Prepared for:

North Dakota Industrial Commission

and

Energy Development and Transmission Committee

Liquids Gathering Pipelines: *A Comprehensive Analysis*

Prepared by:

Energy & Environmental Research Center
University of North Dakota
15 North 23rd Street, Stop 9018
Grand Forks, ND 58202-9018

EERC
UND UNIVERSITY OF NORTH DAKOTA

December 2015

TABLE OF CONTENTS

Continued…

TABLE OF CONTENTS (continued)

Continued…

TABLE OF CONTENTS (continued)

Continued…

TABLE OF CONTENTS (continued)

LIST OF FIGURES

Continued…

LIST OF FIGURES (continued)

LIST OF TABLES

Continued…

LIST OF TABLES (continued)

NOMENCLATURE

For the purpose of this report, the terms "brine" and "produced water" are used interchangeably. Additionally, an unauthorized leak, spill, or a release has been mentioned as a "spill."

AAC	Alaska Administrative Code
ABS	acrylonitrile butadiene styrene
AC	alternating current
ADEC	Alaska Department of Environmental Conservation
ANPRM	Advanced Notice of Proposed Rule Making
ANSI	American National Standards Institute.
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASTM	ASTM International
bbl	barrel
BLOS	beyond line of sight
BOE	barrels of oil equivalent
Cal OES	California Governor's Office of Emergency Services
CCR	California Code of Regulations
CFR	Code of Federal Regulations
CGC	California Government Code
COGCC	Colorado Oil and Gas Conservation Commission
CP	cathodic protection
CPM	computational pipeline monitoring
CPVC	chlorinated polyvinyl chloride
CTB	central tank battery
C-UT	circumferential ultrasonic testing
DC	direct current
DMR	Department of Mineral Resources
DOT	Department of Transportation
DR	dimension ratio
DSPR	Division of Spill Prevention and Response
EDTC	Energy Development and Transmission Committee
EERC	Energy & Environmental Research Center
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
FAA	Federal Aviation Administration
FBE	fusion-bonded epoxy
FLIR	forward-looking infrared
FRP	fiberglass-reinforced thermosetting plastic pipe
GAO	Government Accounting Office
GIS	geographical information system
HB	House Bill
HC	hydrocarbon
HCA	high-consequence area

HDD	horizontal directional drilling
HDPE	high-density polyethylene
HDS	hydrostatic design stress
HT	heater treater
ICCP	impressed current cathodic protection
ILI	in-line inspection
INGAA	Interstate Natural Gas Association of America
IR	infrared
LDPE	low-density polyethylene
LDS	leak detection system(s)
lidar	light detection and ranging
LOS	line of sight
MAWP	maximum allowable working pressure
MFL	magnetic flux leakage
MMbbl	million barrels
MMBOE	million barrels of oil equivalent
MOP	maximum operating pressure
NACE	National Association of Corrosion Engineers
NDAC	North Dakota Administrative Code
NDDH	North Dakota Department of Health
NDIC	North Dakota Industrial Commission
NGL	natural gas liquid
NMAC	New Mexico Administrative Code
NPRM	Notice of Proposed Rule Making
NS	nonsupervisory
NTSB	National Transportation Safety Board
OAC	Oklahoma Administrative Code
OCC	Oklahoma Corporation Commission
PB	polybutylene
PE	polyethylene
PENT	Pennsylvania notch test
PEX	crosslinked polyethylene
PHMSA	Pipeline and Hazardous Materials Safety Administration
PP	polypropylene
PR	pressure rating
PSC	Public Service Commission
PSMS	pipeline safety management system
PVC	polyvinyl chloride
PVDF	polyvinylidene fluoride
RBDMS	risk-based data management system
ROM	rough order of magnitude
ROW	right-of-way
RP	recommended practice
RRC	Railroad Commission of Texas
RTP	reinforced thermoplastic pipe
RTTM	real-time transient model

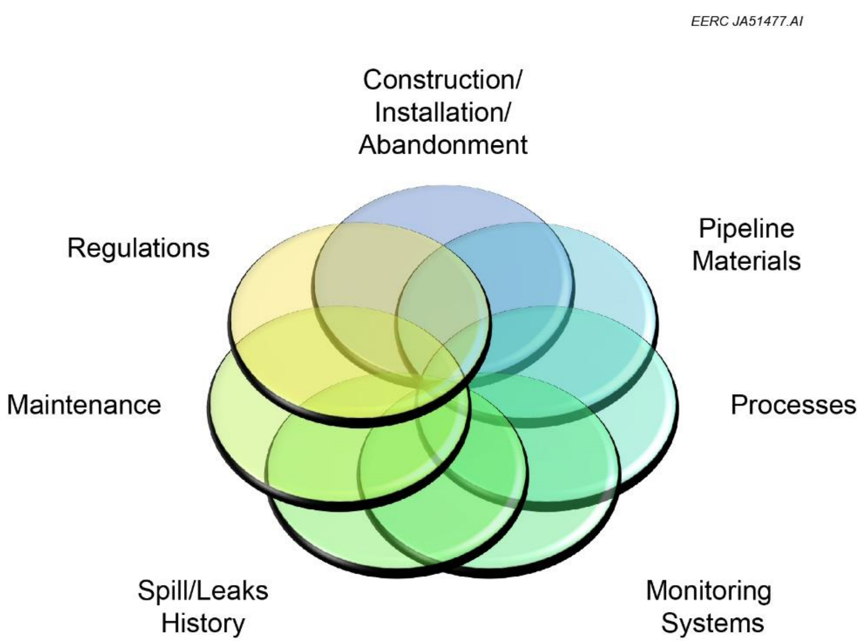
SAR	synthetic aperture radar
SCADA	supervisory control and data acquisition
SCC	stress corrosion cracking
SCP	spoolable composite pipe
SDR	standard dimension ratio
SME	subject matter expert
SMYS	specified minimum yield strength
SPE	Society of Petroleum Engineers
SWIR	shortwave infrared
TAC	Texas Administrative Code
TFI	transverse flux inspection
TRFL	Technische Regel für Rohrfernleitungen (Technical Rules for Pipelines)
UAS	unmanned aerial systems
USA	unusually sensitive areas
UT	ultrasonic tool
VPCRx	vapor pressure of crude oil

A GUIDE TO REPORT STRUCTURE

This Energy & Environmental Research Center report will guide the reader, through increasing detail, to directly address installation practices and leak detection systems that may prevent or severely limit the incidence of leaks on pipeline systems in North Dakota. To accomplish this, we discuss why gathering pipelines are required and the challenges presented by alternatives to pipelines. An introductory discussion on the configuration and operation of these pipeline systems is also provided.

Several ancillary topics are addressed on the way to installation and leak detection system topics. These ancillary topics all directly impact employment of best installation practices and leak detection systems. The figure illustrates the interconnection of these topics.

Throughout the report, blue balloons are interspersed that highlight key observations, findings, and resulting recommendations. We embedded these balloons in an effort to assist the reader in understanding how we formed these recommendations. The logic of each recommendation is generally presented in the text before each balloon. The text within the balloons is meant to quickly summarize the key outcomes of this study. The balloon information is also compiled in one location, starting on p. xvii.



ANALYSIS OF THE STATE OF PRODUCED LIQUIDS GATHERING PIPELINES IN NORTH DAKOTA

EXECUTIVE SUMMARY

The last decade has seen growth in the oil industry at a rate that is unprecedented in the history of North Dakota. There are over 12,000 oil wells in the state, with oil production undergoing a nearly fivefold increase since 2008. Produced water is also generated along with the oil in volumes that are comparable to oil production. Industry has installed nearly 23,000 miles of gathering pipeline to move these tremendous volumes of fluids from the wellhead to various processing facilities. The vast majority of the fluids moving through the state's pipeline infrastructure reach their destination without incident. In fact, for every 10,000 barrels of fluid handled, only one is spilled. However, the increasing size of the system means that even low incident rates may result in a greater number of spills and attendant volumes in a given year. There has been growing public concern in North Dakota about the effects of spills of oil and produced water on agriculture, public health, and the environment.

To address those concerns, Section 8 of North Dakota House Bill 1358 directed the Energy & Environmental Research Center (EERC) to study the key aspects of gathering pipelines in North Dakota. Specifically, the EERC was tasked with evaluating existing regulations on construction and monitoring of crude oil and produced water pipelines, determining the feasibility and cost-effectiveness of requiring leak detection and monitoring technology on new and existing pipeline systems, and providing a report with recommendations to the North Dakota Industrial Commission (NDIC) and the Energy Development and Transmission Committee (EDTC). The study resulted in a comprehensive description of pipeline systems and their operation and a robust statistical analysis of pipeline spills in North Dakota. Information regarding the use of pipeline materials, maintenance practices, and methods of pipeline inspection, pipeline monitoring, and pipeline leak detection were also obtained and evaluated. Current regulations pertaining to spill reporting and pipeline construction and operation practices were examined at the federal and state levels, including a comparison of regulations from the top seven oil-producing states. The study provides NDIC and EDTC decision makers with technical information to support the development and implementation of administrative rules regarding pipeline safety and integrity.

A primary goal of the state is to ensure that industry is employing best practices to ensure safe transport of fluids and rapid leak detection and attendant response in the event that a leak occurs. The results of the study will support the state's efforts to develop prudent regulations that enable the monetization of North Dakota's vast petroleum resources while protecting public safety and the environment. The dynamic nature of oil production, rural geography and, occasionally, the extreme climate conditions of North Dakota make the design, installation, and operation of gathering lines more difficult than pipelines in other industries and areas. These regionally unique aspects must be considered as operational practices, regulations, and technologies are developed to improve the safety and reliability of gathering lines.

Key Findings of the Study

Key findings of the study with respect to the statistical analysis of spills and analyses of regulations, construction materials and practices, and leak detection systems are summarized below.

Key Findings of Spill Statistical Analysis

Data on all oil- and gas-related spills and leaks in North Dakota from 2001 to 2014 were evaluated. These data indicated that approximately 0.01% of the total oil and brine handled in North Dakota is spilled. In other words, for every 10,000 barrels of fluid handled, one of those barrels is spilled. In 2014, approximately 20,000 barrels of oil and 71,000 barrels of brine were spilled. While the number of spills has increased over the past 6 years, statistical analysis shows that the pipeline-specific spill trends are actually slightly declining. In essence, a very small number of high-profile, large pipeline spills have greatly skewed the trend lines. When compared to other states that have seen recent booms in oil production, North Dakota has performed at par or better than its peer states with regard to spill volumes per unit of production. This is despite the fact that North Dakota's threshold for spill reporting is among the lowest of comparable states. North Dakota requires reporting of all spills off of the well pad, regardless of size. Establishing a data management system that streamlines spill data reporting and analysis would facilitate reporting by industry, assessment of data by stakeholders, and appropriate actions on the part of regulators. Such a system would also improve the state's ability to identify root causes and prioritize future regulations based on statistics rather than anecdotal evidence or perceived problems within the gathering industry. Such a system could also be used to track the progress of remedial responses.

Key Findings of Regulatory Analysis

Oil and gas gathering lines are not generally regulated by the federal government. Therefore, most of the crude and brine pipelines in North Dakota are not under federal jurisdiction. Notable exceptions to this are pipelines that exist within the political boundaries of cities, towns, and villages and certain pipelines installed near environmentally sensitive areas referred to as unusually sensitive areas (USA) by PHMSA. Today, liquid gathering lines in North Dakota are largely unregulated. The North Dakota Department of Mineral Resources (DMR) has authority to administer punitive actions but does not have authority to shepherd the installation and operation of gathering lines. It may be beneficial to reconsider DMR's role in the implementation and enforcement of a pipeline safety management system for North Dakota operators. A recommended practice (RP) developed by the American Petroleum Institute (API), API RP 1173, provides a reasonable model for a pipeline regulatory system (American Petroleum Institute, 2015).

Furthermore, information on pipeline failures is typically sealed by legal settlement terms and is not available to all. To regulate wisely, the state needs to have authority to participate in failure analyses. With this authority, the state could compile knowledge on leading causes, share that knowledge with industry, and contribute to a significant decrease in leak incidents. The state would need to do this in a manner that that does not conflict with possible litigation constraints (e.g., confidentiality). It is, therefore, recommended that the state consider rule making that facilitates this participation and the dissemination of lessons learned from such failure analyses. This critical recommendation will provide the state with a pathway to avoid repetition of critical failures among multiple operators.

Rules that encourage sharing of pipeline monitoring data among adjacent business interests would ensure that at least one operator has a complete view of the pipeline system. Rapid identification of potential leaks would be facilitated, which, in turn, could lead to more effective first responses to leaks. Effective regulations and best practices should be flexible enough to allow for systems tailored to operate in unique conditions.

Key Findings of Analysis of Current Construction/Installation Practices

Robust standard practices for construction and installation exist for steel pipelines. However, far less standardization and regulation governing installation practices exist for plastic pipelines. This is especially true for the spoolable pipe products widely used in North Dakota. Anecdotal evidence suggests line strikes, poor workmanship, and lack of inspection are the root cause of many gathering line leaks. However, analysis of spill statistics data could not corroborate this statement. While each company performs its own failure analysis when a spill occurs, companies are disincentivized to share that information because of the litigious environment in which they operate. Many companies have internal standards based on broadly accepted practices for pipeline installation. However, the execution of those standards is not always consistent, and failures are largely attributed to a lack of adherence to company standards by pipeline installation contractors. Implementing construction standards consistent with practices being followed by many operators and current federal pipeline codes may be an effective means of reducing leaks. Additional state inspection staff could ensure that such standards are being followed. Installation crews should be thoroughly trained and contractually bound to use standard procedures. Adequate bonding would provide a guarantee of funds for remediation and serve as an incentive for thorough self-inspection protocols.

Key Findings of Analysis of Pipeline Products Installed in North Dakota

Several organizations have developed RPs for testing, handling, and installation of pipelines made of most commercially available materials. The use of spoolable reinforced plastic pipe in North Dakota is widespread and has increased in recent years. The industry standard for testing spoolable plastic pipe is API RP 15S, although other standard practices do address other aspects of their testing (American Petroleum Institute, 2013a). While API RP 15S covers some of the spoolable plastic pipe used in North Dakota, it does not include newer reinforced spoolable pipe materials (American Petroleum Institute, 2013a). Because those newer materials are already in use in North Dakota, any North Dakota rules adopted from federal pipeline guidelines will have to allow for variances. API RP 15S is currently being modified and should be upgraded to a standard practice in early 2016. Once it is upgraded to a standard practice, it is our understanding that it will be accepted by the Pipeline and Hazardous Materials Safety Administration. Getting a DMR subject matter expert appointed to the API committee studying modifications to API RP 15S may ensure that such modifications take the unique characteristics of North Dakota into account. DMR monitoring of the development of composite material pipeline products, particularly with respect to erosion-resistant materials, would help inform future rule-making efforts (American Petroleum

Institute, 2013a). Further, ensuring installation crew and inspector familiarity with all manufacturer-prescribed installation practices could reduce execution-related failures.

Key Findings of Analysis of Leak Detection Systems

The leak detection technologies reviewed by this study have been reported by or considered for use on transmission pipelines where their success has been limited. No body of knowledge has been uncovered by this study documenting application of these technologies to gathering lines, which are expected to be more problematic than transmission pipelines. Significant experience will likely be required in successful gathering line applications before gathering line operators and the public will acquire reasonable confidence in these technologies.

Most pipeline leaks are discovered visually by people who happen to be in the area of the spill. Sensor and software technology is evolving to meet the needs of leak detection, but they have not yet been demonstrated as reliable. To identify leaks earlier, and thereby minimize their impacts, operators should be encouraged to incorporate SCADA (supervisory control and data acquisition) technologies on their gathering systems. This will improve communication within and between the various operators using the system. A modest investment in advanced systems to decrease the impact of pipeline spills is easily justified when a company recognizes that costs of remediation efforts may be larger by orders of magnitude.

The gathering pipeline monitoring and leak detection pilot project prescribed by House Bill 1358 will serve as a platform to test current and new leak detection technologies applied to gathering systems. This pilot project will be conducted to test performance, determine infrastructure requirements, estimate investment cost to pipeline operators, and provide objective analysis of the cost/performance ratio.

CONCLUSION

As a result of this study into the operations of liquids gathering pipeline systems in North Dakota and elsewhere, recommendations are proffered to assist the state in determining wise, new regulations to minimize the occurrence, frequency, and magnitude of pipeline leaks and spills in North Dakota. It is hoped that these recommendations, supported by the data contained in this report, provide guidance and solid foundation for the state in its efforts to responsibly oversee the important operations of liquid product and liquid waste gathering pipelines.

This document summarizes the findings of Phase I of this project and illuminates near-term opportunities for improvement to pipeline construction, inspection, and leak detection and potential state actions to facilitate such improvements. Phase II of this project will demonstrate commercially available technologies with the highest probability of decreasing the incidence and total volume of pipeline leaks.

SUMMARY OF KEY OBSERVATIONS, FINDINGS, AND RECOMMENDATIONS

	ID	Page No.	Observation	Key Finding	Resulting Recommendation
Infrastructure	1	17	Producing, gathering, and terminal or disposal well asset ownership varies in North Dakota. In some situations, a single company owns all assets, while in other situations, the producer, gathering line operator, and terminal or disposal well operator are three different entities. Lack of communication and consequent awareness between a disposal well operator and a gathering line operator contributed to extending the duration of a spill when a leak occurred in a gathering line that fed a produced water disposal well. The disposal well operator was unaware of flow in the gathering line, so rationalized that the lack of flow from the line was expected. Conversely, the gathering line operator was unaware of the lack of flow at the disposal well.	Sharing of operational data along a gathering line and over time is critical to monitoring and leak detection.	North Dakota DMR should carefully consider rulemaking that encourages real-time data sharing among adjacent, partnering business interests in any given gathering system comprising more than one operating company. If different entities own assets connected to a gathering line, they should be encouraged to share real-time operational data so that at least one individual or entity has a complete view of the pipeline status at any given time. This sharing may be accomplished best by shared access to SCADA databases between adjacent companies.
	2	18	Liquid gathering pipelines are complex, dynamic systems operated under a wide range of conditions and diverse business arrangements.	The unique and constrained conditions under which liquid gathering systems operate in North Dakota require different design, operations, and monitoring than pipelines used in other industrial sectors.	New regulations and best practices developed for gathering pipelines can build upon successes from other pipeline sectors, but they must be tailored to the conditions under which gathering lines must operate, address the unique properties of different fluids being transported, and provide flexibility to address the variable conditions that exist across North Dakota.

Continued…

SUMMARY OF ALL KEY FINDINGS AND RECOMMENDATIONS (CONTINUED)

	ID	Page No.	Observation	Key Finding	Resulting Recommendation
Leaks and Spills Analysis	3	20	In compiling incident data from the DMR and NDDH databases, we discovered duplicate reporting of incidents, improperly entered categories (fluid type, incident type, etc.), and missing information which made analyzing the data difficult. In addition, the processes used to manage incidents among state agencies are not conducive to data analysis.	The analysis of the spill data highlights the need to examine how data are collected and compiled within the state system. All parties involved want to reduce the quantity and severity of leaks and spills, and yet it is difficult to assess where the largest problems are in the current reporting format and database structure. Therefore, it is even more difficult to strategically assign resources to address the issues.	• The state should streamline the ways spill data are reported, processed, and analyzed to facilitate data analysis. Implementing such a data management function within the state will likely necessitate additional resources at North Dakota DMR. • After streamlining is achieved, North Dakota DMR should collect and analyze data continually to determine root causes of pipeline leaks and then continually refine regulatory language that addresses root cause determinations.
	4	31	Anecdotal information from pipeline operators and DMR personnel suggest the leading causes of pipeline leaks are related to third-party strikes and poor workmanship. Poor workmanship includes, but is not limited to, lack of inspection supervision, poor performance of company inspectors and third-party independent inspectors, performance of pipe joining by unqualified personnel resulting in substandard joint integrity, unwillingness to report suspect joints and other pipe damage, and lack of attention to foreign debris in trenches and during backfill.	North Dakota spill data do not substantiate nor refute observations about third-party strikes and poor workmanship. If indeed true, it is likely that errors during pipeline installations in the early Bakken development phase manifested as spills and leaks years later. The conditions described in the associated Observation that may have contributed to these incidents have largely been addressed as the pace of construction has slowed, new regulations requiring submittal of pipeline location data to the state database (NDAC 43-02-03-29) are in effect, and companies implement better practices and oversight.	• As the State improves the function and utility of its incident database, the State should continue to evaluate incident data to identify root causes of pipeline failures and prioritize future guidance and/or regulations accordingly. • The State should establish an improved data management system within State offices that streamlines spill data reporting and facilitates analysis of root causes of pipeline failures. It is further suggested that this data management system must be collaborative among several agencies with complementary reporting jurisdictions to eliminate redundant and misleading data.

Continued…

SUMMARY OF ALL KEY FINDINGS AND RECOMMENDATIONS (CONTINUED)

	ID	Page No.	Observation	Key Finding	Resulting Recommendation
Leaks and Spills Analysis (continued)	5	35	Other states reviewed in this study prescribe a range of minimum reporting thresholds for reportable crude oil and produced water spills. North Dakota's reporting threshold is among the lowest, requiring reporting for all spills greater than 1 barrel for spills contained on location and no minimum for spills that are off location (where all spills are reported).	North Dakota has among the lowest minimum reporting thresholds of the top seven oil-producing states. This creates the potential to skew the comparison of spills between states with higher reporting thresholds, making it appear that North Dakota has more spills than other oil-producing states.	The state of North Dakota should recognize the impact the minimum reporting threshold has on spill statistics and evaluate accordingly how to interpret and report these data.
Regulatory	6	56	Fluid properties and operating conditions of liquid gathering lines differ significantly from pipeline to pipeline. Ensuring that the pipeline selected for each application can withstand these operating conditions is critical to ensuring safe operation.	Most of the states reviewed have regulations requiring that gathering pipelines can withstand the operating conditions of the gathering system and have appropriate chemical compatibility. Many refer to 49 CFR 195 as a basis for regulation.	North Dakota should consider adopting regulations on pipeline material selections, as has been done in comparable oil-producing states.
	7	57	Other large oil-producing states include regulatory language regarding maintenance and corrosion control. North Dakota does not currently include language constraining maintenance and corrosion control practices to best practices.	North Dakota may benefit from inclusion of regulatory language addressing maintenance and corrosion control. 49 CFR 195, ASME B31.3, ASME B31.4, ASME B31.8, and NACE Standard RP-01-69 all offer language and concepts that may be considered for any new regulations in North Dakota on these topics.	State regulators should address maintenance and corrosion control best practices in any new regulations.
	8	58	Other comparable oil-producing states include regulatory language that demands prior notification of construction, including design information (size, material, operating pressure, design pressure, depth, installation protocols, etc.), and routing information.	North Dakota pipeline safety may be enhanced by ensuring that state regulators have advance notice of key design features associated with new liquid gathering pipelines. This information would serve to generally inform the state, provide data for post-incident analysis of root cause of failures, and permit the state to have a baseline upon which inspections can be measured.	North Dakota DMR consider developing a requirement to provide notice of intent to install liquid gathering pipelines 30 days prior to installation of said pipelines. The advance notice should include design information (size, material, operating pressure, design pressure, depth, installation protocols, etc.), and routing information.

Continued…

SUMMARY OF ALL KEY FINDINGS AND RECOMMENDATIONS (CONTINUED)

	ID	Page No.	Observation	Key Finding	Resulting Recommendation
Materials	9	60	Plastic pipeline fillers are powders of solid materials that are added to plastics. They can be highly variable depending on the product and manufacturer.	The type and size of the fillers can significantly affect the erosion resistance of the plastic.	Companies procuring pipeline should consult closely with the pipeline manufacturer for data about the erosion resistance of the manufactured parts if erosion is a possible issue in the proposed application. The company procuring the pipelines may want to ask for test evidence demonstrating erosion resistance against fluids with characteristics comparable to that expected in the field.
	10	64	Slow crack growth is a crack that can develop in PE pipe, usually at a flaw or outside stress concentration, which grows slowly through the pipe wall. According to the Plastics Pipe Institute, it is the dominant field failure mode, excluding third-party damage, for PE pipes.	Installation procedures prescribed by the pipeline manufacturer must be precisely followed to avoid the risk of slow crack growth and other material-related failure modes.	Installation crews should be thoroughly trained in all manufacturer-prescribed installation procedures and be contractually bound to use those procedures. Further, independent inspectors should have the responsibility to ensure that manufacturer specifications are precisely followed.
	11	72	Since API RP 15S was approved, additional spoolable reinforced plastic pipe products have become available—in particular, piping reinforced with steel. The company that makes that product is currently performing qualification testing and working to have its product included. Simultaneously, the RP15 committee is working to upgrade the recommended practice to a standard practice.	Because this material is not currently included in a standard practice, it is generally not included in standard PHMSA pipeline guidelines for transportation pipelines.	North Dakota DMR should seek to place its own SME on the API committee studying modifications to API RP 15S. If North Dakota DMR considers deriving in-state regulations governing installation of reinforced pipe from PHMSA standards, variances to the PHMSA-based regulations should allow for use of reinforced, spoolable pipeline materials not yet included in a standard practice.

Continued…

SUMMARY OF ALL KEY FINDINGS AND RECOMMENDATIONS (CONTINUED)

	ID	Page No.	Observation	Key Finding	Resulting Recommendation
Materials (continued)	12	73	Because gas can diffuse through the inner liner of a composite pipeline and build up in a dry reinforcement layer, these types of pipeline products are typically vented at each end. This venting may allow for pressure or composition monitoring to determine if a leak exists in the pipe. Manufacturers have just begun to test this capability.	These pipeline products may provide some level of leak detection capabilities.	Composite pipeline manufacturers with applicable products should develop a collection of test data to support claims that these pipeline materials can assist LDS. North Dakota DMR should continue to monitor development of this aspect of these pipeline products and carefully consider its impact on future rulemaking.
Construction	13	93	Some areas of the Williston Basin present unique challenges related to the construction of pipelines in or near environmentally sensitive areas, such as wetlands and other small surface waterbodies.	Although no specific information was provided or observed regarding the current construction practices specific to wetland and small surface waterbodies, these areas warrant special consideration during pipeline construction.	Horizontal directional drilling may be the most appropriate construction method to reduce surface disturbances. In addition, other measures may be warranted to ensure the impact to these areas are minimized in the case of a leak.
	14	94	Based on information gathered from pipeline operators, we conclude that the general description of their pipeline construction process is similar to pipeline construction requirements for PHSMA-regulated and other traditional pipelines. Bedding requirements seemed to be an area where great variability exists. In general, published pipeline construction requirements (included PHMSA/DOT) do not require specific bedding, but rather defer to language such as "…must provide adequate support along the entire length of the pipe." A notable exception to this exists in ASTM standard ASTM D2321.	Many North Dakota pipeline operators are already employing widely used, appropriate standards in gathering pipeline installation. This indicates that prescription of best practices is not the primary factor in the North Dakota pipeline spills record. It does NOT, however, guarantee that these standards are always followed by contractors and subcontractors in the field.	The state may consider implementing construction standards consistent with practices being followed by many operators and currently required for larger, federally regulated transmission pipelines. It would be the responsibility of the third-party inspectors to ensure compliance with state construction standards, and state inspectors would serve the role of verifying that third-party inspectors were maintaining adequate oversight of the project.

Continued…

SUMMARY OF ALL KEY FINDINGS AND RECOMMENDATIONS (CONTINUED)

	ID	Page No.	Observation	Key Finding	Resulting Recommendation
Maintenance and Inspection	15	102	Hydrostatic testing is an industry- and regulator-accepted practice for evaluating the integrity of both newly constructed and in-service pipelines. It is applicable to all types of pipelines, although the details of test procedures may vary by pipeline type and material of construction. The purpose of hydrostatic testing is to force a failure caused by any defects that might threaten the pipeline's ability to sustain its MOP.	North Dakota pipeline safety may be enhanced by ensuring that hydrostatic tests are conducted according to manufacturer recommendations on all pipelines initially upon installation and upon repair of an installed pipeline. Periodic hydrostatic testing on in-service pipelines presents logistical challenges and may shorten pipeline lifetimes, significantly increase operational costs, and increase pipeline system downtime—all for unquantifiable increases to pipeline integrity assurance.	North Dakota DMR should consider a requirement to provide assurance of completed hydrostatic testing according to manufacturer recommendations on all newly installed or newly repaired liquid gathering pipeline segments.
	16	110	Smart pig-based diagnostic technologies are becoming increasingly reliable and cost-effective in locating and assessing the extent of pipeline corrosion and other potential failure-causing defects. Significant improvement in diagnostic capability is achieved when the smart pig is applied to a clean pipeline, and pig-based cleaning techniques typically work better than non-pig-based techniques.	Through surveys of gathering line operators, construction contractors, producers, and engineering firms, it was found that the majority of gathering lines in the Bakken are designed without the ability to use pigs for cleaning, maintenance, and inspection.	It may be worthwhile to assess the cost of making gathering (and other) lines compatible with pig use and compare this cost to the benefit of an improved ability to monitor pipeline integrity and prevent failures.
Monitoring and Leak Detection	17	114	Most of the industry's standard methods for leak detection are called out in API 1130 for regulated transmission pipelines. Advanced LDS methods are used infrequently by North Dakota gathering line operators.	Company decisions regarding implementing new pipeline monitoring and leak detection technology rely upon, among other things, analysis of the cost and benefit. There is a need for objective data on the performance of different leak detection technologies under real-world conditions.	The gathering pipeline monitoring and leak detection pilot project prescribed by HB1358 will serve as a platform to test current and new leak detection technologies applied to gathering systems. This pilot project will test performance, determine infrastructure requirements, estimate costs to pipeline operators, and provide objective analysis of the cost/performance ratio.

Continued…

SUMMARY OF ALL KEY FINDINGS AND RECOMMENDATIONS (CONTINUED)

	ID	Page No.	Observation	Key Finding	Resulting Recommendation
Monitoring and Leak Detection (continued)	18	118	Because of the corrosive nature of produced water from the Bakken, most operators use some form of composite or HDPE materials in gathering pipelines.	Reviewing the leak detection alternatives for pipelines transporting produced water, it is clear that a technology gap exists for implementing external leak detection in the plastic pipeline/produced water market.	The state of North Dakota should encourage development and testing of low-cost external leak detection technologies specific to the needs of produced water gathering line operations.
	19	126	The 1999 and 2010 ADEC reviews on spill statistics and the NTSB report on the 2010 Enbridge incident reported a common theme that extensive operator training and proactive pipeline inspection and maintenance have the greatest impact on reducing pipeline leaks. Secondarily, improved leak detection and a well-planned spill response to an incident were found to decrease the severity of the release.	API RP 1173 establishes a PSMS framework needed to identify and manage risk and address pipeline operation and integrity using the operator's existing pipeline safety systems, processes, and procedures.	The DMR's role in the implementation and enforcement of a PSMS for North Dakota operators, modeled after API RP 1173, should be examined.
	20	127	Flows from wellsite tanks into gathering lines are based on tank levels. Pumps turn on when levels exceed a preset maximum and turn off when a minimum level is passed. Thus gathering line flows are uncoordinated, inconsistent, and highly variable. Gathering systems seldom incorporate intermediate tanks or pumps. Incorporating these unit operations often triggers a change in regulatory requirements and jurisdiction to the Public Service Commission.	The sensitivity and performance of most internal leak detection methods tend to benefit by predictable, consistent flows through liquid-filled pipelines. Creating a similar regulatory environment for both gathering and transmission pipelines could eliminate the incentive to avoid breakout tanks and pumps and promote gathering system design and operation that provides the best possible performance.	The state, in conjunction with operators and vendors, could investigate alternate gathering system design features or unit operations that would enable pressurized and/or more consistent/steady-state flow conditions, thereby enabling improved leak detection system performance and accuracy. Any operational changes would necessitate an examination of the operational impacts, cost, and regulatory implications (example: breakout tanks and pumps triggering Public Service Commission oversight).

Continued…

SUMMARY OF ALL KEY FINDINGS AND RECOMMENDATIONS (CONTINUED)

	ID	Page No.	Observation	Key Finding	Resulting Recommendation
Monitoring and Leak Detection (continued)	21	129	In a number of locations, lagging infrastructure development is still evident where produced water and crude oil deliveries and receipts are recorded manually.	Manual monitoring of delivery or receipt locations because of poor infrastructure or lack of instrumentation creates the potential for prolonged undetected leaks. Keys to minimizing impacts from pipeline releases are frequent inspections and improved monitoring of operational parameters.	In an attempt to identify leaks earlier and minimize their impacts, operators should be encouraged to incorporate technologies such as SCADA to improve communication within and between operators.
	22	132	UAS can provide large amounts of data to assist in detecting leaks. Current limitations (both technology and regulatory in nature) generally limit their use to localized monitoring within line of sight of the operator. Maximum benefits of employing UAS will likely not be realized until beyond line of sight (BLOS) operations are approved by the Federal Aviation Administration (FAA) (several years in the future for commercial operations). Immediate monitoring gains from UAS can be realized if proper leak detection signatures are identified so that sensor systems can be flown to identify leaks and automatically report the data.	UAS shows potential as a monitoring tool over pipelines and oil production sites and should be leveraged within future monitoring architectures.	North Dakota should seek opportunities to demonstrate the role of UAS in pipeline monitoring. With its vast rural landscape, the state and industry within the state have more to gain from this remote sensing than other locations across the nation.
Abandonment	23	143	In the past, industry stakeholders indicated a frustration with lack of available information regarding existing pipeline locations during new pipeline installation activities at the time. To mitigate this issue, new rules have been implemented requiring new pipeline locations to be reported to the state using GIS.	The new GIS rule addresses the issue of pipeline information going forward on new pipeline installations but does not address the issue of information on pipelines already in existence when the rule went into effect. It also does not address the issue of providing the information in a timely manner.	• The state should continue to work with industry stakeholders to inventory and catalog existing pipeline locations for pipelines that were installed prior to the new GIS reporting rule. • The state should also work with industry stakeholders to develop a mechanism that allows for rapid acquisition of information about pipelines for use in construction activities.

ANALYSIS OF THE STATE OF PRODUCED LIQUIDS GATHERING PIPELINES IN NORTH DAKOTA

INTRODUCTION

The last decade has seen growth in the oil industry at a rate that is unprecedented in the history of North Dakota. There are over 12,000 oil wells in the state, with oil production undergoing a nearly fivefold increase since 2008. Saltwater ("produced water") is also produced along with the oil in volumes comparable to oil production. Industry has installed nearly 23,000 miles of gathering pipeline to move these tremendous volumes of fluids from the wellhead to various processing facilities. While the vast majority of the fluids moving through the state's pipeline infrastructure reach their destination without incident, the ever-increasing size of the system means that even low incident rates may result in a greater number of spills and attendant volumes in a given year. With that in mind, public concern has been growing in North Dakota about the effects of spills of oil and produced water on agriculture, public health, and the environment.

Legislative Mandate to Assess Oil and Produced Water Gathering Pipelines

On April 20, 2015, Governor Jack Dalrymple signed into law North Dakota House Bill 1358 (HB1358). The purpose of this legislation was to address public concern over what was perceived as a growing problem with oil and produced water spills in the state as a result of increased exploration and production activity in the oil industry. The bill sought to direct state funding for cleanup efforts and research efforts intended to minimize the number of spills and the volume of fluids spilled.

The North Dakota Legislature passed HB1358 in response to growing concern by lawmakers, landowners, and the general public over the frequency and size of several spills that were widely reported in the media. In fact, this pressure has been building since the early days of oil production, when the industry was much less regulated. Headlines underscored the situation, causing the 2015 North Dakota legislature to act:

> "Pipeline Leaks 63,000 gallons of Saltwater, Some Enters ND Lake," *Forum News Service*, Fargo, North Dakota, May 6, 2015. www.inforum.com/news/3739187-pipeline-leaks-63000-gallons-saltwater-some-enters-nd-lake
>
> "Tesoro Oil Spill: Over 20,000 barrels Seep into North Dakota Wheat Field," *Associated Press*, Bismarck, North Dakota, October 10, 2013. www.theguardian.com/environment/2013/oct/10/north-dakota-tioga-tesoro-oil-spill
>
> "Millions of Gallons of Saltwater Leak into North Dakota Creek," *Reuters*, Williston, North Dakota, January 22, 2015. www.reuters.com/article/2015/01/23/us-usa-north-dakota-spill-idUSKBN0KV1ZR20150123

One of the key elements of HB1358 that was enumerated to address many of the public's concerns was a mandate for the Energy & Environmental Research Center (EERC) to conduct a study of the oil and produced water gathering pipeline network in North Dakota. Specifically, Section 8 of HB1358 directed the EERC to analyze the existing regulations on construction and monitoring of crude oil and produced water pipelines, determine the feasibility and cost-effectiveness of requiring leak detection and monitoring technology on new and existing pipeline systems, and provide a report with recommendations to the North Dakota Industrial Commission (NDIC) and the Energy Development and Transmission Committee (EDTC) by December 1, 2015. The intent of this study was to assess ways to improve the performance of produced water and crude oil pipelines in North Dakota, with the purpose of supporting NDIC's decisions regarding possible adoption of administrative rules impacting pipeline safety and integrity. The EERC initiated the study in June 2015, in partnership with the NDIC Oil and Gas Research Program (OGRP) and in compliance with HB1358. This report represents the culmination of that study. A complete copy of HB1358 is included as Appendix A.

Definitions of Key Terms

While a comprehensive glossary of key technical terms, abbreviations, and acronyms are presented in the preamble of this report, expanded definitions of a few terms used frequently throughout many sections of this document are provided below to help orient the reader. Some of these terms can have multiple definitions, depending on which sector of the oil and gas industry or regulators is using them. The definitions provided below apply to the terms as they have been used in the context of this study:

- *Monitoring* – procedures and equipment employed by pipeline controllers and operators to observe pipeline conditions to ensure the safe, efficient, and environmentally acceptable operation of pipelines.

- *Inspection systems* – a class of procedures and equipment that assesses the condition of pipeline piping and surrounding media to determine the existence of or conditions that promote the appearance of leaks from pipelines. Inspection differs from leak detection by tending to monitor smaller portions of pipelines at a given instant; is scheduled to occur at discrete times; and often distracts, interferes with, or suspends normal operation.

- *Gathering pipelines* – a pipeline transporting oil or produced water that leads from a well or lease tanks to a central accumulation point.

- *Produced water* – fluids that are produced from an oil well in association with the production of oil, the primary constituent of which is saltwater, sometimes also referred to as "brine."

- *Fracturing fluids* – also commonly referred to as "frac fluids," fracturing fluids are injected into a well to crack the rock at the bottom of the well, creating pathways to release trapped oil. This simulates operation during the completion phase of a well to improve productivity.

- *Spill* – any unauthorized release of a fluid into the surface or near-surface environment. This term may be used interchangeably with “leak.”

- *American Petroleum Institute (API)* – an oil and gas trade association that represents all aspects of America’s oil and gas industry. API works with leading industry subject matter experts (SMEs) to maintain an inventory of over 600 standards and recommended practices, including those applying to all types of pipelines.

- *American Society of Mechanical Engineers (ASME)* – a not-for-profit membership organization that encompasses all engineering disciplines and is the leading international developer of codes and standards associated with the science and practice of mechanical engineering.

- *ASTM International (ASTM)* – an international organization that develops and publishes voluntary technical standards derived from robust testing efforts and the consensus of teams of qualified technical experts. ASTM standards have been published for test methods, specifications, accepted practices, and accepted terminology for materials, products, systems, and services used throughout the world.

- *Code of Federal Regulations (CFR)* – the codification of the general and permanent rules published in the *Federal Register* by the departments and agencies of the federal government, representing broad topic areas subject to federal regulation.

- *Pipeline and Hazardous Materials Safety Administration (PHMSA)* – the agency within the U.S. Department of Transportation (DOT) that develops and enforces regulations for the safe, reliable, and environmentally sound operation of the nation’s 2.6-million-mile pipeline transportation system. PHMSA’s mission is to protect people and the environment from the risks inherent in the transportation of hazardous materials by pipeline and other modes of transportation.

Background

Gathering pipelines provide an efficient mechanism for gathering oil, produced water, and gas from oil wells that currently number in excess of 12,000 in North Dakota. The North Dakota Department of Mineral Resources (DMR) is currently projecting that, at full maturity of the oil fields in North Dakota, these wells may number more than 60,000.

Produced fluids are either brought to market (in the case of natural gas or crude oil) or disposed of via saltwater disposal wells (in the case of produced water). These produced fluids are transported either by pipeline or overland trucking. The trend in North Dakota in recent years has been a substantial move toward pipeline transport of oil, as shown in Figure 1. Although these numbers are not as readily available for produced water as they are for crude oil, it can be assumed that similar trends exist.

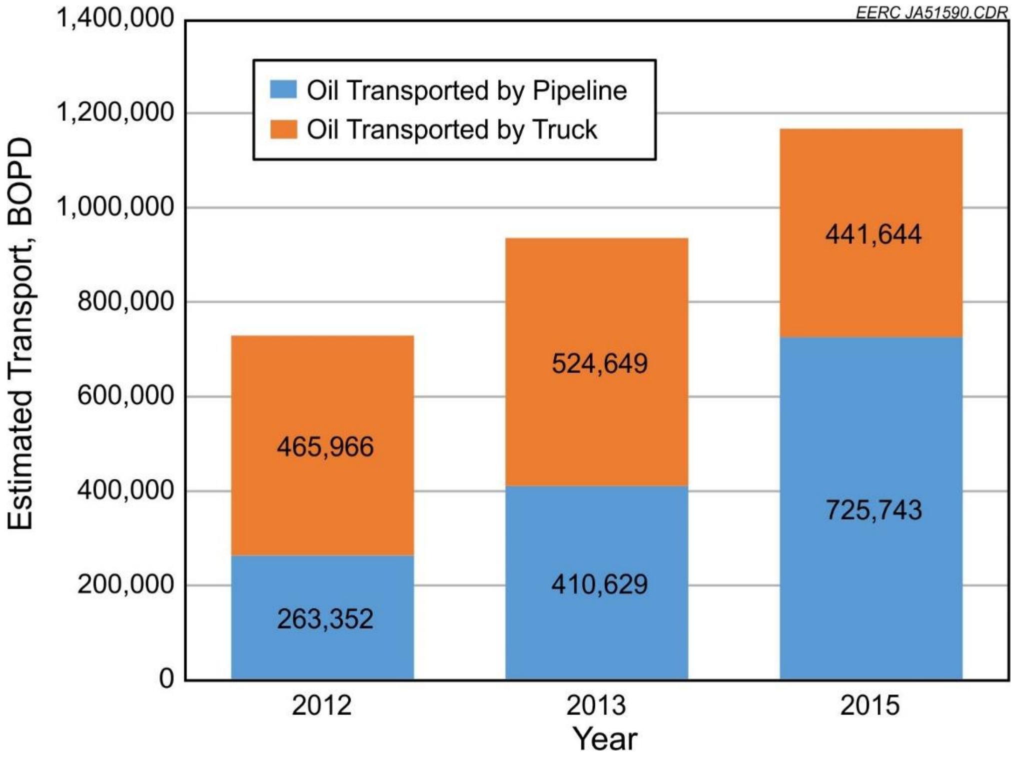


Figure 1. Evolution of oil gathering in North Dakota (adapted from Kringstad, 2015).

If an average oil tanker truck holds approximately 220 barrels of oil, this resulted in approximately 2000 truckloads shipped by truck per day in 2015. Conversely, nearly 3,300 truckloads per day were avoided by employing pipelines in 2015.

Both mechanisms for fluids transport involve risks, but it is widely acknowledged that pipelines are, by far, the safer means of transport. In general, pipelines transport fluids more efficiently and lead to reduced truck traffic, thereby alleviating congestion, highway accidents, road repair, and road dust. That being said, gathering pipeline networks are complex and dynamic systems. The dynamic nature of oil production, rural geography, and the extreme climate conditions of North Dakota make the design, installation, and operation of gathering lines more difficult than pipelines in other industries and areas. These regionally unique aspects must be considered as we assess different operational practices, regulations, and technology to improve the safety and reliability of gathering lines in North Dakota.

Although pipeline spills and spill prevention are the focus of the current report, it must be stated that trucking of fluids, whether in the petroleum industry, or any other industry, also unavoidably results in spills. The quantities of some trucking spills may be smaller than the quantities of some pipeline spills, but the frequency and total number of spills is potentially much greater. Given this and the accepted operational and economic advantages of pipelines over trucking, there is a preference toward the use of pipelines as quickly as rights of way (ROW) can be secured and capital can be put in place. If a robust oil and gas production industry is to be maintained in the state, it is highly likely that more pipelines will be constructed over the coming decades.

Purpose of This Study

Goals and Objectives of the Study

A primary goal of the state is to ensure that industry is employing best practices to ensure safe transport of fluids and rapid leak detection and leak response in the event that a leak occurs. The state also wants to make sure that regulations strike an appropriate balance between the monetization of the state's petroleum resources and the protection of public safety and the environment. Both sides of that equation are equally important to sustaining a high quality of life for the citizens of North Dakota. To support the state's efforts to achieve these goals, this study set out to identify and assess ways to improve the performance of produced water and crude oil gathering pipelines in North Dakota.

Many issues are associated with pipelines, and a wide variety of regulations and technologies exists to address those issues. While pipeline issues are multifaceted, they are also intertwined, and one aspect cannot be fully understood without considering many of the others. With that in mind, the study had many objectives and multiple focal points:

- Conduct a robust statistical analysis of pipeline spills in North Dakota, including a comparison to spill data for other states.

- Develop a comprehensive description of gathering pipeline systems in the state and their operation.

- Compile information regarding the use of pipeline materials, maintenance practices, and methods of pipeline inspection, pipeline monitoring, and pipeline leak detection.

- Determine the feasibility and cost-effectiveness of requiring leak detection and monitoring technology on new and existing pipeline systems.

- Compare North Dakota's current regulations related to pipeline construction, operation, and spills to the regulations of other major oil-producing states.

That information derived over the course of the study was evaluated in the context of identifying critical issues, approaches, technologies, and their relationship to the unique characteristics of North Dakota. The ultimate goal of the study was to provide NDIC and EDTC policymakers with technical information to support decisions by the state of North Dakota that may result in development and implementation of prudent and effective administrative rules regarding pipeline safety and integrity or, perhaps, no additional regulations. The decision to further regulate gathering pipelines or not is clearly at the state's discretion and is not a direct recommendation of this report.

Factors Evaluated for the Study

For the purpose of this study and this report, the EERC evaluated factors impacting liquids gathering pipelines not regulated by federal agencies, regardless of pipe size, operating conditions, and associated facilities (tanks, pumps, etc.):

- For produced water pipelines, the study focused on pipelines and facilities from the point they leave an oil production location (oil well pad) to the facility boundary of a treatment and/or disposal facility.

- For crude oil (or commingled produced fluids including combinations of oil, water, gas, and condensate) pipelines, the study included all pipelines and facilities from the point they leave the oil production location to a terminal that transfers the crude to a petroleum refinery, a rail loading facility, or an interstate pipeline terminal regulated by DOT's PHMSA.

Previous Pipeline Technology Working Group Efforts

In 2013, the Pipeline Technology Working Group was established by Governor Jack Dalrymple. The group includes representatives from private sector engineering firms, PHMSA, the North Dakota Public Service Commission (PSC), the North Dakota Pipeline Authority, the North Dakota State University Center for Surface Protection, and pipeline companies operating in the state. The current EERC study is built upon a solid foundation that was generated by the efforts of the North Dakota Pipeline Technology Working Group, particularly its "Pipeline Technology Review," which was released on December 1, 2014. That report summarized, at a relatively high level, current and future technologies used for leak detection. The report is provided in Appendix B. That report concluded that there are four main categories to address regarding pipeline best practices and technology:

- **Prevention**: The working group stated that a strong focus on incident prevention is paramount in North Dakota. The area of incident prevention included, but was not limited to, third-party damage prevention, robust design and construction practices, comprehensive integrity management programs, corrosion control procedures, employee training, and strict operating and maintenance practices. The working group endorsed the recommendations and guidelines of Common Ground Alliance for damage prevention and NACE (National Association of Corrosion Engineers) for corrosion control.

- **Detection**: The working group believed that imaging technologies continue to evolve and may significantly improve the ability to detect a spill incident sooner. The working group recommended further state support for the research and subsequent usage of new imaging and sensing packages that work in North Dakota's unique climate and terrain conditions.

- **Response**: The working group believed that an effective and timely incident response plan may help to further reduce the consequences of a leak. The working group further stated that incident response depends highly on the type and robustness of the leak detection system (LDS), how soon a leak is detected and verified, and how soon incident response actions are initiated. The group strongly recommended that response capabilities should address access to equipment and tools necessary to respond, as well as action steps to protect the health and property of impacted landowners, citizens, and the environment.

- **Reclamation**: The working group supported the efforts of current research and the further utilization of the North Dakota University System to continue researching the best practices in incident reclamation.

The EERC's efforts expanded upon the working group's prior efforts and used its findings as a basis for this study's approach and activities. It is the intent of this report to provide information that is complementary to the "Pipeline Technology Review" and which will inform stakeholders and decision makers regarding prudent regulation of the gathering pipeline industry in North Dakota.

Historical Background

The rush of the Bakken boom (2007–2014) created pressures on industry to grow quickly to secure positions in this lucrative unconventional oil play. To secure lease holdings, wells must be drilled on a new lease within a specified time frame of acquiring the lease, typically 3 years. To monetize the oil produced from those wells, pipelines must be installed very quickly after that. During the peak of the rush, North Dakota experienced an astounding shortage of qualified labor, which sometimes resulted in substandard contractors performing work not up to the quality expected by oil producers and gathering pipeline operators. Industry is now recognizing the need to improve upon past practices in produced fluids gathering and employ rapidly evolving technology to meet the unique demands of this market.

Gradually, the buildout of liquids gathering infrastructure is catching up with production, resulting in fewer trucks and more pipelines to transport fluids from the wellsite to their destination. Further, many companies have revised existing practices and adopted new practices to:

1) Improve the quality of pipeline installation.
2) Ensure that construction oversight and pipeline inspection occur.
3) Monitor operations to reduce the likelihood and severity of future pipeline leaks.

Across the various aspects of pipeline design, construction, operation, and monitoring, guidance and best practices are being incorporated within these gathering pipelines. DOT's PHMSA, API, ASTM, and other standards setting organizations have extensive rules and guidance designed to improve pipeline performance. Although not all of the guidance developed by these organizations is applicable to the unique characteristics of gathering pipelines, they do provide some commonsense approaches to reducing the frequency and severity of leaks. Where applicable, these guidelines are being adopted by companies and incorporated into individual company standard practices.

In 2015, North Dakota oil production grew to 1.2 million bpd, a nearly fivefold increase from 2008 when oil production was only 250,000 bpd. During this time frame, the buildout of infrastructure to support this production has been enormous. Nearly 23,000 miles of gathering pipeline has been installed in the state in addition to the related infrastructure, consisting of crude oil pipeline and rail terminals and produced water disposal well facilities. This rapid expansion and construction have not occurred without incident. The occurrence of leaks and spills has negatively impacted many landowners, requiring the remediation of damages caused by spills of oil or produced water and reclamation of land to return it to productive use. Even when pipelines operate properly, the number of pipelines installed to transport fluids from 12,000 producing wells has resulted in challenges to farmers and ranchers as they work to raise their crops and livestock amid the steady request for pipeline ROW and construction activities. Not surprisingly, the recent pace of construction activity has led to some fatigue by landowners trying to balance their agricultural operations or other land use needs with the industry need for additional pipeline infrastructure. With this background, it is easy to understand that there is a common desire by all parties that pipelines be installed and operated using the best practices possible to enable safe, efficient, and economical transport of liquids from production sites to their endpoint.

A Primer on Production and Conditioning in North Dakota

The production of oil and gas begins after a well has been drilled and completed, typically by hydraulic fracturing. After an initial flowback period during which fracture fluids flow back out of the well, oil begins to flow from the well to processing equipment on the production location or well pad. The fluids flowing from the well consist of a mixture of crude oil, water, and associated gas which flows (or is pumped) through pipe (production tubing) to the surface where the pressure and temperature of the mixed fluid decrease. Pressures at the bottom of the well are elevated, but decrease as the fluid mixture flows to the surface. This mixture of fluid must be processed at the wellhead (or nearby facility) to remove solid material entrained in the flow and to separate liquid hydrocarbons from gases and water for subsequent transport of each of those streams off of the production location (well pad).

The processing of crude oil in proximity to the production well is referred to as primary separation and/or conditioning. Impurities include the gases, water, and solids produced with the crude oil. Gaseous product includes hydrocarbons and inorganic gases that either existed as a separate phase exiting the well or were in solution but evolved from the crude oil during conditioning. The natural gas and natural gas liquid (NGL) product have economic value and are generally collected in relatively low-pressure gathering lines. These lines convey the gases to gas-processing plants that subsequently process the stream and ultimately sell it as natural gas and NGLs.

Depending on the quality of the produced water, the water may be recycled or treated and disposed of—typically by deep-well injection. Solids that were carried with the oil also require treatment and proper disposal.

Crude oil separated from conditioning equipment is typically transported to a refinery for further processing into finished fuels and/or chemicals.

Depending on the composition of the produced fluid mixture, the oil and water might easily form two phases with little treatment. Alternately, the two might form an emulsion that requires chemical additives, heat, quiet flow, centrifugation, or other means to separate. After processing through separators, the conditioned petroleum, segregated wastewater, and solids streams are retained on-site in tanks until collected and transported away from the wellsite by truck or gathering pipeline.

Multiple crude oil and water tanks are often utilized to accommodate the volume of production fluids from a production location. Tanks range in size but often have capacity of several hundred barrels. The pipelines, which transport liquids such as crude oil, water, or oil–water mixtures (emulsions) to aggregation points such as a crude oil refinery, crude oil pipeline, or water treatment/disposal sites, are considered gathering lines and are the focus of this study.

Figure 2 depicts a notional Bakken wellsite conditioning configuration (North Dakota Industrial Commission, 2014a). The number of separators, existence of a free-water knockout vessel just upstream of the crude heater, and presence of other equipment vary greatly by wellsite and over time at specific wellsites.

A common separator used at Bakken production sites is the emulsion heater treater (HT) which is capable of removing gases, free water, and solids from petroleum. Additionally, their ability to heat petroleum enables them to "break" water–oil emulsions to free and remove water that would otherwise have been tied up and carried with the crude oil. An HT's location at the end of a separator train means that it operates at the lowest pressure of the train. A photograph of wellsite conditioning equipment and tankage, including an HT, is provided in Figure 3.

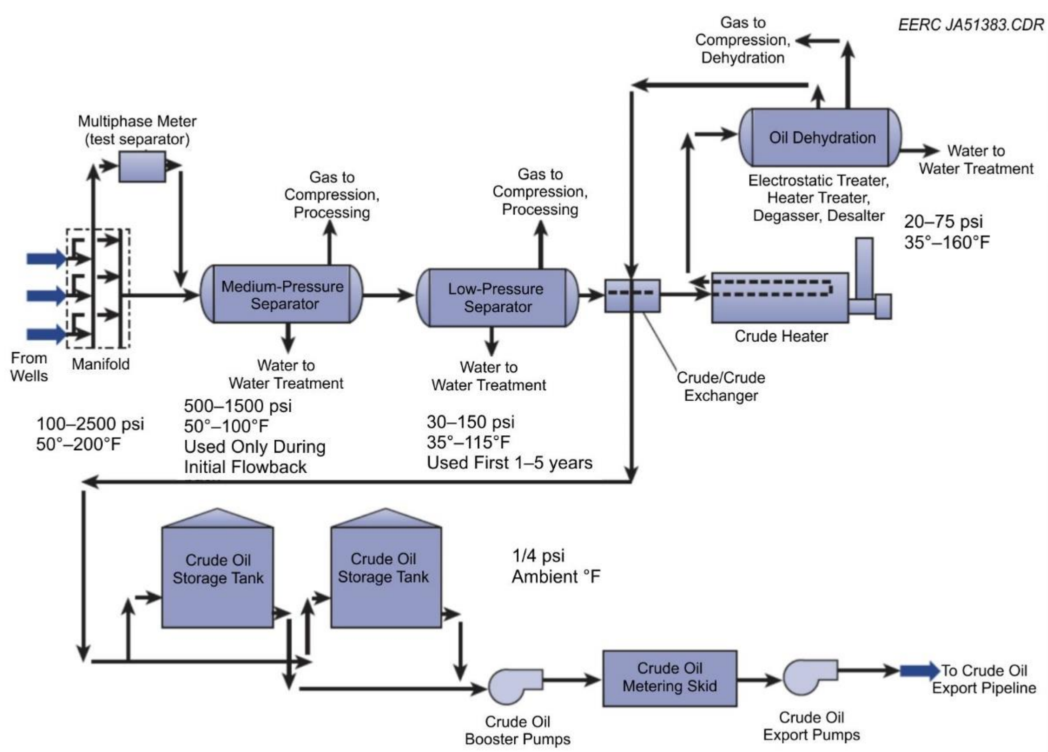


Figure 2. Notional Bakken wellsite conditioning equipment configuration (North Dakota Industrial Commission, 2014a).

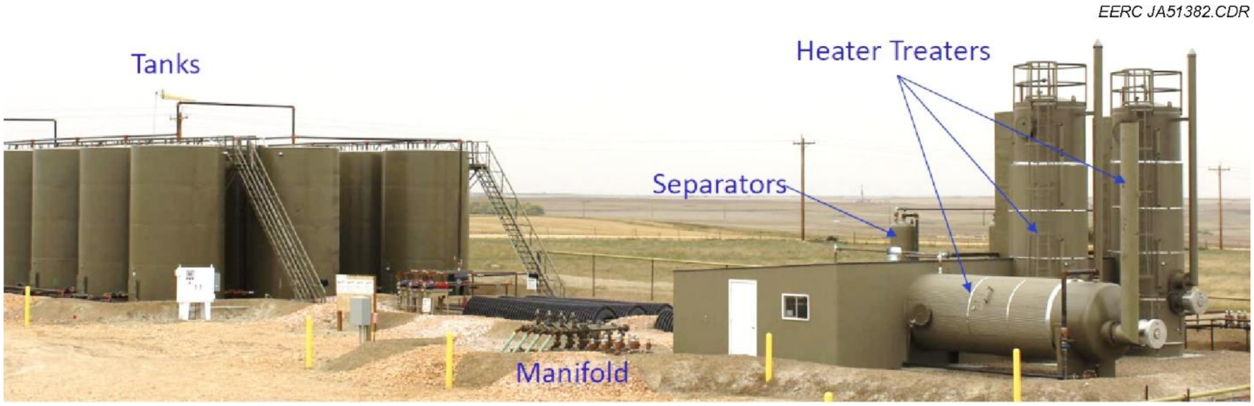


Figure 3. Photograph of Bakken wellsite (Oasis Petroleum, 2014).

The HT operating temperature and pressure vary by location depending upon the nature of the oil produced at that location. NDIC regulates crude oil conditioning in an effort to achieve sufficient gas and oil separation to meet a crude oil vapor pressure of 13.7 psi. Although variation is allowed within the rule, HTs are often operated at temperatures above 110°F and at pressures below 50 psi. A summary of crude oil conditioning requirements can be found in Table 1.

Table 1. Final Order HT and Separator Operating Requirements (North Dakota Industrial Commission, 2014b)

Equipment and Conditions	Min. Temp.	Comment
<50 psig	110°F	
>50 psig	110°F	Vapor recovery is required on or before crude oil storage tanks
Other Conditions		VPCRx[1] 13.7 psi or less, or 1 psi less than ANSI[2]/API RP3000 (whichever is lower) with quarterly testing
No HT or Separator		NDIC approval, 13.7 psi maximum VPCRx or safe delivery to stabilization plant

[1] Vapor pressure of crude oil.
[2] American National Standards Institute.

Although all oil production includes a well, conditioning equipment, and tanks, the configuration and logistics vary depending on factors such as production rates, geography, and contractual issues. Figure 4 illustrates three configurations commonly deployed in North Dakota (A, B, C). In many cases, oil wells, conditioning equipment, and tanks are all located on a single production location, as illustrated in Configuration A within Figure 4. In these instances, multiple wells may supply multiple pieces of conditioning equipment and associated crude oil and produced water tanks, but all equipment is located within a single production location. In these situations, trucks or gathering pipelines transport crude oil and produced water off-location to another facility for aggregation, further processing, or disposal.

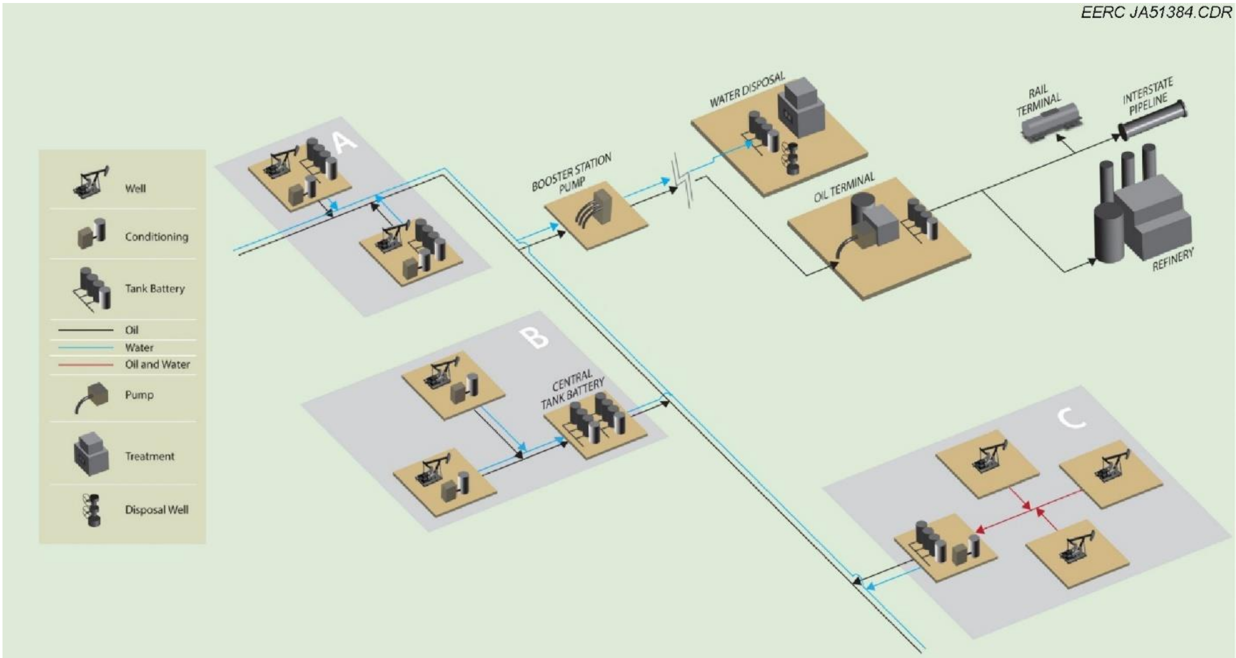


Figure 4. Notional Bakken conditioning and gathering system configuration.

An alternate configuration consists of a central tank battery (CTB) which collects oil and water from multiple production locations each with their own wells and conditioning equipment. This may be done if space constraints prevent tanks from being located on the production location or to minimize truck traffic to individual production locations (wellsites). In these situations, gathering pipelines transfer crude oil and water from the production location to the CTB, and additional gathering lines transport the same products from the CTB to another facility for aggregation or further processing or disposal. An illustration of this process configuration can be found in Configuration B within Figure 4.

A third alternative includes locating conditioning and tank equipment at a centralized facility, supplied by multiple, separate wellsites using gathering pipelines to transport produced fluid (mixture of oil, water, and gas) from the wellsite to the centralized conditioning and tank location. An illustration of this type of production location is represented in Configuration C within Figure 4. In this configuration, gathering pipelines are used to transport mixed fluids from the wellsite to the centralized conditioning location, and additional gathering lines transport crude oil and produced water to another facility for aggregation, further processing, or disposal.

Once crude oil and produced water are separated and in a tank at a production location or CTB, they can be transported off-site several ways. When pipelines are not available, trucks are used to haul crude oil to pipeline terminals, rail terminals, or refineries. Produced water can likewise be trucked to treatment or disposal facilities.

When pipelines are available, they are typically configured similarly and include the following:

- A pump skid to transfer liquids from the tank to the pipeline
- A meter skid to measure flow and create a location for sample collection
- A network of small diameter (4–12-inch diameter) underground pipelines
- Safety valves
- Backflow prevention
- Instrumentation for pressure, temperature, and flow rate
- A booster pump station somewhere along the pipeline route
- A delivery point meter skid

In the case of crude oil, the oil is metered, stored in a tank and, ultimately, transferred to a refinery, railcar, or interstate pipeline system carrying crude to distant refineries. Once the crude oil is received at a terminal, subsequent transport is regulated by the North Dakota PSC or DOT's PHMSA. Communication of fluid volumes received at a terminal is monitored closely, as it is the basis for a financial transaction. Typically, crude oil volumes received by the terminal are compared with volumes metered at the production site to verify transfer of the product. This comparison, whether done on a daily basis with manual recording of data or continuously using computer-controlled data collection, provides a basic leak detection function, ensuring that all of the crude entering the gathering system is received at the terminal.

For produced water, the endpoint of the gathering system is typically a disposal well facility consisting of a flowmeter, tanks, pumps, and an injection well. In some cases, crude oil and produced water gathering pipeline systems and terminals are colocated, but in other cases, they are entirely separate and operated by different companies. Produced water received at a disposal facility accumulates in large storage tanks. The volume of water received is measured and, like crude oil, compared to volumes pumped from production locations. This flow comparison forms the basis of the financial transaction associated with water disposal fees and provides a basic leak detection mechanism. Once sufficient produced water volume has accumulated, a pump is activated to transfer produced water from the tanks through an injection well and into a saline aquifer thousands of feet beneath the surface. Several saline aquifers exist in western North Dakota and are capable of receiving large volumes of produced water generated from Bakken wells. Many injection wells exist throughout the Williston Basin and allow produced water to be disposed of relatively close to production wells, keeping transportation distances to a minimum.

The Trend of Multiwell Pads

As technology has advanced, many producers have moved toward colocating more wells on a single pad to avoid costs, minimize impact to surrounding lands, and optimize truck traffic patterns. Previously, it was common to have 3–5 wells on a single pad. Producers are now exploring use of multiwell pad configurations that contain 30 wells or more on a single large wellpad. Several multiwell pads that contain 25+ wells are currently installed in North Dakota.

This may present an opportunity pertinent to the topic at the heart of this report. North Dakota regulators and industry, alike, are striving for the goal of minimizing fluid releases from gathering pipelines. One manner of achieving this goal is to eliminate pipelines where feasible. In the case of produced water, it may be feasible to colocate a saltwater disposal well on-site at these very large wellpads with many wells. The produced water could immediately be disposed of on-site, within containment berms on a wellpad, to minimize attendant risk from pipelines on surrounding lands.

Analysis is not yet in place to confirm that this prospect is feasible. It would certainly necessitate site-specific verification of the presence of quality disposal zones that would accept the produced brine volumes, and attendant economic considerations, at a minimum. This level of analysis is beyond the scope of this report and will likely be the subject of ongoing case-by-case consideration. It does, however, present an interesting concept for industry and regulators to contemplate. Therefore, this report brings the notion forward only to highlight the potential alternative in certain cases. This report is only recommending that state regulators and industry jointly consider this alternative on a case-by-case basis.

REVIEW OF NORTH DAKOTA CRUDE OIL AND PRODUCED WATER GATHERING PIPELINE INFRASTRUCTURE

Williston Basin Gathering Pipeline Infrastructure

Liquid gathering pipelines are large, dynamic, and complex systems. In North Dakota, pipelines service an area of over 15,000 square miles (Hicks, 2015), as shown in Figure 5. The large geographic area of the Williston Basin, one of the largest oil-producing regions in the world, results in fluids being transported long distances, often over rugged and sparsely populated terrain. In some instances, pipelines are installed and operated in areas with significant changes in elevation, necessitating additional pumping capacity and higher pressure ratings for pipelines, valves, and fittings. In other areas, soil erosion from wind and water can leave pipelines exposed to cold-winter temperatures, increasing the risk of freezing and rupture.

Currently, North Dakota has an estimated 23,000 miles of gathering pipeline (Ritter, 2015). A map illustrating the complexity and extent of liquids gathering lines currently accounted for in the North Dakota DMR database is provided in Figure 5. This map, provided by DMR, includes approximately 4000 miles of liquid gathering pipeline, primarily those new pipelines placed into service since August 2011. To further highlight the extent of pipelines currently operating in North Dakota, a map illustrating the extent of one company's liquid gathering lines in approximately a 16-square-mile area is provided in Figure 6. Information about the location of older pipelines is retained by the respective operator and is not included in the DMR database. In 2014, new regulations were implemented requiring that pipeline locations be reported to the state. North Dakota Administrative Code (NDAC) 43-02-03-29, enacted on April 1, 2014, now requires operators of any underground gathering pipeline placed into service between August 1, 2011, and June 30, 2013, to file with DMR, by January 1, 2015, geographical information system (GIS) data showing the location of the pipeline centerline. The operator of any underground gathering line placed into service after June 30, 2013, is required to submit GIS data within 180 days of the in-service date.

Statistics describing pipeline location, size, and other attributes are not publicly available for all gathering lines in North Dakota. However, the recently created DMR database does contain this information for pipelines installed since 2011. These liquid pipelines range in diameter from 2 to 24 inches and carry a variety of fluids, including crude oil, produced water, freshwater, and mixtures of oil and water.

EERC JA51385.AI

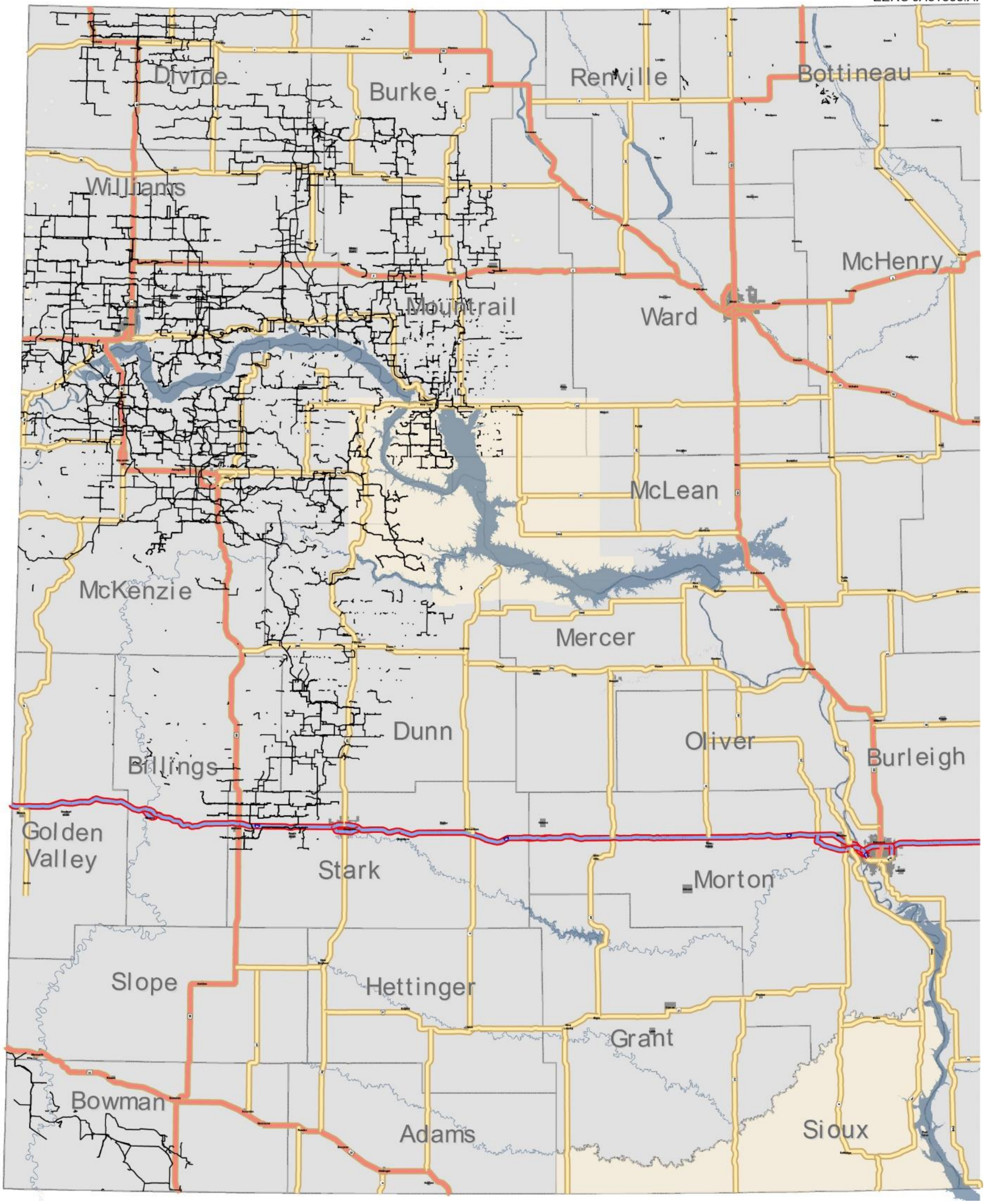


Figure 5. North Dakota DMR map of gathering pipelines installed since 2011.

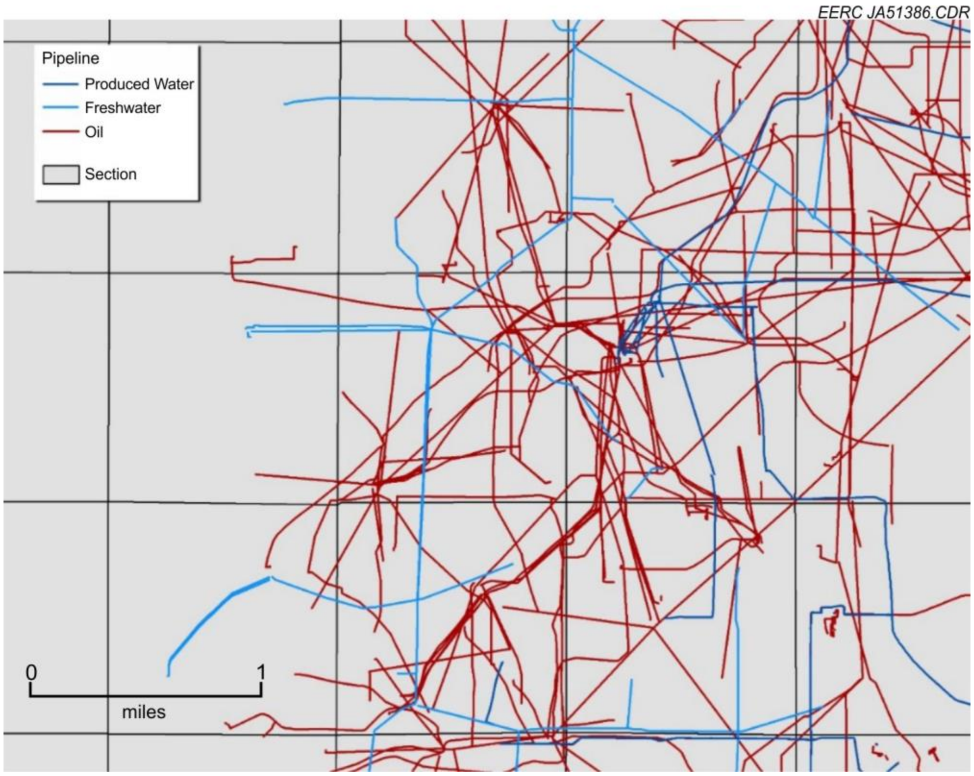


Figure 6. A single company's map demonstrating the complexity of overlapping fluids gathering pipelines.

Business Aspects of Williston Basin Gathering Pipelines

Diverse ownership and business models exist in the gathering or midstream industry ranging from fully integrated ownership and operation of production, gathering infrastructure, and final disposition of liquids to the other extreme in which each of these components is provided by separate companies. These different models each offer companies different advantages and disadvantages and are selected based on individual company philosophies.

In a fully integrated business model, a company owns and operates all aspects of oil production, liquid transport, waste disposal, and oil terminal operations. In these situations, coordination of infrastructure buildout, operational changes, and transfer of liquids along the production chain occurs within a single company. In some cases, this integrated model can make communication and coordination simple.

Nonetheless, different business units within an integrated company can lead to complicated communication protocols and competing interests related to financial and operational matters. In either case, effective communication within or between companies is critical to ensuring that:

1) Infrastructure is built to match production volumes.

2) Production operations match pipeline capacity.

3) The volume of fluid leaving a production location is received at a terminal or disposal site and not lost to leaks within the gathering network.

The measurement of fluids is typically conducted at the wellsite at the point it is transferred from the production tank to the gathering line. Liquid flow rate and volume are not typically measured within the gathering pipeline until the fluid reaches either a pipeline or rail terminal, in the case of crude oil, or a water treatment disposal site, in the case of produced water.

In some instances, a fully integrated company may accept others' produced water or crude oil into its gathering system. This is especially true where one company has a predominant presence within a defined geographic area. In other instances, oil production companies own and operate some of their midstream infrastructure and contract to third-party providers for others. These third-party midstream companies may own or operate one or more parts of the gathering infrastructure, which includes crude oil gathering pipelines, crude oil terminal or loading facilities, produced water gathering pipelines, and produced water treatment or disposal facilities. In these situations, oil-producing companies either sell the fluids to the midstream company or pay a fee for service. The separate ownership of various crude and produced water-handling operations enables specialization among companies and is a widely used business model. The coordination of capital buildout, operational activities, and communication of fluid transfer must still be communicated, and doing so across multiple companies can create unique challenges that must be overcome to enable efficient operation of oil production.

1

Key Finding and Recommendation

Observation: Producing, gathering, and terminal or disposal well asset ownership varies in North Dakota. In some situations, a single company owns all assets, while in other situations, the producer, gathering line operator, and terminal or disposal well operator are three different entities.

Lack of communication and consequent awareness between a disposal well operator and a gathering line operator contributed to extending the duration of a spill when a leak occurred in a gathering line that fed a produced water disposal well. The disposal well operator was unaware of flow in the gathering line, so rationalized that the lack of flow from the line was expected. Conversely, the gathering line operator was unaware of the lack of flow at the disposal well.

Finding: Sharing of operational data along a gathering line and over time is critical to monitoring and leak detection.

Recommendation: North Dakota DMR should carefully consider rulemaking that encourages realtime data sharing among adjacent, partnering business interests in any given gathering system composed of more than one operating company. If different entities own assets connected to a gathering line, they should be encouraged to share realtime operational data so that at least one individual or system has a complete view of the pipeline status at any given time. This sharing may be accomplished best by shared access to SCADA databases between adjacent companies.

When third-party companies provide liquid gathering services, companies must communicate operational information, most importantly flow rates and volumes. In some cases, crude oil and produced water flow rates and volume measurements are measured by the producing company, and these operational data (among other process data) are shared with the midstream company. Sometimes the third party provides flow measurement and supplies that information to the producing company. Sometimes process monitoring and instrumentation are replicated, adding a check and balance that the transaction and/or transfer of fluids are accurately measured. Regardless of the configuration, this communication and sharing of flow rate and volume data and subsequent comparison to volumes received at a terminal or disposal site serve as the basis for transacting crude oil for sale and produced water for disposal and provide a fundamental basis for identifying leaks.

2

Key Finding and Recommendation

Observation: Liquid gathering pipelines are complex, dynamic systems operated under a wide range of conditions and diverse business arrangements.

Finding: The unique and constrained conditions under which liquid gathering systems operate in North Dakota require different design, operations, and monitoring than pipelines used in other industrial sectors.

Recommendation: New regulations and best practices developed for gathering pipelines can build upon successes from other pipeline sectors, but they must be tailored to the conditions under which gathering lines must operate, address the unique properties of different fluids being transported, and provide flexibility to address the variable conditions that exist across North Dakota.

The dynamic nature of oil and gas production also has a significant impact on how gathering pipelines are designed and operated and must be considered in efforts to improve pipeline performance. New producing wells are being added to existing gathering infrastructure on a continuous basis. Producing wells do not typically operate under consistent, steady-state conditions and typically experience highly variable production rates, changing fluid properties, and dramatic production decline rates over the first several months of operation. This variability in production from each well inevitably transfers to variability in the rate at which fluids are pumped from tanks on the production location to the gathering pipelines. This variability in flow rate, pressure, fluid temperature, and fluid physical properties inevitably leads to fluid volumes reaching pipeline capacity (flow rate and pressure) one moment and slack or zero-flow conditions the next. In some cases, the pipeline is not full, leaving void space within the hundreds of miles of pipeline. This variability in line fill (extent of void space within the pipeline) creates multiple challenges to reliable flow measurement and flow balancing. Most flowmeters cannot accurately measure flow rate in a pipe that is not full. Additionally, when a pipeline is not full, liquid can accumulate in the system, creating discrepancies between measurements of fluids pumped into the system and those received at the oil terminal or disposal facility. These conditions can lead to lower accuracy of flow measurement than can be achieved from continuous, steady-state flow systems such as what is observed in interstate transmission pipelines or typical processing/manufacturing plant operations.

A REVIEW OF PRODUCED FLUID LEAKS AND SPILLS

As ways to improve the safety and efficiency of gathering pipelines in North Dakota are identified, it is important to consider the many factors influencing pipeline operations in North Dakota and how those operations can impact the frequency and size of pipeline incidents, including leaks, seeps, and spills.

This section provides an overview of leak and spill statistics, providing a basis from which to assess and prioritize opportunities to improve pipeline performance. The rapid growth and large number of pipelines operating in North Dakota have clearly had a significant impact on recent leaks and spills. Based on probability alone, the recent expansion of infrastructure and volume of fluids moved by pipeline would be expected to result in a noticeable increase in incidents.

A more detailed analysis was performed on the North Dakota data in an attempt to observe trends as well as identify the root causes of the reported spills. The analysis of peer states was limited to only those data necessary to compare oil and brine spill data and annual oil production.

This section will begin with a detailed analysis of North Dakota spill data and then expand to the broader comparison of spill statistics from other large producing oil and gas states.

Spill and Leak History in North Dakota

Spill and leak data presented in this section were obtained from the General Environmental Incidents and Oilfield Environmental Incidents databases accessible on the North Dakota Department of Health (NDDH) Web site. Additional data were provided by DMR. Data were compiled, and analysis was performed on spill and leak data from 2001 through 2014, representing approximately 7 years prior to and 7 years after initial development of the Bakken Formation.

Spills reported in the Oilfield Environmental Incidents database include spills that were “contained’ on the oil production pad or location, while spills reported in the General Environmental Incidents database include spills that occurred off of the oil production location.

The spill reports are a summary of information submitted by responsible parties or individuals with direct knowledge of the initial spill. Information regarding the spill is sometimes reported verbally to agency (NDDH or DMR) personnel, but in most cases, spill information is submitted electronically via the NDDH or DMR Web site. Regardless of how the information is reported, it eventually is inputted electronically to a main database called the Risk Based Data Management System (RBDMS). This database, developed by the Ground Water Protection Council and revised to fit individual oil-producing states, warehouses the information and sends out notification to the appropriate agency individuals to determine the level of action as well as jurisdictional oversight. From then on, the supervising agency is in communication with the responsible party to develop an appropriate strategy to address the initial release and long-term remediation activities (if required).

Challenges in Data Analysis

Since only a limited amount of data is accessible electronically, an automated process was developed to download information for each spill reported from 2001 through 2014, including the pdf-format Incident Summary. Through a several-step process, specific information was imported into Microsoft® Excel for analysis. The entire process was performed for spills reported to the General Environmental Incidents and Oilfield Environmental Incidents databases. During the compiling process, several concerns arose which are highlighted in the next paragraphs.

> 3
>
> **Key Finding and Recommendation**
>
> **Observation**: In compiling incident data from the DMR and NDDH databases, we discovered duplicate reporting of incidents, improperly entered categories (fluid type, incident type, etc.), and missing information which made analyzing the data difficult.
>
> In addition, the processes used to manage incidents among state agencies are not conducive to data analysis.
>
> **Finding**: The analysis of the spill data highlights the need to examine how data are collected and compiled within the state system. All parties involved want to reduce the quantity and severity of leaks and spills, and yet it is difficult to assess where the largest problems are in the current reporting format and database structure. Therefore, it is even more difficult to strategically assign resources to address the issues.
>
> **Recommendation**:
> - The state should streamline the ways spill data are reported, processed, and analyzed to facilitate data analysis. Implementing such a data management function within the state will likely necessitate additional resources at North Dakota DMR.
> - After streamlining is achieved, North Dakota DMR should collect and analyze data continually to determine root causes of pipeline leaks, then continually refine regulatory language that addresses root cause determinations.

Product volumes in the General Environmental Incidents database were often reported in gallons, while volumes in the Oilfield Environmental Incidents database were reported in barrels. All product volumes reported in gallons were converted to barrels prior to combining the two data sets.

While the data were compiled, it was observed that several spills (approximately 70 incidents) were present in both databases. These duplicate entries were removed from the data that were analyzed. The most notable duplication was the Tesoro pipeline leak of 20,700 barrels of crude oil that occurred in 2013.

Data were initially compiled and analyzed for all liquid spills associated with oil and gas production. These liquids are reported in three categories in the Oilfield Environmental Incidents database: oil, saltwater, and other. In the case of some spills reported in the General Environmental Incidents database, it appears that the user manually determined how to categorize the type of spill.

Products included in the oil category are self-explanatory, although allowing the user to enter the product type in the General Environmental Incidents database did complicate data analysis, as oil was inputted in a variety of ways, such as crude, crude oil, sweet crude, Bakken crude, etc. The same issue existed for the saltwater category in the General Environmental Incidents database as a variety of terms were used to describe saltwater, including brine, produced water, etc. The other category included all other liquids that did not fall into the other two categories and includes, but was not limited to, emulsion, drilling fluid, fracture fluid, and other chemicals.

North Dakota Data Analysis Results

Data analysis was performed to examine the trends of all oilfield-related spill incidents and volume with time (pre- and post-Bakken development) as well as the portion of the total spills attributable to pipeline-related releases. Spills are also reported as "contained" or "not contained." Data indicate that 75%–80% of the spills are reported as contained, meaning the spill was contained on the production location.

From 2001 through 2014, roughly 10,400 spills were reported involving nearly 582,000 barrels of all liquid types that would be associated with the production of oil and gas in North Dakota. For crude oil and brine, the total spill volume was compared to the total volume of product handled. Figures 7 and 8 show that from 2001 through 2014, the oil and gas industry spilled on average 0.01% of the total oil and brine volume that was produced each year. In more common terms, for every 10,000 barrels (or gallons) produced, 9999 barrels (or gallons) was delivered to its destination, and 1 barrel (or gallon) was spilled.

The spilled volume for oil and brine does vary from year to year but ranged from 0.005% to 0.014% for oil and from 0.006% to 0.016% for brine. In 2014, nearly 20,000 barrels of oil was spilled of the 396,000,000 barrels of oil produced, and approximately 71,000 barrels of brine was spilled of the slightly more than 432,000,000 barrels of brine produced with the oil.

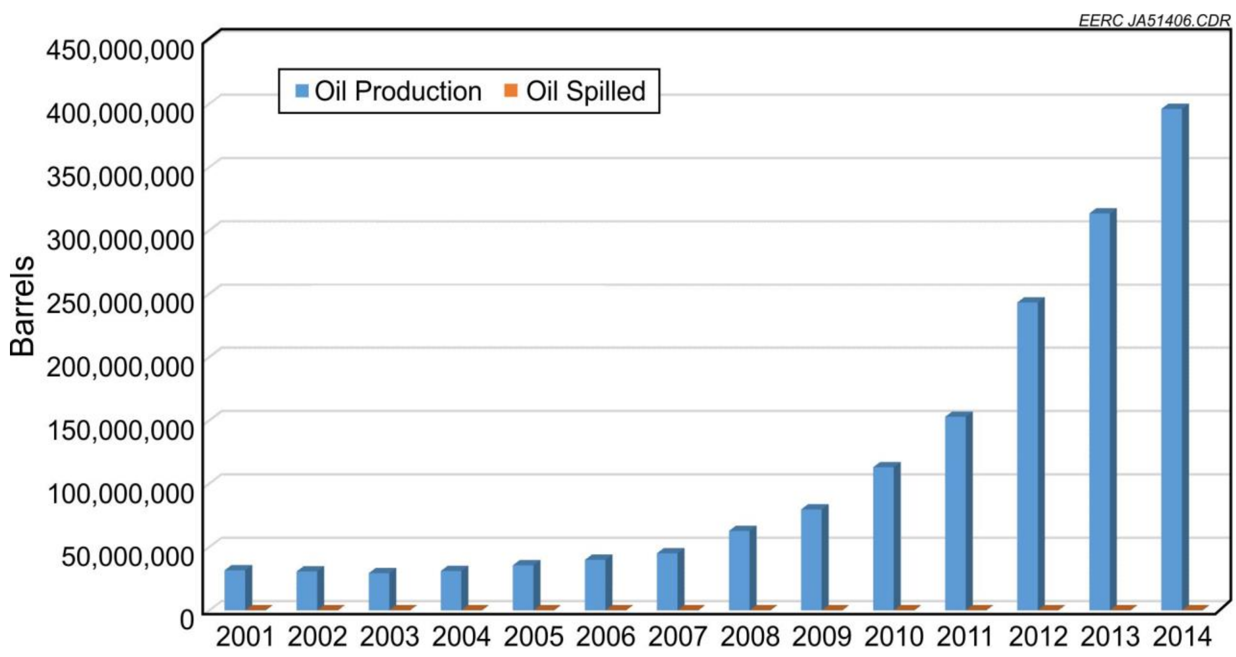


Figure 7. Oil produced spilled from 2001 through 2014 in North Dakota.

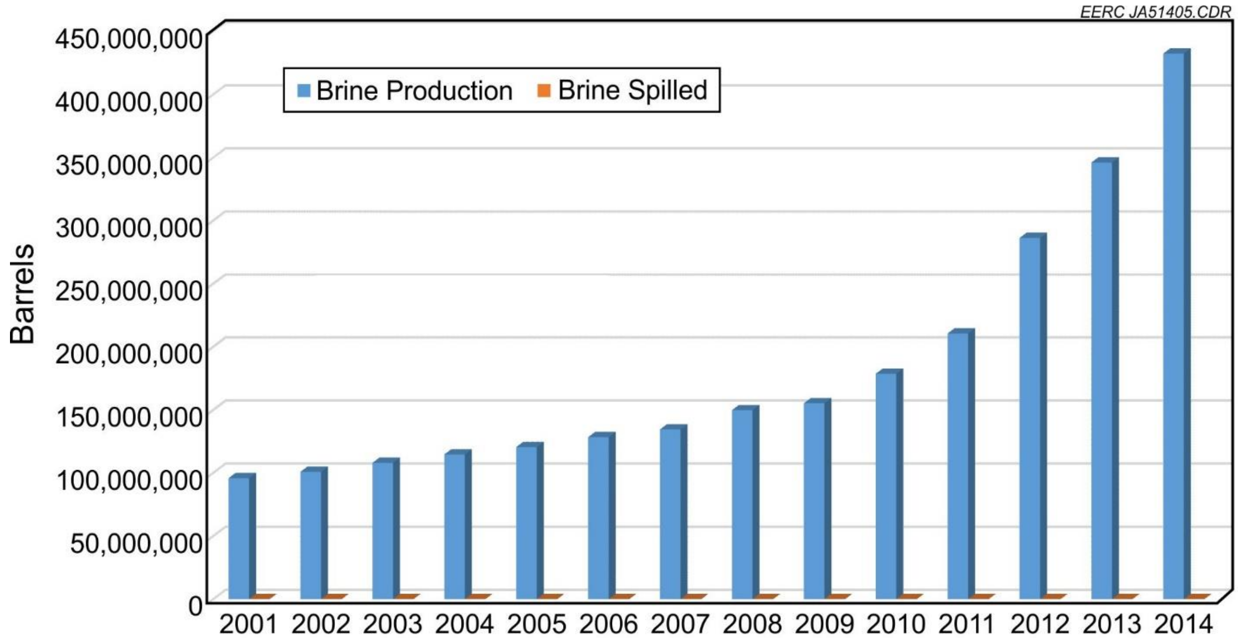


Figure 8. Brine produced and spilled from 2001 through 2014 in North Dakota.

Table 2 contains the detailed spill data used to generate Figures 7 and 8. In more detail, Figure 9 shows the annual spill incidents for the three product categories that are reported to DMR as well as the total spill incidents. Figure 10 contains the same elements but shows annual spill volume. The three categories are oil, brine, and other. Oil and brine categories are self-explanatory, but the other category is further described for clarity. The other category includes substances that could not be reported as oil or brine and include, but are not limited to, fluids such as drilling fluids, hydraulic fracturing chemicals, refined petroleum products, fracture makeup water and, more recently, freshwater. The spill incidents and volume shown in Figures 9 and 10 clearly show an increasing trend. This may not be all that surprising since the volume of oil and brine produced has also increased significantly, and statistically speaking, this correlation would be expected.

One specific example of how outliers can affect the overall spill circumstances can be seen in Figure 10 where some operators reported releases of freshwater in the "other" category. The freshwater reported in 2013 totaled approximately 70,000 barrels or 90% of the other category, and notable is that it also represented 43% of the total spill volume for that year. Although the release of large quantities of freshwater is likely not without impacts, at a minimum the spilling of freshwater should be reported separately or treated differently within the database. This highlights the magnitude of how a single incident report can impact the overall spills picture and also the need to clarify or provide formal guidance regarding types of liquids to report.

Notable in Figure 10 is that single large-volume spills created trend outliers in 2011 and 2013. In addition, it was discovered that several spills reported in the "other" category were actually freshwater containing no chemicals or other additives.

Table 2. Summary of Total Oil- and Gas-Related Spills from 2001 Through 2014 in North Dakota

	Oil		Brine		Other		All Liquids	
Year	Incidents, no.	Volume, bbl	Incidents, no.	Volume, bbl	Incidents, no.	Volume, bbl	Incidents,[a] no.	Volume, bbl
2001	99	3012	96	6192	3	1	172	9205
2002	107	2141	104	6475	7	93	191	8709
2003	117	3144	120	9394	14	1165	224	13,704
2004	141	2538	155	9363	11	1482	257	13,384
2005	188	5046	181	9457	13	830	341	15,333
2006	204	3457	217	16,896	19	1716	396	22,069
2007	244	5449	244	16,798	19	1711	471	23,959
2008	279	7858	234	15,043	36	1757	524	24,658
2009	272	5654	204	10,385	45	1804	494	17,843
2010	330	6749	258	14,809	74	4534	655	26,092
2011	611	12,540	389	23,855	211	22,157[b]	1210	58,551
2012	680	14,528	536	30,564	207	8967	1339	54,060
2013	1057	35,330[c]	687	52,336[d]	252	77,418[e]	1875	165,083
2014	1160	19,660	855	71,345[f]	319	38,258[g]	2268	129,263
Total	5489	127,106	4280	292,912	1230	161,894	10,412	581,912

[a] Some spills involved the release of multiple products in a single incident; therefore, the total incidents are not the sum of the “oil,” “brine,” and “other” incidents.
[b] Includes 15,500 barrels of freshwater reported as “other” product spilled.
[c] Includes a single 20,600-barrel pipeline crude oil pipeline leak.
[d] Includes a single 17,000-barrel brine pipeline leak.
[e] Includes approximately 70,000 barrels of freshwater reported as “other” product spilled.
[f] Includes a single 24,000-barrel brine pipeline leak.
[g] Includes the 23,600 barrels of freshwater reported as “other” product spilled.

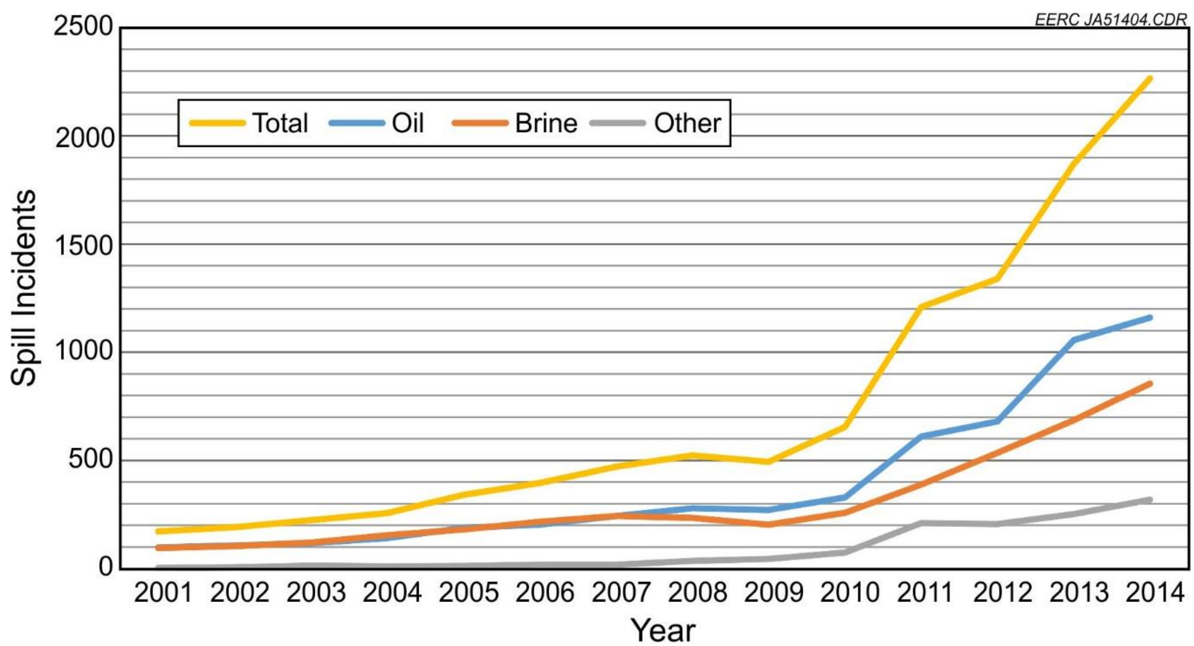


Figure 9. Individual product and total spill incidents from 2001 through 2014 in North Dakota.

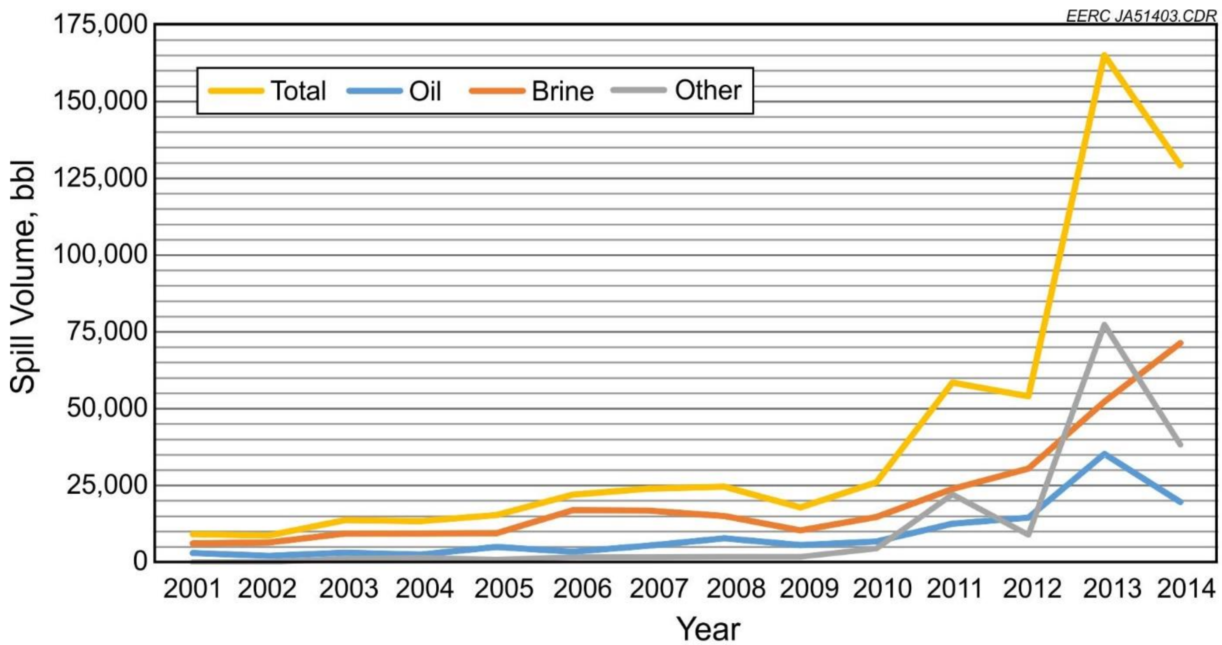


Figure 10. Individual product and total spill volume from 2001 through 2014 in North Dakota.

In an effort to examine spill data sets between states as well as analyze trends within North Dakota that take into account the rate of oil production, spill data were "normalized" by two methods:

1) The ratio of spill incidents and spill volume as a function of oil production
2) The ratio of spill incidents and spill volume as a function of producing wells

Figures 11 and 12 show the total spill incidents and total spill volume data from Table 2 graphed as a function of the annual oil production, respectively. Figures 11 and 12 show that when spill incidents and volumes are viewed in relation to the volume of oil produced, the general trends are flat over the 14-year analysis period and decreasing since 2007.

More detailed graphs of the individual liquid types normalized by both methods are included in Appendix C. When reviewing those graphs, one will note that when spill incidents and volume of the individual liquid types are graphed in relation to the number of producing wells, an increasing trend occurs, but when the same spill data are graphed in relation to annual oil production, the general trend is flat or slightly decreasing (with the exception of the "other" category).

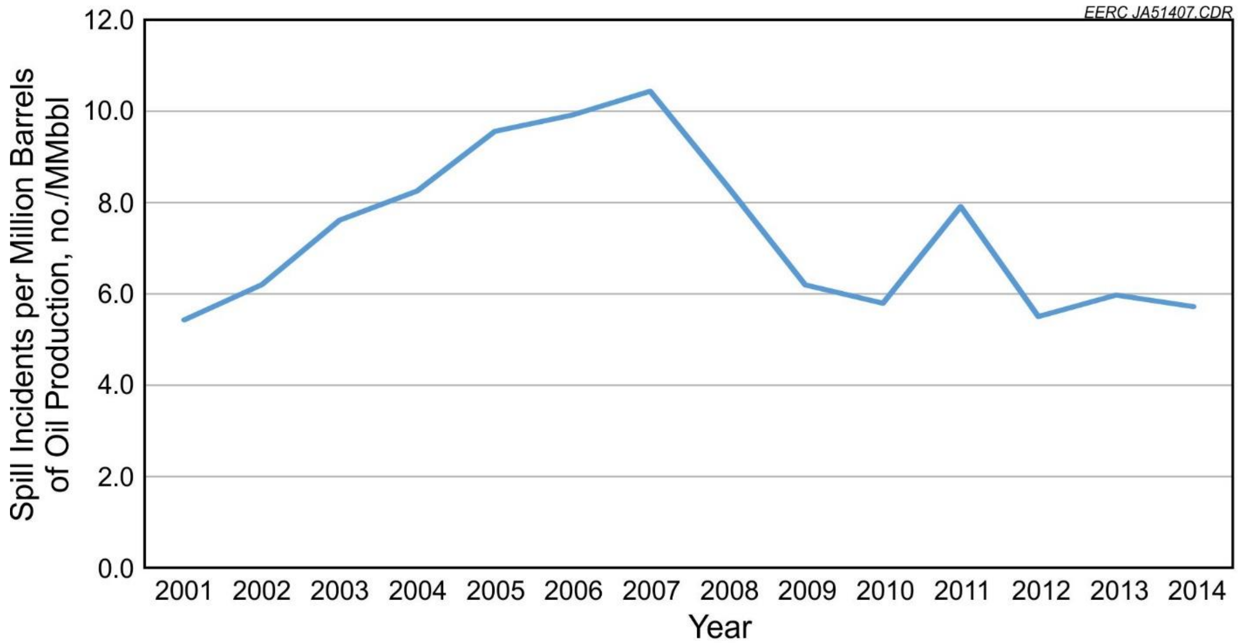


Figure 11. Total spill incidents per million barrels of oil production (2001–2014) in North Dakota.

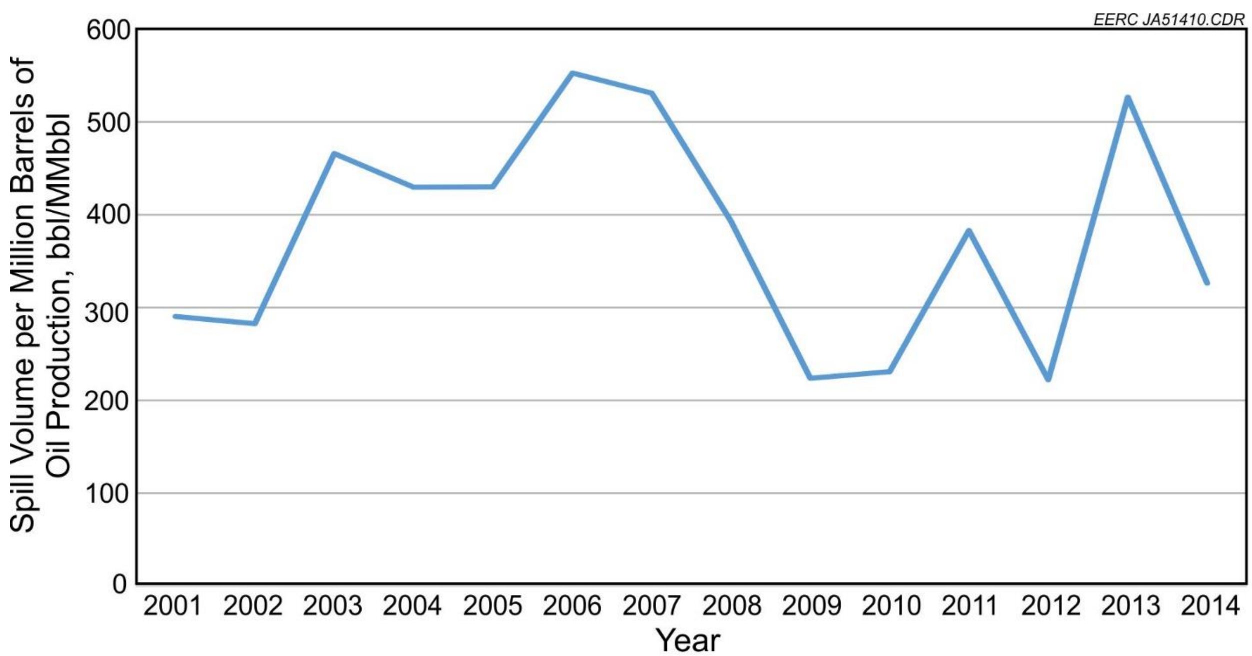


Figure 12. Total spill volume per million barrels of oil production (2001–2014) in North Dakota.

To analyze the subset of the spill data specific to pipelines, the "Type of Incident" user entry from the incident reports was utilized to isolate pipeline-related spills from the many other types. Notably, many incident reports had nonstandard entries in this field which required manually reviewing these incident reports in an attempt to categorize the type of incident. In some cases, the type could still not be identified, and these spills were labeled as undetermined. In addition, the current reporting system requires the person reporting the spill to determine which type of incident to choose, and in some cases, an incident that might be considered a "pipeline leak" was reported as a "valve/piping connection leak." Short of reviewing each incident report, every effort was made to verify that incidents were properly categorized, but it is possible that some pipeline incidents exist in the nonpipeline category.

With this in mind, a detailed summary of the type of incident breakdown for oil- and gas-related spills is presented in Table 3. In addition, the spill incident and volume data by type of incident are shown as two sets of pie charts in Figures 13 and 14, respectively. Each figure contains two pie charts representing a different time period (2001 through 2007 [pre-Bakken] and 2008 through 2014 [post-Bakken]). The data were presented this way to allow for an examination of where leaks and spills are occurring and how the cause may have changed prior to and after initial development of the Bakken Formation.

As reported in the incident reports, the data would indicate that prior to development of the Bakken, pipeline-related spills (both incidents and volume) represented a significant portion of the spills (39% and 42%, respectively). Tank overflow, tank leak, pump leak, and valve/piping connection leak were the other major contributors. During the post-Bakken period of 2008 through 2014, the "other" category has emerged as a significant contributor along with pipeline leak, tank overflow, and valve/piping connection leak. Over the entire 14-year period, the major contributors remain other, pipeline leak, tank overflow, and valve/piping connection leak.

Table 3. Summary of Total Oil- and Gas-Related Spills by Type from 2001 Through 2014 in North Dakota

	2001–2007		2008–2014		2001–2014	
Incident Type	Incidents, no.	Volume, bbl	Incidents, no.	Volume, bbl	Incidents, no.	Volume, bbl
Blowout	9	96	82	14,084	91	14,180
Fire	39	2,860	294	19,653	333	22,513
Other	89	5,770	1,417	113,876	1,506	119,646
Pipeline Leak	807	44,741	1,085	97,920	1,892	142,661
Pump Leak	122	9,630	250	7,231	372	16,861
Stuffing Box Leak	65	828	422	3,361	487	4,189
Tank Leak	169	12,757	496	35,892	665	48,649
Tank Overflow	264	13,279	1,346	47,853	1,610	61,132
Treater Leak	146	4,895	463	11,174	609	16,069
Treater Pop-Off	41	570	228	2,872	269	3,442
Truck Overflow	11	43	435	3,927	446	3,970
Undetermined	6	53	0	0	6	53
Valve/Piping Connection Leak	207	8,155	1,682	94,632	1,889	102,787
Vehicle Accident	8	529	64	2,500	72	3,029
Vessel Leak	9	228	96	20,576	105	20,804
Wellhead Leak	60	1,929	0	0	60	1,929
Total	2,052	106,363	8,360	475,551	10,412	581,914

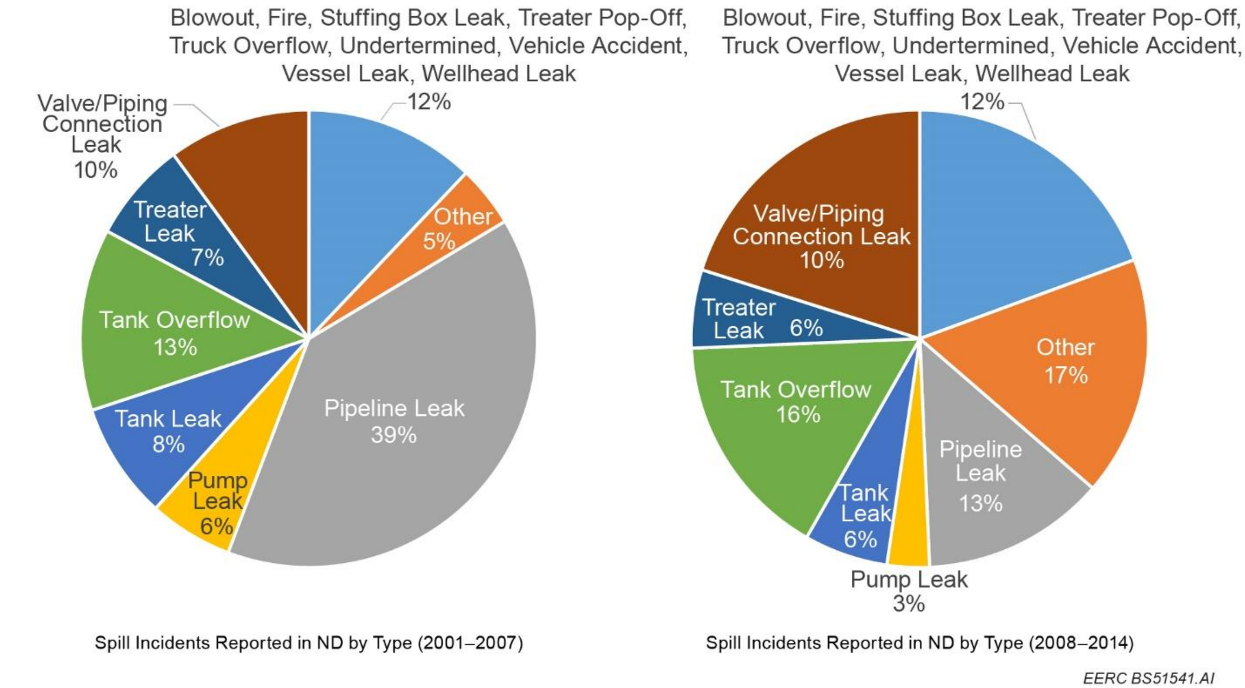


Figure 13. Comparison of reported North Dakota spill *incidents* by time periods (pre-Bakken vs. Bakken Boom).

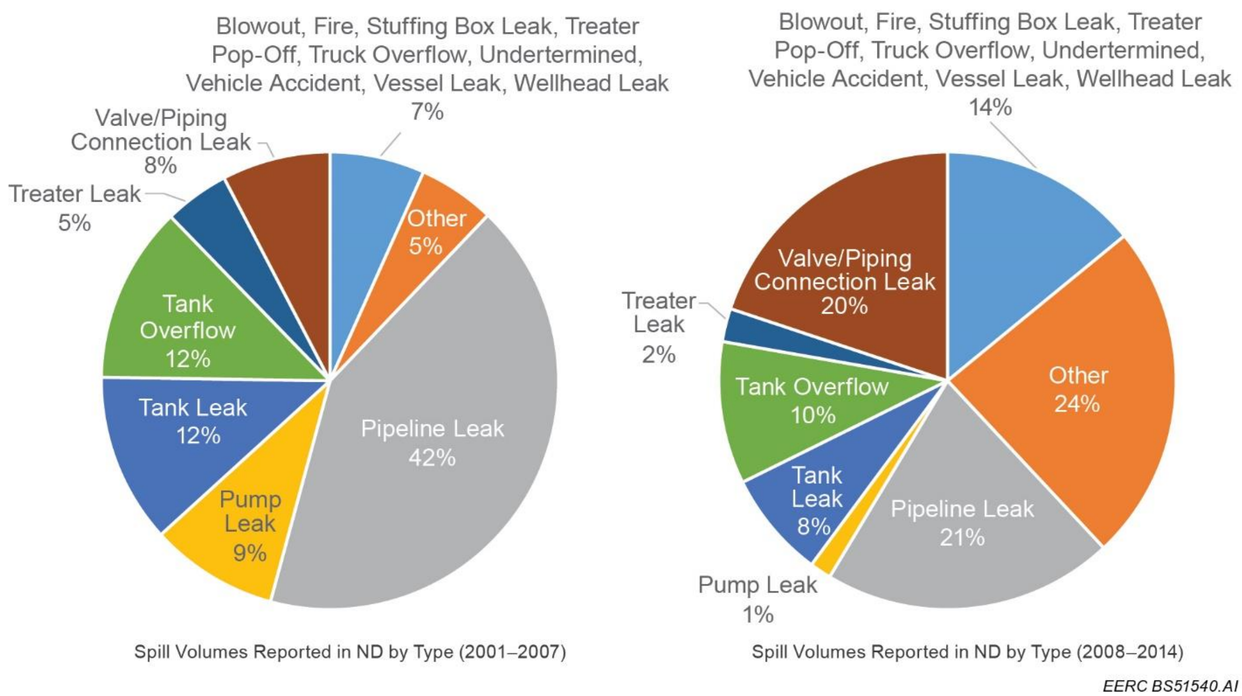


Figure 14. Comparison of reported North Dakota spill *volumes* by time periods (pre-Bakken vs. Bakken Boom).

North Dakota Pipeline-Specific Statistics

The pipeline-specific spill data were then compiled by product type and year to examine trends. These data are summarized in Table 4, and the "all liquids" pipeline spill incidents and volume data are shown in Figures 15 and 16. The orange dashed line in Figure 16 represents how the graph would look without the three large pipeline releases noted on the graph that occurred in 2013 and 2014.

Similar to the total spill data, pipeline-specific spill incidents and volume have also increased since 2001, with incidents more than doubling and volume up roughly ten times (although the volume increase is significantly skewed by the three large spills in 2013 and 2014 noted previously). The normalized graphs for pipeline-specific spills show a decreasing trend for both incidents and volume since 2001. These graphs are contained in Appendix D.

Figures 17 and 18 illustrate the pipeline spill incidents and volume graphed as a percentage of the total spill incidents and volume, and in both cases, the percentages have decreased over the 14-year analysis period. As reported in the spill incident reports, pipeline spill incidents accounted for 48% of the total spill incidents and 42% of the total spill volume in 2001, while in 2014, the pipeline spills represented 9% of the total spill incidents and 30% of the total spill volume. This

Table 4. Summary of Pipeline-Related Spills Reported in North Dakota from 2001 Through 2014

	Oil		Brine		Other		All Liquids	
Year	Incidents, no.	Volume, bbl	Incidents, no.	Volume, bbl	Incidents, no.	Volume, bbl	Incidents,[a] no.	Volume, bbl
2001	41	708	49	3140	1	1	82	3849
2002	39	253	56	2151	2	51	83	2455
2003	48	1576	63	6577	9	1099	102	9252
2004	61	631	75	3143	7	94	121	3868
2005	55	1487	78	4338	6	181	127	6006
2006	51	654	98	9048	4	231	148	9933
2007	63	1236	75	7968	5	173	144	9377
2008	60	1565	65	3896	5	178	124	5638
2009	47	677	48	2139	9	228	103	3044
2010	56	1266	60	4044	7	1035	125	6345
2011	78	1853	88	9194	14	235	170	11,282
2012	67	627	105	8397	14	773	166	9797
2013	101	21,616[b]	110	24,305[c]	18	813	198	46,734
2014	62	1739	78	31,279[d]	48	6062[e]	199	39,080
Total	829	35,887	1048	119,619	149	11,153	1892	166,660

a. Some pipeline spills involved the release of multiple products in a single incident; therefore, the total incidents are not the sum of the "oil," "brine," and "other" incidents.
b. Includes a single 20,600-barrel pipeline crude oil pipeline leak.
c. Includes a single 17,000-barrel brine pipeline leak.
d. Includes a single 24,000-barrel brine pipeline leak.
e. Includes two 2000-barrel "source water" pipeline leaks.

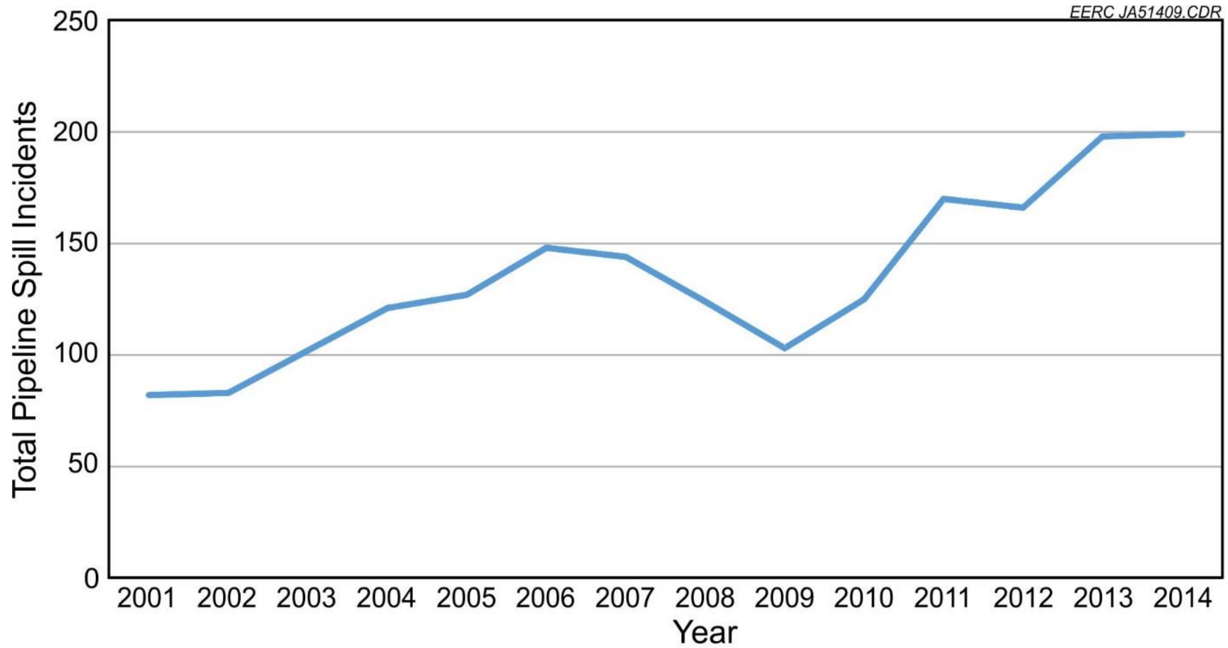


Figure 15. Reported North Dakota pipeline spill incidents from 2001 through 2014.

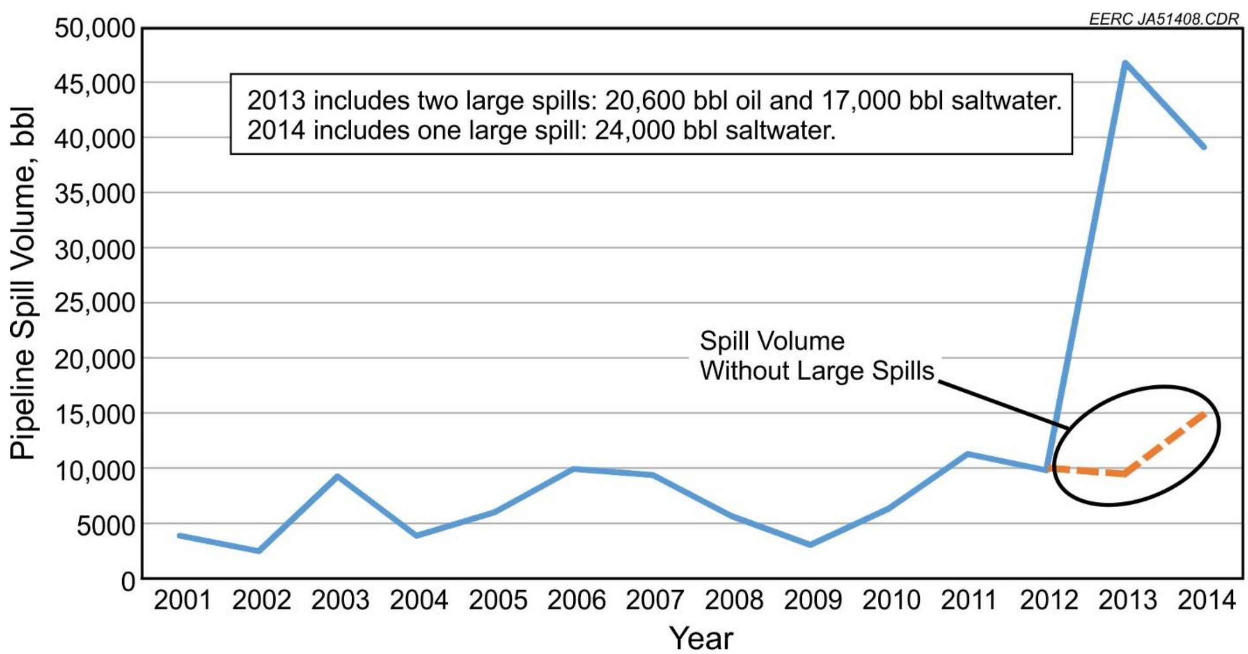


Figure 16. Reported North Dakota pipeline spill volumes from 2001 through 2014.

would indicate that pipeline-related spills have decreased over the analysis period. Caution should be exercised in drawing this conclusion as some categories, specifically "valve/piping connection leak" and "other," have increased significantly, and it is likely that some pipeline leaks were reported in these categories.

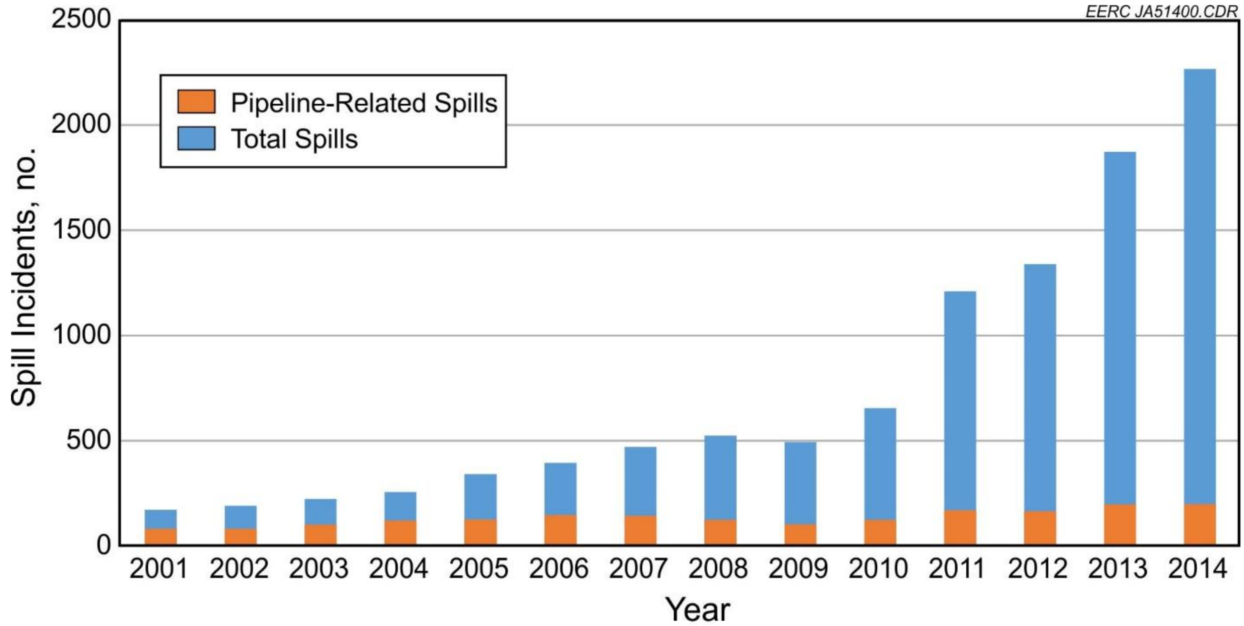


Figure 17. Reported North Dakota pipeline spill incidents in relation to total spill incidents (2001–2014).

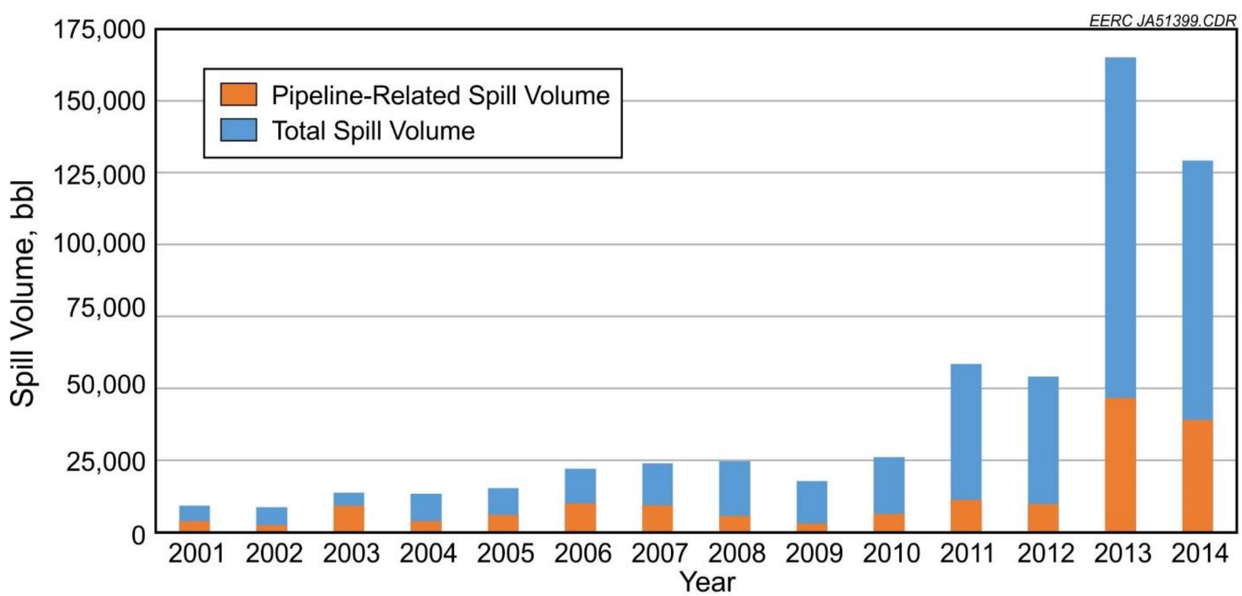


Figure 18. Reported North Dakota pipeline spill volume in relation to total spill volume (2001–2014).

Root-Cause Analysis of Pipeline Spills

Within the pipeline-specific spill data, an attempt was made to analyze the data even further to determine the cause of the pipeline spills. Although the "Root Cause of Incident" is a required field in the spill report submitted to DMR, that field is not in the Incident Summary that was used to analyze the spill data, and of the 1892 pipeline spills from 2001 through 2014, only 48 incident reports contained enough detailed information regarding the specific cause of the pipeline release to identify cause.

For those pipeline leaks where causation could not be determined from the incident report, a request was made to DMR to provide that information. Based on the data received from North Dakota DMR, the root-cause data were viewed as only marginally representative since 53% of the causes were listed as "null," "other," and "unknown" categories. Of the root-cause data that were usable, the top four causes in order were "equipment failure/malfunction" (15%), "external corrosion" (13%), "internal corrosion" (9%), and "human error" (7%).

4

Key Finding and Recommendation

Observation: Anecdotal information from pipeline operators and DMR personnel suggest the leading causes of pipeline leaks are related to third-party strikes and poor workmanship. Poor workmanship includes, but is not limited to, lack of inspection supervision, poor performance of company inspectors and third-party independent inspectors, performance of pipe joining by unqualified personnel resulting in substandard joint integrity, unwillingness to report suspect joints and other pipe damage, and lack of attention to foreign debris in trenches and during backfill.

Finding: North Dakota spill data do not substantiate nor refute observations about third-party strikes and poor workmanship. If indeed true, it is likely that errors during pipeline installations in the early Bakken development phase manifested as spills and leaks years later. The conditions described in the associated Observation that may have contributed to these incidents have largely been addressed as the pace of construction has slowed, new regulations requiring submittal of pipeline location data to the state database (NDAC 43-02-03-29) are in effect, and companies implement better practices and oversight.

Recommendation:

- As the state improves the function and utility of its incident database, the state should continue to evaluate incident data to identify root causes of pipeline failures and prioritize future guidance and/or regulations accordingly.
- The state should establish an improved data management system within state offices that streamlines spill data reporting and facilitates analysis of root causes of pipeline failures. It is further suggested that this data management system must be collaborative among several agencies with complementary reporting jurisdictions to eliminate redundant and misleading data.

The analysis of the spill data highlights the need to examine how data are collected and compiled within the spill-reporting system. All parties involved want to reduce the quantity and severity of leaks and spills, and yet it is difficult to assess where the largest problems are in the current reporting format and database structure and, therefore, even more difficult to strategically assign resources to address the issues.

Establishing an improved data management system within state offices that streamlines spill data reporting and analysis would facilitate more accurate reporting by industry, better assessment of data by stakeholders, and refinement of appropriate actions on the part of regulators. Such a system would also improve the state's ability to identify root causes and prioritize future regulations based on statistics rather than anecdotal evidence or perceived problems within the gathering industry. Such a system could also be used to track the progress of remedial responses. For these reasons, the findings of this report lead naturally to a recommendation to establish an improved data management system (Recommendation No. 4).

This improved data management system will only be successful if the state can address the litigation concerns associated with many pipeline failures. The primary obstacle presented by litigation concerns is in the area of confidentiality. The state will likely need to collect this level of data with a statutory guarantee that confidential company information will be withheld from publicly available databases to avoid conflict with the legal process in courts.

Comparing North Dakota with Other States

An effort was made to collect data on historical leak and spill statistics of the top seven oil-producing states. The top seven oil producers in the nation are listed below, in order of their 2014 annual oil production values compiled by the U.S. Energy Information Administration (EIA):

1. Texas
2. North Dakota
3. California
4. Alaska
5. Oklahoma
6. New Mexico
7. Colorado

Leaks, spills, and other releases of crude oil and produced water generally must be reported to a designated entity or entities within each state. Jurisdictional authority for reporting varies depending on the location of the leak, spill, or release. Specific rules for reporting also vary by state.

As a general rule, once a leak occurs, a report is required to be filed within a certain time period by the person or organization that owns the equipment or facility from where the leak occurred. In most instances, the information from these reports, or the report itself, is then uploaded to a central location. This information typically includes the organization responsible, human injuries or casualties if any, location of spill, volume of spill, cause of spill, etc. Availability of these reports and data from these agencies vary greatly from state to state, as well.

While data were collected for this report, it was found that spill and leak data for Oklahoma were not obtainable from the Oklahoma Corporation Commission (OCC) Web site, and subsequent requests to the OCC went unanswered. As a result, no leak and spill data for Oklahoma have been included in this study.

Annual Oil Production by State

When oil production volumes of the top seven oil-producing states in the country are compared, Texas, North Dakota, Oklahoma, New Mexico, and Colorado have had increasing oil production over the 7 years from 2008 to 2014, while California and Alaska have had a declining production trend over that same time period. These trends are shown in Figure 19. Many of these high-oil-producing states also produce significant quantities of natural gas, primarily from shale formations. Natural gas production data from 2008 through 2013 is presented in Figure 20 (2014 natural gas production data were not yet available).

Information about oil and natural gas production is important because it provides insight into the type of activity occurring in each state. In the case of California and Alaska, the oil production is primarily conventional, with relatively stable production and little to no growth of infrastructure. In contrast to this, the increase in oil production in Texas, North Dakota, Oklahoma, New Mexico, and Colorado comes from new drilling in shale formations, resulting in growing oil and natural gas production volumes and gathering pipelines and associated infrastructure. A subsequent analysis of spills of crude oil and brine has been conducted in the states with the highest oil production and where spill data were available. Since spill reporting threshold for each state varied, which was likely to have a direct impact on the spill incident data and would make comparing spill incident data between states difficult, only spill volume data were compiled and analyzed for state comparison in the following sections.

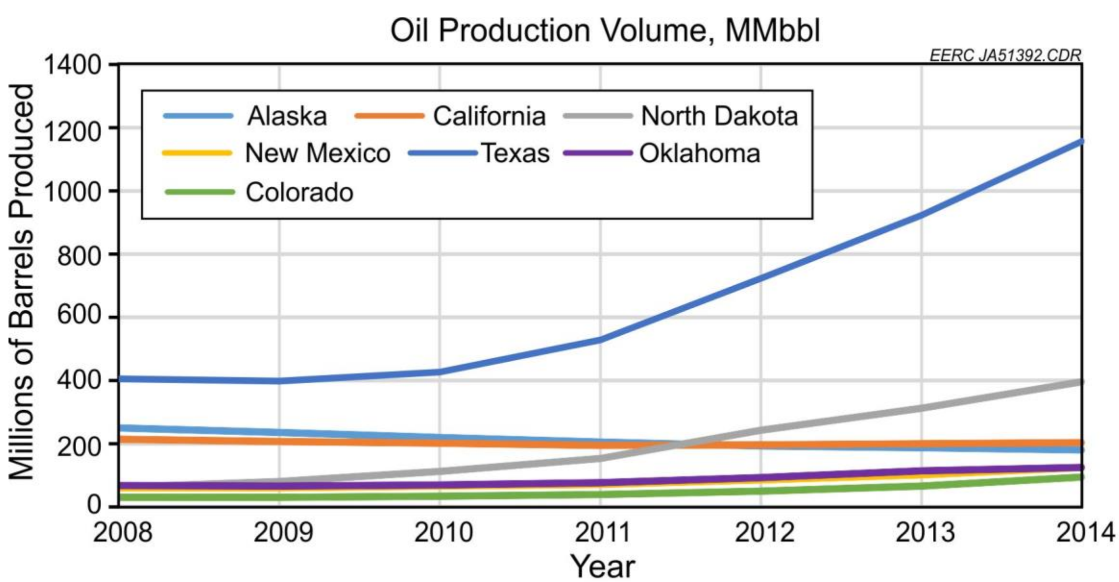


Figure 19. Comparison of annual crude oil production volume by state.

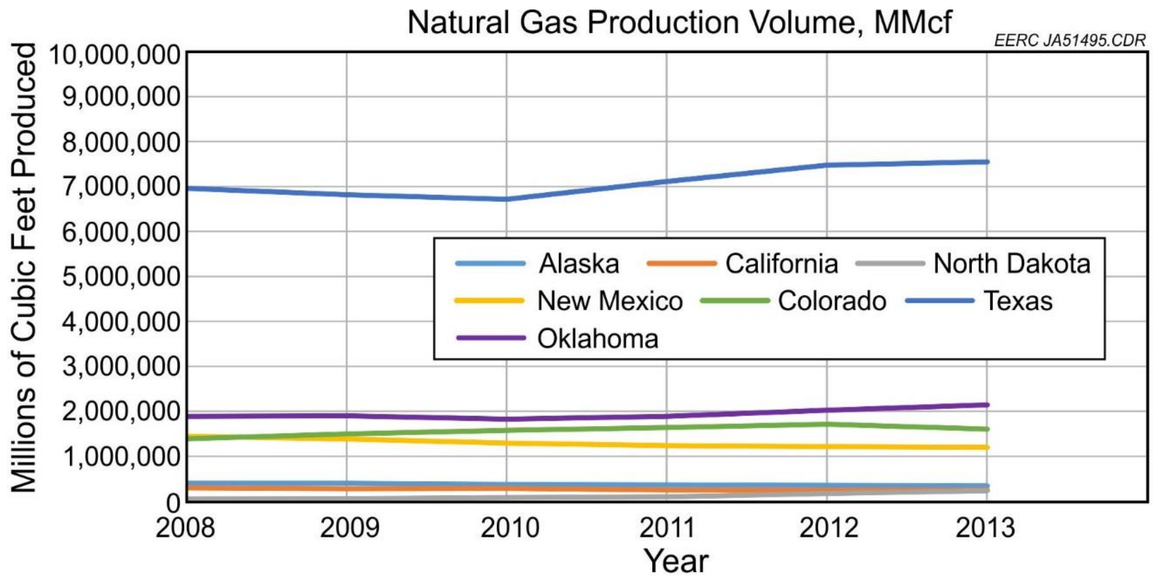


Figure 20. Comparison of natural gas production volume by state.

Spill Reporting Requirements by State

Texas (Texas Administrative Code, 2015; Texas Commission on Environmental Quality, 2014)

Texas requires operators to provide immediate notice of a fire, leak, spill, or break on land by phone or telegraph. It further requires that this be followed by a letter giving a full description of the event including, but not limited to, the volume of product lost. Other information that needs to be specified is the exact location of the spill and steps taken to remedy the situation. If the loss of crude oil is less than 5 barrels, loss reporting is not required, although a spill of crude oil directly on water must be reported as long as the quantity is enough to create sheen on the water.

North Dakota (North Dakota Department of Health, 2009, 2015; North Dakota Department of Mineral Resources, 2012)

In the state of North Dakota, no notification or reporting is required if the leak, spill, or release is less than 1 barrel of total volume and remains on-site (on location) of a facility. Verbal notification must be made immediately after the discovery has been made and must be followed up with an initial notification report within 24 hours. No specific minimum quantity for mandatory reporting of spills has been established for spills that occur off-site (off location), but all incidents with potential impact to human safety, water of the state (either surface water or groundwater), or other impacts to the environment must be reported.

California (California Governor's Office of Emergency Services, 2014, 2015)

In the state of California, a discharge of crude oil greater than 1 barrel on land must be reported immediately upon knowledge of the release. In certain San Joaquin Valley oil fields, 5 barrels or more of an oil spill must be reported if it is not contained, and 10 barrels or more must be reported if it is contained provided they do not create a threat to state waters. If the crude oil is released in federal waters or California state waters, any quantity of spill must be reported immediately.

Alaska (Alaska Department of Environmental Conservation, 2015b)

In the state of Alaska, spills of 1 to 10 gallons must be recorded in a spill-reporting log that is submitted once a month. Spills of more than 10 gallons but less than 55 gallons must be reported within 48 hours after the person has knowledge of the spill. Spills in excess of 55 gallons must be reported immediately. If crude oil is spilled to water, it must be reported immediately, irrespective of volume spilled.

5

Key Finding and Recommendation

Observation: Other states reviewed in this study prescribe a range of minimum reporting thresholds for reportable crude oil and produced water spills. North Dakota's reporting threshold is among the lowest, requiring reporting for all spills greater than 1 barrel for spills contained on location and no minimum for spills that are off location (where all spills are reported).

Finding: North Dakota has among the lowest minimum reporting thresholds of the top seven oil-producing states. This creates the potential to skew the comparison of spills between states with higher reporting thresholds, making it appear that North Dakota has more spills than other oil-producing states.

Recommendation: The state of North Dakota should recognize the impact the minimum reporting threshold has on spill statistics and evaluate accordingly how to interpret and report these data.

New Mexico (New Mexico Energy, Minerals and Natural Resources Department, 2015)

In the state of New Mexico, an unauthorized release of 5 barrels, but not more than 25 barrels, must be reported within 15 days of the spill being discovered. Spills in excess of 25 barrels must be reported by an immediate verbal notice within 24 hours after discovery of the spill. Additionally, a written notification must be provided within 15 days of spill discovery.

Colorado (Colorado Oil & Gas Conservation Commission, 2015)

In the state of Colorado, a spill needs to be reported within 24 hours of discovery in an "Initial Report" if it meets one of the following conditions: any quantity released into water, a spill of 1 barrel or more outside a berm, or a spill of 5 barrels or more regardless of whether it occurred in a berm.

The initial report needs to be followed up by a detailed report no more than 10 calendar days after the initial report was submitted.

Spill Statistics by State

Texas

Information for all oil- and gas-spills in Texas was collected from the Railroad Commission of Texas (RRC) (2015) and is summarized in Table 5. Crude oil, gas well liquids, or associated product loss reports are available for download on the RRC Web site (Railroad Commission of Texas, 2015). RRC only makes data available for crude oil spills. The Web site does not provide any information regarding brine spill incidents or brine spill volumes.

Data files for each of the years from 2009 to 2014 were obtained from the RRC Web site while data for 2008 were obtained separately from RRC officials. In the data files, annual information was sorted according to the "Type Liquid." The number of reports for "Crude" values was calculated and reported as "Spill Incidents" for that particular year. The values reported under "Gross Loss" for crude were summed and reported as "Spill Volume" for that specific year. It was assumed that all of the volumes reported were in barrels since the data reporting form used barrels as the only unit in which spills could be reported.

Table 5. Texas Production and Spill Data (Railroad Commission of Texas, 2015; U.S. Energy Information Administration, 2015f, g)

Year	Number of Spill Incidents		Volume of Spills		Annual Crude Oil Production	Annual Natural Gas Production	Oil Spill Incidents/ Oil Production	Oil Spill Volume/ Oil Production	Brine Spill Incidents/Oil Production	Brine Spill Volume/Oil Production
	Crude Oil	Brine	Crude Oil	Brine						
			bbl	bbl	MMbbl[1]/yr	Bcf[2]/yr	no./MMbbl	bbl/MMbbl	no./MMBOE[3]	bbl/MMBOE
2008	739	NA[4]	91,010	NA	406	6961	1.82	224.16	NA	NA
2009	548	NA	42,230	NA	399	6819	1.37	105.84	NA	NA
2010	629	NA	78,086	NA	427	6715	1.47	182.87	NA	NA
2011	723	NA	61,002	NA	529	7113	1.37	115.32	NA	NA
2012	781	NA	59,143	NA	724	7476	1.08	81.69	NA	NA
2013	1033	NA	75,455	NA	924	7545	1.12	81.66	NA	NA
2014	1036	NA	62,034	NA	1157	NA	0.90	53.62	NA	NA

[1] Million barrels.
[2] Billion cubic feet.
[3] Million barrels of oil equivalent.
[4] Not available.

North Dakota

Information for all oil- and gas-related leaks and spills in North Dakota was collected from the NDDH Web site (2015) and is summarized in Table 6. Spills were recorded either in the General Environmental Incidents or the Oilfield Environmental Incidents database, depending upon whether the spill was on-site at an oil production facility or off-site. Crude oil and brine spill data were collected from the Oilfield Environmental Incidents and the General Environmental Incidents separately. Redundant data were then eliminated. Individual reports quantified spilled oil volumes, spilled saltwater volumes, and spilled other contaminant volumes.

As discussed earlier in this section when North Dakota data were described in detail, accessibility to spill data is quite onerous in the existing data management system, and data quality and accuracy are questionable.

Since there is no minimum reportable volume for off-location spills, all spills of any quantity are reported. This very likely explains why the number of spills reported in North Dakota trends higher than other states that have a minimum amount of crude oil spilled after which the spill is reported.

Table 6. North Dakota Production and Spill Data (North Dakota Department of Health, 2015; U.S. Energy Information Administration, 2015e, f)

Year	Number of Spill Incidents		Volume of Spills		Annual Crude Oil Production	Annual Natural Gas Production	Oil Spill Incidents/Oil Production	Oil Spill Volume/Oil Production	Brine Spill Incidents/Oil Production	Brine Spill Volume/Oil Production
	Crude Oil	Brine	Crude Oil	Brine						
			bbl	bbl	MMbbl/yr	Bcf/yr	no./MMbbl	bbl/MMbbl	no./MMBOE	bbl/MMBOE
2008	279	234	7858	15,043	63	52	4.43	124.73	3.26	209.45
2009	272	204	5654	10,378	80	59	3.40	70.68	2.35	119.34
2010	330	258	6749	14,809	113	82	2.92	59.73	2.03	116.45
2011	611	389	12,540	23,805	153	97	3.99	81.96	2.29	140.23
2012	680	536	14,528	30,564	243	172	2.80	59.79	1.96	111.74
2013	1057	687	35,330	52,161	313	236	3.38	112.88	1.94	147.12
2014	1160	855	19,660	71,345	396	NA	2.93	49.65	NA	NA

California

Information for all oil- and gas-related leaks and spills in California was collected from the California Governor's Office of Emergency Services (Cal OES) (2015) and is summarized in Table 7. The data available on the Cal OES Web site characterize all spills called into the Cal OES Warning Center from 1993 to 2014. Data for each of the years between 2008 and 2014 were extracted from records available on this Web site.

Based on the information in the files, it was understood that an individual spill incident reported up to three components of the spilled substance. To collect crude oil spill incident numbers and crude oil spill volumes, all reports with "crude" in the spill type description were separated. The separated data were then counted for incident numbers. It was found that volumes of crude spilled were reported in varying range of units. Volumes for crude oil spilled were then all converted to barrels, summed, and reported as being the crude oil spill volume. In many cases, for a particular crude oil spill report, a second type of liquid—"2. Type"— was reported and was smaller in volume. This second substance was, in most cases, reported as "Produced water." 2. Type liquids were also converted to barrels, summed, and added to the tally of produced water spill volumes for that particular year. This process was repeated for produced water (brine) and 2. Type in produced water which was typically found to be crude oil, and the number was added to the tally of crude oil spill volumes of that particular year.

Table 7. California Production and Spill Data (California Governor's Office of Emergency Services, 2015; U.S. Energy Information Administration, 2015b, f)

Year	Number of Spill Incidents		Volume of Spills		Annual Crude Oil Production	Annual Natural Gas Production	Oil Spill Incidents/Oil Production	Oil Spill Volume/Oil Production	Brine Spill Incidents/Oil Production	Brine Spill Volume/Oil Production
	Crude Oil	Brine	Crude Oil	Brine						
			bbl	bbl	MMbbl/yr	Bcf/yr	no./MMbbl	bbl/MMbbl	no./MMBOE	bbl/MMBOE
2008	234	50	3873	4347	214	296	1.09	18.10	0.19	16.37
2009	178	38	9007	2153	207	277	0.86	43.51	0.15	8.45
2010	166	30	2253	1573	201	287	0.83	11.21	0.12	6.27
2011	136	33	2562	3547	194	250	0.70	13.21	0.14	14.95
2012	140	61	2465	5163	197	247	0.71	12.51	0.25	21.53
2013	156	85	1161	2516	199	236	0.78	5.83	0.35	10.38
2014	136	47	1971	7625	204	NA	0.67	9.66	NA	NA

Alaska

Information for all oil- and gas-related leaks and spills in Alaska was collected from the Alaska Department of Environmental Conservation Division of Spill Prevention and Response (DSPR) (2015a, b) and is summarized in Table 8. Annual data summaries for leaks and spills have been provided for the years 2008–2014. It is important to note that for the state of Alaska, no raw data were available as it was with other states. Instead, a summarized report is provided annually by the state. It is also important to note that Alaska reports all leaks and spills over a fiscal year, not a calendar year as with all other states.

Annual reports contain information divided into an overall summary of spill products and individual summaries of crude oil, non-crude oil, hazardous substances, and process water. The crude oil subsection contains information for the total number of spills reported and the total volume of crude oil spilled in gallons. To get data for the volume of brine spilled, data from the process water section were used. The process water section of the report contains information for the volume of water released by product in percentages which were used in calculating the volume of the produced water (brine) for that specific year. The report contains no information for calculating the number of produced water (brine) spills in a specific year.

Table 8. Alaska Production and Spill Data (Alaska Department of Environmental Conservation Division of Spill Prevention and Response, 2015a, b; U.S. Energy Information Administration, 2015a, f)

	Number of Spill Incidents		Volume of Spills		Annual Crude Oil Production	Annual Natural Gas Production	Oil Spill Incidents/Oil Production	Oil Spill Volume/Oil Production	Brine Spill Incidents/Oil Production	Brine Spill Volume/Oil Production
Fiscal Year	Crude Oil	Brine	Crude Oil	Brine						
			bbl	bbl	MMbbl/yr	Bcf/yr	no./MMbbl	bbl/MMbbl	no./MMBOE	bbl/MMBOE
2008	59	30	238	2023	250	398	0.24	0.95	0.09	6.35
2009	66	18	76	3111	235	397	0.28	0.32	0.06	10.24
2010	57	27	673	1372	219	374	0.26	3.07	0.10	4.84
2011	40	29	358	7	205	365	0.20	1.75	0.11	0.03
2012	39	60	258	318	192	351	0.20	1.34	0.24	1.26
2013	47	61	35	412	188	338	0.25	0.19	0.25	1.67
2014	47	70	277	2297	181	NA	0.26	1.53	NA	NA

New Mexico

Information for all oil- and gas-related leaks and spills in New Mexico was obtained from the New Mexico Energy, Minerals and Natural Resources Department of Oil Conservation Division (2015) and is summarized in Table 9. A spill search was used to locate data for specific leaks and spills.

To collect data for spill incidents, a date range for the entire year was entered and processed. For collecting information for crude oil spills, in the spill information section, in the drop-down menu for the spill material, crude oil was selected. After the search with the above attributes was performed, the results were filtered. The total number of spills reported were the spill incidents for the specific year. The volumes spilled for each report were summed and reported as the crude oil volume spilled for the specific year. A similar process was conducted for produced water spill statistics; however, in the drop-down menu for the spill material, produced water was selected.

Table 9. New Mexico Production and Spill Data (New Mexico Energy, Minerals and Natural Resources Department of Oil Conservation Division, 2015; U.S. Energy Information Administration, 2015d, f)

Year	Number of Spill Incidents		Volume of Spills		Annual Crude Oil Production	Annual Natural Gas Production	Oil Spill Incidents/Oil Production	Oil Spill Volume/Oil Production	Brine Spill Incidents/Oil Production	Brine Spill Volume/Oil Production
	Crude Oil	Brine	Crude Oil	Brine						
			bbl	bbl	MMbbl/yr	Bcf/yr	no./MMbbl	bbl/MMbbl	no./MMBOE	bbl/MMBOE
2008	196	361	11,117	45,126	60	1446	3.27	185.28	1.17	145.10
2009	237	450	8956	48,670	61	1383	3.89	146.82	1.67	180.53
2010	191	453	5100	32,027	65	1292	2.94	78.46	1.57	111.14
2011	200	436	6469	33,970	71	1237	2.82	91.11	1.53	119.35
2012	256	493	10,210	50,573	85	1215	3.01	120.12	1.67	171.53
2013	298	524	13,916	55,144	101	1195	2.95	137.78	1.70	179.34
2014	392	784	13,740	81,753	124	NA	3.16	110.81	NA	NA

Colorado

Information for all oil- and gas-related leaks and spills in Colorado was obtained from the Colorado Oil & Gas Conservation Commission (2015) and is summarized in Table 10. A report is available online that gives data for the volume of oil and brine spilled from 1999 to 2015. Although the report includes cumulative data for incident numbers, separate data for the number of crude oil spills and brine spills are not included in the report. An attempt was made to retrieve information for the number of crude oil spills and brine spills but was not readily available. As a result, this information has not been included in Table 10.

Table 10. Colorado Production and Spill Data (Colorado Oil & Gas Conservation Commission, 2015; U.S. Energy Information Administration, 2015c, f)

Year	Number of Spill Incidents		Volume of Spills		Annual Crude Oil Production	Annual Natural Gas Production	Oil Spill Incidents/Oil Production	Oil Spill Volume/Oil Production	Brine Spill Incidents/Oil Production	Brine Spill Volume/Oil Production
	Crude Oil	Brine	Crude Oil	Brine						
			bbl	bbl	MMbbl/yr	Bcf/yr	no./MMbbl	bbl/MMbbl	no./MMBOE	bbl/MMBOE
2008	NA	NA	3195	71,959	30	1389	NA	106.50	NA	237.36
2009	NA	NA	2787	22,213	30	1499	NA	92.90	NA	76.94
2010	NA	NA	3279	33,647	33	1578	NA	99.36	NA	110.35
2011	NA	NA	3286	33,801	39	1638	NA	84.26	NA	105.11
2012	NA	NA	4503	14,678	49	1709	NA	91.90	NA	42.66
2013	NA	NA	3948	14,296	65	1605	NA	60.74	NA	41.79
2014	NA	NA	2441	17,857	94	NA	NA	25.97	NA	NA

Comparisons … Putting North Dakota's Pipeline Leak Record in Context

Crude Oil Spill Volumes

For each state, crude oil spill volumes were calculated as a percentage of the total volume of crude oil produced from 2008 through 2014. Table 11 summarizes these data. The orange bars within cells of the table depict the relative magnitude of the spills as a percentage of oil production and are intended to give the reader a quick and intuitive way to determine the rankings between states as well as the trending performance of a state from year to year. For example, Texas had the highest percentage of oil spills in 2008, but the largest bar in 2014 is New Mexico, indicating it had the highest oil spill percentage among other states in that year. A similar analysis was performed for the brine spills later in this section, with one difference. For the brine analysis, BOE was used as the "normalizing" factor to account for the fact that in some states brine is also produced from natural gas wells, and if the analysis had been performed normalizing with annual oil production, the results would have been artificially higher.

An examination of Table 11 shows that the volume of oil spilled tends to correlate with the volume of oil produced. This results in increasing volumes of oil spilled for Texas, North Dakota, New Mexico, and Colorado and decreasing volumes spilled in California and Alaska. Figure 21 shows the spilled oil volume for each state from 2008 through 2014.

Table 11. Oil Spill Quantities by State*

			2008	2009	2010	2011	2012	2013	2014
Texas	Oil produced	bbl	406,000,000	399,000,000	427,000,000	529,000,000	724,000,000	924,000,000	1,157,000,000
	Oil spilled	bbl	91,010	42,230	78,086	61,002	59,143	75,455	62,034
	%		0.022	0.011	0.018	0.012	0.008	0.008	0.005
North Dakota	Oil produced	bbl	63,000,000	80,000,000	113,000,000	153,000,000	243,000,000	313,000,000	396,000,000
	Oil spilled	bbl	7858	5649	6729	12,703	14,644	35,330	19,645
	%		0.012	0.007	0.006	0.008	0.006	0.011	0.005
California	Oil produced	bbl	214,000,000	207,000,000	201,000,000	194,000,000	197,000,000	199,000,000	204,000,000
	Oil spilled	bbl	3873	9007	2253	2562	2465	1161	1971
	%		0.002	0.004	0.001	0.001	0.001	0.001	0.001
Alaska	Oil produced	bbl	250,000,000	235,000,000	219,000,000	205,000,000	192,000,000	188,000,000	181,000,000
	Oil spilled	bbl	238	76	673	358	258	35	277
	%		0.000	0.000	0.000	0.000	0.000	0.000	0.000
New Mexico	Oil produced	bbl	60,000,000	61,000,000	65,000,000	71,000,000	85,000,000	101,000,000	124,000,000
	Oil spilled	bbl	11,117	8956	5100	6469	10,210	13,916	13,740
	%		0.019	0.015	0.008	0.009	0.012	0.014	0.011
Colorado	Oil produced	bbl	30,000,000	30,000,000	33,000,000	39,000,000	49,000,000	65,000,000	94,000,000
	Oil spilled	bbl	3195	2787	3279	3286	4503	3948	2441
	%		0.011	0.009	0.010	0.008	0.009	0.006	0.003

* Orange bars within cells of the table depict the relative magnitude of the spills as a percentage of oil production.

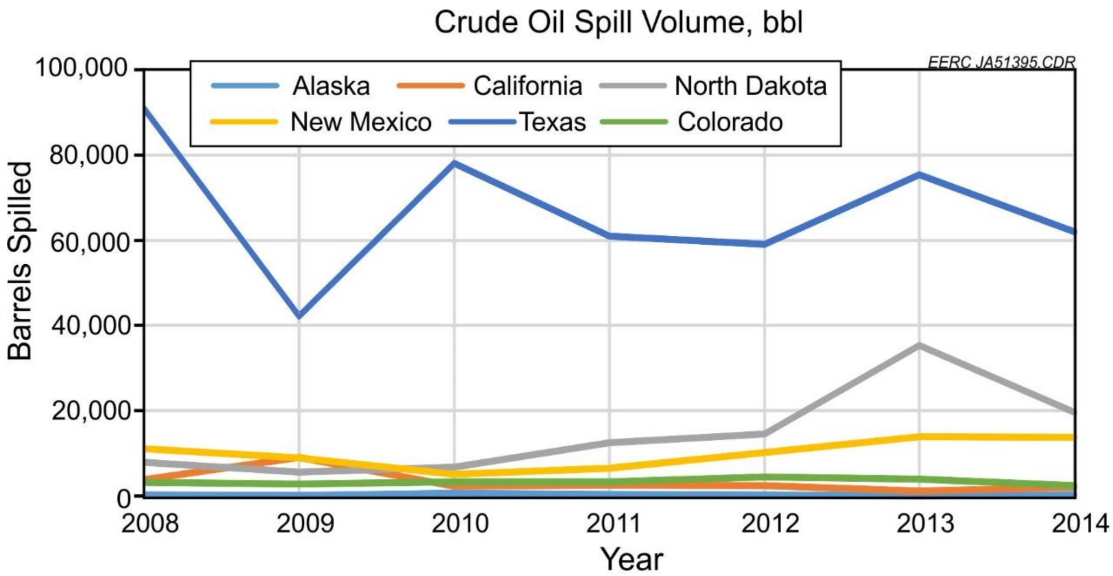


Figure 21. Comparison of crude oil spill volumes by state.

Although important information, the raw oil spill statistics only provide a partial picture of how the states compare. To further evaluate performance among states, the oil spill volumes percentage, which is oil spill volumes as a function of oil production, from Table 11 was graphed and is presented in Figure 22. From this figure, it is clear that states with increasing oil production during the analysis period had higher oil spill volume percentages than states with stagnant or declining oil production. The states with increasing oil production (Texas, North Dakota, New Mexico, and Colorado) are states with active shale plays being produced, and states with declining oil production (California and Alaska) are producing almost exclusively from traditional formations.

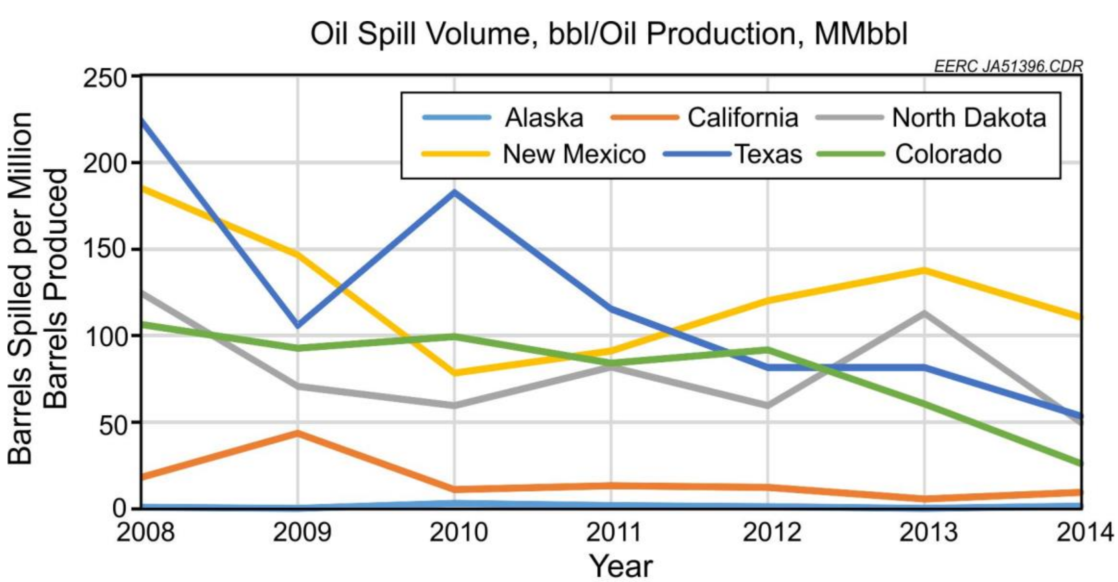


Figure 22. Comparison of normalized crude oil spill volumes by state.

Comparing data from 2008 through 2014, North Dakota performed at par or better than the other shale play states. Table 12 provides values for normalized crude oil spill volumes and incidents for the beginning and the end of the 7 years being analyzed in addition to the average over 7 years.

Table 12. State Comparison of Normalized Crude Oil Spill Volume and Incidents

		Texas	North Dakota	California	Alaska	New Mexico	Colorado
bbl/MMbbl	2008	224.16	124.73	18.1	0.95	185.29	106.5
	2014	53.62	49.65	9.66	1.53	110.81	25.97
	Average	120.74	79.91	16.29	1.31	124.34	80.23
Incidents/MMbbl	2008	1.82	4.43	1.09	0.24	3.27	NA
	2014	0.9	2.93	0.67	0.26	3.16	NA
	Average	1.3	3.41	0.81	0.24	3.15	NA

Brine Spill Volumes

Brine spill volume data were compiled and analyzed using BOE as the normalizing factor. These results are presented in Table 13 and Figure 23. Comparing states on the basis of brine spill volume as a percentage of BOE should provide better context to evaluate performance between states. This comparison is shown in Figure 24. Since brine spill data were not available for the state of Texas, information has not been included here.

In addition to the potential impact that natural gas production has on spill statistics, formation production characteristics will likely impact the brine statistics, as some states are known to produce more water with their oil and gas than other states. This phenomenon, although acknowledged to exist, was beyond the scope of this study.

Table 13 provides a summary of the normalized brine spill volumes and incidents for the beginning and the end of the 6 years being analyzed as well as the average over 6 years. The analysis period for brine is 6 instead of 7 years since natural gas production data (used in the BOE calculation) were not yet available for 2014.

Table 13. Brine Spill Quantities by State*

			2008	2009	2010	2011	2012	2013	2014
Texas	Oil produced	bbl	406,000,000	399,000,000	427,000,000	529,000,000	724,000,000	924,000,000	1,157,000,000
	Brine spilled	bbl	NA	NA	NA	NA	NA	NA	NA
	%		NA	NA	NA	NA	NA	NA	NA
North Dakota	Oil produced	bbl	63,000,000	80,000,000	113,000,000	153,000,000	243,000,000	313,000,000	396,000,000
	Brine spilled	bbl	15,043	10,378	14,809	23,805	30,564	52,161	71,345
	%		0.024	0.013	0.013	0.016	0.013	0.017	0.018
California	Oil produced	bbl	214,000,000	207,000,000	201,000,000	194,000,000	197,000,000	199,000,000	204,000,000
	Brine spilled	bbl	4347	2153	1573	3547	5163	2516	7625
	%		0.002	0.001	0.001	0.002	0.003	0.001	0.004
Alaska	Oil produced	bbl	250,000,000	235,000,000	219,000,000	205,000,000	192,000,000	188,000,000	181,000,000
	Brine spilled	bbl	2023	3111	1372	7	318	412	2297
	%		0.001	0.001	0.001	0.000	0.000	0.000	0.001
New Mexico	Oil produced	bbl	60,000,000	61,000,000	65,000,000	71,000,000	85,000,000	101,000,000	124,000,000
	Brine spilled	bbl	45,126	48,670	32,027	33,970	50,573	55,144	81,753
	%		0.075	0.080	0.049	0.048	0.059	0.055	0.066
Colorado	Oil produced	bbl	30,000,000	30,000,000	33,000,000	39,000,000	49,000,000	65,000,000	94,000,000
	Brine spilled	bbl	71,959	22,213	33,647	33,801	14,678	14,296	17,857
	%		0.240	0.074	0.102	0.087	0.030	0.022	0.019

* Green bars within cells of the table depict the relative magnitude of the spills as a percentage of oil production.

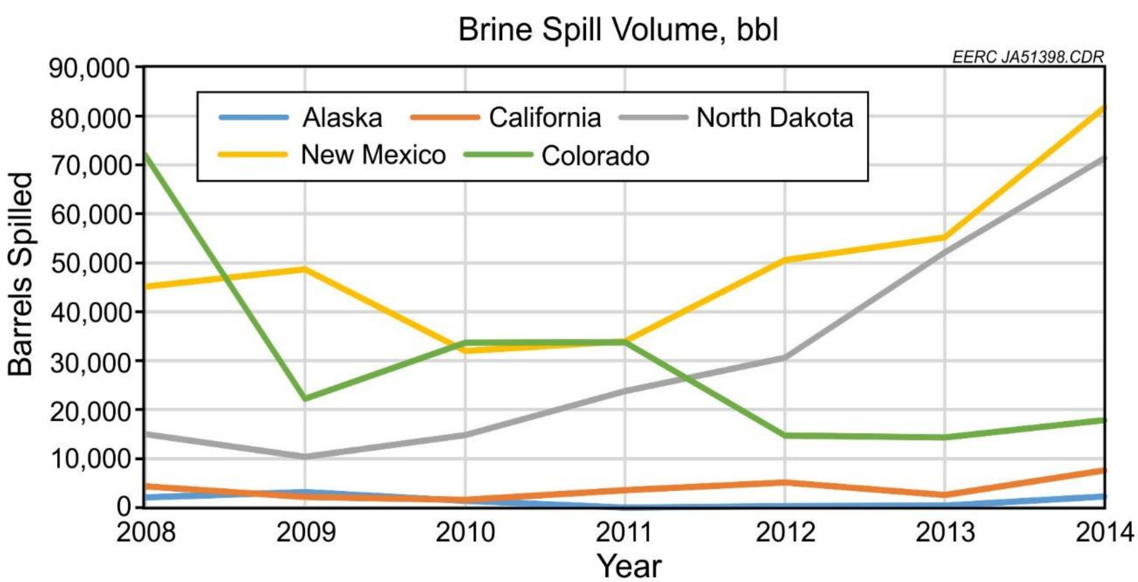


Figure 23. Comparison of brine spill volumes by state.

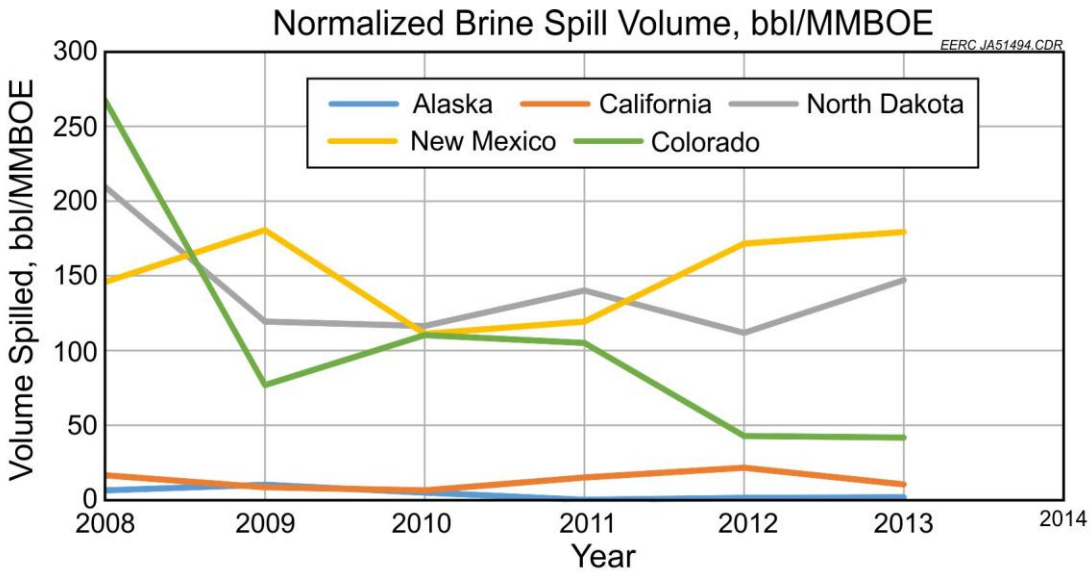


Figure 24. Comparison of normalized brine spill volumes by state.

Oil and Brine Incident and Production Analysis

In summary, a comparison of spill data from the top six oil-producing states provides some valuable insight as to the performance of North Dakota in relation to its peers:

- States with growing oil production have more oil and brine spills than states with little or no growth in production.
- Crude and brine spill incident data are difficult to compare as states have different minimum spill reporting thresholds, which has a direct impact on the number of spills reported.
- Although rankings vary from year to year, over the analysis period (2008–2014), North Dakota's normalized oil spill volume is consistent with other shale play states analyzed.
- Regarding normalized brine spill volume, North Dakota is similar to other shale play states analyzed until recent years when Colorado has greatly improved.

REGULATORY ENVIRONMENT FOR GATHERING OF PRODUCED FLUIDS

Today's Regulatory Framework

Comparison of North Dakota Regulations to Those of Other Large Oil-Producing States and PHMSA

Federal and State Jurisdictions

The federal government, through PHMSA, has statutory authority over the transportation of hazardous liquids like crude oil or petroleum products through pipelines. The federal rules are provided in CFR, Title 49 "Transportation," Parts 190–199. Typically, PHMSA regulates interstate gas pipelines and intrastate and interstate hazardous liquid pipelines but does not regulate most gathering pipelines, unless they are located in high-consequence areas (HCAs) such as heavily populated areas, navigable waterways, or areas unusually sensitive to environmental damage.

Although PHMSA maintains responsibility for inspecting and enforcing federal regulations in some cases, states may be authorized to perform these duties. In North Dakota, this function is provided by the North Dakota PSC. Additionally, state pipeline safety offices are allowed to issue regulations supplementing or extending federal regulations for pipelines contained entirely within its border, provided such requirements are no less stringent than the minimum federal regulations. PHMSA pipeline regulations are generally deemed minimum thresholds.

Regulatory Comparison among States

Gathering pipelines transporting crude oil and produced water from production locations to a rail terminal or brine disposal facility do not fall under federal jurisdiction. Each state has the ability to regulate these gathering lines as they deem appropriate. Some states have no regulations pertaining to gathering pipelines. Others defer to CFR or guidance from API, ASME, or others. Some states implement requirements more extensive than federal regulations on various aspects of pipeline design, installation, operation, and maintenance.

For many states, regulations are a complex mixture of federal and state rules administered by different agencies. In the course of this study, pipeline-related regulations were reviewed from seven states with the highest oil production. For the purpose of comparison, these regulations have been compiled in Tables 14–20. While some states give in-depth detail about requirements of pipelines, other states do not, deferring instead to the standards provided in 49 CFR 195 as required by PHMSA.

Not all state rules have been captured in the tables below. Rather, these tables serve as a summary of those most relevant to pipelines. For each state summary, regulations for pipelines have been separated into four distinct sections: construction, corrosion prevention and mitigation, spills, and materials.

Texas

Table 14. Summary of Texas Liquids Gathering Pipeline Regulations

Category	Summary of Regulations
Construction	An operator is required to inform at least 30 days prior to the commencement of construction of the originating and terminating points of the pipeline, counties traversed, size and type of pipe used, type of service, design pressure, and length of pipe (TAC T 16-P 1-C 8-S/C B-R §8.115).* Each pipeline operator is required to maintain most current records for 5 years as required by 49 CFR Parts 195 and 199. The records that are maintained are required to include information such as design calculations, pipeline specification, minimum yield strengths, information regarding all pipeline constructions, trainings, inspections regarding welding, hydrostatic tests, etc. (TAC T 16-P 1-C 8-S/C B-R §8.105).
Corrosion Prevention and Mitigation	Operators are required to ensure that all metallic pipelines being installed have sufficient corrosion control. It is required that all pipelines be tested for adequate coating on pipelines and fittings, have adequate cathodic protection (CP), and exceed the minimum criteria of NACE Standard RP-01-69 (TAC T 16-P 1-C 8- S/C D-R § 8.305). TAC – Title 16 – Part 1 – Chapter 3 – Oil and Gas Division provide specific requirements for fire protection, check valves, CP wells, etc. (TAC T 16-P 1-C3). TAC establishes minimum standards of accepted good practice with respect to operation and maintenance, corrosion control, etc., that refer to 49 CFR 195 (TAC T 16-P 1-C8-S/C B-R §8.101).
Spills	It is required that soil exposed to a spill of crude oil be remediated according to the guidelines given in TAC T 16-P 1-C 3-R §3.91. TAC gives details on how spills should be reported and as to how any reclamation is done after the occurrence of a spill. Spill notifications must be made immediately or within 2 hours of the discovery to give full details of the spill including, but not limited to, the company or operator name, location of the spill, time and date of the spill, steps taken to remedy the situation, quantity spilled, other damage caused, etc. A report is required only if the loss exceeds 5 barrels. Leaks must be reported by 49 CFR 195.50 and 195.52. An additional report must be submitted within 30 days (TAC T 16-P 1-C 3-R §3.20) (TAC T 16-P 1-C 8-S/C D-R§ 8.301).
Materials	The material for the pipe and components should be able to maintain structural integrity of the pipeline under temperature and environmental conditions that are anticipated. They should also be chemically compatible with the substance they carry and with which they are in contact. In general, TAC establishes minimum standards for accepted good practice that includes standards for choice of material for gathering lines as in 49 CFR 195.

*TAC – Texas Administrative Code, P – part, C – chapter, S/C – subchapter, R – rule.

North Dakota

The regulatory framework pertinent to gathering pipelines in North Dakota is contained in two main bodies of work: the North Dakota Century Code Title 38 and the North Dakota Administrative Code Title 43.

Table 15. Summary of North Dakota Liquids Gathering Pipeline Regulations

Category	Summary of Regulations
Construction	North Dakota Century Code 38-08-26 and 38-08-27 apply construction-related regulation in the following areas. "An owner or operator of an underground gathering pipeline shall submit to the commission, in a time period no longer than one hundred eighty days of putting any underground gathering pipeline into service, a shape file showing the centerline of the pipeline." In addition, "for an oil and gas underground gathering pipeline that is in service after August 1, 2011, and before August 1, 2013, the owner or operator or most recent owner or operator shall submit, within eighteen months from August 1, 2013, shape files for all existing underground gathering pipelines, including any known abandoned pipeline." For underground gathering pipeline that is designed or intended to transfer crude oil or produced water from a production facility for disposal, storage, or sale purposes and which was placed into service after August 1, 2015, the operator shall provide upon request "engineering construction design drawings and specifications, list of independent inspectors, and a plan for leak protection and monitoring for the underground gathering pipeline," and "within sixty days of an underground gathering pipeline being placed into service, the operator of that pipeline shall file with the commission an (I-37) 08/2015 independent inspector's certificate of hydrostatic or pneumatic testing of the underground gathering pipeline." North Dakota Administrative Code 43-02-03-29 also addresses underground gathering pipeline construction with only limited guidance and language. Regarding construction, "pipelines installed in a trench must be installed in a manner that minimizes interference with agriculture, road and utility construction, the introduction of secondary stresses, the possibility of damage to the pipe, and tracer wire shall be buried with any nonconductive pipes installed." Regarding backfilling, "it must be backfilled in a manner that provides firm support under the pipe and prevents damage to the pipe and pipe coating from equipment or from the backfill material." North Dakota Administrative Code 43-02-03-29 also describes the GIS reporting requirements from Century Code 38-08-26 highlighted above.
Corrosion Prevention and Mitigation	No pipeline monitoring or corrosion mitigation measures are required by rule in North Dakota for gathering pipelines.
Spills	North Dakota Administrative Code 43-02-03-30 addresses spills in the following manner. "All persons controlling or operating any well, pipeline, receiving tank, storage tank, or production facility into which oil, gas, or water is produced, received, stored, processed, or through which oil, gas, or water is injected, piped, or transported, shall verbally notify the director immediately and follow up utilizing the online initial notification report within 24 hours after discovery of any fire, leak, spill, blowout, or release of fluid."
Materials	No materials guidance is required by rule in North Dakota for gathering pipelines.

California

Details for instructions on construction, monitoring/mitigation, spills, and pipeline materials have been given in the California Government Code (CGC).

Table 16. Summary of California Liquids Gathering Pipeline Regulations

Category	Summary of Regulations
Construction	According to the CGC, the State Fire Marshal maintains a centralized database for all intrastate pipelines that includes information of the location, age, reported leak incidences, inspection history, etc. The information should have the capability to be mapped and should be compatible with any pipeline mapping project to provide information for GIS mapping and data management (CGC 51017). According to CGC, every operator of intrastate pipelines must conform to 49 CFR 195 (CGC 51012.3). In addition, Title 14 of the California Code of Regulations (CCR) requires newly installed pipelines to be designed, constructed, tested, operated, and maintained in accordance with practices and standards set forth in either API, ASTM, 49 CFR 192, or other methods approved by the Supervisor (CCR Title 14, Division 2, Chapter 4, Subchapter 2, Article 3, 1774).
Corrosion Prevention and Mitigation	According to CGC, in addition to other rules and regulations, all pipelines must be tested in accordance with 49 CFR 195 Subpart E. Pipelines must be equipped with pressure relief, CP, pressure relief devices, etc. Pipelines which normally operate under conditions of constant flow also need to include means of leak detection according to CGC 51013. Depending on the presence of CP, pipelines are required to be pressure-tested every 3, 5, or 10 years. Additionally, a pipeline that previously leaked will be added to a list of higher-risk pipelines which will be subject to a test at least every 2 years for 5 years (CGC 51012.3). In general, every operator of pipelines must conform to 49 CFR 195 (CGC 51012.3). CCR Title 14, Division 2, Chapter 4, Subchapter 2, Article 3, 1774.1 requires visual inspection of aboveground pipelines at least once a year. In addition, 1774.1 requires mechanical integrity testing on all active environmentally sensitive gathering pipelines and all urban pipelines greater than 4 inches in diameter every 2 years. Pipelines less than 10 years old are exempt from this requirement. CCR Title 14, Division 2, Chapter 4, Subchapter 2, Article 3, 1774.2 requires operators to prepare a pipeline management plan summarizing pipeline type, grade, installation date, pressures, history, and testing method among other things.

Continued…

Table 16. Summary of California Liquids Gathering Pipeline Regulations (continued)

Category	Summary of Regulations
Spills	Any rupture, explosion, or fire involving a pipeline must be reported immediately even if the spill was a result of a pressure test. A spill of less than 5 barrels is not considered a rupture for the purposes of reporting (51018). In an oil discharge to land including onshore drilling, exploration, or a production operation, a discharge of 1 barrel or more must be reported immediately upon knowledge of the spill according to California Public Resources Code 3233. In an oil discharge to land including onshore drilling, exploration, or a production operation, a discharge of 5 barrels or more uncontained in certain San Joaquin Valley oil fields, if no threat to state waters, and 10 barrels or more contained in certain San Joaquin Valley oil fields must be reported immediately according to California Water Code Section 13272. In general, in every operator of pipelines must conform to 49 CFR 195 (CGC 51012.3). In addition, Title 14 of the CCR requires development of a spill contingency plan (CCR Title 14, Division 2, Chapter 4, Subchapter 1, Article 3, 1722.9).
Materials	Every pipeline operator must conform the pipeline to 49 CFR 195 and, as a result, should conform to the design requirements in Subpart C of CFR that address the minimum design requirements of pipelines.

Alaska

Table 17. Summary of Alaska Liquids Gathering Pipeline Regulations

Category	Summary of Regulations
Construction	The Alaska Administrative Code (AAC) gives great details about the kind of information that must be provided when an application is made for a ROW lease. Applications for ROW must be submitted with information including, but not limited to, point of origin and termination, length, map of proposed pipeline, proposed ROW, width of corridor, nature of substance being transported, diameter of pipe, size of pipe, transportation capacity, estimated life of pipeline, etc. (11 AAC 80.005). In addition to the requirements by the AAC, minimum safety standards of 49 CFR 195 are required to be met.
Corrosion Prevention and Mitigation	It is required that the operator must comply with one of the following standards: ASME B31.3-2004, ASME B31.4-2002, or ASME B31.8-2003. It is also required by the AAC that pipelines be equipped with CP and coating and be checked visually for leaks, etc. (18 AAC 75.080). Every pipeline operator must conform to 49 CFR 195 for leak detection and mitigation.
Spills	Title 18 of AAC, Chapter 75, Article 3 gives detailed guidelines on discharge reporting, cleanup, and disposal of oil and other hazardous substances. When a spill occurs, the operator must notify the department and provide information including, but not limited to, the date and time, location, name and owner of the facility, name of the responsible person, type of substance released, cause, amount, action taken, etc., about the release of any substance. If the release is in excess of 55 gallons to land outside of a secondary containment area, immediate notification must be made. If the release is in excess of 10 gallons, but less than 55 gallons, to land outside of secondary containment and a release is in excess of 55 gallons within the secondary containment area, a notification must be made within 48 hours. Additionally, an operator must maintain a monthly written record of releases of 1 to 10 gallons. Spills must be reported within 15 days (18 AAC 75.300).
Materials	In addition to other detailed requirements under 18 AAC 75.047, pipelines need to meet the following standards: ASME *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids* (American Society of Mechanical Engineers, 2002); ASME *Gas Transmission and Distribution Piping Systems* (American Society of Mechanical Engineers, 2003); and other equivalent and nationally recognized standards adopted by the department etc. (18 AAC 75.047). AAC has also given details on facility piping that should also meet the following standards: ASME *Process Piping* (American Society of Mechanical Engineers, 2004); ASME *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids* (American Society of Mechanical Engineers, 2002); ASME *Gas Transmission and Distribution Piping Systems* (American Society of Mechanical Engineers, 2003); etc. (18 AAC 75.080). In addition to the above-mentioned requirements in AAC, every pipeline operator must conform to 49 CFR 195 for leak detection and mitigation. All individuals must also be in compliance with 49 CFR 199 related to drug testing.

Oklahoma

Table 18. Summary of Oklahoma Liquids Gathering Pipeline Regulations

Category	Summary of Regulations
Construction	The OCC requires that the operator notify them within 7 days prior to commencement of construction, to include name of operator, address, and contact information; date of construction to begin and end; map showing route of proposed pipeline, pipeline specification; maximum operating pressure (MOP) and design pressure, type of CP, depth of pipeline, location of equipment etc. (Oklahoma Administrative Code [OAC] 165:20-5-32).
Corrosion Prevention and Mitigation	In general, the OCC establishes minimum standards for accepted good practice that includes standards for choice of material for gathering lines, as in 49 CFR 195.
Spills	Under gas and hazardous liquid pipeline safety in OAC 165:20-5-11, 12, 13, and 14, spills need to be reported by telephone at the earliest practicable moment, but no more than 1 to 2 hours following the discovery with the name of the operator of the pipeline, location of the incident, time of the incident, number of fatalities if any as a result of the incident, and all other significant facts about the incident. This should be followed by a report no more than 30 days after the discovery of the incident using DOT PHMSA Form F 7100.2, 7000-1; OAC 165:20-5-11; OAC 165:20-5-12; OAC 165:20-5-13; and OAC 165:20-5-14. Under prohibition of pollution in OAC 165:10-7-5, all operators must report a spill within 24 hours of discovery if larger than 10 bbl or any quantity if it is released in water. A written or oral report must be submitted within 10 days with the location of the spill, facility name, date of occurrence, volume of substance spilled, type of material spilled, method of cleanup, volume recovered, etc. (OAC 165:10-7-5). Each operator must report according to 49 CFR 191.5, 191.7, 191.9, 191.11, 191.13, 191.15, and 191.17. Each operator must submit antidrug results pursuant to 49 CFR 199.
Materials	In general, the OCC establishes minimum standards for accepted good practice that includes standards for choice of material for gathering lines, as in 49 CFR 195.

New Mexico

Table 19. Summary of New Mexico Liquids Gathering Pipeline Regulations

Category	Summary of Regulations
Construction	The New Mexico Public Regulation Commission requires that, prior to the construction of any intrastate pipeline of a value $50,000 or more, the operator must give a notice to construct with information on the pipeline material, finished diameter, length, approximate location of the pipeline, the size and capacity of any compressors or pumps, and the approximate completion date (New Mexico Administrative Code [NMAC] 18.60.2.9). In addition to the above-mentioned regulation, New Mexico has adopted the CFR for pipeline safety and, as a result, adopts 49 CFR 195.
Corrosion Prevention and Mitigation	The New Mexico Public Regulation Commission establishes minimum standards for accepted good practice that includes standards for choice of material for gathering lines, as in 49 CFR 195 (NMAC 18.60.2.8).
Spills	In the state of New Mexico, an unauthorized release of 5 barrels, but not more than 25 barrels, must be reported within 15 days of the spill being discovered. Spills in excess of 25 barrels must be reported by an immediate verbal notice within 24 hours after discovery of the spill. Additionally, written notification must be provided within 15 days of the spill discovery (NMAC 19.15.29.8). Since New Mexico conforms to PHMSA regulations, all reporting is done in accordance with 49 CFR 195 (NMAC 18.60.2.8).
Materials	All materials are chosen according to 49 CFR 195 (NMAC 18.60.2.8).

Colorado

Table 20. Summary of Colorado Liquids Gathering Pipeline Regulations

Category	Summary of Regulations
Construction	The Colorado Oil and Gas Conservation Commission (COGCC) states that pipelines should be covered under a minimum of 3 feet on cropland to prevent damage unless there is a written agreement between surface owner or other uncontrollable conditions. When backfill is done, soil should be replaced to its original relative positions. Reasonable effort must be taken to run pipelines parallel to crop irrigation rows on flood-irrigated land (COGCC Rule 1100). In addition to the rules set forth by COGCC, since Colorado is under PHMSA jurisdiction for pipeline safety, 49 CFR 195 applies in addition to COGCC Rule 1100.
Corrosion Prevention and Mitigation	Each component should be designed so that it withstands corrosion and can withstand other operating conditions: external and internal loadings. Lines must be pressure-tested to maximum anticipated operating pressure. Precautions must be taken to protect all employees while a pressure test is conducted. One should be conducted every year. Each operator is required to take reasonable precautions to prevent failures, leakage, and corrosion of pipelines. If a fault is found, it should be fixed in reasonable time (COGCC Rule 1100).
Spills	Spills must be reported in an "initial report" within 24 hours of discovery. Spills of any volume should be reported if released to water. A spill or release of 1 barrel or more outside of a berm must be reported. A spill of 5 barrels or more regardless of whether contained by a berm must be reported. The initial report must include, at a minimum, the location of the spill and any information about the type of spill and the volume of the spilled substance. If an initial report is not made, a report must be made within 72 hours. If an initial report is made, a supplemental report should be made with greater detail, including a topographical map, aerial photograph of the location of the spill, and all other steps taken to mitigate the spill, no more than 10 days after the initial report is submitted. Notification of the spill must be made to the surface owner, local government, and appropriate environmental agency. Spills must be remediated according to Rule 906 and 907 (COGCC Rule 906).
Materials	Material for the pipe and other components of the pipe should be able to maintain the structural integrity of the pipeline under temperature, pressure, and other conditions that may be anticipated compatible with the substance transported and locatable by a tracer line or a location device placed adjacent to or in the trench of all buried nonmetallic pipelines to facilitate the location of such pipelines (COGCC Rule 1100).

Potential Changes in Federal Gathering Line Regulations

In response to the Enbridge accident in 2010, PHMSA published an Advanced Notice of Proposed Rule Making (ANPRM) in the *Federal Register* on October 18, 2010. Subsequent legislation included provisions relevant to regulating hazardous liquid pipelines in 2011. Shortly after, the National Transportation Safety Board (NTSB) released an investigation report that included recommendations to PHMSA regarding detection of pipeline cracks and discovery of pipeline condition (threats).

On October 13, 2015, PHMSA published a Notice of Proposed Rule Making (NPRM) into the *Federal Register* (80 FR 61610) proposing to make further changes to the hazardous liquids safety regulations in direct response to NTSB recommendations. However, more relevant to the current study, the Government Accounting Office (GAO) also issued a recommendation in 2012 concerning hazardous liquid and gas gathering pipelines. Recommendation GAO-12-388, dated March 22, 2012, states “To enhance the safety of unregulated onshore hazardous liquid and gas gathering pipelines, the Secretary of Transportation should direct the PHMSA Administrator to collect data from operators of federally unregulated onshore hazardous liquid and gas gathering pipelines, subsequent to an analysis of the benefits and industry burdens associated with such data collection.” The purpose of this recommended effort is to collect data to assess safety performance and pipeline risk from gathering systems. These data will determine if there is a need to extend PHMSA regulations to gathering lines in exempted rural areas. Interested parties have until January 8, 2016, for submitting comments.

Analysis

A review of comparable state regulations reveals that North Dakota’s regulatory framework is currently less detailed than that of other comparable states. Following is a summary of the contrasts between North Dakota’s regulatory framework governing liquid gathering pipelines and that of other comparable states whose rule summaries are presented in Tables 14–20.

6

Key Finding and Recommendation

Observation: Fluid properties and operating conditions of liquid gathering lines differ significantly from pipeline to pipeline. Ensuring that the pipeline selected for each application can withstand these operating conditions is critical to ensuring safe operation.

Finding: Most of the states reviewed have regulations requiring that gathering pipelines can withstand the operating conditions of the gathering system and have appropriate chemical compatibility. Many refer to 49 CFR 195 as a basis for regulation.

Recommendation: North Dakota should consider adopting regulations on pipeline material selections, as has been done in comparable oil-producing states.

- Material Selection: Other comparable states include regulatory language regarding selection of pipeline materials appropriate for the environments found in the state. Although many operators in North Dakota already follow appropriate standards, it may benefit North Dakota to stipulate a known and accepted standard to ensure that all industry entities are adhering to these best practices. Many other states already address material requirements in their state regulations. Key Finding and Recommendation No. 6 addresses this issue.

- Spills Reporting: Other comparable states include regulatory language that stipulates minimum thresholds that trigger spill reporting to avoid misleading statistics stemming from reporting of miniscule, insignificant spills of small quantities and spills within engineered containment areas. Key Finding and Recommendation No. 5 already addresses this issue.

- Mitigation of Contributing Factors of Leaks: Other comparable states include regulatory language that mandates employment of best practices for maintenance, corrosion control, and pressure testing. North Dakota may benefit from considering inclusion of regulatory language addressing maintenance and corrosion control. Other states simply make reference to practices found in 49 CFR 195 Part H to address this. ASME B31.3, ASME B31.4, ASME B31.8, and NACE Standard RP-0169 may also offer guidance to North Dakota regulators. Key Finding and Recommendation No. 7 addresses maintenance and corrosion but specifically avoids discussion pertaining to pressure testing.

- Requirement of Prior Notification of Construction: Other comparable states include regulatory language requiring pipeline operators to provide advance notice to the state regulatory bodies of intent to construct new gathering lines. This notice helps to inform the state and provides another inspection point to ensure proper construction procedures are planned and executed.

Key Finding and Recommendation 7

Observation: Other large oil-producing states include regulatory language regarding maintenance and corrosion control. North Dakota does not currently include language constraining maintenance and corrosion control practices to best practices.

Finding: North Dakota may benefit from inclusion of regulatory language addressing maintenance and corrosion control. 49 CFR 195, ASME B31.3, ASME B31.4, ASME B31.8, and NACE Standard RP-01-69 all offer language and concepts that may be considered for any new regulations in North Dakota on these topics.

Recommendation: State regulators should address maintenance and corrosion control best practices in any new regulations.

This study cannot, however, recommend specific periodic pressure-testing procedures as other states have done. The pressure-testing requirement is too material- and design-specific to be broadly addressed by blanket regulations. Instead, if materials and construction standards are adequately employed, this will naturally lead to system-specific recommendations for pipeline pressure-testing procedures and schedules. What must be considered in these pressure-testing approaches is the risk induced by repeated pressure testing of both steel and plastic pipelines. Again, materials and construction standards will drive this risk assessment.

8

Key Finding and Recommendation

Observation: Other comparable oil-producing states include regulatory language that demands prior notification of construction, including design information (size, material, operating pressure, design pressure, depth, installation protocols, etc.), and routing information.

Finding: North Dakota pipeline safety may be enhanced by ensuring that state regulators have advance notice of key design features associated with new liquid gathering pipelines. This information would serve to generally inform the state, provide data for postincident analysis of root cause of failures, and permit the state to have a baseline upon which inspections can be measured.

Recommendation: North Dakota DMR should consider developing a requirement to provide notice of intent to install liquid gathering pipelines 30 days prior to installation of said pipelines. The advance notice should include design information (size, material, operating pressure, design pressure, depth, installation protocols, etc.) and routing information.

MATERIAL SELECTION FOR CRUDE OIL AND PRODUCED WATER GATHERING PIPELINES

Plastic Pipeline Materials

Pipelines for moving liquids and gas have been in use for thousands of years. Initially, they were made of hollowed wood or bamboo sealed with mud. Once smelting technologies were developed, metals began to be used because of their superior strength and ability to seal more completely. In 1821, the first pipeline to carry natural gas from a natural seep to a Lake Erie lighthouse was built to provide fuel to the lighthouse flame. This pipeline was made of wood, but by the 1820s, cast iron was becoming the preferred material for larger pipelines in the United States. In the 1800s, steel was adopted as a pipeline material, especially after 1885 when seamless steel pipe was invented (Miesner and Leffler, 2006). In the 1950s, HDPE was developed and first used as a pipeline material. Since then, many other plastic materials have been developed and used in pipeline systems.

The following discussion is meant to provide background information on materials currently used in liquids gathering pipelines. It is not the intent of this discussion to identify superior or inferior pipeline materials because many factors influence the type of pipeline material chosen, such as operating conditions and cost that must be considered for each particular system. Additionally, because of the tremendous opportunities afforded by the onset of the shale oil revolution, the field of pipeline technology is rapidly changing. New materials, new configurations of existing products, and new options for existing products are constantly evolving. As such, the information contained in this section is intended as preliminary guidance only.

Plastics are materials composed of resins (polymers) and additives. Two types of plastics are often used in engineering applications: thermosets and thermoplastics. Thermoset resins like epoxy or polyester start as a liquid that is polymerized with the addition of a curing compound. Epoxy is often used as a coating material for steel pipes or as the matrix material that is strengthened with glass fibers in fiberglass pipe. Thermosets soften upon heating but cannot be reformed by melting the way that thermoplastics can. However, their maximum use temperatures are usually higher than for thermoplastics.

Thermoplastics are the most commonly used piping material. Thermoplastics soften upon heating, then regain their original properties when cooled. Therefore, the maximum use temperature is an important factor in determining the strength of the material required for an application. This property allows many of the thermoplastics to be heat fusion-bonded. The array of thermoplastics used in piping includes polyvinyl chloride (PVC), chlorinated polyvinyl chloride (CPVC), polyethylene (PE), high-density polyethylene (HDPE), acrylonitrile butadiene styrene (ABS), polypropylene (PP), and nylon. Most thermoplastics have good chemical resistance, except to strong oxidizing acids or aromatic organic compounds.

Erosion of pipeline materials, including steel, is also an issue if the line carries a fluid contaminated with solid particles. Erosion is caused both by impact of small particles that can chip off small pieces of the pipeline material and by abrasion as the particles are dragged along the surface. Abrasion failures occur in both liquid and gas pipelines, but abrasion in gas lines can be hundreds of times higher for a given particle loading (Larsen and Reichert, 2003) than in a liquid line because the liquid acts as a lubricant to reduce the abrasiveness of the particles.

Key Finding and Recommendation

9

Observation: Plastic pipeline fillers are powders of solid materials that are added to plastics. They can be highly variable depending on the product and manufacturer.

Finding: The type and size of the fillers can significantly affect the erosion resistance of the plastic.

Recommendation: Companies procuring pipeline should consult closely with the pipeline manufacturer for data about the erosion resistance of the manufactured parts if erosion is a possible issue in the proposed application. The company procuring the pipelines may want to ask for test evidence demonstrating erosion resistance against fluids with characteristics comparable to that expected in the field.

Abrasion resistance usually does not relate directly to hardness of the material. Several abrasion tests are described in Table 21, but it is important to note that they usually do not correlate directly to abrasion occurring in service.

Table 21. Common Pipeline Abrasion Resistance Tests

Abrasion Test	Description
ASTM D4060 (The Taber Test)	A flat panel of the material being tested is weighed and then rotated under abrasive wheels, with a 1-kilogram load, for 5000 to 10,000 cycles. The panel is weighed or measured every 1000 cycles to determine the amount of material lost (Lauer, 2012).
ASTM G75	A test fixture repeatedly slides test blocks over stationary test laps of abrasive material. An electric motor is used to move the blocks in a reciprocating manner. Weights are placed on top of the sliding blocks to produce a controlled normal force, and the blocks are moved back and forth for set periods of time. Either the reduction in thickness or weight change is used to determine the resistance to abrasion of the material. Different fluids can also be added to the surface of the test laps to determine their effects on abrasion rates.
ASTM D968	Silicon carbide grains are allowed to free-fall onto the coated surface of a metal coupon that has been secured at a 45° angle. The test measures how many liters of abrasive are required to completely penetrate a plate of the material of interest (Lauer, 2012).
Nonstandard Tests	Flowing slurries in pipes test the relative erosion resistance of HDPE to that of mild steel pipe. The weight-loss percentage of steel was found to be three to five times that of HDPE, depending upon the configuration of the system (U.S. Department of the Army, 1986). However, other tests using fertilizer abrasion showed that steel had twice the abrasion resistance of HDPE (Wingate-Hill, 1970).

A problem with data from such tests, as well as with much of the data given in the following sections, is that many different grades and types of each kind of plastic material exist. Importantly, compositions and additives can be modified by manufacturers to alter the material properties. Of particular importance in determining abrasion resistance are the types and sizes of solid filler particles that are used in the plastic. Therefore, pipeline system designs need to include specific material requirements, such as maximum temperature and pressure, required lifetime, number of pressure cycles a day, fluid composition, and others, which must be discussed with pipeline manufacturers to arrive at mutually agreed upon materials and joining methods for the specific system.

Plastic pipes that are not reinforced with a layer of stronger structural material such as fiberglass, aramid fiber, or steel have maximum pressure ratings in the hundreds of psi range depending on the diameter and thickness of the pipe. Because the pipes are extruded, they can be made in practically any diameter and thickness. For a given operating condition, the maximum pressure ratings are functions of the diameter of the pipe and its wall thickness. The ratio of the diameter of the pipe to its wall thickness is known as the standard dimension ratio (SDR) of the pipe. Because the SDR is inversely related to the wall thickness, smaller SDRs have higher pressure ratings than higher SDRs. Pipes made of the same material but with different diameters will have the same pressure ratings if their SDRs are the same. SDRs usually vary from 5 (strongest) to 17 (weakest). It should be noted that strength is also a function of temperature, with strength dropping as the temperature increases. Therefore, the maximum use temperatures listed in the following discussion are for nonpressurized service.

Material Options

PVC

PVC is the most employed plastic pipeline material in the United States, but it is mostly used for low-pressure sewage or waterlines, such as those shown in Figure 25. PVC exhibits good chemical resistance to brine and petroleum (Willoughby and others, 2002). It has higher strength and rigidity than most other thermoplastics. Type I PVC is more rigid and more brittle than Type II PVC. The maximum use temperature for PVC is 150°F (Willoughby and others, 2002), but it has a larger temperature derate than PE. PVC’s minimum installation temperature is 0°F (Plastics Pipe Institute, 1999). PVC is usually joined by solvent welding or threading, but it can be done with bell-and-spigot ends. Solvent welding is not recommended at lower temperatures, and threading is not recommended for use at high temperatures because of the strength derate, especially for pipes over 4 inches in diameter (Plastics Pipe Institute, 1999). Although PVC contains additives to stabilize it against damage by the ultraviolet portion of sunlight, it is recommended that parts exposed to sunlight be painted and unjoined sticks and fittings should be stored under an opaque tarp (Silowash, 2010).

Figure 25. PVC pipeline installation.

CPVC

CPVC exhibits many of the same properties as PVC, but it can be used at higher temperatures up to 210°F (Plastics Pipe Institute, 1999). However, it is not recommended for use with petroleum-containing fluids because of chemical resistance issues (Plastics Pipe Institute, 1999). For clean water systems, CPVC must be protected from sunlight exposure in ways similar to PVC. CPVC is joined with either one-step cement that does not require a primer or a two-step process that does require a primer.

PE

PE, shown in Figure 26, is the second most employed plastic pipeline material in the United States. PE exhibits good chemical resistance to brine and petroleum (Willoughby and others, 2002). It is weaker and less rigid than PVC at ambient temperatures but maintains superior flexibility, toughness (tolerance for abrasion and bruising), and ductility, especially at lower temperatures.

Figure 26. HDPE pipeline installation.

PE is made by polymerization of ethylene with propylene, butene, or hexene. Early PE compositions had many side branches coming off of the main molecular chain which prevented tight packing of the chains. This material is known as low-density polyethylene or LDPE. It is not often used for pipeline because of its lower strength compared to more modern versions that have fewer side chains so that the molecular chains can be more tightly packed, making the resultant HDPE considerably stronger.

The maximum use temperature for HDPE is 180°F (Plastics Pipe Institute, 1999), but it has a smaller temperature derate than PVC. The minimum installation temperature is −30°F (Plastics Pipe Institute, 1999). Because of its flexibility and chemical resistance, HDPE is sometimes used in combination with structural fiberglass or steel layers in composite spoolable pipeline materials that are much stronger than monolithic HDPE. HDPE is usually joined by heat fusion, but inserts can also be used. Heat-fused joints have the same chemical resistance as the pipe.

In the 1960s to the mid-1980s, PE pipelines developed a reputation for rapid crack propagation, a type of brittle failure. However, significant progress since then has been made to reduce that mode of failure, although caution should be used to not suddenly pressurize the pipe and to use fittings and operating procedures to minimize water hammer.

One common method of damage to HDPE pipeline reported to the EERC team occurs when a leak in a pressurized line is repaired. By leaving the line pressurized, the time for repairs is much reduced. However, the repairs are made by first compressing the HDPE line on each side of the leak to stop fluid flow using specialized clamping rigs. It has been reported to the EERC that no matter how carefully done, damage to the HDPE almost always occurs during the clamping and unclamping processes. This damage can be the source of future leaks. Therefore, the EERC suggests that repairs to all thermoplastic pipelines be done by first depressurizing and then draining the line near the breach before making an unclamped repair of the line.

PE pipes can also fail in a ductile manner known as slow crack growth, but the newer materials have significantly reduced that problem as well. However, it remains the dominant field failure mode, excluding third-party damage, for PE pipes (Plastics Pipe Institute, 2007). Slow crack growth is a crack that can develop in PE pipe, usually at a flaw or outside stress concentration, which grows slowly through the pipe wall. An example of a pipe that failed through slow crack growth is shown in Figure 27. Poor backfill, excessive surface damage, rock impingement, excessively tight bend radii, improper backfill, and other field conditions could cause localized stress concentrations resulting in slow crack growth in PE pipes.

EERC JA51387.CDR

Figure 27. An example of a pipe that failed through slow crack growth (Farshad, 2006).

10

Key Finding and Recommendation

Observation: Slow crack growth is a crack that can develop in PE pipe, usually at a flaw or outside stress concentration, which grows slowly through the pipe wall. According to the Plastics Pipe Institute, it is the dominant field failure mode, excluding third-party damage, for PE pipes.

Finding: Installation procedures prescribed by the pipeline manufacturer must be precisely followed to avoid the risk of slow crack growth and other material-related failure modes.

Recommendation: Installation crews should be thoroughly trained in all manufacturer-prescribed installation procedures and be contractually bound to use those procedures. Further, independent inspectors should have the responsibility to ensure that manufacturer specifications are precisely followed.

The Pennsylvania notch test (PENT) described in ASTM F1473 is a laboratory test method that measures relative resistance to slow crack growth. A specimen is cut from a compression-molded plaque. It is precisely notched and then exposed to a constant tensile stress at a temperature of 176°F (80°C). The time to failure is recorded, and this failure time is related to actual service life in the field. The PENT test has proven to be a very good indicator of resistance to slow crack growth in PE pipes.

Given the variability in resins used to make PE, the PE grade is commonly designated with a four digit code such as PE3408:

- The first digit designates the density of the material, with 1 being the least dense and 4 being the most dense.

- The second digit designates the resistance of the material to slow crack growth in accordance with test procedures outlined in ASTM D3350. Higher numbers mean higher resistance to slow crack growth.

- The last two numbers are the hydrostatic design stress (HDS) for the material at 73°F divided by 100. In the case of PE3408, that would be 800 psi. This is NOT the same as the maximum allowable pressure for the pipe because the maximum pressure can only be determined with pipe dimensions and allowances for various derates. An example of how this is done is given in this report in the section on spoolable reinforced plastic pipe.

The most dense, crack-resistant, and strongest modern HDPE material is PE4710.

The following is an example of the engineering benefits of PE4710 over PE3408, which was copied from Plastics Pipe Institute TN-41/2007. It uses the phrase dimension ratio (DR) which is the ratio of the diameter of the pipe to its wall thickness. It is the same as the SDR described previously.

> *There are two ways that increased hydrostatic design stress may be utilized by the water design engineer. One way is to operate the PE pipe with a particular wall thickness at a higher pressure. The other way is to operate the PE pipe at the same pressure but using a higher DR or thinner wall, which increases the inside diameter and, thus, increases the flow or capacity.*
>
> *The best way to show the impact of the new pipe material designation code PE4710 is to show the effect of the HDS on the pressure rating. Table 14* (Table 22) *shows the pressure rating (PR) for a PE4710 (using the 1000-psi HDS) compared to a PE3408 (using the 800-psi HDS) at various dimension ratios. For a given wall thickness, the PE pipe may be operated at a higher pressure when using a PE4710 material compared to a PE3408 material. For each DR, the pressure rating is about 25% higher for the PE4710 pipe, because of the higher HDS.*
>
> *Another benefit of the higher design stress for the PE4710 compared to PE3408 is to use a higher DR pipe. The higher DR (thinner wall) results in a larger inside diameter, lighter*

weight for the pipe, and lower pipe cost. A key benefit of the larger inside diameter is increased water flow capacity. Table 15 (Table 23) *shows the effect of the higher design stress for a PE4710 compared to a PE3408 operating at the same pressure. By using pipe that is one standard DR higher (for example DR17 instead of DR13.5), Table 15* (Table 23) *also shows the corresponding increase in capacity as a result of the larger inside diameter.*

Table 22. Pressure Rating (psig) Comparison Between PE4710 and PE3408 for Water Applications

	DR9	DR11	DR13.5	DR17
PE4710	252	202	161	126
PE3408	200	160	128	100

Table 23. Comparative Water Flow Increase for 1 DR Increase from PE3408 to PE4710

System Pressure	200 psig	160 psig	130 psig	100 psig
Capacity Increase	15.4%	12.0%	10.4%	7.3%

Crosslinked PE

For higher-pressure applications and where stress cracking may be an issue, crosslinked PE (PEX) can be used. PEX is a thermosetting polymer rather than a thermoplastic polymer. It is not affected by heat as much as PE is. It also has improved resistance to abrasion and chemical attack and can be used at temperatures up to 210°F (Plastics Pipe Institute, 1999). The minimum installation temperature for specialty PEs is −30°F (Plastics Pipe Institute, 1999). Threading is the most common joining technique, although crimping techniques are also used. In the United States, PEX is available with diameters of 2 inches or less.

ABS

ABS is a copolymer made from three monomers: acrylonitrile, butadiene, and styrene. It is listed as “not recommended” for use with brine and petroleum (Willoughby and others, 2002) but is often used in freshwater lines. It is a rigid plastic with good impact resistance down to 0°F and up to 180°F (Plastics Pipe Institute, 1999). The minimum installation temperature for ABS is 0°F (Plastics Pipe Institute, 1999). ABS is usually joined by solvent welding or threading.

PP

PP is listed as “conditionally resistant” to brine, so it may have a shortened lifetime when carrying produced water (Willoughby and others, 2002). Compared to HDPE, PP has a lower impact strength but superior working temperature and tensile strength. The maximum temperature for PP is 194°F (Willoughby and others, 2002). The minimum installation temperature is not listed by Plastics Pipeline Institute TN-11/99 (Willoughby and others, 2002). PP is usually joined by heat fusion, threading, or mechanical sealing (flanges).

Nylon

Nylon is the strongest of the engineering thermoplastics. However, limited information is available because spoolable nylon line pipe such as Raptor (made by Invista, a subsidiary of Koch Industries) is a new product (September 2014). Raptor nylon pipe is currently available up to 4 inches in diameter in spools up to 1000 feet. Reportedly, it will be available as 6-inch pipe in spools up to 300 feet in 2015. Larger diameters may become available in 30-foot-long sticks. Invista reports that its nylon pipe can be used at temperatures up to 200°F or up to 500 psi at room temperature. It should only be installed at temperatures above 32°F.

Joints are made by heat fusion much like HDPE. Invista says that its tests have indicated that Raptor nylon is resistant to both brine and petroleum. However, because it is a very new product, no Raptor pipelines have been installed in North Dakota as of October 1, 2015, although many have been installed in the Permian Basin (Texas).

Joining Methods

All of the engineering plastics can be joined together or to fittings using a variety of methods. Because of the stiffness of the materials, they can be joined using physical methods such as threading, flanged connectors, grooved joints, mechanical compression, or elastomeric seals. Threaded connections should be sealed using paste sealants rather than Teflon tape because the tape can deform the female fitting which can cause it to crack (Silowash, 2010). If seals are used, they must be compatible with the fluid to be carried in the pipeline.

PVC, ABS, and CPVC can also be joined through solvent welding. In that process, a one- or two-part solvent is painted on both of the male and female parts to be joined. The male end is inserted and twisted one-quarter turn to ensure adequate contact. The parts dissolve into each other and then reharden, forming very strong joints. Solvent welding should not be used between different types of plastics.

PE, PP, and nylon products are more commonly joined using thermal fusion of butt joints. In this process, shown in Figure 28, the two ends of pipe to be joined are clamped in a fusion machine and then faced so they are square and smooth. A heated plate is then brought into contact with the ends to cause them to soften and partially melt. The two ends are then brought together under force and held until the plastic cools and rehardens. During the process, a bead of melted plastic is forced up around both the inside and outside of the joint. If done correctly, the joints are stronger than the pipes themselves (Silowash, 2010).

In situations where it may be impractical to use a fusion machine, an electrofusion sleeve (shown in Figure 29) can be used to join two pieces of pipe. The sleeve has an internal diameter closely matching the external diameter of the pipes to be joined. The ends of the pipe are held together inside the sleeve, and then an electric current is passed through the sleeve, causing it to heat and fuse the inside of the sleeve to the outsides of the pipes, bonding them together. Generally, full-butt welds are considered to be superior to electrofusion sleeves (Silowash, 2010).

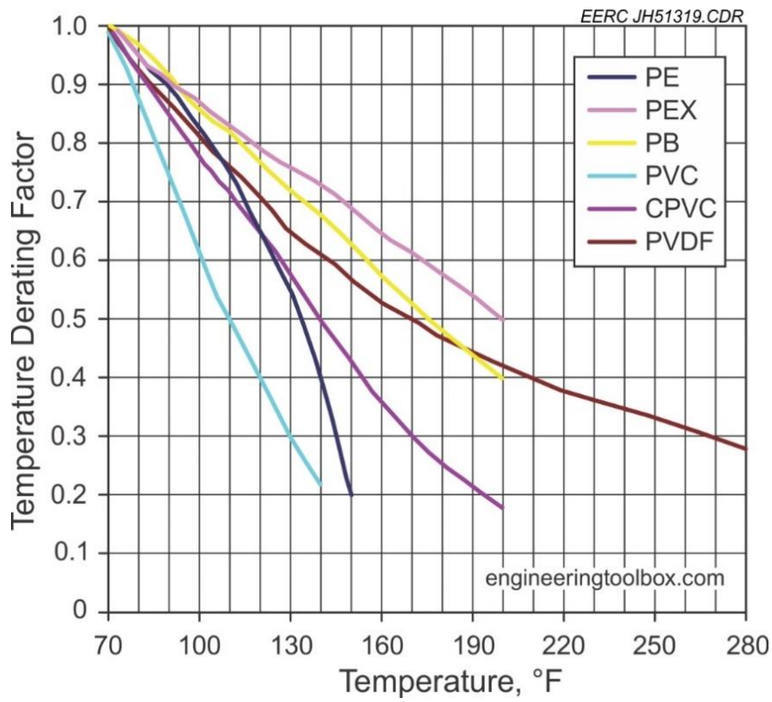
EERC JH51315.CDR

Figure 28. Thermal fusion joint.

Figure 29. An electrofusion sleeve.

Thermoplastic Temperature Derates

Thermoplastic materials lose their strength to pressure and tension with increasing temperature. Figure 30 can be used as a guide to common thermoplastics and their derated strength with temperature (The Engineering ToolBox, 2015). Actual manufacturer data should always be consulted when pipeline system designs are devised.



Note: PB is polybutylene; PVDF is polyvinylidene fluoride.

Figure 30. Plastic pipe temperature derating curves.

Reinforced Pipeline Materials

Fiberglass

Shown in Figure 31, fiberglass is a composite material that consists of a thermosetting resin matrix such as epoxy or vinyl ester that is strengthened with glass fibers. By embedding the fibers in a resin, the fibers are not able to rub against each other which could otherwise cause damage during handling. It is also known as fiberglass-reinforced thermosetting plastic pipe (FRP). If specified correctly, it can exhibit good chemical resistance to produced water. It also is much stronger and abrasion-resistant than noncomposite thermoplastic piping, having strengths into the thousands of psi, but it is usually much more brittle than thermoplastics. The primary negative effect of this brittleness is known in the field as "bruising" which can occur if the pipe is not handled correctly. Bruised fiberglass actually introduces small flaws into the reinforced resin matrix and may create a flaw at which pipe failure can be initiated.

Figure 31. Fiberglass pipeline segments.

A variant of FRP known as cold-exposure piping is tested by cooling it to −29°F and dropping it 6 feet to the pavement, after which it must pass a leakage test (Fiberglass Tank & Pipe Institute, 2013). It can also be used at temperatures of up to 275°F and has a lower-temperature derate than thermoplastics. Fiberglass pipe is joined with either adhesive bonds, threaded connections (shown in Figure 32), bell and spigot, or other mechanical joints. If the pipe connections are adhesive-bonded, the temperature of the pipe should be between 70° and 100°F (American Petroleum Institute, 2013b). If the pipe connections are threaded, one must exercise extreme care to avoid dust infiltration into either the male or the female threads (American Petroleum Institute, 2013b). Also, because of its hardness, a fine-grained fill material must be used in the trench next to the pipe (American Petroleum Institute, 2013b).

Spoolable Reinforced Plastic Pipe

According to API RP 15S (American Petroleum Institute, 2013a), spoolable reinforced plastic pipe consists of a continuous plastic inner liner reinforced with a middle structural layer of glass-reinforced epoxy (known as spoolable composite pipe, or SCP) or aramid fibers (known as reinforced thermoplastic pipe, or RTP). A cover polymer layer is added over the reinforcement layer to protect the structural layer from corrosion or abrasion. Since API RP 15S was approved, additional spoolable reinforced plastic pipe products have become available, in particular, piping reinforced with steel. The company that makes that product is currently performing qualification testing and working to have its products included in RP 15S. The RP 15S committee is also working to change the practice status to a “standard” rather than a “recommended” practice. Since the spoolable reinforced products are not currently included in a standard practice, they generally are not included in standard PHMSA pipeline guidelines for transportation pipelines. Therefore,

Figure 32. Threaded fiberglass joints.

any regulations addressing spoolable reinforced pipe use in North Dakota must go beyond PHMSA guidelines to include steel-reinforced pipe. However, it is expected that API RP 15S will be accepted as a standard practice in early 2016.

SCP and RTP are continuous-flow-line systems capable of being reeled for storage, transport, and installation. Reels may be more than 1000 feet long, so the number of joints between sections is drastically reduced. Because connections are only required between each reel of pipe, the number of potential leak paths is reduced, and the installation process is faster. One mile of spooled pipe may have only six or seven connections, while a mile of stick pipe may have 130 joints.

The most common inner liner material is HDPE, but PEX, nylon, and PVDF are alternates used on occasion. Chemical resistance and temperature limits are provided by the inner liner, but the structural support facilitates higher-pressure ratings to several thousand psi. SCP and RTP structural outer layers often possess lower expansion and temperature derate coefficients than the liner materials. Also, no stress cracking has been reported with a PE liner down to −40°F (American Petroleum Institute, 2013a).

Key Finding and Recommendation

Observation: Since API RP 15S was approved, additional spoolable reinforced plastic pipe products have become available—in particular, piping reinforced with steel. The company that makes that product is currently performing qualification testing and working to have its product included. Simultaneously, the RP15 committee is working to upgrade the recommended practice to a standard practice.

Finding: Because this material is not currently included in a standard practice, it is generally not included in standard PHMSA pipeline guidelines for transportation pipelines.

Recommendation: North Dakota DMR should seek to place its own SME on the API committee studying modifications to API RP 15S. If North Dakota DMR considers deriving in-state regulations governing installation of reinforced pipe from PHMSA standards, variances to the PHMSA-based regulations should allow for use of reinforced, spoolable pipeline materials not yet included in a standard practice.

Overview of Specific Products Commonly Employed in North Dakota

The following are several specific spoolable reinforced plastic line pipes that are available for the construction of gathering lines. The information provided in this report is obtained from product Web sites.

FlexSteel

FlexSteel, shown in Figure 33, is a steel-reinforced HDPE spoolable pipe. FlexSteel highly recommends that the pipe be preheated if installing below −13°F, but it can operate down to −40°F. FlexSteel is available with pressure ratings of 750–3000 psi, operating temperatures of −40° to 180°F, and diameters of 2 to 8 inches. Connectors are installed by FlexSteel personnel using compression fittings and hydraulic cold-working equipment.

The 4710 HDPE lining used in FlexSteel pipe exhibits good resistance to both brine and petroleum. The helically wound steel banding surrounding the inner core provides the strength required to operate at the design pressure. The outer HDPE shell protects the steel from corrosion and from wear during installation. Because the HDPE lining does allow some diffusion of gas through it, the gas can accumulate in the spaces between the steel bands. Therefore, FlexSteel provides for venting of that space at either end of a spool next to the joining connections. The fact that gas could accumulate in this space could possibly provide an opportunity for monitoring either the gas pressure or composition in order to determine if a leak exists in the line.

FlexSteel pipe connections are made using a hydraulically swaged system of compression fittings that are tested to API RP 15S and other standards, as shown in Figure 34 (American Petroleum Institute, 2013a). These fittings are available in stainless or carbon steel and eliminate the need for project site welding, thus reducing installation crew size.

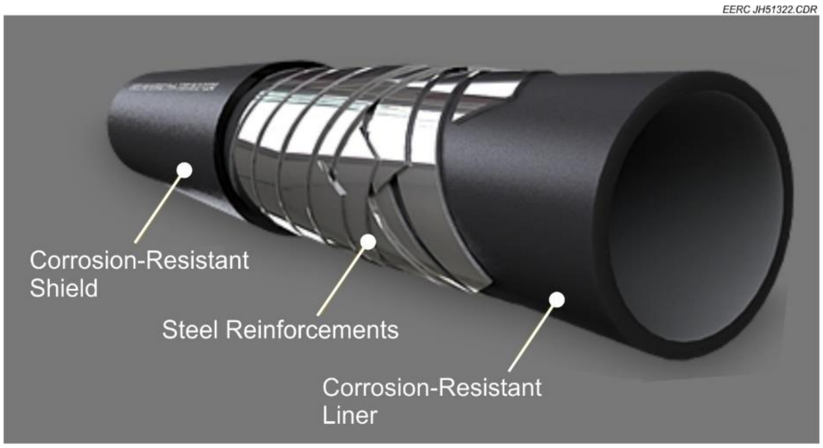


Figure 33. FlexSteel pipe composition.

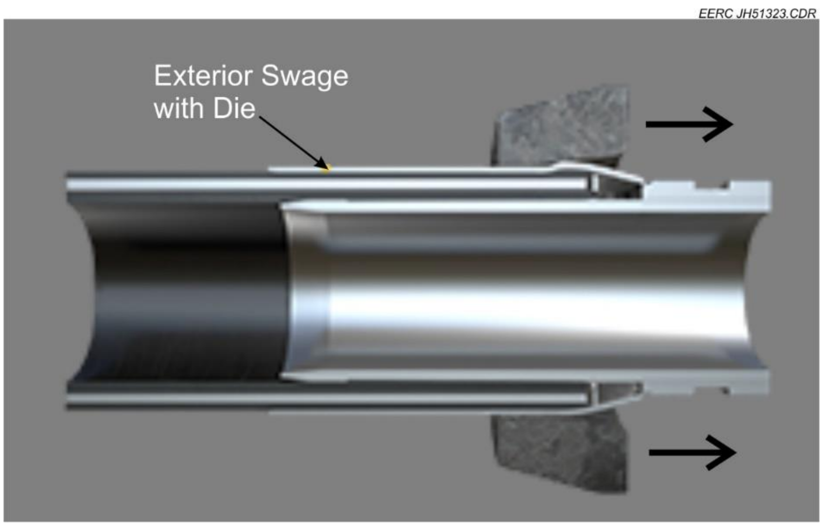


Figure 34. FlexSteel compression fittings.

12

Key Finding and Recommendation

Observation: Because gas can diffuse through the inner liner of a composite pipeline and build up in a dry reinforcement layer, these types of pipeline products are typically vented at each end. This venting may allow for pressure or composition monitoring to determine if a leak exists in the pipe. Manufacturers have just begun to test this capability.

Finding: These pipeline products may provide some level of leak detection capabilities.

Recommendation: Composite pipeline manufacturers with applicable products should develop a collection of test data to support claims that these pipeline materials can assist LDS. North Dakota DMR should continue to monitor development of this aspect of these pipeline products and carefully consider its impact on future rulemaking.

Fiberspar

Fiberspar, shown in Figure 35, is a fiberglass-reinforced HDPE spoolable pipe with pressure ratings up to 3500 psi, operating temperatures of −29° to 203°F, and diameters of 2.5 to 6.5 inches. The fiberglass is embedded in a layer of epoxy so that no space exists in which gas could accumulate, which prevents a possible collapse of the inner liner during a rapid depressurization. The epoxy also prevents the fibers from rubbing together during handling and protects them from chemical attack. The compression fitting pipeline connectors shown in Figure 36 can be installed using hand tools.

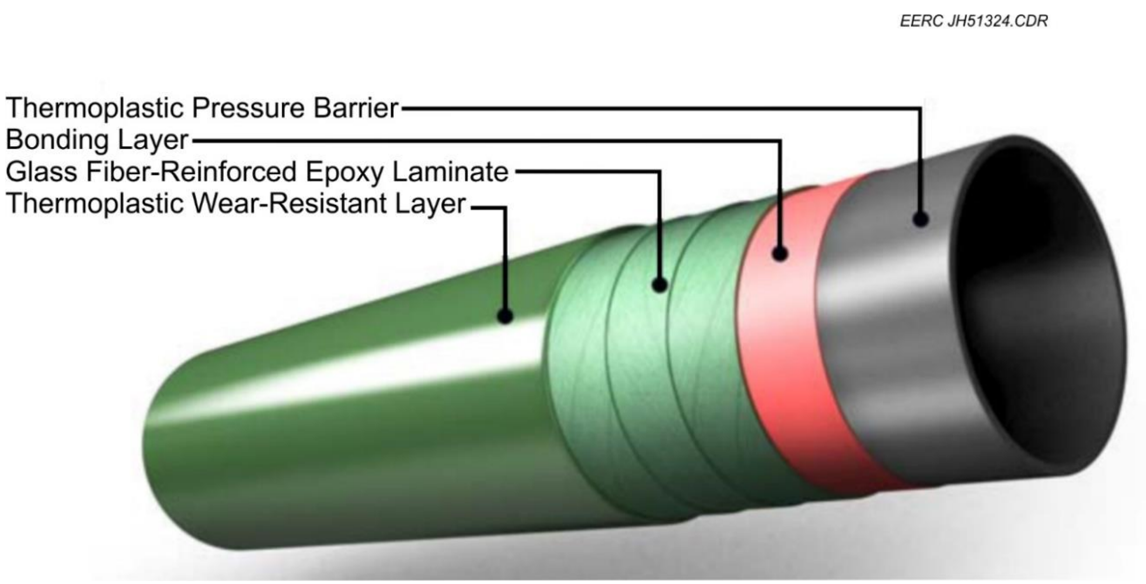


Figure 35. Fiberspar pipe composition.

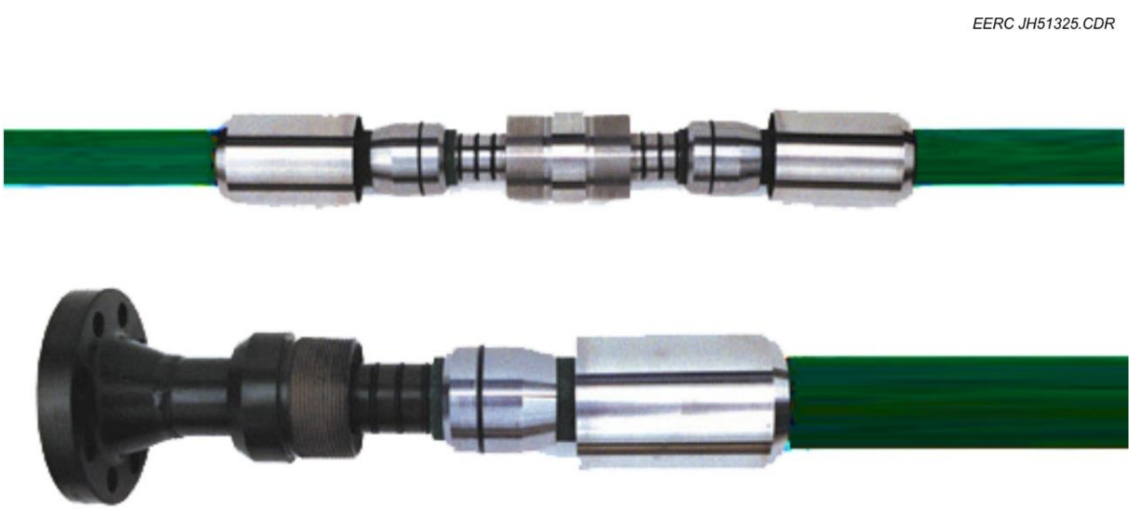


Figure 36. Fiberspar compression fitting options.

Some foremen and independent, third-party inspectors interviewed by the EERC team in the field stated for the record that they believe that this product is less tolerant of deviations to very strictly prescribed installation procedures because the epoxy/fiberglass reinforcement layer is more easily bruised by improper handling than the reinforcement layers in other reinforced plastic piping. It was conveyed to the EERC team by these field personnel that a small flaw can serve as a seed for a catastrophic failure after the line is installed and buried. The EERC observes that this does not seem to be an issue with the Fiberspar product, but rather of improper installation procedures executed below standards by contractors not sufficiently attentive to handling and installation concerns demanded by this product.

This report cannot provide exculpatory or critical assessment of any specific products because that level of product evaluation and comparison with available alternative products requires a series of stringent laboratory tests. Clearly, this level of evaluation is outside the scope of this project.

This report can state that if each and every handling procedure and installation procedure are followed precisely when Fiberspar is installed, it would be likely that the damages that have caused failures in this installed product could be avoided.

Flexpipe

Flexpipe, shown in Figure 37, is another family of fiberglass-reinforced HDPE spoolable pipe with pressure ratings of up to 1500 psi, operating temperatures from −50° to 140°F, and diameters from 2 to 4 inches. Flexpipe also makes a high-temperature version that operates from −12° to 180°F. Flexpipe differs from Fiberspar in that Flexpipe uses dry fiberglass reinforcement, meaning that the fiberglass is not embedded in epoxy. Because gas can diffuse through the inner liner and build up in the dry fiberglass layer, it is vented at each end next to any fittings. Like FlexSteel, this may allow for pressure or composition monitoring to determine if a leak exists in the pipe, although this is unproven at the time of this report. Flexpipe also makes a steel wire-reinforced product known as Flexcord linepipe which delivers a pressure rating up to 2250 psi and maximum operating temperature of 140°F. The company claims that this product is especially resistant to degradation by severe pressure cycles and pulsations such as are generated with piston pumps.

Flexpipe employs patented crimp fittings, shown in Figure 38, which allow joining directly to steel lines, standard flanged connections, or other Flexpipe pipelines. A Flexpipe fitting consists of a mandrel which is inserted into the pipe and a sleeve which is crimped around the pipe. The mandrel and sleeve are both equipped with teeth that securely grip the liner and jacket of the pipe. Fittings are installed using specialized installation equipment that energizes the fitting. The energizing force creates a clamping pressure that holds the pipe in place and provides a seal between the thermoplastic liner and the fitting. Each fitting is also equipped with two O-rings to enhance leak protection. The fitting system does not require the application of heat or adhesives.

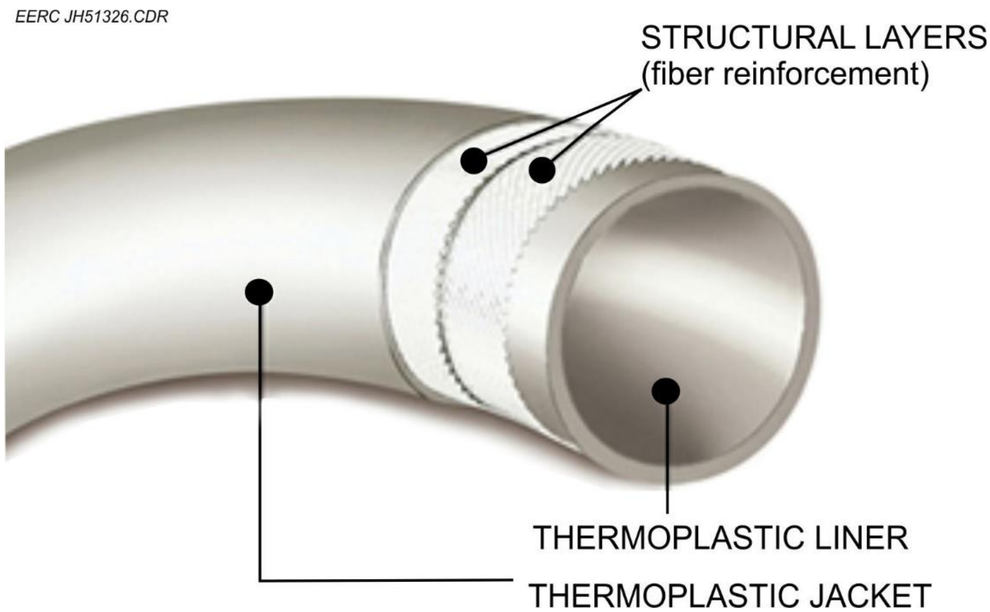


Figure 37. Flexpipe composition.

Polyflow

Polyflow makes Thermoflex tubing, shown in Figure 39, which is reinforced with braided aramid fibers and uses either nylon or polyphenylene sulfide inner and outer liners rather than HDPE. It is available in diameters from 1 to 6 inches outside diameter with operating pressures from 250 to 2500 psi and maximum temperature ratings to 150°F. The manufacturer did not respond to requests about minimum operating or installation temperatures. Because it uses aramid fiber for strength, the company claims that it has a very low derate because of long-term exposure to pressure pulsing. Termination and splice couplings are hydraulically swaged to the pipe to bite and hold the braid ends in place. Polyflow makes zinc chromate-plated carbon steel couplings for low-sulfur fluids or duplex stainless steel couplings for more severe applications.

Figure 38. Flexpipe compression fitting.

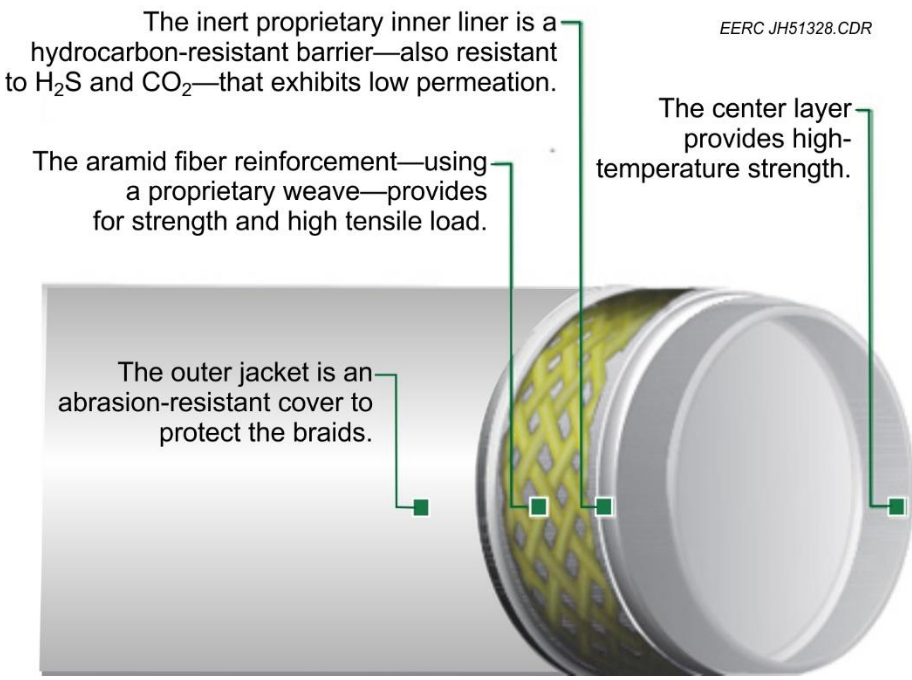


Figure 39. Polyflow thermoflex pipe.

Summary of Plastic and Composite Pipeline Materials Available for Use in North Dakota

As described in the previous discussion, many different types of plastics and reinforced plastics can be used to make pipelines. Generally, plastic materials are more resistant to corrosion than steel pipelines and, therefore, are frequently used for transporting produced water. The type of material to use for a given pipeline depends on its chemical resistance, the operating temperature and pressure of the line, ease of assembly and repair, resistance to damage, and overall cost.

Table 24 provides comparisons of the properties of different unreinforced and reinforced plastic pipeline materials that are options for use in building pipeline systems. This table is meant to serve as a quick reference to describe the functional features of each material in summary.

Table 24. Comparison of Specifications of Pipeline Material Options

Plastic Pipeline Product/ Material	Operating Temp. Range, °F	Installation Temp. Range, °F	Operating Pressure Range, psig	Joint Configuration	Available Sizes
Fiberglass	−29 to 275	70 to 100	Up to 3000	Adhesive-bonded joints	All sizes
PVC	0 to 150	0 to 120	Hundreds of psi	O-ringed lap joints or solvent-welded lap joints	All sizes
CPVC	0 to 210	0 to 120	Hundreds of psi	O-ringed lap joints or solvent-welded lap joints	All sizes
Polyethylene (HDPE)	−40 to 180	−30 to 130	Hundreds of psi	Heat-fused or inserts	All sizes
Polyethylene (PEX)	−30 to 210	−30 to 140	Hundreds of psi	Threaded, compression, or crimped	Up to 24" (Israel)
ABS	0 to 180	0 to 120	Hundreds of psi	Solvent welding or threaded joints	All sizes
PP	14 to 194	14 to 194	Hundreds of psi	Heat-fused, threaded, or flanges	All sizes
Nylon (Invista Raptor®)	−40 to 200	Above 32	Up to 500	Heat-fused	Up to 6"
Fiberspar	−29 to 203	Above −20	Up to 3500	Compression applied with hand tools	Up to 6.5"
Steel/HDPE Composite (FlexSteel)	−40 to 180	Preheat when below −13	Up to 3000	Swaged, applied by FlexSteel or other certified personnel	Up to 8"
Flexpipe	−50 to 140	Above −12	Up to 2250	Crimped with special equipment	Up to 4"
Polyflow Thermoflex	Below 150	No data	Up to 2500	Hydraulically swaged	Up to 6"

Plastic Pipeline Pigging Considerations

"Pigging" is the practice of sending a bolus through the pipeline to either clean the pipeline or to perform diagnostic measurements on the pipeline from within the pipeline (termed "smart pigging"). Cleaning pigs are often spheres made of solid foam. Smart pigs contain electronic instrumentation packages that scan the walls of the pipeline with a variety of instruments. Following are summary items on compatibility of pigging with the pipeline types described above (for more information on pigs and pigging, see the pipeline maintenance section of this report):

- Foam cleaning pigs can be used with any of the plastic pipeline materials, depending on the manufacturer's advice. Flexible foam pigs can tolerate transitions in pipeline dimensions such as at the lips that form at fused joints in nylon or HDPE pipes or steel connections in some composite pipes.

- Smart pigging is not routinely performed on either thermoset or thermoplastic pipeline materials. This is because the intelligent instrumentation package normally scans metallic pipe for corrosion, cracks, and leaks using ultrasonic, electrical resistance, or magnetic technologies. None of these technologies is generally compatible with plastic or composite pipe.

Steel Pipelines

Although plastics are often used for transporting produced water because of the inherent chemical resistance of plastic pipelines to corrosion by aqueous solutions, steel pipelines are most often used for transporting crude oil. Steel is preferred because it is very strong, does not suffer pressure derates due to absorption of hydrocarbons, and is not corroded by hydrocarbons. The use of steel in oil pipelines has a long history dating back to the late 1800s, which results in a solid understanding of solutions available for most commonly occurring problems.

The steel composition and tensile properties are based on standards set forth under API 5L. In general, as long as the steel meets this standard and is coated with an appropriate material to resist damage by the exterior environment, cathodically protected to resist corrosion at coating breaches (holidays), and water is removed from the hydrocarbon being transported, steel pipelines provide excellent service.

Design Considerations for Steel Pipelines

ASME B31 Code for Pressure Piping is one of the most commonly used codes to follow for designing, building, and operating steel piping systems. ASME B31.4-2012, entitled "Pipeline Transportation Systems for Liquids and Slurries" is applicable to steel pipeline gathering systems. As the code states in Chapter 1, it applies to hydrocarbons, liquid petroleum gas, anhydrous ammonia, alcohols, and carbon dioxide which are jointly referred to as liquid pipeline systems. The requirements of the code are adequate for safe operations under normal operating conditions. Requirements for special operating conditions are not addressed.

The purpose of B31.4 is to establish requirements for safe design, construction, inspection, testing operation, and maintenance of liquid pipelines for the protection of the public and operator personnel. It also addresses reasonable protection of the system from vandalism and accidental damage, as well as protection of the environment. Existing industrial safety regulations are not intended to be supplanted by the code.

The code is not a design handbook. Instead, it offers a simplified engineering approach. It is up to designers to produce a more rigorous approach to handle the specifics of their particular system. As the code states, it prescribes requirements for the design, materials, construction, assembly, inspection, testing, operation, and maintenance of piping transporting liquids between production facilities, tank farms, natural gas-processing plants, refineries, pump stations, ammonia plants, terminals, and other delivery and receiving points. It does not, however, provide much specific information about pipeline design, construction, or operation, but it is a good source for standard practices and definitions and especially lays out which other industrial codes should be followed for specific activities.

Corrosion

Corrosion is the deterioration of a material, usually a metal, which results from a chemical or electrochemical reaction with its environment. Although steels made according to API 5L requirements have the appropriate physical properties to serve as line pipe, they do not have adequate additions of elements necessary to make them corrosion-resistant. Therefore, they can undergo a variety of corrosion modes because of interactions with internal and external environments. For a detailed discussion on corrosion, please refer to Appendix E – Details of Corrosion-Related Design Considerations.

Corrosion Considerations in Pipeline Design

NACE SP0106-2006 deals with methods for controlling internal corrosion of steel pipelines. Sections 1 and 2 of the standard practice provide a general background and some term definitions. Section 3 describes pipeline structure design. It says that when designing a pipeline, the purchaser and producer must negotiate the quality specifications of the liquid being transported because the impurities in the liquid can significantly affect measurement, operation, pipeline efficiency, and corrosion of the pipe. However, liquid corrosiveness cannot be determined by these predicted impurities alone. In general, pipelines carrying pure petroleum or petroleum products are not subject to internal corrosion, but industry experience has shown that water and other corrosive impurities can unintentionally enter the pipeline during operational upsets and accumulate in low spots despite liquid quality monitoring that shows adherence to quality standards. It is the presence of water that largely leads to corrosion of steel pipelines carrying petroleum or petroleum products. In addition, salts may deposit and absorb water, creating a thin water-rich film on the steel surface. The standard practice says that because of the complex nature and interaction of the impurities, a corrosive condition can exist even if the concentration of the impurities may be low. The types of corrosion that occur due to the presence of impurities are listed in Appendix C of the NACE standard practice document. That appendix is provided with permission in Appendix F of this report for the reader’s general information.

When corrosion occurs, it leads to physical deterioration of the pipe as a result of thinning, pitting, hydrogen embrittlement, or stress corrosion cracking (SCC). SCC is a situation in which corrosion is accelerated because of a physical stress that is applied to the pipe. If corrosion is anticipated, then mitigation methods should be considered, such as increased pigging, use of corrosion inhibitors, internal coating of the pipeline (usually an epoxy paint or other plastic liner), or a combination of those methods.

Design consideration should also be given to control the flow velocity within a range that reduces corrosion. The lower limit of the flow velocity range should be one that will keep impurities suspended in the liquid to minimize accumulation of the impurities at points in the line. The upper limit of the velocity range should be one in which erosion, cavitation, or impingement of particulates on the pipeline walls is kept to a minimum. For this reason, intermittent flow conditions should be minimized because as the flow slows, the impurities can settle onto the pipe surface. This can also happen because of turbulence or stagnation associated with a change in line diameter or dead ends, so they should be avoided in the system design. The system should also be designed to eliminate air entry because the presence of oxygen can increase corrosion rates. Chemicals such as corrosion inhibitors, oxygen scavengers, and biocides can be employed to reduce corrosion as well. If serious corrosion problems are anticipated, internal coatings can be used, especially if coating methods allow for coating weld areas. Alternatively, an inner tubing liner can be used to provide corrosion protection, in which case the steel piping provides the strength to handle the pressure of the fluid.

When corrosion problems are anticipated, and especially when corrosion-inhibiting chemicals are used, the system should include corrosion-monitoring facilities to evaluate the effectiveness of the corrosion mitigation methods. Corrosion-monitoring facilities may include pipe spools, gas or liquid perturbation methods (field signature), or hydrogen probes. According to the standard practice, details of the various corrosion-monitoring methods are listed in NACE publication 3T199 (NACE International, 2012). A summary of corrosion considerations detailed in NACE Standard Practices is presented in Table 25. Monitoring may include in-line inspection (ILI), in which case the pipeline should be designed to accommodate the inspection tools.

Table 25. Corrosion Considerations Detailed in NACE Standard Practices

Corrosion Detection and Measurement (described in NACE Section 4)	Because corrosion primarily occurs where water accumulates, predicting these locations is a good method for targeting local examinations such as inspection, monitoring, and sampling. Visual inspection is done by opening a section of pipeline to observe internal material damage. Types of corrosion such as etching, pitting, and elongation of attack are noted. Wall thicknesses are measured, positions and sizes of attack noted, and the existence of any deposits or corrosion under deposits identified. Samples of deposits are retrieved for later analysis. The use of properly located coupons (small pieces) of steel or probes inside the pipe can also be used to determine existence, types, and rates of corrosion to expect. Care must be taken to place the coupons and probes in such a way that pigging operations can still be performed.
Methods for Controlling Corrosion (described in NACE Section 5)	• Periodic line cleaning with pigs in conjunction with other corrosion mitigation measures such as chemical inhibition and dehydration are most commonly used. Pigging helps to remove settled water, corrosion products, loose sediment, and waxes that can sometimes shield the corroding areas from the protection provided by chemical inhibitors. • Because most corrosion occurs when water is present, dehydration of the fluid being carried can significantly reduce corrosion inside of the pipeline. Deaeration to remove oxygen or the use of oxygen-scavenging chemicals can reduce oxidation issues. Other gases can be removed using strippers and scrubbers. • Numerous types and formulations of corrosion inhibitors that are added to the fluid being carried in the line are also commercially available. The most important factor in choosing an inhibitor is to understand the probable corrosion problem and work with the supplier to choose an appropriate compound. • Internal coating of pipelines can also be considered as an internal corrosion control measure. They may be used in selected areas that are probable candidates for corrosion. They may include epoxies, cement, plastics, or metallic compounds. Performance is dependent on suitable surface preparation and cleaning and appropriate application practices.
Evaluating the Effectiveness of Corrosion Control Methods (described in NACE Section 6)	One major method is the use of coupons and probes for determining time-related changes in corrosion conditions. Another method for measuring how well corrosion control methods are working includes fluid sampling and chemical analysis to determine if a change has occurred in the corrosive medium being transported. Visual inspection of solid contaminants and changes in weight or volume of corrosion products removed from filters is also useful. Periodic corrosion monitoring using magnetic, electronic, ultrasonic, or radiographic methods may also be helpful. Measurements of changes in fluid pressure drop along sections of the line may also indicate the formation of deposits.
Operation and Maintenance of Internal Corrosion Control Systems (described in NACE Section 7)	This describes the frequency of pigging operations, along with descriptions of inhibitor injection operations and inspecting internal coatings.
Corrosion Control Records (described in NACE Section 8)	This states that for design considerations the following should be recorded: • Analysis of the liquid, including impurity content • Pipe size, wall thickness, grade, flow velocity, line size changes, internal coating, and type • Considerations for treatment such as dehydration, deaeration, chemicals, internal coatings, and corrosion-monitoring facilities The following should also be recorded on detecting, controlling, and evaluating corrosion problems and operations maintenance: • Visual inspections by qualified personnel whenever a piping system is opened • Inspections and tests of probes, coupons, and other corrosion-monitoring devices such as samples, chemical analyses, bacteria results, and internal inspection tool runs • ILI of line-cleaning pig runs, including date, type of pig, and amounts of water and solids removed by location • Name and quantity of inhibitor, biocide, and other chemicals used • Leak and failure records

External Corrosion

The best way to prevent external pipeline corrosion is by using a high-performance coating of the steel along with sufficient CP. NACE SP0169-2013 presents methods and practices for achieving effective control of external corrosion on underground or submerged metallic piping systems (NACE International, 2013). The methods and practices are also applicable to many other underground or submerged metallic structures. The standard describes the use of electrically insulating coatings, electrical isolation, and CP. The standard does not include corrosion control methods based on injection of chemicals into the environment, use of electrically conductive coatings, or on the use of nonadhered PE encasement. The standard also does not explain very well the many types of corrosion issues experienced by underground pipelines. An explanation of different types of corrosion that can occur because of the interaction of steel pipeline with the underground environment is offered in Appendix E.

Coatings to Inhibit External Corrosion

The function of coatings is to control corrosion by isolating the external surface of the piping from the environment, to reduce CP requirements, and to improve the cathodic current distribution. Coatings are usually applied to piping materials at the factory to areas of the pipe that will not be heated during welding of the pipe, as shown in Figure 40. The areas of the pipe that are affected by heat during welding need to be coated in the field after welding so that they are also protected from corrosion. NACE SP0169-2013 provides standards to be followed for the different types of coatings.

EERC JA51390.CDR

Figure 40. Epoxy-coated steel pipeline.

The desired characteristics of coatings used for corrosion protection are as follows:

- Effective electrical insulation
- Effective moisture barrier
- Good adhesion to the pipe surface
- Applicable by a method that will not adversely affect the properties of the pipe
- Applicable with a minimum of defects
- Ability to resist the development of holidays (disbonded areas) with time
- Ability to resist damage during handling, storage, and installation
- Ability to maintain substantially constant resistivity with time
- Resistance to chemical degradation
- Ease of repair
- Retention of physical characteristics
- Nontoxic to the environment
- Resistance to changes or deterioration during storage or transport

Cathodic Protection

In addition to coatings, CP should be used to reduce external corrosion of steel pipelines. NACE SP0169-2013 describes the criteria for CP, design and installation of CP systems, control of stray currents, and operation and maintenance of CP systems. However, it does not describe very well the underlying mechanisms of CP; therefore, we summarize that information here.

Steel lines, as previously mentioned, tend to be the most utilized type of pipeline for oil, oil emulsions, and gas gathering. These steel lines are generally externally coated with protective wrap to inhibit oxidation and corrosion of the material. Oxidation and corrosion are electrochemical processes caused by moisture in the environment of the iron metal, causing it to transform from a metal, Fe, to an oxide, Fe_2O_3. This iron oxide is commonly referred to as rust. Three conditions must be present to establish an electrochemical cell that will cause corrosion:

- Presence of two different metals, one acting as the cathode and one as the anode

- Presence of an electrolyte acting as a pathway for the flow of electrons from one metal to the other

- Presence of an additional electrical connection between the two metals to complete the circuit

In the case of steel pipe, these two different metals can be two dissimilar spots within the same pipe that possess slightly different electrical potentials. The flow of electrons in the electrolyte will always proceed from the anode to the cathode, with the anode being corroded.

CP offers an alternative (or perhaps a complementary measure) to protective wrap. There are two types of CP: passive and impressed current. In passive CP, the steel is protected by attaching a sacrificial metal anode which corrodes more readily than the steel, as illustrated in

Figure 41. The driving force for the CP current is the difference in electrode potential between the anode and the cathode. These sacrificial anodes need to be monitored and replaced periodically to ensure proper CP. While sacrificial anodic protection can be utilized on short pipelines, this tends to be ineffective on larger systems. This type of protection can and is frequently used on steel connections in HDPE and other types of pipelines.

In other larger steel line systems, where this sacrificial passive CP is not adequate, the pipeline can use an external source of electrical direct current (DC) power to drive the anodic protection circuit. In this type of system, a DC voltage is used to enhance the strength of the anodic protection by energizing the electrons from a larger bed of anodes, and this is then applied across the pipe. The energizing of the electrons is accomplished through use of what is known as a rectifier to convert alternating current (AC) to DC. In this scenario, the anodes are not necessarily anodic to the steel pipeline but rather are, in fact, naturally cathodic to the steel and if wired to the pipe without the impressed current would actually cause enhanced corrosion of the pipe. With the addition of the DC from the rectifier, the polarity of the material is reversed, and this causes the materials to become anodic to the steel. However, these anodes do not corrode as in passive systems as the oxidation reaction is usually another reaction, such as of oxygen or chlorine evolution, and the anodes are then not consumed (ASM Handbook, 2003).

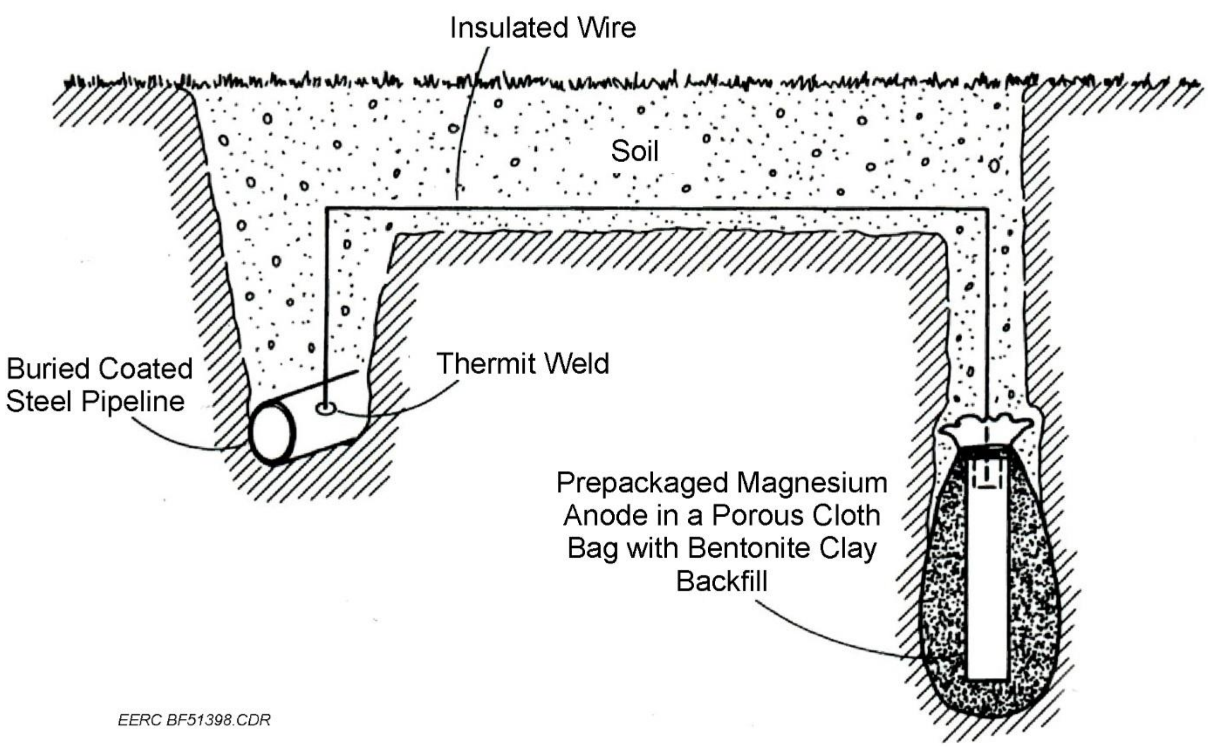


Figure 41. Illustration of passive CP of a pipeline (ASM Handbook, 2003).

Passive sacrificial anodes differ from impressed current cathodic protection (ICCP) anodes. Typically sacrificial anodes are of materials of magnesium, zinc, or aluminum, with magnesium being extensively used for buried soil applications. Many of the magnesium anodes commercially available in the United States come in a package of clay, as shown in Figure 41. This clay packaging ensures the anode has an environment that will allow the anode to corrode in a consistent and reliable fashion (ASM Handbook, 2003). ICCP anodes come in a variety of materials, and selection is dependent on the application. The selection of the type and design of CP system is typically performed by companies which specialize in this activity; however, several examples of how to specify and design a system are given in the ASM Handbook (2003).

ICCP systems can also be utilized to monitor the system integrity by identifying pipe and coating irregularities or holidays where disbonding occurs, exposing the steel underneath to the environment and, therefore, potential corrosion activity.

Chemical Maintenance for Corrosion Control

Another method of corrosion control that is sometimes utilized for steel pipelines is the addition of chemicals that may inhibit corrosion activity. Several different types of corrosion inhibitors and methods of application are available. Inhibitors can be of a cathodic and/or anodic nature to the steel pipe. Some inhibitors such as phosphorus-based chemicals are used to inhibit the corrosive aspects of oxygen. Amine compounds are used to reduce corrosion by hydrogen sulfide and carbon dioxide.

CONSTRUCTION OF CRUDE OIL AND PRODUCED WATER GATHERING PIPELINE

General Construction Process for Gathering Pipelines Carrying Crude Oil or Produced Water

Pipeline construction comprises several steps, each with its own unique relationship to pipeline integrity and long-term service life. For each step in the pipeline construction process, the following section provides a summary of what might be considered best practices for pipeline construction and installation and the observed current practices by pipeline operators in the Williston Basin.

The basis for "best practices" was established from the review of numerous sources and discussions with pipeline industry participants. The sources reviewed pertained to pipelines that fall under PHMSA jurisdiction as well as traditional water and wastewater pipelines. Regardless of the pipeline project, many of the best practices related to trench construction, bedding, pipe placement, and backfilling are quite similar and are generally followed with variation by company, site conditions, or regulatory requirements.

The following description of current practices and how they compare to common practices is based on several field visits to pipeline construction and operation sites, conversations with pipeline operators, as well as information provided by stakeholders about their pipeline operations in the Williston Basin.

Currently, NDAC 43-02-03-29 addresses underground gathering pipeline construction with only limited guidance and language. With respect to pipeline materials, "all constructed underground gathering pipelines must be devoid of leaks and constructed of materials resistant to external corrosion and to the effects of transported fluids." With respect to pipeline installation, "pipelines installed in a trench must be installed in a manner that minimizes interference with agriculture, road and utility construction, the introduction of secondary stresses, the possibility of damage to the pipe, and tracer wire shall be buried with any nonconductive pipes installed." Regarding backfilling, "it must be backfilled in a manner that provides firm support under the pipe and prevents damage to the pipe and pipe coating from equipment or from the backfill material." In general, these requirements set forth an expectation of performance but lack detail related to how the objectives are to be achieved.

Initial construction activities: This would include both preconstruction activities such as securing easements, surveying the pipeline ROW and centerline, and locating other utilities that may be in the pipeline ROW, as well as clearing and grading of the pipeline ROW to allow for a safe working environment for equipment and personnel. Erosion controls would also be put in place during this phase.

These activities were not considered significant to the topic of pipeline spills; therefore, no further discussion is provided regarding preconstruction activities or clearing and grading.

Trenching: Prior to actually digging the trench, topsoil is stripped and stockpiled separately from other excavated material such that it can be replaced as a final step of the backfilling process or as a first step of reclamation. All information provided indicated that operators are stockpiling topsoil separately.

With the topsoil removed, equipment is brought in to excavate the trench suitable for laying the pipeline. Trench widths and depths will vary depending on the size and type of pipe being installed. The trench is excavated with attention to maintaining a level, undisturbed bottom to provide a solid and uniform support for the pipe once it is laid in the trench.

Trenches for gathering pipelines in the Williston Basin are typically constructed by excavation method as opposed to ploughing or the like and are performed using a tracked excavator or similar piece of equipment.

Based on information provided by the various pipeline operators, specific trenching requirements are being provided to contractors. The trench itself is excavated to a depth sufficient to meet each company's minimum pipe cover requirements. Trench depth requirements range from 48 to 96 inches, and minimum pipe cover requirements range from 42 to 84 inches. Trench width requirements are largely dependent on the size of pipe being installed, with as little as 6 inches minimum pipe/sidewall clearance and, in some cases, a trench width no less than 36 inches. Requirements regarding the minimum clearance between the pipe being installed and other utilities were most often reported as 24 inches, but it was as little as 18 inches in one case.

The following bullets summarize areas that warrant extra attention during the trench construction and laying-in process. Many of these practices are currently being specified and performed by pipeline owners but deserve to be emphasized:

- Pipeline trenches should be dug to allow for the pipeline to rest on undisturbed native soil and provide continuous support along the length of the pipe, while still providing satisfactory cover. Trench bottoms should be free of rocks, debris, trash, and other foreign material. If a trench bottom is overexcavated, the trench bottom should be backfilled with appropriate material and compacted prior to installation of the pipe to provide continuous support along the length of the pipe.

- Trenches should be dug sufficiently wide to provide a minimum of 6 inches of clearance on each side of the pipe. Trench walls should be excavated to ensure minimal sluffing of sidewall material into the trench and provide safe entry into the trench by personnel. Trenches greater than 4 feet in depth that will require entrance by personnel should have sloped or stepped sidewalls.

- Topsoil should be stripped from the pipeline ROW and stockpiled separately from subsoil for later use. Subsoil from the excavated trench should be stockpiled separately from previously stripped topsoil.

- Cover depths should be a minimum of 4 feet from the top of the pipe to the finished grade, with a preferred depth of cover more in the range of 6 to 8 feet. Depth of cover is of importance for both impact to the pipe itself as well as insulation from freezing temperatures. This is especially important when a pipeline is transporting freshwater and brine but may also be an important consideration to reduce the exposure to freeze/thaw cycling conditions.

- Clearance between the pipeline and other underground structures should be a minimum of 12 inches, with greater clearances desirable.

- Although not specified in the "Current Practices" section, handling of pipe through the entire process is important (this would include during shipping and unloading). In all phases, whether it be during transport, stringing, joining, or lowering in, handling of the pipe in a manner to minimize stresses and eliminate physical damage to the pipe is critical.

- Overall, current trenching and pipeline installation practices, although they vary from company to company, appear to be consistent with sound practices.

Pipe stringing and bending: The stringing and bending phase involves laying out pipe sections in the ROW next to the trench and bending sections to match the contour of the trench bottom. Bending is only performed when steel pipe is laid. Plastic, composite, and fiberglass pipes all bend under their own weight to match the trench bottom contour within manufacturer-supplied limits.

All information provided and limited observations by the authors indicated that the pipeline installation companies and the operators understand the importance of proper handling of pipe in the field. It is important when stringing pipe to handle the pipe in a manner to avoid damaging the pipe.

Pipe joining, coating, and inspection: The next step is joining the pipe sections that have been staged along the trench. In the case of steel pipe, the sections are welded together by certified welders. For nonsteel pipe such as poly, composite, and fiberglass, the joints are made with applicable methods such as thermal welding, solvent welding, etc. In some instances, nonsteel pipe is laid in the trench, and joints are made in the trench.

After steel pipes are welded, the joints are coated to minimize external corrosion. Since steel pipes are fabricated with an outer coating (except at the ends), the entire pipe is now covered in a protective coating. No additional coatings are applied to nonsteel pipes.

Although inspections occur at numerous points during the pipeline construction process, the joining phase is particularly important. For nonsteel pipe, the inspection of joints is a visual assessment to ensure a satisfactory joint has been made. For steel pipe, an x-ray image of the joints is generated to verify a satisfactory weld has been achieved. It is also important to perform the necessary inspections and x-ray examinations of the risers that connect the pipeline to the above-ground infrastructure. The frequency of joint x-raying is dictated by either regulation or project specification.

Again, information provided by pipeline operators regarding their standard practice for joining, coating, and inspection of joints demonstrates a recognition of proper installation procedures. Field observations were only able to be made on plastic and composite pipes, and in these cases, the joining process was performed in a manner consistent with the pipe manufacturer's procedures.

A more thorough description related to the various pipe joining and coating methods is provided in the Material Selection for Crude Oil and Produced Water Gathering Pipelines section.

Lowering pipe in and backfilling: In some nonsteel applications, the pipe would have been lowered in prior to the pipe sections being joined. Special care should be taken during the lowering-in process to support the pipe string properly so as not to induce excess stresses on the pipe or the joints and weaken it or cause damage to the outer surface of the pipe.

With the pipe in the trench, the backfilling process begins. The backfilling process technically involves four stages, although they may be performed in what seems like a single process. Figure 42 aids in the understanding of the backfill process.

The first stage of the backfilling process is referred to as bedding the pipe. In this step, a proper bed is prepared for the pipe. Often the native undisturbed trench bottom is considered adequate bedding for the pipeline, although in some cases contract specifications or regulatory requirements dictate that a specific bedding material (usually a sand or uniform aggregate) be placed in the trench bottom prior to laying in the pipe.

Significant variability exists among various standards and procedures on the topic of bedding requirements. In general, published pipeline construction requirements (included PHMSA/DOT) do not require specific bedding, but rather defer to language such as "…must provide adequate support along the entire length of the pipe." A notable exception to this exists in ASTM standard ASTM D2321.

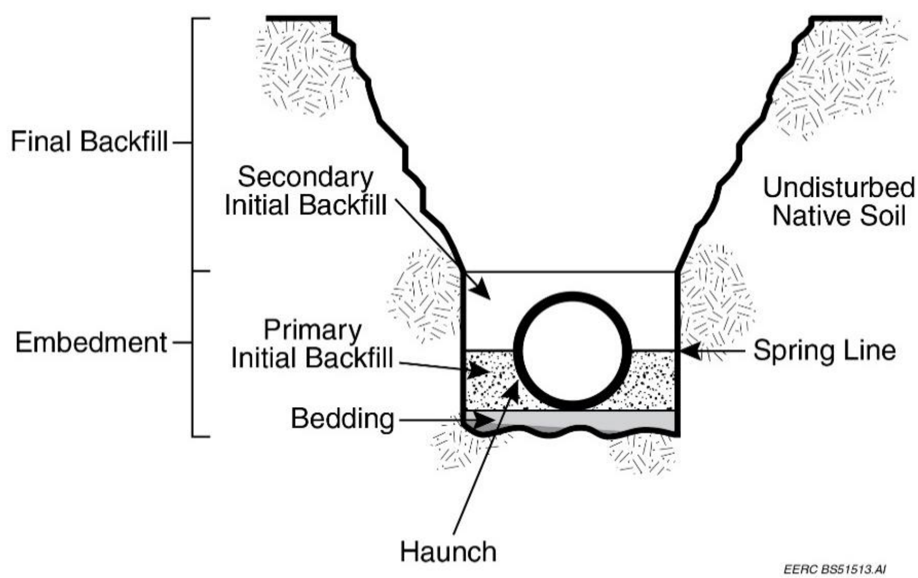


Figure 42. Cross section of pipeline trench and backfill labels (Plastics Pipe Institute, 2009).

In the strictest definition of bedding, respondents indicated that bedding of pipelines is not done. That is to say that a specific material in the trench bottom for the pipe to be laid into is not used. Some indicated that they use excavated material free of rocks and other debris for bedding, although it would appear that these responses are actually not referring to bedding in the strict traditional sense but instead initial backfill.

The next step is primary initial backfill, and this is typically considered to be placement of backfill material (typically debris-free native material from the trench excavation) from the trench bottom or top of the bedding material to the centerline or spring line of the pipe. In this phase, proper attention is given to ensure sufficient backfill material is placed in the haunches of the pipe as this is a key area of long-term support for the pipe.

After primary initial backfill, the pipeline is full-covered with backfill material to a specified depth of cover above the pipe (often 6 to 12 inches). This step is referred to as secondary initial backfill. These three steps combined are often called embedment.

In all cases, backfill material was described as excavated material free of rocks (of varying size limits). Initial backfill material typically had smaller rocks removed than final backfill (if specified, usually greater than 2 inches in diameter). Initial backfill was often described as being placed in lifts ranging from 12 to 24 inches, and on rare occasions, mechanical compaction is also specified (but not a specific compaction requirement). The initial backfill was often specified to a depth above the pipe ranging from 6 to 24 inches.

The last step in the backfilling process is final backfill. As the name implies, this is the process of backfilling the remaining depth of the trench with native excavated material.

Final backfill requirements also specify removal of rocks, albeit larger rocks are allowed than in initial backfill (i.e., greater than 12 inches). Material is often placed in lifts, and occasionally mechanical compaction is specified, but more often compaction requirements are more associated with a surface settlement requirement. As part of many pipeline easement agreements, attention is also given to maintaining a rock-free material near the surface prior to topsoil replacement.

Specific topsoil placement and reclamation requirements are most often specified in the individual easement agreements with the landowner. In general, the topsoil is removed of rock and placed on top of the final backfill.

The following bullets are a summary of areas that warrant extra attention during the backfilling process. Many of these practices are currently being specified and performed by pipeline owners but deserve to be emphasized:

- The use of excavated material as the backfill material should be satisfactory, assuming rocks and foreign debris are removed from the material when placed in the trench, especially in the initial backfill. Some stakeholders indicated the need to import specific material for bedding of the pipe. Although this may be ideal, it would most certainly be costly and logistically challenging.

- Special attention should be paid to the adequacy of the native trench bottom to provide full support to the pipeline as well as initial backfilling in the haunch area and around the pipe.

- Generally speaking, during the entire backfilling process, material placed in lifts with some form of compaction at the time of placement provides better support for the pipe and will settle and shift less in the future, reducing the potential for damage to pipes and joints.

- Some stakeholders did advocate the use of mechanical devices such as shaker buckets to ensure suitable material is placed during the backfill process. Although this is likely accurate, it may be inappropriate to dictate the method used to prepare backfill material. However, specifying a maximum size of rock in the initial backfill is important.

- In general, backfilling procedures are consistent with sound practices. Again, indications are that pipeline construction issues that would raise concern are a function of execution or workmanship and not design.

Horizontal directional drilling: The use of horizontal directional drilling (HDD) has been used widely in the Williston Basin in areas where traditional trench construction is not possible or less feasible than HDD, such as under waterways, lakes, and wetlands as well as certain roads. As described in brief by the *Handbook of Polyethylene Pipe* (Plastics Pipe Institute, 2009), the HDD process begins with boring a small, horizontal pilot hole under the crossing obstacle (e.g. a highway) with a continuous string of steel drill rod. When the bore head and rod emerge on the opposite side of the crossing, a special cutter, called a back reamer, is attached and pulled back through the pilot hole. The reamer bores out the pilot hole so that the pipe can be pulled through. The pipe is usually pulled through from the side of the crossing opposite the drill rig. Since no information was obtained that would indicate HDD-installed pipelines were a direct cause of spills and leaks, this topic is not discussed in detail in the current report. However, operators that use this pipeline installation method should perform adequate due diligence in the design and installation phase of a project using HDD to ensure that the process follows pipeline manufacturer recommendations.

Where pipelines are to be constructed in or near environmentally sensitive areas, such as wetlands and other small surface waterbodies, special consideration should be given to the construction of these pipelines. HDD may be the most appropriate construction method to reduce surface disturbances. In addition, other measures may be warranted to ensure the impact to these areas are minimized in the case of a leak.

13

Key Finding and Recommendation

Observation: Some areas of the Williston Basin present unique challenges related to the construction of pipelines in or near environmentally sensitive areas, such as wetlands and other small surface waterbodies.

Finding: Although no specific information was provided or observed regarding the current construction practices specific to wetland and small surface waterbodies, these areas warrant special consideration during pipeline construction.

Recommendation: Horizontal directional drilling may be the most appropriate construction method to reduce surface disturbances. In addition, other measures may be warranted to ensure the impact to these areas are minimized in the case of a leak.

Pipe integrity testing: Upon completion of backfilling, the pipeline is pressure-tested at pressures higher than MOPs with water or air to ensure the pipe, joints, and fittings can operate without leaking. If done with water, this is referred to as hydrotesting.

Pipeline integrity testing is discussed in greater detail in the Crude Oil and Produced Water Gathering Pipeline Maintenance and Inspection section.

Reclamation: With pipeline integrity testing complete, the pipeline ROW is reclaimed to restore the work area to its original condition (or as close as possible). The typical process for reclamation involves recontouring the ground surface to original grade, replacing topsoil (stockpiled separately during trenching), preparing the topsoil for reseeding vegetation, and reseeding.

An area not specifically described in the pipeline installation process but vitally important is inspection. Inspection operations are part of every phase of pipeline construction best practices.

Currently, most if not all operators require some form of inspector supervision during pipeline construction. The inspector may be a direct employee, a contracted employee, or an independent company employee.

Additional Remarks

Based on descriptions provided, documented installation requirements provided, and installations observed, it appears that pipeline projects are specified using appropriate construction methods and, in some cases, strict requirements similar to PHMSA pipeline standards. Information compiled indicates that deficiencies, when encountered, are in the execution of these installation requirements. This section highlights the pipeline construction steps that warrant special attention by operators and pipeline installers to ensure pipelines are meeting performance and integrity expectations.

The role of the inspector during pipeline projects is by most accounts the most critical of every aspect of this section. The inspector, with the sole responsibility of ensuring specification adherence, has the potential to identify and prevent potential problems that could develop into pipeline leaks in the future.

Given the large number of pipeline projects in the Williston Basin and the geographic extent of the projects, supervision of construction and installation of pipelines is most effectively accomplished by either third-party inspectors or specific company inspectors. The role of these inspectors must be to verify that pipeline contractors are installing pipelines in accordance with construction specifications, with no regard for the financial implications of stopping work to rectify problems.

In addition, DMR may consider the implementation of state inspections of pipeline construction projects. State inspectors would serve the role of validating that the contractors, company inspectors, and third-party inspectors are performing the work in accordance with construction specifications and that construction personnel are qualified to perform assigned tasks. This would also require the establishment of regulatory authority such that the state inspectors could enforce adherence to construction specifications.

14

Key Finding and Recommendation

Observation: Based on information gathered from pipeline operators, we conclude that the general description of their pipeline construction process is similar to pipeline construction requirements for PHSMA-regulated and other traditional pipelines. Bedding requirements seemed to be an area where great variability exists. In general, published pipeline construction requirements (included PHMSA/DOT) do not require specific bedding, but rather defer to language such as "…must provide adequate support along the entire length of the pipe." A notable exception to this exists in ASTM standard ASTM D2321.

Finding: Many North Dakota pipeline operators are already employing widely used, appropriate standards in gathering pipeline installation. This indicates that prescription of best practices is not the primary factor in the North Dakota pipeline spills record. It does NOT, however, guarantee that these standards are always followed by contractors and subcontractors in the field.

Recommendation: The state may consider implementing construction standards consistent with practices being followed by many operators and currently required for larger, federally regulated transmission pipelines. It would be the responsibility of the third-party inspectors to ensure compliance with state construction standards, and state inspectors would serve the role of verifying that third-party inspectors were maintaining adequate oversight of the project.

CRUDE OIL AND PRODUCED WATER GATHERING PIPELINE MAINTENANCE AND INSPECTION

The complexity of oil, gas, and produced water gathering lines is increasing as more wells are completed and more systems come online. Inspection and maintenance of gathering lines are not regulated by the state of North Dakota, and operating companies typically devise their own best practice inspection and maintenance routines or follow API guidelines. Systematic maintenance of these gathering lines requires an integrated approach to communication between the inspection, maintenance, and engineering departments.

Maintenance systems that can facilitate reliable communication of inspection findings and their required remediation processes to appropriate departments and responsible parties can significantly improve effectiveness of the mechanical integrity program. Added complexity is introduced when gathering systems are operated possessing pipelines made of different materials, requiring different maintenance procedures.

While each company develops its own maintenance routine based on line material and fluids collected, almost all companies perform some form of visual inspection routine ranging from a dedicated individual to ride the lines daily, scheduled aerial inspections, visual inspection as part of traveling between job sites, and even unmanned aerial system (UAS) inspections. Beyond that, there appears to be no systematic maintenance program that is universally applied by all companies.

Pipeline Maintenance

This section will discuss a few of the more well-developed and most routinely used maintenance techniques which will be divided into the two most utilized pipeline materials: HDPE and steel.

Corrosion Protection

Corrosion protection is both a design feature of most corrodible pipelines and pipeline connections and is also a maintenance issue. Maintenance of anticorrosion features must be conducted over the lifetime of a pipeline system. This includes replacement of consumable CP plates and consistent supply of anticorrosion chemicals added to pipelined fluids. This was discussed under a previous section pertaining to corrosion design of pipelines and is, therefore, not repeated here.

Hydrostatic Testing

Hydrostatic testing is an industry- and regulatory community-accepted practice for evaluating the integrity of both newly constructed and in-service (existing) pipelines. The purpose of hydrostatic testing is to either eliminate any defect that might threaten the pipeline's ability to sustain its MOP or to show that no such defects exist (Kiefner, 2001). Hydrostatic testing consists of raising a pipeline's pressure level above normal operating pressure to look for the occurrence of any pipeline failure-causing defects. If any defects result in failure and are subsequently repaired (eliminated) or if no failure occurs because no such defect exists, a safe margin of pressure above normal operating pressure is demonstrated. In its application to new pipelines, the practice is often used to validate pipeline integrity and/or identify manufacturing flaws in pipeline materials (including pipe sections, joints, valves, meters, and other ancillary systems), damages incurred during material transport prior to pipeline construction/ installation, and damages or performance-degrading defects incurred during installation. ASME B31.4 calls for each newly installed liquid pipeline to be hydrostatically tested to 1.25 times its MOP. It is important to note the difference between MOP and "SMYS" (specified minimum yield strength), which refers to the pressure at which a pipe will undergo permanent deformation. For high-strength steel pipelines, SMYS is typically 52,000 psi. Depending on a variety of factors including pipe size and material(s) of construction, pipelined product type and hazard level, and "location class" (determined based on the pipeline vicinity population density), MOPs can range from 40% to 80% of SMYS.

Hydrostatic testing of existing pipelines can be especially beneficial in situations where records, surveys, and other pipeline history documents are of questionable accuracy, unverifiable as to source, and/or incomplete to the extent that concern is raised regarding the safe maximum operating pressure of the pipeline. Other reasons for hydrostatic testing of an existing pipeline include the need to:

- Assess the stability of pipeline defects that are impacted by hoop stress (internal pressure).
- Validate or establish the pipeline MOP.
- Requalify the pipeline after a location class change.
- Establish pipeline "safety reassessment" intervals.
- Verify pipeline integrity after a pressure excursion above MOP.

In its application to in-service or existing pipelines, hydrostatic testing essentially comprises:

- Taking the pipeline (or a specific section of the pipeline) out of service.

- Cleaning the pipeline. Depending on pipeline material(s) of construction (steel, plastic, HDPE, etc.) and pipelined product (crude oil, brine, oil–water combinations), different cleaning methods are needed, ranging from water flush to the use of chemicals and "pigs."

- Filling the pipeline with water.

- Raising the internal pressure of the pipe to a designated pressure or stress level (referred to as "hoop stress").

- Holding the pipe at or above the designated pressure for prescribed period of time, during which the pipe is monitored (via a variety of methods) for integrity.

There are limitations, both technical and economical, to the use of hydrostatic testing for revalidating the integrity of an existing pipeline. Taking the pipeline out of service for the time needed for test execution can sometimes be economically challenging, especially with single line systems where no other viable product transportation scenarios are available. A key technical limitation is the fact that a hydrostatic test is essentially a "go/no-go" device, in that it reveals weaknesses by causing ruptures or leaks, rather than indicating weaknesses by detecting the presence of corrosion or other potential failure-causing defects. A limitation that has both technical and economic implications is that a “test-pressure-to-operating-pressure ratio” of sufficient magnitude to generate high confidence in pipeline integrity may result in numerous breaks or leaks. For this reason, it is important to establish a test pressure that appropriately balances the benefit of establishing the maximum safety margin with the cost of dealing with any failures resulting from testing at too high a pressure.

Hydrostatic testing has been used for identifying and eliminating defects in existing pipelines since the early 1950s, when Texas Eastern Transmission Corporation and Battelle used it as the basis for rehabilitating the War Emergency Pipelines and converting them to natural gas service. Prior to testing, the pipelines exhibited numerous failures due to original manufacturing defects in the pipe. After testing to levels of 100% to 109% of SMYS—during which hundreds of test breaks occurred (and were repaired)—not one manufacturing defect-caused in-service failure was observed. Over the last 60+ years, key learnings acquired (from field experience and laboratory tests) regarding the benefits and limitations of hydrostatic testing include:

- The higher the test pressure, the smaller will be the defects—if any—that survive the test. The essential corollary to this is that the higher the test pressure-to-operating-pressure ratio, the more effective the test.

- Longitudinally oriented pipe material defects have unique failure pressure levels that are predictable on the basis of the axial lengths and maximum depths of the defects and the geometry of the pipe and its material properties (Kiefner and others, 1973).

- With increasing pressure, defects in a typical line-pipe material grow by ductile tearing prior to failure. If a defect is sufficiently near to failure, this ductile tearing will continue even if pressurization is stopped and pressure is held constant. The damage created by this tearing can be severe enough such that after pressure release and subsequent repressurization to a level below test pressure, the pipe may fail (McAllister, 2015). This is referred to as a “pressure reversal” (Brooks, 1968; Kiefner and others, 1980).

- A test may be terminated short of the initial pressure target, if necessary to limit the number of test breaks (failures), provided the MOP guaranteed by the test is acceptable to the pipeline operator.

Because an inherent feature of hydrostatic testing is the risk of pipeline failure in the form of uncontrolled releases of energy, water, and possible pipeline contaminants that represent health and/or environmental hazards, comprehensive planning and effective communication (to potentially impacted citizens) of test objectives and execution requirements is needed to minimize risk to public health and safety. Of key importance to effective hydrostatic testing is establishing if and when it should be done and at what test pressure. According to pipeline integrity assessment experts Kiefner and Maxey, if an existing pipeline is suspected to contain defects that are becoming larger with time in service and these time-dependent defects can be reliably located with an ILI tool, using the tool is usually preferable to hydrostatic testing (McCallister, 2015). However, ILI tools are not always viable, especially in pipeline systems with numerous internal diameter changes (such as many gathering line systems) that increase the difficulty of tool movement through the line. Also according to Kiefner and Maxey, if hydrostatic testing is to be conducted to revalidate the serviceability of a pipeline suspected to contain time-dependent defects, the highest feasible test pressure level should be used (McCallister, 2015). Although testing at the highest feasible pressure will establish the highest-possible safe operating pressure and/or rule out as many defects as possible, testing at a pressure beyond what is necessary to achieve safe operability objectives has the potential to result in numerous failures, each of which represents a repair cost. For this reason, hydrostatic test planning and objective setting must include a review of all available data and information regarding the subject pipeline history, especially including any references to corrosion-related leaks and/or damages.

Hydrostatic testing of existing in-service pipelines presents unique challenges not associated with new pipeline testing. Several of these challenges are briefly described below:

1) The line must be taken out of service for an extended period of time, which may require advanced planning to deal with the interruption in pipelined product flow. If available, large water storage systems can be used to minimize the time associated with water fill and discharge.

2) The line may have multiple internal diameters, wall thicknesses, and grades that complicate pipeline cleaning and/or test design and execution.

3) The line must be cleaned prior to water filling. Cleaning is important for several reasons, including the possibility that the pipeline may contain health- and/or environment-degrading contaminants, which, if released along with test water during a failure, could contaminate the environment and potentially pose a health threat. Depending on pipeline type (brine versus crude oil) and "complexity," (bends, elevation changes, valves, internal diameter variations, and numerous other features that impact cleaning difficulty), different cleaning regimens are required. Because brines essentially comprise minerals dissolved in water, brine pipelines are typically easier to clean than crude oil pipelines, since effective cleaning of brine pipelines can often be achieved via water flushing, whereas water flushing of crude oil lines may not be as effective because of the differences in water-based and hydrocarbon-based chemistries. Simply put: oil and water do not mix well. For this reason, crude oil and crude oil–water combination pipelines are often best cleaned using pig-based techniques; however, the presence of multiple internal diameter changes in many gathering line systems can make pig use challenging.

4) The cleaning process may generate hazardous waste streams that require permitted handling, transportation, and disposal.

5) Discharge of test waters to ground may not be allowed, and test water handling and disposal may be subject to environmental regulations.

6) In situations where an existing pipeline is in close proximity to the public, notifications and evacuations may be needed, since leaks and ruptures can be disruptive and/or hazardous. Testing (the intention of which is to improve safety) may heighten rather than

abate public interest and concern if important information regarding the test is not communicated properly. Venting and purging of pipelined product(s) in preparation for testing can be mistaken for evidence of pipeline damage and leaks, which can translate to public alarm.

Hydrostatic testing of existing pipelines comes with risks to the public as well as workers associated with test execution. During testing, access to exposed and pressurized piping and test equipment should be limited to only employees needed to execute the test. Special attention should be given to worker and public safety during the depressurization and dewatering steps because of the combination of temporarily installed equipment operating in a large pressure/energy-containing system undergoing a planned, controlled pressure/energy release, which has the potential to result in "jumping" of unsecured piping and/or equipment. A brief overview of key risks is provided below:

- Buried pipeline failure – Failure may result in water breaking the ground or paving surface, and subsequent erosion could occur in steep areas and/or loose soils. Pipeline contaminants could be released into the environment if containment and mitigation strategies are not adequately planned and executed.

- Exposed pipeline failure – In addition to the risks associated with buried pipelines, failure of an exposed pipeline has the potential to subject people and equipment to an intense energy release in the form of a water blast.

- Public safety – Hydrostatic testing in populated areas exposes the public to the pipeline failure impacts described above. Based on test pressure to be used, test pressure as a percentage of SMYS, and pipeline material(s) of construction and known history, safety zones should be established and patrolled during testing to prevent public access. In situations where safety zone enforcement may be constrained and/or inadequate, barricades, barriers, and blast mats may be needed.

- Worker safety – The Interstate Natural Gas Association of America (INGAA) Construction Safety Consensus Guideline, "Pressure Testing (Hydrostatic/Pneumatic) Safety Guidelines," offers a comprehensive strategy for identifying and mitigating risks to workers.

General guidelines for hydrostatic testing of steel, plastic, and HDPE pipes are briefly summarized below.

- For steel pipe, the test pressure utilized is generally 1.24 to 1.4 times the MOP for 4 hours.

- For plastic pipe, the pressure testing is also dependent on the particular pipe material and must be below the pressure rating of the pipeline component with the lowest pressure rating in the test section.

- For HDPE pipe, the pipe will expand to some degree with pressure, and this must be taken into account. Therefore, testing comprises a three-step process:

- In Step 1, the pipe is filled with water, the air allowed to vent, and the pipe allowed to equilibrate without positive pressure for 60 minutes. The pipe is then pressurized to the specified test pressure. As the pipe expands slowly, more water is added to maintain the specified pressure for the first 30 minutes. At 30 minutes with the pipe at the specified pressure, the pipe is valved off and allowed to relax for 90 minutes. This is recorded as the residual test pressure. If the residual pressure is greater than or equal to 70% of the specific test pressure, the pipe has passed; if it is less than this, the pipe has failed the test because of a leak or too much air in the line.

- In Step 2, the residual test pressure is reduced by 10% to 15%, and the volume of water removed recorded. A calculation is performed to determine if the amount of water removed is less than the maximum allowable volume at the specified temperature and pressure. If the volume of water removed is more than the calculated maximum, the pipe fails the test, typically because of too much air in the line, and Steps 1 and 2 must be repeated.

- During Step 3, after the pressure in the pipe has been reduced in Step 2, the pressure should rebound slightly and then hold constant. If the pressure shows a continuously falling pressure, the pipe has failed Step 3 because of a leak (Plastics Pipe Institute, 2013; Kiefner, 2001).

Pneumatic Testing

Pressure testing with gas rather than liquids is another method of leak and strength testing but requires more care because of the inherent potential energy in a compressed gas versus a practically incompressible fluid such as water. Pressurizing water to 500 psi will decrease the volume by approximately 0.16%, a very slight reduction. Compressing air to the same 500 psi will decrease the volume to approximately 1/35 of volume of air at atmospheric conditions, giving the compressed gas a much higher decompression energy. This can lead to explosive decompression in a pipe leak/failure that can cause serious damage to the pipe as well as the surrounding area and personnel. PHMSA states that pneumatic testing is rarely performed on pipelines that have a MOP of 100 psi or greater for this reason. In some cases, the location may dictate the use of pneumatic testing for a specific case. Costs for compression in pneumatic testing can be higher and more complicated because of reaching the desired pressure in stages when compared to hydrotesting.

When pneumatically testing plastic pipe, the Plastic Pipe Institute recommends "Pneumatic testing should not be considered unless one of the following conditions exists:

- The piping system is so designed that it cannot be filled with a liquid.

Or

- The piping system service cannot tolerate traces of liquid testing medium (Plastic Pipe Institute)."

If it is determined that a pneumatic pressure test is the only viable option for an HDPE pipeline, the Plastic Pipe Institute recommends the following procedural test structure:

The pressurizing gas should be nonflammable and nontoxic.

- *Restraint* – The pipeline test section must be restrained against movement in the event of catastrophic failure. Joints may be exposed for leakage examination provided that restraint is maintained.

- Leak test equipment and the pipeline test section should be examined before pressure is applied to ensure that connections are tight, necessary restraints are in place and secure, and components that should be isolated or disconnected are isolated or disconnected. All low-pressure filling lines and other items not subject to the leak test pressure should be disconnected or isolated.

- *Leak Test Pressure* – For pressure piping systems where test pressure-limiting components or devices have been isolated, removed, or are not present in the test section, the maximum allowable test pressure is 1.5 times the system design pressure for a leak test duration of 8 hours or less. If lower pressure-rated components cannot be removed or isolated, the maximum test pressure is the pressure rating of the lowest pressure-rated component that cannot be isolated from the test section. Leak test pressure is temperature dependent and must be reduced at elevated temperatures.

- The pressure in the test section should be gradually increased to not more than one-half of the test pressure, then increased in small increments until the required leak test pressure is reached. Leak test pressure should be maintained for 10 to 60 minutes, then reduced to the design pressure rating (compensating for temperature if required), and maintained for such time as required to examine the system for leaks.

- Leaks may be detected using mild soap solutions (strong detergent solutions should be avoided) or other nondeleterious leak-detecting fluids applied to the joint. Bubbles indicate leakage. After leak-testing, all soap solutions or leak-detecting fluids should be rinsed off of the system with clean water.

- If leaks are discovered, the test section is depressurized before leaks are repaired. Correctly made fusion joints do not leak. *Leakage at a butt fusion joint may indicate imminent catastrophic rupture. Depressurize the test section immediately if butt fusion leakage is discovered.* Leaks at fusion joints require the fusion to be cut out and redone.

- If the pressure leak test is not completed because of leakage, equipment failure, etc., the test section should be depressurized and repairs made. To retest the test section, it should remain depressurized for at least 8 hours.

Typical gases that may be used in testing for strength pneumatically include air, nitrogen, and methane. One advantage that pneumatic testing has over hydrostatic testing is the mass of the materials used to pressure test. Liquids such as water have a significantly higher mass than a gas such as air. Vertical changes in elevation with water will increase the pressure at the low point by approximately 0.433 psi per foot of rise. Therefore with a HDPE pipeline rated for 150 psi maximum allowable working pressure (MAWP), full of water, the change in height cannot exceed 346 feet or the low point will exceed the MAWP when the high point is at atmospheric pressure. Utilizing a gas to pressure test will not have this issue, and the entire length of pipeline being tested will remain at a constant pressure throughout.

Pigging

A common maintenance technique used in steel lines and, less frequently, HDPE lines is pigging. Pigging is defined by NACE as "the operation of transporting a device or combination of devices (scraper, sphere of flexible or rigid plastic) through a pipeline for the purpose of cleaning, chemical application, inspection, or measurement" (National Association of Corrosion Engineers, 2006). A pig is the device that is transported through the pipeline. Pigs come in many different varieties, such as utility pigs for routine cleaning operations, geometry pigs for dimensional inspections, and inline inspection pigs or smart pigs for more complex inspections such as corrosion identification. Figure 43 illustrates three common types of pigs: a poly foam pig bottom left, unibody cast polyurethane pigs upper and lower right, and a steel mandrel smart pig in the center:

- Poly foam pigs are generally used for cleaning and light scouring or abrasion work. These pigs have the benefit of being low-cost, flexible, and able to transit tight radius bends as well as transitions in pipeline dimensions such as at steel connections on some HDPE and composite pipelines.

15

Key Finding and Recommendation

Observation: Hydrostatic testing is an industry- and regulator-accepted practice for evaluating the integrity of both newly constructed and in-service pipelines. It is applicable to all types of pipelines, although the details of test procedures may vary by pipeline type and material of construction. The purpose of hydrostatic testing is to force a failure caused by any defects that might threaten the pipeline's ability to sustain its MOP.

Finding: North Dakota pipeline safety may be enhanced by ensuring that hydrostatic tests are conducted according to manufacturer recommendations on all pipelines initially upon installation and upon repair of an installed pipeline. Periodic hydrostatic testing on in-service pipelines presents logistical challenges and may shorten pipeline lifetimes, significantly increase operational costs, and increase pipeline system downtime—all for unquantifiable increases to pipeline integrity assurance.

Recommendation: North Dakota DMR should consider a requirement to provide assurance of completed hydrostatic testing according to manufacturer recommendations on all newly installed or newly repaired liquid gathering pipeline segments.

- Unibody cast polyurethane-style pigs can be outfitted with multiple disks and are generally used for cleaning, separation of liquids, removal of water, removal of paraffin buildup, application of internal coatings, batching of corrosion inhibitors, etc.

- Steel mandrel pigs are generally used as smart pigs, a more complex data-collecting device such as for corrosion detection.

- Smart pigs are battery-operated and outfitted with numerous measurement devices for corrosion detection, geometry sensing, and pipeline integrity.

All pigs must be inserted into the pipeline using pig launchers, as shown in Figure 44. The pig is removed from the pipeline using a very similar device, called a pig receiver, with fluid flow in the opposite direction.

EERC JA51389.CDR

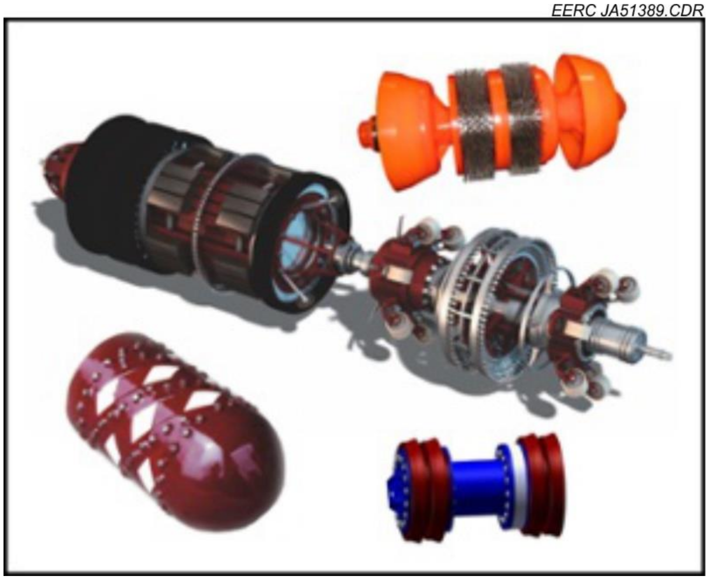


Figure 43. Illustration of pig types.

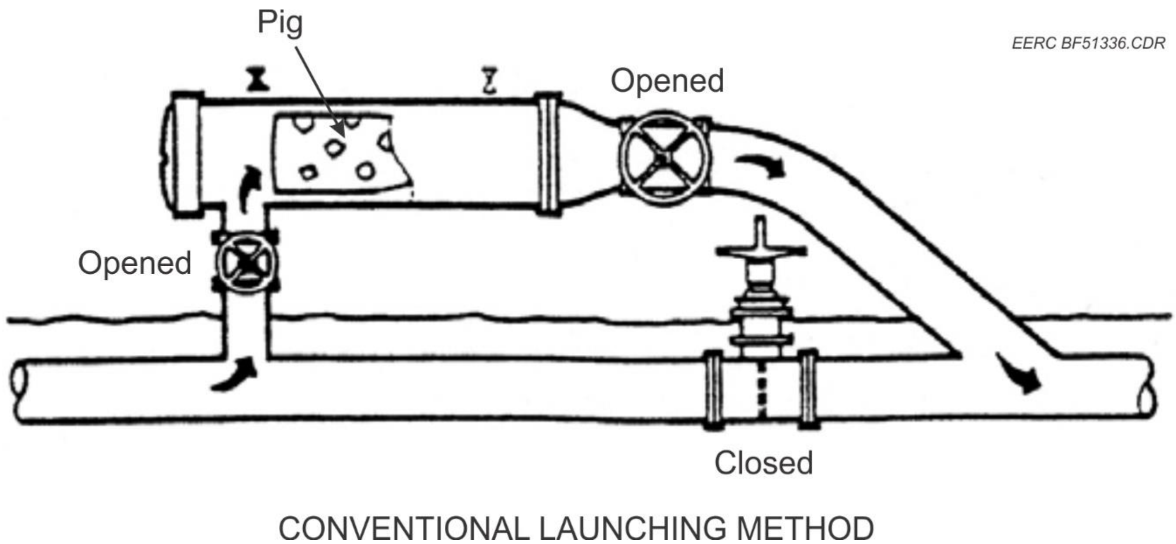


Figure 44. Illustration of a pipeline pig launcher system.

General Cleaning Pigs

Pigs are an effective tool for pipe cleaning and can assist in corrosion control by removing contaminants in the pipe such as water that has settled out in low areas, dirt and other loose materials that may aid in localized corrosion sites, and corrosion products and waxes that may also aid in producing local corrosion sites. In most HDPE and composite pipelines used for brine transport, pigging can also prevent buildup of salts and loose material such as sand from flowback that may cause an overpressure situation to occur, damaging pipe integrity. Cleaning pigs can be outfitted with abrasive materials such as wire brushes or scrapers to help in removing materials adhering to the internal pipe.

Through surveys of gathering line operators, construction contractors, producers, and engineering firms, it was found that the majority of gathering lines in the Bakken are designed without the ability to use pipeline pigs for cleaning, maintenance, and inspection. While pigs are used on longer and larger PHMSA-regulated interstate pipelines, this is not the case for most gathering lines. It is postulated that the smaller diameter, shorter length of the lines, nonuniform diameter, and the number of tie-ins and junctions have led most gathering line designers, builders, and operators to forego the extra costs involved in making them accessible to pigs. Larger PHMSA-regulated lines tend to have more uniform diameter over longer lengths, which is more amenable to running pigs for cleaning and inspections. Frequently, in gathering lines, the lines are shorter in length and will consist of segments of varying diameters.

Additionally, joining techniques for gathering lines of HDPE and composite material can be, but are not necessarily, areas of reduced diameter which can limit the type of pigs that can navigate through the unions. Foam pigs have the ability to navigate tight radius turns and to compress when subjected to smaller diameter regions of the pipe. However, too much compression and abrasion by reducing unions can damage the foam pig and diminish its effectiveness for cleaning. Most other styles of pigs do not possess this ability to navigate reduced-diameter pipe sections, which limits their use in many gathering line situations.

Monitoring the material that is removed and the condition of the cleaning pig after a routine cleaning can help to identify frequency required for maintenance cleaning to ensure pipeline integrity.

Smart Pigs

Smart pigs come in several variations such as ultrasonic, magnetic flux, and geometry sensing. Two common types of ultrasonic pigs are compressive wave and shear wave testing. Compressive wave ultrasonic tools (UT) for ILI use transducers to propel an ultrasonic wave in a direction perpendicular to the pipe wall. The UT tools are equipped with sensors to record and measure the signal return from both the internal and external surface. In this fashion, the tool can determine the speed through the pipe wall and, subsequently, the pipe thickness and any variations in the pipe wall as it moves down the line. As with all ILI tools, location sensors are critical to be able to locate any potential problem areas after the tool has been removed from the line. For UT ILI tools to function correctly, a clean wall surface is needed, and these tools are generally preceded by a cleaning or scraping pig.

The second type of ultrasonic ILI tool is the shear wave UT, sometimes referred to as circumferential ultrasonic testing (C-UT). This type of ILI tool is used for detecting longitudinal defects and cracks. These types of defects tend to be perpendicular to the main stress in the pipe which is the hoop stress. To account for the longitudinal nature of these defects, the ultrasonic pulses are propelled in a circumferential direction. The shear wave is manifested by angular transmission of the ultrasonic pulse through a liquid medium such as oil or water, with the angle of incidence made to sustain the propagation angle of 45° in the pipe. As in UT, the device carries sensors to record the returning signal and determine defects in a similar fashion.

Magnetic flux leakage (MFL) ILI tools use an applied magnetic field that is induced in the pipe wall between the north and south poles of magnets on the ILI tool. If the pipe wall is without defects, the induced magnetic field produces a homogeneous magnetic flux distribution. Defects in the pipe wall will result in a change in this distribution. The ILI tool is equipped with sensors that detect, measure, and record this magnetic flux pattern. Here again, the ILI tool must have location sensors for finding the locations detected once the tool is removed and the data downloaded.

As with the UT ILI tools, MFL tools also have a circumferential measurement tool known as a transverse flux inspection (TFI) tool. In this design, the magnetic field is turned and oriented circumferentially and uses the same principle as the MFL ILI tools. A TFI ILI tool can be useful for detecting defects in weld seams and SCC that cannot be detected with other means.

Geometry-sensing tools are tools that typically have mechanical arms that follow the bore of the pipe to measure its shape and determine defects such as dents and out-of-round areas. These tools can also find changes in welds and wall thickness. Here again it is necessary for the device to have a means of determining location and recording this information for later download once the ILI tool is removed from the pipeline (U.S. Department of Transportation, 2014).

Chemical Treatment-Based Pipeline Cleaning

The use of hydraulic fracturing techniques developed in oil and gas shales over the last decade has opened up an enormous amount of oil and gas reserves in the United States. Hydraulic fracturing involves injecting a large amount of water into the underground shale formation at high pressure that induces fracturing of the shales, increasing the formation permeability and, therefore, its ability to flow oil and gas. The water injected into the formation is generally freshwater that has been treated with specific chemicals such as biocides and surfactants, but fracture fluids can also be previously used water from prior operations (flowback water) that has been treated to remove undesirable constituents.

Produced water typically contains many salts, including calcium chloride, sodium chloride, magnesium chloride, potassium chloride, sulfates, bicarbonates, bacteria, and other materials specific to the formation geology. When the water reaches the surface, the temperature and pressure will change, evolving gas that will change the pH of the solution which collectively affects the solubility of the salts and the ability to retain suspended solids. The changing conditions allow for precipitation of materials onto pipeline surfaces.

Pipelines that carry flowback and produced water generally do not run full at pressure and, therefore, will have areas of lesser velocity and lower pressures, again allowing deposition and scale formation of brine material onto the surface of the pipe. Carbonate scale deposition is generally acid-soluble, while sulfate scale formations are largely acid-insoluble. Treatment with acid solutions is one way carbonates are removed along with mechanical means such as pigging. For the sulfate formations insoluble in acid, chelating solutions are used to break up the scale and remove it along with mechanical means such as pigging (Horner and others, 2011; Nergaard and Grimholt, 2010).

Most crude oils transported in pipelines contain “associated water” at contents ranging from 0.2 to 5 volume percent, which is why crude oil pipelines can experience mineral scale deposition and corrosion issues primarily associated with water pipelines. Crude oil pipelines also become fouled with organic scales resulting from oil-contained paraffins, naphthenes, naphthenic acids, asphaltenes, and other high-molecular-weight organics, which can build up on internal pipeline surfaces and impede flow to the extent that their removal is required to sustain pipeline operation.

The most common method for pipeline cleaning is pigging (Wylde, 2011). Although removal of scale (both inorganic and organic) can be effected by pigging alone, in many cases scales can become compacted on internal pipe surfaces to the extent that pig movement is restricted, resulting in less effective cleaning. In some cases when organic materials are deposited on steel pipeline walls, moisture is trapped underneath the fouling deposit, resulting in localized areas of corrosion that can be hard to detect, even with smart pigs, since deposits can “block” a smart pig’s diagnostic capability. For these reasons, “chemically assisted pigging” (the use of chemicals along with cleaning pigs) is increasingly being employed to break up, soften, and transport deposits, which is especially important prior to inspection with smart pigs.

Cleaning chemicals include acids or chelating solutions for removal of carbonate and sulfate scale formations from produced water pipelines and mixtures of surfactants for dealing with the often more complex deposition problems associated with crude oil pipelines. Surfactants are "surface-active" chemicals that lower the surface tension (or interfacial tension) between two liquids or between a liquid and a solid. Surfactant functionalities/properties of value to pipeline cleaning include the ability to effect wetting, formation of emulsions, solubilization, dispersion, and detergency, as briefly described below:

- Wetting reduces the surface tension of a material so that it can be more easily suspended in another material. For pipeline cleaning, wetting agents are typically used to help remove hydrocarbon deposits from oil-wet scale, thereby allowing access to inorganic materials beneath.

- Emulsifiers enable the formation of a stable emulsion (mixture of two or more immiscible liquids) and are used in pipeline cleaning to keep materials removed from the pipeline wall from downstream redeposition.

- Solubilizers are chemicals that—when used at sufficiently high concentrations—can effectively bring otherwise insoluble materials (like hydrocarbon and water) together into an apparent solution, which is helpful in transporting removed materials out of a pipeline.

- Dispersing agents help to keep insoluble particles from aggregating and becoming larger particles, which is needed to ensure against particle growth to the extent that particles become too large and heavy for suspension, drop out of the cleaning solution, and redeposit.

- Detergents remove particles from a surface, and detergency is needed to mobilize hydrocarbon phases after wetting to remove them from the pipeline wall (Wylde and Slayer, 2010).

Various companies have developed pipeline-cleaning solutions that offer some or all of the above functionalities, depending on the specific cleaning application for which the solution was formulated. For example, a pipeline carrying a high-volatility crude oil with high contents of dissolved gases and water will likely sustain formation of deposits with a different chemistry than a pipeline carrying a low-volatility crude with high asphaltene and low water contents. Both of these pipelines will likely differ in deposit chemistry from a pipeline carrying briny produced water. While solvents and surfactant-based pipeline-cleaning solutions can be used with or without cleaning pigs, cleaning effectiveness is typically increased with pigs.

Although chemically assisted pigging is a relatively new and still-developing approach to pipeline cleaning, procedures often comprise an initial injection of surfactant-based cleaning solution followed by injection of water and use of a pig to push the cleaning solution and water through the pipe. Procedures may also utilize mixtures of aromatic solvents and cleaning solutions. Following recovery of initially injected cleaning solution along with the "pig trash" (material removed from the pipeline wall) at the end of the pipe, the pig trash can be weighed (or otherwise quantified) and analyzed. Analysis is important because it can provide information regarding the occurrence and extent of any pipeline corrosion. Depending on the amount of pig trash recovered after the initial cleaning solution injection, another run can be made using the initial or an adjusted cleaning solution recipe, with additional runs performed as needed to achieve the desired level of cleaning.

The following pipeline-cleaning "case history" (taken from Wylde, 2011) provides insight on the execution, logistics, and equipment requirements of chemically assisted pigging. An approximate 2-mile-long, 10-inch-inside diameter carbon steel crude oil pipeline was needed to be brought back into service after being mothballed for several years. A legislative directive required determination of the pipeline's integrity (via use of intelligent pigging) and ability to transport 8000 barrels/day of a mixture comprising 60% water and 40% heavy crude. Based on substantial knowledge of pipeline deposits that had been acquired via intelligent pigging conducted prior to mothballing, it was determined that the pipeline would need to undergo extensive cleaning prior to integrity determination to ensure the effectiveness of the prescribed intelligent pigging operation (i.e., to ensure that the intelligent pig would be "looking at" the actual pipeline wall rather than material deposited on the wall). To achieve the necessary cleanup, a three-stage chemically assisted pigging strategy was devised, comprising:

1) Preflush with 300 gallons (about 14 barrels) cleaning solution, followed by 5400 gallons (129 barrels) treated seawater and a "brush pig."

2) Cleaning Run 1 with 3000 gallons (71 barrels) aromatic solvent, followed by 1000 gallons (24 barrels) cleaning solution, followed by 9000 gallons (214 barrels) treated seawater and a brush pig.

3) Cleaning Run 2 with 1000 gallons (24 barrels) aromatic solvent, followed by 2500 gallons (60 barrels) cleaning solution, followed by 22,500 gallons (536 barrels) treated seawater and a brush pig.

Large deposits were removed during the preflush, and during the first cleaning run, the entire 30-foot trap was filled with trash. A further 20 feet of material had to be removed before the brush pig could be retrieved. Following the final cleaning stage, smaller volumes of trash were recovered. Figure 45 shows the brush pig as it emerged following Cleaning Run 2. Figure 46 shows the intelligent pig utilized for integrity determination following completion of the three-stage cleaning operation. Had the integrity determination been attempted without first cleaning the pipeline, it is likely that the information acquired with the intelligent pig would have been inadequate to establish the pipeline condition and comply with the legislative directive.

Figure 45. Brush pig after emerging from Cleaning Run 2.

Figure 46. Intelligent pig after integrity determination run following three-stage chemically assisted pigging operation—note cleanliness.

16

Key Finding and Recommendation

Observation: Smart pig-based diagnostic technologies are becoming increasingly reliable and cost-effective in locating and assessing the extent of pipeline corrosion and other potential failure-causing defects. Significant improvement in diagnostic capability is achieved when the smart pig is applied to a clean pipeline, and pig-based cleaning techniques typically work better than non-pig-based techniques.

Finding: Through surveys of gathering line operators, construction contractors, producers, and engineering firms, it was found that the majority of gathering lines in the Bakken are designed without the ability to use pigs for cleaning, maintenance, and inspection.

Recommendation: It may be worthwhile to assess the cost of making gathering (and other) lines compatible with pig use and compare this cost to the benefit of an improved ability to monitor pipeline integrity and prevent failures.

Visual Inspection

Ground Crews

Nearly all gathering pipeline operators informing this study conveyed that they employ regularly scheduled visual inspections by ground crews by vehicle and/or foot. These simple inspections are meant to provide a last line of defense against spills and leaks. Employees walking or driving along segments of gathering pipeline networks are able to visually verify that pipelines appear to be in good working order and that no leaks exist, as evidenced by pipeline drips or wet ground.

Aerial Inspection

A very small percentage of the crude oil gathering lines in North Dakota are regulated by PHMSA. Those that are not regulated by PHMSA have no required ROW inspection. PHMSA requires that "Each operator shall, at intervals not exceeding 3 weeks, but at least 26 times each calendar year, inspect the surface conditions on or adjacent to each right-of-way." This inspection tends to be performed by aerial inspection using airplanes or helicopters to visually inspect the ROW. While not required for gathering lines, some oil and gas gathering line operators have used this as part of their maintenance and monitoring procedure. This can be an effective but relatively expensive form of maintenance and monitoring for small gathering line systems. In aerial inspections, typically the ROW is flown over and images recorded of the area. These images are then analyzed by the operator for disturbances in the ROW that may either be a leak or may be activities that endanger the pipeline integrity. While visual images are effective to determine the status of the ROW, if used primarily for maintenance and inspection, more effective imagery such as IR (infrared) imagery and other inspection and analysis methods coupled with the visual images may be more effective at determining if leaks have occurred or if conditions are conducive to line damage in the near future with the potential to cause leaks.

An interesting aspect of aerial maintenance inspection is the potential for use of UAS. UAS may provide a less expensive version of the currently performed aerial inspections for visual imagery at shorter intervals, leading to quicker response times acting on potentially damaging situations. In addition, aerial inspections currently require flying at levels that may not allow for "sniffer" techniques to detect volatile emissions indicative of leaks in oil and gas lines, where UAS may be able to overcome this by very low altitude, slow-speed surveillance of the pipeline. Additional discussions of the potential for UAS as inspection and monitoring tools are provided in later sections of this report under Possible External Above-Surface Leak Detection.

GATHERING PIPELINE MONITORING AND LEAK DETECTION

Monitoring conditions in and around pipelines is necessary to maintain safe, efficient, and environmentally acceptable pipeline operation. Many different monitoring techniques are currently being applied while many others have been proposed or are being developed that are aimed at achieving these three objectives; however, the appropriateness, effectiveness, and cost of any specific approach are situation-dependent.

Numerous resources were accessed in developing the following description of the current state of pipeline monitoring and leak detection technology:

- Gathering line operator stakeholder meetings, field visits, surveys, teleconferences, and e-mail
- Technology vendor cost estimates, product specifications, teleconferences, and e-mail
- International regulations from Canada (CSA-Z662-03, Canadian Standards Association, 2003) and Germany (Technische Regel für Rohrfernleitungen [TRFL, Technical Rules for Pipelines], 2003)
- Standards from API (e.g., API Recommended Practice 1130 [American Petroleum Institute, 2012]) and the U.S. Navy (LeFave and Karr, 1998)
- Federal government studies and reports by the U.S. Environmental Protection Agency (EPA), PHMSA, and the National Transportation Safety Board (NTSB)
- Federal government regulations (e.g., DOT, 49 CFR Part 195, EPA 40 CFR Part 280)
- Other federal government publications (e.g., PHMSA Advisory Bulletins)
- Technical conference reports and presentations (e.g., SPE [Society of Petroleum Engineers] conference, Europe's annual Pipeline Technology Conference, Alaska 2011 Leak Detection Technology Conference, Pipeline Simulation Interest Group annual conferences, Australian Institution of Engineers 2001 Conference on Hydraulics in Civil Engineering)
- Industry publications (e.g., *Pipeline Technology Journal*, *Pipeline & Gas Journal*)
- Others (e.g., Pipeline Research Council International, Inc.)

With the exception of information acquired from gathering line operators by this study, the overwhelming majority of these resources describe leak detection technologies that have been reported by or considered for use on transmission pipelines. No body of knowledge—outside of direct communication with gathering line operators—has been uncovered by the current study that documents the application of leak detection to gathering lines. Consequently, because of this lack of reported gathering line experience, descriptions in this section generally relate to transmission pipeline experience and not gathering line. It should be emphasized that gathering lines present unique challenges to leak detection technologies. As a result, some care must be taken when extrapolating transmission line experience to gathering lines.

Purpose and Definition of a Pipeline Monitoring and Leak Detection System

For clarity, it is important to define several terms which will be discussed in this section on pipeline monitoring and leak detection:

- *Supervisory control and data acquisition (SCADA)* system means a computer-based system or systems used by personnel in a control room that collects and displays information about a pipeline facility and may have the ability to send commands back to the pipeline facility (i.e., start or stop pumps, control process equipment remotely, etc.).

- *Computational pipeline monitoring* (CPM) means a software-based monitoring tool that alerts pipeline personnel of a possible pipeline operating anomaly that may be indicative of a fluid release.

- *Controller* means a qualified individual who remotely monitors and controls the safety-related operations of a pipeline facility via a SCADA system from a control room and who has operational authority and accountability for the remote operational functions of the pipeline facility.

A wide variety of pipeline monitoring and pipeline LDS exist, each with their own unique characteristics, advantages, and limitations. In the most simplistic form, leak detection can be achieved through physical inspections and/or periodic (daily) comparisons of volumes pumped into and flowing from a gathering system. In some instances, this flow balancing is done manually by technicians visiting wellsites and recording data in a log book or entering it into a computer. Automation of this process with process computers and communication infrastructure, or SCADA, allows for near-continuous monitoring of operating conditions and represents a significant evolution in pipeline monitoring. SCADA is used to monitor and control pipeline parameters or operations, while leak detection focuses on loss of pipeline integrity. Leak detection may use data from SCADA, but it is not necessary for all leak detection methods to use SCADA. Once SCADA capabilities are in place, a variety of more advanced technology can be added to provide additional accuracy and/or response time relative to leak detection. Some leak detection technologies rely on evaluating data that exist within the pipeline monitoring system; others require the use of sensors in the ground, on the pipeline, or within a remote sensing application.

Pipeline leak detection methods are typically divided into three categories:

1) Internal systems: These systems use pipeline measurement sensors such as flow, pressure, temperature, and density to calculate the state of the liquids in the pipeline. Leaks are determined through inferential analysis.

2) External systems: These systems use specific instrumentation designed to detect a leak directly and are typically located external to the pipeline.

3) Visual or inspection systems: These methods include visual inspections from air or ground patrols, advanced imaging technology, or electronic internal inspection of the pipeline during maintenance or after repairs.

In-depth discussion and explanation of leak detection methods can be found in Shaw and others (2012), Alaska Department of Environmental Conservation Division of Spill Prevention and Response (1999 and 2012), and Appendixes G and H.

Internal Leak Detection Systems

Internal leak detection identifies the existence, and possibly location, of leaks based upon measurements of fluid conditions within the pipeline. Such methods have been practiced on major interstate pipelines carrying high-value or hazardous fluids for many years. By 1995, these technologies had advanced to the point that API felt compelled to release its first version of its Recommended Practice 1130, "Computational Pipeline Monitoring."

17

Key Finding and Recommendation

Observation: Most of the industry's standard methods for leak detection are called out in API 1130 for regulated transmission pipelines. Advanced LDS methods are used infrequently by North Dakota gathering line operators.

Finding: Company decisions regarding implementing new pipeline monitoring and leak detection technology rely upon, among other things, analysis of the cost and benefit. There is a need for objective data on the performance of different leak detection technologies under real-world conditions.

Recommendation: The gathering pipeline monitoring and leak detection pilot project prescribed by HB1358 will serve as a platform to test current and new leak detection technologies applied to gathering systems. This pilot project will test performance, determine infrastructure requirements, estimate costs to pipeline operators, and provide objective analysis of the cost/performance ratio.

Supporting this point is the fact that nine of the 57 special conditions that were developed by PHMSA to improve the safety of the Keystone XL pipeline in the final Environmental Impact Statement for the Keystone XL Project were related to pipeline monitoring and internal LDS (U.S. Department of State Bureau of Oceans and International Environmental and Scientific Affairs, 2011). This contrasts with external leak detection methods, such as IR sensors and fiber-optic cables, which TransCanada decided in 2013 not to deploy in the Keystone XL Pipeline Project (Penty and Lee, 2013).

Since July 6, 1999, controllers of hazardous liquids pipelines were required under 49 CFR Part 195 to utilize some form of continual leak detection methods. These regulations specifically call out API Standard Practice API 1130—Computational Pipeline Monitoring (CPM) for Liquid Pipelines (American Petroleum Institute, 2012). Although these regulations do not necessarily apply to North Dakota gathering lines, the internal LDS for which API 1130 was written are already in use by most North Dakota operators.

From API 1130, the SCADA system is a computer-based communications system that gathers, processes, displays, and controls data from field instrumentation. CPM systems will generally use data gathered by the pipeline SCADA system, but some systems may gather data independently. CPM is a term that refers to algorithmic monitoring tools that are used to enhance the abilities of a pipeline controller to recognize hydraulic anomalies that may be indicative of a pipeline leak or commodity release. CPM techniques comprise the vast majority of internal leak detection technologies. Internal conditions that deviate from normal or possess characteristics of leak situations are inferred to be leaks and identified to the LDS for examination and response by pipeline controllers and operators. The sensitivity (ability to identify smaller leaks) of CPM techniques depends upon the accuracy with which internal pipeline conditions are measured and the accuracy with which normal conditions or leak-indicative conditions are understood.

Conservation of Mass Techniques

Conservation of mass techniques balance the mass injected into a pipeline with the mass delivered from that pipeline. Any difference between these two measurements comes from mass accumulated in the pipeline or lost from the pipeline by some type of release. These methods benefit by liquid-filled lines which minimize the possible accumulation of fluids in otherwise empty line and permit imbalances between injection and delivery to be attributed to leaks. Conservation of mass techniques differs with respect to the accuracy with which they account for factors such as temperature, pressure, composition, and elevation at the measurement points:

- The line balance technique is the easiest to implement since it does not consider such factors but, consequently, is also the least accurate.

- The volume balance, modified volume balance, compensated line balance, and real-time transient model (RTTM) are techniques that consider progressively more factors and thus achieve increasing sensitivity but are also progressively more difficult and expensive to implement and maintain.

- More advanced methods require not only accurate measurements of pipeline conditions but also physical knowledge of the pipeline (such as the elevations at which measurements are taken along the pipeline and the effects of temperature, pressure, and other conditions on the pipeline) and knowledge of how the fluid properties (such as density) change with temperature, pressure, and composition. Applying this knowledge requires more sophisticated CPM algorithms and more computer power with which to execute them.

Signature Recognition Techniques

Signature recognition techniques are a second class of CPM methods that monitor fluid measurements for changes or trends that deviate from those expected under “normal” fluid flow conditions or that are similar to conditions that are expected to exist with leaks. Some techniques are simple and inexpensive to implement and maintain but are less sensitive than more sophisticated techniques. These methods include:

- Monitoring the pipeline for higher-than-expected flow rates or changes in flow rates and pressures or lower-than-expected pressures.

- More advanced techniques that monitor magnitudes and rates of change of both pressure and flow rate at a single location or pressures and flows at multiple locations.

These techniques monitor deviation from normal conditions. Still more advanced techniques that monitor fluid properties for conditions indicative of leaks include:

- Acoustic (or negative pressure wave) monitoring.
- Pressure and flow pattern recognition.
- Negative pressure wave modeling.

Some internal leak detection techniques such as acoustic or negative pressure wave monitoring not only identify leaks but may also assist in locating leaks with some precision. All signature recognition techniques require knowledge of what comprises normal conditions or conditions indicative of leaks. This might only involve determining how much of a decrease in pressure is normal, so that any decreases in excess of that would indicate a leak. With more advanced techniques, careful study of the physical system so as to mathematically model its behavior or thorough training of a neural net to be capable of distinguishing normal from leak-indicative conditions might be required.

Statistical Analysis Techniques

Statistical analysis techniques represent a third class of CPM detection methods. Strictly speaking, statistical analysis techniques are signature recognition methods. They have been segregated from other signature recognition methods because of their significantly decreased reliance on knowledge of pipeline and fluid characteristics and properties and the associated effort and costs of gathering such information. Statistical analysis techniques collect data on the past behavior of key measurements and compare those with the current values, then apply statistics to the data to provide a measure of confidence that the current values are representative of normal or leak-indicative conditions.

Other Techniques

Other CPM leak detection techniques exist in addition to the above classes and include:

- State estimation – a model-based approach to improving measurements based upon such mathematical tools as the Kalman filter.

- Enhanced RTTM – adds leak location functionality to leak detection.

- Preprocessing of data – can recognize instrument failures and can improve the reliability of LDS by avoiding false alarms.

- Combinations of any of the previously described methods – incremental improvement in effectiveness depending on overlap or similarity among existing and added techniques.

Ultimately, achieving a desired sensitivity depends upon adequate measurement accuracy and knowledge of the pipeline network and properties of its contents. In addition, consistent operation of the pipeline might be necessary. With increased sensitivity comes increased cost to:

- Procure, install, and maintain adequate measurement instrumentation, communications, power, and computer infrastructure.

- Acquire necessary knowledge of pipeline and liquid characteristics, properties, and/or previous behavior.

- Perform the programming and configuration required to implement the techniques.

For simple, less accurate techniques, existing pipeline instrumentation might be adequate. However, greater accuracy will require more resources.

Appendix I describes the components that comprise an automated, SCADA-based monitoring system. Appendix G contains descriptions, advantages, and disadvantages of major CPM leak detection techniques. In some instances, some names of products and vendors are included. Appendix H contains a list of leak detection technology products, vendors, and brief descriptions of the products.

In 2011, 18 CPM and at least 80 external (i.e., distributed temperature sensing and acoustic) vendors in the United States were reportedly operating (Summa, 2011). In 2012, proceedings from a pipeline leak detection conference sponsored by the state of Alaska listed six subsurface and three above-surface external technology vendors and eleven internal technology vendors. Appendix H includes these and other LDS vendors.

External Leak Detection Systems

External LDS are either attached directly to the outside of the pipe or are next to the pipe in the form of a probe, tube, cable, or wire. Many of these external systems are applicable only to hydrocarbons and not to produced water pipelines. Others are deployed as point sensors at a strategic location or in short pipe runs in HCAs where rapid response and leak location are essential. Currently, there is no equivalent to API 1130 for guidance in selection and installation of external systems. External systems should be incorporated into the design phase of the pipeline, as many are not amenable to retrofit. They are generally too expensive and risky because the required reexcavation near pipelines can lead to accidental damage. Failure to discover minor damage could lead to a future leak.

The majority of the external systems can be divided into six categories based on physical operating principles:

1. Sensing liquids with acoustic emissions

2. Sensing liquids with temperature or strain using fiber-optic cable
3. Sensing liquids by a change in resistance in an electrical cable when wetted
4. Sensing hydrocarbons with a coated fiber-optic cable
5. Sensing hydrocarbons using gas-swept permeable tubes
6. Sensing hydrocarbons using optical methods, e.g., IR absorption

A majority of this technology is oriented toward the gas/crude industry and not necessarily applicable to produced water leaks. However, resistance cables can be used for finding water leaks if used in double-wall construction or other installations in which sensors located outside of the pipe would not be impacted by groundwater or infiltration from precipitation. Because of the inherent moisture and salts in the subsurface, the only potentially effective solutions using external methods for produced water leak detection are fiber-optic cable and acoustic emissions.

18

Key Finding and Recommendation

Observation: Because of the corrosive nature of produced water from the Bakken, most operators use some form of composite or HDPE materials in gathering pipelines.

Finding: Reviewing the leak detection alternatives for pipelines transporting produced water, it is clear that a technology gap exists for implementing external leak detection in the plastic pipeline/produced water market.

Recommendation: The state of North Dakota should encourage development and testing of low-cost external leak detection technologies specific to the needs of produced water gathering line operations.

Acoustic Emissions

This technique relies on the sound signature created by a leak, where the frequency range and amplitude depend upon the fluid and the size of the leak, respectively. This technology can be implemented in many ways: attached to pipe, tapped into the pipe, positioned next to the pipe as a probe, walking surveys, or using internal inspection devices listening for leaks as the pipeline is traversed. Acoustic systems are short-range systems, several hundred feet, and should not be confused with the internal "negative pressure wave" method having ranges of miles.

Fiber-Optic Cables

This technique can be universally employed as a distributed temperature sensor. As a natural consequence of temperature (or strain), the refractive index of the fiber-optic cable is changed. Using a pulsed laser, the temperature profile of the entire cable length can be monitored with a resolution of 3 feet. If fluid leaks from the pipeline and contacts the fiber-optic cable, a strain to the cable occurs and can be detected. In addition, any strain induced to the cable by a shift in the surrounding terrain can be detected. This can be beneficial in areas where erosion or seismic activity could induce pipeline exposure or failure. For this technology to work properly, there needs to be a measureable temperature differential between the fiber cable and the fluid in the pipe. Another implementation of this technology utilizes a patented coating receptive to hydrocarbons that similarly changes the refractive index as a function of concentration. This technique may not be applicable to produced water. An added benefit of this technology is that it can be used as a high-speed communications network for both data and voice applications as well.

Liquid-Sensing Cables

These cables are usually buried along the length of the pipeline. When a hydrocarbon comes in contact with the cable, the special wires swell and cause a change in impedance. This change is reflected back to the microprocessor that interprets the change as a leak and determines the location (time-domain reflectometry). A direct current version of this cable detects the leak but is not capable of determining location. Although simple in application, these cables are generally expensive and utilized mainly in specialized areas like HCAs or road crossings. For this type of system to be effective for produced water applications, double-wall pipe construction would need to be implemented, otherwise ambient moisture would be detected.

Vapor Sensing

This technology is very robust and sensitive but generally used in short pipe runs because of the complex nature of the installation. A gas-permeable tube that keeps out air, but allows hydrocarbons to pass, is installed along the entire length of the pipeline. This tube can be external to the pipe or located in the annular space of a double-wall construction. Gas is passed through the tube and analyzed at one end. The location of a leak can be determined by the time it takes for the peak to reach the detector. This technique is not applicable to produced water.

Optical Sensing

IR imaging is the most widely used tool for leak detection of hydrocarbon pipelines. A leak in a pipe will eventually lead to hydrocarbon vapors reaching the surface. Hydrocarbon vapors absorb IR radiation at very specific wavelengths that are detectable by IR cameras. This can be done both actively, where an IR source is employed to increase sensitivity, or passively using available radiation. Cameras used for this purpose can be handheld, tower-mounted, or used in airborne surveys. This technology is not applicable to produced water.

Pipeline Inspection

Gathering line operators routinely deploy ground and aerial patrols to trace pipeline routes in search of indications of leakage. Discussion with one gathering line operator indicated that even though he has staff permanently assigned to ground patrols, patrol efforts basically respond to requests to locate pipelines, not to perform thorough and systematic reconnoitering. Aerial patrols, which were reported to occur on the order of twice a month, are systematic and survey at least main lines and larger lateral gathering lines. These aerial patrol intervals align closely with 49 CFR 195.412, which for transmission pipelines (or PHMSA-regulated lines) requires that:

> *"Each operator shall, at intervals not exceeding 3 weeks, but at least 26 times each calendar year, inspect the surface conditions on or adjacent to each pipeline ROW. Methods of inspection include walking, driving, flying or other appropriate means of traversing the ROW."*

Currently, visible spectrum cameras are the most common aboveground inspection technology, although additional sensors can be incorporated into these inspection methods. Aerial sensors employed in leak detection can be classified into two categories: passive sensors (which are sensitive to naturally occurring radiation reflected from or emitted by target objects) and active sensors (which illuminate target objects and measure the amount of radiation reflected back). Passive sensors that are commercially available for UAVs generally are sensitive to visible and IR radiation. They include visible light sensors that record single frames and continuous video, multispectral sensors which measure several (e.g., three to ten) different bands in the electromagnetic spectrum, shortwave IR (SWIR) sensors which are sensitive to radiation in the 0.9- to 1.7-μm range, hyperspectral sensors which are sensitive to numerous (i.e., tens to hundreds) narrow spectral bands, and thermal IR sensors (e.g., forward-looking IR [FLIR] sensors) which collect IR thermographic images. Active sensors that are commercially available and appropriate for UAV include light detection and ranging (lidar) sensors, which transmit and monitor reflection of multiple hundreds of thousands of pulses a second of near-IR radiation, and radar (synthetic aperture radar, SAR), which transmits and monitors reflection of pulses of radio waves in the 0.002–1-m wavelength range.

Setting Expectations for LDS Performance

The former API 1155 (replaced by API 1130 [American Petroleum Institute, 2012]) states there are four results by which modern leak detection performance is graded:

1. The system correctly indicates that there is no leak.
2. The system correctly indicates that there is a leak.
3. The system incorrectly indicates that there is a leak (false positive alarm).
4. The system incorrectly indicates that there is no leak (no alarm).

A tremendous amount of instrumentation and technology is required to achieve the first two of these performance benchmarks. Further elimination of false alarms escalates the costs, training, and complexity to a much greater level. API 1155 further expands on four metrics describing the installed LDS performance:

1. Sensitivity – a composite measure of the size of a detectible leak and the time required for detection.

2. Reliability – a measure of a LDS's ability to accurately assess whether a leak exists or not while operating within the LDS's design envelope.

3. Accuracy – a measure of the ability of an LDS to provide valid estimates of leak parameters such as the leak flow rate and location.

4. Robustness – a measure of the ability of a LDS to continue to function and provide useful information under changing pipeline conditions or when data are lost or suspect; i.e., robustness is a measure of the effective size of the LDS's operating envelope.

These metrics were developed for transmission lines operating near steady-state conditions, where vast distances are traversed with minimal instrumentation. These concepts are applicable to gathering lines; however, the added complexity of gathering line systems would seemingly make it difficult to satisfy all of those goals. For example, the LDS would have to be robust because of intermittent flow characteristics, but as a consequence, it probably will not be very sensitive or even reliable.

Gathering line systems are constantly transitioning in flow, pressure, and line-packing. Unlike transmission pipelines with very few branches, gathering systems have tens to hundreds of pipeline connections. These and other differences between transmission pipelines and gathering lines create greater challenges for designing, installing, and operating internal leak detection on gathering lines than transmission pipelines.

As a countermeasure to uncertainty, measurements are accumulated or examined over a longer time interval to improve signal-to-noise ratio. This correction increases "time to detect" and the spill volume if an incident occurs. Applying CPM techniques using multivariable measurements and modeling techniques can improve leak detection sensitivity and reliability. Some benefit may be obtained from the very expensive advanced-CPM technologies (RTTM, line-pack correction); however, the improvement in performance would probably be marginal for many of the North Dakota gathering line systems, especially those using HDPE pipelines. In some instances, the communication infrastructure is inadequate to support the necessary sampling rates required to support these technologies. In spite of the disadvantages and obstacles, traditional CPM techniques are commonly employed by transmission pipeline operators and offer benefit for gathering line LDS.

External LDS are immune to internal operational conditions but have limited retrofit potential, making them applicable only to new installations. Produced water lines have even fewer alternatives, as composite or HDPE lines cannot be used with acoustic sensors or hydrocarbon cable sensors. Fiber-optic cables that detect leaks by temperature excursions could be used for the main trunk lines, the strategy being that the trunk lines are much larger than the laterals in terms of spill volume. This technique can be competitive to more advanced CPM methods, especially when yearly operating expenses are included in the economic analysis. The lack of cable coverage to the laterals could expose the operator to more risk; however, lateral lines can be covered by fiber optics using splicing and/or proper planning of a new pipeline network. In many situations, volume balances calculated from custody transfer data can compensate for these disadvantages by providing inferred leak detection coverage to the uncovered laterals.

As effective as external technologies appear to be, transmission pipeline operators do not consider them to be "proven" technologies. For example, in the design of the Keystone XL pipeline, nine of the fifty-seven special conditions incorporated into the design were related to LDS: none included external leak detection—all were related to SCADA and/or CPM (U.S. Department of State Bureau of Oceans and International Environmental and Scientific Affairs, 2011). This apparent effectiveness was called into question July 2015 when an external technique, considered by some to be "fail-safe," failed to detect a 31,500-bbl emulsion spill from a Nexen pipeline in Alberta (Mehler Paperny and Ramsay, 2015). The cause of the apparent failure of the external LDS has not been released at the time of the current EERC report.

Performance of LDS

Perspectives Offered by a PHMSA Study of LDS Performance

The most comprehensive collection of leak detection incidents compiled to date is in a 2012 "Leak Detection Study" final report to DOT PHMSA (Shaw and others, 2012). This report covered incidents reported during a 30-month period starting on January 1, 2010, and ending July 7, 2012. Data extracted from these incident reports to PHMSA were as-filed, and any incorrect or misreported data will carry through into our final statistics. The filings on the incident report are an ongoing process and are often revised. In some instances, the most recent update may not have been incorporated.

A total of 1337 pipeline spill incidents were recorded in the "Leak Detection Study." This number included 766 incidents for hazardous liquids, 295 incidents for gas transmission lines, and 276 for natural gas distribution lines. Of all of the subclasses of incidents, the most relevant to the North Dakota pipeline study are for hazardous liquid releases occurring along the ROW. This excludes all leaks occurring with well pads, refineries, and tanks. No specific statistics in the PHMSA study address produced water.

Of the total ROW releases, the 197 events occurring for hazardous liquid releases were the most relevant because the operators were required to report the status of the pipeline SCADA system and the CPM systems at the time of the incident. These 197 ROW spills will be examined in this section.

Unlike most gathering lines used for crude and produced water, transmission pipelines are highly regulated by federal and state agencies, requiring some form of leak detection methodology. These pipelines are generally much larger, 12–48 inches in diameter, and in the event of an unplanned release, the volume of the event is correspondingly much larger when they occur. Even without regulation, the consequences from loss of operation, loss of product, environmental impacts, reclamation, and public perception provide an incentive to protect the operator's pipeline investment with leak detection. In addition, transmission pipelines often move product through populated areas and other HCA such as drinking water supplies or protected habitat.

In contrast, North Dakota gathering pipelines range in size from 3 to 10 inches in diameter, with the vast majority of these pipelines located in rural areas. Because of the relatively small line sizes, unplanned releases from these lines should result in smaller spill volumes provided adequate monitoring is utilized and the response time is rapid. The consequences of released produced water are generally more expensive than crude, as the reclamation is more difficult. Risk and the risk management associated with gathering pipelines would intuitively seem to be much less when compared to transmission pipelines, based upon the smaller volumes of product transferred over much shorter distances. This point may be debated, but it is a factor to the pipeline operators when considering the total investment placed into SCADA and LDS.

Before delving into the specifics of leak detection performance, it should be pointed out that the release volumes for the 197 ROW incidents ranged from 843,000 to 0.42 gallons, a 2,000,000:1 ratio. In a generic sense, this implies that the leak detection methods were tested robustly from a seepage rate to a rupturelike rate. However, it is important to observe some caution in interpretation: a long-term, undetected seepage can produce a significant leak volume. When the failure mode of many of these incidents is known, some insight can be gleaned about the effectiveness of the employed leak detection technology as a function of leak rate. It is known from the incident report data that 132 of the releases were from the pipe body or pipe seam, 17 were valve releases, five were flange releases, and 47 were attributed to other reasons.

The data indicate that the effectiveness of internal leak detection methods is questionable, except for the largest of releases. However, that conclusion has to be tempered with further analysis by observing that only 44% of the 197 incidents reported using CPM, 78% reported using SCADA, and 44% reported using both. It should be noted that 32 incident reports (16%) had no data for how the leak was identified or whether CPM or SCADA was functional. Figure 47 depicts the initial method of identifying 165 of 197 ROW releases. As seen from the statistics in this figure, the majority of the incidents are reported by the public, followed by local operators and contractors.

One cannot discuss the feasibility and cost-effectiveness of requiring leak detection and monitoring technology for North Dakota gathering pipeline systems without considering the performance record of these internal methods. The following are a summary of the relevant observations from the PHMSA leak detection study (Shaw and others, 2012):

1. The pipeline controller/control room identified a release around 17% of the time (33/197 incidents reported).

2. The combination of air and ground patrols, operator ground crews, and contractors was more likely (26% or 52/197 incidents reported) to identify a release than the pipeline controller/control room (17% or 33/197 incidents reported).

3. A member of the public was more likely to identify a release (23% or 45/197 incidents reported) than air and ground patrols (7% or 14 of 197 incidents reported).

4. A CPM-based LDS was the initial leak identifier only 20% of the time (17 out of 86 releases in which the CPM system was reported as functional).

5. The SCADA system was the initial leak identifier only 28% of the time (43 out of 152 releases in which the SCADA system was reported as functional).

This does not negate the need for pipeline monitoring for the goal of detecting leaks. The instrumentation used for pipeline operation and custody transfer is already in place for leak detection. Most pipeline operators would agree that the investment in LDS could decrease severity of cleanup and reclamation costs and may catch some spills at minimal incremental cost. Nonetheless, the data indicate that SCADA, CPM, and control room monitoring of these systems were not the primary methods for identifying leaks, although these systems existed on most of the pipelines involved in the 197 incidents.

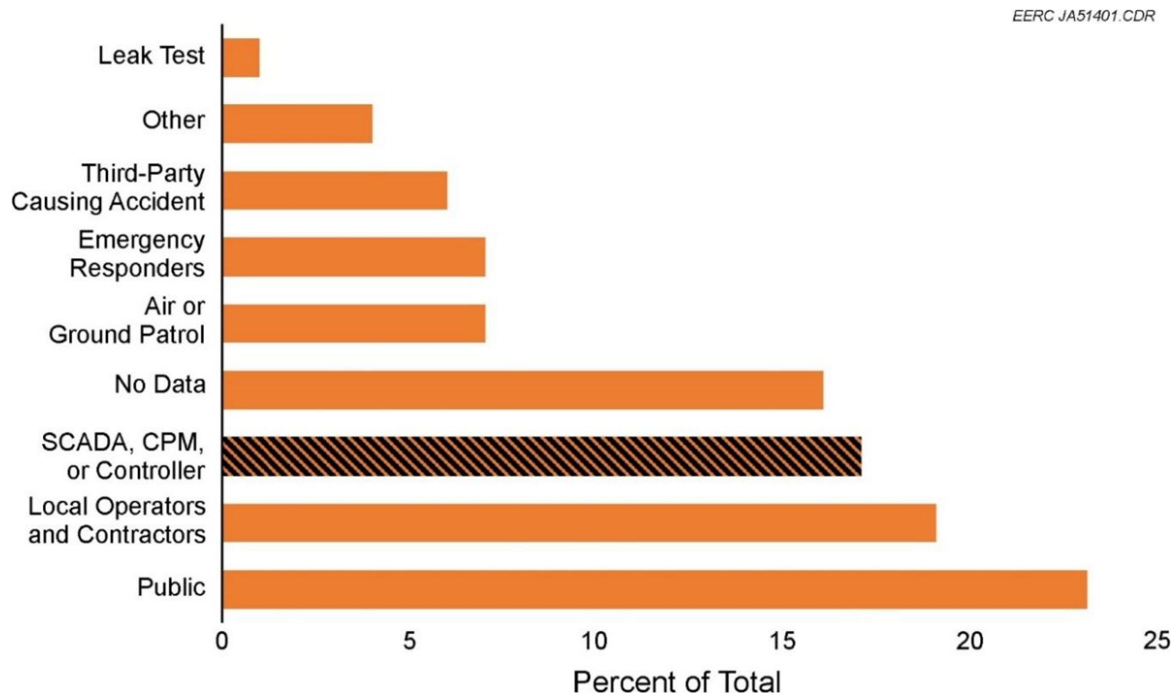


Figure 47. Method of initial incident identification for ROW pipeline releases (Shaw and others, 2012).

Perspectives Offered by Alaska Studies of LDS Performance

Over 16 years ago, the Alaska Department of Environmental Conservation (ADEC) released a technical review of crude oil pipelines (Alaska Department of Environmental Conservation Division of Spill Prevention and Response, 1999). In that report, ADEC made the observations that:

> *"Analysis of recent data from the U.S. Department of Transportation Office of Pipeline Safety (DOT-OPS) indicates that, despite stricter regulations and enforcement, the rate at which pipeline accidents occurs has not significantly changed over the last two decades (Hovey and Farmer, 1999). The statistics suggest that short pipelines will have at least one reportable accident during a 20-year lifetime and longer pipelines (800 or more miles of line pipe) can expect a reportable incident every year. Research indicates that the best opportunities to mitigate pipeline accidents and subsequent leaks are through prevention measures such as aggressive controller training and strict enforcement of safety and maintenance programs (Hovey and Farmer, 1999; Borener and Patterson, 1995). The next most productive enhancement comes from implementing better pipeline monitoring and leak detection equipment and practices. Early detection of a leak and, if possible, identification of the location using the best available technology allows time for safe shutdown and rapid dispatch of assessment and cleanup crews. An effective and appropriately implemented leak detection program can easily pay for itself through reduced spill volume and an increase in public confidence."*

Similarly, in its 2010 study of spill statistics, the *Alaska North Slope Spills Analysis* investigated data from spills reported to ADEC from North Slope oil production operators during the period of July 1, 1995, to December 31, 2009. The goal of the Alaskan study is very similar to the North Dakota study:

> *"to reduce the frequency and severity of future spills from crude oil piping infrastructure integrity loss. The process selected to achieve this goal involved analyzing the data trends in loss-of-integrity spills from crude oil piping infrastructure and developing recommendations for mitigation measures to interrupt any negative trends."*

A spills database was constructed consisting of 640 loss-of-integrity spills from the Alaskan North Slope oil production infrastructure. These data consisted of process lines, facility lines, flowlines, and transmission pipelines. In Alaska, the facility lines and flowlines are similar to North Dakota gathering lines in scope, but the flowlines usually carry three phases (water, crude, and gas) and are much larger in diameter. Facility lines connect individual wells to a manifold that feeds the flowline. Flowlines move the contents to the crude processing facility. Of the 640 spills in the database, only 80 incidents were from flowlines or transmission pipelines. Of the 38 cases where method of leak detection method was identified, 35 were detected visually, two were detected by odor, and only one was detected both visually and by LDS.

Based upon their in-depth analysis of the incident reports, the Alaskan expert panel presented seven recommendations to help them reach their goal. The highest priority of these findings was to move to an Integrity Management Program that focuses on leading indicators (precursors leading to pipeline damage resulting in failure). This position goes further than the enforced maintenance programs recommended in the 1999 ADEC study in that it focuses on the root cause and requires data tracking and auditing procedures to foster a culture of correction and improvement. Another interesting recommendation from the North Slope Spills report was to "standardize and improve spill data collection in order to better assess trends and common causes of spills so that prevention measures can be targeted and evaluated to reduce future leaks." The current study independently adopts a similar position in the previous section of this report after its review of North Dakota spill databases.

Although the two Alaskan studies recommended a proactive approach to pipeline maintenance and failure-mode analysis, neither diminished the need for an effective LDS for improving response time to spills.

Following the 2010 Enbridge spill near Marshall, Michigan, NTSB cited systematic flaws in operational decision making, PHMSA's weak regulations on pipeline assessment and repair, and the oil spill response plan as contributing to the severity of the incident (Pipeline and Gas Journal, 2014). These comments closely mirror findings cited in both of the aforementioned Alaskan (ADEC) studies. The NTSB report on the incident also recommended that API develop a pipeline safety system. API responded by developing RP 1173, "Pipeline Safety Management System Requirements" (American Petroleum Institute, 2015). The description of this standard provided by the API Web site reads:

"This recommended practice (RP) establishes a pipeline safety management systems (PSMS) framework for organizations that operate hazardous liquids and gas pipelines jurisdictional to the US Department of Transportation. Operators of other pipelines may find this document applicable useful in operating to their systems.[sic] This RP provides pipeline operators with safety management system requirements that when applied provide a framework to reveal and manage risk, promote a learning environment, and continuously improve pipeline safety and integrity. At the foundation of a PSMS is the operator's existing pipeline safety system, including the operator's pipeline safety processes and procedures. This RP provides a comprehensive framework and defines the elements needed to identify and address safety for a pipeline's life cycle. These safety management system requirements identify what is to be done, and leaves the details associated with implementation and maintenance of the requirements to the individual pipeline operators. This RP presents the holistic approach of "Plan-Do-Check-Act" and is the American National Standard for pipeline safety management systems."

The state of North Dakota should examine the potential utility of PSMS for assisting gathering line operators in developing procedures for monitoring, inspection, maintenance, and spill response. This standard can be voluntarily adopted by operators or phased in as part of a pilot program. The API RP 1173 standard is very new; the first edition was published July 1, 2015.

19

Key Finding and Recommendation

Observation: The 1999 and 2010 ADEC reviews on spill statistics and the NTSB report on the 2010 Enbridge incident reported a common theme that extensive operator training and proactive pipeline inspection and maintenance have the greatest impact on reducing pipeline leaks. Secondarily, improved leak detection and a well-planned spill response to an incident were found to decrease the severity of the release.

Finding: API RP 1173 establishes a PSMS framework needed to identify and manage risk and address pipeline operation and integrity using the operator's existing pipeline safety systems, processes, and procedures.

Recommendation: The DMR's role in the implementation and enforcement of a PSMS for North Dakota operators, modeled after API RP 1173, should be examined.

Perspectives on LDS Performance Offered by the Alberta Spill Example

Based on the recent PHMSA report, one could assert that any improvement in LDS technology has not manifested itself in industry statistics. The present study agrees that reducing leaks and minimizing environmental impact would be best achieved by better enforcement in prevention measures such as controller training, pipeline and instrumentation maintenance, and a documented and rehearsed spill response plan. An automated SCADA-based LDS has no effect on stopping or reducing the likelihood of a leak; however, when a leak occurs, LDS increases the probability that the leak will be found.

The Nexen Energy pipeline in northern Alberta should be one of the more technologically advanced and safest pipelines ever commissioned. It consisted of double wall, pipe-in-pipe construction, with a state-of-the-art continuous fiber-optic external LDS. On July 15, 2015, a contractor walking along the pipeline discovered a 5-million-liter (31,500-barrel) spill of bitumen, sand, and water. It is possible, based on news accounts (D'Aliesio and others, 2015), that the pipeline may have been leaking for almost 2 weeks before being discovered. This would also imply that the containment pipe, the external fiber-optic system, and any internal leak detection and SCADA monitoring systems were ineffective in detecting the 31,500-barrel leak. The cause of the pipeline and LDS failures has not been released at the time of this study. However, whether the root cause is found to be controller error, LDS error, or a design flaw, the principles of aggressive controller training, examining leading indicators (causing failure), and spill response planning (recommended by the Alaskan studies) are still relevant.

20

Key Finding and Recommendation

Observation: Flows from wellsite tanks into gathering lines are based on tank levels. Pumps turn on when levels exceed a preset maximum and turn off when a minimum level is passed. Thus gathering line flows are uncoordinated, inconsistent, and highly variable.

Gathering systems seldom incorporate intermediate tanks or pumps. Incorporating these unit operations often triggers a change in regulatory requirements and jurisdiction to the PSC.

Finding: The sensitivity and performance of most internal leak detection methods tend to benefit by predictable, consistent flows through liquid-filled pipelines.

Creating a similar regulatory environment for both gathering and transmission pipelines could eliminate the incentive to avoid breakout tanks and pumps and promote gathering system design and operation that provides the best possible performance.

Recommendation: The state, in conjunction with operators and vendors, could investigate alternate gathering system design features or unit operations that would enable pressurized and/or more consistent/steady-state flow conditions, thereby enabling improved leak detection system performance and accuracy. Any operational changes would necessitate an examination of the operational impacts, cost, and regulatory implications (example: breakout tanks and pumps triggering PSC oversight).

Performance of External LDS

Although the record for internal LDS has been highly publicized, no analogous PHMSA studies have scrutinized the effectiveness of external leak detection methods. API 1130 recognizes external LDS systems, but there is no guidance for the design and implementation of these systems (American Petroleum Institute, 2012). Such a standard needs to be established to aid the industry in adopting these systems. As a consequence, most external LDS are used as secondary systems, supporting the primary internal system.

Case studies highlight external leak detection performance (presented by vendors), but these affirmations can be found for the internal methods as well. Because external systems are highly engineered systems, requiring design and planning well before the pipeline is constructed, they are usually dismissed for the easier internal methods, where adding or retrofitting instruments at a few key locations is deemed adequate.

Considerations for LDS Use in North Dakota

Factors Affecting Implementation of LDS

Many factors influence the implementation and effectiveness of pipeline monitoring and leak detection in liquid gathering pipelines. In an effort to familiarize the study team with North Dakota gathering pipelines, many of the larger operators invited the EERC to tour their facilities. Several systems, beginning at well pads and terminating at saltwater disposal wells or crude oil delivery sites, were examined for all aspects of construction, materials, instrumentation, operation, and infrastructure. The study team asked employees and management detailed questions regarding operational challenges and practices. Additionally, written responses to an in-depth survey requested of the stakeholders were reviewed by the study team to get a sense of the current status of operating practices, monitoring capabilities, and design and construction standards.

Typical operating practices for liquid gathering lines create a unique environment for pipeline monitoring and leak detection. Internal leak detection methods generally work best when pipelines are liquid-filled and operated within a relatively constant flow rate. The better defined the operational conditions are, the more sensitive the leak detection method that can be applied. Low-pressure operation is common, and multiple flow inlets and very few outlets lead to significant flow variation as pumps cycle on and off or wells begin or cease production. The very nature of oil production leads to fluctuations that are not easily reduced or eliminated.

Power and communication infrastructure is critical to implementing system automation and data transfer needed to support effective leak detection technology. The availability of adequate communication can be very dependent on location: topography can obstruct access to existing commercial facilities (e.g., cellphone towers), and political units can obstruct and delay construction of communication links. Since topography, infrastructure, and political factors vary across the Bakken, the quality of communications likewise varies among locations and gathering line operators. These factors (especially communications quality and the amount of data being communicated) help explain the variation in polling rates reported by gathering line operators, which range from 5 seconds to 15 minutes.

Gathering system complexity in physical configuration, diversity of pipeline materials, and different instrumentation and communication equipment make implementation of any single leak detection technology difficult. The result is a diverse mixture of technologies and operations designed to meet the needs of the particular application.

The rapid buildout of gathering infrastructure and subsequent business mergers and acquisitions have further contributed to the diversity of system designs, pipeline materials, hardware, and instrumentation utilized in North Dakota’s gathering infrastructure. In general, companies that have acquired legacy assets that do not conform to company desires for minimum system design are studying or installing equipment to bring these older assets up to their current standards. Assuming that the instrumentation and automation equipment are properly maintained, the improved instrumentation and automation standards also provide a basis for improved leak detection.

Current Use of SCADA and LDS in North Dakota

The majority of North Dakota gathering lines are monitored for flow and pressure using instrumentation connected remotely to a SCADA system. Leak detection is often accomplished with pressure and volume balance alarms and, in some cases, data analysis tools that fall within the definition of CPM. More advanced detection systems are rarely used. However, only a few years ago, the surge in oilfield development left infrastructure lagging behind. As a result, many pipeline operators had sites where either no SCADA system was available or it was operated intermittently. In some of these cases, manual remote monitoring occurred, making a rapid response to pipeline leaks nearly impossible. Recently, the infrastructure has been significantly upgraded to the point where an estimated 80%–90% of the in-service gathering pipelines are being minimally monitored using some form of a SCADA package.

Surveys of gathering line operators and field visits to their facilities indicate progress on the part of many gathering line operators in installing and upgrading gathering line measurement instrumentation and SCADA systems to enable and improve remote monitoring and leak detection. Much of this has been coincident with improvements in communications infrastructure, such as commercial cellphone infrastructure or spread spectrum radio infrastructure installed specifically by gathering line operators for monitoring lines and stations.

The transition from pre-2010 manual data logging to current, typical SCADA-based systems provides many benefits to the gathering line operators, such as reduced staffing needs for monitoring wellsites and improved "vision" of the performance of those sites over time. Additionally, automated systems provide a platform for operators to add new features and capabilities, such as extracting leak indications from existing measurement instrumentation, with minimal additional capital outlay. Simple leak detection methods, such as identifying deviations in line pressures and flow rates from expected values and unexpected large rates of change of pressure and flow rates, are built into SCADA systems—they require little more effort than setting the expected values and activating the functions. A modest amount of programming of SCADA-based systems can provide line- and volume-balancing functionality to detect conditions

21

Key Finding and Recommendation

Observation: In a number of locations, lagging infrastructure development is still evident where produced water and crude oil deliveries and receipts are recorded manually.

Finding: Manual monitoring of delivery or receipt locations because of poor infrastructure or lack of instrumentation creates the potential for prolonged undetected leaks. Keys to minimizing impacts from pipeline releases are frequent inspections and improved monitoring of operational parameters.

Recommendation: In an attempt to identify leaks earlier and minimize their impacts, operators should be encouraged to incorporate technologies such as SCADA to improve communication within and between operators.

indicative of leaks. These simple methods possess limited sensitivity even under ideal pipeline conditions. Simple statistical analysis could also be deployed with similar ease and sensitivity. Beyond those, more instrumentation and installation of advanced algorithms would be required to attain improved sensitivity. Attaining improved sensitivity would likely require more consistent and predictable gathering line operation for most gathering line operators along with improved communication infrastructure for some.

This study has discovered only one instance of a pipeline operator in North Dakota experimenting with external leak detection methods. Specifically, the company informed the study team that it is installing sensors in the ground every 100 feet along a section of pipeline to determine whether the sensors can identify leaks of produced water. Unfortunately, detailed information on this experiment has not been provided to the study team and, therefore, cannot be offered here.

Future Use of SCADA and LDS in North Dakota

Leak detection technology will likely play an important role in ongoing efforts to improve the safety and reliability of gathering pipeline operation. Nonetheless, there are limitations to the effectiveness of LDS, as was illustrated in studies by PHMSA, the state of Alaska, and NTSB. The recent evolution from manual data collection to SCADA-based monitoring systems provides the ability to conduct continuous monitoring of pipeline conditions that can dramatically reduce the response time when a leak occurs. More importantly, the use of SCADA and its associated infrastructure can form the basis for addition of incremental LDS technology for particular applications. Out of ten gathering line operators who responded to the leak detection survey, one reported adopting only manual monitoring, one reported implementing SCADA and LDS, and the remainder reported operating SCADA-only monitoring. Respondents who installed SCADA systems generally reported plans to improve their monitoring and leak detection capabilities as improvements in knowledge of their systems and confidence in the capabilities of leak detection technologies warrant. These respondents also reported that SCADA has substantial value beyond its basic leak detection function, including quantifiable items such as reduced field labor requirements to operate the pipeline, as well as less tangible benefits such as more consistent and frequent data; the ability to acquire, integrate, and analyze data; and the ability to quickly disseminate and act on results of the analyses.

Improvements in the ability of internal leak detection methods like CPM to more accurately identify leaks and eliminate false leak indications could improve operator confidence and enable greater implementation of these technologies. Analysis of the largest hazardous liquid pipeline incidents in the United States over the period 2010 to July 2012 (Shaw and others, 2012) revealed that in 11 of the largest 28 incidents, CPM and SCADA each presented controllers/operators with "definitive" leak indications for only about 18% (36% combined) of the incidents, representing 8% and 10%, respectively, of the total volume leaked. A more detailed investigation by Shaw and others (2012) suggests that CPM revealed leaks about 27% of the time to controllers, while SCADA presented information on leak detection about 55% of the time, 82% combined. This leak indication value for CPM represents 12% of the total volume leaked, while the SCADA detection represents 84% of the total volume leaked, 96% combined. This suggests that the SCADA or CPM systems did identify anomalies suggesting the possibility of a leak, but they were similar to many other false positive indications of leaks and, as such, were ignored. Transient periods—such as during pipeline start-up and shutdown and periods when CPM software and SCADA are not functioning—provide misleading, false leak indications, or no indication, which controllers often ignore or are unaware of and, in the process, miss valid indications. Consequently, improved reliability of SCADA and LDS indications, i.e., improved rejection of false indications and improved LDS up-time, might lead to improved detection rates.

Except perhaps in HCAs, SCADA and CPM are preferred to external LDS. Supporting this observation is the fact that nine of the 57 special conditions that were recommended by PHMSA to improve the safety of the Keystone XL pipeline in the final Environmental Impact Statement for the project were related to SCADA-based pipeline monitoring and internal LDS. This contrasts with external leak detection methods, such as IR sensors and fiber-optic cables, which TransCanada decided in 2013 not to deploy in the Keystone XL pipeline project. The higher costs and difficulty retrofitting external technologies place them at a disadvantage to SCADA and CPM. Additionally, the stated advantage of superior sensitivity of external technologies has come into question because of the July 2015 Nexen Long Lake oil-sands pipeline spill in Alberta, Canada, which went undetected for about 2 weeks by a technology that was claimed to be one thousandfold more sensitive than volumetric leak detection methods.

In the absence of a revolutionary advancement in pipeline monitoring and leak detection, extrapolating these conditions leads to the forecast that:

- Additional demonstration of long-term performance will be helpful in establishing the confidence needed to invest in additional leak detection technologies.

- Operators will:
  1) Increasingly utilize and experiment with basic SCADA systems to acquire better understanding of the systems' abilities and of gathering line behavior.
  2) Increasingly use leak detection capabilities inherent in SCADA.
  3) Introduce LDS as they develop confidence in and can justify the cost of such a system.

- Simpler, cheaper, and less complicated systems will likely be preferred initially, which might limit the sensitivity and performance of the techniques employed.

- SCADA and CPM technologies will continue to be implemented in preference to external techniques.

- Improvements in separating "false" from "real" leak indicators will help increase adoption of CPM-based LDS. Improvements or changes in gathering line operations that create more steady-state operation could contribute to better LDS performance.

Unlike monitoring and leak detection for which no revolutionary advancements were discovered during this study, a potentially significant advance in inspections, specifically aerial patrolling, has been uncovered in the form of unmanned reconnaissance. The use of UAS has potential for future use as an LDS tool and to monitor spills of oil, gas, and saltwater mixtures across North Dakota. With proper planning, UAS can be employed persistently over risk-prone areas to enhance spill response or leak detection at scales previously not feasible. Used historically as a tool by the Department of Defense for military intelligence applications, UAS continues to mature as a tool to provide near-real-time information to decision makers. As with most new technologies, UAS continues to evolve into forms that can support both industry and government to save money and gain efficiencies. Enhancements to various technologies that comprise the aircraft and its sensors are critical to UAS-enhanced monitoring programs. Concurrently, the regulatory framework that enables commercial UAS operations must evolve quickly in order to merge with a compelling public benefit to monitor oil fields and pipelines for leaks.

Because UAS technology is not yet broadly commercially deployable, a detailed discussion on this technology is not being included in the main body of this report. However, for those interested in details of how UAS might be applied, a detailed discussion is included in Appendix J.

22

Key Finding and Recommendation

Observation: UAS can provide large amounts of data to assist in detecting leaks. Current limitations (both technology and regulatory in nature) generally limit their use to localized monitoring within line of sight of the operator. Maximum benefits of employing UAS will likely not be realized until beyond line of sight (BLOS) operations are approved by the Federal Aviation Administration (FAA) (several years in the future for commercial operations). Immediate monitoring gains from UAS can be realized if proper leak detection signatures are identified so that sensor systems can be flown to identify leaks and automatically report the data.

Finding: UAS shows potential as a monitoring tool over pipelines and oil production sites and should be leveraged within future monitoring architectures.

Recommendation: North Dakota should seek opportunities to demonstrate the role of UAS in pipeline monitoring. With its vast rural landscape, the state and industry within the state have more to gain from this remote sensing than other locations across the nation.

SCADA and LDS Cost-Effectiveness

There are many reasons for investing in leak detection technology. The value of lost product, negative impacts to the environment, loss of pipeline functionality, spill remediation costs, and public perception all impact decisions regarding the implementation of leak detection. Some of these factors can be tied to an economic analysis, many cannot. Pipeline leaks are generally unpredictable; therefore, it is difficult to assign a cost to things like remediation, loss of product, or pipeline repairs. Other factors, such as public perception, cannot be evaluated on an economic basis. Nonetheless, bad publicity can lead to the promulgation of more regulations or changes in operational guidelines which can translate to cost. Ultimately, the extent to which monitoring and leak detection systems will be implemented beyond regulatory requirements will be decided by the individual company based on its operating paradigm and an analysis of risk. For this study, a high-level comparison of the cost of different pipeline monitoring and leak detection approaches was completed. The purpose is to illustrate, using rough order of magnitude (ROM) values, the relative difference in cost of different levels of monitoring and LDS.

This comparison has been done for three categories, representing the evolution of LDS experienced in North Dakota from manual observations to automated SCADA-based monitoring to addition of leak detection technologies:

1. Manual: manual inspections and data collection with little or no automation.

2. SCADA only: basic data acquisition and control functionality with built-in alarming for unusual conditions.

3. SCADA + LDS: SCADA plus additional software and/or field instrumentation, including external LDS, the primary purpose of which is leak detection.

Costs of Manual Monitoring

Prior to pipeline installation, wellsites are visited regularly by oil and produced water trucks and production personnel who can identify wellsite spills. When pipelines are installed, the area requiring surveillance for potential spills increases, but staffing does not increase proportionately. An interview of one gathering line operator that had moved from manual monitoring to SCADA-based monitoring produced the following observations regarding manual monitoring costs:

- Aerial patrols continued unchanged at two patrols a month at an annual cost of $12,000.

- Ground patrols continued unchanged with two full-time persons.

- Control room (terminal) personnel continued unchanged at two persons a shift for 12-hour shifts.

- Gathering line operations field personnel are decreasing from 14 day-shift persons and 4 night-shift persons to 5 to 6 day-shift persons and 1 night-shift person. Based on these values, this study estimates annual field labor and vehicle expense savings of:

  – $3 million to $4 million in field labor costs (assuming 10-hour shifts at $30 to $36 an hour with a multiple of 2½ for employer paid taxes, benefits, and other overhead).

  – $0.3 million in vehicle costs (assuming one vehicle a person traveling 140 miles a day with a $0.60/mile expense).

The interviewee indicated that such staffing and savings could be roughly applicable to a field of 100 to 200 wellpads or 300–600 wells. It was pointed out to the interviewee that, while substantial, these estimated savings do not compensate for the installation and operating costs of a SCADA. The interviewee agreed but stated that many other tangible and intangible savings appear with automation. One example of savings is the reduction in effort to produce accounting records.

Manual logging often produced errors that had to be reconciled—typically with significant effort at the end of accounting periods. Ultimately, the interviewee and his company perceived the benefits of SCADA as exceeding the cost. Unfortunately, no specific SCADA installation costs were reported for this installation.

Costs of SCADA Monitoring

SCADA-only systems lack the sensitivity of CPM, negative pressure-wave, or other internal LDS, but they do offer leak detection through continuous monitoring of pressure and flow. Additionally, SCADA systems form the platform for more robust LDS with the addition of CPM.

Three gathering line operators responded to a survey regarding SCADA costs. The results from the survey are presented in Table 26. The survey provided substantial latitude to describe costs. As a result, costs were categorized and apportioned by each respondent differently. Despite these variations, SCADA equipment costs were within ±1%, assuming an average of 2.75 wells on a wellpad.

The greatest variation involved reporting of personnel and their related costs. Table 27 depicts staffing numbers and costs reported by two survey respondents.

Table 26. Reported SCADA Equipment and Facility Expenses on a Per Well Expense

Location	Equipment	Initial Expense, $/well	Annual Expense, $/well
Control Center	Facilities	1667	1167 to 1387
	Communications		20
Field	Instruments	5500 to 6060	
	Control devices	25,000 to 27,000	
	SCADA	1333 to 1750	267 to 650
	Communications interface	533	17
	TOTAL	34,810 to 35,177*	417 to 650
Infrastructure	Field communications	4000	1440

* One survey respondent provided a range of field initial costs based on a variable number of wells per pad. The other two respondents' initial costs averaged $35,000 per well which is well within the range provided by the first respondent.

Table 27. Reported SCADA Labor Expenses on a Per Well Basis

Location	Job Function	Annual Expense, $/well	Number of Staff: Nonsupervisory (NS) and Supervisory (S)
Control Center	Controller	5667	8 (NS)/4 (S)[a]
	Communications	1333	4 (NS)[a]
	SCADA maintenance	1300[b]	5 (NS)/1 (S)[c]
Field	SCADA maintenance	1500[b]	4 (NS)/1 (S)[a,c]

[a] Respondent "a" provided cost and numbers.

[b] Estimated based on number of supervisory and nonsupervisory staff. Field values rely heavily on Respondent a costs.

[c] Respondent "b" only provided staff numbers.

Constrained communication and electric power infrastructure present challenges and increase costs of implementing SCADA. Another significant cost factor is the existence and amount of SCADA and the number of sites across which costs can be spread. A vivid example of this was provided by a gathering line operator in response to a survey: a nearly 60% decrease in cost of installing a SCADA for the fourth well on a well pad versus the first well.

This economy-of-scale effect also was apparent in control center personnel and facility costs acquired from survey responses of another gathering line operator who estimated initial and annual costs of establishing and operating control center facilities to be $0.5 million up-front and $0.3 million annually. Staffing the facility cost almost an additional $1.75 million. The cost per well varies dramatically with the number of wells monitored by the control center as to whether the center monitors tens, hundreds, or thousands of wells. Some gathering line operators forecast that they will integrate monitoring of North Dakota assets into out-of-state centers that monitor numerous fields across the United States.

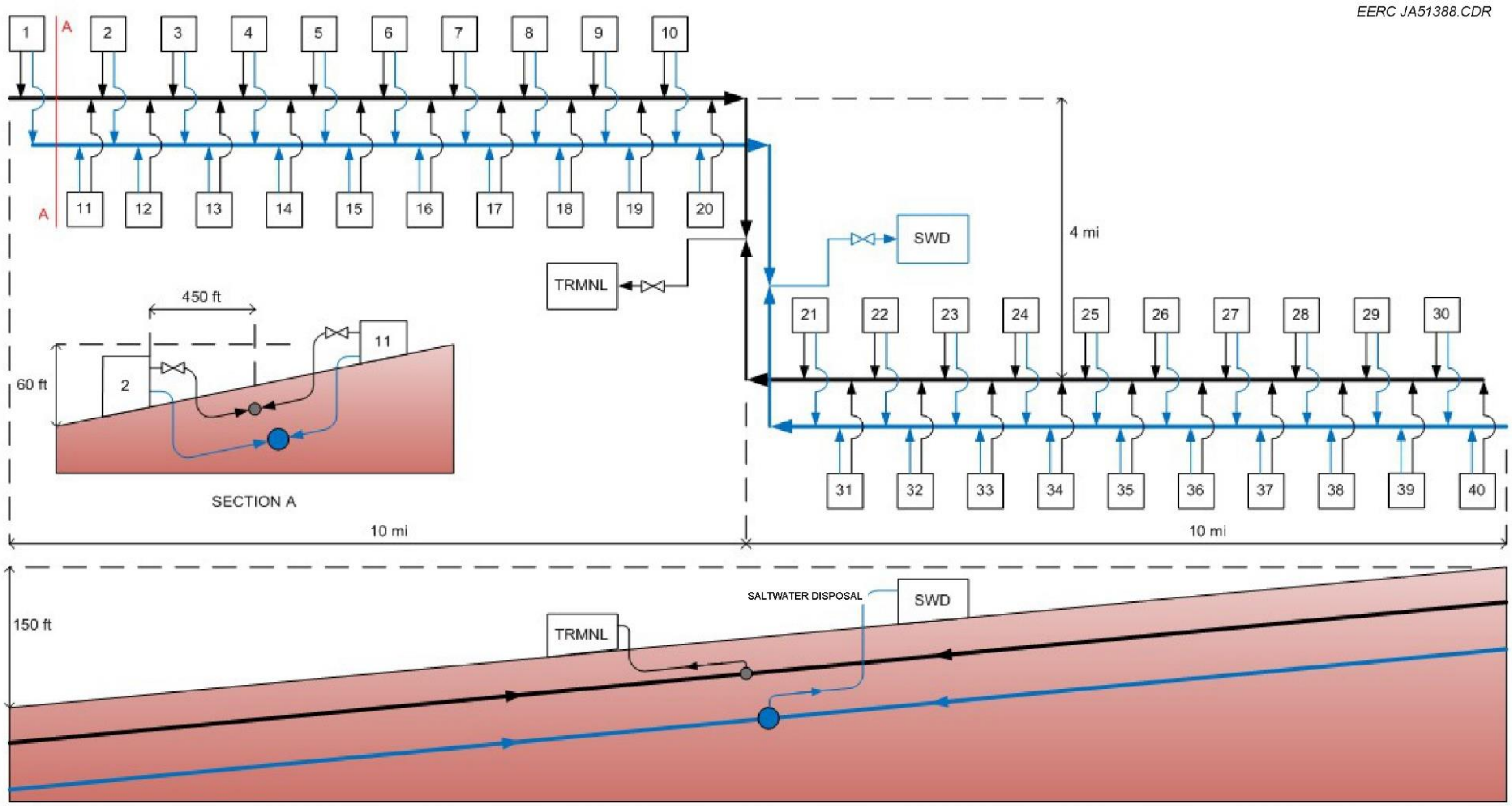
Such large investment in a control center is not necessarily typical. One gathering line operator provided a tour of its facility which was located in a dispatcher's office at a crude oil terminal in which two dispatchers shared their monitoring activities with handling terminal truck traffic. Another gathering line operator took advantage of mobile computing to provide great flexibility by adopting a Web-based interface for controllers. Thus any computer located anywhere that possessed adequate access to the Internet could potentially serve as a controller's console.

These observations illustrate that while SCADA equipment costs in the field were observed to be surprisingly consistent, control center/communications/electric power infrastructure situations and costs varied substantially depending upon factors such as monitoring system design, staffing, and location. Beyond these is the possibility to employ third-party resources to avoid initial costs. This was the case for one gathering line operator that used hosted Internet cloud-based resources to provide some control facility functionality.

Costs of SCADA Plus Leak Detection Monitoring

As a first step toward gathering costing information on SCADA and LDS systems applicable to liquid gathering lines in North Dakota, a list of LDS providers was compiled based upon Internet searches, contacts obtained from gathering line operators, and conference reports. Although more than 30 vendors and 40 technologies were identified, many vendors were no longer in business, could not be located, had no applicable technology, or failed to respond to information requests. This reduced the number of potential order-of-magnitude cost estimates achievable for the purposes of this study.

As a next step, and in order to establish a costing basis to compare internal and external leak detection systems with SCADA, a model gathering line system was specified. This model is shown in Figure 48.



	CRUDE OIL PIPELINE	2" STEEL	350 PSIG
	PRODUCED WATER PIPELINE	4" HDPE	250 PSIG
TRMNL	TERMINAL		
SWD	SALT WATER DISPOSAL		

Figure 48. Model North Dakota gathering line system for crude and produced water.

This model uses steel lines for crude oil and HDPE for handling produced water. The model has 40 well pads distributed over 24 miles, with a centrally located crude oil terminal and water disposal well. Obviously, no two North Dakota gathering line systems are the same; however, based on stakeholder responses, the model is believed to be reasonably representative for this study. The model was distributed to several internal and external LDS vendors for order-of-magnitude costing information. Generally, the cost estimates received in response to this request reflect the costs related to the equipment and its implementation but not infrastructure and installation costs. Nonetheless, this information establishes a minimum cost-to-implement baseline for relative comparisons of differing technologies.

Ultimately, requests for order-of-magnitude cost estimates were sent to several internal and external LDS providers, with only a few responding. While the requests attempted to be consistent and specific by providing vendors with a model section of gathering line and pipeline properties and operating conditions, assumptions adopted by the vendor still varied, in part due to the inherent differences in the technologies being proposed, which complicates comparing technologies. Given the limited detail included in the request, the limited time the vendors had to respond, and the variation among the technologies, it must be recognized that the inherent errors in the cost estimates are significant because of, among other factors, the assumption that appropriate SCADA and communication facilities were already in place and the greater complexity of an actual design compared to a simple simulated design.

Costs of Internal Leak Detection Systems

Table 28 displays order-of-magnitude cost estimates that were provided by technology vendors of three different internal LDS technologies. Requests for estimates were submitted to vendors of both software-based and hardware-enhanced LDSs. Vendors assumed that appropriate infrastructure and SCADA were already installed and available. The cost estimate provided by the vendors represents incremental costs above SCADA.

Currently, no single leak detection technology has been demonstrated as turnkey or completely reliable, but that does not mean one will not appear in the future. Several vendors have expressed interest in leak detection demonstration projects. These provide an opportunity for vendors to demonstrate their technologies and to acquire gathering line-specific learning to improve their products. The sensitivity of leak detection methods likely could be improved if gathering lines were operated in a manner more compatible with leak detection needs. Despite their undemonstrated effectiveness, the costs in Table 28 are included to provide an approximation of costs if/when any of the technologies become demonstrated. It is assumed that there will be

Table 28. Internal Leak Detection Technology Order-of-Magnitude Cost Estimates

Technology Identifier	Hardware (H) Software (S) Both (B)	Fixed Equipment Initial Cost, $	Labor Installation Cost, $	Variable Initial Cost Per Well, $	Operating Cost, $
A	S	300,000	25,000	8000	NA*
B	B	700,000	NA	17,500	NA
C	S	260,000	NA	6500	NA

* Not available.

limited modification of their basic structure and instrumentation, which will not significantly impact their cost.

Costs of External Leak Detection Systems

Table 29 summarizes equipment cost estimates provided by three external technology vendors. These technologies represent state-of-the-art, commercially available products. Variations of these technologies exist but generally rely upon the same basic principles. For example, despite physical differences in fiber-optic cables that sense temperature, composition, or acoustics, they are connected to essentially the same instrumentation and equipment and possess essentially the same installation requirements.

External LDS is highly specific to its application. None of the technologies in Table 29 is readily applicable to retrofitting situations and generally does not cater to the produced water market. However, acoustic sensors can be retrofitted to steel pipelines where ROW agreements allow for vertical excavation to attach sensors to pipe and route wiring. Liquid-sensing cables suitable for water detection are not applicable to buried pipelines where groundwater and surface moisture will quickly render them ineffective. In addition, produced water pipeline operators often use composites or HDPE, which is incompatible with acoustic leak detection. There is a technology gap for servicing external leak detection in the plastic pipeline/produced water market.

External LDS requires greater planning and investment but lowers maintenance costs. However, gathering line systems require flow and pressure maintenance for accurate product custody transfer. Therefore, adding an external LDS does not alleviate any normal maintenance costs when compared to basic SCADA system. Minimizing spill volume is the only true cost reduction directly attributed to external LDS implementation. If the choice to the operator were between implementing advanced CPM or external LDS, a detailed economic analysis may show external LDS to be very competitive. In that case, the recurring software annual upgrade and retuning costs associated with CPM can become significant. The key to the economic analysis is the pipeline life cycle or business model that the operator uses to forecast operating expenses.

Table 29. External Technology Equipment Costs for Select Pipeline Segments

Technology	Hardware (H) Software (S) Both (B)	Main Line Fixed Equipment Initial Cost, $	Lateral Lines Fixed Equipment Initial Cost, $	Retrofit	Applicability
Fiber-Optic Cable	B	370,000	387,045[a]	N	Yes
Acoustic Emission	B	3,358,080[a]	633,000	Y[b]	Steel pipe only
HC[c] Liquid Sensing Cable	H	5,429,600[a]	826,000	N	Crude oil only

[a] Denotes an academic exercise of extrapolating costs to other pipeline segments based on original quotes. Economy of scale may reduce/increase costs significantly.
[b] Retrofit can be accomplished through vertical excavation at select distances.
[c] Hydrocarbon.

Summary of Cost-Effectiveness of LDS

Cost Analysis

Using the price data gathered from vendors, the incremental capital cost for upgrading a typical North Dakota gathering SCADA system is presented in Table 30. This number is calculated as a percent increase from the $1,628,000 original investment. The total SCADA investment is used interchangeably with crude or produced water for simplicity but obviously may differ. In the case of the internal LDS, the percent increase in capital cost is for the entire 24-mile pipeline and 40 laterals connected to each well pad. However, with external LDS, the laterals and main lines were divided into separate entities. One reason for separation is that, unlike internal LDS, external systems can be placed where there is a perceived higher risk, and it is more difficult to add into an existing system. For example, if fiber-optic cable is utilized for the main line, there may be little benefit to splice in a short lateral line going to a newly commissioned well pad. Another reason is that each lateral can be run as an independent LDS, with leak detection integrated through local communication at the well pad.

It is evident from the capital investments why internal LDS is preferred by the pipeline industry. The internal systems increased costs from 16% to 43% for the entire pipeline network, while external systems ranged from a 24% to 51% increase just for the lateral line coverage. For the main 24-mile line, the external fiber-optic cable showed an increase of 24% in capital expenses. Clearly, some of the external methods are more suitable for localized leak detection near HCAs. It should be noted that although the external LDS methods require a higher initial capital investment, they are expected to require less maintenance. Although they are expected to be functional and available, insufficient data exist on their application to gathering lines to assess whether these methods can provide required accuracy.

Table 30. Projected Increase in Capital Costs for Upgraded LDS

Equipment	Initial Cost, $	Incremental Cost of LDS Relative to SCADA, %
SCADA, Field	1,400,000	
Communications, Field	160,000	
SCADA, Control Center	68,000	
SCADA Total	1,628,000	
Internal LDS Options		
A (software)	300,000	18.4
B (sensors and software)	700,000	43.0
C (software)	260,000	16.0
External (main only) LDS Options		
Fiber-Optic Cable	370,000	22.7
Acoustic Emission	3,358,080	206.3
Liquid-Sensing Cable (HC)	5,429,600	333.5
External (laterals only) LDS Options		
Fiber-Optic Cable	387,045	23.8
Acoustic Emission	633,000	38.9
Liquid-Sensing Cable (HC)	826,000	50.7

Table 31 presents a detailed estimate for equipment, installation, and commissioning of a fiber-optic LDS for 48 miles of pipeline, covering 24 miles of produced water and crude oil trunk lines, respectively. Using the same basis as Table 30, the increase in capital cost would be about 15% for combined produced water and crude oil systems. When installation costs ($122,000) are included in the analysis, the total cost rises to 19%.

The complete quoted system cost is estimated at 22% over the installed SCADA system. If the fiber-optic system were applied to only one pipeline, the total cost rises to 31%. The quoted fiber-optic system only applies to a new pipeline installation, where the cost of trenching is incurred as part of the pipeline construction.

Table 31. Estimated Equipment and Installation Costs for a Fiber-Optic LDS

	Quantity	Unit Cost, $	Unit	Total Cost, $
Instrumentation to Monitor Sensor Cable				
Equipment Cost				250,000
Installation Cost				50,000
Total Instrumentation Installed Cost			Total	300,000
Sensor Cable Costs				
Direct Burial Splice Closures	15	1000	Each	15,000
Fiber-Optic Crossing Conduit	2000	5	m	10,000
Sensor Cable TMC – 3 × 12 + 3 Multipurpose	80,000	3.28	m	262,400
Sensor Cable Cost			Subtotal	287,400
Pipeliner/Fiber Install Procedure Development				6,000
Installation Supervision				20,000
Fiber-Optic Cable Install/Splice/Test (4-person crew)	16	6000	day	96,000
Sensor Cable Installation Cost			Subtotal	122,000
Total Sensor Cable Installed Cost			Total	409,400
Total System Installed Cost			Total	709,400
Annual Operating Cost				25,000

Cost Analysis Discussion

As stated in the previous LDS performance section of this report, the concept of effectiveness is really one of performance. Cost-effectiveness is essentially an assessment of whether an incremental investment in leak detection technology results in a commensurate improvement in its performance. It is also an assessment of diminishing returns.

The technology argument can be bracketed between an ideal LDS system that is fail-safe with almost instant notification and leak-locating capabilities and a basic manual system using air and ground patrols to reactively respond to in-progress leaks. A "high-reliability" LDS is technically feasible with current technology but comes at a large cost using external LDS methods. Another element to cost analysis exists when we consider which alternate product transportation methods such as trucking are more economical than using a pipeline. The impact of trucking on infrastructure, traffic, accidents, and road spills is a topic of another analysis, but the context is important when risks and environmental damage from pipeline spills are compared with the alternative.

Recognizing that leak detection technology can be unreliable does not imply that monitoring and leak detection have no value. The overall analysis of 197 incidents in the PHMSA study discussed earlier in this report (Shaw and others, 2012) showed the industry's use of internal LDS with or without CPM had a 20% chance to detect any leak (small to large) and a 50% chance of discovering a leak with an above-average release. It is, therefore, concluded that an investment in advanced systems to decrease the impact of pipeline spills is easily justified when a company recognizes that costs of remediation efforts may be larger by orders of magnitude. Several North Dakota industry entities involved in pipeline spill cleanup efforts in recent years have severely underestimated the costs of spill cleanup at the start of each effort. Anecdotal information provided to the EERC by unnamed companies indicates that some saltwater spill cleanup efforts are running into the tens of millions of dollars and are not yet completed.

Determining cost-effectiveness of monitoring and leak detection technologies has two aspects: cost and benefit. The discussion immediately above provides insight into the benefit aspect, which is poorly defined at best. Large interstate pipelines have experienced detection rates of about one detection in three incidents. If the technologies could improve the reliability of their indications and software up-time, they would significantly improve detection rates.

Despite this, control systems are employed across the refining and chemical process industry. Many of the reasons are quantifiable, such as more consistent quality, but many more are intangible, such as:

- More consistent and frequent data.
- Increased process predictability.
- Ability to rapidly and widely disseminate and share data.
- Ability to acquire, integrate, and analyze data, then quickly disseminate and act on results of the analyses.

These benefits beyond leak detection and their intangible nature complicate cost–benefit analyses.

A final complexity in evaluating the benefit aspect of cost-effectiveness lies in quantifying the likelihood that leak detection can remediate the severity of leaks and the probability when a leak will occur on the pipeline. Greater risk that is difficult to quantify is presented in:

- Older lines.
- Lines that are less well documented.
- Lines in more difficult service or locations.

- Lines with other issues present, but that could benefit from increased monitoring and leak detection to mitigate against that risk.

PIPELINE ABANDONMENT

It is important to briefly discuss observations related to pipeline abandonment as part of this study because it was highlighted as a concern by several stakeholders during the investigative phase.

Current Practices

Pipeline abandonment requirements are clearly defined currently under NDAC 43-02-03-29. As defined by the Code, an operator shall leave an oil and gas underground gathering pipeline in a safe condition by conducting the following:

- Disconnect and physically isolate the pipeline from any operating facility or other pipeline.
- Cut off the pipeline or the part of the pipeline to be abandoned below surface at pipeline level.
- Purge the pipeline with freshwater, air, or inert gas in a manner that effectively removes all fluid.
- Remove CP from the pipeline.
- Permanently plug or cap all open ends by mechanical means or welded means.

23

Key Finding and Recommendation

Observation: In the past, industry stakeholders indicated a frustration with lack of available information regarding existing pipeline locations during new pipeline installation activities at the time. To mitigate this issue, new rules have been implemented requiring new pipeline locations to be reported to the state using GIS.

Finding: The new GIS rule addresses the issue of pipeline information going forward on new pipeline installations but does not address the issue of information on pipelines already in existence when the rule went into effect. It also does not address the issue of providing the information in a timely manner.

Recommendation:
- The state should continue to work with industry stakeholders to inventory and catalog existing pipeline locations for pipelines that were installed prior to the new GIS reporting rule.
- The state should also work with industry stakeholders to develop a mechanism that allows for rapid acquisition of information about pipelines for use in construction activities.

In addition, the operator must file with the director of the North Dakota DMR a GIS layer showing the location of the pipeline centerline and an affidavit of completion containing the following information within 180 days of completion of the abandonment:

- A statement that the pipeline was abandoned in compliance with Section 43-02-03-29
- The type of fluid used to purge the pipeline

Assessment of Current Practices

Current practices for gathering pipeline abandonment as prescribed in NDAC 43-02-03-29 are sufficient to adequately protect the environment from unnecessary saline and oil impacts, assuming that the pipeline owner followed required procedures.

Several stakeholders indicated that verifying older abandoned pipelines becomes troublesome as little or no information is available to them regarding these pipelines when they are encountered. This results in a slowdown in the project progress and an uncertainty about whether they need to report the pipeline strike.

A LOOK AHEAD TO A GATHERING PIPELINE MONITORING AND PIPELINE LEAK DETECTION PILOT DEMONSTRATION PROJECT

Section 8 of HB1358 also mandates a pilot project to evaluate pipeline leak detection and pipeline monitoring systems. Therefore, Phase II of this project is intended to demonstrate best practices in pipeline monitoring and pipeline leak detection on actual operating pipelines. To satisfy this mandate, the EERC and North Dakota DMR will partner with one or multiple pipeline operators handling actual produced fluids. The hardware and operations demands of such a system dictate that this demonstration be integrated with an operational gathering pipeline.

Approaches to LDS Pilot Demonstration Project Design

Several potential partners have stepped forward to express interest in participating in the pilot demonstration. One of these entities envisions a new-build pipeline with advanced LDS employed. Other potential partners feel that their existing systems are advanced in nature and want to tout their capabilities via this public demonstration. Others see opportunity to retrofit existing lines and existing systems with additional advanced equipment and software to explore possibilities of advanced LDS.

All companies expressing interest to date seem to recognize that true LDS applied to gathering lines is a new application that is evolving alongside the unconventional oil revolution currently under way in the United States. As such, all companies in discussion with the EERC regarding this pilot demonstration seem to recognize that this is not only an opportunity to establish their methodologies as best practice, but also an opportunity to push their systems to achieve more performance from them.

Preliminary Test Design

With each of these potential demonstration systems, unfettered access to the data collected by the respective systems will be necessary to enable an objective evaluation of those systems to be achieved. Additionally, it is envisioned that challenge tests will be an integral part of the overall demonstration project. These challenge tests will include EERC-triggered, controlled release of various flow rates at various points within the demonstration pipeline systems. These leaks would not be announced to the control rooms of partnering companies, thus ensuring an unbiased, objective assessment of the respective system's ability to detect the leak and the response time associated with the whole process from leak start to leak stop. This system performance monitoring and leak detection response assessment will be carried out over several months during 2016.

This test design targets comparison of several system configurations and their impact on LDS. These comparisons are, of course, dependent upon the mix of systems offered by demonstration partners. In a perfect situation, they will include the following:

- **Comparison of SCADA and CPM** – Tests conducted under this demonstration will assess the sensitivity and response time of a controlled leak using both SCADA and CPM. Testing of the SCADA package would rely on the industry partner's existing SCADA system with alarm notification of "leak" conditions. Pending participation from applicable vendors, a

CPM system will be configured to utilize existing SCADA information and provide an "add-on" leak analysis tool. This condition would enable a comparison of standard SCADA-based alarm functionality versus more sophisticated data analysis utilized by CPM systems in terms of sensitivity to small leaks and number of induced false alarms.

- **Comparison of Pressurized vs. Unpressurized Operation** – The ability of both SCADA- and CPM-based technologies to detect a controlled leak will be tested under two operating conditions: one in which the gathering system pressure is maintained above a minimum set point and another under which system pressure is allowed to drop to atmospheric, resulting in some gravity flow of fluids. These tests are intended to assess the effect operating pressure has on leak detection sensitivity and/or response time.

- **Comparison of Steady State vs. Variable (normal) Operating Conditions** – The ability of both SCADA- and CPM-based technologies to detect a controlled leak will be tested under both steady-state and variable/transient flow conditions. The research team will attempt to operate a portion of the gathering system under steady-state flow and pressure conditions for a period of time sufficient to induce a controlled fluid release and subsequently evaluate SCADA and CPM ability to identify the leak. Results will be compared to tests under more common gathering line conditions where flow rates and pressures are changing.

The EERC is promoting the following outline of a project plan to potential participating companies:

1. Monitoring of Pilot Project Performance
   a. Data monitoring
      i. The EERC would require transparent access to data but would not require access to system control, only data.
      ii. The EERC would require a complete system description including operational algorithms, piping and instrumentation diagrams, geolocation of all components, ROW access constraints, etc.
      iii. The EERC would utilize a modified version of a SCADA system or CPM, different from the partner's system, that would use as input the data being transmitted from partner, to provide for additional analysis of effectiveness of various operational scenarios in parallel to the partner's system. SCADA and CPM operational systems may be vendor-supplied.
   b. Controlled leak tests to determine response time (EERC-triggered with cooperation from partnering companies).
      i. The EERC, with assistance from the partnering company to ensure safety, will either open a valve or simulate a leak in the pipeline without knowledge of the control center.
      ii. Data polling frequency may be adjusted to determine effects on leak detection.
      iii. Instrumentation may be replaced with alternate instrumentation to assess effects on leak detection.
   c. Ongoing instrument health assessment
      i. Instrument calibration will be verified at appropriate times during testing.

    ii. Operational characteristics affecting instrument accuracy and functionality will be determined (e.g., change in fluid composition or salt concentration).
d. Surface Leak Detection Testing
    i. The research team may explore use of UAS coupled with advanced imaging systems to detect simulated or controlled fluid releases.
    ii. The research team may explore use of other spectral leak detection techniques to identify and quantify simulated or controlled fluid releases.

2. Analysis of Pilot Project Performance (EERC-led)
    a. The EERC team will use data acquired during the pilot demonstration project to evaluate advanced monitoring and leak detection concepts, evaluate the effects of data polling rates on leak detection performance, evaluate the effects of off-nominal instrument measurements on leak detection performance, or other purposes.
    b. The EERC will perform statistical analyses of all data collected.

3. Reporting on Pilot Project to State of North Dakota (EERC report to state)

The EERC, with cooperation from North Dakota DMR, will solidify industry participation by very early in 2016 and will subsequently solidify specific test plans with all involved parties.

Anticipated Results

It is anticipated that this demonstration will inform industry and the state on the potential of advanced pipeline monitoring and LDS. There is no implied guarantee that any of the systems will perform as all interested parties desire, but the demonstration will serve to calibrate expectations of these systems. Currently, it seems that the only information available on application of advanced LDS to liquid gathering pipeline systems is sales information touting possibilities of these systems. None of these systems has yet been thoroughly proven or employed on gathering pipeline systems in North America.

Leak Detection Systems That Should Be Included in the Demonstration

The EERC believes that a truly robust, comparative demonstration of multiple technologies is the best objective method to determining whether any system adequately addresses the expectations implied in HB1358. The EERC believes that current leading contenders in this space include:

- Computational modeling systems
    - Several variants available
    - Complex, requiring extensive system model data and months of tuning
    - No publicly available comparative data exist

- Negative pressure wave systems
    - Likely applicable to only pressurized lines
    - Unproven in smaller gathering systems with high-frequency perturbances

- External leak sensors
  - Few candidates exist
  - Little data exist on performance
  - One North Dakota producer/operator currently experimenting with one variant

Looking Ahead – What More Might Be Done in Additional Phases

If additional funding and scheduling were to be made available, it may benefit the state to consider an additional phase of work. That phase would demonstrate complementary technologies outside of the monitoring systems and LDS prescribed by HB1358. Likely contributors to improvements in pipeline leak mitigation are technologies such as automated shutoff devices, improved pipeline materials, and improved communications infrastructure to enhance response times. These technology areas could also be demonstrated and evaluated for their relative contributions to decreased leak incidence and severity.

CONCLUSION

North Dakota HB1358 mandated the EERC to conduct a study to:

- Analyze the existing regulations on construction and monitoring of crude oil and produced water pipelines.
- Determine the feasibility and cost-effectiveness of requiring leak detection and monitoring technology on new and existing pipeline systems.
- Provide a report with recommendations to the Industrial Commission and the Energy Development and Transmission Committee by December 1, 2015.

The intent of this study is to assess ways to improve the performance of produced water and crude oil pipelines in North Dakota by informing the NDIC's decisions regarding possible adoption of administrative rules impacting pipeline safety and integrity.

This study is a detailed analysis of many aspects of pipeline performance, each one impacting the potential for leaks and spills. The key findings listed at the beginning of the report are an abridged set of lessons resulting from the study and can be used to summarize the substantial detail provided in this report, but the reader is cautioned to examine the details for justification of the key findings.

In the final analysis, no single pipeline product option, installation technique, or leak detection technology will impact the rate of leaks and spills more than ensuring that each and every person on each and every installation crew is made acutely aware of the risks of improper installation procedures and that each person follows these procedures to the letter. Increased state inspection with limited additional regulatory authority may help to ensure that proper procedures are followed, but the ultimate responsibility still rests with contractors performing the work.

Across the nation and the globe, pipeline leaks and spills occur. They are an unavoidable reality. The best society can do is minimize the number, frequency, and volumetric extent of leaks. In the end, pipelines will undoubtedly always be safer and more economical than truck transport or other alternatives to transporting energy products to market.

KEY FINDINGS AND RECOMMENDATIONS

Gathering Processes

- Gathering pipelines are complex and dynamic systems. The dynamic nature of oil production, the large and rural geography of the Williston Basin, and constrained supporting infrastructure inevitably lead to non-steady-state operating conditions. These conditions make the design, installation, and operation of gathering pipes more difficult than pipelines in most other industries and applications. The dynamics of gathering pipelines must be considered as different operational practices, regulations, and technology are assessed to improve the safety and reliability of gathering pipelines in North Dakota.

Regulations

- Not all pipelines in a state are regulated by PHMSA. Those pipelines that are not federally regulated are regulated by the state, and as a result, minimum safety standards for these unregulated pipelines vary from state to state. For federally regulated pipelines, PHMSA adopts the CFR as minimum standards to be met by pipelines.

- State regulations on pipelines differ significantly in many aspects. While some states go into great detail for standards on construction, record keeping, leak mitigation, etc., in addition to adopting the CFR, other states provide comparatively lesser detail without adopting specific standards. For example, states differ significantly in the minimum spill reporting thresholds, to exemplify the complexity in comparing spill statistics among states.

- While there are differences in spill-reporting requirements, all states maintain the same structure in certain aspects; for example, a detected spill must be reported immediately and subsequently followed up by a more detailed report about the spill and actions taken to remedy the spill, etc.

- North Dakota regulations for pipeline safety and construction are not as extensive and detailed compared to other states being studied.

Spill and Leak History

- Data from 2001 through 2014 were compiled and analyzed to evaluate oil- and gas-related spills and leaks in North Dakota. The evaluation of that data provided some interesting results, including the fact that, as an industry, approximately 0.01% of the oil and brine handled is spilled. In other words, for every 10,000 barrels handled, 9999 barrels is delivered without incident, and 1 barrel is spilled. That is not to say the spill volumes are not of concern, as exhibited by the fact that 20,000 barrels of oil and 71,000 barrels of brine were spilled in 2014.

- Data also showed that the increase in oil production has resulted in an increase in spills of both oil and brine, but when spills are analyzed in relation to oil production over the entire 14-year analysis period, spill trends are flat or slightly declining. Pipeline-specific spills normalized by annual oil production also exhibit a slightly decreasing trend.

- Although pipeline-related spills do represent a prominent portion of the total spills, other types of spills such as valve/piping connection leaks and tank overflows are also notable. In fact, pipeline-related leaks as a percentage of total spills may actually be decreasing (although the data entry method makes this conclusion unreliable). One thing is certain, a small number of large pipeline spills in recent years have greatly skewed the trend lines.

- Based on spill and leak data from 2008 through 2014 of the top seven oil-producing states, North Dakota and other states with shale production have seen a significant increase in annual oil production, which has resulted in an increase in spills in those states. States without shale plays have had flat or decreasing annual oil production, and spills have also been flat or declining. Comparing spill volume data as a function of annual oil production for states with increasing production, North Dakota has performed at par or better than its shale-play peer states.

Pipeline Materials

- Several national and international organizations such as API, ASTM, and ASME have put forward standard or recommended practices for testing, handling, and installing pipelines made of most, but not all, commercially available materials. If the pipeline components are tested and installed following these practices, they will perform as expected. However, components made of more brittle materials are more prone to damage or installation errors than more flexible materials. In addition, pipelines made of longer continuous materials such as spoolable pipe contain far fewer joints than those made of stick pipe, so there are fewer chances for making a bad joint with spoolable pipe.

- API RP 15S is the industry standard covering testing of spoolable reinforced plastic pipe. It specifically addresses only pipes with reinforcement layers composed of glass-reinforced epoxy (Fiberspar) or aramid fibers (Polyflow). Since API RP 15S was approved, additional spoolable reinforced plastic pipe products have become available, in particular, piping reinforced with steel (FlexSteel). The company that makes that product is currently performing qualification testing and working to have its products included in RP 15S. In addition, the RP 15S committee is working to change the practice status to a “standard” rather than a “recommended.” Since the spoolable reinforced products are not currently included in a standard practice, they generally are not included in standard PHMSA pipeline guidelines for transportation pipelines. Therefore, if they are to be used in North Dakota for gathering lines, variances to the PHMSA transportation pipeline guidelines must be allowed in rules set forward for gathering lines. However, it is expected that API RP 15S will be accepted as a standard practice in early 2016. It is our understanding that once the spoolable reinforced products are covered by a standard practice, they will be accepted by PHMSA regulations (American Petroleum Institute, 2013a).

Pipeline Maintenance and Inspection

- This study found that the majority of gathering lines in the Bakken are designed without the ability to use pipeline pigs for cleaning, maintenance, and inspection. While pigs are used in longer and larger PHMSA-regulated interstate pipelines, this is not the case for most gathering lines. It is postulated that the smaller diameter, shorter length of the lines and the number of tie-ins and junctions have led most gathering line designers, builders, and operators to forego the extra costs involved in making them accessible to pigs.

- At the height of the Bakken buildout, maintenance of gathering lines and their subsequent components such as valves, gauges, and pumps was not as rigorous and methodical as it could have been because of the speed at which the development was occurring. More recently, producers, operators, and owners have improved their maintenance routines, and the pace of the buildout has diminished. This improved maintenance has included replacing components that were failing faster than anticipated because of the high salinity of the Bakken Formation water and specifying better-suited materials for new applications.

Pipeline Construction and Installation

- Much work has been done to develop standard practices and regulation of the construction and installation of steel pipelines, and less standardization has been developed for the plastic pipes (specifically spoolable pipes used in the oil industry). In the absence of specific construction standards, many gathering line operators have adopted practices similar to PHMSA standards and guidelines.

- Anecdotal indications suggest that many pipeline leaks are caused by poor workmanship and lack of inspection. Although this could not be corroborated from the spill data analyzed, it is clear that many companies have adequate construction standards to properly install pipelines and the failures, if they exist, are in the execution of those construction standards.

Pipeline Monitoring and Leak Detection

- At this time, no technology has demonstrated undisputed reliability in detecting spills on interstate pipelines, much less on more problematic gathering lines.

- A major portion of pipeline leaks are discovered by persons (employees, contractors, and the public) who happen to be in the area of a spill.

- To aid in detecting spills, interstate pipeline operators have installed sensors in the ground, near pipelines, to warn operators when they contact liquids that have been released from those lines. However, the high cost of these sensors is such that they are installed primarily in environmentally sensitive HCAs. These sensors are extremely difficult to install on existing pipelines and are subject to false alarms from similar liquids in the ground; major improvements with respect to these disadvantages are not foreseen at this time.

- Interstate pipeline operators also have added sophisticated software to their existing pipeline computer control systems to watch for indications of leaks. Such systems generally are required by PHMSA on new interstate pipelines and range from easy to install and inexpensive to modestly expensive and time consuming. To a great extent, their ability to detect leaks varies with cost. Unfortunately, these systems suffer from excessive numbers of false alarms which diminish their usefulness, although software vendors and operators are working to understand

and reduce these. Additionally, the complexity and unpredictability with which gathering lines typically operate reduce their performance compared to interstate pipelines.

- Interest has been increasing in the use of UAVs (drones) to patrol pipelines and employ in conjunction with other leak detection technologies; their capability currently is under study.

- Ultimately, each pipeline is different to the extent that whatever detection technology(ies) is (are) installed, they will need to be customized to the particular pipeline of interest.

REFERENCES

Alaska Department of Environmental Conservation Division of Spill Prevention and Response, 1999, Technical review of leak detection technologies—crude oil transmission pipelines: v. 1.

Alaska Department of Environmental Conservation Division of Spill Prevention and Response, 2012, Industry preparedness program: Pipeline leak detection technology 2011 Conference Final Report: March, Prepared by Shannon & Wilson, Inc.

Alaska Department of Environmental Conservation Division of Spill Prevention and Response, 2015a, Oil and hazardous substance spill data summaries: http://dec.alaska.gov/spar/PPR/data.htm (accessed August 22, 2015).

Alaska Department of Environmental Conservation Division of Spill Prevention and Response, 2015b, Report oil and hazardous substance spills: January, http://dec.alaska.gov/spar/PPR/docs/placard_current.pdf (accessed 2015).

Alaska North Slope Spills Analysis, 2010, Final report on North Slope spills analysis and expert panel recommendations on mitigation measures: Nuka Research and Planning Group, LLC, November.

American Society of Mechanical Engineers, 2002, Pipelines transportation systems for liquid hydrocarbons and other liquids: ASME B31.4:49, October 4.

American Society of Mechanical Engineers, 2003, Gas transmission and distribution piping systems: ASME B31.8-2003.

American Society of Mechanical Engineers, 2004, Processing piping: ASME B31.3-2004.

American Petroleum Institute, 2012, API Recommended Practice 1130—Computational pipeline monitoring for liquids, 1st ed. September 2007, reaffirmed April.

American Petroleum Institute, 2013a, API Recommended Practice 15S—Qualification of spoolable reinforced plastic line pipe: October.

American Petroleum Institute, 2013b, API Recommended Practice 15TL4—Recommended practice for care and use of fiberglass tubulars: reaffirmed October.

American Petroleum Institute, 2015, API Recommended Practice 1173—Pipeline safety management system requirements: June.

ASM Handbook, 2003, Cathodic protection, *in* Cramer, S.D., and Covino, B.S., eds. Corrosion—fundamentals, testing, and protection: ASM International, v. 13A, p. 855–870.

ASM Handbook, 2006, Corrosion—environments and industries, *in* Cramer, S.D., and Covino, B.S., eds., ASM International, v. 13C.

Beavers, J.A., and Thompson, N.G., 2006, External corrosion of oil and natural gas pipelines, *in* Cramer, S.D., and Covino, B.S., eds, ASM Handbook: ASM International, v. 13C, p. 1015–1025.

Borener, S.S., and Patterson, T., 1995, Remote control spill reduction technology—a survey and analysis of applications for liquid pipeline systems: U.S. Department of Transportation, Volpe National Transportation Systems Center, 71 p.

Brooks, L.E., 1968, High-pressure testing—pipeline defect behavior and pressure reversals: ASME, 68-PET-24.

California Governor's Office of Emergency Services, 2014, Release reporting requirements matrix: www.caloes.ca.gov/FireRescueSite/Documents/Release%20Reporting%20Matrix%20-%20Feb2014.pdf (accessed 2015).

California Governor's Office of Emergency Services, 2015, Spill release reporting: www.caloes.ca.gov/FireRescueSite/Pages/Spill-Release-Reporting.aspx (accessed August 22, 2015).

Canadian Standards Association, 2003, Standard Z662, Oil and gas pipeline systems.

Colorado Oil & Gas Conservation Commission, 2015.

D'Aliesio, R., Lewis, J., and Jones, J., 2015, Nexen pipeline may have been leaking for over two weeks, executives say: The Globe and Mail, www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/nexen-pipeline-could-have-been-leaking-for-more-than-two-weeks-executives-say/article25629960/ (accessed August 2015).

The Engineering ToolBox, 2015, www.engineeringtoolbox.com/thermoplastic-pipes-temperature-strength-d_794.html (accessed 2015).

Farshad, M., 2006, Plastic pipeline systems: Elsevier Ltd., p. 56.

Fiberglass Tank & Pipe Institute, 2013, Fiberglass reinforced thermoset plastic tank & piping standards: FTPI RP 1997-5.

Hicks, B., 2015, DMR presentation to the National Association of Royalty Owners, Minot, North Dakota: June 26, 2015, www.dmr.nd.gov/oilgas/presentations/ActivityUpdate2015_2015-06-26_NARO.pdf (accessed 2015).

Horner, P., Halldorson, B., and Slutz, J.A., 2011, Shale gas water treatment value chain—a review of technologies, including case studies: SPE Annual Technical Conference and Exhibition, 30 October – 2 November, Denver, Colorado.

Hovey, D.J., and Farmer, E.J., 1999, DOT stats indicate need to refocus pipeline accident prevention: Oil & Gas Journal, v. 97, no. 11.

Kiefner, J., 2001, Role of hydrostatic testing in pipeline integrity assessment: Northeast Pipeline Integrity Workshop, Albany, New York.

Kiefner, J.F., Maxey, W.A., and Eiber, R.J., 1980, A study of the causes of failure of defects that have survived a prior hydrostatic test: Pipeline Research Committee, American Gas Association, NG-18 Report No. 111.

Kiefner, J.F., Maxey, W.A., Eiber, R.J., and Duffy, A.R., 1973, Failure stress levels of flaws in pressurized cylinders—progress in flaw growth and toughness testing: ASTM STP 536, American Society for Testing and Materials, p. 461–481.

Kringstad, J., 2015, Crude oil gathering 11-10-15: North Dakota Pipeline Authority, http://northdakotapipelines.com/presentations/ (accessed November 2015).

Larsen, H.A., and Reichert, B.A., 2003, Coiled tubing abrasion—an experimental study of field failures: SPE 81724.

Lauer, R.S., 2012, Advancements in the abrasion resistance of internal plastic coatings: SPE 162182.

Lefave, J., and Karr, L., 1998, Underground pipeline leak detection and location technology application guide: Naval Facilities Engineering Service Center, User Guide UG-2028-ENV, April.

McAllister, E.W., 2015, Pipeline rules of thumb handbook—a manual of quick, accurate solutions to everyday pipeline engineering problems: Gulf Professional Publishing, p. 146–157.

Mehler Paperny, A., and Ramsay, M., 2015, 'We sincerely apologize'—Nexen's 'failsafe' system didn't detect massive northern Alberta pipeline spill: Global News, July 17, 2015 retrieved from globalnews.ca/news/2116785/nexen-to-provide-update-on-northern-alberta-pipeline-spill/ (accessed October 23, 2015).

Miesner, T.O., and Leffler, W.L., 2006, Oil and gas pipelines: PennWell Corporation, Tulsa, Oklahoma.

NACE International, 2012, Techniques for monitoring corrosion and related parameters in field applications: NACE Publication 3T199, Product No. 24203-SG.

NACE International, 2013, Standard Practice 0169-2013—control of external corrosion on underground or submerged metallic piping systems.

National Association of Corrosion Engineers, 2006, Standard Practice 0106-2006—Control of internal corrosion in steel pipelines and piping systems.

Nergaard, M., and Grimholt, C., 2010, An introduction to scaling causes, problems and solutions: Institutt for Petroleumsteknologi og Anvendt Geofysikk, Trondheim, Norway.

New Mexico Energy, Minerals and Natural Resources Department Oil Conservation Division, 2015, www.emnrd.state.nm.us/OCD/documents/SearchablePDFofOCDTitle19Chapter15 created3-2-2012_updated_07-06-2015.pdf (accessed September 2015).

North Dakota Department of Health, 2009, Environmental incident reports: www.ndhealth.gov/ehs/eir/Eirform.htm (accessed August 2015).

North Dakota Department of Health, 2015, Environmental incident reports: www.ndhealth.gov/EHS/Spills/ (accessed August 2015).

North Dakota Department of Mineral Resources, 2012, www.dmr.nd.gov/oilgas/rules/ rulebook.pdf (accessed 2015).

North Dakota Industrial Commission, 2014a, Case Number 23084 Order Number 25417; December 9.

North Dakota Industrial Commission, 2014b, Crude oil processes: www.dmr.nd.gov/oilgas/ presentations/NDIC082614CrudeOilProcesses.pdf (accessed December 11, 2014).

North Dakota Pipeline Technology Working Group, 2014, Pipeline technology review: December 1.

Oasis Petroleum, 2014, Oasis facility operations: September 23, 2014, Testimony before the North Dakota Industrial Commission, Case Number 23084 and Order Number 25417.

Penty, R., and Lee, M., 2013, Bloomberg story on leak detection—Keystone XL Pipe shuns infrared sensors to detect leaks: http://keystone-xl.com/clarification-bloomberg-story-on-leak-detection/ (accessed August 17, 2015).

Pipeline & Gas Journal, 2014, API considers new voluntary recommended practice for pipeline safety: v. 241, no. 5.

Plastics Pipe Institute, 1999, Suggested temperature limits for the operation and installation of thermoplastic piping in non-pressure applications: TN-11/99.

Plastics Pipe Institute, 2007, High performance PE materials for water piping applications: TN-41/2007, Municipal and Industrial Division, November.

Plastics Pipe Institute, 2009, Handbook of polyethylene pipe, 2d ed.

Plastics Pipe Institute, 2013, Guidance for field hydrostatic testing of high density polyethylene pressure pipelines—owner's considerations, planning, procedures, and checklists: TN-46/2013a.

Railroad Commission of Texas, 2015, Crude oil, gas well liquids or associated products (H-8) loss reports: www.rrc.state.tx.us/oil-gas/compliance-enforcement/h-8/ (accessed August 22, 2015).

Ritter, A., 2015, DMR presentation to the North Dakota Interim Energy Development and Transmission Committee: www.dmr.nd.gov/oilgas/presentations/EDTC072915.pdf (accessed 2015).

Shaw, D., Phillips, M., Baker, R., Munoz, E., Rehman, H., Gibson, C., and Mayernik, C., 2012, Leak detection study—DTPH56-11-D-000001: U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration Final Report No. 12-173, December 10, 2012.

Silowash, B., 2010, Piping systems manual: McGraw-Hill.

Summa, J., 2011, Pipeline leak detection operational improvements: 6th Pipeline Technology Conference, Hannover, Germany, April 4–5.

Technische Regel für Rohrfernleitungen (Technical Rules for Pipelines), 2003, TRFL 2003—Technische Regel für Rohrfernleitungen: Heymanns Verlag GmbH, 1211 p.

Texas Administrative Code, 2015.

Texas Commission on Environmental Quality, 2014, Spills—reportable quantities: www.tceq.texas.gov/response/spills/spill_rq.html (accessed August 22, 2015).

U.S. Department of State Bureau of Oceans and International Environmental and Scientific Affairs, 2011, Final supplemental environmental impact statement for the Keystone XL project: Appendix B, p. 2–26.

U.S. Department of the Army, U.S. Army Corps of Engineers, 1986, Engineering and design—field applications of polyethylene pipe in dredging: Technical Letter No. 1110-2-530, December 15.

U.S. Department of Transportation, 2014, Fact sheet—in-line inspections (smart pig): https://primis.phmsa.dot.gov/comm/FactSheets/FSSmartPig.htm (accessed August 10, 2015).

U.S. Energy Information Administration, 2015a, Alaska field production of crude oil: www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPAK1&f=A (accessed September 2015).

U.S. Energy Information Administration, 2015b, California field production of crude oil: www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPCA1&f=A (accessed September 2015).

U.S. Energy Information Administration, 2015c, Colorado field production of crude oil: www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPCO1&f=A (accessed September 2015).

U.S. Energy Information Administration, 2015d, New Mexico field production of crude oil: www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPNM1&f=A (accessed September 2015).

U.S. Energy Information Administration, 2015e, North Dakota field production of crude oil: www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPND1&f=A (September 2015).

U.S. Energy Information Administration, 2015f, State energy production estimates 1960 through 2013: www.eia.gov/state/seds/sep_prod/SEDS_Production_Report.pdf (accessed October 2015).

U.S. Energy Information Administration, 2015g, Texas field production of crude oil: www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPTX1&f=A (accessed August 22, 2015).

Willoughby, D.A., Woodson, R.D., and Sutherland, R., 2002, Plastic piping handbook; McGraw Hill.

Wingate-Hill, R., 1970, The resistance of some thermoplastics to abrasion by granular compound fertilizer: Journal of Agricultural Engineering Research, v. 15, no. 4, p. 388–392.

Wylde, J.J., 2011, Chemically assisted pipeline cleaning for pigging operations: Pipeline and Gas Journal, v. 238, no. 8, August.

Wylde, J.J., and Slayer, J.J.L., 2010, Development, testing, and field application of a heavy-oil pipeline-cleaning chemical—a cradle-to-grave case history: SPE Projects, Facilities & Construction, v. 5, no. 10.

APPENDIX A

NORTH DAKOTA HOUSE BILL 1358

15.0460.05000

Sixty-fourth
Legislative Assembly
of North Dakota

SECOND ENGROSSMENT
with Senate Amendments
REENGROSSED HOUSE BILL NO. 1358

Introduced by

Representatives D. Anderson, Hatlestad, J. Nelson, Porter, Weisz

Senators Bekkedahl, O'Connell

A BILL for an Act to create and enact a new section to chapter 38-08 and a new subsection to section 38-08-26 of the North Dakota Century Code, relating to the operation of underground gathering pipelines and the sharing of information by a surface owner; to amend and reenact subsection 18 of section 38-08-02, subdivisions d and l of subsection 1 of section 38-08-04, subsection 6 of section 38-08-04, and section 38-08-04.5 of the North Dakota Century Code, relating to an exception to confidentiality of well data, to underground gathering pipelines, to temporarily abandoned status, and the uses of the abandoned oil and gas well plugging and site reclamation fund; to provide a report to the legislative management; to provide a transfer; to provide an appropriation; and to declare an emergency.

BE IT ENACTED BY THE LEGISLATIVE ASSEMBLY OF NORTH DAKOTA:

SECTION 1. AMENDMENT. Subsection 18 of section 38-08-02 of the North Dakota Century Code is amended and reenacted as follows:

18. "Underground gathering pipeline" means an underground gas or liquid pipeline ~~that~~<u>with associated above ground equipment which</u> is designed for or capable of transporting crude oil, natural gas, carbon dioxide, or water produced in association with oil and gas which is not subject to chapter 49-22. <u>As used in this subsection, "associated above ground equipment" means equipment and property located above ground level, which is incidental to and necessary for or useful for transporting crude oil, natural gas, carbon dioxide, or water produced in association with oil and gas from a production facility. As used in this subsection, "equipment and property" includes a pump, a compressor, storage, leak detection or monitoring equipment, and any other facility or structure.</u>

SECTION 2. A new section to chapter 38-08 of the North Dakota Century Code is created and enacted as follows:

Controls, inspections, and engineering design on crude oil and produced water underground gathering pipelines.

The application of this section is limited to an underground gathering pipeline that is designed or intended to transfer crude oil or produced water from a production facility for disposal, storage, or sale purposes and which was placed into service after August 1, 2015-. Upon request, the operator shall provide the commission the underground gathering pipeline engineering construction design drawings and specifications, list of independent inspectors, and a plan for leak protection and monitoring for the underground gathering pipeline. Within sixty days of an underground gathering pipeline being placed into service, the operator of that pipeline shall file with the commission an independent inspector's certificate of hydrostatic or pneumatic testing of the underground gathering pipeline.

SECTION 3. AMENDMENT. Subdivision d of subsection 1 of section 38-08-04 of the North Dakota Century Code is amended and reenacted as follows:

d. The furnishing of a reasonable bond with good and sufficient surety, conditioned upon the full compliance with this chapter, and the rules and orders of the industrial commission, including without limitation a bond covering the operation of any underground gathering pipeline transferring oil or produced water from a production facility for disposal, storage, or sale purposes, except that if the commission requires a bond to be furnished, the person required to furnish the bond may elect to deposit under such terms and conditions as the industrial commission may prescribe a collateral bond, self-bond, cash, or any alternative form of security approved by the commission, or combination thereof, by which an operator assures faithful performance of all requirements of this chapter and the rules and orders of the industrial commission.

SECTION 4. AMENDMENT. Subdivision l of subsection 1 of section 38-08-04 of the North Dakota Century Code is amended and reenacted as follows:

l. The placing of wells in abandoned-well status which have not produced oil or natural gas in paying quantities for one year. A well in abandoned-well status must be promptly returned to production in paying quantities, approved by the commission for temporarily abandoned status, or plugged and reclaimed within six months. If none of the three preceding conditions are met, the industrial commission may require the well to be placed immediately on a single-well bond in an amount equal to the cost of plugging the well and reclaiming the well site. In setting the bond amount, the commission shall use information from recent plugging and reclamation operations. After a well has been in abandoned-well status for one year, the well's equipment, all well-related equipment at the well site, and salable oil at the well site are subject to forfeiture by the commission. If the commission exercises this authority, section 38-08-04.9 applies. After a well has been in abandoned-well status for one year, the single-well bond referred to above, or any other bond covering the well if the single-well bond has not been obtained, is subject to forfeiture by the commission. <u>A surface owner may request a review of the temporarily abandoned status of a well that has been on temporarily abandoned status for at least seven years. The commission shall require notice and hearing to review the temporarily abandoned status. After notice and hearing, the surface owner may request a review of the temporarily abandoned status every two years.</u>

SECTION 5. AMENDMENT. Subsection 6 of section 38-08-04 of the North Dakota Century Code is amended and reenacted as follows:

6. To provide for the confidentiality of well data reported to the commission if requested in writing by those reporting the data for a period not to exceed six months. <u>However, the commission may release:</u>
   <u>a.</u> <u>Volumes injected into a saltwater injection well.</u>
   <u>b.</u> <u>Information from the spill report on a well on a site at which more than ten barrels of fluid, not contained on the well site, was released for which an oilfield environmental incident report is required by law.</u>

SECTION 6. AMENDMENT. Section 38-08-04.5 of the North Dakota Century Code is amended and reenacted as follows:

38-08-04.5. Abandoned oil and gas well plugging and site reclamation fund - Budget section report.

There is hereby created an abandoned oil and gas well plugging and site reclamation fund.

1. Revenue to the fund must include:

a. Fees collected by the oil and gas division of the industrial commission for permits or other services.

b. Moneys received from the forfeiture of drilling and reclamation bonds.

c. Moneys received from any federal agency for the purpose of this section.

d. Moneys donated to the commission for the purposes of this section.

e. Moneys received from the state's oil and gas impact fund.

f. Moneys recovered under the provisions of section 38-08-04.8.

g. Moneys recovered from the sale of equipment and oil confiscated under section 38-08-04.9.

h. Moneys transferred from the cash bond fund under section 38-08-04.11.

i. Such other moneys as may be deposited in the fund for use in carrying out the purposes of plugging or replugging of wells or the restoration of well sites.

j. Civil penalties assessed under section 38-08-16.

2. Moneys in the fund may be used for the following purposes:

a. Contracting for the plugging of abandoned wells.

b. Contracting for the reclamation of abandoned drilling and production sites, saltwater disposal pits, drilling fluid pits, and access roads.

c. To pay mineral owners their royalty share in confiscated oil.

d. Defraying costs incurred under section 38-08-04.4 in reclamation of oil and gas-related pipelines and associated facilities.

<u>e.</u> <u>Reclamation and restoration of land and water resources impacted by oil and gas development, including related pipelines and facilities that were abandoned or were left in an inadequate reclamation status before August 1, 1983, and for which there is not any continuing reclamation responsibility under state law. Land and water degraded by any willful act of the current or any former surface owner are not eligible for reclamation or restoration. The commission may expend up to one million five hundred thousand dollars per biennium from the fund in the following priority:</u>

<u>(1)</u> <u>For the restoration of eligible land and water that are degraded by the adverse effects of oil and gas development including related pipelines and facilities.</u>

(2) For the development of publicly owned land adversely affected by oil and gas development including related pipelines and facilities.

(3) For administrative expenses and cost in developing an abandoned site reclamation plan and the program.

(4) Demonstration projects for the development of reclamation and water quality control program methods and techniques for oil and gas development, including related pipelines and facilities.

3. All moneys collected under this section must be deposited in the abandoned oil and gas well plugging and site reclamation fund. This fund must be maintained as a special fund and all moneys transferred into the fund are appropriated and must be used and disbursed solely for the purpose of defraying the costs incurred in carrying out the plugging or replugging of wells, the reclamation of well sites, and all other related activities.

4. The commission shall report to the budget section of the legislative management on the balance of the fund and expenditures from the fund each biennium.

SECTION 7. A new subsection to section 38-08-26 of the North Dakota Century Code is created and enacted as follows:

The surface owner may share information contained in the geographic information system database.

SECTION 8. TRANSFER - ABANDONED OIL AND GAS WELL PLUGGING AND SITE RECLAMATION FUND TO OIL AND GAS RESEARCH FUND - PRODUCED WATER PIPELINE STUDY - REPORT TO LEGISLATIVE MANAGEMENT. The director of the office of management and budget shall transfer the sum of $1,500,000 from the abandoned oil and gas well plugging and site reclamation fund to the oil and gas research fund for the purpose of funding a special project through the energy and environmental research center at the university of North Dakota during the biennium beginning July 1, 2015, and ending June 30, 2017. The special project must focus on conducting an analysis of crude oil and produced water pipelines including the construction standards, depths, pressures, monitoring systems, maintenance, types of materials used in the pipeline including backfill, and an analysis of the ratio of spills and leaks occurring in this state in comparison to other large oil and gas-producing states with substantial volumes of produced water. The industrial commission shall contract with the energy and environmental research center to compile the information and the center shall work with the department of mineral resources to analyze the existing regulations on construction and monitoring of crude oil and produced water pipelines, determine the feasibility and cost effectiveness of requiring leak detection and monitoring technology on new and existing pipeline systems, and provide a report with recommendations to the industrial commission and the energy development and transmission committee by December 1, 2015. The industrial commission shall adopt the necessary administrative rules necessary to improve produced water and crude oil pipeline safety and integrity. In addition, the industrial commission shall contract for a pilot project to evaluate a pipeline leak detection and monitoring system.

SECTION 9. APPROPRIATION. Notwithstanding section 38-08-04.5, there is appropriated out of any moneys in the abandoned oil and gas well plugging and site reclamation fund in the state treasury, not otherwise appropriated, the sum of $500,000, or so much of the sum as may be necessary, to the industrial commission for the purpose of conducting a pilot program involving the oil and gas research council in conjunction with research facilities in this state to determine the best techniques for remediating salt and any other contamination from the soil surrounding waste pits reclaimed by trenching between 1951 and 1984 in the north central portion of this state, for the biennium beginning July 1, 2015, and ending June 30, 2017.

SECTION 10. EMERGENCY. This Act is declared to be an emergency measure.

APPENDIX B

NORTH DAKOTA PIPELINE TECHNOLOGY WORKING GROUP

PIPELINE TECHNOLOGY REVIEW

North Dakota Pipeline Technology Working Group

Pipeline Technology Review

Submitted: December 1, 2014

Governor Appointed Working Group Members

- Niles Hushka, Niles - Chief Executive Officer, KLJ engineering
- Mike Seminary - Business Development Manager, Houston Engineering
- Allan Beshore - Federal Pipeline and Hazardous Materials Safety Administration
- Lynn Helms - Director, North Dakota Dept. of Mineral Resources
- Sandi Tabor - Former North Dakota Transmission Authority Director, Director of Government Relations, KLJ engineering
- Gordon Bierwagen - North Dakota State University Center for Surface Protection, Department of Coatings and Polymeric Materials
- Wayne Armenta - Workforce, Safety and Field Operations, ONEOK Partners
- Kari Cutting - Vice President, North Dakota Petroleum Council
- Arti Bhatia - Director of Pipeline and Corridor Risk Management, Alliance Pipeline
- Patrick Fahn - Director of Compliance, North Dakota Public Service Commission
- Scott Fradenburgh - Vice President of Operations, WBI Energy
- Brent Horton - Director of Engineering for North Dakota, Enbridge Pipeline
- Mike McGrath - Pipeline Safety, Performance and Compliance, Alliance Pipeline
- Tad True - Vice President, Bridger and Belle Fourche Pipeline
- Justin Kringstad - Director, North Dakota Pipeline Authority

Introduction

On December 27, 2013, North Dakota Governor Jack Dalrymple announced the formation of the North Dakota Pipeline Technology Working Group. The members were asked to research current and future technologies used for leak detection. The technical working group is made up of private sector pipeline operators, energy industry leaders, university scientists, and state and federal officials. The group first began meeting in January 2014.

North Dakota currently has over 18,000 miles of gathering and transmission pipelines in the state. In an effort to keep up with growing volumes of natural gas, crude oil, and produced water, pipeline operators have recently been installing over 2,000 miles of new pipeline each year. With the addition of these new pipeline systems, it is imperative that the required steps are taken during construction and operation to protect human life and the environment.

Review of existing leak detection information

Products unintentionally released from a pipeline system are typically assigned to three general categories; seeps, leaks and ruptures. Different types of leak detection systems (LDS) are appropriate for each of previously mentioned categories.[1]

LDS can range from sophisticated instrumentation and computer based computational pipeline monitoring (CPM) to simple visual surveillance from the air or ground. It is not uncommon for a single pipeline system to utilize two or more types of LDS in order to improve the chances of early detection. [2]

United States Department of Transportation's methods of electronic leak detection:[2]

- *Volume balance "meter out" versus "meter in". This is a simple inventory balance to compare the volume of product at an originating point on the pipeline with the volume monitored at intermediate or destination points elsewhere on the pipeline. This method works best for products that are relatively incompressible.*
- *Mass balance "meter out" versus "meter in". This is a more complex inventory balance to verify that no discrepancy exists between the mass of product measured at an originating point on the pipeline with the mass observed at intermediate or destination points elsewhere on the pipeline. Because this system measures mass, additional instrumentation is used to capture on-line temperatures and pressures. This method works best for products that have some degree of compressibility.*
- *Simple "Rate-of-Change". This method monitors key operating parameters at various points along the pipeline and reacts when these variables change at an abnormal rate or in some other unusual way.*
- *Combination "Rate-of-Change". This method monitors key operating parameters at various points along the pipeline and reacts when different combinations of these variables change at an abnormal rate, or in some other unusual way.*
- *Computational pipeline monitoring. This leak detection method employs numerous monitored variables, and a sophisticated computer model to identify upsets or potential leaks. Monitored inputs include operating parameters for temperature, pressure, flow and density, and include equipment inputs such as pump start/stop and valve open/close signals. The data from all*

sensors is compared against a baseline model for values that differ from the modeled case indicating a potential leak. Operational transients such as pump starts, line fills, valve closures, etc., may be modeled as well, so that this automatic leak detection system can continue to work during operational changes that occur in the normal day-to-day operation of the pipeline system.

Other types of leak detection

- Routine surveillance, with or without instrumentation, from ground travel or aircraft. Inspector is looking for signs of product release or potential threats such as right-of-way encroachment or landslides. Surveys may be recorded using modern video equipment for additional analysis and archiving. Surveys accompanied with measurement instrumentation help in identifying and classifying the severity of a leak.
- Vapor detection may involve burying a perforated tube along with the pipeline through which air can be drawn and tested for the presence of hydrocarbons. An alternative form may include the additional of a tracer gas into a pipeline system and then using sensitive above-ground monitoring equipment to check for small amounts of the tracer gas.[3]
- Fiber optic cables may be buried adjacent to a pipeline to detect thermal changes associated with product leaks. Fiber optics may also be used to detect acoustic signals, such as digging, to warn of right-of-way encroachment.[3]
- Pressure testing of the pipeline is a typical practice to detect leaks on a pipeline system. This method involves shutting down the pipeline and pressurizing the system to ensure it holds the pressure for a specific amount of time.
- Some Inline line Inspection (ILI) tools can either identify leaks directly or identify the threat for leakage through the identification of corrosion, cracks, gouges before they progress to failure.
- Acoustic leak detection – is an ILI device run inside the pipeline with product flow which identifies acoustic anomalies associated with leaks.

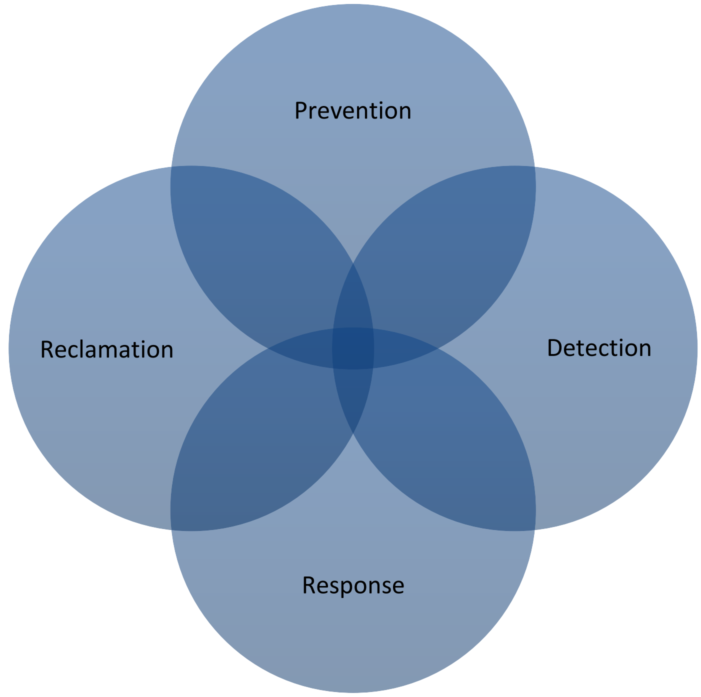
Benefit and drawback information for various types of leak detection techniques can be found in Appendix B.

Supervisory Control and Data Acquisition (SCADA)

It is important to draw the distinction between LDS and SCADA. SCADA systems not only monitor pipeline operating conditions, but also allows for remote operations of the pipeline from a central control room. LDS may utilize some of the same equipment as SCADA, but a LDS purpose is solely focused on determining if there was a release of pipeline content, rather than operational control of the pipeline.[1]

<u>Working Group Conclusions</u>

There are four main categories to address regarding pipeline incident technology and best practices. The categories include incident prevention, detection, response, and reclamation. The NDPTWG has come to the following conclusions:



Incident prevention:

Incident prevention begins with a strong company safety culture. This culture supports robust design and construction practices, comprehensive integrity management programs, corrosion control procedures, employee training, and strict operating and maintenance practices.

A universal concern of all pipeline operators is the prevention of third party pipeline damage. A comprehensive working document on incident prevention best practices is available through the Common Ground Alliance (CGA)[4]. The CGA best practices are continually under review and updated annually as new information is available. Rather than recreate the work of CGA; policy makers, regulators, and industry should use the current CGA best practices as a reference for incident prevention.

North Dakota is fortunate to have a university system with world class resources and expertise in the area of pipeline protection. Research and development efforts in new materials and testing for pipelines are ongoing at the university level. The NDPTWG supports the efforts of current research and the further utilization of the North Dakota University System to continue researching the best materials, testing and practices for protection and incident prevention. If opportunities exist for additional state agency and/or university system research on these prevention measures, the NDPTWG would support such efforts. In particular, the State should take steps to enhance public awareness of existing research programs and encourage new public/private partnerships focused on researching improvements to existing technologies for incident prevention measures.

Corrosion control is another critical component of incident prevention and the NDPTWG recommends policy makers and regulators reference the recommendations and standards of NACE, formerly known as the National Association of Corrosion Engineers. A recently formed NACE Bakken committee should prove beneficial for collaboration on the topic of corrosion control in North Dakota.

Incident detection:

Given the wide scope of products, age, and function of North Dakota's pipeline network, it is difficult to identify a specific individual component of a LDS or SCADA system for timely incident detection. However, a universal industry practice is the visual inspection of a pipeline right-of-way to detect an incident that may not be identified using LDS or SCADA. Currently, this important form of incident detection primarily relies on the human eye to detect a problem. Imaging technologies continue to be enhanced and could significantly improve the ability to detect an incident sooner. These imaging packages can be deployed on traditional aircraft, as well as on unmanned aircraft. Given its ability to be deployed on both new and legacy pipeline systems, it is recommended that North Dakota further support the research and subsequent usage of imaging packages that work in North Dakota's unique climate and terrain conditions.

Data also supports the importance of robust public awareness and the value that landowners and the public can have in detecting leaks as part of the multiple layers of defense for leak detection. It is important for the public to know when to call and who to call and have a good relationship with the operators in the area.

Incident Response:

While not directly tasked with incident response, it seemed appropriate to comment that having an effective and timely incident response process can help to further reduce the consequence of leak if one occurs. The timeliness of incident response needed can depend highly on the type and robustness of a leak detection system implemented. How quickly a leak is detected, verified, and responded to are critical in mitigating the effects of a leak. Effective leak mitigation should include consideration for valve placement and method of actuation. Valves are actuated manually, remotely (RCV) or automated (ACV). (Appendix C includes commentary on the advantages and disadvantages of installing automated valves on pipelines)

It is important for local emergency managers to work closely with pipeline operators to tailor response capabilities for the specific risks in their jurisdiction. Response capabilities should address access to equipment and tools necessary to respond, as well as action steps to protect the health and property of impacted landowners, citizens, and the environment.

Incident reclamation:

While not directly tasked with incident reclamation, it seemed appropriate to at least comment generally on the fact that when an incident does occur, the reclamation process must be handled appropriately. The North Dakota University System could be utilized to further research how to best reclaim an area in which an incident occurs. Some work is currently underway in the area of reclamation through the Oil & Gas Research Program. The NDPTWG supports the efforts of current research and the North Dakota University System's continued research in best practices for incident reclamation.

References:

1. Kiefner & Associates. (2012, December 10). Leak Detection Study – DTPH56-11-D-000001. Retrieved May 2014, from http://www.phmsa.dot.gov/pv_obj_cache/pv_obj_id_4A77C7A89CAA18E285898295888E3DB9C5924400/filename/Leak Detection Study.pdf
2. Pipeline Safety Stakeholder Communications. (2011, December 1). Retrieved July 2014, from http://primis.phmsa.dot.gov/comm/FactSheets/FSLeakDetectionsystems.htm
3. Shannon & Wilson, Inc. (2012, March 1). Pipeline Leak Detection Technology 2011 Conference Report. Retrieved April 2014, from https://dec.alaska.gov/spar/ipp/docs/Final%20PLD%20Technology%202011%20Conference%20Report%20March%202012%20-%20Revised%20041912.pdf
4. Best Practices - Version 11.0. (n.d.). Retrieved October 2014, from http://www.commongroundalliance.com/Template.cfm?Section=Best_Practices_2014&Template=/TaggedPage/TaggedPageDisplay.cfm&TPLID=68&ContentID=8194

Supplemental Information:

APPENDIX A: 2012 Pipeline and Hazardous Material Safety Administration (PHMSA) Report: Incident Identification Information

APPENDIX B: 2012 Pipeline and Hazardous Material Safety Administration (PHMSA) Report: Benefits/Drawbacks of internal and external leak detection technologies

APPENDIX C: GAO-13-168, PIPELINE SAFETY: Better Data and Guidance Needed to Improve Pipeline Operator Incident Response: Advantages and Disadvantages of Installing Automated Valves on Pipelines

APPENDIX D: Government Agency Oversight of Energy Pipelines in North Dakota

APPENDIX A:

2012 Pipeline and Hazardous Material Safety Administration (PHMSA) Report:

Incident Identification Information

In late 2012, Kiefner and Associates, Inc. published a comprehensive report for the U.S. Department of Transportation's Pipeline and Hazardous Material Safety Administration titled, "Leak Detection Study – DTPH56-11-D-000001." The 280 page report outlines the findings of how various sized pipeline leaks around the U.S. were detected and what types of technology exist for detecting leaks.

Table 3.4 Hazardous Liquids Releases – Initial Identification – Excerpt from: Kiefner and Associates, Inc., 2012

Identifier	# of Reported Incidents	% of 197 Incidents Reports
AIR PATROL	10	5%
CONTROLLER	10	5%
CPM LEAK DETECTION SYSTEM OR SCADA-BASED INFORMATION	23	12%
GROUND PATROL BY OPERATOR OR ITS CONTRACTOR	4	2%
LOCAL OPERATING PERSONNEL, INCLUDING CONTRACTORS	38	19%
NOTIFICATION FROM EMERGENCY RESPONDER	14	7%
NOTIFICATION FROM PUBLIC	45	23%
NOTIFICATION FROM THIRD PARTY THAT CAUSED THE ACCIDENT	11	6%
STATIC SHUT-IN TEST OR OTHER PRESSURE OR LEAK TEST	2	1%
OTHER	8	4%
BLANK - No Data Entry	32	16%
# of Identifiers Reported	165	84%
January 2010 to July 2012		

Table 3.5 Above Average Hazardous Liquids Releases, Initial Identifier – From Kiefner and Associates, Inc.

Identifier	# of Incidents	% of Incidents
AIR PATROL	1	4%
CONTROLLER	2	7%
CPM LEAK DETECTION SYSTEM OR SCADA-BASED INFORMATION	11	39%
GROUND PATROL BY OPERATOR OR ITS CONTRACTOR	1	4%
LOCAL OPERATING PERSONNEL, INCLUDING CONTRACTORS	5	18%
NOTIFICATION FROM EMERGENCY RESPONDER	5	18%
NOTIFICATION FROM PUBLIC	3	11%
NOTIFICATION FROM THIRD PARTY THAT CAUSED THE ACCIDENT	0	0%
STATIC SHUT-IN TEST OR OTHER PRESSURE OR LEAK TEST	0	0%
OTHER	0	0%
BLANK - No Data Entry	0	0%
January 2010 to July 2012		

Table 3.7 Hazardous Liquid Gathering Lines Releases, Initial Identifier – From Kiefner and Associates, Inc.

Identifier	# of Incidents	% of Incidents
AIR PATROL	1	5%
CONTROLLER	0	0%
CPM LEAK DETECTION SYSTEM OR SCADA-BASED INFORMATION	0	0%
GROUND PATROL BY OPERATOR OR ITS CONTRACTOR	0	0%
LOCAL OPERATING PERSONNEL, INCLUDING CONTRACTORS	2	9%
NOTIFICATION FROM EMERGENCY RESPONDER	1	5%
NOTIFICATION FROM PUBLIC	7	32%
NOTIFICATION FROM THIRD PARTY THAT CAUSED THE ACCIDEN	3	14%
STATIC SHUT-IN TEST OR OTHER PRESSURE OR LEAK TEST	0	0%
OTHER	0	0%
BLANK - No Data Entry	8	36%
January 2010 to July 2012		

Table 3.9 Natural Gas Transmission Releases, 2010 to July 2012, Initial Identifier – From Kiefner and Associates, Inc.

Identifier	# of Incidents	% of Incidents
AIR PATROL	5	3.55%
CONTROLLER	1	0.71%
GROUND PATROL BY OPERATOROR ITS CONTRACTOR	7	4.96%
LOCAL OPERATING PERSONNEL, INCLUDING CONTRACTORS	40	28.37%
NOTIFICATION FROMEMERGENCY RESPONDER	4	2.84%
NOTIFICATION FROMPUBLIC	38	26.95%
NOTIFICATION FROMTHIRD PARTY THAT CAUSED THE ACCIDENT	15	10.64%
OTHER	10	7.09%
CPMLEAK DETECTION SYSTEMOR SCADA-BASED INFORMATION	21	14.89%
January 2010 to July 2012		

Table 3.10Above Average Gas Transmission/Gathering Releases, Initial Identifier – From Kiefner and Associates, Inc.

Identifier	# of Reported Incidents	% of 197 Incidents Reports
AIR PATROL	2	9%
CONTROLLER	0	0%
GROUND PATROL BY OPERATOR OR ITS CONTRACTOR	0	0%
LOCAL OPERATING PERSONNEL, INCLUDING CONTRACTORS	2	9%

NOTIFICATION FROM EMERGENCY RESPONDER	1	5%
NOTIFICATION FROM PUBLIC	5	23%
NOTIFICATION FROM THIRD PARTY THAT CAUSED THE ACCIDENT	1	5%
OTHER	1	5%
SCADA-BASED INFORMATION	10	45%
January 2010 to July 2012		

APPENDIX B:

2012 Pipeline and Hazardous Material Safety Administration (PHMSA) Report:

Benefits/Drawbacks of internal and external leak detection technologies

Table 4.2 Benefits / Drawbacks of Internal Systems – Excerpt from: Kiefner and Associates, Inc., 2012

	Internal System	Benefits	Drawbacks
	Overall - Internal LDS	1. Widely used and easy to understand. 2. Provides / utilizes other non-LDS functions (better metering, an RTTM for operations, etc.) . 3. Procedural and regulated.	1. Completely dependent on the quality of metering, SCADA and telecommunications. 2. False alarms dominated by line pack effects. 3. Usually, a sensitivity / reliability tradeoff, and generally poor sensitivity.
1.a)	**Volume Balance (Over/Short Comparison)**	Elementary to understand. Fast to deploy a basic system, given existing metering. Also valuable for metering operations.	False alarms dominated by line pack effects. No leak location. Not for gas pipelines.
1.b)	**Rate of Pressure / Flow Change**	Essentially, already part of any SCADA system.	Very insensitive, many missed leaks. No leak location.
1.c)	**Pressure Point Analysis**	Provides a leak location using Internal methods. Improves pressure analysis sensitivity and response time.	Not very sensitive. Requires good pressure measurement. Impractical for gas pipelines.
1.d)	**Negative Pressure Wave Method**	Provides a leak location using Internal methods.	Very insensitive, many missed leaks. Requires good pressure measurement. Impractical on short lines. Not for gas pipelines.
2.a)	**Mass Balance with Line Pack Correction**	Elementary to understand. Fast to deploy a basic system, given existing metering. Improves volume balance false alarms.	False alarms still dominated by line pack effects. No leak location. Not for gas pipelines.
2.b)	**Real Time Transient Modeling**	Reduced false alarms, time to detection, and is able to operate during pipeline transients. Provides leak location. RTTM is also valuable for operations.	Requires expertise to deploy, operate, and maintain. Especially dependent on the quality of metering, SCADA and telecommunications.
2.c)	**Statistical Pattern Recognition**	Not tied to a fixed a priori threshold. Reduced false alarms and is able to operate during pipeline transients.	Requires training to understand. Still a volume balance method. No leak location.
2.d)	**Pressure / Flow Pattern Recognition**	Standalone operation. Locates leaks and much better detection than ordinary pressure analysis.	Requires good pressure measurement and dedicated hardware. Less effective on short lines and gas lines.
2.e)	**Negative Pressure Wave Modeling**	Improves RTTM leak localization significantly.	Requires good pressure measurement. Adds complexity to an already complex RTTM. Untested on gas pipelines.
3.a)	**Statistical Methods**	Reduce false alarms by introducing statistical degree of	Still relies upon a physical principle - measurement or calculated

		confidence. Can combine multiple alarm signals consistently.	value.
3.b)	**Digital Signal Analysis**	Pre-processes measurements or calculated values to eliminate errors and detect anomalies.	Still relies upon a physical principle - measurement or calculated value.

Table 4.3 Benefits / Drawbacks of External Systems – From Kiefner and Associates, Inc., 2012

	External System	Benefits	Drawbacks
	Overall - External LDS	1. Highly sensitive (when engineered and deployed well). 2. Immune to pipeline operational changes / transients. 3. Mostly standalone, simple instrumentation systems.	1. Require individual engineering design. 2. No procedural approach or regulation. 3. Standalone, dedicated LDS.
1	**Acoustic**	Highly sensitive, mature technology. Arrays can locate leaks accurately.	Requires careful design. Custom electronics and specialized DSP dominate performance.
2	**HC Sensing Fiber Optic**	Provides high level of reliability. Can be packaged / deployed numerous ways, even as a point detector.	Limited availability. Since usually deployed for short intervals or at points, requires planning.
3	**Temperature Fiber Optic**	Very simple, widely available. Provides accurate leak location.	Typically, must be deployed as a continuous cable. Sensitive to all strain and temperature changes, not just leak induced.
4	**Liquid Sensing Cable**	Very simple, widely available. Provides accurate leak location. Can be used on short, HCA sections.	Cable must be physically close to the pipe to become wet. Cable (not electronics) must be replaced after a leak.
5	**Vapor Sensing Tube**	Exceptional sensitivity, speed, and location capability.	Large maintenance requirement (chemicals, pumps, electronics). Very sensitive to any hydrocarbon near the pipe, not just leaks. Tube must be directly below pipe.
6	**Vapor Sensors**	Very simple, widely available.	Some conditions e.g., buried liquids pipelines, are not very sensitive. On the other hand, sensitive to any hydrocarbon near the pipe, not just leaks. On-line versions with built-in chemical analyzers require maintenance.
7	**Optical Systems**	Very simple, widely available. Extremely good sensitivity and leak location.	Requires line-of-sight to the atmosphere above the line. Requires DSP to identify precisely

			the hydrocarbons in the pipe.
a.	**Instrumentation attached to the pipeline**	Improves sensitivity and reliability enormously.	Typically, only exposed points of a buried pipeline are available for attachment, so design is driven by mechanical realities.
b.	**Point sensors**	Very simple to install.	Require an array to locate leaks. Placement requires planning. Potentially many sensors required for complete coverage.
c.	**Cable sensors**	Provide excellent leak location capability, and also sensitivity if they can be placed right by the pipe.	Retrofit is very laborious for long buried sections of pipeline.
d.	**Portable/mobile tools**	Zero installation requirement.	Only intermittent service, as part of an inspection program.
e.	**Tools launched internally**	Zero installation requirements. The best leak sensitivity and location capability. Perhaps the only viable option for slow, creeping leaks.	Only intermittent service, as part of an inspection program. There are limitations where the tools can travel.
i.	**Permanent installation / continual**	Continual, on-line leak detection coverage with External systems benefits.	May require rights to the surface. Does require SCADA of some form.
ii.	**Permanent installation / intermittent**	Very simple to install.	May require rights to the surface. Only intermittent service, as part of an inspection program.
iii.	**Periodic or on-demand deployment**	Zero installation requirement.	Only intermittent service, as part of an inspection program, e.g., for slow leaks.

APPENDIX C:

GAO-13-168, PIPELINE SAFETY: Better Data and Guidance Needed to Improve Pipeline Operator Incident Response, 2013: http://www.gao.gov/assets/660/651408.pdf

Advantages and Disadvantages of Installing Automated Valves on Pipelines

Advantages and Disadvantages of Installing Automated Valves on Pipelines

Excerpt from: GAO-13-168

Advantages

- Improved response time
  - Can reduce injuries and fatalities for some locations, such as hospitals or prisons, where people cannot evacuate quickly.
  - Can reduce the amount of damage by limiting the amount of fuel for secondary fire(s) and environmental cleanup.
  - Can allow operator personnel and emergency responders to access the affected segment more quickly and safely.
  - Can reduce the potential monetary cost of an incident for the operator by limiting the amount of product lost.

Disadvantages

- Accidental closures
  - For natural gas pipelines, accidental closures can result in the loss of service to utilities and critical customers (e.g., winter-time outages can leave people without heat).
  - For hazardous liquid pipelines, accidental closures can cause an incident, when a valve closes and the subsequent pressure buildup causes the pipeline to rupture.

Monetary costs

- Requires operators to purchase equipment, including devices to remotely communicate or sense pressure drops, actuators to close the valve, and power sources for this new equipment.
- Requires operators to take on installation costs, which can involve temporarily shutting down the pipeline, purging the product from the pipeline, and pulling product from the market. Operators may also have costs related to accessing the valve location (e.g., right of way, permitting, and physical space to install the new equipment) and updating their leak detection technologies.
- May require operators to incur additional recurring costs to train staff, maintain the valves, increase security, and conduct inspections of the new valve.

APPENDIX D:

Government Agency Oversight of Energy Pipelines in North Dakota

	Intrastate			Interstate	
	Gathering	Transmission	Distribution	Gathering	Transmission
CO2					
➢ Facility location	IC[5]	PSC[4]	IC[5]	IC[5]	PSC[4]
• Construction	IC[5], PHMSA[6]	PHMSA[2]	IC[5]	IC[5], PHMSA[6]	PHMSA[2]
○ Operation & Safety	IC[5], PHMSA[6]	PHMSA[2]	IC[5]	IC[5], PHMSA[6]	PHMSA[2]
❖ Incident Response	NA	DES, DOH, EPA, local responders, PHMSA[2]	NA	NA	DES, DOH, EPA, local responders, PHMSA[2]
Hazardous Liquids					
➢ Facility location	IC[5]	PSC[4]	NA	IC[5]	PSC[4]
• Construction	IC[1], PHMSA[6]	PHMSA[2], PSC[4]	NA	IC[1], PHMSA[6]	PHMSA[2], PSC[4]
○ Operation & Safety	IC[5], PHMSA[6]	PHMSA[2]	NA	IC[5], PHMSA[6]	PHMSA[2]
❖ Incident Response	DES, DOH, EPA, local responders	DES, DOH, EPA, local responders, PHMSA[2]	NA	DES, DOH, EPA, local responders	DES, DOH, EPA, local responders, PHMSA[2]
Natural Gas					
➢ Facility location	IC[5]	PSC[4]	Utility, local agency	Federal, IC[5]	FERC
• Construction	IC[1]	IC[1], PSC[3,4]	PSC[3]	IC[1]	FERC[1], PHMSA[3]
○ Operation & Safety	IC[5]	PSC[3]	PSC[3]	IC[5]	PHMSA[3]
❖ Incident Response	DES, DOH, EPA, local responders	DES, DOH, EPA, local responders, PSC[3]	Local responders, PSC[3]	DES, DOH, EPA, local responders	DES, DOH, EPA, local responders, PHMSA[3]
Saltwater or brine					
➢ Facility location	IC[5]	IC[5]	IC[5]	IC[5]	IC[5]
• Construction	IC[1]	IC[5]	IC[5]	IC[1]	IC[5]
○ Operation & Safety	IC[5]	IC[5]	IC[5]	IC[5]	IC[5]
❖ Incident Response	DES, DOH, EPA, local responders	DES, DOH, EPA, local responders	NA	DES, DOH, EPA, local responders	DES, DOH, EPA, local responders

PLEASE NOTE: This chart is provided for reference only, and should not be solely relied-upon to determine jurisdiction. Oversight responsibility is always fact-specific, so be sure to consult appropriate personnel to make decisions about your circumstances. This chart compiled by Patrick Fahn-Public Service Commission staff to the best of his knowledge as of March 3, 2014.

PHMSA inspects and enforces the pipeline safety regulations for interstate gas pipeline operators in North Dakota. PHMSA also inspects and enforces the pipeline safety regulations for interstate and intrastate hazardous liquid pipeline operators in North Dakota. Through certification by PHMSA, the state inspects and enforces the pipeline safety regulations for intrastate gas pipeline operators in North Dakota. This work is performed by the North Dakota Public Service Commission.

[1] scope of oversight unknown
[2] scope of oversight under 49 CFR Part 195 Pipeline Safety Regulations-Transportation of Hazardous Liquids by Pipeline and 49 CFR Part 194 – Response Plans for Onshore Oil Pipelines
[3] scope of oversight under 49 CFR Part 192: Pipeline Safety Regulations- Transportation of Natural and Other Gas by Pipeline-Minimum Federal Safety Standards
[4] scope of oversight under N.D.C.C. ch. 49-22: Energy Conversion and Transmission Facility Siting Act
[5] N.D. Admin. Code § 43-02-03-29 regulates the location and construction of underground gathering pipelines and also requires submittal of operation and leak detection equipment. N.D.C.C. § 38-08-02 defines underground gathering pipelines as an underground gas or liquid pipeline that is designed for or capable of transporting crude oil, natural gas, carbon dioxide, or water produced in association with oil and gas which is not subject to chapter 49-22.
[6] PHMSA has pipeline safety jurisdiction regarding all natural gas and hazardous liquids pipelines. Pipelines subject to PHMSA's current hazardous liquids pipeline safety regulations include high-stress liquids transmission lines (lines larger than 8-5/8 inches nominal outside diameter), low-stress liquids transmission lines that are located in, or within a half mile of an unusually sensitive area (USA); gathering lines located a non-rural area, and high-stress liquids gathering lines from 6-5/8 to 8-5/8 inches in diameter that are located in or within a quarter mile of a USA. USAs include areas requiring extra protection because of the presence of sole source drinking water, endangered species, or other ecological resources that could be damaged by oil leaks. In its next phase, PHMSA rules would make subject to its regulations, smaller diameter low-stress liquids pipelines and larger-diameter pipelines located outside of one-half mile of a USA.

49 U.S.C. 60102 requires that PHMSA issue regulations subjecting low-stress hazardous liquid pipelines (like many gathering lines) to the same standards and regulations as other hazardous liquid pipelines. PHMSA is issuing regulations.

DES: North Dakota Department of Emergency Services
DOH: North Dakota Department of Health-Water
EPA: Environmental Protection Agency
FERC: Federal Energy Regulatory Commission
IC: North Dakota Industrial Commission-Department of Mineral Resources-Oil and Gas Division
NA Not applicable
PHMSA: U.S. Department of Transportation-Pipeline and Hazardous Materials Safety Administration-Office of Pipeline Safety
PSC: North Dakota Public Service Commission

Other potential State incident response agencies: County officials, ND Department of Agriculture, ND Department of Human Services, ND Department of Mineral Resources, ND Department of Parks and Recreation, ND Game and Fish Department, ND National Guard, regional public health units, State Fire Marshall. (this information provided by DES).

APPENDIX C

GRAPHS OF NORMALIZED INDIVIDUAL LIQUID SPILL TYPES

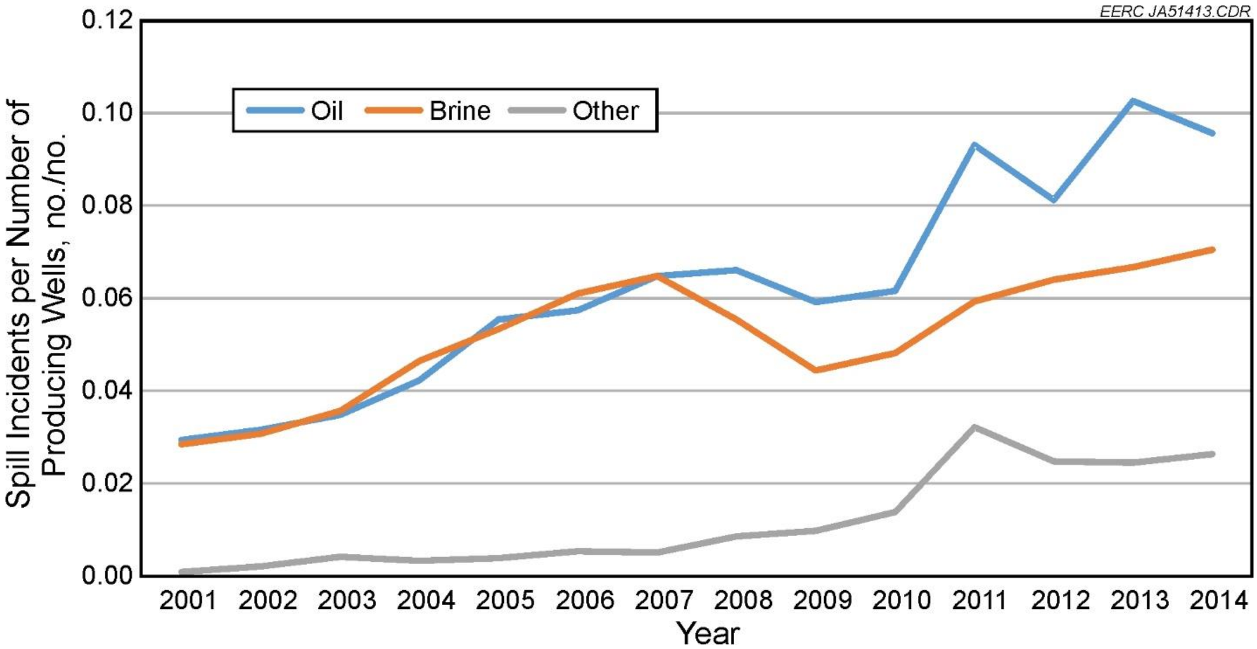


Figure C-1. Spill incidents per number of production wells (2001–2014) in North Dakota.

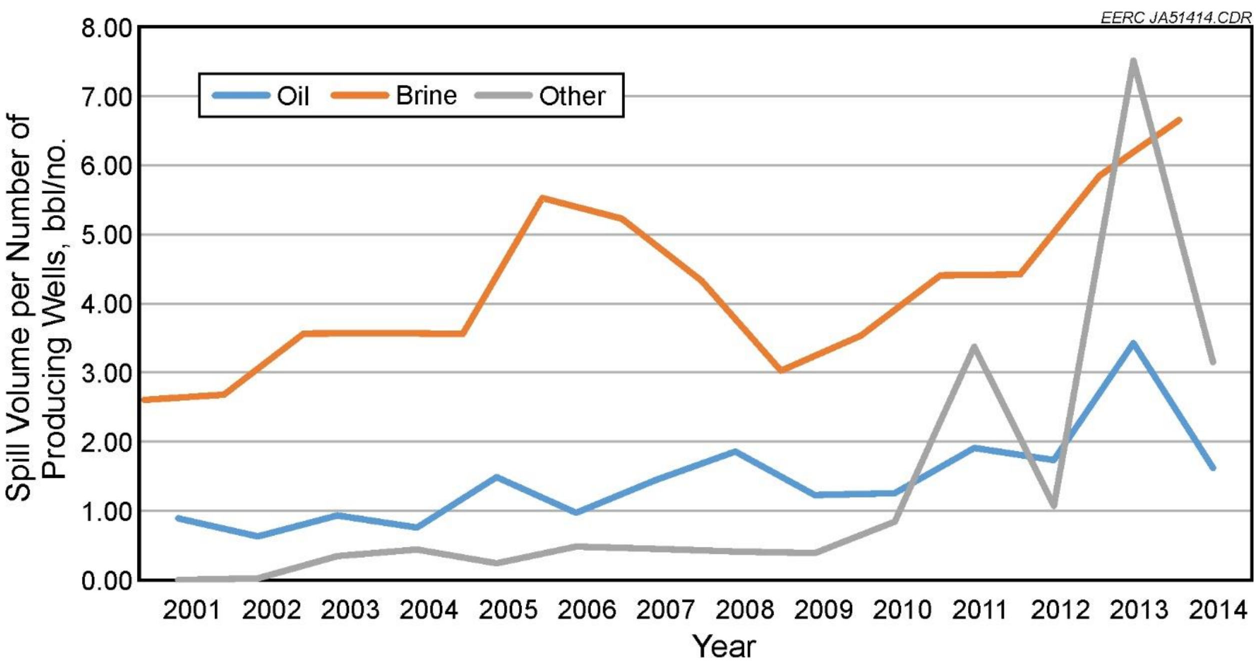


Figure C-2. Spill volume per number of producing wells (2001–2014) in North Dakota.

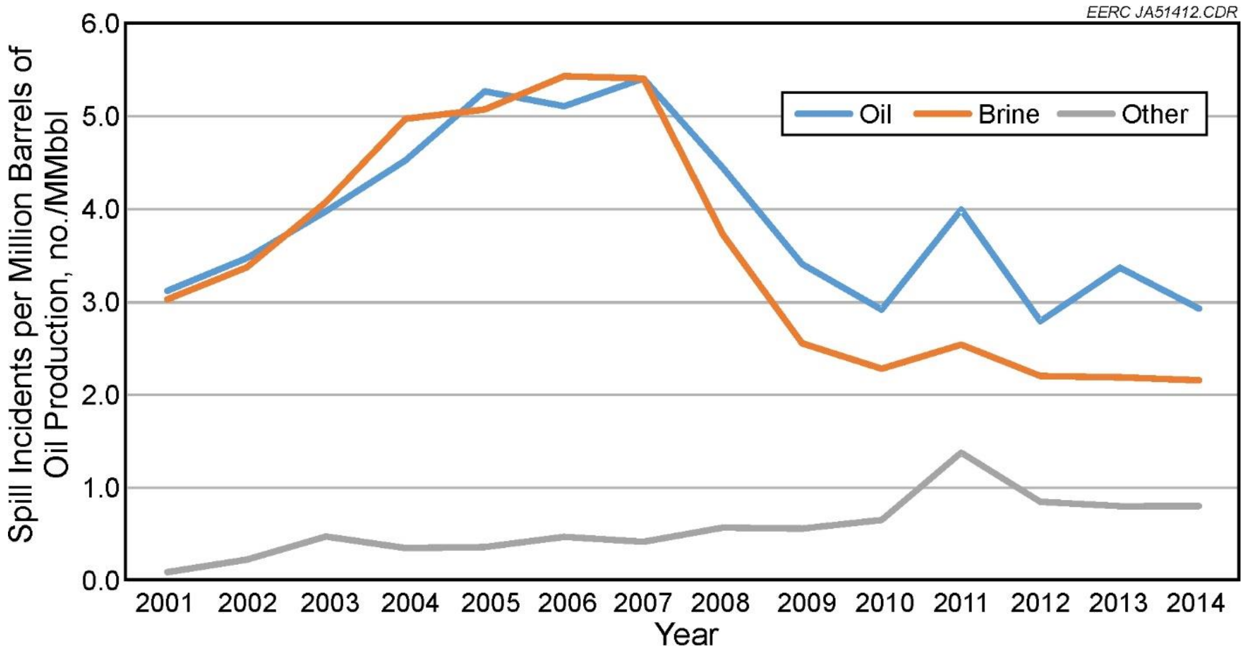


Figure C-3. Spill incidents per million barrels of oil production (2001–2014) in North Dakota.

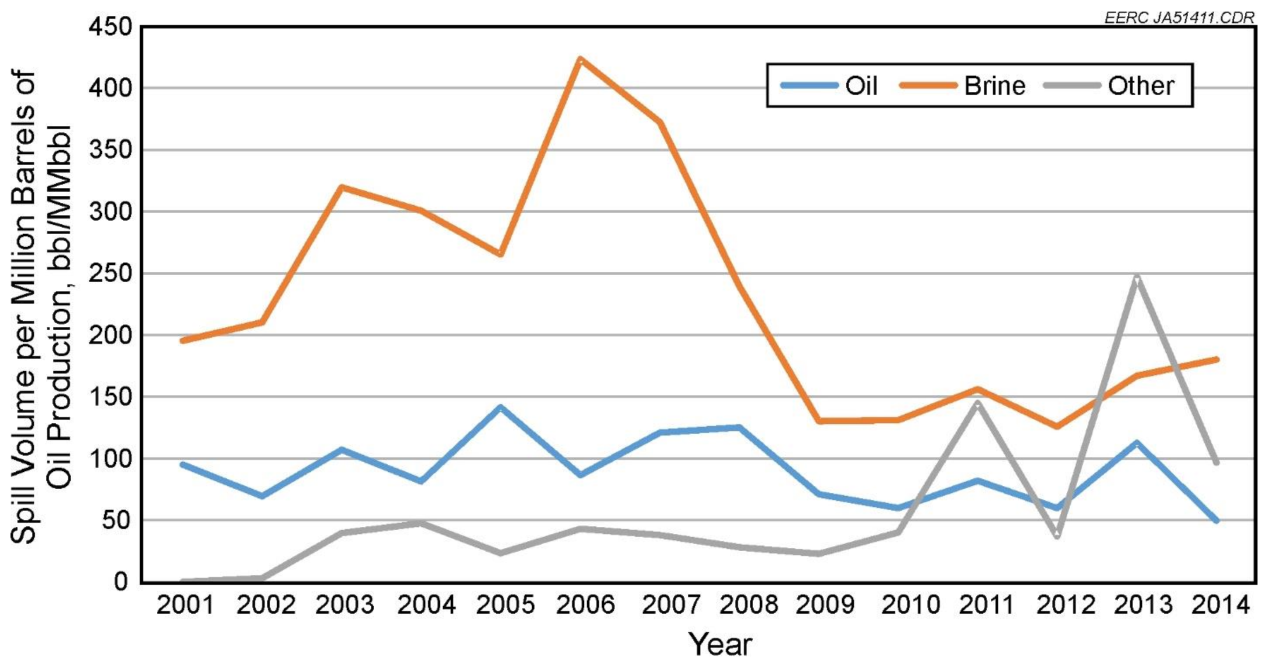


Figure C-4. Spill volume per million barrels of oil production (2001–2014) in North Dakota.

APPENDIX D

GRAPHS OF PIPELINE-SPECIFIC SPILLS

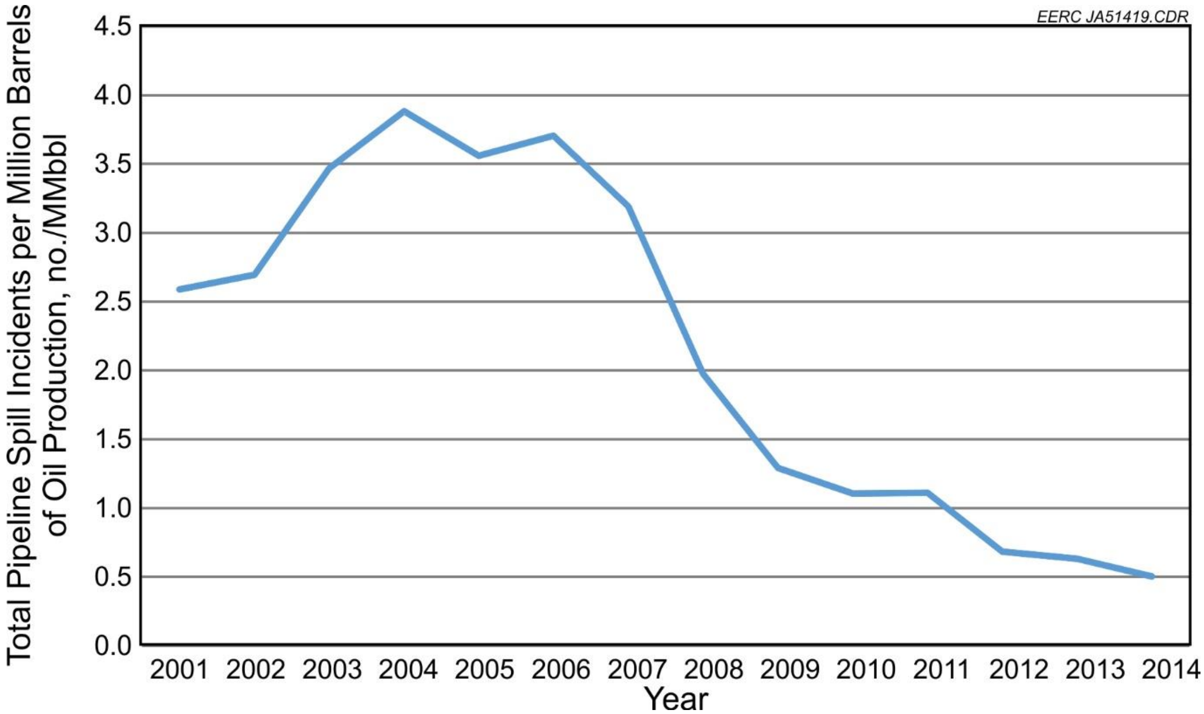


Figure D-1. Total pipeline spill incidents per million barrels of oil production (2001–2014) in North Dakota.

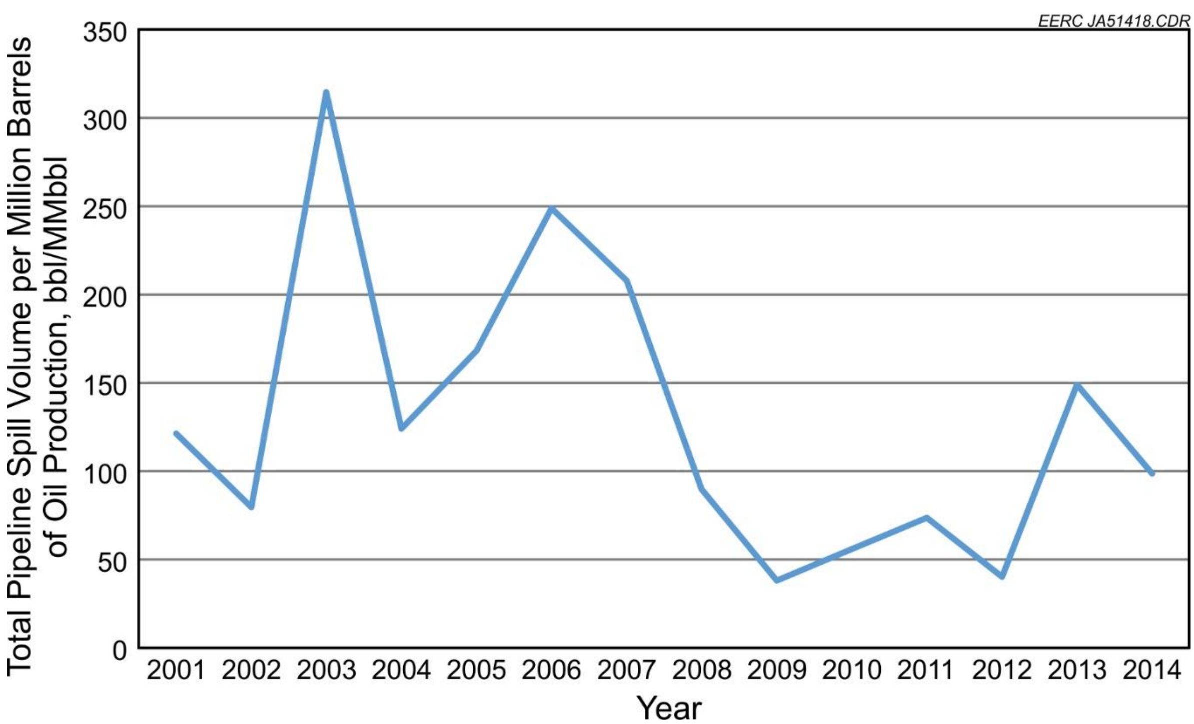


Figure D-2. Total pipeline spill volume per million barrels of oil production (2001–2014) in North Dakota.

APPENDIX E

DETAILS OF CORROSION-RELATED DESIGN CONSIDERATIONS

DETAILS OF CORROSION-RELATED DESIGN CONSIDERATIONS

Corrosion is the deterioration of a material, usually a metal, which results from a chemical or electrochemical reaction with its environment. Although steels made according to American Petroleum Institute (API) 5L requirements have the appropriate physical properties to serve as line pipe, they do not have adequate additions of elements necessary to make them corrosion-resistant. Therefore, they can undergo a variety of corrosion modes because of interactions with internal and external environments. These corrosion modes include general corrosion, pitting corrosion, and stress corrosion cracking (SCC).

NACE International (NACE) has published two standard practices dealing with corrosion of steel pipelines: NACE SP0106-2006 Control of Internal Corrosion in Steel Pipelines and Piping Systems and NACE SP0169-2013 Control of External Corrosion on Underground or Submerged Metallic Piping Systems.

INTERNAL CORROSION

The following is a short summary of the information provided in NACE SP1016-2006. The practice describes internal corrosion issues as well as procedures and practices to effectively control internal corrosion in steel pipe being used to carry crude oil, refined products, or gas. The practice notes that because of the complex nature and interactions between the liquids and gas present in the liquids being carried, such as oxygen, carbon dioxide, hydrogen sulfide, chlorides, bacteria, etc., the identification of a possible corrosion situation can only be achieved by the analysis of operating conditions, identification of impurities, physical monitoring, computer modeling, or other methods. Therefore, the composition of the gases, liquids, and operating conditions must be monitored and evaluated on an individual basis in order to accurately assess the effects of their presence or absence in the pipeline.

CORROSION CONSIDERATIONS IN PIPELINE DESIGN

Sections 1 and 2 of the standard practice provide a general background and some term definitions. Section 3 describes pipeline structure design. It says that when designing a pipeline the purchaser and producer must negotiate the quality specifications of the liquid being transported because the impurities in the liquid can significantly affect measurement, operation, pipeline efficiency, and corrosion of the pipe. However, liquid corrosiveness cannot be determined by these predicted impurities alone. In general, pipelines carrying pure petroleum or petroleum products are not subject to internal corrosion, but industry experience has shown that water and other corrosive impurities can unintentionally enter the pipeline during operational upsets and accumulate in low spots despite liquid quality monitoring that shows adherence to quality standards. It is the presence of water that largely leads to corrosion of steel pipelines carrying petroleum or petroleum products. In addition, salts may deposit and absorb water, creating a thin water-rich film on the steel surface. The standard practice says that because of the complex nature and interaction of the impurities, a corrosive condition can exist even if the concentration of the impurities may be low. The types of corrosion that occur because of the presence of impurities are listed in Appendix C of the NACE standard practice document.

When corrosion occurs, it leads to physical deterioration of the pipe as a result of thinning, pitting, hydrogen embrittlement, or SCC. SCC is a situation in which corrosion is accelerated because of a physical stress that is applied to the pipe. If corrosion is anticipated, then mitigation methods should be considered, such as increased pigging, use of corrosion inhibitors, internal coating of the pipeline (usually an epoxy paint or other plastic liner), or a combination of those methods.

Design consideration should also be given to control the flow velocity within a range that reduces corrosion. The lower limit of the flow velocity range should be one that will keep impurities suspended in the liquid to minimize accumulation of the impurities at points in the line. The upper limit of the velocity range should be one in which erosion, cavitation, or impingement of particulates on the pipeline walls is kept to a minimum. For this reason, intermittent flow conditions should be minimized because as the flow slows, the impurities can settle onto the pipe surface. This can also happen because of turbulence or stagnation associated with a change in line diameter or dead ends so they should be avoided in the system design. The system should also be designed to eliminate air entry because the presence of oxygen can increase corrosion rates. Chemicals such as corrosion inhibitors, oxygen scavengers, and biocides can be employed to reduce corrosion as well. If serious corrosion problems are anticipated, internal coatings can be used, especially if coating methods allow for coating weld areas. Alternatively, an inner tubing liner can be used to provide corrosion protection, in which case the steel piping provides the strength to handle the pressure of the fluid.

When corrosion problems are anticipated, and especially when corrosion-inhibiting chemicals are used, the system should include corrosion-monitoring facilities to evaluate the effectiveness of the corrosion mitigation methods. Corrosion-monitoring facilities may include pipe spools, gas or liquid perturbation methods (field signature), or hydrogen probes. According to the standard practice, details of the various corrosion-monitoring methods are listed in NACE Publication 3T199. A summary of corrosion considerations detailed in NACE standard practices is presented in Table E-1. Corrosion monitoring may include in-line inspection, in which case the pipeline should be designed to accommodate the inspection tools.

Table E-1. Corrosion Considerations Detailed in NACE Standard Practices

Corrosion Detection and Measurement (described in NACE Section 4)	Because corrosion primarily occurs where water accumulates, predicting these locations is a good method for targeting local examinations such as inspection, monitoring, and sampling. Visual inspection is done by opening a section of pipeline to observe internal material damage. Types of corrosion such as etching, pitting, and elongation of attack are noted. Wall thicknesses are measured, positions and sizes of attack noted, and the existence of any deposits or corrosion under deposits. Samples of deposits are retrieved for later analysis. The use of properly located coupons (small pieces) of steel or probes inside the pipe can also be used to determine existence, types, and rates of corrosion to expect. Care must be taken to place the coupons and probes in such a way that pigging operations can still be performed.
Methods for Controlling Corrosion (described in NACE Section 5)	• Periodic line cleaning with pigs in conjunction with other corrosion mitigation measures such as chemical inhibition and dehydration are most commonly used. Pigging helps to remove settled water, corrosion products, loose sediment, and waxes that can sometimes shield the corroding areas from the protection provided by chemical inhibitors. • Because most corrosion occurs when water is present, dehydration of the fluid being carried can significantly reduce corrosion inside of the pipeline. Deaeration to remove oxygen or the use of oxygen scavenging chemicals can reduce oxidation issues. Other gases can be removed using strippers and scrubbers. • Numerous types and formulations of corrosion inhibitors that are added to the fluid being carried in the line are also commercially available. The most important factor in choosing an inhibitor is to understand the probable corrosion problem and work with the supplier to choose an appropriate compound. • Internal coating of pipelines can also be considered as an internal corrosion control measure. They may be used in selected areas that are probable candidates for corrosion. They may include epoxies, cement, plastics, or metallic compounds. Performance is dependent on suitable surface preparation and cleaning and appropriate application practices.
Evaluating the Effectiveness of Corrosion Control Methods (described in NACE Section 6)	One major method is the use of coupons and probes for determining time-related changes in corrosion conditions. Another method for measuring how well corrosion control methods are working includes fluid sampling and chemical analysis to determine if a change has occurred in the corrosive medium being transported. Visual inspection of solid contaminants and changes in weight or volume of corrosion products removed from filters is also useful. Periodic corrosion monitoring using magnetic, electronic, ultrasonic, or radiographic methods may also be helpful. Measurements of changes in fluid pressure drop along sections of the line may also indicate the formation of deposits.
Operation and Maintenance of Internal Corrosion Control Systems (described in NACE Section 7)	This describes the frequency of pigging operations, along with descriptions of inhibitor injection operations and inspecting internal coatings.
Corrosion Control Records (described in NACE Section 8)	This states that for design considerations the following should be recorded: • Analysis of the liquid, including impurity content • Pipe size, wall thickness, grade, flow velocity, line size changes, internal coating, and type • Considerations for treatment such as dehydration, deaeration, chemicals, internal coatings, and corrosion-monitoring facilities The following should also be recorded on detecting, controlling, and evaluating corrosion problems and operations maintenance: • Visual inspections by qualified personnel whenever a piping system is opened • Inspections and tests of probes, coupons and other corrosion-monitoring devices such as samples, chemical analyses, bacteria results, and internal inspection tool runs • In-line inspection of line cleaning pig runs including date, type of pig, and amounts of water and solids removed by location • Name and quantity of inhibitor, biocide, and other chemicals used • Leak and failure records

EXTERNAL CORROSION

The best way to prevent pipeline corrosion is by using a high-performance coating of the steel along with sufficient cathodic protection. NACE SP0169-2013 presents methods and practices for achieving effective control of external corrosion on underground or submerged metallic piping systems. The methods and practices are also applicable to many other underground or submerged metallic structures. The standard describes the use of electrically insulating coatings, electrical isolation, and cathode protection. The standard does not include corrosion control methods based on injection of chemicals into the environment, use of electrically conductive coatings, or on the use of nonadhered polyethylene encasement. The standard also does not explain very well the many types of corrosion issues experienced by underground pipelines. Therefore, we present a brief explanation of different types of corrosion that can occur because of the interaction of steel pipeline with the underground environment. It is largely taken from a review of underground corrosion issues by Beavers and Thompson (2006) found in ASM Handbook 13C (2006).

Differential Corrosion Cell

Differential corrosion cells occur because of oxidation and reduction reactions that occur at or near the same location on the metal. In this case, one atom is being oxidized while another nearby atom is being reduced in order to keep the net charge of the system neutral. It is also possible for the sites of oxidation and reduction to be occurring in separate locations on the metal surface. This is referred to as a differential corrosion cell. Conditions for the formation of a differential corrosion cell occur for different reasons:

- A differential aeration cell is probably the most common corrosion cell found on pipelines or other underground structures. It occurs because one area of the pipeline is exposed to higher concentrations of oxygen, such as in a sandy area, and becomes a cathode, and another area, such a section that is in clay, has less oxygen and becomes an anode, such as shown in Figure E-1. Electrical current leaves the surface of the metal at the anode, increasing the corrosion rate there, and flows through the soil to the oxygenated cathodic area, decreasing the corrosion rate there. At the anode, metal ions produced by the corrosion reactions react with water, reducing the local pH. At the cathodic sites, the reduction reactions increase the pH and improve the protective nature of the surface films.

- Galvanic corrosion occurs when different metals are in contact or otherwise electrically coupled. This occurs because one metal has a lower corrosion potential than the other, and so it is stabilized at the expense of the metal with the higher corrosion potential.

- Surface films on pipes can also produce differential cells. When an older oxidized pipe is connected to a newer less oxidized pipe, the oxidation rate of the older pipe is often reduced at the expense of a faster rate of oxidation of the new pipe.

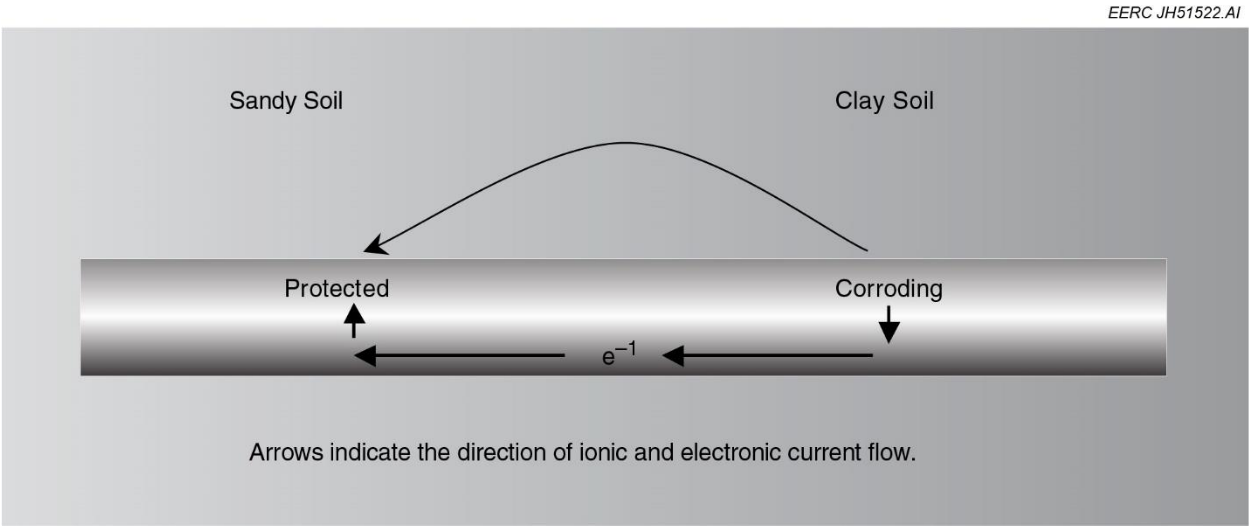


Figure E-1. A differential corrosion cell created by differences in soils (Beavers and Thompson, 2006).

Microbiologically Influenced Corrosion (MIC)

MIC occurs because of the activities of microorganisms, as shown in Figure E-2. It is estimated that 20%–30% of corrosion in underground pipelines is due to MIC. Typically, the products of a growing microbiological colony accelerate the corrosion process by either interacting with the corrosion products to prevent natural protective films or providing an additional reduction reaction that accelerates the corrosion process.

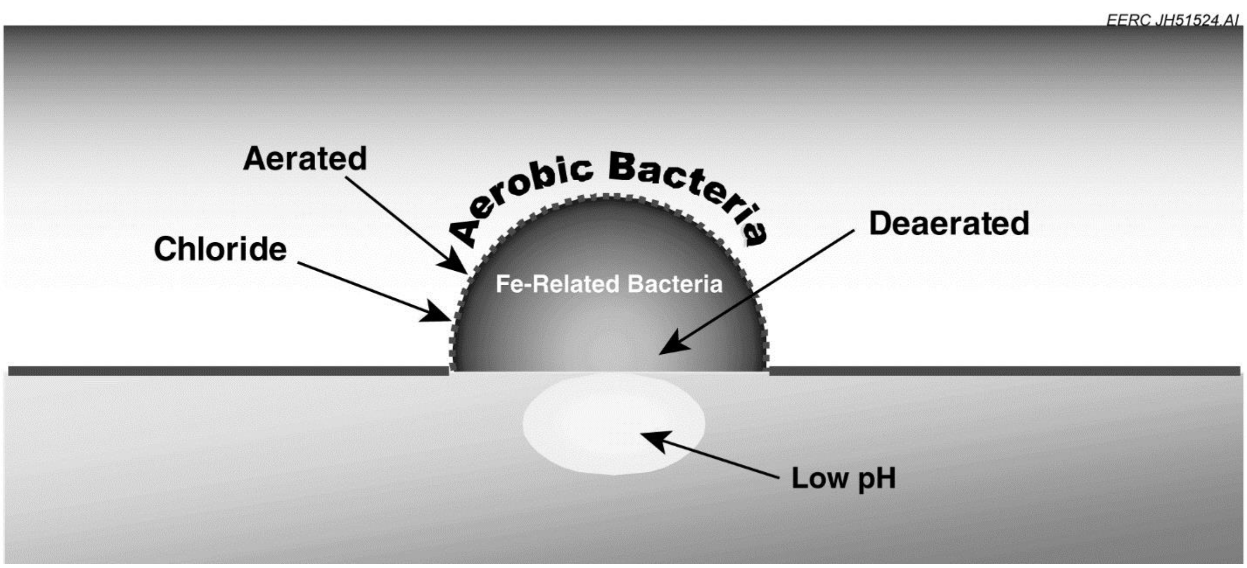


Figure E-2. Iron-related bacteria creating a differential oxygen and pH cell on a metal surface (Beavers and Thompson, 2006).

Stray Current Corrosion

Stray current corrosion occurs when direct electrical current is flowing in the soil near the pipeline. Electrified railroads, mining operations, and similar industries that use large amounts of direct current sometimes allow a significant portion of the current to use a ground path to complete the circuit. This stray current can be conducted down the pipeline for a significant distance and discharged back into the ground near the current return. Where the current is picked up, the pipeline is protected, but where it is discharged, the pipeline is corroded. Stray current corrosion tends to be very isolated at coating defects or holes and can result in rapid perforation of a pipeline, such as shown in Figure E-3.

EERC JH51526.AI

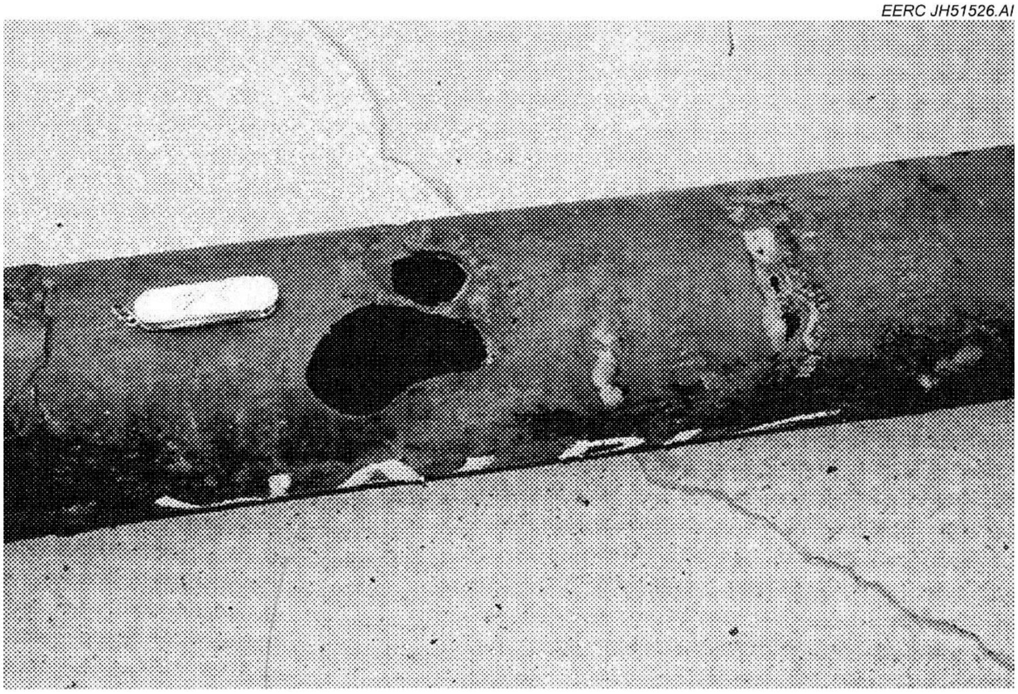


Figure E-3. Evidence of stray current corrosion in a pipeline (Beavers and Thompson, 2006).

Stress Corrosion Cracking

SCC is defined as cracking of a material caused by the combined effects of corrosion and tensile stress, as shown in Figure E-4. There are two types: high-pH SCC, which is also referred to as classical SCC, and near-neutral-pH SCC, which is also referred to as low-pH SCC. A characteristic of both forms is development of groups of longitudinal cracks that link up to form large flaws that are of sufficient size to cause ruptures. The high-pH form occurs between the grains (intergranular) of the metal whereas the near-neutral-pH form occurs through the grains (transgranular or intragranular).

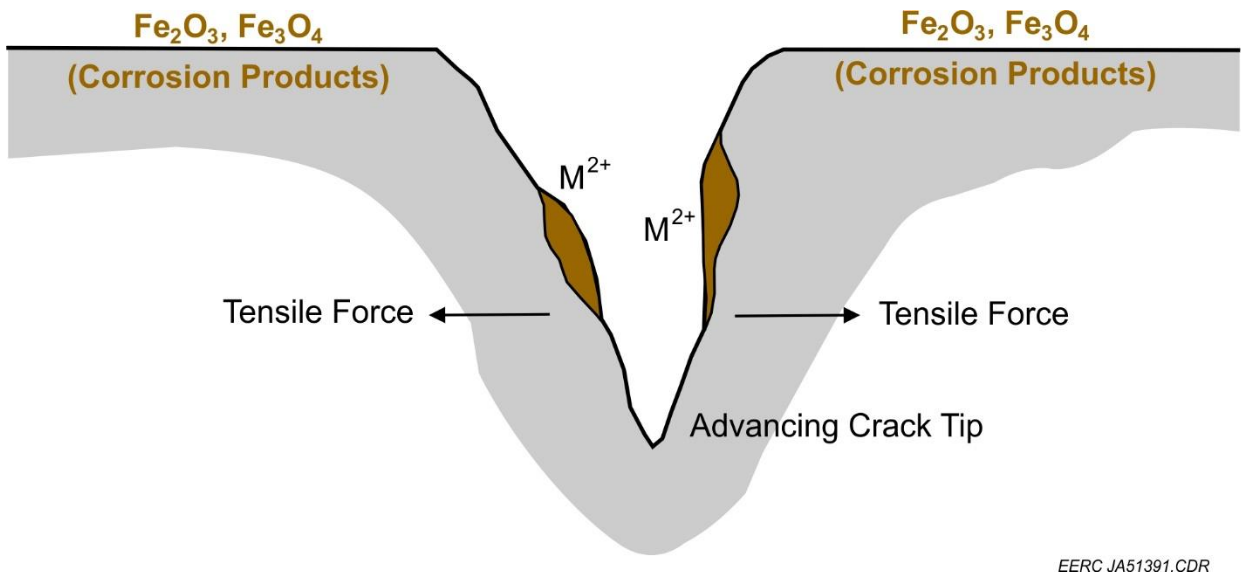


Figure E-4. Schematic of SCC.

Examples of the different crack shapes are shown in Figure E-5. In both cases, the presence of CO_2 dissolved in water seems to be the main cause, along with the added tensile stress. The high-pH forms in the presence of cathodic protection beneath disbonded coatings, whereas the near-neutral form occurs when cathodic protection is not sufficient.

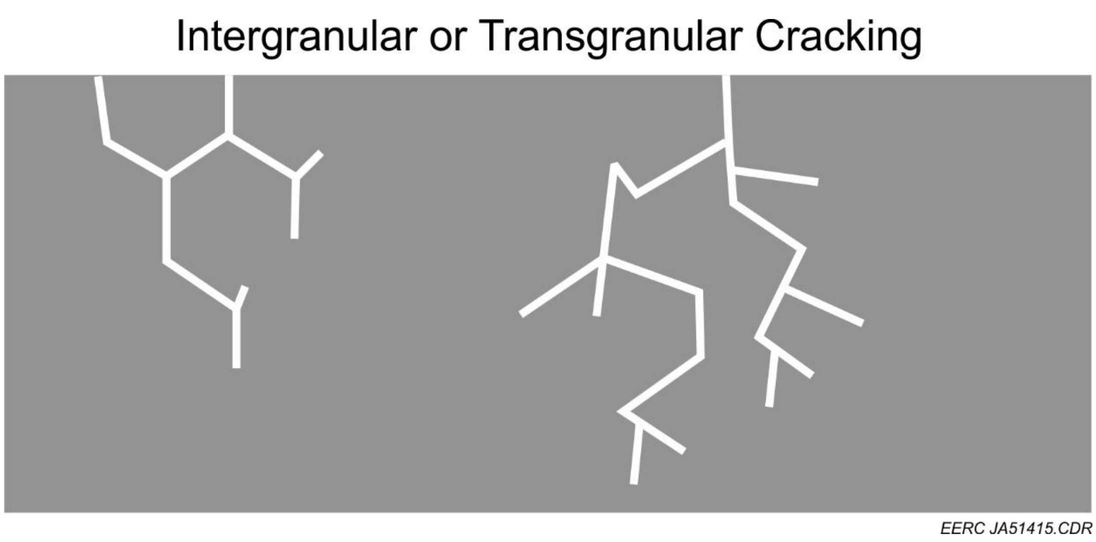


Figure E-5. Different crack shapes depending on the type of SCC.

COATINGS TO INHIBIT EXTERNAL CORROSION

The function of coatings is to control corrosion by isolating the external surface of the piping from the environment, reduce cathodic protection requirements, and improve the cathodic current distribution. Coatings are usually applied to piping materials at the factory to areas of the pipe that will not be heated during welding of the pipe, as shown in Figure E-6. The areas of the pipe that are affected by heat during welding need to be coated in the field after welding so that they are also protected from corrosion. NACE SP0169-201 provides standards to be followed for the different types of coatings. It does not describe very well the different types of coatings that can be used to reduce or prevent corrosion of pipelines.

Some commonly used coatings are listed in Table E-2 (Beavers and Thompson, 2006).

EERC JA51390.CDR

Figure E-6. Epoxy-coated steel pipeline.

Table E-2. Commonly Employed Steel Pipeline Coatings

Coating	Description
Bituminous Enamels	Made from coal tar pitches or petroleum asphalts and have been widely used for 75 years. They are available in summer and winter grades. They may be combined with fiberglass or felt to obtain more mechanical strength for handling. They can be designed for installation and used within a temperature range of 30°–180°F. When temperatures fall below 40°F, extra precautions should be taken during installation to prevent cracking or disbonding. They should be protected from sunlight. Their use has declined because of environmental and health standard restrictions.
Asphalt Mastic	A dense mixture of sand, crushed limestone, and fiber bound together with a selected air-blown asphalt. Selection of asphalt is based on operating temperatures and climactic conditions. The coating is ½ to 5/8 inches thick and is extruded so it is seamless. It has been used for over 60 years. The asphalt can be designed for use between 40° and 190°F. Precautions to prevent disbonding or cracking should be taken when handling at freezing temperatures. It should be protected from sunlight.
Liquid Epoxies and Phenolics	Cure by heat or chemical reaction. Some are solvent types, and some are 100% solids. They can operate at up to 200°F. Coal tar epoxies have added coal tar pitch, making it especially resistant to an alkaline environment such as occurs around a cathodically protected pipe. They can become brittle if exposed to sunlight. They require a near-white, blast-cleaned surface for application.
Extruded Plastic Coatings	Thermoplastics such as polyethylene (PE) or polypropylene (PP) that are extruded through a die and bonded to the pipe using an adhesive. Properties of these plastics are described elsewhere in this report. Adhesives include an asphalt–rubber blend, PE copolymer, butyl rubber, or polyolefin rubber blend.
Fusion-Bonded Epoxy (FBE)	Heat-activated, chemically cured coatings applied to heated pipe at the factory using fluid-bed, air spray, or electrostatic spray methods. A near-white, blast-cleaned surface is required. The coatings are applied in thicknesses of 12 to 25 thousandths of an inch. They exhibit good mechanical and physical properties and are the most resistant to hydrocarbons, acids, and alkalies. A primary advantage of FBEs is that because they are so thin, they do not hide surface defects, so the steel surface can be inspected after it is coated. Increasing the thickness minimizes holiday (a discontinuity, skip, or pinhole in the coating) formation. The excellent resistance of the coatings to electrically induced disbondment has resulted in their popular use.
Tape	Can be applied in the field or at the mill. It has been used for 40 years. Under normal construction conditions, prefabricated, cold-applied tapes are a three-layer system consisting of a primer, corrosion-preventive layer (inner), and mechanically protective outer layer. The primer provides a bonding medium between the pipe surface and the adhesive on the corrosion-preventive layer. The corrosion-preventive layer consists of an adhesive with a plastic backing which has high electrical resistivity and low moisture absorption and permeability. The outer tape is a plastic film with an adhesive coating to provide mechanical protection and resistance to the elements.
Three-Layer Polyolefin	Developed in the 1990s as a way to combine the excellent adhesion of FBE with the damage resistance of extruded PE and tape wraps, they consist of an FBE primer, an intermediate copolymer, and a topcoat of PE or PP. The intermediate layer bonds the FBE primer to the polyolefin topcoat.

Continued…

Table E-2. Commonly Employed Steel Pipeline Coatings (continued)

Coating	Description
Wax Coatings	Used for 60 years and still employed on a limited basis. They are usually used with a protective overlap. The wax waterproofs the pipe, and the protective coating protects the wax. The most prevalent use of wax coatings is the over-the-ditch application with a combination machine that cleans, coats, wraps, and lowers into the ditch in one operation.
Concrete	Longest history of use in protecting steel or wrought iron from corrosion. The alkalinity of the concrete promotes the formation of protective iron oxide film on the steel. This passive protection can be compromised by permeation of chlorides into the coating. Typically, external application is usually employed over a corrosion-resistant coating for armor protection or to add negative buoyancy in water environments.
Metallic or Galvanic	The Canadian Energy Pipeline Association has recommended that FBE, liquid epoxy, extruded PE, and multilayer coatings should be considered based on their ability to reduce SCC in steel pipelines. Coatings such as zinc or cadmium should not be used in underground pipe. Such coatings are intended for the mitigation of atmospheric-type corrosion activity.

The desired characteristics of coatings used for corrosion protection are as follows:

- Effective electrical insulation
- Effective moisture barrier
- Good adhesion to the pipe surface
- Applicable by a method that will not adversely affect the properties of the pipe
- Applicable with a minimum of defects
- Ability to resist the development of holidays (disbonded areas) with time
- Ability to resist damage during handling, storage, and installation
- Ability to maintain substantially constant resistivity with time
- Resistance to disbanding
- Resistance to chemical degradation
- Ease of repair
- Retention of physical characteristics
- Nontoxic to the environment
- Resistance to changes or deterioration during storage or transport

REFERENCES

Beavers, J.A., and Thompson, N.G., 2006, External corrosion of oil and natural gas pipelines, *in* Cramer, S.D., and Covino, B.S., eds, ASM Handbook: ASM International, v. 13C, p. 1015–1025.

APPENDIX F

NACE INTERNATIONAL STANDARD PRACTICE SP0106-2006
APPENDIX C – IMPACTS OF COMMON IMPURITIES ON CORROSION

NACE INTERNATIONAL STANDARD PRACTICE SP0106-2006

Appendix C: Impacts of Common Impurities (Nonmandatory)

(a) Bacteria

Microbes commonly found in oil and gas systems are sulfate-reducing bacteria (SRB) and acid-producing bacteria (APB). Some of the bacterial are planktonic, free floating in the liquids; others are sessile and are attached to the surfaces in the system. Samples of the liquids indicate the presence of the planktonic bacterial; however, their presence does not necessarily indicate that microbiologically influenced corrosion (MIC) has or will occur. Coupons place in the system must be used for detection of the sessile bacteria. See NACE Standard TM0194 (NACE Standard TM0194) for details on monitoring to determine the presence, location, and severity of bacterial contamination. See chemical vendor for biocide recommendation and treatment concentration level.

(b) CO_2

If no liquid water is present, carbon dioxide (CO_2) is noncorrosive. In the presence of liquid water, the partial pressure of CO_2 (mole percent of CO_2 x system pressure in kPa [psi]) is used as a guideline to determine the corrosiveness of CO_2. See *Corrosion Control in Petroleum Production*. (H. Byars)

1. A partial pressure of CO_2 above 207 kPa (30 psi) is usually corrosive in the presence of water.

2. A partial pressure of CO_2 between 21 kPa (3 psi) and 207 kPa (30 psi)-may be corrosive in the presence of water.

3. A partial pressure of CO_2 below 21 kPa (3 psi) is generally considered noncorrosive.

Caution should be used with the above guidelines in the presence of low molecular weight organic acids (acetic, propionic, etc.) or H_2S that will interfere.

A large number of predicative models have been developed for CO_2 corrosion. The rate of CO_2 can be calculated using the deWaard, et al. model. (C. de Waard 1993, C. de Waard, 1995). The corrosion rate is calculated using the partial pressure of CO_2, temperature, and pressure of the system. Corrosion models by A. Anderko, et al. (A. Anderko) and S. Nesic, et al. (S. Nesic) take organic acids into account.

(c) Chloride

Steel must have a conductive solution on its surface to form a cell for corrosive attack to occur. The addition of salts containing chloride, commonly found in gas and oil production, increases the conductivity and corrosiveness of water, resulting in pitting or general corrosion.

Chloride stress corrosion cracking (SCC) results from the interaction of chloride and mechanical tensile stresses. UNS S30400 cracks in the presence of parts per million (ppm) chloride. Pages 21–22 of *Corrosion Control in Petroleum Production* (H. Byars) include a table listing the susceptibility of metal to SCC.

(d) H_2S

H_2S is very soluble in water. It is 200 times more soluble than oxygen and 3 times more soluble than CO_2 in water at atmospheric pressure and temperature. H_2S corrodes steel forming various forms of iron sulfide, which result in pitting corrosion.

Hydrogen blistering may occur in some steels in the presence of H_2S. Hydrogen atoms are sufficiently small to allow entry into the migration within the steel structural lattice. Some of the hydrogen atoms enter structural defects within the steel, such as voids, where they quickly react with other hydrogen atoms to form molecular hydrogen. This molecular hydrogen occupies a greater space and can no longer migrate through steel. Trapped blisters are sufficiently large, they can be detected by external deformation of the steel surface. Hydrogen gas trapped within higher-strength steels can lead to stepwise cracking (also called hydrogen-induced cracking [HIC]) within the steel. The hydrogen atoms in the metal migrate into a void and form hydrogen gas, eventually developing a blister on the surface of the steel. See pp. 17–18 of *Corrosion Control in Petroleum Production*. (H. Byars).

Sulfide stress cracking (SSC) occurs in high-strength steels exposed to moist H_2S conditions. Four conditions are required for SSC to occur.

1. Presence of H_2S

2. Presence of water – trace amount is sufficient

3. High-strength materials

4. Steel must be under tensile stress or loading (stress may be residual or applied). Plain carbon steels with strength below 620 MPa (90,000 psi) and Rockwell hardness below 73.0 HR 15 or 22 HRC are not affected. See NACE MR0175/ISO 15156 (A. Anderko) for detailed hardness requirements. Steels with yield strengths above this level are susceptible to cracking. The time to failure increases as the H_2S concentration decreases. Cracking can occur at 0.1 ppm levels of H_2S in water with a very long time to failure. (H. Byars, A.K. Dunlop).

(e) Organic acids — Low-molecular-weight organic acids (acetic, propionic, etc.) can cause severe corrosion when present in the gas phase at ppm levels. (B. Hedges, J. Crolet). The presence of low-molecular-weight organic acids, which will partition into the water, are often not detected in the water analysis due to the interference of bicarbonate present in the water.

(f) Oxygen — If water saturated with air, containing 7 to 8 ppm oxygen, is used to hydrotest a pipeline, little corrosion of the pipeline results. The oxygen immediately interacts with steel and is removed from solution, resulting in very little corrosion loss. However, if a constant supply of water contacting oxygen flows through the line, severe pitting of the pipeline results. When large quantities of water flow through steel pipelines, the oxygen content should be less than 1 ppm. (L.W. Jones)

An equation to estimate the corrosion due to oxygen relates the corrosion rate to total dissolved oxygen concentration, mineral saturation index, and exposure time. (R.A. Pisigan)

(g) Water — If liquid water is not present in a steel pipeline, corrosion does not occur. The presence of oxygen, CO_2, or H_2S in a steel pipeline in the absence of liquid water does not cause corrosion at temperatures below 200°C (390°F). (R.A. Pisigan) Hygroscopic salt deposits on the steel surface can cause the formation of an invisible water film on the surface below dewpoint conditions, which can cause corrosive attack.

APPENDIX G

LEAK DETECTION METHODS DESCRIPTION AND PERFORMANCE ADVANTAGES

LEAK DETECTION METHODS DESCRIPTION AND PERFORMANCE ADVANTAGES

The advantages and disadvantages stated in the following table are relative, for comparison purposes.

The extent and quality of advantages and disadvantages vary based upon pipeline-specific contents, configuration, and operating conditions.

Advantages are most apparent for large-diameter, liquid-filled pipelines possessing simple configurations and operating at steady state.

Most methods can be custom-configured or programmed into SCADA (supervisory control and data acquisition) by consultants or knowledgeable employees; many methods can be procured as software packages from vendors who may offer additional services related to their products.

Name of Method	Description	Advantages	Disadvantages
Conservation of Mass Techniques:	Monitor pipeline instrumentation to detect imbalances between incoming amounts received by a pipeline and outgoing amounts delivered from a pipeline. The desired sensitivity determines the frequency of calculating imbalances, with more frequent calculations being less sensitive; i.e., longer durations are required to detect smaller leaks.		
Line Balance, Basic Volume Balance, or Over/Short Comparison	Incoming (received) and outgoing (delivered) volumes are measured by flowmeters and/or tank gauges. Imbalances are compared to alarm thresholds. No pressure, temperature, or composition compensation is performed.	• Low cost, since the method only requires flow measurements at all injection and delivery points, which existing instrumentation might be able to provide.	• Relatively insensitive. • Possesses same disadvantages as modified volume balance method (below).
Modified Volume Balance, e.g., PLM (Pipeline Monitoring) by Telvent (Schneider Electric)	An enhanced line balance method whereby pipeline flow measurements are adjusted to standard conditions. Sensitivity of technique depends on leak size, frequency of volume balance calculation, accuracy and repeatability of instrumentation, and operating conditions.	• Easy to implement or retrofit on any pipeline configuration. • Easy to learn. • Easy to test and maintain. • Relatively low cost. • Able to detect 5% leak in minutes to hours in suitable conditions.	• Ineffective during shut-in conditions. • Reduced accuracy and increased incidence of false alarms when pipeline is only partially liquid-filled. • Smaller leaks require longer detection times. • Transient conditions mask leaks and induce more frequent alarms. • Unable to identify leak locations. • Limited accuracy in estimating leak volumes.
Mass Balance	Similar to line balance, except mass flowmeters are use in place of volume flowmeters, or densitometers are used in conjunction with volume flowmeters.	• More accurate than basic volume balance which does not account for density differences.	• Requires installation of mass flowmeters or densitometers which makes it more difficult to implement, retrofit, and maintain than basic volume balance. • Possesses similar disadvantages as modified volume balance method (above).

Continued…

Name of Method	Description	Advantages	Disadvantages
Compensated Mass Balance, also Referred to as a Mass Balance with Line Pack Correction, e.g., MassPack™ module of LEAKNET™ by EFA Technologies, Inc.	An enhanced mass balance method which accounts for changes in pipeline inventory (line pack). In one approach, the rate of change in line pack is measured along the pipeline using pressure and temperature sensors and/or densitometers. Pipelines are divided into segments based on instrument locations, measurement points, pipeline elevation profile, and desired accuracy. Volumes are adjusted for each segment based on conditions in the segment. Another approach predicts line pack based on a transient flow model in which inlet pressure, temperature, and/or density measurements adjust inlet boundary conditions.	• Able to detect existing leaks and leaks during transient flow and shut-in conditions. • Able to detect 1% leaks in minutes in suitable conditions. • Often able to detect leaks in transient conditions with fewer false alarms than mass balance methods. • Easy to learn and use. • Easy to test. • Suitable for any pipeline configuration. • Basic systems can deploy rapidly.	• Reduced accuracy when pipeline is partially liquid-filled. • Difficult to implement, retrofit and maintain. • Unable to identify leak location. • Relatively high cost.
Real-Time Transient Model (RTTM), e.g., PipelineManager® by EnergySolutions International, LeakWarn by EnergySolutions International (previously Simulations, Inc.), SimSuite™ by Schneider Electric (previously Telvent), Stone Pipeline Simulator/Leakfinder by GL Industrial Services (previously Stoner Associates), and Leak Track 2000 by Auspex Inc. (previously EnviroPipe Applications Inc.).	Incorporates detailed pipeline models based upon physical laws of conservation of mass/momentum/energy and pipeline and fluid physical properties (e.g., fluid compressibility, pipe wall elasticity, pipeline expansion, and density dependence on temperature) to estimate property profiles along pipelines. Applying 1) deviation analysis, leaks are detected by identifying deviations between calculated and measured conditions along segments of the pipeline, whereas applying 2) model compensated mass balance, the line fill is calculated from the RTTM and is used to calculate imbalances.	• Able to detect 1% leak in seconds in suitable conditions. • Able to detect leaks in shut-in, partially liquid-filled, start-up, and other transient conditions. • Able to estimate leak flow rate and location. • Able to assist in operation of pipelines by providing such functionality as pressure profile, look-ahead modeling, batch tracking, composition tracking, pig tracking, operational planning and so on.	• Difficulty in detecting existing leaks. • Difficult to learn and use. • Must be customized and tuned for each pipeline configuration, including modifications. • Difficult to implement, test, and maintain, in part due to extensive information describing pipeline and its contents that is required. • Sensitive to the quality of metering, SCADA, and telecommunications. • Sensitive to fluid properties. • Often desensitized during transient conditions. • Relatively very high cost.

Continued…

Name of Method	Description	Advantages	Disadvantages
Signature Recognition Techniques	Monitor pipeline measurements and calculated values derived from pipeline measurements to detect patterns characteristic of leaks.		
Pressure Monitoring	Pipeline pressure is monitored locally at a single point. a. Pressures are compared to an alarm threshold, typically the lowest pressure in the normal operating range. b. Deviations of pressure measurements from expected operating values are compared to alarm thresholds, typically the largest positive and negative pressure deviations in the normal operating range. c. Rates of change in pressure are compared to alarm thresholds, typically the highest pressure rate of change in the normal operating range. d. Deviations of measured pressure rates of change from expected operating rates of change are compared to alarm thresholds, typically the largest positive and negative rate-of-change deviations in the normal range.	• Capability inherently available in typical SCADA systems. • Able to be performed locally, without need for distance communications. • Able to detect leaks in shut-in conditions. • Easy to retrofit and maintain. • Able to estimate the locations of large leaks. • Able to detect 5% leak in minutes in suitable conditions.	• Very insensitive, especially near pumps. • Difficulty detecting small leaks, existing leaks, and leaks in partially liquid-filled pipelines. • Difficult to implement and test. • Difficulty in learning and using. • Transient conditions tend to generate false alarms. • Limited robustness.
Flow Monitoring	Fluid flow rate is monitored locally at a single point. a. Flow rates are compared to an alarm threshold, typically the lowest flow rate in the normal operating range. b. Deviations of measured fluid flow rates from expected operating values are compared to alarm thresholds, typically the largest positive and negative flow rate deviations in the normal operaing range. c. Rates of change in flow rates are compared to alarm thresholds, typically the highest rate of change in the normal operating range. Deviations of rates of change in measured fluid flow rates from expected operating rates of change are compared to alarm thresholds, typically the largest positive and negative positive and negative flow rate rate-of-change deviations in the normal range.	• Capability inherently available in typical SCADA systems. • Able to be performed locally, without need for distance communications. • Easy to retrofit and maintain. • Able to estimate the volumes of large leaks. • Able to detect 5% leak in minutes in suitable conditions.	• Very insensitive, especially near pumps. • Difficulty detecting small leaks, existing leaks, and leaks in partially liquid-filled pipelines. • Difficult to implement and test. • Difficulty in learning and using. • Transient conditions tend to generate false alarms. • Limited robustness. • Unable to identify leak location.

Continued…

Name of Method	Description	Advantages	Disadvantages
Combined Pressure and Flow Monitoring, e.g., Pressmon by Schneider Electric (previously Telvent)	Single pressure and fluid flow measurements are monitored locally. Pressures and flow rates, deviations in pressures and flow rates, and rates of change of pressures and flow rates are combined mathematically to provide metrics indicative of leakage.	• Capability available in typical SCADA systems. • Able to be performed locally, without need for distance communications. • Able to detect leaks in shut-in conditions. • Easy to retrofit and maintain. • Able to estimate the location and volumes of large leaks. Able to detect 5% leak in minutes in suitable conditions.	• Very insensitive, especially near pumps. • Difficulty detecting small leaks, existing leaks, and leaks in partially liquid-filled pipelines. • Difficult to implement and test. • Difficulty in learning and using. • Transient conditions tend to generate false alarms. Limited robustness.
Acoustic or Negative Pressure Wave Monitoring, e.g., ATMOS Wave Using a SPRT (sequential probability ratio test) Algorithm by ATMOS International and WaveControl® by Group LB	Measurements from multiple high-response-rate and moderately accurate pressure transducers along a pipeline are combined to detect rapid pressure changes characteristic of waves produced by leaks. Waves traverse both downstream and upstream of leak points and possess a brief, high-amplitude wave and a longer-term, lower-amplitude standing wave. The high-amplitude wave requires high-frequency sampling to detect. Incorporation of filtering or methods such as sequential probability ratio testing (a statistical technique) improve sensitivity and reduction in false alarms.	• Typically able to incorporate existing pressure sensors. • Able to detect leaks in shut-in and steady-state flow conditions. • Able to identify leak location under favorable conditions. • Relatively insensitive to fluid properties. • Inclusion of filtering, SPRT, and other enhanced techniques significantly improves performance; pressure and flow pattern recognition and negative pressure wave modeling and signature recognition represent other advanced modifications (below).	• Decreased effectiveness with increasing distance between pressure sensors. • Less effective on short lines. • Requires higher-speed data acquisition instrumentation. • Modestly difficult and expensive to retrofit longer lines. • Sensitivity decreases for transient conditions and sensors located near pumps and other noise sources. • Incorporation of enhanced modifications increases the difficulty in installing, using, and maintaining the technology.

Continued…

Name of Method	Description	Advantages	Disadvantages
Pressure and Flow Pattern Recognition, e.g., RLDS by Asel-Tech Inc.	Pattern classification approaches are applied to measured and calculated pressure (e.g., pressure point analysis) and fluid flow rate (e.g., imbalance) values. Common techniques include the following: a. Maximum entropy transfer b. Naive Bayes classifier c. Neural networks	• Similar advantages to negative pressure wave monitoring techniques. • Superior sensitivity and reduced false alarms to basic negative basic pressure wave techniques.	• Similar disadvantages to negative pressure wave monitoring techniques. • Increased difficulty to implement, understand, use, and maintain compared to basic pressure wave techniques.
Negative Pressure Wave Modeling, e.g., SimSuite™ by Schneider Electric (previously Telvent)	Forecasts of the expected pressure response of a pipeline leak based on a mathematical model that incorporates pipeline physical characteristics and fluid properties are compared with measured pressures along the pipeline to identify similarities indicative of leakage and to locate leaks. Applied in conjunction with RTTM.	• Similar advantages to negative pressure wave monitoring techniques. • Superior sensitivity and reduced false alarms to basic negative basic pressure wave techniques. • Improves RTTM leak localization.	• Similar advantages to negative pressure wave monitoring techniques. • Increased difficulty to implement, understand, use, and maintain compared to basic pressure wave techniques.
Statistical Analysis	Applies statistical methods to measured variables to identify deviations from statistically expected behavior represented by a distribution (e.g., Gaussian or normal probability distribution) and expressed in terms of a statistical parameter (e.g., confidence). An example is comparing the statistical likelihood of a leak with the likelihood of no leak. Multiple different statistical leak alarms running in parallel can be combined to provide a single, more reliable confidence measure.	• Able to detect 1% leak in seconds to minutes in suitable conditions. • Depending upon which variable(s) are measured, able to detect leaks in shut-in and transient conditions. • Easy retrofitting and maintenance. • Suitable for any pipeline configuration. • Robust. • Relatively insensitive to fluid properties. • Fewer false alarms. • Able to estimate leak location. • Data requirements are not as large as model-based approaches. • Does not require a fixed, a priori alarm threshold.	• Unable to detect existing leaks and leaks in partially liquid-filled pipelines. • Difficulty estimating leak volume. • Difficult to implement and test. • Relatively high cost for some methods. • Requires establishing a baseline parameter distribution, which might require extended time. • Hampered if conditions which established the baseline parameter distribution change in a manner not otherwise accounted for.

Continued…

Name of Method	**Description**	**Advantages**	**Disadvantages**
Statistical Process Control	Observes the real-time behavior of measured variables over relatively brief time windows to identify statistically significant trends and inconsistencies that indicate possible leaks.	• Easy to implement and understand.	• Less reliable than other statistical methods. • Assumes steady-state process with errors being random, unbiased, and from an unchanging distribution. • Requires significant time to detect a leak.
Pressure Point Analysis, e.g., PPA™ module of LEAKNET™ by EFA Technologies, Inc.	Measurements from a single pressure sensor are input into two moving average estimators which differ in the number of samples that comprise their sample windows. The Student's t-distribution statistic is applied to the two averages to yield a measure of confidence that the two averages differ which implies a possible leak.	• Improved sensitivity and response time compared to basic pressure monitoring.	• Limited sensitivity.
SPRT, e.g., ATMOS Pipe by ATMOS International Using a Statistical (SPRT) Volume Balance Method with Data Filtering	Monitors measurements over time to detect a statistically significant deviation from previous measurements indicative of a leak. Measurements include single sensors such as pressure transducers or calculated values such as volume balance which relies on multiple sensors.		
Statistical Pattern Recognition	The application of statistical hypothesis testing or decision theory to any leak detection method that monitors a measured or calculated value for exceeding a threshold value. Statistical pattern recognition, then, applies statistical methods to estimate the confidence that the threshold has been transgressed.	• Reduces false alarms.	• Requires training to understand. • Unable to locate leaks. • Increases complexity of the leak detection method with which it is associated.
Other Techniques			
Leak Location Analysis	Applies any of various methods (e.g., pressure gradient analysis and negative pressure wave modeling) to estimate the location of a pipeline leak.		

Continued…

Name of Method	Description	Advantages	Disadvantages
Enhanced Real-Time Transient Model (E-RTTM), e.g., PipePatrol E-RTTM by Krohne and ATMOS SIM RTTM by ATMOS International	An enhanced real-time transient model method to which either or both a) leak signature analysis and b) leak location estimation are added to RTTM. Leak signature analysis analyzes the characteristics of residuals (i.e., differences between measured and RTTM estimated values) to identify leak signatures. Leak locators monitor pressure profiles along pipelines (gradient intersection method) or wave transit times (wave propagation method) to locate pipeline leaks.	• Able to detect 1% leak in seconds in suitable conditions. • Able to estimate leak flow rate and location. • Able to detect leaks in shut-in, partially liquid-filled, and transient conditions.	• Difficult to learn and use. • Must be customized and tuned for each pipeline configuration, including modifications. • Difficult to implement, test, and maintain, in part due to extensive information describing pipeline and its contents that is required. • Sensitive to the quality of metering, SCADA, and telecommunications. • Relatively very high cost.
State Estimation	Provides an estimate of the internal condition of a pipeline based upon a detailed pipeline model and measurements of pipeline conditions and of pipeline equipment (e.g., valve positions and pump status) which can be of better quality than individual measurements. Kalman filters, for example, integrate the above along with measures of model and measurement inaccuracies to improve the quality of measured variables and to estimate the values of variables that cannot otherwise be measured.	• Increased sensitivity. • Some ability to adapt with changing pipeline conditions.	• Increased complexity and difficulty in installing, maintaining, and understanding.
Preprocessing of Measured Data	Methods—often simple (e.g., moving averages)—that manipulate (e.g., filter) or screen outlier measurements to avoid false alarms.	• Reduced false alarms. • Easy to implement, learn, and use. • Some capabilities are included in many SCADA systems.	• Incorrect tuning can desensitize leak detection system.
Other Combinations of Methods, e.g., ATMOS Wave Flow by ATMOS International Combining Volume Balance and Rarefaction Wave Methods and I-RLDS by Asel-Tech Inc. Combining Compensated Mass Balance and Acoustic Technologies (I-RLDS-W Also Incorporated Sensing Cable [exterior] Technology).	Various combinations of the above methods can be incorporated to produce more reliable indications and measures of leaks and their locations: • ATMOS Wave Flow by ATMOS International combining volume balance and rarefaction wave methods • I-RLDS by Asel-Tech Inc. combining compensated mass balance and acoustic technologies (I-RLDS-W also incorporated sensing cable [exterior] technology).	• Reduced false alarms. • Increased sensitivity of leak detection system.	• Increased complexity and difficulty in installing, maintaining, and understanding.

Continued…

Name of Method	Description	Advantages	Disadvantages
Adaptive Methods (e.g., expert systems, process identification, and other methods)	Computational pipeline monitoring (CPM) methods require knowledge of past behavior or the physics of a given pipeline to detect the signature of or a deviation from expected behavior that represents a leak. Ultimately, a key characteristic(s) of the pipeline must be known. The consistent (nearly steady-state) operation of large pipelines is favorable to CPM methods because the key characteristic(s) are relatively constant. As typically operated, gathering lines often lack such consistency. Adaptive systems provide an opportunity to aid CPM methods in tracking gathering line status as key characteristic(s) change with operating changes.	• Able to compensate for changes in gathering line operations. • Reduced false alarms.	• Difficult to learn and use. • Must be customized and tuned for each pipeline configuration and operating mode, including modifications. • Difficult to implement, test, and maintain, especially as the number of modes and their similarities increase. • Relatively high cost.

SOURCES

den Hollander, H., and Bollermann, B., 2007, Why is pipeline leak detection more than just installing a flowmeter at inlet and outlet?: Pipeline Technology Conference 2007, Hannover, Germany, April 17.

Geiger, G., 2012, Principles of leak detection: Krohne Oil & Gas, krohne.com/fileadmin/files-2/PipePatrol/KROHNE_Gerhard_Geiger_Principles_of_Leak_Detection_2012.pdf (accessed on August 18, 2015).

Mastandrea, J., 1982, Petroleum pipeline leak detection study: U.S. Environmental Protection Agency, EPA-600/2-82-040, January.

Shaw, D., Phillips, M., Baker, R., Munoz, E., Rehman, H., Gibson, C., and Mayernik, C., 2012, Leak detection study—DTPH56-11-D-000001: Kiefner & Associates, Inc. for the U.S. Department of Transportation, Final Report No. 12-173, December 10.

Summa, J., 2011, Pipeline leak detection operational improvements: 6th Pipeline Technology Conference, Hannover, Germany, April 4–5.

Terry, T., 2012, Pipeline leak detection technology 2011 conference report—final report: Anchorage, Alaska, prepared for Alaska Department of Environmental Conservation, March.

U.S. Department of Transportation, 2007, Leak detection technology study for PIPES Act H.R. 5782: December 31.

Zhang, J., Hoffman, A., Murphy, K., Lewis, J., and Twomey, M., 2013, Review of pipeline leak detection technologies: Pipeline Simulation Interest Group, PSIG 1303, presented at the PSIG Annual Meeting, Prague, Czech Republic, April, 16–19.

APPENDIX H

LEAK DETECTION PRODUCTS AND PROVIDERS

Technology Provider	Technology Product Name	Technology Description
Acoustic Systems Incorporated (CPM)[1]	WaveAlert	Uses sensitive acoustic sensors situated at the ends of the pipeline and some intermediate valve sites to detect leaks and determine leak location.
AREVA NP GmbH	LEOS	Monitors for chronic leaks by air sampling with permeable plastic "sensor tube" that is installed with the pipeline. Leakage substance is collected inside sensor tube by through-wall diffusion.
Asel-Tech (CPM)	ILDS (integrated leak detection system)	Combines two detection techniques defined by API 1130: acoustic (negative pressure wave) and mass balance technologies.
ATMATA	Pipeline Leak Detection Monitoring Solution	Provides a complete solution including 1) CPM software that performs material balance, RTTM (real-time transient model), and pressure/flow signature analysis; 2) very accurate field instrumentation; 3) high-efficiency data acquisition systems; 4) wireless networking; and 5) solar energy electrical systems.
ATMOS International, Inc. (CPM)	ATMOS Pipe ATMOS Wave	Uses learned volumetric flow difference for a pipeline and compares it to the current flow difference to determine probability of a leak. Detects the negative pressure waves associated with the onset of a leak.
Auspex (fka EnviroPipe Applications) (CPM)	Leak Track 2000 (LT2000)	Uses deviation methodology to detect leaks. Deviation includes mass balance/line pack, flow deviation, pressure wave analysis, and other monitored data.
Ausenco	Pipeline Advisor™	Leak detection is a component of a real-time advice and performance and safety optimization software monitoring package. Leak detection occurs, a least in part, by monitoring pressure waves in the fluid.
Avateq (CPM)	WaveControl	Leak detection system based on the principle of detection and identification of pressure waves that occur in pipelines during leaks.
Chelsea Technologies Group	Sub-Sea PLD	Pipeline leak detection (PLD) system that finds leaks in subsea pipelines by sensing the fluorescence of leaking hydrocarbons or, for pipeline commissioning, by introducing fluorescent dyes (such as Rhodamine, Fluorescein, or Agma EP1186/MIS). The system is extremely sensitive and is capable of detecting leaks at levels as low as 1 part per million (ppm) in seawater.
EFA Technology (CPM)	LEAKNET™	Fully integrated software/hardware product that includes the patented Pressure Point Analysis (PPA)™ algorithm and an operationally independent (and proprietary) mass balance system with dynamic line pack compensation called MassPack™.
Energy Solutions International (ESI) (fka Modisette Assoc., LICEnergy Inc., and Simulutions) (CPM)	PipelineManager/LeakWarn	Uses real-time transient models to simulate operating conditions and show the operator and others a complete hydraulic picture of the pipeline, including the position of all batches.
FLIR	GF-300	Optical gas imaging infrared (IR) camera system tuned to "see" volatile organic compound (VOC) gas vapors. Leaking vapors from oil and gas filled pipes are "visible" with the GF-300 camera.

[1] Computational pipeline monitoring.

Continued…

Technology Provider	Technology Product Name	Technology Description
FLIR	P-600	IR camera system that detects leaks based on temperature differences in the surrounding area. Oil on water looks different with an IR camera. Temperature differences on insulated pipe create an anomaly or nonuniformity, indicating insulation is wet or improperly installed, which could lead to corrosion and oil leaks.
hansaconsult Ingenieurgesellschaft	TCS (tightness control system)	Pressure-step and pressure temp. method leak detection system that incorporates a highly accurate static leak detection test and Kleopatra simulation software for dynamic leak detection.
Krohne Oil & Gas (CPM)	PipePatrol (fka Gallileo)	Real-time transient model leak detection system with unique signature analysis to prevent false alarming on pipelines containing crude oil, natural gas, refined hydrocarbons, liquefied gases and supercritical gases, but not multiphase.
MH Consulting	Life Cycle Project Management	Selecting a PLD on a crude oil transmission pipeline with temperature variations as product is conveyed downstream.
Micro Motion, Division of Emerson Process Management	Coriolis Flow and Density Meters	Used to deliver accurate, repeatable flow and density measurements for both crude oil and natural gas and provide good, repeatable performance in multiphase flow regimes for void fractions as high as 20%.
Multi Phase Meters AS	Multiphase Meters (MPMs)	Can measure oil, gas and water without separation using radio frequencies and other technologies to create a three dimensional image of flow through multiple planes that measure the individual parts.
Omnisens SA	DiTEST STA-R LTM	Uses Brillouin optical time domain analyzer (BOTDA) to determine leak time and location by evaluating light scattering that occurs in fiber optic cables positioned along pipeline.
PCE Pacific Inc./ Emerson Process Management	Smart Wireless; WirelessHart; 3051S pressure transmitter, 648 temperature transmitter, 702 discrete transmitter, 2160 vibrating fork transmitter, 708 acoustic transmitter, 775 THUM™	Used to provide pressure, temperature, and flow measurements to support leak detection from remote sensors without the need for cabling, power, or communication infrastructure.
PermAlert ESP, a Division of Perma-Pipe, Inc.	PAL-AT	Uses a coaxial cable connected to a microprocessor-based panel capable of continuously monitoring a sensor string. Liquid hydrocarbons can penetrate the coaxial cable. The control panel uses time domain reflectometry techniques to locate and detect when a leak, break, or short occurs in the coaxial cable.
Praxair (fka Tracer Research)	Tracer Tight and Seeper Trace	Tracer chemicals added directly to the product in the pipeline or in water during hydrotesting. Samples are collected along the pipeline and analyzed. The detection of the tracer chemicals indicates leakage.

Continued…

Technology Provider	Technology Product Name	Technology Description
Pure Technologies	SmartBall®	Consists of an instrumented aluminum core in a urethane shell slightly smaller than the inside diameter of the pipeline. The ball rolls along with the flow in the pipeline using a range of instrumentation, including an acoustic data acquisition system that listens for leaks as the ball travels through the pipeline.
Schlumberger Oilfield Services	Integriti pipeline-monitoring system	Utilizes distributed temperature, strain, and vibration sensing using a combination of coherent Rayleigh noise, Raman, and Brillouin optical time domain reflectometry measurement techniques to detect and locate high-pressure gas and liquid leaks.
Siemens	Sitrans FUH1010 ultrasonic meters	Clamp-on transit-time ultrasonic flowmeters that use patented WideBeam™ technology to induce an axial sonic wave in the pipe wall for leak detection.
Smart Pipe	Smart Pipe	A double-walled HDPE pipe tight fit liner simultaneously manufactured and installed (using trenchless technology) in up to 50,000 feet of an underground pipeline without disruption of the surface areas covering the pipeline except for a small opening at the entry and exit points of the pipeline section being lined. Fiber optic sensors in the interstitial space monitor leak detection.
SPS GL Noble Denton (fka Stoner Pipeline Simulator [SPS]) (CPM)	Leakfinder	Uses active modeling to dynamically modify leak detection thresholds to ensure fast and accurate leak detection and location under all operating conditions, while minimizing potential false alarms.
Telvent USA Corporation (CPM)	SimSuite Pipeline	A two-phase, nonthermal equilibrium real-time transient model with separate dynamic mass, momentum, and energy balances for each phase that provides complete simulation of pipeline systems, including pump stations, compressor stations, injection/delivery stations, tank farms, valves, and control logic.
Tyco Thermal Controls	TraceTek 5000 hydrocarbon sensor cable, TT-FFS fast-acting fuel probes, TTSIM sensor interface, and TTDM-128 alarm panels	Uses sensor cables and probes that interact with spilled liquid hydrocarbons producing electrical changes that are monitored by sensor interfaces and alarm panels to detect leaks and leak location.
Vista Leak Detection, Inc.	LT-100 and HT-100	Thermally compensated, dual pressure, precision volumetric tests for leak detection on pipeline segments under static conditions. Leak condition is determined by comparing volume data at the conclusion of the test period.
Worley Parsons (fka Colt Technologies) (CPM) www.worleyparsons.com	LINEGUARD	A field-proven, innovative approach to modeling the transient behavior of liquid pipelines, providing an accurate, robust, model-assisted, material balance leak detection system.

SOURCES

ATMATA Advanced Engineering Solutions.

Terry, T.M., 2012, Pipeline leak detection technology 2011 conference report: Final report prepared by Shannon & Wilson, Inc., March 2012.

APPENDIX I

COMPONENTS OF AN INTERNAL LEAK DETECTION SYSTEM

COMPONENTS OF AN INTERNAL LEAK DETECTION SYSTEM

Internal leak detection consists of the set of technologies, methods, and personnel that measure and use data acquired from inside pipelines to identify leaks (Figure I-1 displays components of an internal leak detection system [LDS], including computational pipeline monitoring [CPM] as an optional addition to basic monitoring capability and electric power as a supporting infrastructure). Even if pipeline conditions were simple and ideal for detecting leaks, systems installed to detect leaks are inherently complex, containing many and varied components that must operate together continuously and reliably.

The pipeline controller (also known as dispatcher or operator) is the key component at the heart of the system: for many reasons, LDS design and the extent of automation vary among gathering line operators. Ultimately, however, it is a human being who receives then must interpret and decide on the appropriate response to alarms, indications, and other information from other components of the LDS based on training, experience, and procedures. Traditionally, controllers perform their duties in control rooms that are designed around the needs of the controller to keep them alert and focused on pipeline operation and to provide rapid access to critical information. However, with the expansion of Internet and wireless technologies, pipeline information now is remotely accessible across many parts of the oil field. As a result, gathering line operators are providing field personnel with similar access to information while physically situated in critical field or other locations.

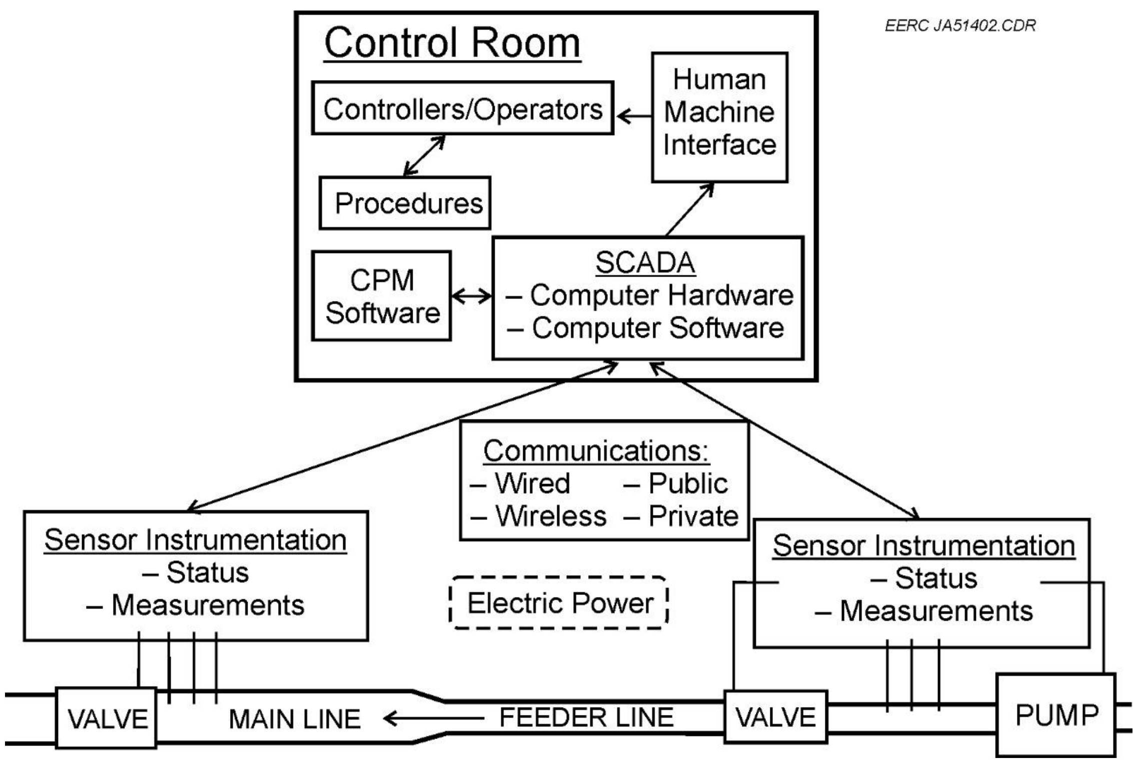


Figure I-1. Components of an internal LDS.

A second, very important component of internal LDS is procedures. Start-up, shutdown, and emergency procedures, such as emergency response procedures for leaks, are important for operating pipelines and minimizing negative impacts of leaks, but more important to internal LDS are routine pipeline operating procedures. The majority of internal LDS technologies are computer-based or CPM technologies. This software relies on accurate measurements of conditions across and good physical understanding of pipeline networks and on predictable pipeline behavior. CPM leak detection methods are most effective in monitoring large, simple-topology, single-phase, liquid-filled pipelines operating at steady state (i.e., constant conditions). Unfortunately, emulsion, oil, and produced water gathering lines typically are not large, they possess numerous branches comprising different-diameter pipes, may not be liquid-filled, and do not operate at steady state. For CPM to perform most effectively, operating procedures need to support predictable, liquid-filled, steady-state operations—operations that are not typical of current gathering line operations. There are several reasons for the current situation. There has been no need to attain these conditions; even if desirable, the justification to acquire the resources and expend the effort required to attain these conditions has been inadequate, and different parties sometimes control different portions of the gathering system (e.g., producers control wellsite tanks and pumps, terminals and disposal companies control the receiving end of the gathering lines), which requires agreement and coordination among multiple companies. This is not to say that modifying procedures and equipment to approach steady-state gathering line operation is impossible; rather, the reasons to do so must justify the cost and effort, especially in light of other inherent obstacles posed by gathering line to effective CPM implementation.

The supervisory and data acquisition (SCADA) system is a third component of an internal LDS. Conventionally, SCADAs comprises the following:

- Field devices such as sensors, actuators (e.g., valves and pumps), and associated lines and instrumentation along the pipeline network that measure variables such as pressure, temperature, flow rate, density, viscosity, sonic velocity, and interface level, to name a few.

- Programmable logic controllers (PLCs) that 1) communicate with field devices by acquiring measurements and other data and transmitting signals to control actuators and other devices, 2) possess various control capabilities, and 3) link to communication portals to supervisory computers.

- Remote terminal units (RTUs) that communicate with field devices (similarly to PLCs), and directly with supervisory computers (unlike PLCs); RTUs possess more rudimentary control capabilities compared to PLCs.

- Supervisory computers that collect data from RTUs and PLCs, process and store data, display data to controllers through human–machine interfaces (HMIs) and communicate controller commands to RTUs and PLCs.

- HMIs that display data and emit audio and visual alarms to and accept control commands from controllers.

- Communication infrastructure that enables communication amongst supervisory computers and RTUs and PLCs.

The fourth component is CPM software that runs on computer networks connected to supervisory computers, acquiring data from supervisory computers; analyzing the data based upon knowledge of the physics of fluid flow, pipeline physical characteristics, and properties of the fluid it contains; then transmitting results to supervisory computers and HMIs for controller consideration. More than one CPM software can run in a SCADA simultaneously; although the benefit of additional software depends on the methodologies they implement, the more similar the approaches, the less the incremental benefit of additional software.

The fifth component of an internal LDS is electric power—an important piece of supporting infrastructure that cannot be taken for granted in the oil field. Not all locations where instrumentation and equipment are required can be assumed to have easily accessible power. While wellsite gathering line injection points and terminal and disposal receiving sites typically have electric power available, other critical locations along gathering lines often lack convenient and adequate sources of electricity.

Performance of an internal LDS depends on the quality of the design and maintenance of all system components. It is difficult, typically impossible, for components to compensate for deficiencies in other components. For example, lesser-quality instrumentation or poorer-quality maintenance of that instrumentation will decrease the quality of measurements processed by the system which will reduce the sensitivity or accuracy of the LDS. CPM software and other LDS components cannot completely compensate for inaccurate measurements. Likewise, unreliable communications and electric power can cause data losses that degrade LDS performance. Finally, nonideal conditions arise in all pipelines and vary from pipeline to pipeline. Such conditions include the following:

- Liquid flow measurements have inherent error that can vary with conditions and are subject to errors in calibration and drift over time.

- Liquid characteristics change with temperature and composition, which affects measurements.

- Pipelines may not be liquid-filled; in such situations, in-flows that exceed out-flows could be due to filling (or “packing”) a partially filled pipeline rather than pipeline leakage.

- Supporting communication is unavailable or difficult to install.

- Flow rates and product value may be too small to economically justify accurate leak detection.

The requirements of some components might make them incompatible with other standard LDS components and complicate their implementation or system retrofit. The standard suite of pipeline instrumentation, even if well-maintained and high quality, is inadequate or inappropriate for some types of CPM. For example, while the negative pressure wave method uses pressure measurements—pressure measurement is a common gathering line measurement—accurate leak detection by this method requires that pressure measurements be made at higher rates than by standard gathering line monitoring systems and potentially requiring more sensors, depending on the topology of the pipeline and if locating the leak is also desired. Adding these capabilities could require changes to the PLC or RTU and introduction of more (possibly better) pressure transducers. This method also benefits by steady-state pipeline conditions, which could require changes in another LDS component, i.e., procedures.

The effectiveness of any specific leak detection technology is related to pipeline and fluid physical characteristics and the specific automation monitoring the line. The most appropriate CPM method depends on the types of measurements acquired by the SCADA, the pipeline fluid and operating condition, and desired features of the system. Potential features include:

- Identification of leak characteristics, e.g., existence, location, and/or size.
- Timeliness in detecting a leak.
- Suppression of false alarms.
- Minimal software configuration and tuning requirements.
- Ability to adjust to transients in flow rates, composition, or other variables and properties.
- Ability to compensate for degraded communications or sensor failures.

The extent, quality, and capabilities of installed instrumentation and automation equipment vary by gathering line operator and, sometimes, section of gathering line. Much of the variation is related to the extent and capabilities of communications and SCADA equipment. Field visits to and surveys of gathering line operators indicate a range of attitudes and capabilities exist from 1) essentially no real-time measurement data communication to 2) gathering line operators actively developing and installing a SCADA systems to 3) fairly well-developed measurement, communication and SCADA systems with operating procedures that support a basic level of leak detection. While the lease automatic custody transfer (LACT) on oil gathering lines provides a baseline amount of measurement, the interest in and ability to communicate and apply that data alone or with expanded and enhanced instrumentation varies substantially amongst gathering line operators.

Table I-1 provides a list of measurements and status that are required by some advanced monitoring system and LDSs. Check marks (√) denote measurements commonly available at critical points along gathering lines, if not also communicated to remote control rooms by SCADA. Some measurements, such as composition, are required by more sensitive leak detection methods. Valve position and pump status indicators can enable producers, gathering line operators and terminal or disposal operators, stay apprised of flow movements and can aid some leak-monitoring systems in tracking and compensating for unpredictable changes.

Table I-1. A Comparison of Common Wellsite Measurements with Measurements and Equipment Status Required by Advanced LDS

	Flow	Pressure	Temperature	Composition	Tank Level	Valve Position	Pump Status
Receiving Point							
Oil and Emulsion	√	√	√		√		
Produced Water	√	√					
Booster Pump Station							
Oil and Emulsion	√	√					
Produced Water	√	√					
Delivery Point							
Oil and Emulsion		√			√		
Produced Water		√			√		

APPENDIX J

DESCRIPTION OF UNMANNED AIRCRAFT SYSTEMS AND THEIR APPLICATION TO PIPELINE MONITORING

DESCRIPTION OF UNMANNED AIRCRAFT SYSTEMS AND THEIR APPLICATION TO PIPELINE MONITORING

Unmanned aircraft systems (UASs), often referred to as "drones," have exceptional potential for current and future use as a tool to monitor spills and/or leaks of oil, gas, and saltwater mixtures across the Bakken region. The necessity to proactively image large areas with repeatable coverage and high-resolution imagery positions the UAS as an attractive monitoring tool within the commercial energy sector. With proper planning, a UAS can be employed persistently over risk-prone areas to enhance spill response or leak detection at scales previously not feasible. Used historically as a tool by the Department of Defense for military intelligence applications, the UAS continues to mature as a tool to provide near-real-time information to decision makers—now being adapted as a tool for use in the commercial sector. As with most new technologies, the UAS continues to evolve into forms that can support both industry and government to save money and gain efficiencies; enhancements to various technologies that comprise the aircraft and its sensors are critical to UAS-enhanced monitoring programs. Concurrently, the regulatory framework that enables commercial UAS operations must evolve quickly in order to merge with a compelling public benefit to monitor oil fields and pipelines for leaks.

Aerial imagery has traditionally been gathered using manned aircraft to document the status of well pads, pipeline corridors, and intermodal transportation hubs (i.e., a Cessna 172 with a color camera). UAS functionally provides the opportunity to gather the same kinds of information, yet provides further benefit by offering an alternate means of completing inspection tasks that reduce risk to employees while increasing situational awareness through concurrent use of multiple sensor types. Because employing a UAS inherently requires the use of airborne sensors, the data generated by a UAS can support documenting the status of pipeline system(s), often with greater accuracy than what current manned aircraft typically provide.

Sensors onboard a UAS are the most critical consideration when selecting a UAS as a monitoring tool. Even if the UAS is designed sufficiently to "fly" over a pipeline, if the sensor is poorly selected, the data generated will be nearly useless within predictive or proactive monitoring programs. Thus both near- and long-term benefits to the energy industry are dependent upon efforts that focus *sensors to identify scientifically defined indicators of leaks* (oil, gas, and water). Only once a definitive list of leak indications is defined can a valid list of aircraft sensors be selected and integrated into the aircraft. Likewise, the aircraft (flying machine) itself cannot be properly selected until the sensors have been identified (because of size, weight, and power considerations that impact small aircraft systems). Often, the UAS being flown lacks sensors that are specifically selected for a task, resulting in flying a machine for the purpose of generalized monitoring; for this reason, the effectiveness of a UAS as a monitoring tool has remained limited. To this end, the energy industry and the UAS industry must collaborate to develop the UAS into a tool that can best support leak detection and monitoring in the future (sensor-driven aircraft systems).

Automating the analysis of sensor data is the key to the success of proactively detecting leaks. Analytical engines that are capable of digesting massive volumes of sensor data are essential to the effectiveness of pipeline leak detection programs and instrumental if predictive leak detection is to be achieved. Perhaps more so than any other aspect of a leak detection program

(UAS or otherwise), timely, accurate, and persistent data analysis will ultimately generate the automated reports to focus repair crews prior to a leak (predictive analysis) or response crews to contain, repair, and remediate detected leaks (responsive postleak detection). UAS-enhanced monitoring programs can facilitate future gains in automating the analysis of sensor data while tackling real-world big-data challenges.

Existing communications networks used to transmit monitored data are insufficient for wide-scale use of UASs; establishing a robust, secure, and responsive communication network for UAS data will enable systemwide/oilfield monitoring for both UAS and other monitoring sensors. Beyond the direct purpose as a monitoring tool, UASs can function as airborne antennas and/or repeaters that can (help) cover existing communication gaps commonly found in the remote locations where pipelines traverse (areas that lack fiber or cellular networks). Being able to facilitate the movement of data to risk managers and response teams is equally important to properly identifying leaks, enabling robust communication networks that can seamlessly move data enables future UAS monitoring evolutions.

Aviation regulations that govern the use of UASs limit their use as a monitoring tool within the energy industry. Specifically, current Federal Aviation Administration (FAA) regulations generally limit long-distance UAS flight operations, such as flying over 300 miles of pipeline, largely because of UAS's inability to autonomously "detect and avoid" other aircraft (required to ensure no risk of collision), and UAS's inability to ensure "command and control" radio links with the pilot cannot be interrupted (casing a fly-away scenario of the UAS from the operator). Collectively, until solutions to these challenges are developed and approved for use (by the FAA), federal aviation regulations will limit large-scale UAS flight operations to within line-of-sight (LOS) of the pilot (generally accepted to be within 1 mile of the human operator so he can provide his/her own collision avoidance (like any other manned aircraft).

Enhancements and potential benefits related to the UAS as a monitoring tool:

- The energy industry would benefit from developing a standardized library of aerial imagery that, with certainty, allows for the use of a UAS to remotely image scenes on the ground to identify a spill or leak to scientifically document what types of sensor(s) are capable of quantifiably detecting them (active and passive sensors).

- Enhancing oilfield communication networks that transmit sensor data, combined with automating data analytics, is paramount to the success of UAS-enhanced monitoring programs if predictive/proactive leak detection is desired.

- Considerations should be made to characterize leaks of various fluids across all four seasons on representative surfaces (dirt, snow, pavement, and vegetation) and tie to real-world situations.

- Develop techniques to detect leaks that occur above and below the surface, including installations that are adjacent to or within bodies of water.

- Secondary indications of leaks/spills may come from gas plumes, resulting in the need to detect the presence of hydrocarbons through detection of gas leaks (i.e., carbon dioxide or methane), requiring the need to integrate potentially disparate sensors onboard the aircraft.

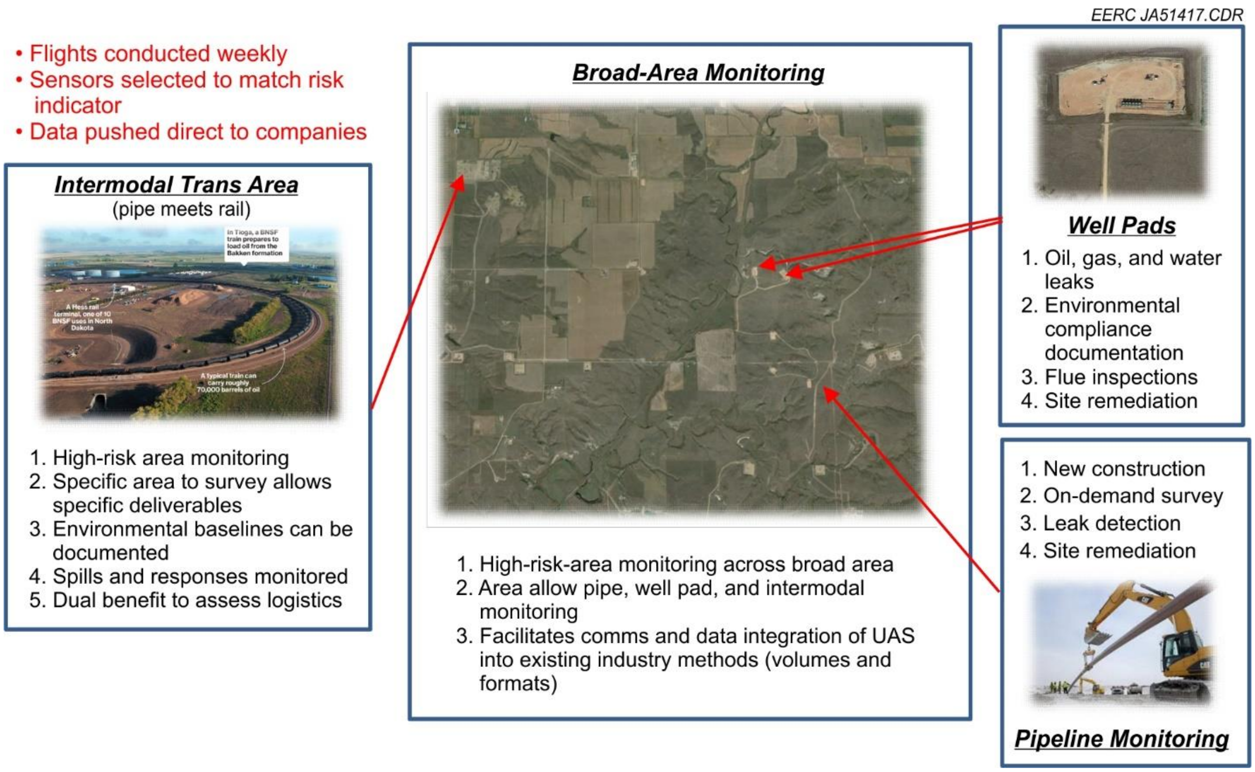


Figure J-1. Example applications for UAS-enabled pipeline monitoring.