be substantially higher than a possible lower-bound value. On the other hand, choosing the absolute lowest possible value in a screening process could result in the inclusion of a large number of sites for further investigation. This can become impractical and lead to inefficient use of resources. In an initial screening process, it may be necessary to choose a reasonable lower bound TSC value. Further investigation can be carried out depending on the outcome of the initial screening. One such example with a levelled approach is demonstrated by Liu, et al. [30].

Ultimately, choosing a right value of TSC or even selecting a right tool for determining TSC depends on the understanding the factors affecting the TSC, such as a pipeline's vintage, its linepipe properties, and its construction methods, including girth welding and inspection for weld flaws.

# Annex F Key Observations and Recommendations

## F.1 Key Observations

- Geohazards are a major threat to pipeline integrity. For many regions, geohazards can be one of the primary causes of loss-of-containment events.
- Landslides are the most prevalent source of geohazard-caused ruptures, followed by hydrotechnical incidents and subsidence, based on both US and European data.
- Geohazard management practices vary among operators, likely because of a lack of standardization in regulatory or guidance documents and because there are relatively few pipeline industry geohazard professionals directly employed by pipeline operators.
- Currently, there are no published API, ASME, or ASCE recommended practices for managing geotechnical hazards. API RP 1133 covers an integrity management approach to manage hydrotechnical hazards.
- Geohazard management differs from managing other integrity threats. Geohazard management requires a hybrid of typical threat management approaches, including (1) ROW and regional surveillance approaches similar to 3rd party damage/ROW intrusion and encroachment (typical time-independent approaches), (2) "pig and dig" integrity management approaches (typical time-dependent approaches), and (3) incorporation of the impact of changing the environment, such as weather, ground water, etc. The need to assess and monitor the ROW and adjoining areas requires different technologies and practices compared to the threats typically managed by pipeline integrity groups. Many operators have personnel who are highly proficient in integrity management using ILI and evaluation techniques focused on the pipeline. Geohazard management, being a relatively new area of focus, has relatively few industry personnel familiar with the technologies and approaches needed to manage geohazards.
- Geohazard management needs to consider the varying behavior of geohazards and the uncertainties associated with geological processes and materials. The goal of a successful geohazard management program is to reduce the potential for a leak or rupture to a level that is as low as reasonably practicable, through a combination of monitoring and mitigative measures. Completely removing or eliminating the hazard is possible in some scenarios, though this may not be practical or even necessary.

- Geohazards need to be managed for the life of a pipeline system. It is not possible with current technology to eliminate many geohazards; thus, an ongoing program of monitoring and threat reassessment is needed for effective management of geohazards.
- New technologies have become commercially available and have become viable tools for geohazard assessment and monitoring over the last few decades (roughly since circa 2000), particularly powerful geographic information systems (GIS) software, LiDAR, and IMU bending strain analysis. These technologies have been adopted by many operators and have improved the ability of pipeline operators to become proactive in their approach to geohazard management and to have more effective and efficient geohazard management programs.
- LiDAR data can be used to identify indications of geohazards with much greater detail than the hazard maps produced by public agencies. For example, landslides are more common in areas where landslide hazard maps show high susceptibility, but landslides can also occur in areas not shown as being landslide susceptible by public landslide hazard maps. Use of LiDAR data enhances geohazard identification, supporting proactive management approaches not previously available to the industry.
- Hazard avoidance and the practice of strain-resistant design and construction can be effective tools for proactive geohazard management, particularly when constructing new pipelines or replacing existing ones.
- Geotechnical hazards can impose longitudinal stresses greater than the yield strength of a pipeline. Strain-based assessment (SBA) can be a powerful tool for determining the integrity of a pipeline exposed to geohazards. SBA is a maturing technology with significant advancement in the last two decades.

## F.2 Recommendations for Improving Current Practice

### F.2.1 Framework for Geohazard Management

Wide-spread adoption of a framework to guide pipeline operators in geohazard threat assessment, monitoring, and mitigation should facilitate the standardization of the approach to geohazard management and facilitate reducing geohazard failure rates. In turn, the standardization should facilitate the work of geohazard pipeline specialists within pipeline operating companies with a consistent standard, rather than relying on trial-and-error or third-party consultants to develop a geohazard management program. This document, and future similar guidelines, can assist such standardization.

### F.2.2 Guidance and Standardization of Strain-Based Assessment

The pipeline industry would benefit from specific and actionable guidelines for strain-based assessment (SBA) with expected inputs and outputs. Knowing the process flow and data requirements should make SBA easy to adopt. The use of SBA would allow operators to understand their pipelines' limits and prioritize their actions to maintain integrity.

### F.2.3 Improved Incident Tracking and Statistical Analysis

Improved incident tracking and statistical analysis would assist the pipeline industry in understanding its exposure to geohazards and evaluating whether geohazard management measures are effective in reducing the number of geohazards-related incidents. In turn, this would help to guide future research and development efforts. Specific recommendations include:

- Allow for multiple causal factors in the PHMSA Significant Incident Database. The following is an example in which two causal factors would be appropriate:
    - A landslide exerts external force on a pipeline, and it causes a girth weld to fail.
    - A defect in the girth weld causes it to fail sooner than it would have without the defect.
    - The causal factor could be both natural force damage and material failure, not just one of them.
- There are many fields in PHMSA's database that capture natural force-related incidents. These fields could be organized to correspond to geotechnical, hydrotechnical, and weather-related threats. These categories could be further subdivided into specific threats that interact with pipelines. This would allow operators to be more consistent in their reporting of incidents and better compare and track incidents across the industry.
- Provide more explicit definitions for causal factors. For instance, many incidents in the PHMSA Significant Incident Database are listed as "subsidence." The review of the descriptions provided within these "subsidence" incidents revealed that some incidents were associated with settlement of post-construction backfill, some were down-dropping of the ground associated with landslide movement, and some were related to sinkhole formation. Having three types of causal factors classified as "subsidence" makes it difficult to evaluate causal factors accurately and consistently without careful review of the descriptions. Defining "subsidence" as explicitly being related to natural sinkhole formation would improve tracking and future analysis.

- Consider moving from a wholly self-reported database (for the PHMSA Significant Incident Database) to a curated one maintained by a small team that would assign casual factors and other information on a set of consistently applied criteria. Having the database maintained by a team would improve consistency and useability of the data.
- Produce more regular analysis of pipeline incidents from the PHMSA Significant Incident Database. The last in-depth analysis of the PHMSA Significant Incident Database was a 2004 report by PRCI that analyzed data from 1985 to 2000. More regular reporting (such as at five-year intervals) would allow pipeline integrity engineers and researchers to effectively evaluate trends over time and use the resulting conclusions to focus future research and development for improving pipeline integrity.
- Consider producing an international incident reporting standard to allow for consistent international cross-comparison of incident data. Such a standard, if adopted, would produce the benefits previously described (e.g., better understanding of exposure to integrity threats and trend-analysis), and have a larger dataset that would allow more robust analysis than that is currently possible.

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