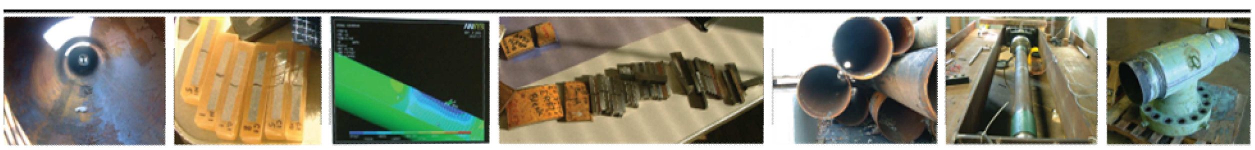
U.S. Department of Transportation
Pipeline and Hazardous Materials Safety
Administration

Final Report No. 12-173

Final Report

Leak Detection Study – DTPH56-11-D-000001

Dr. David Shaw, Dr. Martin Phillips, Ron Baker, Eduardo Munoz,
Hamood Rehman, Carol Gibson, Christine Mayernik
December 10, 2012



Kiefner & Associates, Inc.
585 Scherers Court
Worthinaton. Ohio 43085

(614) 888-8220
www.kiefner.com

0339-1201

Intentionally blank

Final Report No. 12-173

Final Report

on

LEAK DETECTION STUDY – DTPH56-11-D-000001

to

U.S. DEPARTMENT OF TRANSPORTATION

PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

December 10, 2012

by

Dr. David Shaw, Dr. Martin Phillips, Ron Baker, Eduardo Munoz,
Hamood Rehman, Carol Gibson, Christine Mayernik

Kiefner and Associates, Inc.
585 Scherers Court
Worthington, Ohio 43085

0339-1201

DISCLAIMER

This document presents technical issues identified based on engineering services performed by employees of Kiefner and Associates, Inc. The work addressed herein has been performed according to the authors' knowledge, information, and belief in accordance with commonly accepted procedures consistent with applicable standards of practice, and is not a guaranty or warranty, either expressed or implied.

The analysis and technical issues identified in this report are for the sole use and benefit of the Client. No information or representations contained herein are for the use or benefit of any party other than the party contracting with KAI. The scope of use of the information presented herein is limited to the facts as presented and examined, as outlined within the body of this document. No additional representations are made as to matters not specifically addressed within this report. Any additional facts or circumstances in existence but not described or considered within this report may change the analysis, outcomes and representations made in this report.

The authors stand behind their work as performed and presented. Conferring with industry associations as a whole was not included in the scope for this project, with the exception of input received during the public comment periods as part of the original scope of work, and for the draft report. Some operators were also interviewed as part of the work. It is understood there is a diversity of opinion about LDS that may reasonably exist among stakeholders within the industry.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF ACRONYMS

AC	Alternating Current
AGA	American Gas Association
ASV	Automated Shut-off Valve
ANPRM	Advance Notice of Proposed Rule-Making
AOPL	Association of Oil Pipe Lines
API	American Petroleum Institute
BBL	Barrels of oil
CAO	Corrective Action Order
CFR	Code of Federal Regulations
CPM	Computational Pipeline Monitoring
CRM	Control Room Management
CSA	Canadian Standards Association
DC	Direct Current
DOT	Department of Transportation
DSP	Digital Signal Processing
DTS	Distributed Temperature Sensing
EPA	Environmental Protection Agency
FIR	Failure Investigation Report
FLIR	Forward-Looking Infrared
FPU	Field Processing Unit
GTI	Gas Technology Institute
HCA	High Consequence Area
HVL	Highly Volatile Liquid
IMP	Integrity Management Plan
ISA	Instrument Society of America
ISO	International Standards Organization
LDS	Leak Detection System
LPG	Liquefied Petroleum Gas
LIDAR	Light Detection And Ranging
LSS	Leak Sensitivity Study

MSCF	Thousands of standard cubic feet of gas
NGL	Natural Gas Liquid
NTSB	National Transportation Safety Board
OPS	Office of Pipeline Safety
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPES	Pipeline Inspection, Protection, Enforcement, and Safety
PPA	Pressure Point Analysis
PPM	Parts Per Million
PRCI	Pipeline Research Council International
ROW	Right-of-way
RTTM	Real-Time Transient Model
SCADA	Supervisory Control and Data Acquisition
SPRT	Sequential Probability Ratio Test
TRFL	Technical Rule for Pipeline Systems (Germany)

Leak Detection Study – DTPH56-11-D-000001

Dr. David Shaw, Dr. Martin Phillips, Ron Baker, Eduardo Munoz, Hamood Rehman, Christine Mayernik

1.0 INTRODUCTION

This report responds to a request from the Pipeline Hazardous Materials and Safety Administration (PHMSA) for a study of leak detection systems (LDS) for hazardous liquid and natural gas pipelines. The requirements of the study were provided by PHMSA and these are reproduced in Appendix A of this section of the report. This report is a report to PHMSA.

This report does not provide any conclusions or recommendations. The report Summary is a summary of the work presented in other sections of the report. Readers wishing to draw conclusions may do so but the authors did not set out to make conclusions. The authors were tasked only to report data and technical and cost aspects of LDS to PHMSA in the time available for the project.

This report covers Tasks 3 to 7 described in Introduction Appendix A (Tasks 1 and 2 of the contract addressed a kick-off meeting and attendance at the March public workshop). Briefly, these five Tasks cover the following:

1. **Task 3:** An assessment of past incidents to determine if additional LDS may have helped to reduce the consequences of the incident.
2. **Task 4:** A review of installed and currently available LDS technologies along with their benefits, drawbacks and their retrofit applicability to existing pipelines.
3. **Task 5:** A study of current LDS being used by the pipeline industry.
4. **Task 6:** A cost benefit analysis of deploying LDS on existing and new pipelines.
5. **Task 7:** A study of existing LDS Standards to determine what gaps exist and if additional Standards are required to cover LDS over a larger range of pipeline categories.

The structure of this study report (including this introduction) is:

1. Introduction and Study Background.
2. Summary.
3. Task 3 report.
4. Task 4 report.
5. Task 5 report.

6. Task 6 report.
7. Task 7 report.

The intention with each Task report is to provide concise commentary on the purpose of the Task, the method used and the important technical issues identified. Each Task report will contain its own Appendices, as appropriate. This structure is intended to provide the reader with a systematic approach to the technical issues identified from this study.

This is a technical study and does not address regulatory issues, except briefly in Task 4 and Task 7. The study examines leak detection in the pipeline industry against a backdrop of recent past incidents, and through interviewing pipeline operators and vendors to the pipeline industry.

PHMSA held a Workshop on March 27, 2012, at which pipeline operators, industry trade associations and independent experts spoke to the topic of "Improving Pipeline Leak Detection System Effectiveness." Written comments were also received by PHMSA on this topic from interested parties. This report takes into account the presentations made at the workshop and the written comments.

The report focuses entirely on leak detection. It does not consider the causes of the leak. Neither does it consider the consequences of a leak or the mitigation of the consequences of a leak. There are small and large leaks. The industry divides the term "leak" into different categories depending on how the leak happened. LDS are therefore considered as covering all of these sub-categories, regardless of whether the industry may focus on the sub-categories separately. It is the detection of both small and large leaks that is considered within this report. The use of LDS for risk management is considered. Readers wishing to know more detail, particularly with regards to Task 3, can access the publically available data to obtain this information.

1.1 Study Background

Due to the vast mileage of pipelines throughout the nation, it is important that dependable leak detection systems are used to promptly identify when a leak has occurred so that appropriate response actions are initiated quickly. The swiftness of these actions can help reduce the consequences of accidents or incidents to the public, environment, and property.

Recognizing the importance of leak detection, the U.S. Department of Transportation (DOT), Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS) has included leak detection provisions and considerations in several sections of 49 CFR parts 192 and 195. A brief discussion of all applicable sections can be found below:

- Section 192.706, *Transmission lines: Leakage surveys*, requires operators to conduct leakage surveys on all regulated transmission lines. Transmission lines that transport unodorized gas must utilize a leak detector when conducting surveys. Leakage survey intervals will vary depending on the class location of the line.
- Section 192.723, *Distribution systems: Leakage surveys*, requires operators to conduct periodic leakage surveys using leak detectors in several locations. Leakage survey intervals will vary depending on the location of the systems (inside or outside of a business district).
- Part 192 Subpart O, *Gas Transmission Pipeline Integrity Management*, requires operators to take additional measures beyond those already required to prevent and mitigate the consequences of a pipeline failure in a high consequence area (HCA). Additional measures may include, among other things, installing computerized monitoring and leak detection systems. Under the regulation, natural gas operators are required to analyze the need and use of leak detection systems within the pipeline.
- Part 192 Subpart P, *Gas Distribution Pipeline Integrity Management (IM)*, requires operators to have a leak management program. The objective of this plan is to get operators to survey their lines for leaks and have a process by which they will manage and repair leaks that are identified.
- Sections 192.631 and 195.446, *Control Room Management (CRM)*, have inherent requirements that help improve leak detection for operators subject to the CRM regulations.
- Section 195.134, *CPM Leak Detection*, applies to each hazardous liquid pipeline transporting liquid in single phase (without gas in the liquid). On such systems, each new computational pipeline monitoring (CPM) leak detection system and each replaced component of an existing CPM system must comply with section 4.2 of API 1130 in its design and with any other design criteria addressed in API 1130 for components of the CPM leak detection system.
- Section 195.444, *CPM Leak Detection*, requires each computational pipeline monitoring (CPM) leak detection system installed on a hazardous liquid pipeline transporting liquid in single phase (without gas in the liquid) to comply with API 1130 in operating, maintaining, testing, record keeping, and dispatcher training of the system.
- Section 195.412, *Inspection of rights-of-way and crossings under navigable waters*, requires operators to survey along the pipeline rights-of-way and navigable waterways to inspect for signs of leakage. Leakage survey intervals will vary.
- Section 195.452, *Pipeline integrity management in high consequence areas*, requires operators to have a capability to detect leaks in these high consequence areas and must perform any modifications as necessary to assure and improve this capability. Leak

detection is included as one of the measures operators may take to prevent and mitigate the consequences of a pipeline failure to protect HCAs along their pipeline.

In addition to regulations, PHMSA also issued an Advisory Bulletin, ADB-10-01, issued on January 26, 2010. The advisory bulletin goal was to “advise and remind hazardous liquid pipeline operators of the importance of prompt and effective leak detection capability in protecting public safety and the environment.” The bulletin reminded operators of the importance of leak detection and their responsibilities to determine whether a computer-based leak detection system was appropriate for their pipeline.

The Pipeline Inspection, Protection, Enforcement, and Safety (PIPES) Act of 2006 explicitly drew attention to leak detection as part of an overall Integrity Management and Safety Program of a Pipeline. Under Sec. 21, PHMSA was required to produce a periodic leak detection technology study.

PHMSA released a Leak Detection Technology Study for the PIPES Act H.R. 5782 on December 31, 2007. The study described the capabilities and limitations of current leak detection systems used by hazardous liquids operators; issues identified during inspections and enforcement actions, which identified issues with leak detection capabilities; and research and development efforts.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Public Law 112–90 - JAN. 3, 2012), was signed into law on January 3, 2012. Section 8 of this law mandates that PHMSA, through the Secretary of Transportation, submit a leak detection report to Congress. This report will study leak detection systems utilized by operators of hazardous liquid pipeline facilities and transportation-related flow lines. Included in the study shall be an analysis of the technical limitations of current leak detection systems, including the ability of the systems to detect ruptures and small leaks that are ongoing or intermittent, and what can be done to foster development of better technologies and an analysis of the practicality of establishing technically, operationally, and economically feasible standards for the capability of such systems to detect leaks. The actual language from the Act is as follows:

Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011

SEC. 8. LEAK DETECTION.

(a) LEAK DETECTION REPORT.—

(1) IN GENERAL. — Not later than 1 year after the date of enactment of this Act, the Secretary of Transportation shall submit to the Committee on Commerce,

Science, and Transportation of the Senate and the Committee on Transportation and Infrastructure and the Committee on Energy and Commerce of the House of Representatives a report on leak detection systems utilized by operators of hazardous liquid pipeline facilities and transportation-related flow lines.

(2) CONTENTS.—The report shall include—

(A) an analysis of the technical limitations of current leak detection systems, including the ability of the systems to detect ruptures and small leaks that are ongoing or intermittent, and what can be done to foster development of better technologies; and

(B) an analysis of the practicability of establishing technically, operationally, and economically feasible standards for the capability of such systems to detect leaks, and the safety benefits and adverse consequences of requiring operators to use leak detection systems.

The National Transportation Safety Board (NTSB) issued the following safety recommendation to PHMSA in their San Bruno Pipeline Accident Report, PAR-11-01:

NTSB Recommendation P-11-10:

Require that all operators of natural gas transmission and distribution pipelines equip their supervisory control and data acquisition systems with tools to assist in recognizing and pinpointing the location of leaks, including line breaks; such tools could include a real-time leak detection system and appropriately spaced flow and pressure transmitters along covered transmission lines.

For actions conducted to date, the new Control Room Management (CRM) rule addresses human factors and other aspects of control room management for pipelines where pipelines use supervisory control and data acquisition (SCADA) systems. Under this rule, affected pipeline operators must define the roles and responsibilities of controllers and provide controllers with the necessary information, training, and processes to fulfill these responsibilities. Operators must also implement methods to prevent controller fatigue. The rule further requires operators to manage SCADA alarms, assure control room considerations are taken into account when changing pipeline equipment or configurations, and review reportable incidents or accidents to determine whether control room actions contributed to the event.

In addition, on August 25, 2011, PHMSA published an Advance Notice of Proposed Rulemaking (ANPRM), which requested comments regarding leak detection systems on natural gas pipelines.

As part of a larger study on pipeline leak detection technology, PHMSA conducted a public workshop in March 2012 on leak detection effectiveness. PHMSA is looking for this study to, among other aspects, examine how enhancements to SCADA systems can improve recognition of pipeline leak locations.

PHMSA may use the output of the study and other related initiatives to consider what additional actions by PHMSA are needed to address the NTSB recommendation.

As a result of the aforementioned Congressional mandate and NTSB recommendation, PHMSA has issued this task order for a leak detection study that will cover natural gas and hazardous liquid lines.

INTRODUCTION APPENDIX A: LEAK DETECTION STUDY REQUIREMENTS

Task 3 – Review and assess previous pipeline incidents

PHMSA will provide access to its pipeline incident data. The Contractor shall examine past pipeline incidents, including consideration of any non-PHMSA datasets that may provide useful insight and analysis to meet project objectives. Determinations shall be made to conclude whether implementation of further leak detection capabilities would have mitigated effects to the public and surrounding environment. Damage to surrounding environment/public must utilize standard fire science practices. The level of protection needed for adequate mitigation shall be determined.

Task 4 – Technological Feasibility

The Contractor shall compare all methods and determine whether current systems (or multiple systems) are able to adequately protect the public and environment from pipeline leaks and incidents. Legacy equipment currently utilized by operators shall be discussed. Ability to retrofit aforementioned legacy systems shall be addressed. All benefits and drawbacks of methods shall be discussed. Special consideration to the method/systems ability to detect small/intermittent leaks shall be made. Any technology gaps shall be identified and thoroughly explained.

Task 5 – Operational Feasibility

The Contractor shall analyze leak detection methods and systems that are currently being used throughout the industry. Leak detection methods and systems shall be defined and categorized. Methods shall range from visual inspection techniques, instrumented monitoring of internal pipeline conditions, and external instrumentation for detecting leaked hydrocarbons. A view of how many operators are adequately protecting their infrastructure with leak detection systems shall be portrayed. Operational aspects (i.e. procedures, protocols, best practices, workforce, etc.) shall be analyzed. Consideration of reliability, availability and maintainability system aspects shall be discussed. An analysis of how of further leak detection methods/system deployment would affect pipeline operations shall be conducted.

Task 6 – Economical Feasibility

The Contractor shall perform a cost benefit analysis for deploying leak detection systems on new and existing pipeline systems. Cost benefit shall determine the lifetime operational cost of the system and shall take into account the benefit that may be seen by the public and surrounding environment. The analysis shall focus on the entire pipeline infrastructure and a separate analysis shall be conducted to include pipelines in HCAs only. Damage to surrounding environment/public must utilize standard fire science practices.

Task 7– Discuss recommended leak detection standards

Draw together the technology gaps, operational capabilities, and economic feasibility and analyze the practicability of establishing technically, operationally, and economically feasible standards to provide adequate protection to the Nation against pipeline leaks, if such standards don't already exist. Analysis should be specific to the type of pipeline (gas distribution, gas transmission, hazardous liquid, etc.). Analysis shall take into consideration pipeline locations (i.e. Class Locations, HCAs).

2.0 SUMMARY

2.1 Overall Summary of Work

This section of the Leak Detection Systems (LDS) study summarizes the study and lists what the study considers are the significant technical issues related to all five Tasks covered by the report. This study report focuses on technical and economic issues of LDS. This study report does not address regulations associated with LDS, except briefly in Task 4 on LDS technology and Task 7 in relation to Standards.

For the purposes of this report, transport-related flow lines are referred to as hazardous liquid gathering lines. The latter term is common to the industry whereas transportation-related flow lines are newer terminology that is not in such widespread use at this time.

For this study, LDS is defined as any technology or method that can be employed by a pipeline operator to detect the loss of fluid from a pipeline and/or its associated fittings.

This study used the following sources to obtain the summary:

1. The PHMSA LDS Workshop and industry submissions (March 27, 2012)
2. The PHMSA incident report database from January 1, 2010 to July 7, 2012
3. PHMSA Corrective Action Orders (CAOs)
4. PHMSA Failure Investigation Reports (FIRs)
5. NTSB reports
6. Interviews with pipeline operators
7. Interviews and literature reviews for LDS vendors
8. Published Standards on LDS
9. Published Literature

The above information sources are not dealt with individually in the following report. They are used as sources in many different parts of the report.

The reporting covers five Tasks defined by PHMSA. The wording of these 5 Tasks can be found in Introduction Appendix A. Each Task forms a separate chapter and each chapter has its own tables, figures, and appendices, as appropriate. This report is a report to PHMSA.

The purpose of this report is to assess leak detection systems on pipelines. The report focuses entirely on leak detection. It does not consider the causes of the leak. Neither does it consider the consequences of a leak or the mitigation of the consequences of a leak. In Task 3, the authors did not examine data for mitigating circumstances. The authors did not analyze where a loss of containment occurred. The only issue analyzed was how a loss of containment was detected. Readers wishing more detail on how, and where large and small releases took place can analyze the PHMSA databases further. The detection of both small and large leaks was considered, not the consequences or locations or reason for the size of a leak.

The authors fully understand that different failure mechanisms are involved in the loss of containment (a release). The report is not concerned with the failure mechanisms, only detection of the release. As explained later, failure of a pipeline can result in the sudden release of a large volume of fluid in a short period of time. However, other failure mechanisms can result in a buildup of large volumes over a period of time. Timely detection of smaller release volumes per unit time is important to limit the total volume that escapes. With large volume releases per unit time, timely detection is paramount.

The mechanism for large volume releases per unit time is often a rupture of a pipe body or a pipe seam. However, pipeline operator data in the PHMSA database indicates that operators can have large volume releases per unit time that are classified as leaks and not ruptures. In addition, PHMSA does not define a rupture for operators reporting an incident in a way that succinctly refers only to a pipe or weld material rupture. In addition, PHMSA provides other classifications for an operator to choose other than leak or rupture. Hence, the report uses the volume of reported releases as a primary means of examining incident reports filed by pipeline operators with PHMSA.

This study is accompanied by a parallel study by PHMSA on automatic and remotely controlled valves. This study on LDS does not address this issue of shut-off valves in regards to the mitigation effects of loss of containment. This LDS study focuses on how an operator can detect (know) that there is loss of fluid containment and that the controller of the relevant pipeline must respond. The study does not consider control room processes or procedures in any specific detail but it should be noted that such procedures are an essential part of an LDS. The study focuses on the information that is given to the control room.

The study found that the pipeline industry considers LDS differently depending on whether pipelines transport hazardous liquids or natural and other gas. The study infers that many hazardous liquid operators are deploying some form of LDS but the incident reports reviewed from the PHMSA incident database suggest this may not be the case. The study also infers that many natural and other gas operators rely on SCADA as an LDS.

Leak Detection Systems

A leak detection system has no effect in reducing the likelihood of a leak occurring.

It is critical to remember that leak detection systems are *Systems* and can be usefully broken down into Personnel, Procedures and Technologies. Any implementation that focuses on less than all three of these components will not be optimal. The leak incidents that are studied in Task 3 include many where the response to the incident suffered from a weakness in just one of these areas, for example with excellent controllers and LDS technology, but poorly prepared procedures.

Also as a system, an LDS can be in several *States*. Integration using procedures is optimal when it is recognized that alarms from the technology are rarely black-and-white or on/off situations. Rather, at a minimum, there is a sequence: leak occurrence; followed by first detection; followed by validation or confirmation of a leak; followed by the initiation of a shutdown sequence. The length of time that this sequence should take depends on the reliability of the first detection and the severity of the consequences of the release. Procedures are critical to define this sequence carefully – with regard to the technology used, the personnel involved and the consequences – and carefully trained Personnel are needed who understand the overall system, including technologies and procedures.

We note that there is perhaps an over-emphasis of technology in LDS. A recurring theme is that of *false* alarms. The implication is that an LDS is expected to perform as an elementary industrial automation alarm, with an on/off state and six-sigma reliability. Any alarm that does not correspond to an actual leak is, with this thinking, an indicator of a failure of the LDS system. Instead, multiple technical studies confirm that far more thought is required in dealing with leak alarms. Most technologies infer the potential presence of a leak via a secondary physical effect, for example an abnormal pressure or a material imbalance. These can often be due to multiple other causes apart from a leak. The solution can be combination of technology – utilizing multiple redundant independent LDS, for example; procedures – specifying a check-list of other potential causes for the symptom, for example; or personnel – training controllers to understand the physical principles causing the alarm in more detail.

Current Mainstream Practice

Leak detection technologies are available in many different forms, and some are very complex. However, they do represent a wide range of performance indicators and costs that cover a wide range of requirements in terms of sensitivity, accuracy and reliability. Nevertheless, operators have a strong preference for leak detection that utilizes field equipment that is already in place. This accounts for the dominance of leak detection by Pressure/Flow Monitoring and CPM on all pipelines, since the monitoring is already provided by the SCADA system, and the CPM is a relatively inexpensive addition to an existing metering infrastructure. Where SCADA or metering systems are not already in place, they are rarely installed with the sole objective of leak detection.

It is acknowledged that Pressure/Flow Monitoring will catch, at best, large ruptures. Leak detection by CPM is limited by the accuracy of the metering and uncertainties in the line fill, both of which are a percentage of the pipeline flow rate. Therefore a high flow rate pipeline will be exposed quite naturally to large spills. This report explores why, despite the acknowledged shortcomings of these basic methods, they continue to dominate, and why there is general reluctance to upgrade to more complex methods.

SCADA and LDS

The study draws a distinction between supervisory control and data acquisition (SCADA) systems and LDS. SCADA is about controlling the pipeline operating parameters in response to normal operational requirements and abnormal situations. LDS is separate from SCADA in that it focuses on determining if there is an unintentional loss of fluid containment that requires remedial action. The LDS may use SCADA instrumentation but it is not necessary for all types of LDS to use SCADA.

A further clarification is considered necessary. The pipeline industry refers to leaks and ruptures. Release incidents reported to PHMSA are classified this way. PHMSA advises operators that a rupture is a situation where the pipeline becomes inoperable. The study topic is leak detection and the authors wish to convey that, in general, a rupture of a pipeline, piping or other pressurized fluid[1] container is a situation that needs to be detected very rapidly and responded to and contained in the shortest possible time. A rupture is generally a crisis situation that needs to be brought under control. Volume released from a rupture per unit time is much greater than where a pipe or other pressurized fluid container is leaking without rupturing.

It became clear after study that these classifications do not necessarily reflect the volume released across all incidents in a way that makes sense to use these classifications as data filters. That is, incidents described as leaks can also have reported large release volumes. Hence, KAI decided to ignore rupture and leak classifications entirely. Instead, the data was managed by dividing them between incidents along the right-of-way (ROW) and those incidents on operator property. The data assessment then proceeded with those incidents associated with a ROW, regardless of whether an operator had classified the incident as a leak or a rupture. For incidents

[1] Fluid refers to both the liquid and gaseous state inside a pipeline.

on operator property, it is considered that operators can monitor and maintain equipment more easily to prevent leaks or ruptures than on long lengths of buried pipeline.

Types of Leak Detection

Leak detection systems are intended to detect all three: Leaks, Ruptures and small Seeps. Therefore, it is important to remember that different LDS are typically appropriate for each of these three categories of fluid loss. In principle, an LDS intended for rupture mitigation need not be very sensitive, but should be very fast. An LDS intended for leaks may take longer to detect a loss, but should be sensitive and reliable in its diagnosis. It should also try to provide information to assist with localization, since the release may not yet be visible to fly-over or walking patrols. LDS for small seeps may be performed using intermittent high-resolution inspection, perhaps using in-line tools or the newer fly-over technologies.

Leak detection systems are most valuable by providing continual monitoring between periodic over-line surveys, and where operators cannot easily inspect the actual pipe and fittings for leaks. These locations are mostly on long distances of buried pipe. Pipe, welds and appurtenances associated with the overall pipeline and its facilities that are above ground are locations that can be checked by operators frequently and much more easily than for buried pipe. Nevertheless, remote LDS is valuable at remote and un-manned surface facilities.

Incident Reports

Task 3 reviews PHMSA incident reports. The volume of unintentional releases reported in the PHMSA incident reports vary over a large range. There are some large release volumes and a lot of small release volumes in the incident data studied. Generally, the large volumes are those that have the most impact on people, property and environment. The study has not defined a large release volume but instead has separated those incident reports with above-average release volumes from those below average release volumes on the pipeline ROW.

In all three categories of pipeline, hazardous liquids, natural and other gas transmission and gathering and natural and other gas distribution, ROW incidents and above- average release volume incidents on the ROW provide adequate numbers of incidents for the purpose of this study.

Task 3 of the report summarizes pipeline operator supplied data for all release volumes over the 30-month period from January 1, 2010 to July 7, 2012. Release volume was used as the primary means to sort the data. It was then further divided between ROW and operator property for reasons given in the section on Task 3. Pipeline operators report to PMHSA under three different categories: hazardous liquid pipeline systems, natural and other gas transmission and gathering pipeline systems, and gas distribution systems. These three reporting categories are used in Task 3.

While all release volumes are reported in all categories, a separate report is provided on large volume releases, regardless of the mechanism for the loss of containment or the location of the release. This separate reporting was to look more closely at the detection of large volume releases without including the much larger number of small volume releases.

The data supplied by pipeline operators to the PHMSA incident databases is not always complete. It is the pipeline operator's responsibility to ensure the completeness and accuracy of the data. Operators are allowed to file supplementary reports to both update and correct data. The authors in Task 3 of this report used incomplete filings as best they could. However, the authors did not have the resources to check the accuracy of the data used. Hence, the authors do not accept responsibility for any inaccurate or incomplete data supplied or not supplied by operators.

Task 3 also used PHMSA Corrective Action Orders and Failure Investigation Reports, which are publically available from the PHMSA website. The authors took this information at face value and did not have the resources to check this publically available information with specific operators. Therefore, the authors do not take responsibility that this information is accurate.

The reporting performed of operator data in Task 3 was intentionally simple. As previously stated, the purpose was to assess detection of loss of containment as reported by operators. The purpose was not to perform an in depth study of these databases to extract fine detail or cross reference different data types. A statistical or probabilistic analysis was not performed. That was not the intent. The data were ranked by release volumes and presented in both graphical and tabular format for communication to PHMSA. The number of incident reports in each operator category was considered adequate to represent what operators have reported for incidents over the 30 month period used. The results presented here are not considered to have misrepresented what operators have reported.

If additional detail is required by industry based on the PHMSA incident reporting databases, this can be performed but is outside the scope of this report.

Internal and External Detection

Task 4 covers the summary of the limitations of current LDS technology. The objectives in Task 4 are:

- A technical study of the state-of-the-art and current industry practices.

- A comparison of LDS methods to determine whether current systems (or multiple systems) are able to adequately protect the public and environment from pipeline leaks and incidents:
- Legacy equipment currently utilized by operators
- Ability to retrofit legacy systems
- Benefits and drawbacks of LDS methods
- Ability to detect small/intermittent leaks
- Identification and explanation of current technology gaps

In particular, with regard to gas pipelines, we reviewed SCADA system tools to assist in recognizing and pinpointing the location of leaks, including line breaks; including real-time leak detection systems and appropriately spaced flow and pressure transmitters along covered transmission lines.

The approach to this technical review is two-fold. It covers the purely technical engineering analysis components of Task 4, including:

- An analysis of the current state-of-the-art and accepted best practices
- Ability to retrofit legacy systems, benefits and drawbacks of LDS methods, and ability to detect small/intermittent leaks, from a technical and theoretically practical point of view
- An identification of major current technology gaps

It also includes a study of actual operator technology choices and current industry practices, summarizing direct contacts with industry operators and technology suppliers.

This review covers both internal LDS and external LDS. Internal LDS is an LDS that uses the flow and pressure within the pipeline to detect a potential rupture or leak. External LDS is LDS that senses, by some means, that fluid is escaping from the pipeline from outside of the pipeline.

Task 4 also reports on interviews held with nine liquids pipeline companies – including two smaller crude oil and petroleum products pipelines; five gas transmission pipelines; and five gas distribution pipelines.

Interviews were also held with twelve technology suppliers covering Computational Pipeline Modeling (CPM, four suppliers); Acoustic and Pressure Wave Analysis (four suppliers); Fiber optic cables (two suppliers); Hydrocarbon sensors (two suppliers); and Thermal imaging (two suppliers). Note that two of these suppliers develop multiple technologies.

The technology part of the interviews covered three purely technical issues:

1. Technology in place at present
2. Performance of current systems and current technology “gaps”
3. Retrofit capability, and plans for retrofitting and improving current technology

Task 5 reports on operational feasibility of LDS including the following objectives:

- A technical study of recommended best operational procedures and current industry practices
- Consideration of reliability, availability and maintainability
- Risk assessment and benefit assessment
- Testing, maintenance, training and qualification, and continual improvement

The approach to this technical review is two-fold. It covers the purely technical engineering analysis components of Task 5, including:

- An analysis of the current standards and accepted best practices
- Current operational regulations and guidelines

It also includes a study of actual operator choices and current industry practices, summarizing direct contacts with industry operators and technology suppliers.

Task 6 reports on the economic feasibility of LDS. The principles of cost benefit analysis for deploying leak detection systems on new and existing pipeline systems are covered. Typical cost elements for equipping a new, and retrofitting an existing, pipeline system are listed as a guideline – covering the technical options presented in Task 4 above but focusing on SCADA and CPM based leak detection, as is the norm today.

The cost benefit is based on the lifetime operational cost of the system. Variables including the benefits to the public and surrounding environment are assessed. These are markedly different for pipelines that are situated within HCAs.

Task 7 reviews and discusses current LDS standards. It draws together the technology gaps, operational capabilities, and economic feasibility and analyze the practicability of establishing technically, operationally, and economically feasible standards to provide adequate protection to the Nation against pipeline leaks, if such standards don’t already exist.

2.2 Overall Summary

For simplicity, the overall summary is listed under each Task and its topic to assist the reader on where to look for additional information.

Overall Summary for Task 3 - Review and Assess Previous Pipeline Incidents

Table 2.1 summarizes some of the data reported for Task 3.

Table 2.1 Summary, January 1, 2010 to July 7, 2012

Metric	Hazardous Liquids Pipelines	Natural Gas Transmission	Natural Gas Distribution	Total
# of Release Incidents	766	295	276	1,337
# of Ruptures	21	41	13	75
# of Leaks	567	136	63	766
# of Mechanical Punctures	33	25	51	109
# of Overfill or Overflow	46	0	0	46
# of Other Release Types	99	93	149	341
# Contained on operators property	521	95	4	620
# Started on operators property	41	0	0	41
Releases Located on right-of-way (ROW)	197	141	42	381
# of Ruptures	12	33	13	58
# of Leaks	139	61	63	263
# of Mechanical Punctures	27	22	51	112
# of Other Release Types	19	25	0	44
# of Pipe body release incidents on ROW	119	86	30	205
# of Pipe seam release incidents on ROW	13	6	-	19
# of valve release incidents on ROW	17	6	-	23
# of flange incidents on ROW	5	1	-	6
# of other reason incidents on ROW	43	42	-	85
Maximum release volume (gals or MSCF)	843,444 gallons	614,257 MSCF	25,555 MSCF	-
First to Identify Release Incident on ROW				381
Air Patrol	10	5	-	15
Pipeline Controller	10	1	-	11
CPM LDS or SCADA	23	21	1	45
Ground Patrols	4	7	4	15
Local Operating Personnel	38	40	50	128
Emergency Responder	14	4	157	175
Public	45	38	19	102
Pressure Test	2	-	-	2
Other	8	10	13	31
Third Party causing the release	-	15	32	47

Observations from the work performed on Task 3, based on pipeline operator data submitted to PHMSA between January 1, 2010 and July 7, 2012 for hazardous liquid pipelines were:

1. The pipeline controller/control room identified a release occurred around 17% of the time.

2. Air patrols, operator ground crew and contractors were more likely to identify a release than the pipeline controller/control room.
3. An emergency responder or a member of the public was more likely to identify a release than air patrols, operator ground crew and contractors.
4. A CPM LDS was the leak identifier in 17 (20%) out of 86 releases where a CPM system was functional at the time of the release.
5. SCADA was the leak identifier in 43 (28%) out of 152 releases where a SCADA was functional at the time of the release.
6. For hazardous liquid pipelines, SCADA or CPM systems by themselves did not appear to respond more often than personnel on the ROW or members of the public passing by the release incident.
7. It appeared that procedures may have allowed alarms to be ignored or to re-start pumps or open a valve by controllers in several of the larger volume releases, thus increasing the size of the release.
8. Large distances between block valves may also have been a contributory factor in the size of some releases.
9. In 132 incidents along the ROW where a leak/rupture occurred on a pipe body or pipe seam, there were 28 incidents above the average volume release and 104 below the average volume of 29,230 gallons
10. The chances of having an above-average release volume were around 1 in 5. That is a release volume greater than around 29,230 gallons.
11. For 32 out of 68 incidents the pipeline shut down time was between 1 and 14 minutes.
12. For 27 out of 68 incidents the pipeline shut down time was between 15 and 40 minutes.
13. For 8 out of 68 incidents the pipeline shut down time was between 1 hour and 44 hours and 30 minutes.

Observations from the work performed on Task 3, based on pipeline operator data submitted to PHMSA between January 1, 2010 and July 7, 2012 for natural gas transmission pipelines were:

1. The pipeline controller/control room identified a release occurred around 16% of the time.
2. Air patrols, operator ground crew and contractors were more likely to identify a release than the pipeline controller/control room.

3. An emergency responder or a member of the public was equally likely to identify a release as air patrols, operator ground crews or contractors.
4. SCADA was the leak identifier in 21 (15%) out of 141 releases where a SCADA was functional at the time of the release.
5. For gas transmission pipelines, SCADA did not appear to respond more often than personnel on the ROW or members of the public passing by the release incident.
6. Large distances between block valves may also have been a contributory factor in the size of some releases.
7. For 92 incidents along the ROW where a leak/rupture occurred in a pipe body or pipe seam, there were 22 incidents above the average volume release and 70 below the average volume of 23,078 MSCF.
8. The chances of having an above-average release volume were around 1 in 4. That is a release volume greater than around 23,078 MSCF.
9. For 40 out of 101 incidents the pipeline shut down time was between 5 minutes and 1 hour.
10. For 61 out of 101 incidents the pipeline shut down time was longer than 1 hour.

Observations from the work performed on Task 3, based on pipeline operator data submitted to PHMSA between January 1, 2010 and July 7, 2012 for gas distribution pipelines were:

1. The pipeline controller/control room identified a release occurred less than 1% of the time.
2. Operator ground crew and contractors were much more likely to identify a release than the pipeline controller/control room.
3. An emergency responder or a member of the public was around 3 to 4 times more likely to identify a release than operator ground crews or contractors.
4. People causing third party damage reported around 1 in 8 releases.
5. Based on the incident reports submitted to PHMSA by pipeline operators, releases on gas distribution lines were more likely to ignite and more likely to explode than releases on gas transmission and hazardous liquids pipelines. Hazardous liquids were the least likely to ignite and explode.

Overall Summary for Task 4 - Technological Feasibility

The overall technical issues identified from the work performed on Task 4 were:

1. This report is an update to the Leak Detection Technology Study for the PIPES Act (H.R. 5782) published by the U.S. Department of Transportation on 31 December 2007. This update confirms the summary of the 2007 Study. It also aims for a definition of technical gaps, a more precise differentiation among forms of Internal LDS, and a simplified exposition of the forms of External LDS.
2. LDS are engineered systems. This means that precisely the same technology, applied to two different pipelines, can have very different results. Even simple technology, applied carefully, can yield very useful leak detection.
3. Recommended best practices for leak detection for gas pipelines are lacking, as are best practices for external sensor-based leak detection.
4. Many technologies have been adopted from other process industries that involve fluid movement, including storage, the chemical process industries, water distribution, and the nuclear industry.
5. Unlike most other subsystems used on a pipeline, LDS do not have nameplate or rated performance measures that can be used universally across all pipelines. This is particularly true of CPM where computer software, program configuration and parameter selection all contribute, in unpredictable ways, to overall performance.
6. Many performance measures present conflicting objectives. For example, leak detection systems that are highly sensitive to small amounts of lost hydrocarbons are naturally also prone to generating more false alarms.
7. The performance of a leak detection system depends critically on the quality of the engineering design, care with installation, continuing maintenance and periodic testing. Differences in any one of these factors can have a dramatic impact on the ultimate value of a leak detection system.
8. There is no technical reason why several different leak detection methods cannot be implemented at the same time. In fact, a basic engineering robustness principle calls for at least two methods that rely on entirely separate physical principles.
9. Practically all Internal LDS technologies applicable to liquids pipelines apply equally well to gas pipelines in principle also. Because of the much greater compressibility of gas, however, their practical implementation is usually far more complex and delicate. Because of these difficulties, most gas operators therefore avoid attempting their implementation.
10. Even though an internal technology may rely upon a relatively simple, basic principle like mass balance, it is a complex overall system. For a mass balance system to work it requires robust metering, robust SCADA and telecommunications, and a robust computer to perform the calculations. Each of these subsystems is individually complex.
11. Pressure/Flow Monitoring, while very widespread, has known limitations. For example:

a. In gas systems, a downstream leak may have almost no effect on flow rate

b. With gas pipelines, only a relatively large fluid loss will cause a measurable pressure drop within normal error limits if the leak is far away from the pressure sensor.

c. Near the inlet and the outlet of the pipeline a leak leads to little or no change in pressure.

d. Flow rates and pressures near any form of pumping or compression will generally be insensitive to a downstream leak

12. External leak detection is both very simple – relying upon routinely installed external sensors that rely upon at most seven physical principles – and also confusing, since there is a wide range of packaging, installation options, and operational choices to be considered.
13. External leak detection sensors depend critically on the engineering design of their deployment and their installation.
14. External sensors have the potential to deliver sensitivity and time to detection far ahead of any internal system.
15. Most technologies can be retrofitted to existing pipelines. The few exceptions are noted in the Task 4 analysis. In general, the resistance to adopting external technologies is, nevertheless, that fieldwork on a legacy pipeline is relatively expensive.
16. The main identified technology gaps – including those identified by operators – include: reduction or management of false alarms; applicable technical standards and certifications; and value / performance indicators that can be applied across technologies and pipelines.

Overall Summary for Task 5 - Operational Feasibility

The overall technical issues identified from the work performed on Task 5 were:

1. In principle, a cost-benefit analysis of an LDS involves a risk reduction analysis, a performance analysis of the LDS, and an engineering design that includes a costing. Operators rarely evaluate the benefits, included in the first two items, in detail.
2. Testing, Maintenance, Control Room Procedures, Training and Continual Improvement are the main operational issues that an operator must consider.
3. Gas pipelines are given very little guidance with these issues, either by the industry associations or by regulations. Liquids pipelines have a complete statement of principles in the CFR. It is our opinion that a complete re-development of these operational guidelines is unnecessary, since the basic principles of responsible operations are very similar.

4. Additional, internal standards at pipeline companies are important since with leak detection “one size does not necessarily fit all”.
5. Since flow metering is usually a central part of most internal leak detection systems, flow meter calibration is by far the most laborious part of an internal system’s maintenance. Also, the central computer and software technology usually has maintenance requirements far greater than most industrial automation and need special attention.
6. A particular organizational difficulty with leak detection is identifying who “owns” the leak detection system on a pipeline. A technical manager or engineer in charge is typically appointed, but is rarely empowered with global budgetary, manpower or strategic responsibilities. Actual ownership of this business area falls variously to metering, instrumentation and control, or IT.

Overall Summary for Task 6 - Economical Feasibility

The overall technical issues from the work performed on Task 6 were:

1. With a few notable exceptions, the benefit of leak detection is best understood as a reduction in risk exposure, or asset liability. This has a hard, economic definition and is understood by investors.
2. Leak detection systems have a very long lifetime. Over a total lifecycle, the cost-benefit approaches the reduction in asset liability caused by the system, divided by annual operational costs. Since the latter is small and the former usually quite large, cost-benefit for these systems is typically very good.
3. Nevertheless, operator practice is instead to budget over a 1 – 5 year timeframe, not total lifecycle. In this case, the cost-benefit is closer to the reduction in asset liability divided by capital costs. Since the latter is rather greater than annual recurring costs, the cost-benefit accordingly appears rather worse.
4. Generally, overall full-lifecycle costs of an LDS are minor compared with other systems on the pipeline: automation and control, metering, inspection and maintenance, for example. The difficulty lies in convincing operators of their value so that they do not waste their investments.
5. Objectively, the largest cost element in any LDS is the investment in personnel who understand, manage, plan and improve leak detection within the pipeline company. Any leak detection beyond the simplest of technologies soon requires these experts.
6. Any form of regulation impacts budget processes. None of the operators we contacted assume the risk of non-compliance with binding standards.

Overall Summary for Task 7 - Discuss Recommended Leak Detection Standards

The technical issues from the work performed on Task 7 were:

1. In our opinion the sections of API RP 1149 that describe the *principles* of how to assess the performance of a leak detection system on a liquids pipeline also apply well to gas pipelines.
2. Similarly, most recommended practices for internal LDS contain principles that are valuable for external systems as well. Equivalent standards for external systems would be very useful to the industry.
3. The Canadian CSA Z662 standard expands in several useful ways on the 49 CFR 195, including by setting measurable performance standards for leak detection.
4. Other potential overseas regulation that has been successful includes the German TRFL regulations and several derivatives in Europe, and the U.K. DTI regulations for safety of offshore pipelines.

3.0 TASK 3: REVIEW AND ASSESSMENT OF PREVIOUS PIPELINE INCIDENTS

3.1 Introduction

Task 3 is about assessing past leak incidents. The purpose of the task as given by PHMSA to KAI is repeated below under "Purpose of Task 3."

In responding to the task requirements, KAI decided to use mostly PHMSA material and base the assessment on incident reports between January 1, 2010 and July 7, 2012. The work presented here follows the way in which PHMSA incident reports are divided between hazardous liquids, gas transmission and gathering, and gas distribution. The results are presented in a top-down fashion, starting first with the big picture, and then looking at incidents along a right-of-way (ROW). These ROW of incidents are further separated into those involving only pipe and pipe seams, with above-average release volumes analyzed further. From the above-average release volume incidents, case studies were selected.

The detail of the method used is described followed by a short discussion on leak and rupture to assist the reader with the definition of these two terms as they relate to this report and leak detection systems. This review was not intended to be an exhaustive summary of the incident data provided by pipeline operators. This review does not provide conclusions or recommendations. It provides data based on a simple review of the data in the incident reports filed with PHMSA by pipeline operators. Where data in these incident reports is incorrect or flawed in some way, then these flaws carry through to the results presented here. The incident reporting process is not a one-time process. Pipeline operators can revise, correct and update filings on an incident as the details of an incident become clarified. Some incident reports are not complete. The authors have managed incomplete reporting as best they could with the resources and time available to perform this work.

Where operators may have updated incident reports after the cut-off date of July 7, 2012, then this updated data is not included in this analysis.

3.2 Purpose of Task 3

The purpose of Task 3 is the following:

> *"The Contractor shall examine past pipeline incidents, including consideration of any non-PHMSA datasets that may provide useful insight and analysis to meet project objectives. Determinations shall be made to conclude whether implementation of further leak detection capabilities would have mitigated effects*

to the public and surrounding environment. Damage to surrounding environment/public must utilize standard fire science practices. The level of protection needed for adequate mitigation shall be determined.”

3.3 Method

To respond to Task 3, KAI used the following data sources:

1. PHMSA LDS Workshop and industry submissions (March 27, 2012)
2. PHMSA incident report database from January 1, 2010 to July 7, 2012
3. PHMSA Corrective Action Orders (CAOs)
4. PHMSA failure investigation reports (FIRs)
5. NTSB reports
6. Interviews with pipeline operators
7. Interviews and literature reviews for LDS vendors
8. Published Standards on LDS.
9. Published Literature

The above information sources are not dealt with individually in the following report on Task 3. The following describes the methodology in more detail including the section titles that are used in the remainder of this report.

This study is confined to incidents that have occurred on onshore pipelines. The categories of pipeline that have been evaluated are:

1. Hazardous liquids, including crude oil, refined products and highly volatile liquids, known as HVLs, including gathering lines (transportation-related flow lines).
2. Natural gas transmission and gathering.
3. Natural gas distribution.

The study is not concerned with the cause of a leak or rupture, although references may be made to the causes of a spill when discussing the data.

The detailed data review is confined to those incidents that have been reported between January 1, 2010 and July 7, 2012. This start date marks the introduction of the new format of PHMSA incident reporting forms. These new forms request additional data relevant to this study whereas the forms prior to 2010 where less detailed. The number of incidents studied is considered sufficiently adequate to enable a satisfactory summary to be made with respect to Task 3.

The study of these data sources has yielded results that are described in following sections, namely:

1. Leaks and Ruptures
2. The Big Picture
3. Specific Data Selected for ROW Assessments
4. Incident Reporting for the Hazardous Liquid Pipeline Industry on the ROW
5. Above Average Hazardous Liquid Releases
6. Hazardous Liquid Gathering Lines (Transportation-Related Flow Lines)
7. Hazardous Liquid Case Studies
8. Incident Reporting for the Natural Gas and Other Gas Transmission and Gathering Industry
9. Natural Gas and Other Gas Transmission Case Studies
10. Incident Reporting for the natural gas and other gas distribution industry
11. Above Average Gas Transmission Releases
12. Natural Gas and Other Gas Transmission Case Studies
13. Incident Reporting for the Natural Gas and Other Gas Distribution Industry

3.4 Leaks and Ruptures

The pipeline industry refers to leaks and ruptures. A rupture is generally considered as a situation where the pipeline becomes inoperable. A leak is where operation of the pipeline and its facilities can continue operating as intended.

The study topic is leak detection and the authors wish to convey that, in general, a rupture of a pipeline, piping or other pressurized fluid[2] container is a situation that needs to be detected and contained in the shortest possible time. When a pipeline ruptures, the volume of escaped fluid escaping can be unavoidably large even if detection, response, and containment are performed very quickly.

If detection and shutdown is not acted on as soon as a rupture occurs the consequences can escalate. It is desirable not to have pipeline ruptures. Leaks and ruptures are not to the same scale in terms of fluid lost per unit time. Leaks and ruptures should not be considered a single class of pipeline failure because they are not.

[2] Fluid refers to both the liquid and gaseous state inside a pipeline.

Fluid volume released from a rupture per unit time is much greater than for a pipe or other pressurized fluid container that is leaking but has not ruptured. Hence, the extent of the consequences from a rupture can be greater than for a leak in relation to the time at which the fluid first started escaping from the pipeline system. However, leaks that continue for some time without detection can also have significant consequences because they are not detected.

Leak detection systems are principally about identifying leaks when you do not know where to look or cannot easily inspect the actual pipe and fittings for leaks. These locations are mostly on long distances of buried pipe. Pipe, welds, and appurtenances associated with the overall pipeline and its facilities that are above ground are locations that can be checked by operators frequently and much more easily than for buried pipe.

To provide meaningful answers from the chosen data sources, KAI considered how to address leak and rupture descriptions, as provided by operators in the PHMSA incident reports. It may seem obvious to filter the incident report database in this way because of the obvious differences between a rupture event and a leak event. It became obvious after study that these classifications do not necessarily reflect the volume released across all incidents in a way that makes sense to use these classifications as data filters. That is, incidents described as leaks can also have reported large release volumes. Some incidents described by operators as leaks are also large volume releases per unit time. In addition, leak and rupture are not the only classifications used in the incident reports to describe a release. Hence, KAI decided not to use rupture and leak classifications in this study because of the way the release classifications are reported in the PHMSA databases. This does not mean that rupture and leak classifications are equal or the distinction is not important. It means that classifying the data by volume released was more appropriate to this study in the time available and with the resources at hand.

If industry needs better resolution of performance on true ruptures of pipe or weld material then additional analyses of the PHMSA databases can be performed and published. But this study is about leak detection and not the mechanism that caused loss of containment.

The data were managed by dividing them between incidents along the right-of-way (ROW) and those incidents on operator property. The data assessment then proceeded with those incidents associated with a ROW, regardless of whether an operator had classified the incident as a leak or a rupture.

3.5 The Big Picture

Before focusing on incident data associated with ROW releases, this section provides some metrics for all release locations between January 1, 2010 and July 7, 2012. The purpose of looking at the entire data set from this period is to provide context for how many incidents were reported to PHMSA over the 30-month period and how data was selected for evaluation required by Task 3.

Table 3.1, "All Incidents, January 1, 2010 to July 7, 2012," provides these metrics from this study covering the 2010 to 2012 incident data set.

In covering hazardous liquid, natural and other gas transmission and distribution pipelines, it is important to note that:

1. Hazardous liquid pipelines transport different types of fluid whereas the natural gas systems only transport natural gas.
2. Hazardous liquid pipelines transport:
    a. Crude oil
    b. Refined products
    c. Highly volatile liquids
3. Refined products are liquids such as:
    a. Gasoline
    b. Diesel
    c. Fuel oil
    d. Jet fuel
    e. Kerosene
4. Refined products are liquids inside the pipeline and usually remain liquids when released from the pipeline.
5. Highly volatile liquids are liquids inside the pipeline and gases when outside the pipeline at ambient conditions.
6. Highly volatile liquids are such liquids as:
    a. Liquefied petroleum gas (LPG)
    b. Natural gas liquid (NGL)
    c. Anhydrous ammonia
    d. Ethane
    e. Propane
    f. Butane
    g. ISO-butane
    h. Ethylene
    i. Propylene
    j. Butylene
    k. Mixtures
7. LPG is mostly propane and butane.

8. NGL is mostly ethane, propane, butanes and higher order saturated hydrocarbons.
9. The remaining liquids transported by pipeline are hydrogen and carbon dioxide.

Whether or not a fluid release ignites or results in an explosion is not covered in any detail by this study but it is mentioned for context. Neither does the study specifically cover injuries or fatalities but they are mentioned when considered appropriate. These consequences while highly undesirable are not needed by this study. However, ignition, explosion, fatalities and injuries may be mentioned to provide an indication of the severity of some incidents.

Table 3.1 needs explanation. The table is separated into 3 parts to assist with interpretation. The first section contains statistics based on the total number of incidents on the first row of the table totaling 1,337 reports. The second section starts with the total number of incidents recorded as on a ROW, of which there are 383. The totals on the ROW are then separated into different categories. For example, private or public property is a category used for gas distribution only. Hazardous liquids and gas transmission refer to ROW pipe and appurtenances. The final section of Table 3.1 relates to maximum and average release volumes for the three different industry categories, which are pipe on the ROW, a release not on the ROW, and for all onshore incidents assessed over the 30 month period.

Table 3.1 presents data where the rules for reporting data to PHMSA differ between hazardous liquids, gas transmission and gathering and gas distribution, respectively. For hazardous liquids, incident reporting to PHMSA is required for the following:

If the release is at least 5 gallons but is less than 5 barrels with no additional consequences (see below), complete only the fields indicated by light-grey shading. If the spill is to water as described in §195.52(a)(4) or is otherwise reportable under §195.50, then the entire Form PHMSA F 7000-1 must be completed.

The entire form must be completed for any release that:

• Involves death or personal injury requiring hospitalization; or
• Involves fire or explosion; or
• Is 5 barrels or more; or
• Has property damage greater than $50,000; or
• Results in pollution of a body of water; or
• In the judgment of the operator was significant even though it did not meet these criteria.

For gas transmission and gas distribution, incident reporting to PHMSA is required for the following:

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

> (i) A death, or personal injury necessitating in-patient hospitalization;
>
> (ii) Estimated property damage of $50,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost.
>
> (iii) Unintentional estimated gas loss of three million cubic feet or more;

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

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

The 1,337 incident reports are divided as 766, 295, and 276 for hazardous liquids, gas transmission and gathering and gas distribution, respectively. In Table 3.1, each of these totals is broken down into the following categories:

1. Number of ruptures
2. Number of leaks
3. Number of mechanical punctures
4. Number of overfill or overflow releases (hazardous liquids only)
5. Number of other release types
6. Number offshore releases (not included in following numbers)
7. Releases contained on operators property
8. Releases started on operators property (hazardous liquids only)
9. Releases located on right-of-way (ROW)
10. Releases located on private property (gas distribution only)
11. Releases located on public property (gas distribution only)
12. Number of nil reports for locations of spill
13. Number of pipe body release incidents on ROW

14. Number of pipe seam release incidents on ROW
15. Number of valve release incidents on ROW
16. Number of flange release incidents on ROW
17. Number of other reason release incidents on ROW
18. Maximum release volume (gallons or MSCF[3]) from pipe on ROW
19. Maximum release volume (gallons or MSCF) not on ROW
20. Average release volume (gallons or MSCF) from pipe on ROW
21. Average release volume (gallons or MSCF) from pipe not on ROW
22. Average release volume (gallons or MSCF) for all onshore incidents
23. Number of onshore incidents greater than average release volume as a percentage of all onshore release incidents.

The 1,337 incident reports divided as 766, 295, and 276 for hazardous liquids, gas transmission and gathering and gas distribution, respectively, are further divided in Table 3.1 in to 21, 41, 13 ruptures respectively, and 567, 136, 63 leaks, respectively for each of these three pipeline categories. For mechanical punctures, hazardous liquids pipelines reported 33, gas transmission reported 25, and gas distribution reported 51. A mechanical puncture is a separate PHMSA release classification that is not reported as a leak or a rupture. Overfill or overflow releases are only applicable to hazardous liquids and in the case of the 766 incident reports, 46 incidents were reported by operators as attributable to this cause. Other release types (Other is a separate classification) accounted for 99 hazardous liquid releases, 93 gas transmission releases and 149 gas distribution releases. The number of releases contained on an operator's property was 521 for hazardous liquid operators, 95 for gas transmission operators and 4 for gas distribution operators.

Of the metrics in Table 3.1, the releases on the ROW are the metrics most important to this study. The ROW metrics are divided into releases from pipe body, pipe seam, valves, flanges, and other fittings. Because gas distribution is reported differently than hazardous liquids and gas transmission and gathering, gas distribution is not strictly comparable to these other two transmission pipeline categories. Hence, numbers are not given for gas distribution for pipe seam, valves, flanges and other causes.

The maximum, single hazardous liquid release volume on the ROW from pipe was 843,444 gallons. This was a crude oil spill. The maximum, single gas transmission release volume on the ROW from pipe was 614,257 MSCF. The maximum single release volumes from incidents not

[3] MSCF stands for thousands of standard cubic feet of gas. In energy terms, 1 MSCF is equal to approximately 7.7 gallons of crude oil.

on the ROW and mostly associated with operators' property were less than those on the ROW but not significantly less. For hazardous liquids, the maximum release on operators' property was 576,156 gallons or 68% of the maximum release on a ROW. For gas transmission, the maximum release not on the ROW was 405,000 MSCF or 66% of the maximum release on the ROW. For gas distribution, the maximum release on the ROW was 11,339 MSCF and off the ROW it was 14,000 MSCF, or 55% of the maximum release on the ROW.

When average release volumes are considered in Table 3.1, it is obvious that the maximum release volumes are many times the average release volumes. For hazardous liquids, the average release volume on the ROW was 29,230 gallons making the maximum release 29 times the average release volume. For gas transmission, the average release volume on the ROW of 23,078 MSCF making the maximum release 26.6 times the average release volume. For gas distribution the maximum release volume on the ROW is 7.5 times the average release volume.

The ratios between the averages and the maximum release volumes demonstrate that large release volumes of hazardous liquids or gases are not the norm for the industry. When the total numbers of onshore incidents on or off the ROW and from all types of pipeline component are considered then the number of above-average release volume incidents by industry are 76 for hazardous liquids, 57 for gas transmission and 29 for gas distribution. As percentages of the total numbers of incidents, these numbers are 10% for hazardous liquids, 19.3% for gas transmission, and 10.5% for gas distribution. That is, over the 30-month period of this review, the numbers of very large release volumes is relatively small compared to the release volumes reported over all 1,337 incidents.

For 795 onshore hazardous liquid pipeline incident reports, SCADA was in place for 388 (51%), not in place for 90 (12%) and not reported for 281 (37%). For these same pipelines, CPM was reported as in place for 192 (25%), not in place for 286 (38%) and not reported for 281 (37%).

For 91 (12%) of the hazardous liquid incidents, SCADA is reported as detecting the release. The number for CPM systems is 28 (4%). While SCADA and/or CPM systems are reported as detecting releases they are not necessarily reported as the identifier of the incident. That is, who told the controller that a release was in progress? For the 91 SCADA detections, 49 (7% of the total 759) of the reports identify the SCADA as the initial identifier. For the 28 CPM system detections, 34 (4% of the total 759) of the reports identify CPM as the initial identifier.

When data on SCADA and CPM systems is evaluated together, that is both SCADA and CPM must be in place and functional at the time of the release, detection of the release by both systems was reported for 26 of the 759 incident reports. The SCADA/CPM systems were reported as the incident identifier for 16 of these 26 reports.

423 (56%) incidents from the 759 in total were reported as “could be in an HCA”, the wording used in the incident reports. SCADA and CPM systems, that is, both systems at the same time, were reported as in place for 100 of the 423 incidents reported as “could be in an HCA”. Both systems detected a release in 10 of these 100 incidents. Seven of these 10 incidents were reported as the incident identifier to the pipeline controller.

Table 3.1 All Incidents, January 1, 2010 to July 7, 2012

	Metric	Hazardous Liquids Pipelines	Natural Gas Transmission	Natural Gas Distribution	Total
	# of Incidents[4]	766	295	276	1,337
1	# of Ruptures	21	41	13	75
2	# of Leaks	567	136	63	766
3	# of Mechanical Punctures	33	25	51	109
4	# of Overfill or Overflow	46	0	0	46
5	# of Other Release Types	99	93	149	341
6	# offshore releases (not included in following numbers)	7	56	0	63
7	Contained on operators property	521	95	4	620
8	Started on operators property	41	0	0	41
9	Located on right-of-way (ROW)	197	141	42	381
10	Located on private property	-	-	152	152
11	Located on public property	-	-	78	78
12	# nil Reports for location of spill	0	0	0	0
13	# of Pipe body release incidents on ROW	119	86	30	235
14	# of Pipe seam release incidents on ROW	13	6	-	19
15	# of valve release incidents on ROW	17	6	-	23
16	# of flange incidents on ROW	5	1	-	6
17	# of other reason incidents on ROW	43	42	-	85
18	Maximum release volume (gals or MSCF) from pipe on ROW	843,444 gallons	614,257 MSCF	25,555 MSCF	-
19	Maximum release volume (gals or MSCF) not on ROW	576,156 gallons	405,000 MSCF	14,000 MSCF	-
20	Average release volume (gals or MSCF) from pipe on ROW	29,230 gallons	23,078 MSCF	1,419 MSCF	-
21	Average release volume (gals or MSCF) from pipe not on ROW	5,588 gallons	57,657 MSCF	324 MSCF	-
22	Average release volume (gals or MSCF) for all onshore incidents	10,771 gallons	19,902 MCSF	975.5 MSCF	-
23	# of onshore incidents greater than average release volume	76 out of 759 incidents (10%)	57 out of 239 Incidents (24%)	29 out of 276 Incidents (10.5%)	-

3.6 Specific Data Selected for ROW Assessments

The purpose of this section of the report is to reiterate and to ensure that readers are familiar with the data selected for the evaluations presented in the remainder of this report. Not all of the data

[4] Data collected between January 1, 2010 and beginning of July 2012

available in the 1,337 PHMSA incident reports covering all three pipeline classifications were used in the analysis that follows. The following is the only data selected:

1. Onshore pipeline data. This was the primary filter.
2. Incident data identified as originating on the ROW. Used for an overview assessment.
3. Pipe or pipe seam releases for detailed assessment, excluding pipe body or seams at facilities along the ROW, and also used to determine the above-average release volumes.

Releases associated with fittings on the ROW are included in item 2 but not used for the final analysis in item 3 above. Sixty-five releases from valves, flanges, and other fittings on the ROW were removed before processing the data for item 3. Operators generally know where fittings are located, whether on the ROW or at facilities. They also know where pipe is located at facilities and pipe that is above ground along the ROW. These locations can be checked by an operator on a routine basis. For long lengths of buried pipe between block valves, there are many miles of pipe and pipe seam to check for leaks and an LDS, possibly of more than one type, is appropriate.

Table 3.2, “Pipeline Right-of-Way Incidents, January 1, 2010 to July 7, 2012,” is a table similar in format to Table 3.1 except that it only describes statistics for ROW incidents, whereas as Table 3.1 provides data on all incidents and ROW incidents over the review period. Table 3.2 shows that 197 onshore hazardous incident reports were on a pipeline ROW, which included valves. For onshore gas transmission, the total on the ROW was 141, and for gas distribution the total was 42. It is these incidents that are discussed in the following sections of this report, with the exception of gas distribution where the analysis has been performed on all 276 incidents.

In all three categories of pipeline, hazardous liquids, natural and other gas transmission and gathering and natural and other gas distribution, the above-average release volume incidents provide an adequate number of incidents for the purpose of this study.

Table 3.2 Pipeline Right-of-Way Incidents, January 1, 2010 to July 7, 2012

Metric	Hazardous Liquids Pipelines	Natural Gas Transmission	Natural Gas Distribution	Total
# of Pipeline ROW Incidents	197	141	42	380
# of Ruptures	12	33	13	58
# of Leaks	139	61	63	263
# of Mechanical Punctures	27	22	51	112
# of Other Release Types	19	25	0	44
Located on private property	-	-	149	149
Located on public property	-	-	78	78
# of Pipe release incidents on ROW	119	86	30	235
# of Pipe seam release incidents on ROW	13	6	-	19
# of valve release incidents on ROW	17	6	-	23
# of flange release incidents on ROW	5	1	-	6
# of other reason release incidents on ROW	43	42	-	85
Maximum unintentional release volume (gals or MSCF) from pipe & pipe seam on ROW	843,444 gallons	614,257 MSCF	25,555 MSCF	-
Maximum unintentional release volume (gals or MSCF) from all other reasons on ROW other than pipe and pipe seam	556,122 gallons	91,089 MSCF	14,000 MSCF	-
Average unintentional release volume (gals or MSCF) from pipe & pipe seam on ROW	29,230 gallons	30,347 MSCF	1,419 MSCF	-
Average unintentional release volume (gals or MSCF) from all other reasons on ROW other than pipe and pipe seam	17,794 gallons	10,766 MSCF	324 MSCF	-
# of onshore incidents greater than average unintentional release volume from pipe & pipe seam on ROW	28 out of 132 incidents (21%)	22 out of 92 incidents (24%)	20 out 160 incidents (12.5%)	-
# of onshore incidents greater than average unintentional release volume from all other reasons on ROW other than pipe and pipe seam	5 out of 65 incidents (8%)	9 out of 49 incidents (18%)	5 out of 111 incidents (4.5%)	-

3.7 Incident Reporting for the Hazardous Liquid Pipeline Industry on the ROW

3.7.1 Hazardous Liquid Incidents

For hazardous liquid incidents located on the ROW, 197 total releases are divided into 119 from pipe body, 13 from a pipe seam, 17 from valves, 5 from flanges, and 43 leaks from something other than pipe, such as a girth weld, repairs, instrumentation etc. The total release volume reported for the 197 incidents was 4,967,895 gallons. The 197 incident reports came from 60 different operators. Of these 197 releases, 12 were attributable to ruptures, 139 to leaks, 27 to mechanical punctures, and 19 to other types of release.

The largest release volume was 843,444 gallons and the smallest was 0.42 gallons.

The second largest hazardous liquid release volume is 556,122 gallons or 66% of the largest release volume. Together, these two release volumes add up to 1,399,566 gallons of hazardous liquid and make up 31% of the total above-average release volume of 4,544,358 gallons from 33 of the 197 incidents reviewed. That is, approximately 1 in 6 incidents produced a release volume between 25,476 gallons and 843,444 gallons of crude oil, refined product or highly volatile liquids (HVLs) based on this data.

Figure 3.1 shows a breakdown of the number of ROW releases by commodity transported by the hazardous liquid pipelines in the 30 month database. It shows that the releases are more or less evenly distributed between HVLs, crude oils, and refined products. When the gallons released by these three commodity categories are compared (Figure 3.2) it can be seen that that crude oil and HVL pipelines have released more volume over the 30 month period than refined product pipelines.

Figure 3.2 also shows that many of the reported release volumes for most of the incidents, in any of the three categories, do not show in Figure 3.2 because of the left-hand scale used for the maximum size of volume released. This theme that a large number of the releases on a ROW are of relatively small volume is repeated throughout the data presented in this report. Although the larger volume releases are significant, the reader should remember that the scale of reported ROW releases covers a range of 0.42 gallons to 843,444 gallons. This is a ratio of 1: 2,008,200

Five of these 197 reported releases ignited and two of the five exploded.

Hazardous liquids incident reports require operators to identify the status of not only the pipeline SCADA but also the computational pipeline monitoring (CPM) system. Both SCADA and CPM systems are seen as primary means within the control room for pipeline operating personnel to detect releases[5] on hazardous liquid pipelines. The response data associated with SCADA and CPM functionality was assessed for all 197 ROW releases.

Commodity Released	# of Releases	% of Total Releases
HVL's	68	34.5%
CRUDE OIL	64	32.5%
REFINED PRODUCTS	61	31.0%
CO2	4	2.0%
BIOFUEL/ALTERNATIVE FUEL	0	0.0%

January 2010 to July 2012

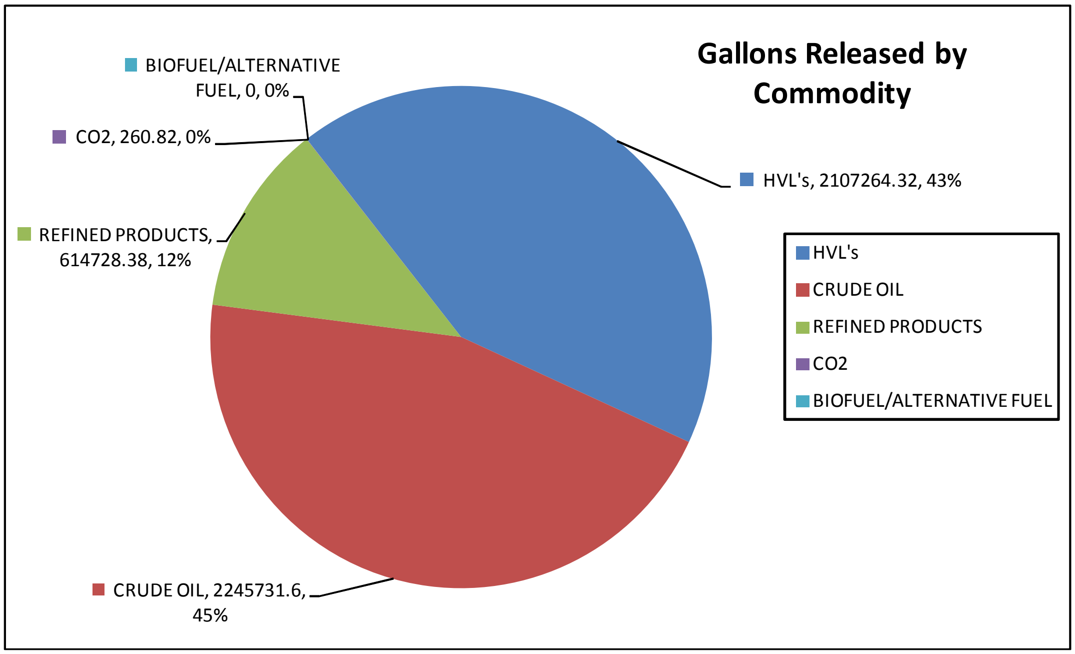


Figure 3.1 ROW Releases by Commodity, 2010 to July 2012

[5] See Task 4 for descriptions of the capabilities of SCADA and CPM.

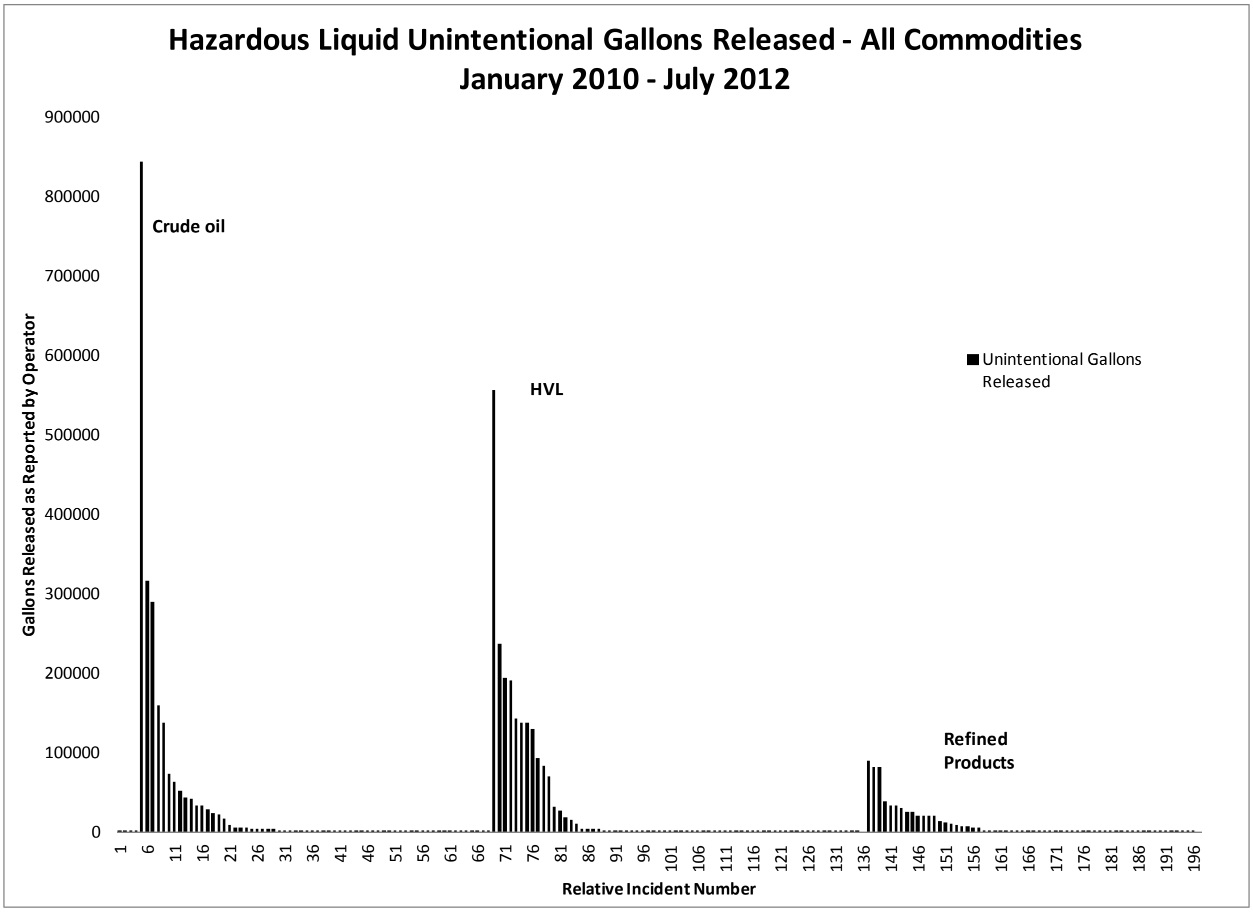


Figure 3.2 ROW Releases, All Commodities, 2010 to July 2012

Table 3.3 summarizes the data provided in the incident reports for whether:

1. A SCADA system was operational at the time of the incident.
2. The SCADA was functioning when the incident occurred.
3. The SCADA information assisted in the detection of the incident.
4. The SCADA information assisted in the confirmation of the incident.
5. A CPM system was in place.
6. The CPM system was operating at the time of the incident
7. The CPM system was functional at the time of the incident.
8. The CPM system assisted in the detection of the incident.
9. The CPM system assisted in the confirmation of the incident.

Table 3.3 ROW Releases, 2010 to July 2012: SCADA and CPM Detail

	# of Reports	% of All 197 Reports
SCADA System Reported as in Place	153	77.7%
SCADA System Reported as NOT in Place	12	6.1%
SCADA System in Place BLANK-No Data	32	16.2%

	# of Reports	% of All 197 Reports	% of 153 Reports where SCADA was In Place
SCADA System Operating at Time of Accident	151	76.6%	98.7%
SCADA System Functional at Time of Accident	152	77.2%	99.3%
SCADA Information Assisted in Detection of Accident	43	21.8%	28.1%
SCADA Information Assisted in Confirmation of Accident	47	23.9%	30.7%
# of Reports with Both SCADA and CPM in Place	87	44.2%	56.9%

	# of Reports	% of All 197 Reports
CPM System Reported as in Place	87	44.2%
CPM System Reported as NOT in Place	78	39.6%
CPM System in Place BLANK-NO Data	32	16.2%

	# of Reports	% of All 197 Reports	% of 87 Reports where CPM was In Place
CPM System Operating at Time of Accident	85	43.1%	97.7%
CPM System Functional at Time of Accident	86	43.7%	98.9%
CPM Information Assisted in Detection of Accident	17	8.6%	19.5%
CPM Information Assisted in Confirmation of Accident	22	11.2%	25.3%

January 2010 to July 2012

For the 197 incident reports, a SCADA system was in place for 153 (78%) of the incidents. Thirty-two (16%) of the incident reports did not respond to this question.

For the 197 incident reports, a CPM system was in place for 87 (44%) of the incidents. Eighty-six (86) of these CPM systems were reported as functional at the time of the incident. A CPM system was not in place at the time of an incident for 78 (40%) of the reports in the database. Thirty-two (16%) of the incident reports did not give an answer to this question as to whether a CPM was in place or not.

The number of incident reports where both SCADA and a CPM system was in place was 87 or 44% of all 197 reports.

The SCADA was reported as functional in 152 of the 197 reported incidents, which is 99.3% of the incidents where a SCADA was operational at the time of the incident. Forty-three (43) of the incident reports stated that SCADA assisted in the detection of the incident. This is 28% of the incident reports that stated a SCADA was operational at the time of the incident.

Seventeen (17) or 20% of the 86 incident reports where CPM was functional stated that CPM assisted in the detection of the incident. The largest release reported as not detected by SCADA was 843,444 gallons. The smallest release not detected by SCADA was 0.42 gallons.

The above statistics on SCADA and CPM are shown in Figure 3.3 and Figure 3.4 but related to gallons released into the environment. Figure 3.3 shows the gallons released where SCADA was either functional, not functional or where information on SCADA was not reported. Figure 3.4 show the gallons released where the CPM was either functional, not functional or where information on CPM was not reported.

Figure 3.3 shows that SCADA was functional for all the of the large volume releases. The one incident reported without SCADA being functional (red on Figure 3.3) occurs on the horizontal axis around incident number 97 with a release volume of 420 gallons. Some of the release volumes where no data on SCADA was reported by the operator (green on Figure 3.3) were as large as 6,300 and 9,030 gallons. As with all graphs of this type in the report, the large volumes were so much greater than the smaller volumes that the scale of the vertical axis causes around 50% of the data to display very close to zero on the horizontal axis.

Figure 3.4 on CPM shows a more complicated picture than for SCADA. A CPM was not functional (red on Figure 3.4) for the largest release volume of 843,444 gallons. This was a release of crude oil by Enbridge Energy Partnership. The green histogram columns on Figure 3.4 represent the releases where no data is provided on the PHMSA incident reports about CPM functionality. Of the 197 incidents being reviewed here, 110 gave no data on CPM functionality. The largest release volume where CPM functionality is not provided in the incident report is 190,848 gallons. This was reported by Enterprise Products Operating LLC.

Further comments on the reported ability of SCADA and CPM systems acting as the initial identifier of the release is given later when above-average ROW releases are evaluated.

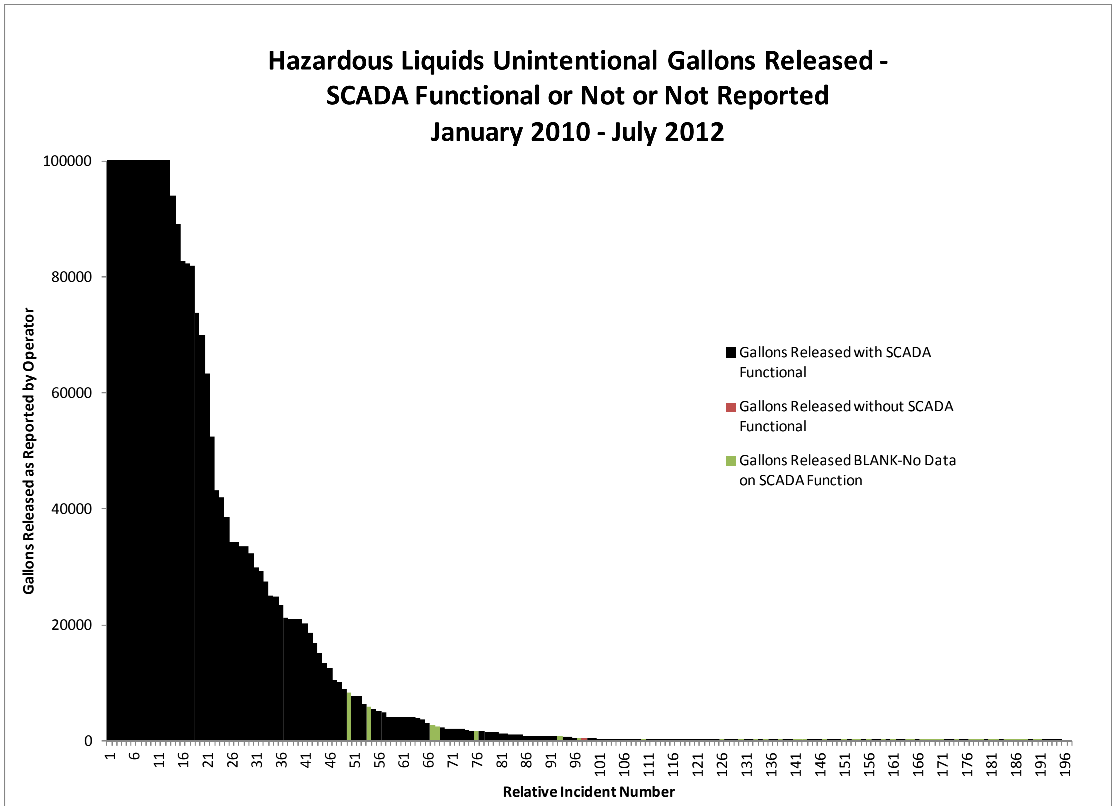


Figure 3.3 Hazardous Liquids Releases, SCADA Detail

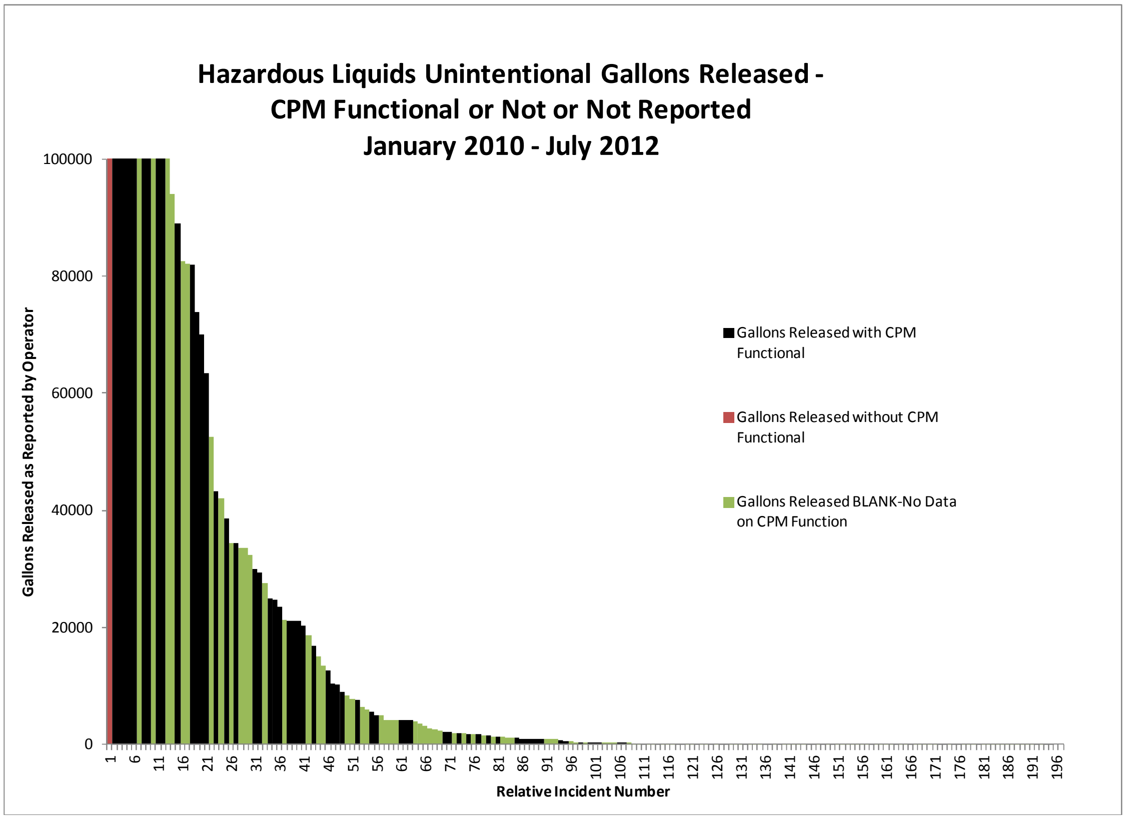


Figure 3.4 Hazardous Liquids Releases, CPM Detail

PHMSA does not require certain information to be submitted on an incident report when the release volume is at least 5 gallons and less than 42 gallons (5 barrels). However, there are overriding provisions that do require all information to be submitted if certain situations occur with the release. These reporting rules could influence the data presented in Figures 3.3 and 3.4. These rules would influence the number associated with gallons released where no data was provided (color green) in these charts.

For the 197 releases on the ROW being assessed here, there were 24 incidents between 5 gallons and 42 gallons. Only some of these satisfied the criteria for not reporting on SCADA and CPM functionality. Of these 24 incidents, 9 indicated that SCADA was functional but did not detect the release and 7 indicated that CPM was functional but did not detect the release.

The review now looks at how these 197 releases were initially detected. That is, how did the pipeline controller or the operator discover that fluid was escaping from the pipeline so that appropriate action could be taken? Figure 3.5 shows the gallons released per incident where the SCADA or CPM is the initial identifier of the release (color black). Twenty-three releases from the 197 were initially detected this way. A further 10 releases were initially identified by a controller. These are not shown on Figure 3.5.

Color red on Figure 3.5 shows the incidents and the gallons released where neither the SCADA nor the CPM was the initial identifier of the release. Thirty-two no data entries were counted. The first of these 32 occurrences is between incident number 127 and 133 on the horizontal axis of Figure 3.5. Hence, these no data entries are for small release volumes.

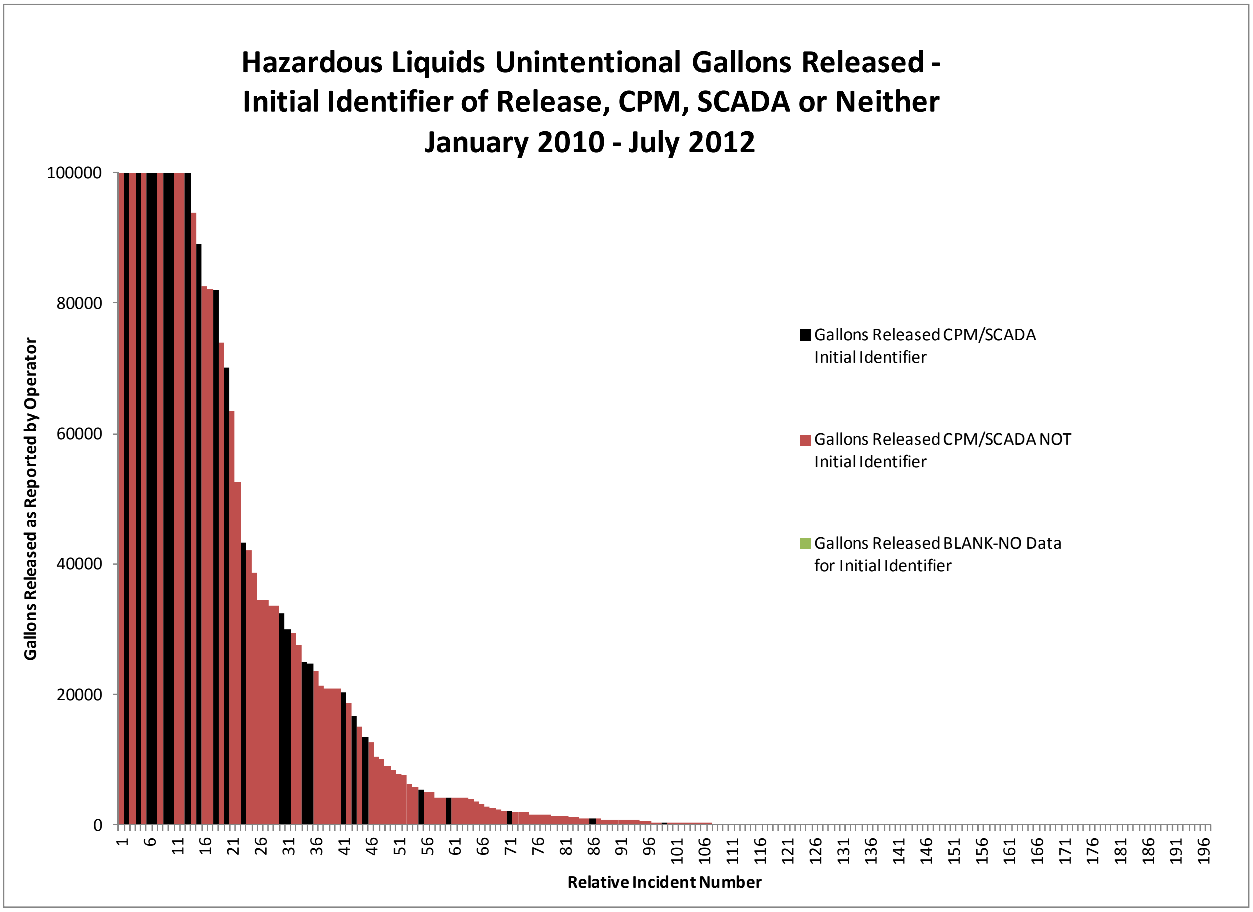


Figure 3.5 Hazardous Liquids Releases, Initial Identifier: SCADA, CPM, None

Figure 3.6 presents a pie-chart showing the means by which a control room was notified of a release for 165 of 197 incidents. Data was not available for 32 of the incident reports. The different means of initial incident identification are tabulated in Table 3.4. That is, who discovered the release first? The range of different initial identifiers is broad. The following categories seem appropriate for grouping the data:

1. Pipeline control and non-control room personnel and contractors (44%).
2. The public (30%).
3. A third party on the ROW (6%).
4. Other (4%).
5. No data (16%).

A possible summary is that pipeline operators' or contractors to the pipeline operator discover half the releases on a pipeline ROW.

Within the 44% statistic for Pipeline control and non-control room personnel and contractors, 17% is attributable to the pipeline control room. In terms of managing a release, particularly a rupture, a sequence of events might be described as:

1. Time to detection for the control room after the release, as it is the control room that has means to shut down the pipeline.
2. A period where fluid is still being pumped into the environment.
3. A period during which valves are closed, the section isolated and drain down occurs.

Where a release is detected by someone other than in the control room the time taken for the control room to acknowledge a release and initiate further action is likely to be longer than when the control room is the initial identifier. Hence, for the 44% described above, it is likely that 27% of the incidents resulted in a longer detection period after the actual release from the pipeline.

When the public, including emergency responders, are the initial identifiers (30% in the above statistics), the elapsed time before the control room is aware of a release may be longer than when operator employees and contractors become aware of a release because of their better knowledge and training on what to do. However, incident reports do not contain data to allow this the different phases of a release to be evaluated.

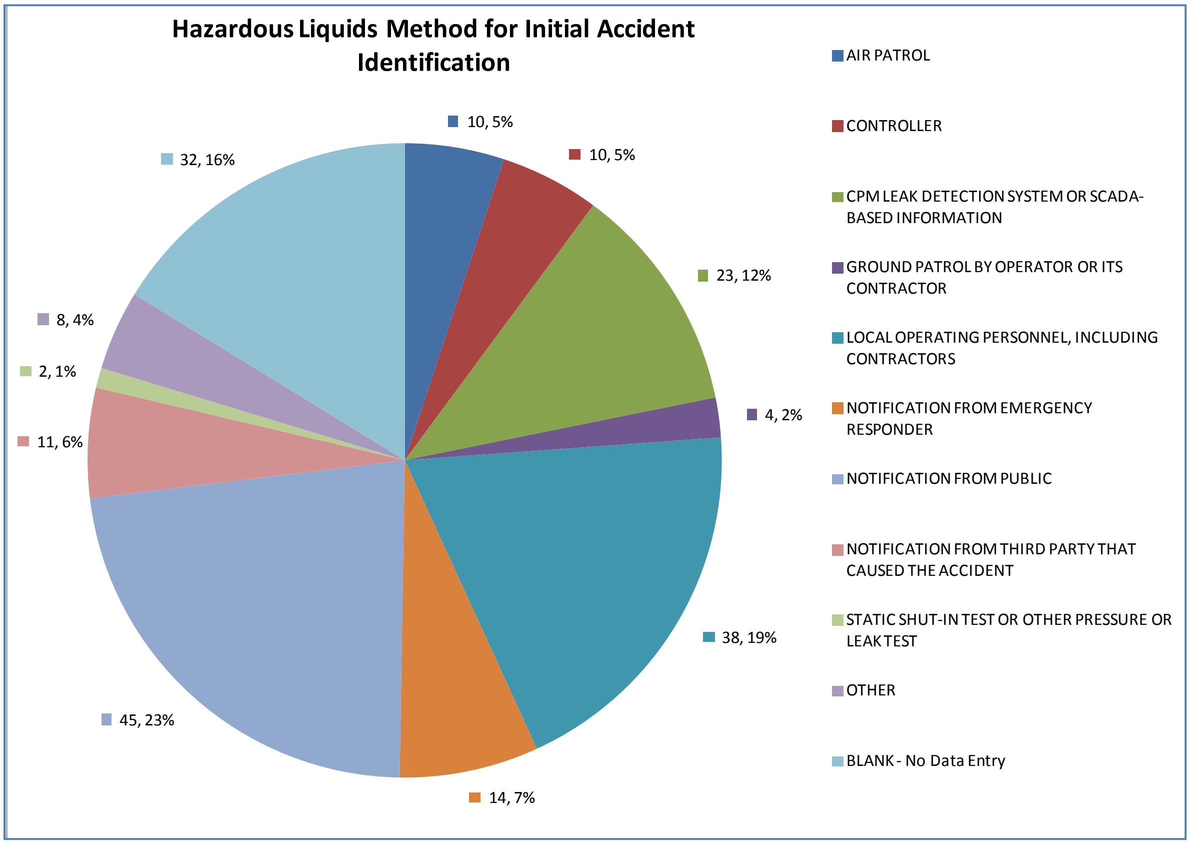


Figure 3.6 Hazardous Liquids Releases, Initial Identifier

Table 3.4 Hazardous Liquids Releases – Initial Identification

Identifer	# 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

Once a release is detected there is a need to respond to the release. PHMSA incident reporting requires operators to provide the date and time the incident was identified by the operator. This is not necessarily the date and time that a release started from a pipe body or pipe seam. Other information provided is the date and time for operator personnel to arrive at the site of the release and the date and time the pipeline was shutdown.

There is not a requirement to report the date and time when the control room became aware of the incident. Nor is there a requirement to record how long the control room took to acknowledge a release had occurred and then to take action. The requirement is to report when an operator became aware of the incident. This date and time may well apply to operator employees and contracts out on the ROW or in a facility.

When an operator reports a date and time to arrive on site, the PHMSA instructions do not require this date and time to relate to the date and time the incident was initially identified. Where operator employees or contractors are the initial incident identifiers, then the time is identical for both the initial identification and the time to arrive on-site. The time to arrive on-site in this situation is zero.

The date on which the operator became aware of the release was not recorded for 30 (15%) of the 197 incident reports in this specific evaluation. These same incident reports also didn't identify the date and time on-site but 6 did provide the date and time of shutting down the pipeline.

It was possible to calculate the time to arrive on-site after the time of initial identification by the operator for 166 incident reports from the total of 197. Figure 3.7 shows this result. For 60 (36%) of these incidents the time was reported as less than 5 minutes. For 50 (30%) of these incidents the time to arrive on site was from one hour to 168 hours. For the maximum release volume of 843,444 gallons, the time to arrive on site was recorded as zero minutes. For the minimum release volume of 0.42 gallons, the time to arrive on-site was also reported as zero minutes. The arrival time recorded as 168 hours is for a release volume given as 11.34 gallons. The largest spill where the time to arrive on-site was over one hour was 316,596 gallons and the on-site arrival took 2 hours and 2 minutes.

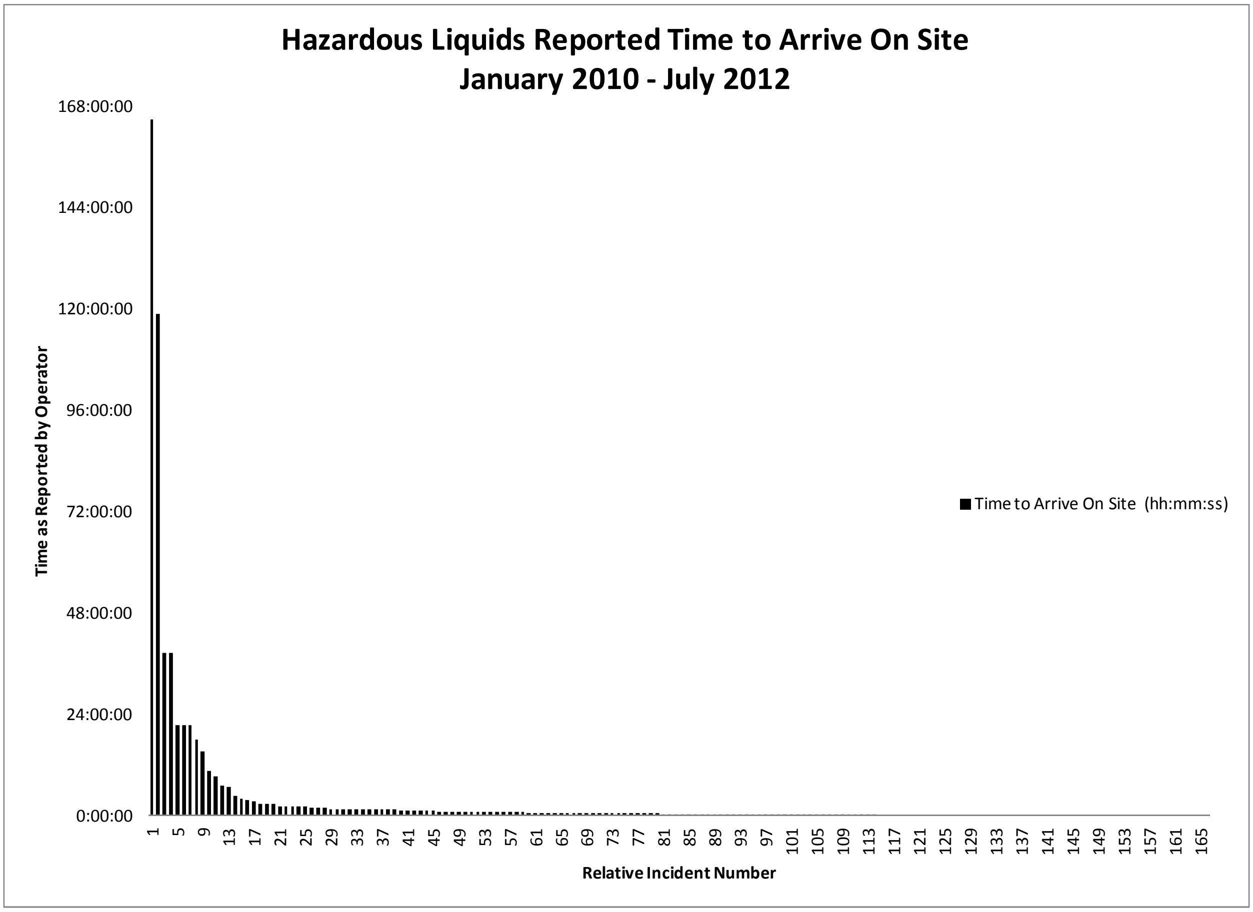


Figure 3.7 Hazardous Liquids Releases, Response Times

The average time to arrive on-site with and without SCADA functional was determined and for the instances where no data about SCADA functionality was provided by the operator. This data is shown in Figure 3.8. The average time to respond was shorter for those incidents where SCADA was functional. The average time was 2.1 hours compared to 4 hours for the one case where the SCADA was not functional and 9 hours where no data on SCADA was provided. However, when volume released is compared for these three categories (Figure 3.8), the gallons released into the environment is considerably greater when the SCADA was functional even though the average respond time on-site was the shortest.

	Average Response Time (hours)
Time to Respond with SCADA Functional	2.1 hrs
Time to Respond without SCADA Functional	4.0 hrs
Time to Respond BLANK-No Data on SCADA Function	9.0 hrs

	Unintentional Gallons Released
Gallons Released with SCADA Functional	4,488,000
Gallons Released without SCADA Functional	420
Gallons Released BLANK-No Data on SCADA Function	17,864

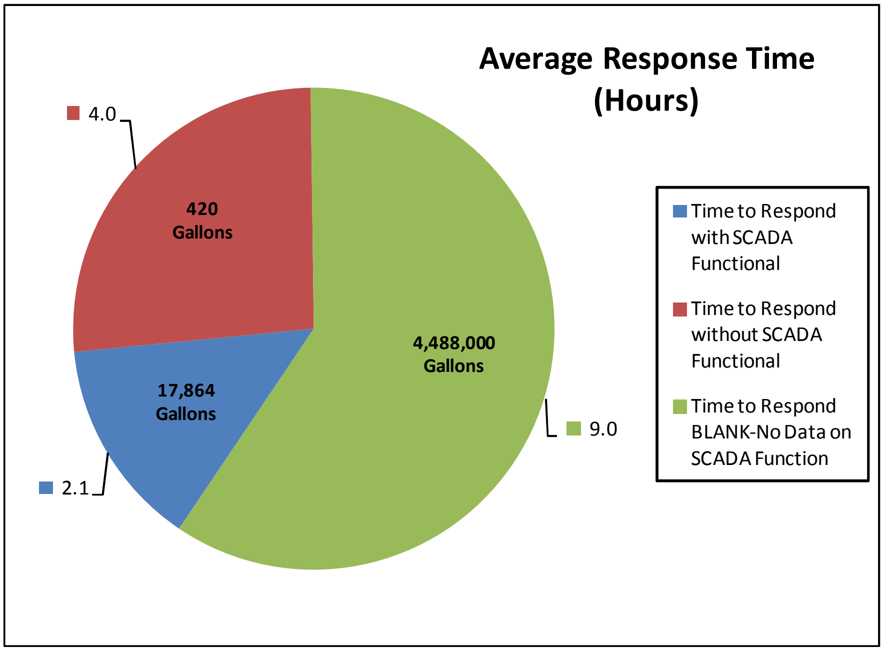


Figure 3.8 Hazardous Liquids Releases, Average Response Time: SCADA Detail

Time to shut down the pipeline is taken to mean that pumping has ceased and the upstream and downstream block valves have been shut to isolate the section of pipeline containing the release. The review of the incident data showed the following for 197 incident reports:

- For 12 (6%) shutdown date and times provided it was not possible to compute the time taken to shutdown because of the date and time values recorded.
- No shutdown time was reported for 66 (33%) of the incidents. Not all pipelines are shutdown as a result of a release.
- 47 (24%) of the incident reports had identical dates and times for the incident identification and the shutdown. This results in zero minutes to shutdown the pipeline.
- For 68 (34%) of the incident reports the elapsed time to shutdown could be calculated using the initial identification and the report shutdown.

- Ignoring zero minute shutdowns, the shortest shutdown time was 1 minute and the longest calculated shutdown time was 44 hours and 30 minutes.
- 8 of the 68 reports where a time to shutdown could be calculated had a shutdown time longer than 1 hour.
- 27 of the 68 reports had a shutdown time between 15 minutes and 40 minutes.
- 32 of the 68 reports had a shutdown time between 1 minute and 14 minutes.

3.7.2 Above Average Hazardous Liquid Releases

To respond to the requirements of Task 3, KAI decided to reduce the number of incidents and to report high volume hazardous liquid releases in more detail. To do this, the ROW releases discussed in the previous section were filtered so that 197 incidents were reduced to 132 ROW releases where the release origin was either the pipe body or the pipe seam. This catches a large number of the high volume releases on the ROW but not all of them. The intent was to identify a small set of high volume releases for further reporting as case studies.

The average release volume from these 132 incidents is 29,230 gallons. The median release volume was 1,004 gallons. The median value is the middle value of all the values used to calculate the average. The most common release volume (the mode) was 84 gallons. This value occurred 6 times in the 132 values used.

Twenty-eight (21%) of the 132 pipe body and pipe seam incidents had a release volume greater than this average release volume of 29,230 gallons and 104 (79%) incidents had below average release volumes. The total of all the releases above the average volume was 3,450,300 gallons. The total of all the below-average release volumes was 378,904 gallons or 11% of the total release volume for the 28 incidents above average. Put another way, around one in five hazardous liquid releases from pipe body or pipe seam on a ROW could have a release volume between 29,230 gallons and 843,444 gallons or thereabouts based on the 30 month period under review.

Release types reported for these above average release volumes were as follows:

1. 7 leaks
2. 6 ruptures
3. 10 mechanical punctures
4. 5 other

These 28 above average release volume incidents were assessed in the same way as the 197 incidents on the ROW discussed previously.

The largest release volume is 843,444 gallons and the smallest is 29,400 gallons. The largest is the crude oil spill by Enbridge Energy Partnership LLC and the smallest is also a crude oil release by Plains Pipeline LP.

The second largest hazardous liquid release volume is 316,596 gallons or 38% of the largest release volume. Together, these two release volumes add up to 1,160,040 gallons of hazardous liquid and make up 34% of the total above average release volume of 3,450,300 gallons from the 28 incidents reviewed.

In the previous section on Task 3, the second largest release volume was 556,122 gallons. This incident is not included in the 28 being reviewed here because the origin of this release was a crack in a fillet weld and not from the pipe body or pipe seam. The fluid was LPG/NGL and the release was described as a leak by the operator.

Figure 3.9 shows a breakdown of the number of ROW releases by commodity transported by the hazardous liquid pipelines in the 30 month database. It shows that the releases are biased towards HVLs and crude oils with fewer releases from refined products. When the gallons released by these three commodity categories are compared (Figure 3.10) it can be seen that that crude oil and HVL pipelines have released more volume over the 30 month period than refined product pipelines incident reports in the database. This is the same pattern observed when all 197 ROW incidents were compared like this. There is no specific commodity trend for high volume releases.

Commodity Released	# of Releases	% of Total Releases
HVL's	10	35.7%
CRUDE OIL	12	43%
REFINED PRODUCTS	6	21%
CO2	0	0
BIOFUEL/ALTERNATIVE FUEL	0	0

January 2010 to July 2012

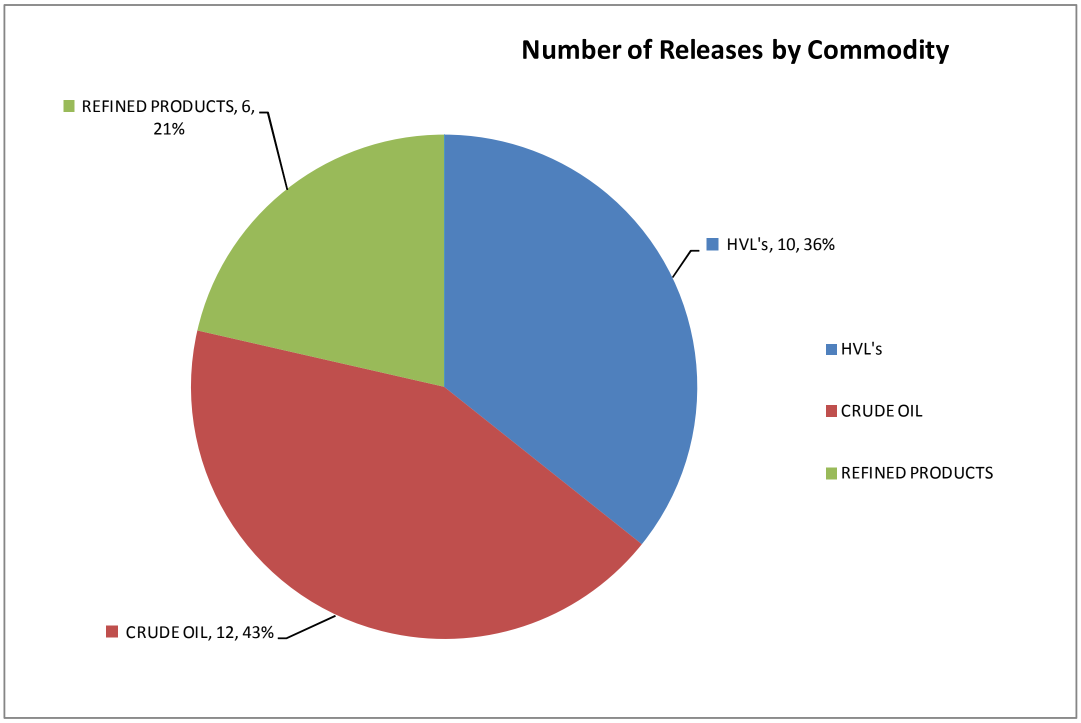


Figure 3.9 Above Average Hazardous Liquids Releases, by Commodity

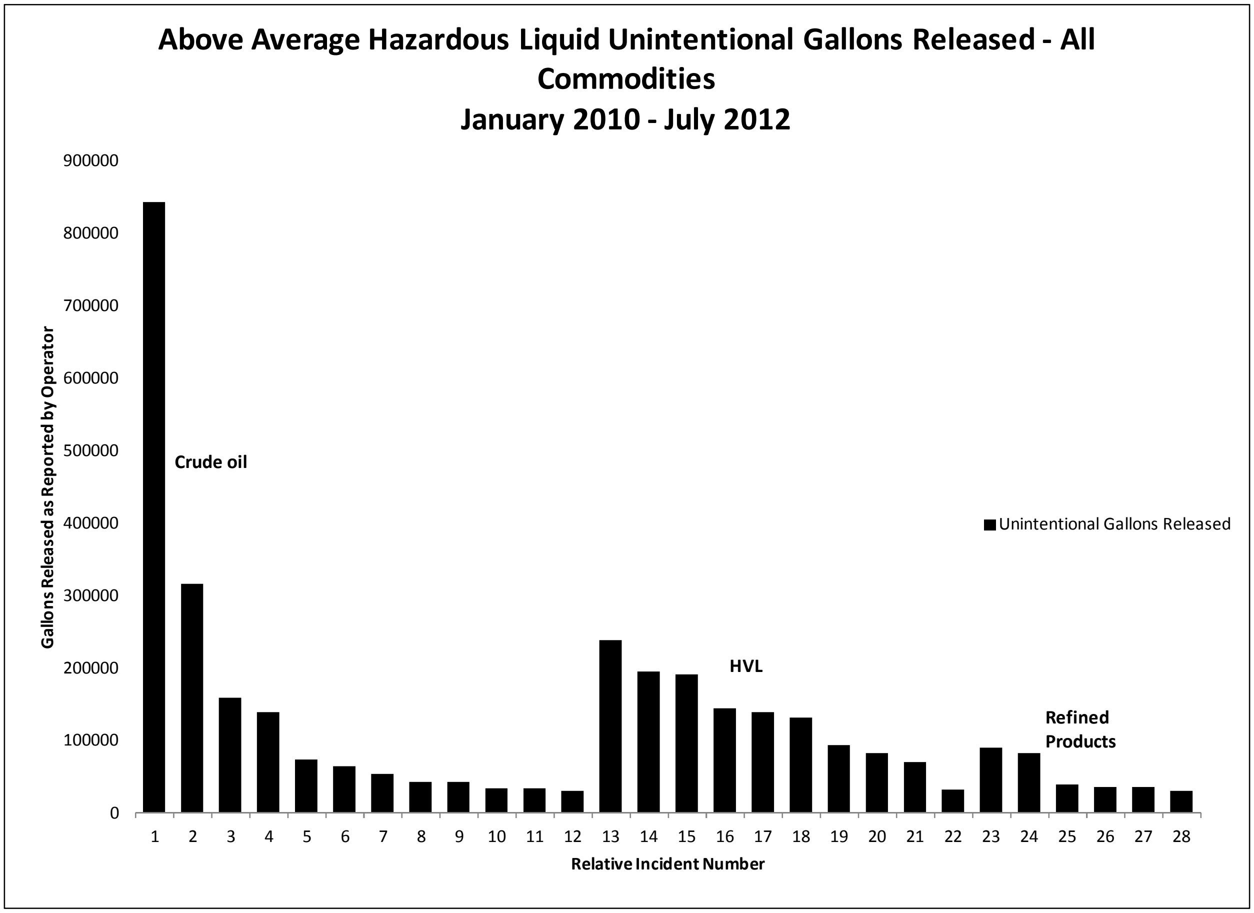


Figure 3.10 Above Average Hazardous Liquids Releases, All Commodities

One of these 28 incidents ignited in an explosive manner. The other 27 incidents did not ignite or explode. The one incident that did explode resulted in the fatality of a member of the public and injury to a member of the public as well. The pipeline is operated by Dixie Pipeline Company LLC and 130,168 gallons of LPG/NGL was released as a result of a mechanical puncture of the pipeline. A mechanical puncture of a pipeline is not classed as a leak or rupture. It is a separate classification.

A SCADA system was in place for all 28 (100%) of the incidents. The SCADA was also functional at the time of the incident was recorded on all incidents and the SCADA system detected 19 (68%) of the incidents.

A CPM system was only in place for 17 (61%) of the 28 incidents. A CPM system assisted with the detection of 7 of the 16 incidents for which a CPM system was functional at the time of the incident. One of the 17 CPM systems was not functional at the time of the incident.

These statistics for SCADA and CPM functionality are shown in Figure 3.11 and Figure 3.12 but related to gallons released to the environment. Figure 3.11 shows the gallons released where SCADA was either functional, not functional or where information on SCADA was not reported and confirms that SCADA was functional for all 28 releases.

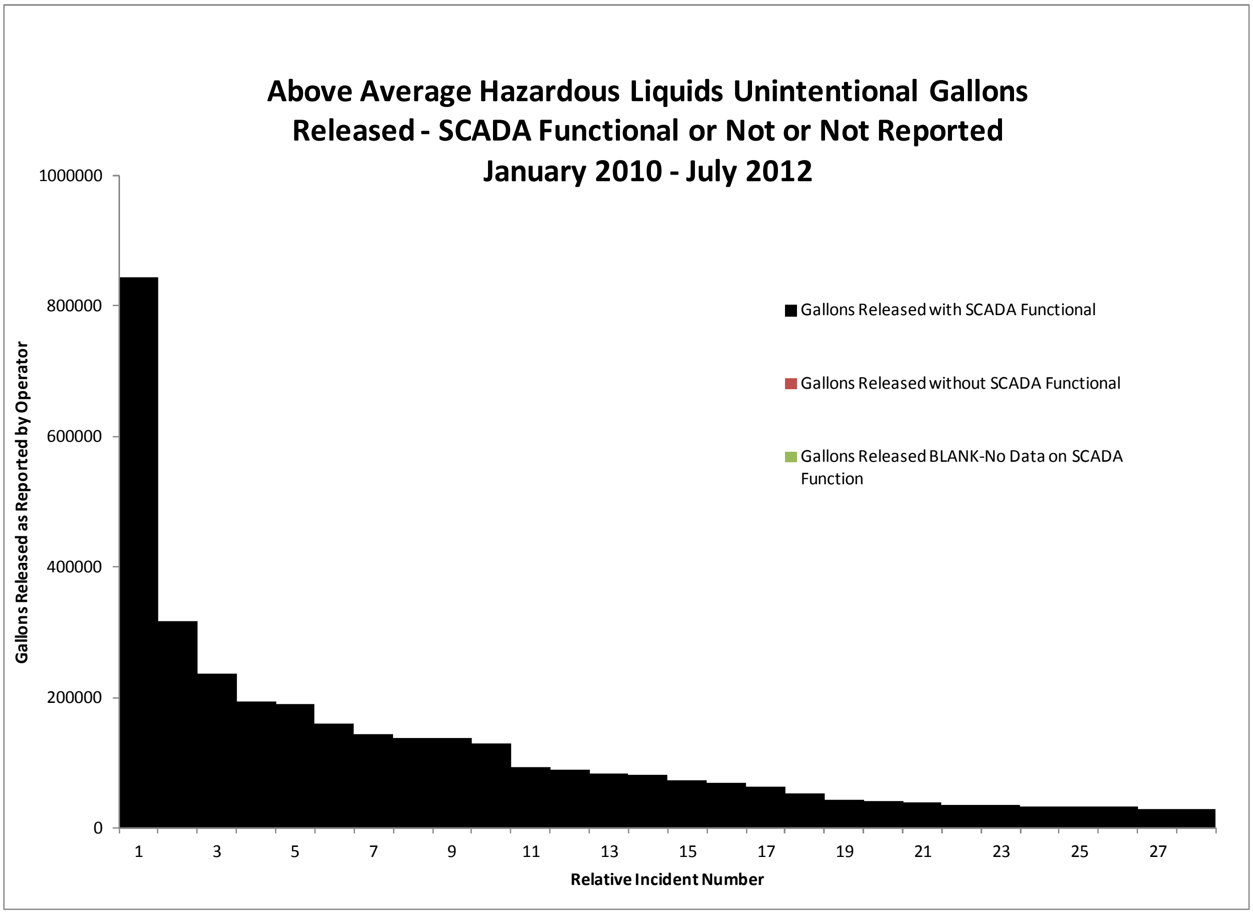


Figure 3.11 Above Average Hazardous Liquids Releases, SCADA Detail

Figure 3.12 shows the gallons released where the CPM was either functional (black), not functional (red) or where information on CPM was not reported (green). The largest release of 843,444 gallons was a release where CPM is reported as non-functional. The largest release where there was no CPM in place was 190,848 gallons. This was reported by Enterprise Products Operating LLC and was mentioned previously where lack of CPM functionality reporting was discussed for all 197 incidents on the ROW.

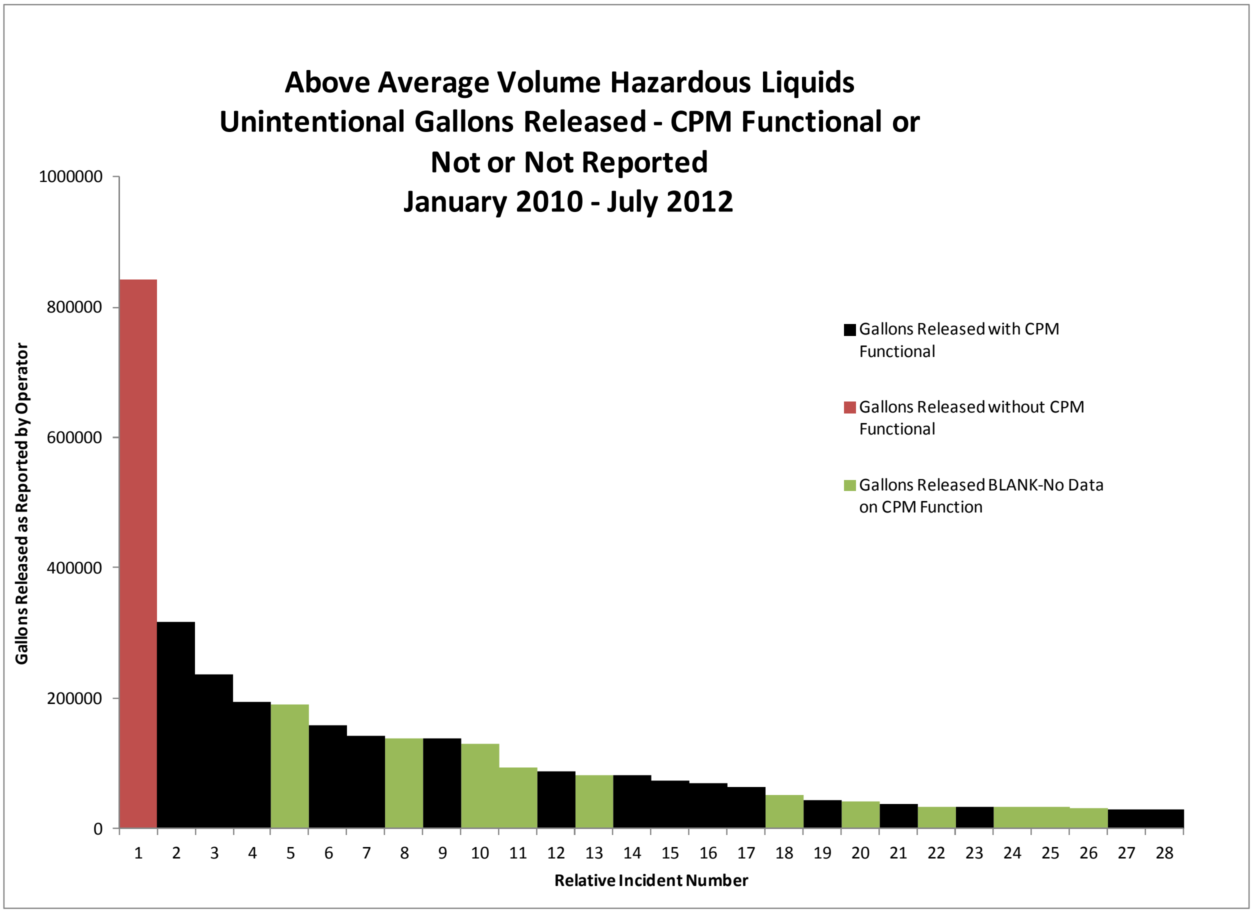


Figure 3.12 Above Average Hazardous Liquids Releases, CPM Detail

Figure 3.13 shows the gallons released per incident where the SCADA or CPM was the initial identifier of the release (color black). Color red on Figure 3.13 shows the incidents (17 in total) and the gallons released where neither the SCADA nor the CPM was the initial identifier of the release.

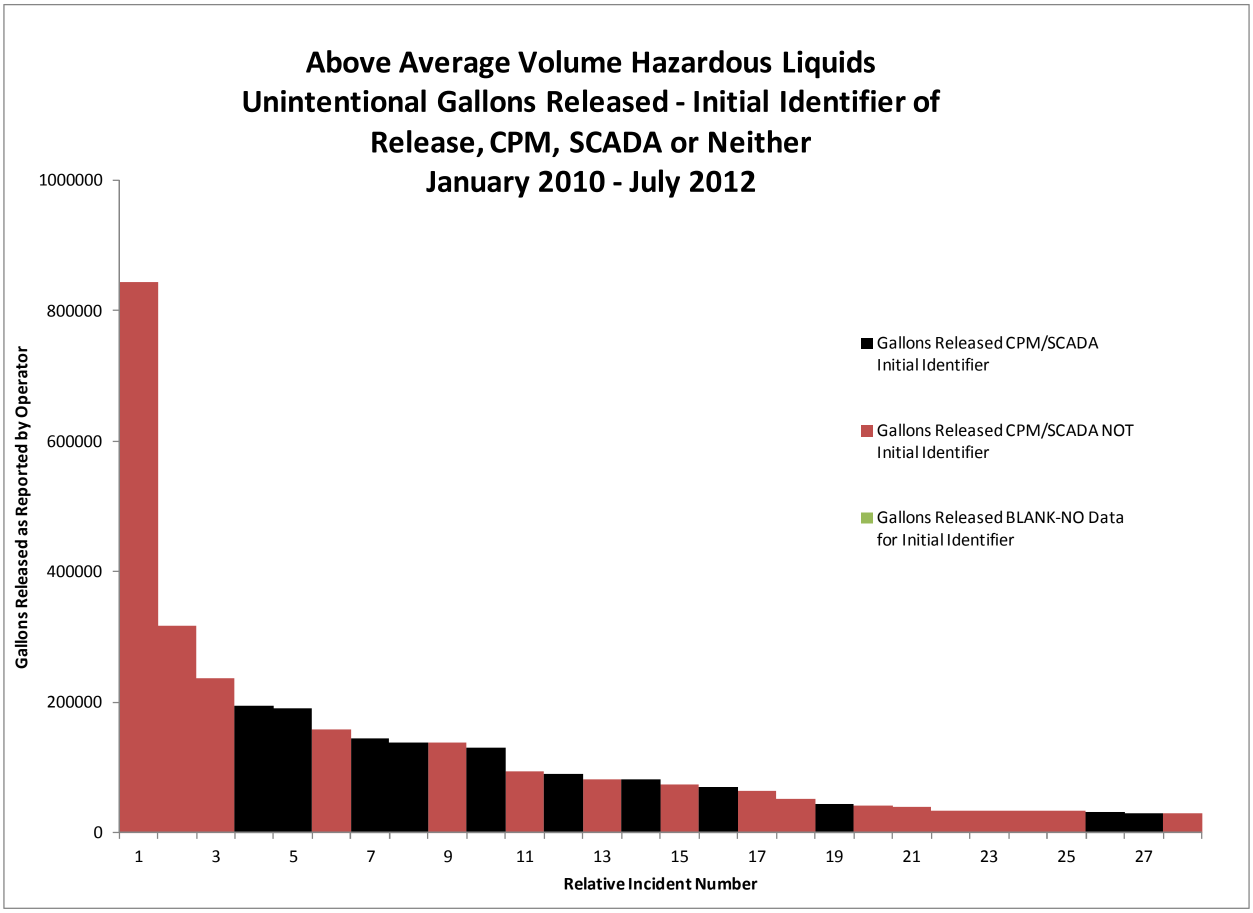


Figure 3.13 Above Average Hazardous Liquids Releases (Gallons), Initial Identifier

Figure 3.14 presents a pie-chart showing the means by which a control room was notified of a release for these 28 incidents. The different means of initial incident identification are tabulated in Table 3.5. That is, who discovered the release first? Seven different categories are initial identifiers. As with the 197 incidents discussed previously, the following categories seem appropriate for grouping the 28 above-average releases:

1. Pipeline control and non-control room personnel and contractors (71%)
2. The public (29%)
3. A third party on the ROW (0%)
4. Other (0%)
5. No data (0%)

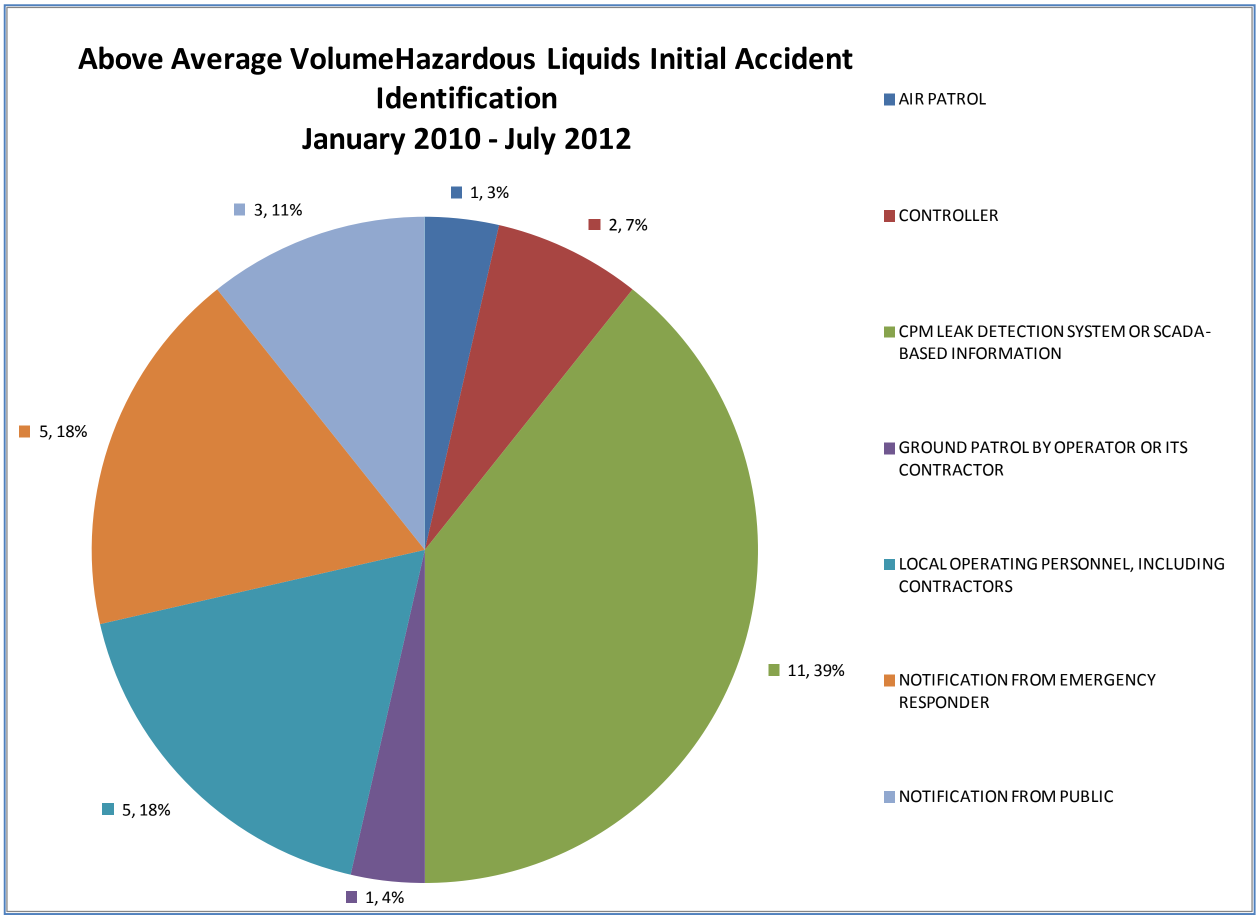


Figure 3.14 Above Average Hazardous Liquids Releases (%), Initial Identifier

Table 3.5 Above Average Hazardous Liquids Releases, Initial 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

A possible summary is that pipeline operators' or contractors to the pipeline operator discover over two-thirds of the releases on a pipeline ROW for above average releases from a pipe body or pipe seam.

Within the 71% statistic for Pipeline control and non-control room personnel and contractors, 46% is attributable to the pipeline control room. This is larger than the percentage of 17% attributed to the pipeline control room for 197 incidents on the ROW considered in the prior section. In terms of managing a release, particularly a rupture, a sequence of events might be described as:

1. Time to detection for the control room after the release as it is the control room that has means to shut down the pipeline.
2. A period where fluid is still being pumped into the environment.
3. A period during which valves are closed, the section isolated and drain down occurs.

Where a release is detected by someone other than in the control room the time taken for the control room to acknowledge a release and initiate further action could be longer than when the control room is the initial identifier. Hence, for the 71% described above, 25% of the incidents may have resulted in a longer detection period after the actual release from the pipeline.

When the public, including emergency responders, are the initial identifiers (29% in the above statistics), the elapsed time before the control room is aware of a release may be longer than when operator employees and contractors become aware of a release because of their better knowledge and training on what to do.

Once a release is detected there is a need to respond to the release. PHMSA incident reporting requires operators to provide the date and time the incident was identified by the operator. This is not necessarily the date and time that a release was initiated. Other information provided is the date and time for operator personnel to arrive at the site of the release and the date and time the pipeline was shutdown.

There is not a requirement to report the date and time when the control room became aware of the incident. Nor is there a requirement to record how long the control room took to acknowledge a release had occurred and then to take action. The requirement is to report when an operator became aware of the incident. This date and time may well apply to operator employees and contracts out on the ROW or in a facility.

When an operator reports a date and time to arrive on site, the PHMSA instructions do not require this date and time to relate to the date and time the incident was initially identified.

Where operator employees or contractors are the initial incident identifiers, then the time is identical for both the initial identification and the time to arrive on-site. The time to arrive on-site in this situation is zero.

The date on which the operator became aware of the release was recorded for all 28 above average release incidents.

It was possible to calculate the time to arrive on-site after the time of initial identification by the operator for 27 of the 28 incident reports. Figure 3.15 shows this result. For 15 (54%) of these 28 incidents the time was less than 1 hour. For 12 (43%) of these incidents the time to arrive on site was from one hour 14 minutes to 3 hours 40 minutes. For the maximum release volume of 843,444 gallons, the time to arrive on site is recorded as zero minutes. For the minimum release volume of 29,400 gallons in this data set, the time to arrive on-site was reported as 30 minutes.

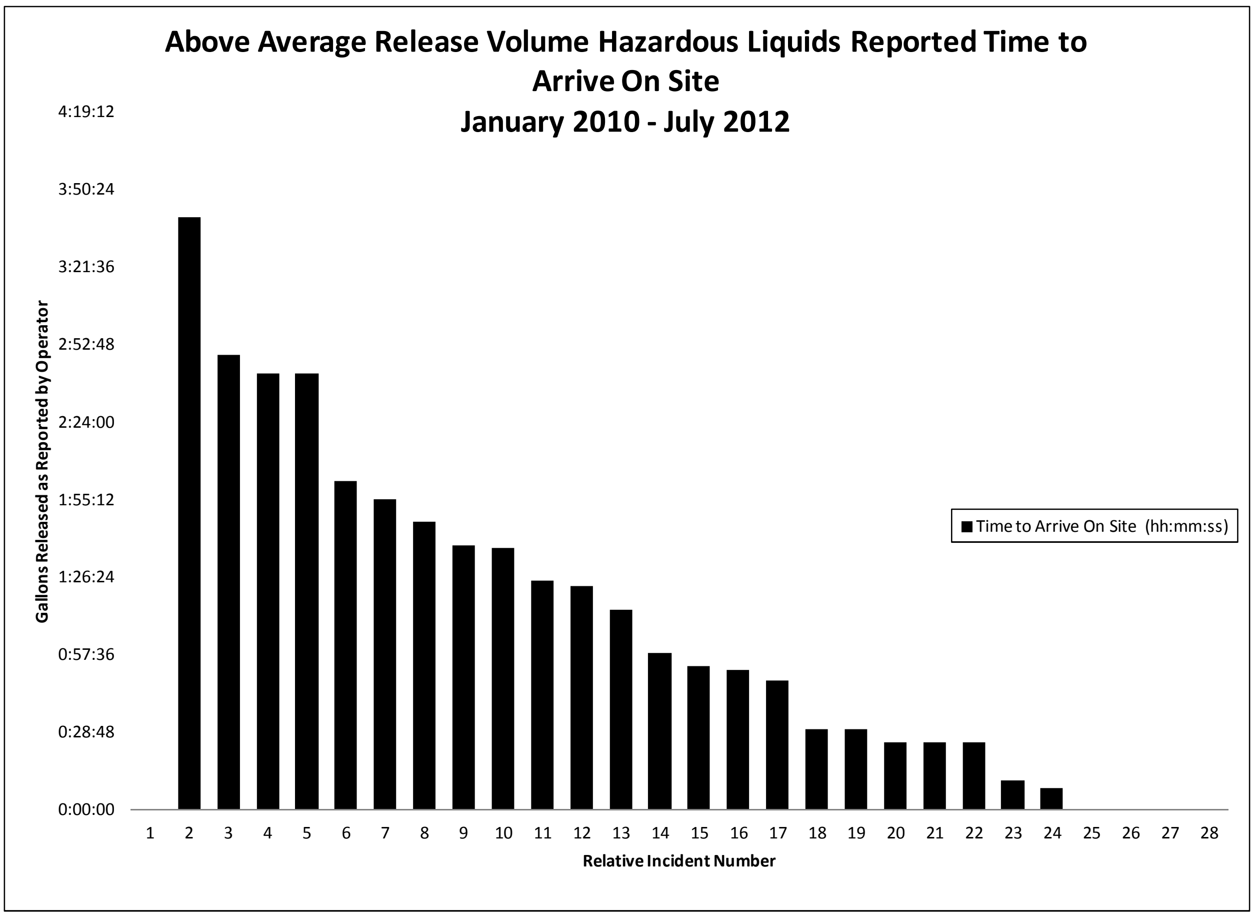


Figure 3.15 Above Average Hazardous Liquids Releases, Response Time

The average time to respond and be on-site with SCADA functional, which was true for all 28 incidents, was 1.1 hours. One incident did not report times to allow this calculation to be made. The volume released into the environment for these 27 incidents with SCADA functional is 3,420,312 gallons.

Time to shut down the pipeline is taken to mean that pumping has ceased and the upstream and downstream block valves have been shut to isolate the section of pipeline with the release. The review of the incident data showed the following for 28 above-average release volume incident reports:

1. Three of the 28 operators did not respond to the question on whether the pipeline was shut down as a result of the incident.
2. In 4 of the 28 incidents the pipeline was shut down for reasons other than the incident or was shut down at the time of the incident.
3. The largest release while a pipeline was shut down and not operating was 237,216 gallons of LPG/NGL liquids per the incident database description.
4. The smallest release while a pipeline was shut down and not operating was 29,400 gallons of crude oil.
5. A shutdown date and time was provided for 20 (71%) of the 28 above-average release volume incidents.
6. It was possible to calculate the time to shut down the pipeline for 19 of the 28 incidents discussed here.
7. The date and time to identify the incident and the date and time to shut down the pipeline was the same for 9 of the incidents. That is, the time taken was zero minutes.
8. Where a time to shutdown could be calculated for 10 of the 28 incidents, the shutdown time ranged from 3 minutes to 30 minutes.

3.7.3 Hazardous Liquid Gathering Lines (Transportation-Related Flow Lines)

Total release volume reported for 22 incidents is 29,956 gallons. The 22 incident reports came from 13 operators. The largest release volume is 8,400 gallons whereas the smallest is 10.08 gallons. The second largest release volume is 8,358 gallons.

Commodity Released	# of Releases	% of Total Releases
HVL's	3	13.64%
CRUDE OIL	19	86.36%

January 2010 to July 2012

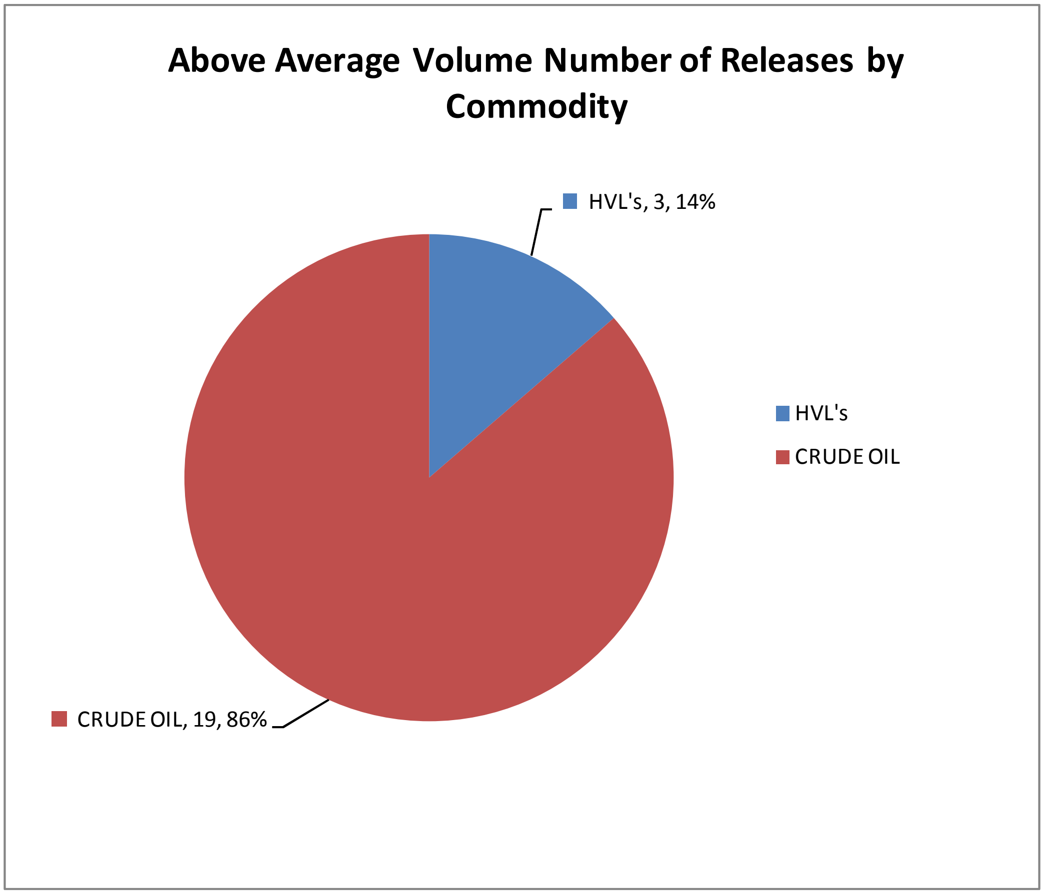


Figure 3.16 shows a breakdown of the number of releases by commodity transported by the hazardous liquid gathering lines in the 30 month database. It shows the two commodities released; crude oil (19 or 86%) and HVLs (3 or 14%). Figure 3.17 shows reported release volumes in gallons.

None (0) of these 22 reported releases ignited and none (0) exploded.

Commodity Released	# of Releases	% of Total Releases
HVL's	3	13.64%
CRUDE OIL	19	86.36%

January 2010 to July 2012

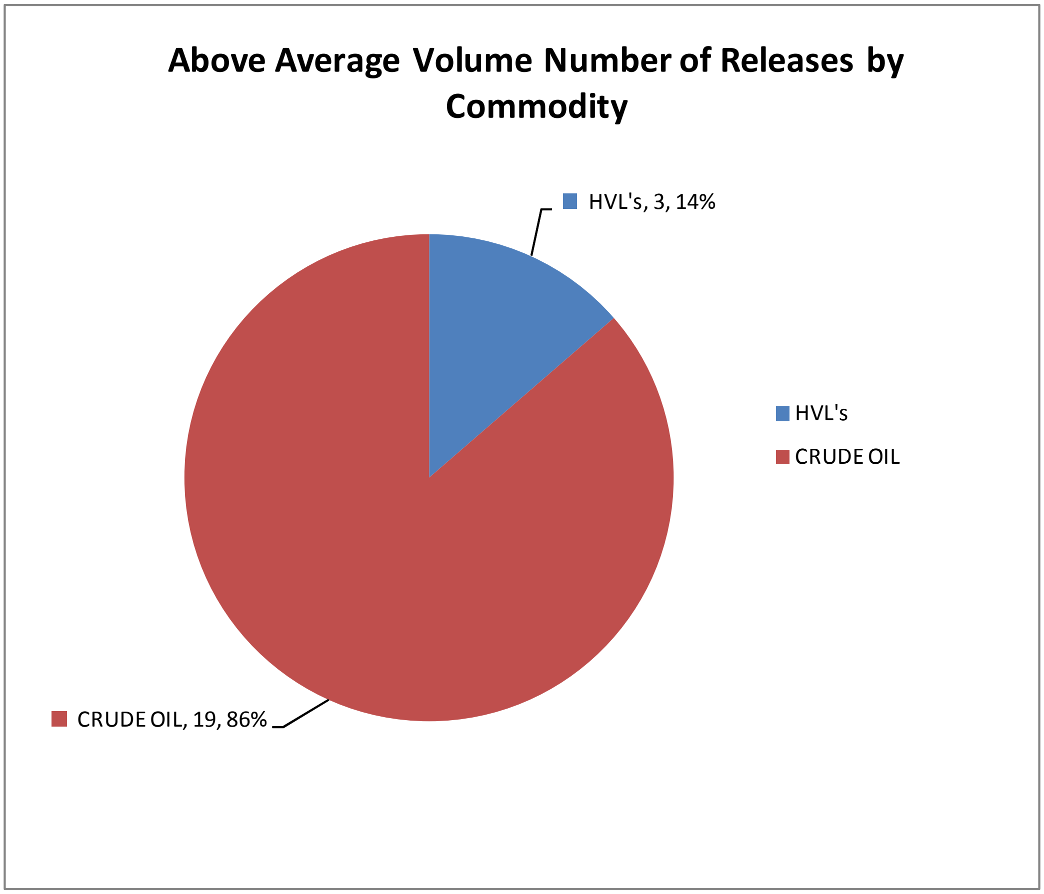


Figure 3.16 Hazardous Liquid Gathering Lines Releases (Number), by Commodity

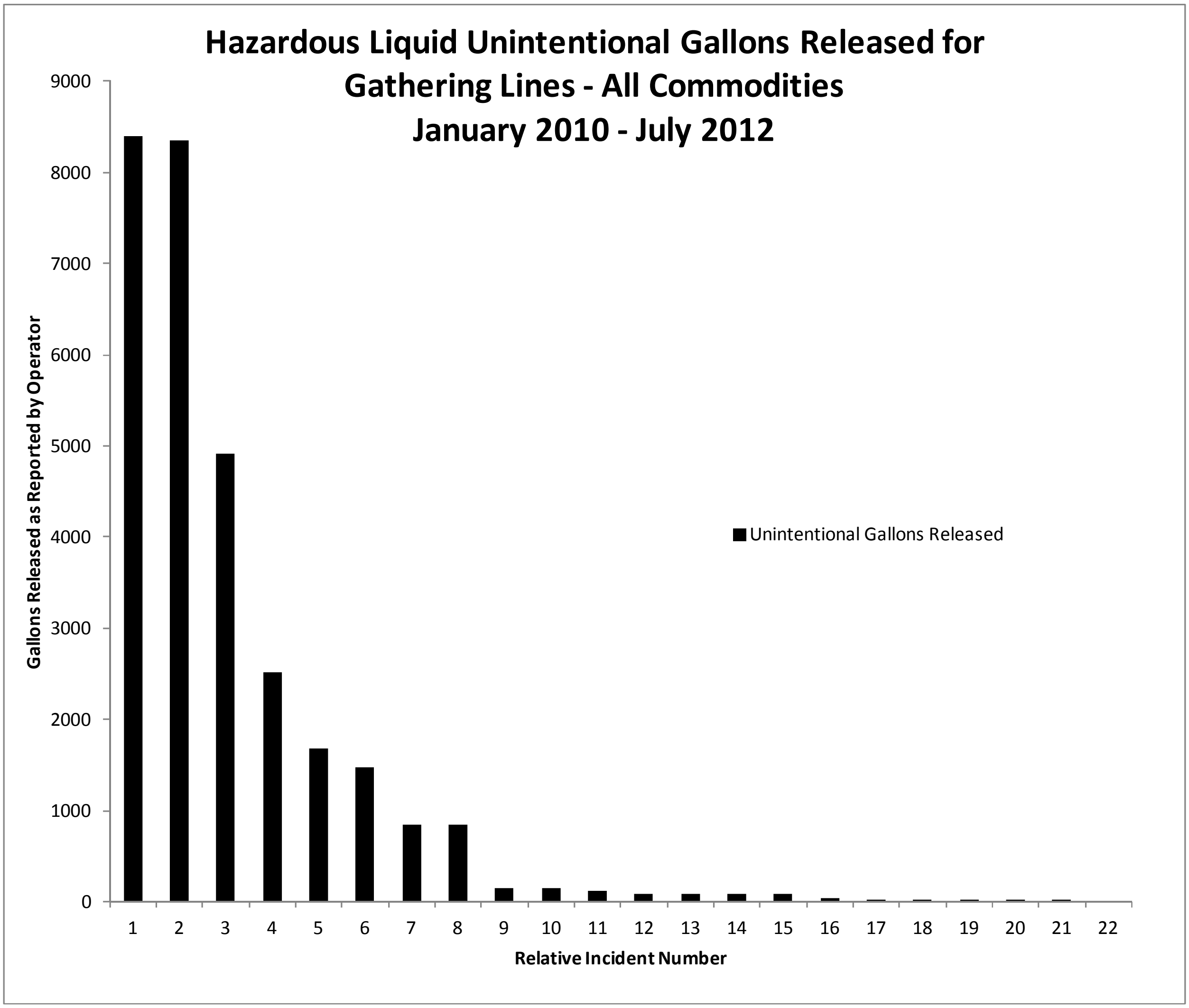


Figure 3.17 Hazardous Liquid Gathering Lines Releases (Gallons)

Hazardous liquids incident reports require operators to identify the status of not only the pipeline SCADA but also the computational pipeline monitoring (CPM) system. Both SCADA and CPM systems are seen as primary means within the control room for pipeline operating personnel to detect releases[6] on hazardous liquid pipelines. The response data associated with SCADA and CPM functionality was assessed for all 22 releases. Table 3.6 summarizes the data provided in the incident reports for whether:

1. A SCADA system was operational at the time of the incident.
2. The SCADA was functioning when the incident occurred.
3. The SCADA information assisted in the detection of the incident.

[6] See Task 4 for descriptions of the capabilities of SCADA and CPM.

4. The SCADA information assisted in the confirmation of the incident.
5. A CPM system was in place.
6. The CPM system was operating at the time of the incident
7. The CPM system was functional at the time of the incident.
8. The CPM system assisted in the detection of the incident.
9. The CPM system assisted in the confirmation of the incident.

Table 3.6 Hazardous Liquid Gathering Lines Releases, SCADA, CPM Detail

	# of Reports	% of Total Reports
SCADA System in Place	5	23%
SCADA System NOT in Place	9	41%
SCADA System in Place BLANK-No Data	8	36%

	# of Reports	% of Total Reports	% of Reports where SCADA was In Place
SCADA System Operating at Time of Accident	5	23%	100%
SCADA System Functional at Time of Accident	5	23%	100%
SCADA Assisted in Detection of Accident	1	5%	20%
SCADA Assisted in Confirmation of Accident	1	5%	20%
# of Reports with Both SCADA and CPM in Place	1	5%	20%

	# of Reports	% of Total Reports
CPM System in Place	1	5%
CPM System NOT in Place	13	59%
CPM System in Place BLANK-NO Data	8	36%

	# of Reports	% of Total Reports	% of Reports where CPM was In Place
CPM System Operating at Time of Accident	1	5%	100%
CPM System Functional at Time of Accident	1	5%	100%
CPM Assisted in Detection of Accident	0	0%	0%
CPM Assisted in Confirmation of Accident	0	0%	0%

January 2010 to July 2012

For the 22 incident reports, a SCADA system was in place for 5 (23%) of the incidents. 8 (36%) of the incident reports did not respond to this question.

For the 22 incident reports, a CPM system was in place for 1 (5%) of the incidents. One CPM system was reported as functional at the time of the incident. A CPM system was not in place at the time of an incident for 13 (59%) of the reports in the database. Eight (36%) of the incident reports did not give an answer to this question as to whether a CPM was in place or not.

The number of incident reports where both SCADA and a CPM system was in place was 1, or 5% of all 22 reports.

The SCADA was reported as functional in 5 of the 22 reported incidents, which is 100% of the incidents where a SCADA was operational at the time of the incident. 1 (one) of the incident reports stated that SCADA assisted in the detection of the incident. This is 20% of the incident reports that stated a SCADA was operational at the time of the incident.

0% of the 22 incident reports where CPM was functional stated that CPM assisted in the detection of the incident.

The statistics on SCADA and CPM are shown in Figure 3.18 and Figure 3.19 but related to gallons released to the environment. Figure 3.18 shows the gallons released where SCADA was either functional, not functional or where information on SCADA was not reported. The SCADA was reported as functional in 5 out of 22 incidents. Figure 3.19 shows the gallons released where the CPM was either functional, not functional or where information on CPM was not reported. There was one reported incident (in black) when the CPM system was functional.

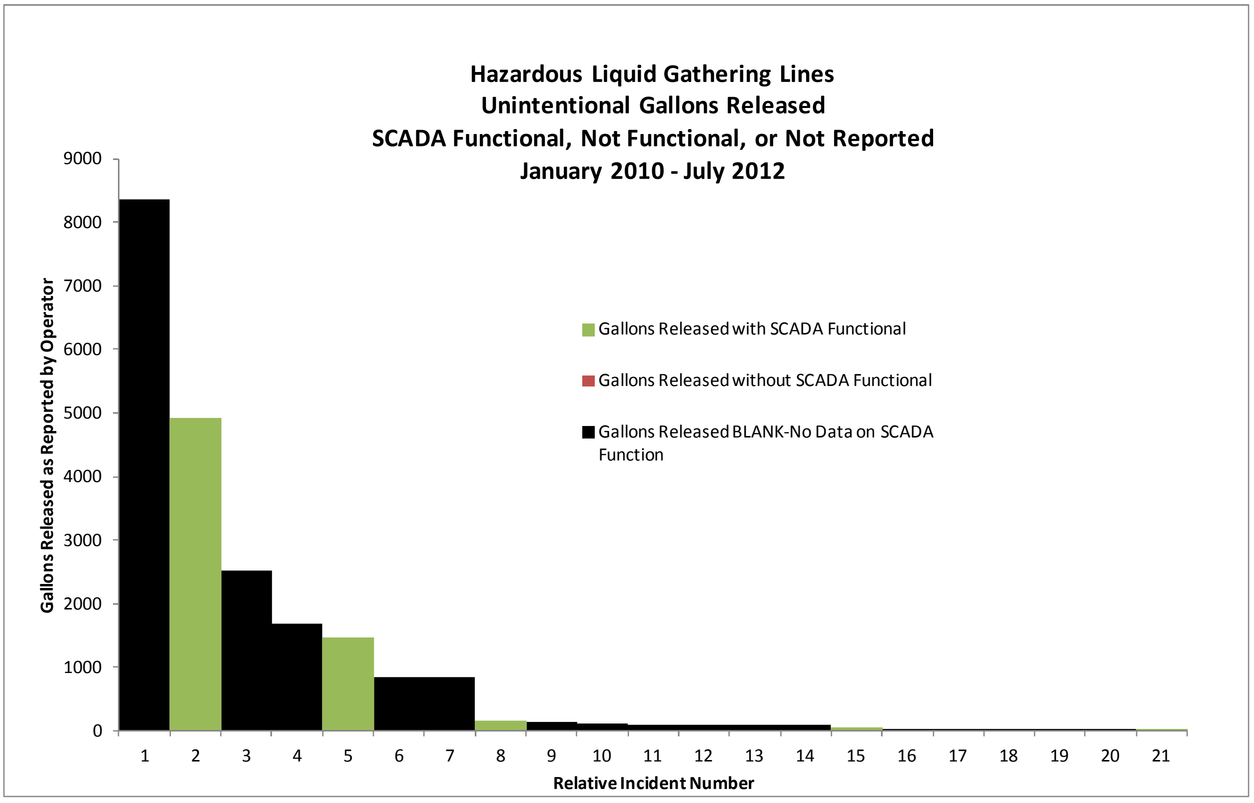


Figure 3.18 Hazardous Liquid Gathering Lines Releases (Gallons), SCADA Detail

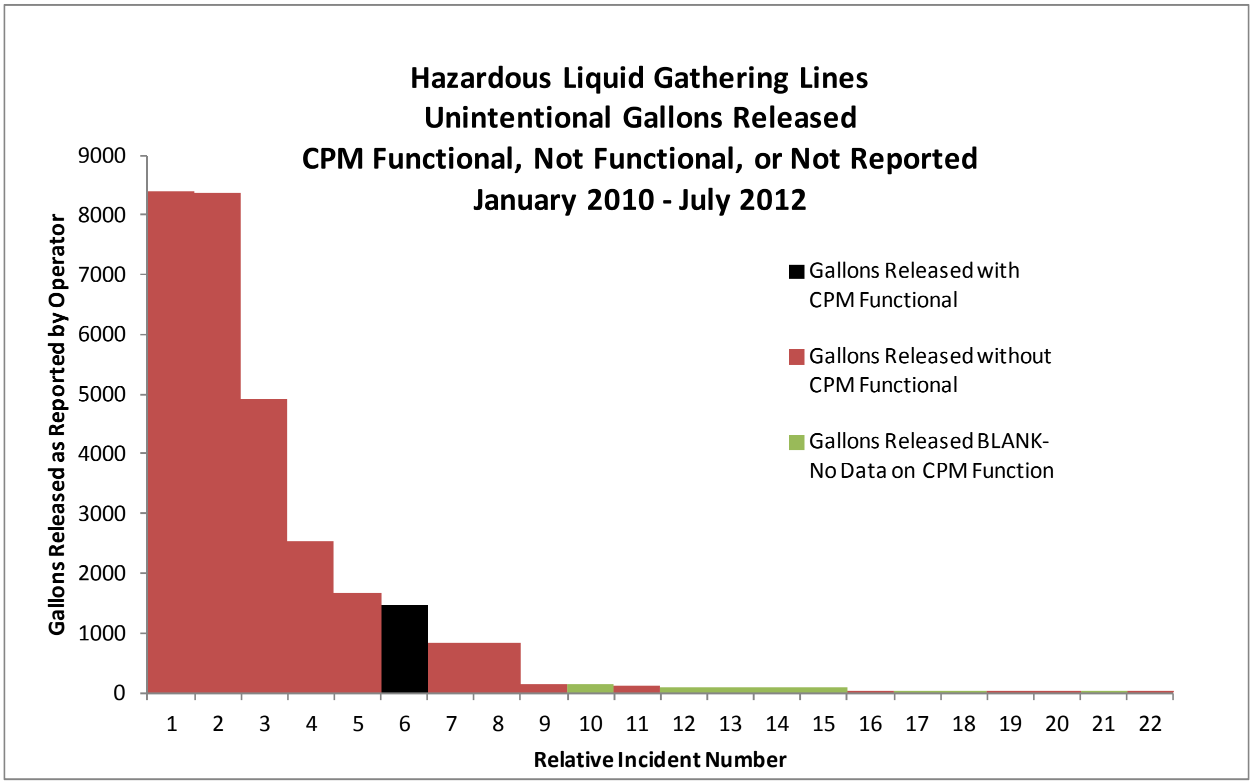


Figure 3.19 Hazardous Liquid Gathering Lines Releases (Gallons), CPM Detail

The review now looks at how these releases were initially detected. That is, how did the pipeline controller in the control room discover that fluid was escaping from the pipeline so that appropriate action could be taken. Figure 3.20 shows the gallons released per incident where the SCADA or CPM is the initial identifier of the release, which is zero in this case. Color Red in Figure 3.20 shows the incidents and gallons released when neither the SCADA nor the CPM was the initial identifier of the release.

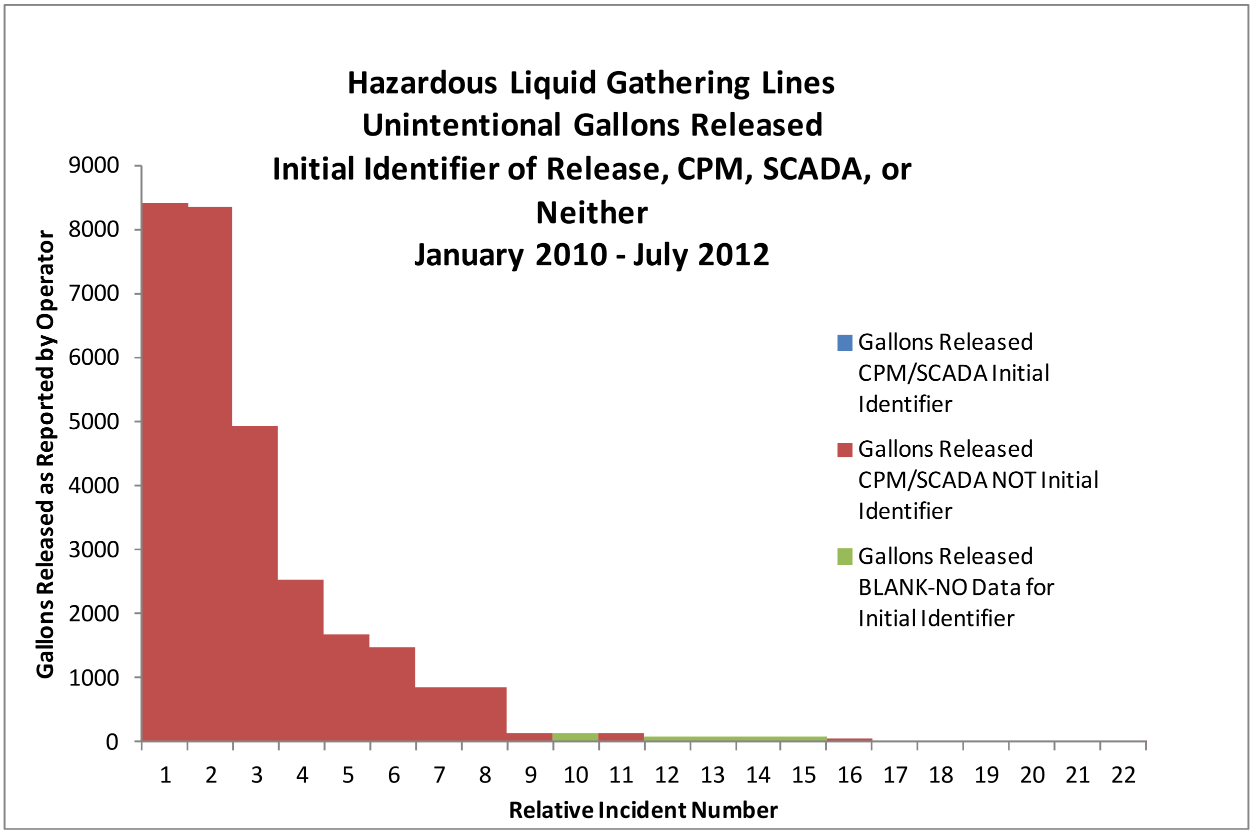


Figure 3.20 Hazardous Liquid Gathering Lines Releases, Initial Identifier SCADA, CPM

Figure 3.21 presents a pie-chart showing the means by which a control room was notified of a release for 14 out of 22 incidents. Data was not available for 8 of the incident reports. The different means of incident identification are tabulated in Table 3.7.

1. The public (32%).
2. Third party that caused accident (14%).
3. Local operating personnel including contractors (9%).
4. Air patrol (5%).
5. Emergency responder (5%).
6. Blank-no entry (36%).

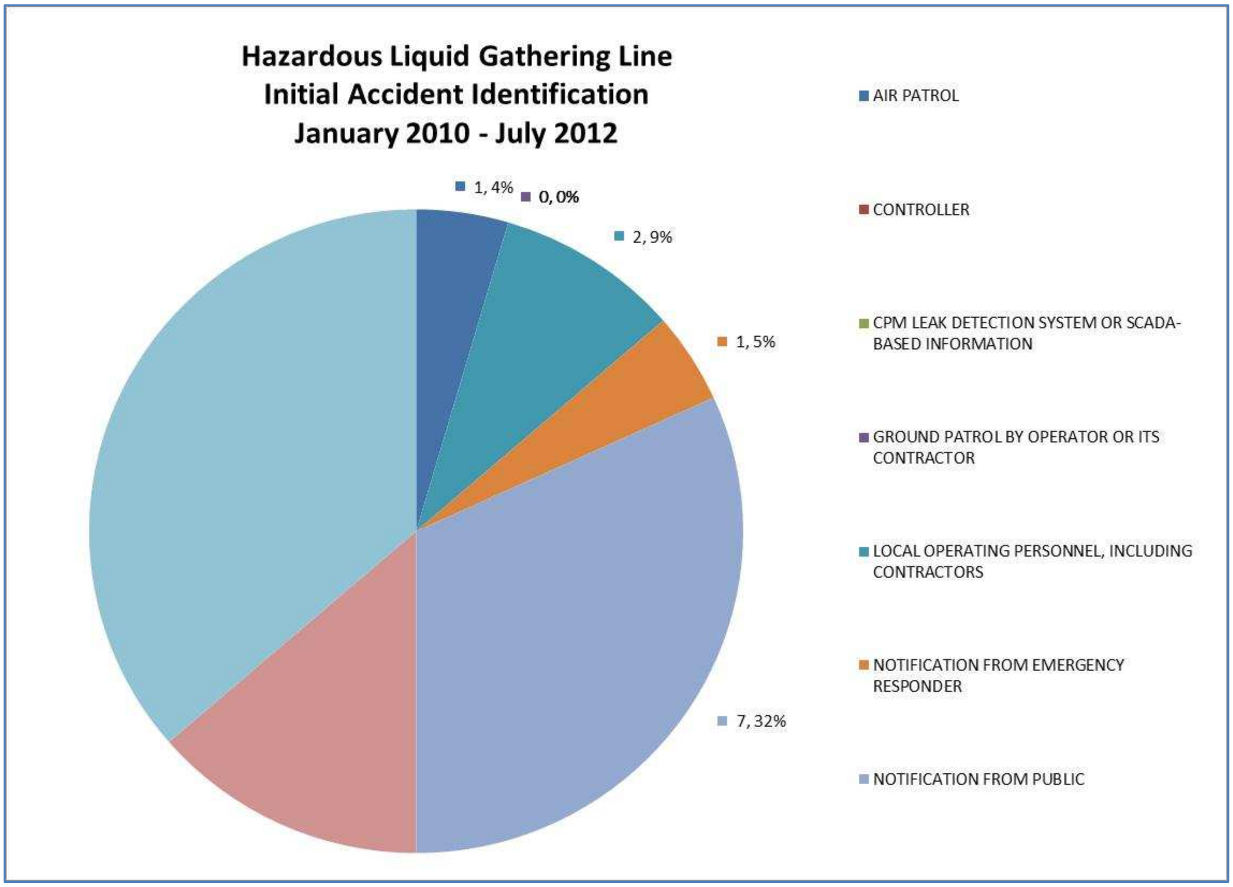


Figure 3.21 Hazardous Liquid Gathering Lines Releases, Initial Identifiers

Table 3.7 Hazardous Liquid Gathering Lines Releases, Initial Identifier

Methodology	# 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 ACCIDENT	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

When the public, including emergency responders, are the initial identifiers (37% in the above statistics), the elapsed time before the control room is aware of a release may be longer than when operator employees and contractors become aware of a release because of their better knowledge and training on what to do.

Once a release is detected there is a need to respond to the release. PHMSA incident reporting requires operators to provide the date and time the incident was identified by the operator. This is not necessarily the date and time that a release from a pipe body or pipe seam started. Other information provided is the date and time for operator personnel to arrive at the site of the release and the date and time the pipeline was shutdown.

There is not a requirement to report the date and time when the control room became aware of the incident. Nor is there a requirement to record how long the control room took to acknowledge a release had occurred and then to take action. The requirement is to report when an operator became aware of the incident. This date and time may well apply to operator employees and contracts out on the ROW or in a facility.

When an operator reports a date and time to arrive on site, the PHMSA instructions do not require this date and time to relate to the date and time the incident was initially identified. Where operator employees or contractors are the initial incident identifiers, then the time is identical for both the initial identification and the time to arrive on-site. The time to arrive on-site in this situation is zero.

It was possible to calculate the time to arrive on-site after the time of initial identification by the operator for 20 incidents reports from the total of 22. Figure 3.22 shows this result. For 3 incidents the time to arrive was zero. The longest time to arrive was one hour and 15 minutes and there were 2 incidents where the time to arrive was above 1 hour. For the maximum release volume of 8,400 gallons, the time to arrive was zero minutes whereas for the second largest release volume of 8,358 gallons, the time to arrive was 18 minutes.

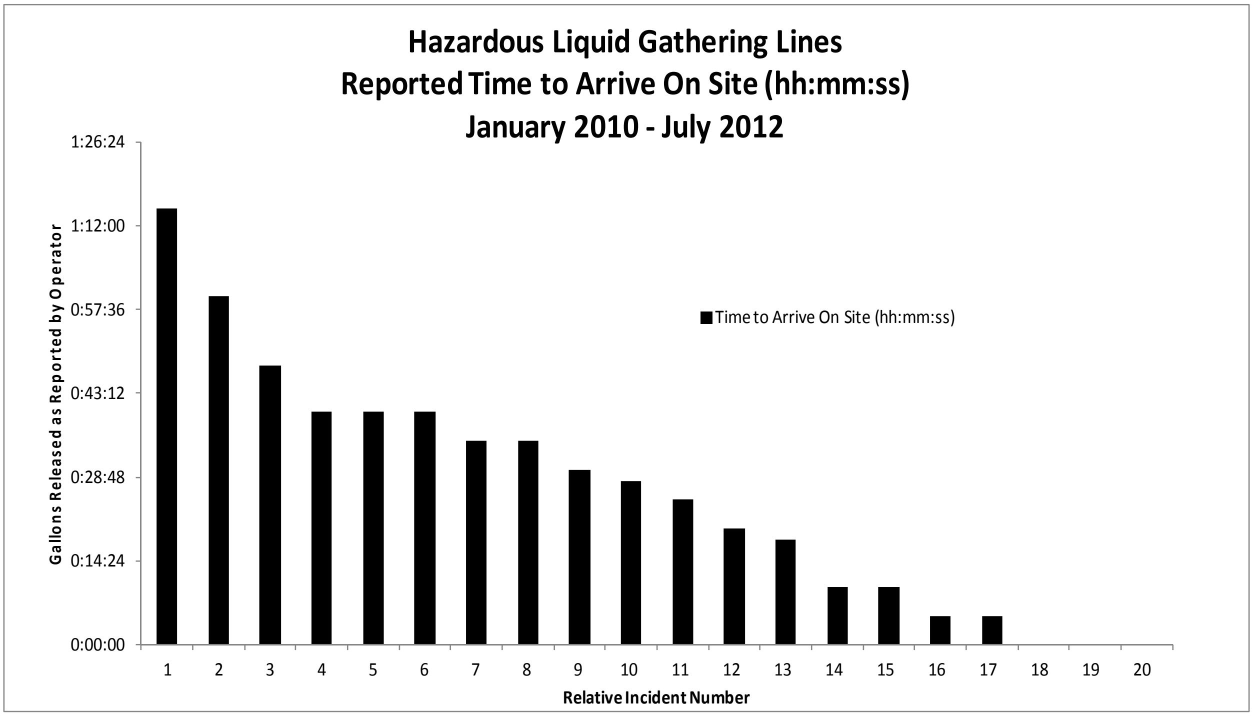


Figure 3.22 Hazardous Liquid Gathering Lines Releases, Response Times

Time to shut down the pipeline is taken to mean that pumping has ceased and the upstream and downstream block valves have been shut to isolate the section of pipeline with the release. The review of the incident data showed the following for 22 incident reports:

1. No shutdown time was reported for 8 (36%) of the incidents. Not all pipelines are shutdown as a result of a release.
2. 4 (18%) of the incident reports had identical dates and times for the incident identification and the shutdown. This results in zero minutes to shut down the pipeline.
3. The shortest shutdown time was 0 minute and the longest calculated shutdown time was 1 hour and 15 minutes.
4. 5 of the 22 incidents reported had a shutdown time of 0 minutes.
5. Only 1 of the 22 had a shutdown time longer than 1 hour.
6. 3 of the 22 had a shutdown time between 15 minutes and 30 minutes.
7. 5 of the 22 had a shutdown time between 1 minute and 15 minutes.

3.7.4 Hazardous Liquid Case Studies

From the 28 incidents described in the previous section, 11 incidents were selected as case studies.

The 11 releases selected had CAOs, FIRs or other documentation in addition to the PHMSA incident reports that enabled KAI to comment on the incident in question. These 11 incidents with the gallons released into the environment, starting with the maximum volume are:

1. 20100181 Enbridge Energy Pipeline Partnership LLC, 843,444 gallons.
2. 20100021 Enbridge Energy Pipeline Partnership LLC, 158,928 gallons.
3. 20100220 TE Products Pipeline Company, LLC, 137,886 gallons.
4. 20100163 Dixie Pipeline Company LLC, 130,368 gallons.
5. 20120041 Sunoco Pipeline L.P., 81,900 gallons.
6. 20110262 ExxonMobil Pipeline CO., 63,378 gallons.
7. 20100287 Shell Pipeline Co., L.P., 43,260 gallons.
8. 20100201 Amoco Oil Co, 38,640 gallons.
9. 20110335 Enterprise Products Operating LLC, 34,356 gallons.
10. 20100146 Chevron Pipe Line Co, 33,600 gallons.
11. 20110331 Magellan Pipeline Company, LP, 29,988 gallons.

Task 3 Appendix A provides details for each of these 11 case studies.

These 11 case studies can be summarized by the following taken from the incident reports submitted by operators:

a) 5 releases were crude oil with a total of 1,425,606 gallons.
b) 2 releases were HVLs with a total of 268,254 gallons.
c) 4 releases were refined products with a total of 184,884 gallons.
d) 3 were ruptures.
e) 3 were leaks, 2 of which are described as pinhole leaks.
f) One was a mechanical puncture.
g) 4 other release types, one described as a crack, one as an electric arc, one a circumferential break, and one combing corrosion and cracking.
h) One explosion.
i) 6 were described as located HCAs.
j) 4 incidents had remotely controlled valves
k) 4 incidents had automatic valves, which are assumed to be remotely controlled valves.

l) 2 incidents had manual valves and one incident did not comment.

m) 10 of the 11 case studies used internal inspection.

n) SCADA was functional in all case studies and 7 releases were detected by SCADA.

o) CPM was functional in 9 of the 11 incidents and CPM detected 3 of the 11 incidents.

p) For 6 of the incidents, the incident identifier was in the control room and for the other 5 incidents the identifier was the public.

q) Times taken for arrival on-site following identification to control were between zero and 2 hours and 49 minutes. These times were taken from the incident reports filed by the operators.

r) The times taken to shut-down the pipeline, where applicable, were between zero and 12 minutes. These times were taken from the incident reports filed by the operators.

Individual Case Studies

The 11 case studies listed above are now reviewed individually in the order they are listed above. Refer to Task 3 Appendix A for details about the incidents. The purpose of the review here is to extract relevant information about the use of LDS in each of these 11 cases. The information used is all public information. The cause of the release is mentioned only when relevant.

The point of view for these studies is that the pipeline controller in the control room is “driving” a pipeline or a number of pipelines. What the pipeline does or doesn’t do is under the control of the controller. The information a controller receives and the timeliness of that information is pertinent to how quickly a controller reacts to changing circumstances. Under all operating conditions, a pipeline controller needs to understand how the pipeline may react and what the pipeline instrumentation is going to tell him for those conditions.

The data presented here comes from reports submitted by the operators to PHMSA, Corrective Action Orders issued by PHMSA and Failure Investigation Reports issued by PHMSA. The authors did not have the time or resources to confirm the accuracy of this information. Most dates and times are taken from the incident report filed by operators.

Enbridge Energy Pipeline Partnership LLC, 843,444 gallons

This incident is very well known in the industry. It was a rupture that released 843,444 gallons of crude oil in to the environment on the ROW from a 30-inch diameter pipeline. This is a very large release volume. The National Transportation Board has produced a report on this incident, which includes how such a large volume release happened. For a chronological sequence of events, the reader is referred to that report.

The pipeline in question was on a shutdown- start up schedule. The pipeline was shutting down when the ruptured occurred. Documentation indicates that a SCADA alarm did sound coincident with the most likely time of the rupture. It was dismissed. The line was shut down for around 10 hrs and crude oil would have drained from the line during this time.

On pipeline start up, alarms in the control room for the ruptured pipeline sounded. They were dismissed. This was repeated two more times. The pipeline was shut down when the control room was notified of the discharge of the crude oil by a member of the public. The time to shut down the pipeline is not relevant here because of the 17 hours that elapsed after the rupture occurred.

The incident report states that the SCADA and CPM did not assist with the detection of the release.

Our review identified the following issues relevant to this Leak Detection Study:

1. Instrumentation on a pipeline that informs a controller what is happening to the pipeline must be definitive in all situations.
2. However, the instrumentation did provide warnings which went unheeded by controllers.
3. Instrumentation could be used to prevent a pump startup.
4. Operators should not rely on the public to tell them when a pipeline has ruptured.
5. Pipeline controllers need to be fully conversant with instrumentation response to different operations performed on the pipeline.
6. If alarms can be cancelled there is something wrong with the instrumentation feedback loop to the controller. This is akin to the low fuel warning on a car being turned off and ignored. The pipeline controller is part of an LDS and failure by a controller means the LDS has failed even if the instrumentation is providing correct alarms.
7. If the first SCADA alarm had been investigated, up to 10 hours of pipeline drainage to the environment might have been avoided. If the second alarm had been investigated, up to 7 hours of pumping oil at almost full capacity into the environment might have been avoided.
8. CPM systems are often either ignored or run at much higher tolerances during pipeline startups and shutdowns, so it is probable that the CPM was inoperative or unreliable. SCADA alarms, on the other hand, should apply under most operating conditions.

Enbridge Energy Pipeline Partnership LLC, 158,928 gallons

This incident is a rupture that released 158,928 gallons of crude oil in to the environment from a 26-inch diameter pipeline. Of the 28 above-average release volumes discussed earlier, this release was the sixth largest. Documentation indicates a rapid shut down on a low suction alarm by the pipeline controller. From rupture to shut down is recorded as taking 4 minutes. The length of pipeline isolated by upstream and downstream remotely controlled valves was 220,862 feet. The inventory for this length of line of 26-inch diameter is 799,497 gallons. The release amount was around 20% of the isolated inventory when the pipeline was shut down.

The orientation of the 50-inch long rupture in the pipe seam is not known. The terrain and elevation of the pipeline is not known. The operator took around 2 hours and 40 minutes to arrive on site. It is surmised that the rupture orientation and local terrain along with the very quick reactions by the pipeline controller may have contributed to the loss of around 20% of the isolated inventory.

The controller was alerted by the SCADA. Although a CPM system was functional the time of the incident it did not play a part in detecting the release event. It did provide confirmation.

Our review identified the following issues relevant to this Leak Detection Study:

1. This release is documented as a text book shut down of a pipeline based on a SCADA alarm.
2. The LDS did not play a part in alerting the pipeline controller according to documentation. However, leak detection using Flow/Pressure Monitoring via SCADA worked well.
3. Although a textbook shut down in 4 minutes is recorded, a large release volume still occurred.
4. The release volume of 158,928 gallons of crude oil is the sixth largest hazardous liquid release reported between January 1, 2010 and July 7, 2012.
5. The length of pipeline between upstream and downstream isolation valves is long at 41.8 miles.
6. If not already performed, the operator should review potential release volumes based on ruptures taking place at different locations on the isolated section.
7. The success of a leak detection system includes planning for the entire process: detection through shutdown through containment. In this case, the operator did not plan adequately for containment so that although the SCADA leak detection technology, the controller and the procedures worked well, the containment systems (isolation valves) were under-designed and placed to allow a very large spill.

TE Products Pipeline Company, LLC, 137,886 gallons

This incident was a release of 137,886 gallons of propane from an 8-inch pipeline through a circumferential crack in the heat affected zone adjacent to a butt weld. The cracking was determined to be stress corrosion cracking and had a length of some inches around the bottom quadrant of the pipe. The pipeline controller was notified by Schoharie County Emergency Management Director after he had been informed by the County Sherriff's department who had been informed by a member of the public. This sequence is recorded as taking 8 minutes. The pipeline operator responded to County Emergency Management Director by checking instrumentation and shut in the pipeline 25 minutes following the call by the County Emergency Management Director. The total time from public identification of a release to shut in of the pipeline was 33 minutes.

The release is considered a leak and not a rupture.

The operator reported that both SCADA and the CPM were functional the time of the incident but neither system assisted in the detection of the release. According to the failure investigation report, a lower than expected pressure reading was observed in the control room about 2 minutes prior to the 911 call made by the member of the public made. The pipeline controller did not react to this as a potential leak in the pipeline.

Both the upstream and downstream block valves were manually operated. This release was the ninth largest release in the incident data between January 1, 2010 and July 7, 2012.

Our review identified the following issues relevant to this Leak Detection Study:

1. Operators should not rely on the public to tell them when a pipeline has ruptured.
2. The SCADA and CPM did not assist the pipeline controller in confirming there was a release on the pipeline.
3. It is generally expected that control room instrumentation should detect leaks of the kind encountered in this incident.
4. It suggests that better LDS is required to detect leaks like in this incident.

Dixie Pipeline Company LLC, 130,368 gallons

This is a release of 130,368 gallons from an 8-inch pipeline transporting propane. It is the tenth largest release in the hazardous liquid releases reported between January 1, 2010 and July 7, 2012. The release was caused by the property owner hitting and puncturing the pipeline with a mechanical digger. The release was classified as a rupture. No one call was made by the property owner prior to starting to dig.

The property owner who punctured the pipeline called 911. It took approximately 5 minutes for the property owner to make the 911 call based on SCADA alarms in the pipeline control room. The control room shut down the pipeline within about 12 minutes of the SCADA alarm. The upstream and downstream valves were closed by the control room. Manually operated valves closer to the release location were closed later on.

The incident report indicates there was no CPM on the pipeline.

Our review identified the following issues relevant to this Leak Detection Study:

1. The rupture was detected by the SCADA and the control room reacted to the alarm.
2. Upstream and downstream valves were closed by the control room.
3. An unfortunate incident as a result of the property owner not identifying the location of a pipeline on his property before digging with a mechanical excavator capable of puncturing a steel pipeline.

Sunoco Pipeline L.P., 81,900 gallons

This release was 81,900 gallons of gasoline from an 8-inch diameter pipeline in a parking lot. The release is classified as a leak but there are no details as to the cause of the release. The identifier of the release is reported as both SCADA and CPM in the control room. Incident reports indicate the pipeline was shut down in 4 minutes. The valves both upstream and downstream of the release location were automatic valves. The length of the isolated section is not recorded.

Our review identified the following issues relevant to this Leak Detection Study:

1. SCADA and CPM alerted the pipeline controller to shut down the pipeline.
2. Despite a very quick shut down (4 minutes) and the pipe being 8-inch in diameter a relatively large volume of gasoline was released in to the HCA environment.

ExxonMobil Pipeline CO., 63,378 gallons

This release was a rupture of a 12-inch diameter crude oil pipeline releasing 63,378 gallons in to the environment (Yellowstone River). The rupture was detected in the control room and the pipeline controller initiated a shutdown of the pipeline. Both the SCADA and CPM are reported to have detected the rupture. Pumps were shutdown 7 minutes after the recognition of the failure from the SCADA and CPM. Upstream block valve isolation was achieved 48 minutes later.

The isolated section is given in the incident report as 1,709 feet. The inventory for this length of pipeline is 10,214 gallons. Approximately, 6.2 times of the isolated inventory was released in to the Yellowstone River during the time it took to isolate the ruptured section.

Our review identified the following issues relevant to this Leak Detection Study:

1. SCADA and CPM alerted the pipeline controller to shut down the pipeline.
2. Pumps were shut down quickly in 7 minutes.
3. Possibly hesitation on the part on the operator in isolating the failed section of pipeline may have contribution to a higher release volume.

Shell Pipeline Co., L.P., 43,260 gallons

This release was rupture of crude oil form a 22-inch diameter pipeline of 43,260 gallons. Both SCADA and CPM are reported as detecting the release. The sequence of events for this release cannot be determined from documentation presently available to the authors. The incident report indicates that the pipeline was shutdown approximately 30 minutes before the incident was identified.

Our review identified the following issues relevant to this Leak Detection Study:

1. SCADA and CPM alerted the pipeline controller to shut down the pipeline.
2. Data in the incident report database should be checked for consistency when entered .

Amoco Oil Co, 38,640 gallons

This release was a leak of 38,600 gallons of gasoline or diesel fuel from a 10-inch/12-inch diameter pipeline. The release occurred at a traffic intersection in the town of Hammond IN. The release was identified by an emergency responder who smelled the refined product in a sewer drain. The incident report identifies the incident was recorded at 9:48 am on August 17, 2010. The pipeline shutdown was recorded at 9:49 am, a time to shutdown of 1 minute. The incident identification was also recorded at 9:48 am. On-site arrival time was 1 minute later at 10:00 am.

The leak was caused by a pinhole due to external corrosion. Neither SCADA nor CPM detected the leak. Neither SCADA nor CPM confirmed the leak,

Our review identified the following issues relevant to this Leak Detection Study:

1. SCADA and CPM did not alert the pipeline controller to shut down the pipeline.
2. From the data available it is not possible to determine how long fluid had been leaking from the pipeline before the emergency responder notified the controller.

Enterprise Products Operating LLC, 34,356 gallons

This release was a circumferential break of 34,356 gallons of propane an 8-inch diameter pipeline located beneath the Missouri River. The release was identified by the controller via the SCADA system. The CPM was functional but did not detect or confirm the release. The control notice a drop in discharge pressure at 1:57 am on August 13, 2011. A low suction pressure alarm confirmed a problem. The pipeline shutdown was started at 2:19 am. Complete shutdown was hindered by one of the crossing remotely controlled block valves having been electrically isolated in June 2011 due to high water levels. This second block valve was shut at 2.29 am. The total shutdown time was 32 minutes. The incident identification is recorded as 2:16 am. The on-site arrival time is recorded as 3:30 am.

Our review identified the following issues relevant to this Leak Detection Study:

1. SCADA alerted the pipeline controller to shut down the pipeline.

2. The CPM system did not alert the controller to shut down the pipeline.

3. The shutdown time may have been prolonged due to one block valve not being immediately operable by the control room.

Chevron Pipe Line Co, 33,600 gallons

This was a 33,600 gallon release of crude oil from a 10-inch diameter pipeline. The leak was caused by electrical discharge causing a hole (approximately 0.5-inch diameter) in the pipe. The crude oil ran in to a creek and then in to a pond.

The incident date and time and the shutdown date and time in the incident report leading to a zero minute shut down. The incident identification data and time is also the same. The incident identifier was an emergency responder. SCADA did not detect or confirm the release. The incident report states that a CPM system was not in place.

The following is taken from a failure investigation report:

"Chevron Pipe Line Company (Chevron) operates a 10" pipeline from their Rangely Terminal in Colorado to their Salt Lake City (SLC) refinery. The last pump station is before Wolf Creek Pass and the crude oil is in slack line flow much of the way from Wolf Creek Pass to SLC. Because of the slack line conditions, it is difficult to identify small leaks on the last 50 miles of pipe. This section of pipeline is low pressure and Chevron uses a meter in/meter out volume balance SCADA system. Because of the slack line conditions, low pressure, and changing density of the crude oil being transported, there are times during normal routine operations where the metering can show positive for hours and alternatively can show negative for hours. "

"A PHMSA engineer reviewed the data received by Chevron's Controller who was on duty throughout the evening of June 11, 2010, through 6:00 am June 12, 2010. An analysis of the data was performed and it is apparent that even though the metering was trending negative, the downstream pressure was increasing. This combination of information told the Controller that everything was progressing normally. At approximately 10:18 CST (9:18 MST), the Controller received a notice that the pressure transmitters at the Red Butte Block Valve approximately 300 feet downstream of the release site were not communicating. The Controller was aware of the storms in the SLC area because of verbal communications with the SLC operator. The Controller did have other pressure transmitters in close proximity to the failed pressure sensors and so continued operations. The Controller initiated a shift of crude from condensate to heavier crude on June 12, 2010, at 4:57 CST (3:57 MST). The SCADA metering continued a negative trend but the downstream pressure were generally on the increase and the Controller thought that the negative metering was due to the crude density switch and the metering loss improved the next hour so the Controller made an educated decision to continue normal operations."

Our review identified the following issues relevant to this Leak Detection Study:

1. The SCADA system did not alert the pipeline controller to the leak.

2. No CPM system was in place.

3. The operator relied on an emergency responder to establish the incident.

4. Different possible outcomes for metering and pressures reading combinations need to be understood and additional instrumentation may be necessary to resolve some situations where the metering and pressure monitoring can lead to conflicting results.

Magellan Pipeline Company, LP, 29,988 gallons

This release was a pinhole leak of 29,988 gallons of refined product from a 12-inch diameter pipeline. The pipeline was not operational when the leak occurred and was shut down for a pressure test. The date and time the leak was known to the controller was 12:20 pm on August 12, 2011. No incident identification or on-site arrival data and time are recorded presumably because the pipeline was shut down. SCADA is recorded as detecting and confirming the leak but the CPM, recorded as functional, did not detect the leak or confirm the leak. The identifier is recorded as the SCADA/CPM system.

Our review did not identify any issues relevant to this Leak Detection Study.

3.8 Incident Reporting for the Natural Gas and Other Gas Transmission and Gathering Industry

3.8.1 Natural Gas and Other Gas Transmission and Gathering Lines Releases

For gas transmission incidents on the ROW, the 141 releases are divided into 86 from pipe body, 6 from pipe seams, 6 from valves, 1 from flanges, and 42 leaks from something other than pipe such as a girth weld, repairs, instrumentation etc. There are 92 incidents from pipe and pipe seam. The average release volume from these 92 incidents is 30,347 MSCF. The total release volume reported for the 141 incidents is 3,323,178 MSCF. The 141 incident reports came from 57 different operators. Of these 141 releases, 33 were attributable to ruptures, 61 to leaks, 22 to mechanical punctures, and 25 to other release types.

The largest release volume reported is 614,257 MSCF and the smallest is 1 MSCF.

The second largest hazardous liquid release volume is 313,870 MSCF or 51% of the largest release volume. Together, these two release volumes add up to 928,127 MSCF of natural gas and make up 38% of the total above-average release volume of 2,429,828 MSCF from 22 of the 141 incidents reviewed. Approximately 1 in 6 incidents on the ROW will produce a release volume between 23,078 MSCF and 614,257 MSCF of natural gas based on this data.

Figure 3.23 shows the reported release volumes (in MSCF) for all 141 ROW incidents. Many of the release volumes do not show in Figure 3.23 because of the left-hand scale used for the maximum size of volume released. Like the similar chart for hazardous liquids a large number of releases on a ROW are of relatively small volume. Although the larger volume releases are significant, the reader should remember that the scale of reported ROW releases covers a range of 1 MSCF to 614,257 MSCF. As with all graphs of this type in the report, the large volumes were so much greater than the smaller volumes that the scale of the vertical axis causes around 70% of the data to display very close to zero on the horizontal axis.

Nineteen of these 141 reported releases ignited and 9 of the 19 resulted in an explosion. These numbers for hazardous liquids were 5 ignitions and 2 explosions.

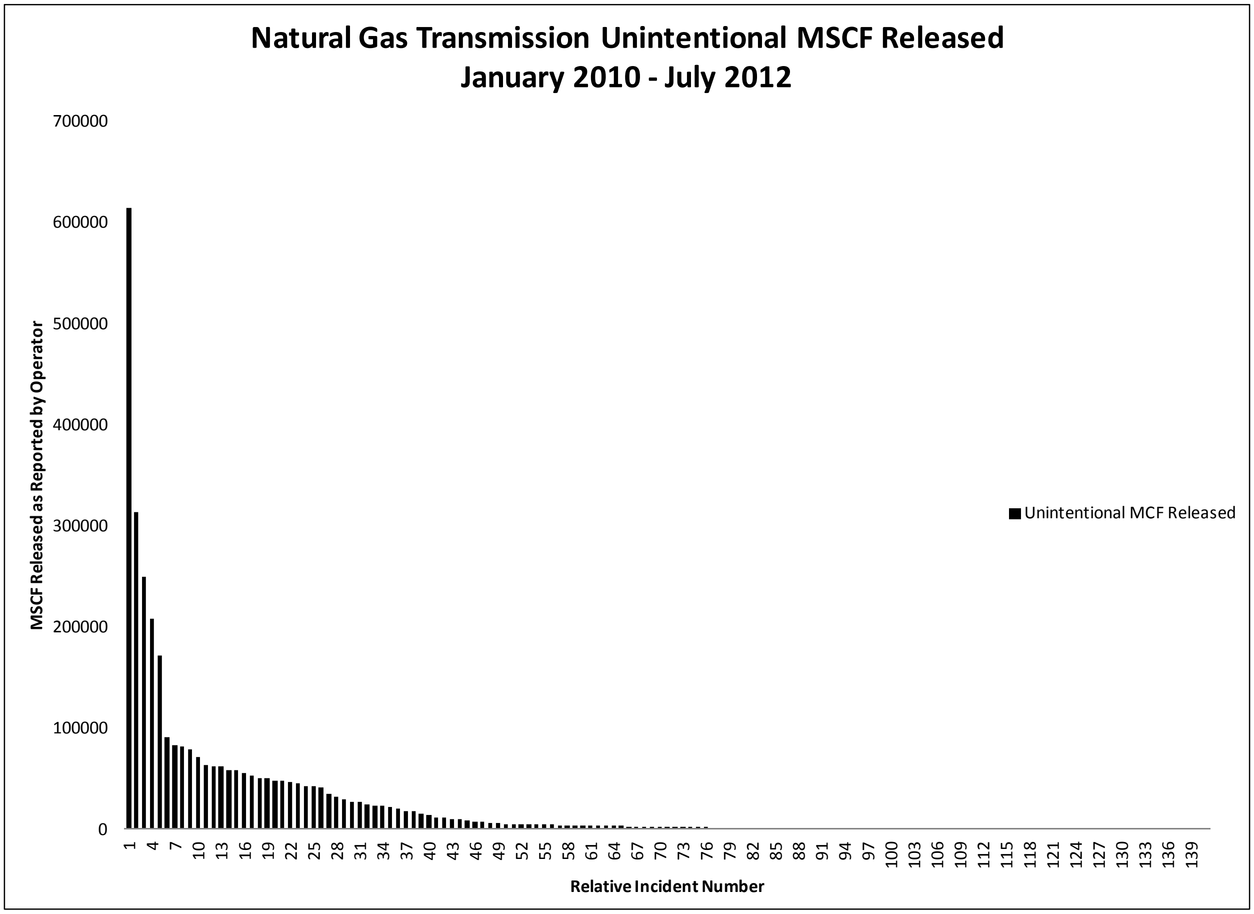


Figure 3.23 Natural Gas Transmission/Gathering Releases, January 2010 to July 2012

Gas transmission pipeline systems are not required to report LDS systems unlike the hazardous liquids systems. For gas transmission, incident reports require operators to only identify the status of the pipeline SCADA. Table 3.8 summarizes the data provided in the 141 incident reports for whether:

1. A SCADA system was operational at the time of the incident.
2. The SCADA was functioning when the incident occurred.
3. The SCADA information assisted in the detection of the incident.
4. The SCADA information assisted in the confirmation of the incident.

Table 3.8 Natural Gas Transmission/Gathering Releases, 2010 to July 2012, SCADA Detail

	# of Reports	% of Total Reports
SCADA System in Place	126	89.36%
SCADA System NOT in Place	15	10.64%
SCADA System in Place BLANK-No Data	0	0.00%

	# of Reports	% of Total Reports	% of Reports where SCADA was In Place
SCADA System Operating at Time of Accident	125	88.65%	99.21%
SCADA System Functional at Time of Accident	124	87.94%	98.41%
SCADA Assisted in Detection of Accident	45	31.91%	35.71%
SCADA Assisted in Confirmation of Accident	52	36.88%	41.27%

For the 141 incident reports, a SCADA system was in place for 126 (89%) of the incidents. For 15 of the incidents, the operators reported that a SCADA was not in place at the time of the incident. At the time of the incident, 124 of the SCADA systems were functional and 45 (32%) assisted in the detection of the release.

The above SCADA statistics are shown in Figure 3.24 but related to MSCF released into the environment. Figure 3.24 shows the MSCF released where SCADA was either functional (black), not functional (red) or where information on SCADA was not reported (green). Figure 3.24 shows that SCADA was functional for the large volume releases. The largest volume release where SCADA was reported as not in place and therefore was not functional (red) was 47,600 MSCF.

Figure 3.25 shows the release volumes that were initially detected by SCADA (black) and those where SCADA was not the initial identifier of the release (green). SCADA was the initial identifier for the largest release of 614,257 MSCF but was not the initial identifier for the next two largest releases of 313,870 and 250,000 MSCF.

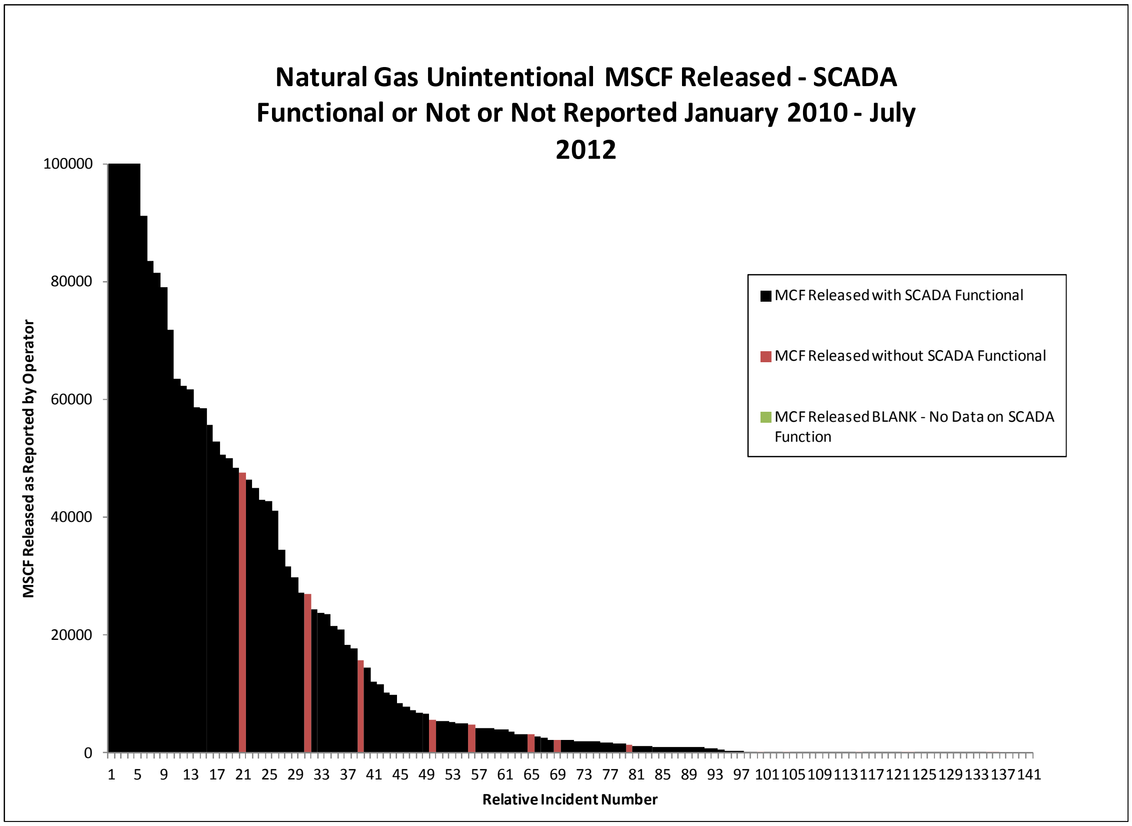


Figure 3.24 Natural Gas Transmission/Gathering Releases, SCADA Detail

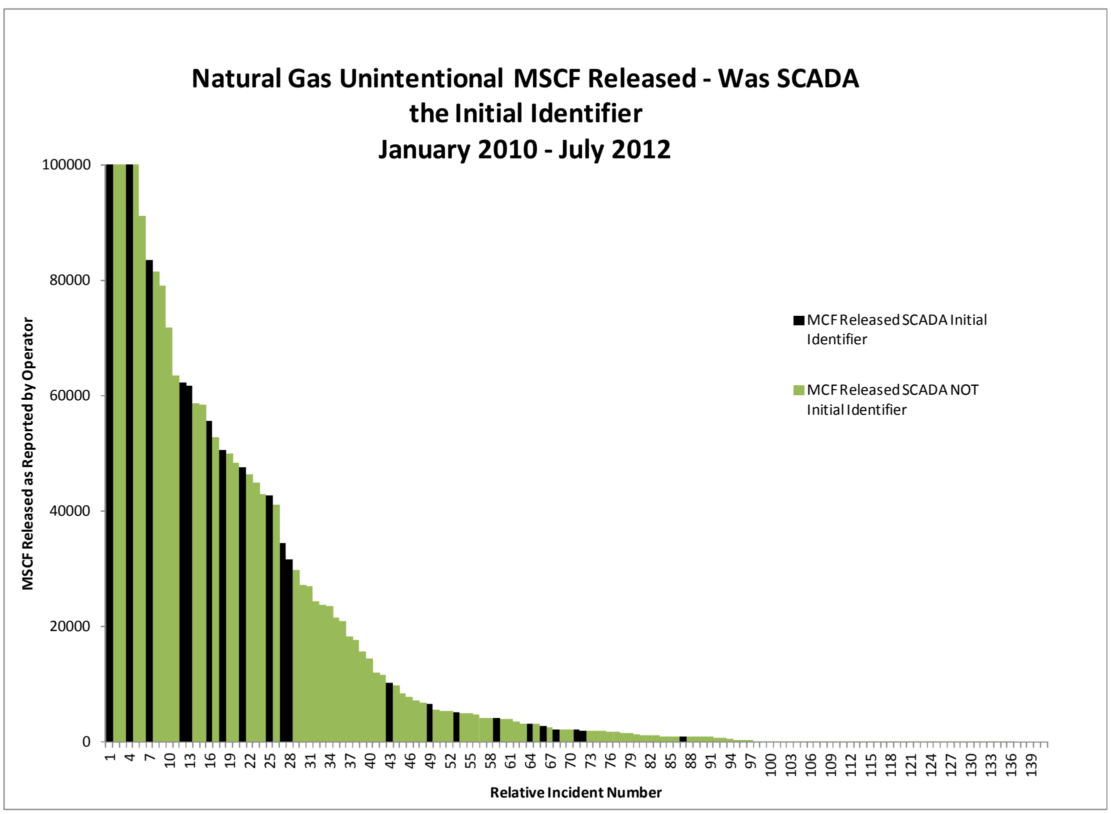


Figure 3.25 Natural Gas Transmission/Gathering Releases, SCADA Initial Identifier

Figure 3.26 presents a pie-chart showing the means by which an operator was notified of a release for all 141 incidents. The different means of initial incident identification are tabulated in Table 3.9. That is, who discovered the release first? The range of different initial identifiers is broad. The following categories seem appropriate:

1. Pipeline control and non control room personnel and contractors (52%).
2. The public (30%).
3. A third party on the ROW (11%).
4. Other (7%).

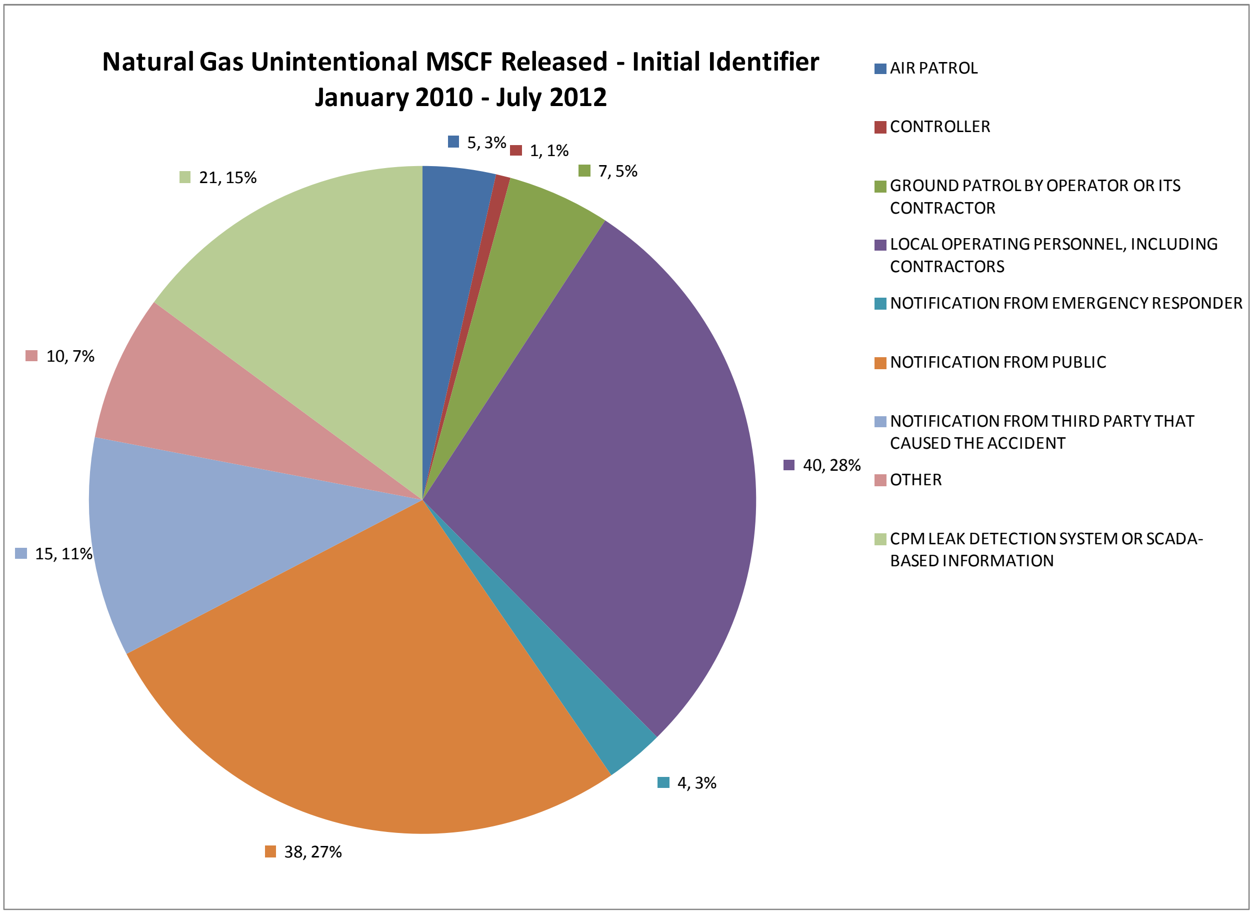


Figure 3.26 Natural Gas Transmission/Gathering Releases, Initial Identifier

A possible summary is that pipeline operators' or contractors to the pipeline operator discover half the releases on a pipeline ROW.

Within the 52% statistic for Pipeline control and non-control room personnel and contractors, 16% is attributable to the pipeline control room. This is a similar percentage as that observed for hazardous liquids for ROW releases.

Table 3.9 Natural Gas Transmission Releases, 2010 to July 2012, Initial Identifier

	# of Incidents	% of Incidents
AIR PATROL	5	3.55%
CONTROLLER	1	0.71%
GROUND PATROL BY OPERATOR OR ITS CONTRACTOR	7	4.96%
LOCAL OPERATING PERSONNEL, INCLUDING CONTRACTORS	40	28.37%
NOTIFICATION FROM EMERGENCY RESPONDER	4	2.84%
NOTIFICATION FROM PUBLIC	38	26.95%
NOTIFICATION FROM THIRD PARTY THAT CAUSED THE ACCIDENT	15	10.64%
OTHER	10	7.09%
CPM LEAK DETECTION SYSTEM OR SCADA-BASED INFORMATION	21	14.89%

January 2010 to July 2012

In terms of managing a release, particularly a rupture, a sequence of events might be described as:

1. Time to detection for the control room after the release as it is the control room that has means to shut down the pipeline.
2. A period where fluid is still being pumped into the environment.
3. A period during which valves are closed, the section isolated and drain down occurs.

Where a release is detected by someone other than in the control room the time taken for the control room to acknowledge a release and initiate further action is likely to be longer than when the control room is the initial identifier. Hence, for the 52% described above, it is likely that 35% of the incidents resulted in a longer detection period after the actual release from the pipeline.

When the public, including emergency responders, are the initial identifiers (30% in the above statistics), the elapsed time before the control room is aware of a release may be longer than when operator employees and contractors become aware of a release because of their better knowledge and training on what to do. However, incident reports do not contain data to allow this the different phases of a release to be evaluated.

The percentage of the public (30%) that are the initial identifiers of a gas transmission release is the same as that for hazardous liquids.

Once a release is detected there is a need to respond to the release. PHMSA incident reporting requires operators to provide the date and time the incident was identified by the operator. This is not necessarily the date and time that a release started from a pipe body or pipe seam. Other information provided is the date and time for operator personnel to arrive at the site of the release and the date and time the pipeline was shutdown.

The date on which the operator became aware of the release was not recorded for 7 (5%) of the 141 incident reports in this evaluation. Two of these incident 7 reports did identify the date and time of shutting down the pipeline.

It was possible to calculate the time to arrive on-site after the time of initial identification by the operator for 134 incident reports from the total of 141. Figure 3.27 shows this result. For 59 of these incidents the time to arrive on-site was zero minutes. For 54 of these incidents the time to arrive on site was from 2 minutes to 1 hour. For 21 of these incidents the time to arrive on site was from 1 hour 2 minutes to 14 hours and 39 minutes. For the maximum release volume of 614,257 MSCF, it was not possible to determine the time to arrive on site. The largest spill with a time to arrive on-site was 313,870 MSCF the on-site arrival took 26 minutes.

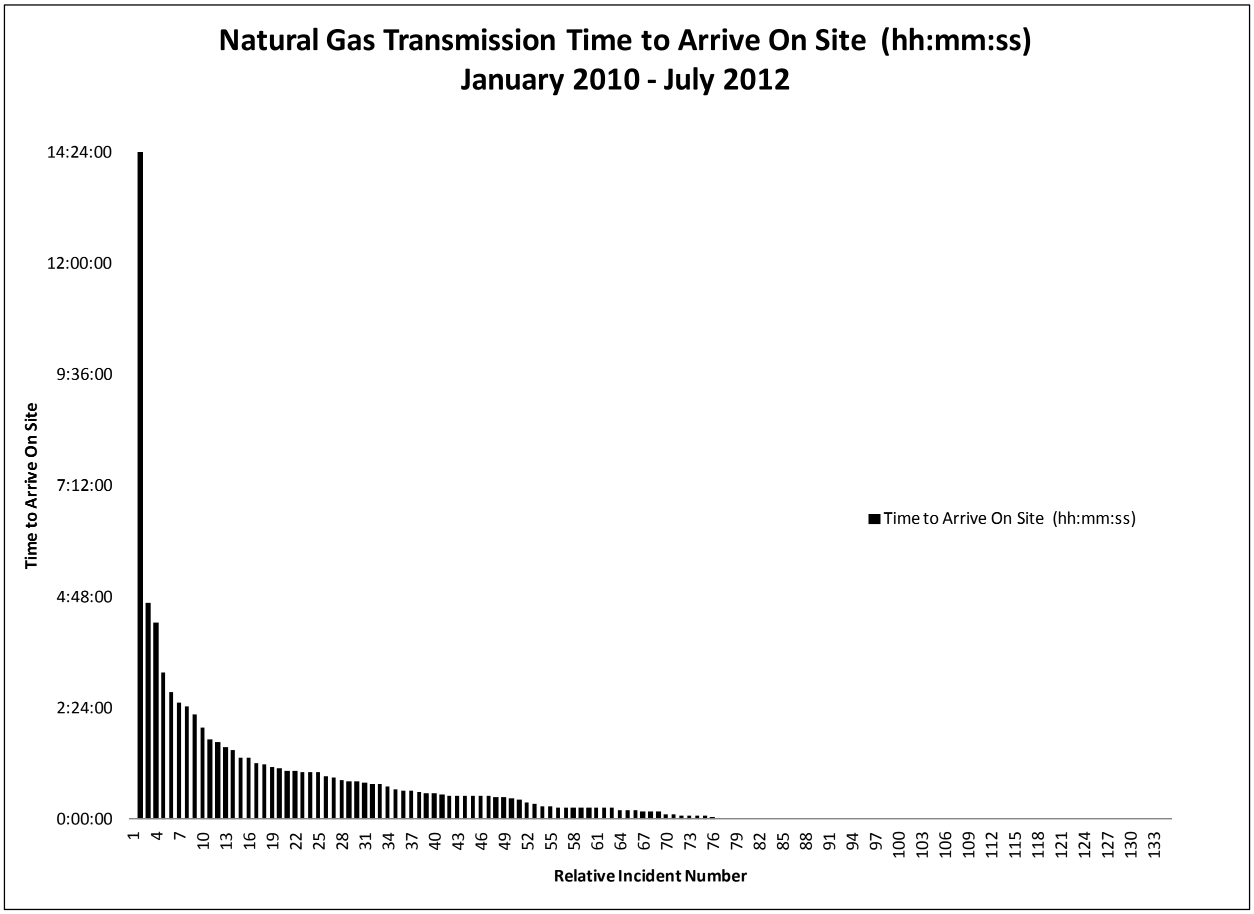


Figure 3.27 Natural Gas Transmission/Gathering Releases, Response Times

The average time to arrive on-site with and without SCADA functional was determined and for the instances where no data about SCADA functionality was provided by the operator. This data is shown in Figure 3.28. The average time to respond for those incidents where SCADA was functional is 0.5 hours. Where SCADA was not functional (2 incidents), the average response time was 0.2 hours. The average response time was 1.2 hours where SCADA information was not available. The volume released with SCADA functional was substantially greater than for either of the other two categories.

	Average Response Time (hours)
Time to Respond with SCADA Functional	0.5 hrs
Time to Respond without SCADA Functional	0.2 hrs
Time to Respond BLANK-No Data on SCADA Function	1.2 hrs

	Unintentional MSCF Released
MSCF Released with SCADA Functional	2,594,306
MSCF Released without SCADA Functional	47,600
MSCF Released BLANK-No Data on SCADA Function	55,027

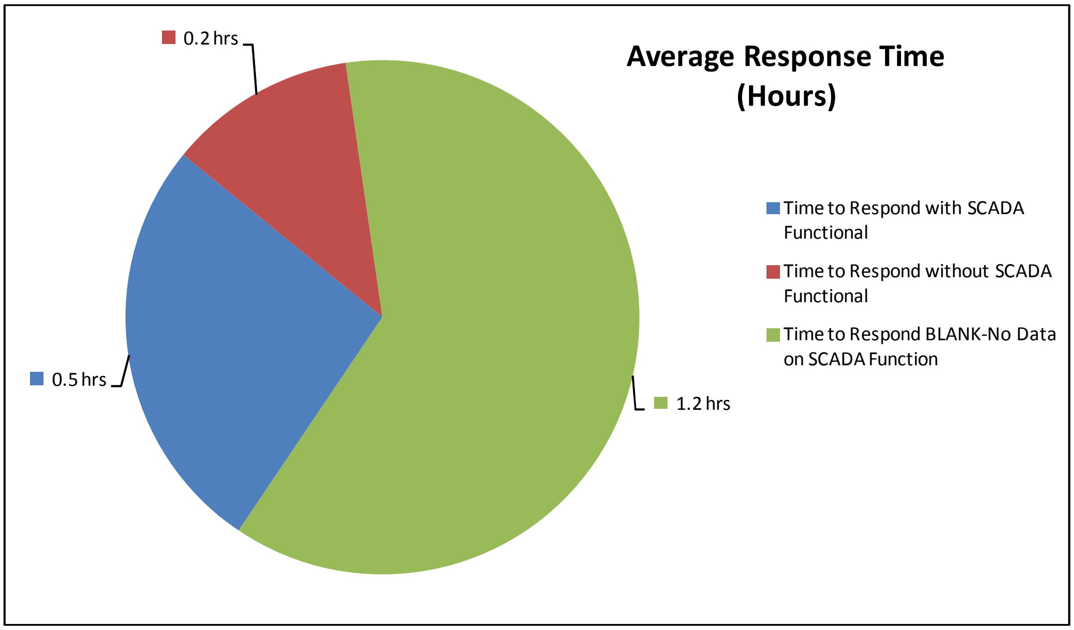


Figure 3.28 Natural Gas Transmission/Gathering Releases, Response Times: SCADA Detail

Time to shut down the pipeline is taken to mean that pumping has ceased and the upstream and downstream block valves have been shut to isolate the section of pipeline containing the release. The review of the incident data showed the following for 141 incident reports:

- For 3 (2%) shutdown date and times provided it was not possible to compute the time taken to shutdown because of the date and time values recorded.
- No shutdown time was reported for 29 (20%) of the incidents. Not all pipelines are shutdown as a result of a release.

- 8 (6%) of the incident reports had identical dates and times for the incident identification and the shutdown. This results in zero minutes to shutdown the pipeline.
- For 101 (72%) of the incident reports the elapsed time to shutdown could be calculated using the initial identification and the report shutdown.
- Ignoring zero minute shutdowns, the shortest shutdown time was 2 minutes and the longest calculated shutdown time was 223 hours and 10 minutes.
- 61 of the 101 reports where a time to shutdown could be calculated had a shutdown time longer than 1 hour.
- 40 of the 101 reports had a shutdown time between 5 minutes and 1 hour.

3.8.2 Above Average Gas Transmission Releases

To respond to the requirements of Task 3, KAI decided to narrow down the number of incidents and look solely at high volume gas transmission releases in more detail. To do this, the ROW releases discussed in the previous section were filtered so that 141 incidents were reduced to 92 ROW releases where the release origin was either in the pipe body or in the pipe seam. This catches a large number of the high volume releases on the ROW but not all of them. The intent was to identify a small set of high volume releases for further comment as case studies.

The average release volume from these 92 incidents is 30,347 MSCF. The median release volume was 4,103 MSCF. The median value is the middle value of all the values used to calculate the average. The most common release volume (the mode) was 1,000 MSCF. This value occurred 5 times in the 92 values used.

Twenty-two (24%) of the 92 pipe body and pipe seam incidents had a release volume greater than this average release volume of 30,347 MSCF and 70 (76%) incidents had below average release volumes. The total of all the 22 releases above-average volume was 2,429,828 MSCF. The total of all the below-average release volumes was 362,121 MSCF or 15% of the total release volume for the 22 incidents of above-average volume. Put another way, around one in four gas transmission releases from pipe body or pipe seam on a ROW could have a release volume between 30,347 MSCF and 614,257 MSCF or thereabouts based on the 30 month period under review.

Release types reported for these above average release volumes were as follows:

1. 3 leaks.
2. 14 ruptures.

3. 4 mechanical punctures.

4. 1 other.

These 22 above average release volume incidents were assessed in the same way as the 141 incidents on the ROW discussed previously.

The largest release volume is 614,257 MSCF and the smallest is 31,653 MSCF. The largest is a release by Columbia Gulf Transmission Co and the smallest is a release by Centerpoint Energy Gas Transmission.

The second largest gas transmission release volume is 313870 MSCF or 51% of the largest release volume. Together, these two release volumes add up to 928,127 MSCF and make up 38% of the total above average release volume of 2,429,828 MSCF from the 22 incidents reviewed.

Figure 3.29 shows the 22 releases by volume in order of large to small.

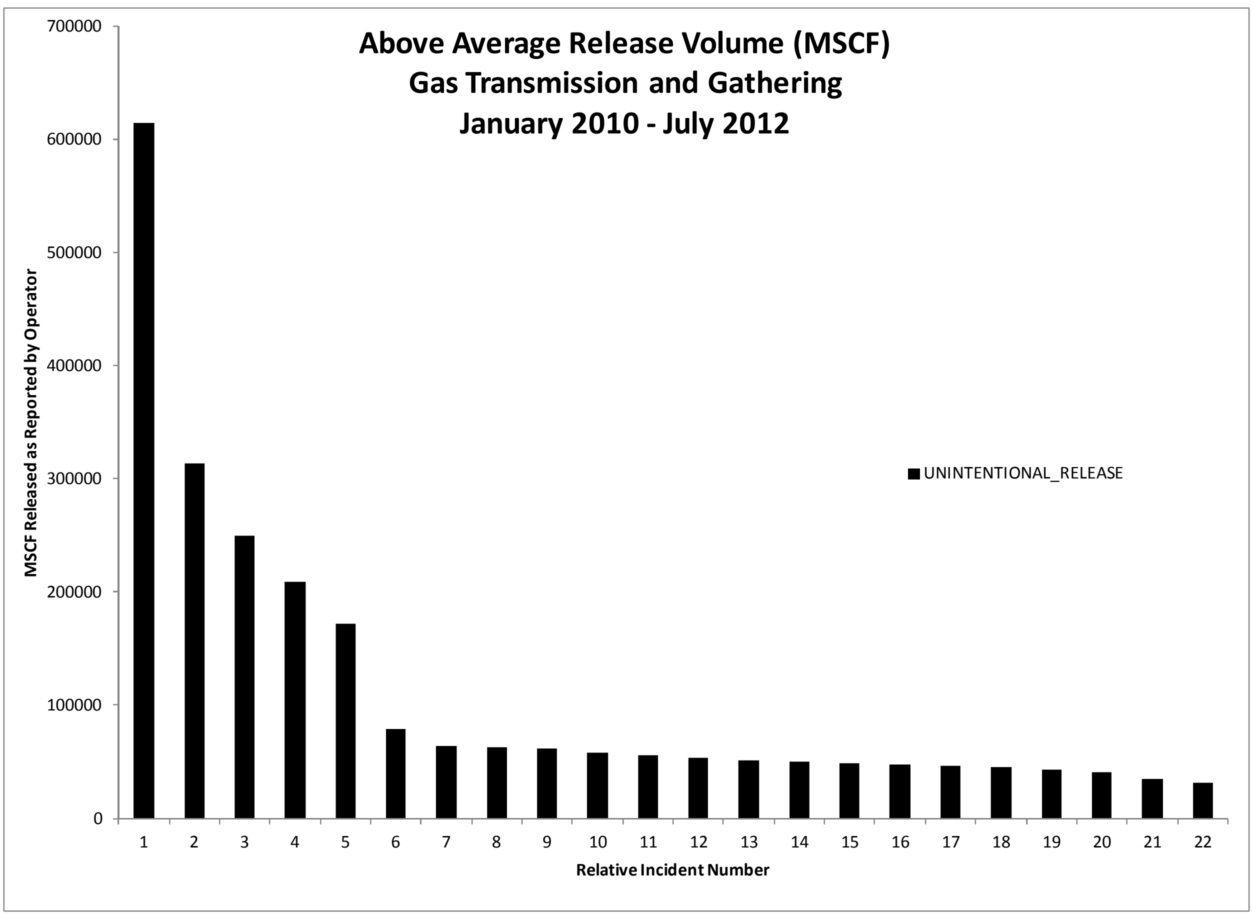


Figure 3.29 Above Average Gas Transmission/Gathering Releases, 2010 to July 2012

Seven of these 22 incidents ignited in an explosive manner and 2 ignited without an explosion. The other 13 incidents did not ignite or explode. Of the 7 incidents that did explode, two of them resulted in the fatality of 8 members of the public and one fatality of a company worker. Injuries were experienced in 3 of the 7 explosions. Seven workers were injured in one incident and 2 workers in another and 51 members of the general public in another. The 8 members of the public that died were as a result of a release of 47,600 MSCF release by Pacific Gas & Electric Co. This same incident also injured 51 members of the public according to the PHMSA database. The other fatality of a company worker occurred as a result of a release of 172,000 MSCF by Enterprise Products Operating LLC. This same incident also injured 7 workers. The PHMSA incident database describes the release as due to a mechanical puncture. It was not classed as a leak or rupture.

A SCADA system was in place for all 22 (100%) of the incidents. The SCADA was functional for 21 of 22 incidents. The SCADA system detected 16 (73%) of the 22 incidents. The release types where SCADA did not detect the release were given as:

- 2 Ruptures, 79,000 and 45,000 MSCF.
- 3 Leaks, 250,000, 58,433, and 52,874 MSCF.
- 1 Mechanical puncture, 46,285 MSCF.

The statistics for SCADA are shown in Figure 3.30 but related to MSCF released to the environment. Figure 3.30 shows the MSCF released where SCADA was either functional (black), not functional (red).

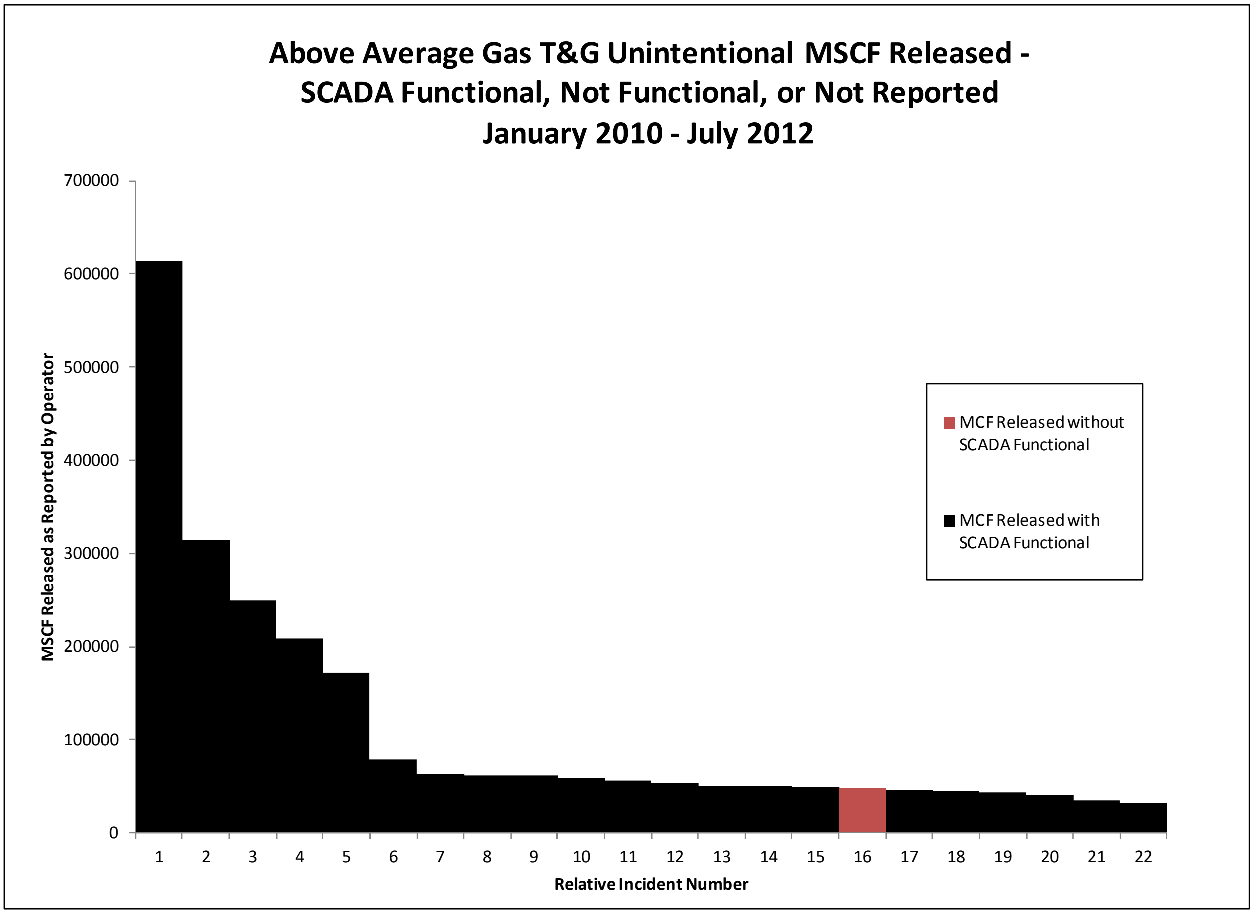


Figure 3.30 Above Average Gas Transmission/Gathering Releases, SCADA Detail

Figure 3.31 shows the MSCF released per incident where the SCADA is the initial identifier of the release (color black). Color red on Figure 3.31 shows the incident release volumes in MSCF where SCADA was not the initial identifier (12 in total) of the release. There were no responses without data.

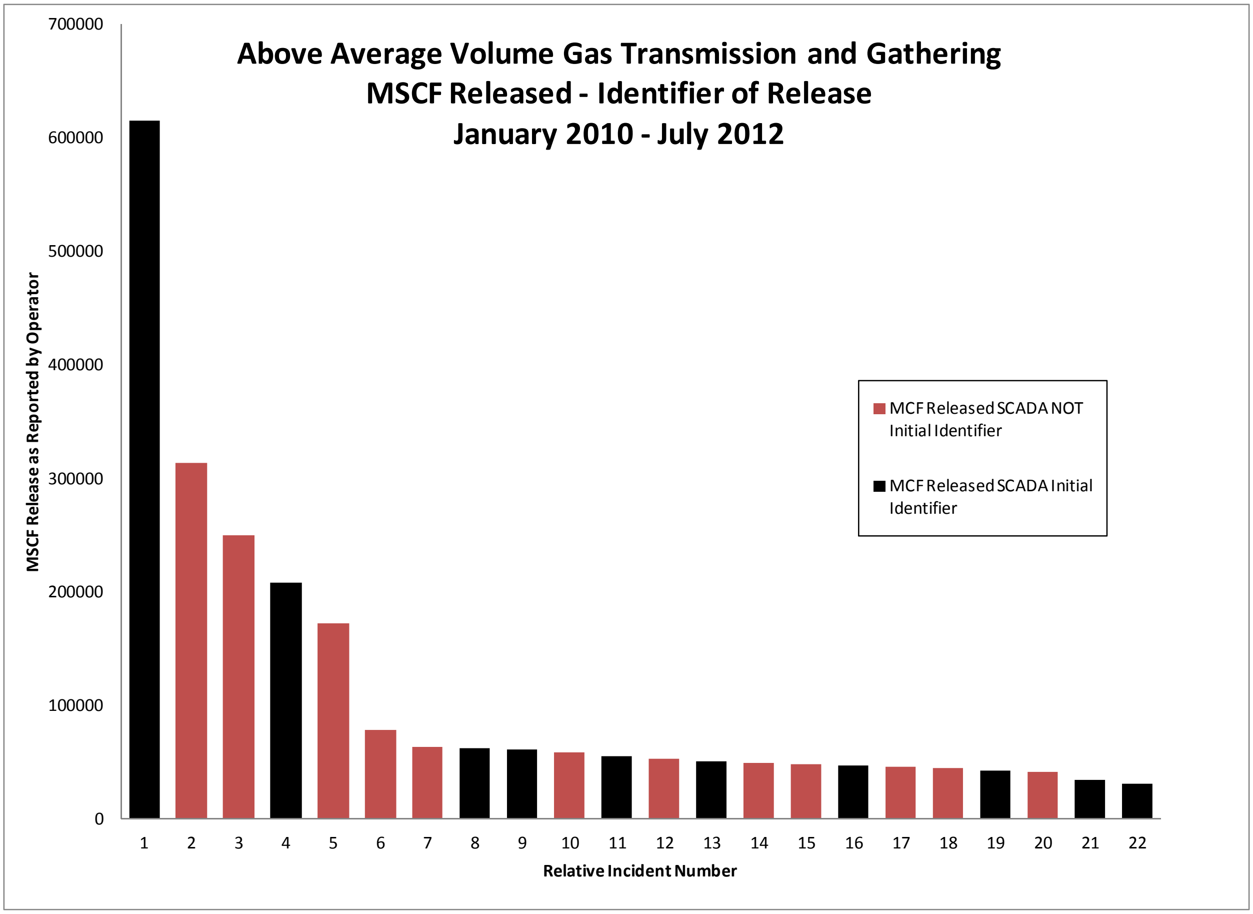


Figure 3.31 Above Average Gas Transmission/Gathering Releases, SCADA Initial Identifier

Figure 3.32 presents a pie-chart showing the means by which a control room was notified of a release for the 22 incidents. The different means of initial incident identification are tabulated in Table 3.10. That is, who discovered the release first? There are seven different categories of initial identifiers. As with the 141 incidents discussed previously, the following categories seem appropriate for the 22 above-average releases:

1. Pipeline control and non-control room personnel and contractors (63%).
2. The public (27%).
3. A third party on the ROW (5%).
4. Other (5%).
5. No data (0%).

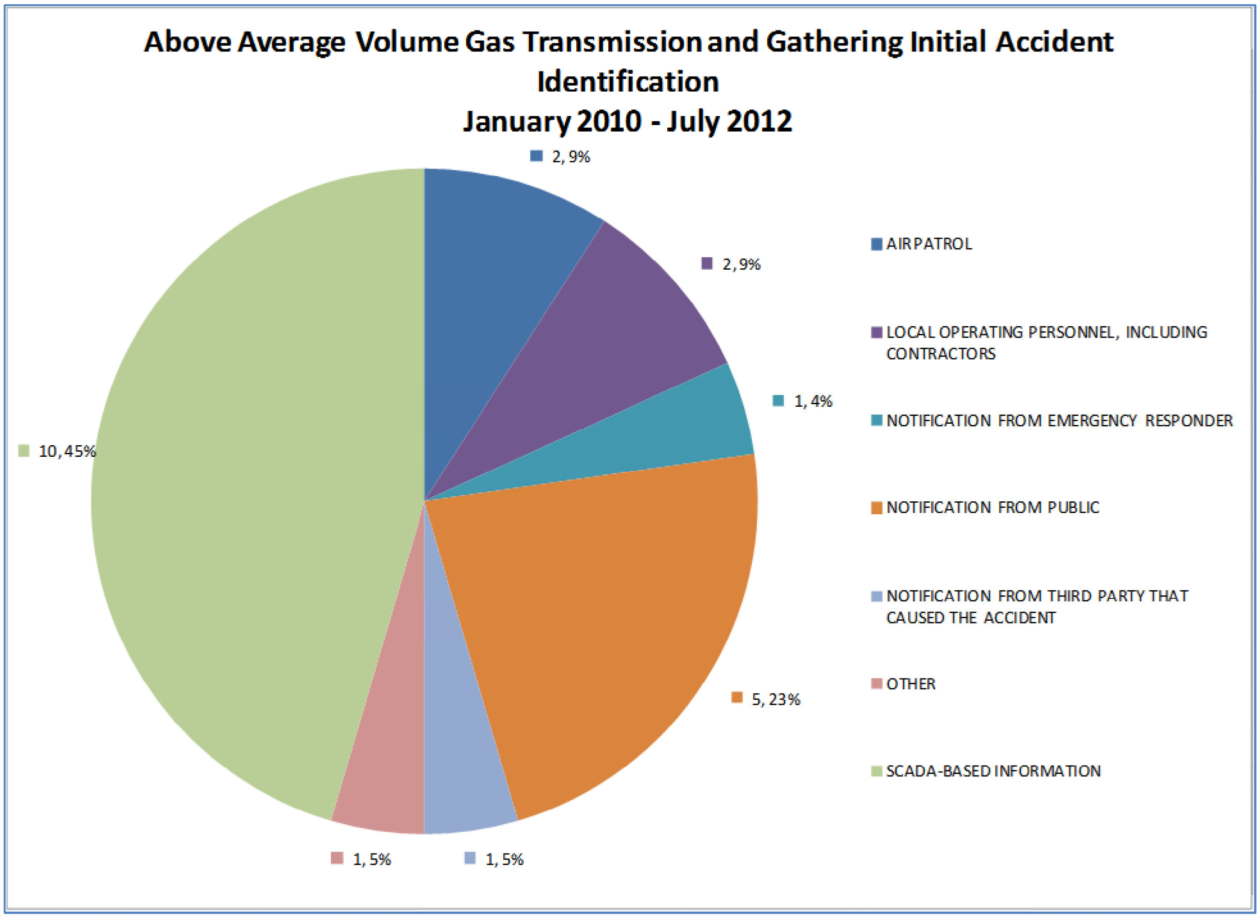


Figure 3.32 Above Average Gas Transmission/Gathering Releases, Initial Identifier

Table 3.10 Above Average Gas Transmission/Gathering Releases, Initial Identifier

	# of Incidents	% of Incidents
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

A possible summary is that pipeline operators' or contractors to the pipeline operator discover almost two-thirds of the releases on a pipeline ROW for above average releases from a pipe body or pipe seam.

Within the 63% statistic for Pipeline control and non-control room personnel and contractors, 45% is attributable to the pipeline control room. In terms of managing a release, particularly a rupture, a sequence of events might be described as:

1. Time to detection for the control room after the release as it is the control room that has means to shut down the pipeline.
2. A period where fluid is still being pumped into the environment.
3. A period during which valves are closed, the section isolated and drain down occurs.

Where a release is detected by someone other than in the control room the time taken for the control room to acknowledge a release and initiate further action could be longer than when the control room is the initial identifier. Hence, for the 63% described above, 18% of the incidents may have resulted in a longer detection period after the actual release from the pipeline.

When the public, including emergency responders, are the initial identifiers (27% in the above statistics), the elapsed time before the control room is aware of a release may be longer than when operator employees and contractors become aware of a release because of their better knowledge and training on what to do.

Once a release is detected there is a need to respond to the release. PHMSA incident reporting requires operators to provide the date and time the incident was identified by the operator. This is not necessarily the date and time of a release from a pipe or pipe seam. Other information provided is the date and time for operator personnel to arrive at the site of the release and the date and time the pipeline was shutdown.

When an operator reports a date and time to arrive on site, the PHMSA instructions do not require this date and time to relate to the date and time the incident was initially identified. Where operator employees or contractors are the initial incident identifiers, then the time is identical for both the initial identification and the time to arrive on-site. The time to arrive on-site in this situation is zero.

The date on which the operator became aware of the release was recorded for all 22 above average release incidents.

It is possible to calculate the time to arrive on-site after the time of initial identification by the operator for all 22 incident reports. Figure 3.33 shows this result. For 18 of these 22 incidents the time was less than 1 hour. For 4 of these incidents the time to arrive on site was from one hour 2 minutes to 4 hours 15 minutes. For the maximum release volume of 614,257 MSCF, the time to arrive on site is recorded as zero minutes. For the minimum release volume of 31,653 MSCF, the time to arrive on-site was reported also as zero minutes.

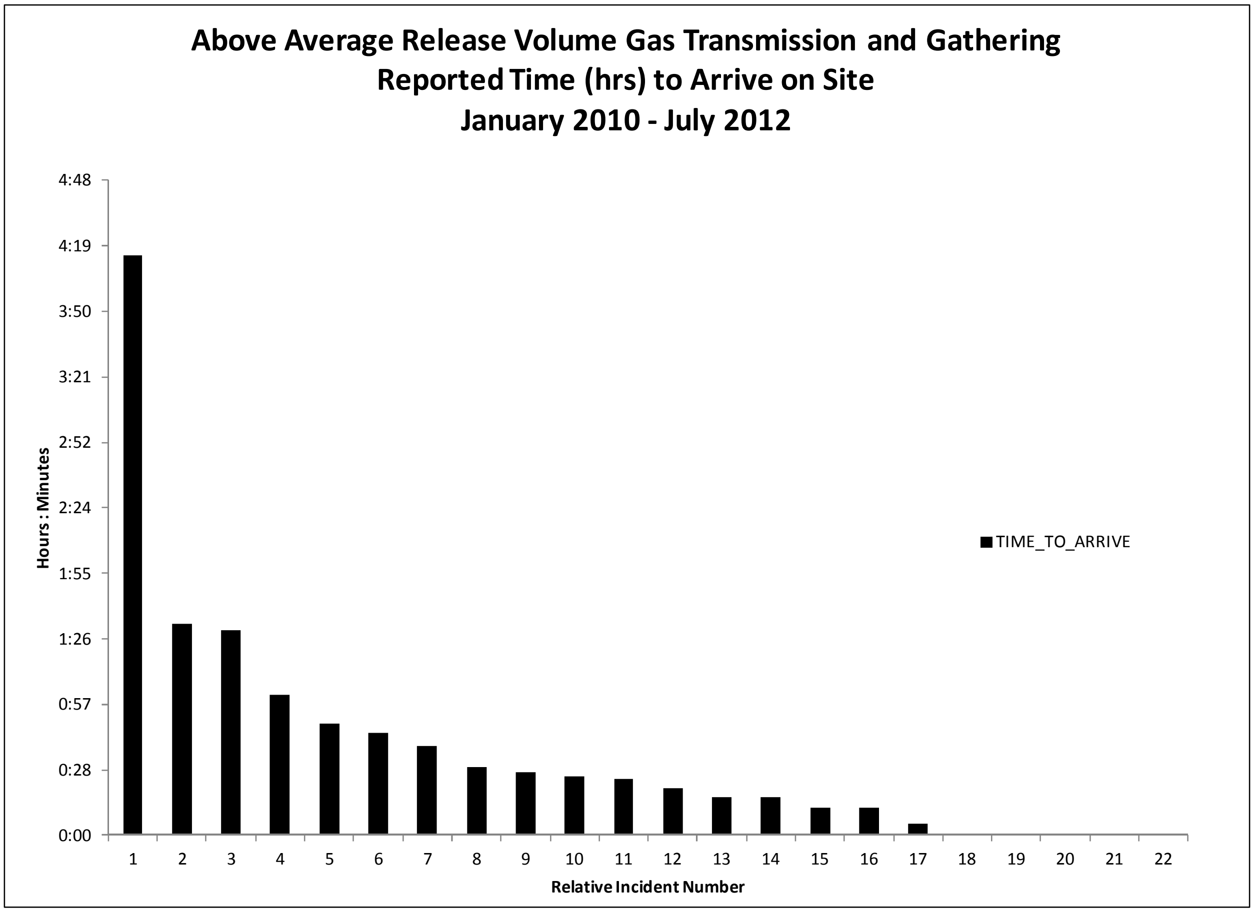


Figure 3.33 Above Average Gas Transmission/Gathering Releases, Response Time

The average time to respond and be on-site with SCADA functional was 38 minutes. For the one incident without SCADA functional, the arrival time was 12 minutes. The total volume released into the environment for the 21 incidents with SCADA functional is 2,197,273 MSCF.

Time to shut down the pipeline is taken to mean that pumping has ceased and the upstream and downstream block valves have been shut to isolate the section of pipeline with the release. The review of the incident data showed the following for 22 above-average release volume incident reports:

1. In all 22 incidents the pipeline was operating just prior to the release. All 22 incidents shut down the pipeline.
2. A shutdown date and time was provided for all 22 above-average release volume incidents.

3. The date and time to identify the incident and the date and time to shut down the pipeline was the same for 2 of the incidents. That is, the time taken was zero minutes.
4. For 10 of the 22 incidents the pipeline was shut down between 1 minute and 55 minutes.
5. For 10 of the 22 incidents the pipeline was shut down between 1 hour and 15 hours. The latter was due to a mechanical puncture.

3.8.3 Natural Gas and Other Gas Transmission Case Studies

From the 22 incidents described in the previous section, 6 incidents were selected as case studies. A release of 83,487 MSCF was chosen because it was classed as a leak coming from a welded sleeve repair. An additional release (making 8 in total) was selected from below the average release volume of 30,347 MSCF.

The 8 releases selected had CAOs, FIRs or other documentation in addition to the PHMSA incident reports that would enable KAI to comment on the incident in question. These 8 incidents with the MSCF released into the environment, starting with the maximum volume are:

1. 20110396 Tennessee Gas Pipeline Co (El Paso), 83,487 MSCF.
2. 20110393 Tennessee Gas Pipeline Co (El Paso, 79,000 MSCF.
3. 20110392 Transcontinental Gas Pipe Line Company, LLC, 61,700 MSCF.
4. 20110294 TransCanada Northern Border Inc, 50,555 MSCF.
5. 20100070 Pacific Gas & Electric Co, 47,600 MSCF
6. 20100002 Southern Natural Gas, 41,176 MSCF.
7. 20120066 Natural Gas Pipeline Co of America (KMI). 34,455 MSCF.
8. 20100106 Tennessee Gas Pipeline Co., 14,980 MSCF. (below average)

Task 3 Appendix B provides details for each of these 8 case studies.

These 8 case studies can be summarized by the following taken from the incident reports submitted by operators:

a) 6 of the releases were ruptures.
b) 2 of the releases were leaks, 1 of which is described as a crack (14,980 MSCF) and the other as a leak from under a welded sleeve (83,487 MSCF).
c) 5 releases ignited.
d) 3 of the releases that ignited also exploded.

e) 1 release was described as located in an HCA.

f) 1 incident had a remotely controlled valve upstream and a manually operated valve downstream.

g) 2 incidents had automatic valves.

h) 4 incidents had manual valves.

i) 1 incident had a manual valve upstream and an automatic valve downstream.

j) 7 of the 8 case studies used internal inspection.

k) SCADA was functional in 7 of the 8 case studies and 6 releases were detected by SCADA.

l) For 5 of the 8 incidents, the incident identifier was in the control room.

m) For 1 of the 8 incidents the identifier was an employee of the operator.

n) For 2 of the 8 incidents the identifier was a member of the public.

o) The times taken to arrive on-site following the identification to control were between zero and one hour and 10 minutes. These times were taken from the incident reports filed by the operators.

p) The times taken to shut-down the pipeline, where applicable, were between zero and one hour and 17 minutes. These times were taken from the incident reports filed by the operators.

q) The leak from a crack (14,980 MSCF) was 1.4 miles downstream of a compressor station and was described as on operators' property.

Individual Case Studies

The 8 case studies listed above are now reviewed individually, in the order they are listed above. Refer to Task 3 Appendix B for details about the incidents. The purpose of the review here is to extract relevant information about the use of LDS in each of these cases. All information used is public information. The cause of the release is mentioned only when relevant.

The point of view for these studies is that the pipeline controller in the control room is "driving" a pipeline or a number of pipelines. What the pipeline does or doesn't do is under the control of the controller. The information a controller receives and the timeliness of that information is pertinent to how quickly a controller reacts to changing circumstances. Under all operating conditions, a pipeline controller needs to understand how the pipeline may react and what the pipeline instrumentation is going to tell him for those conditions.

The data presented here comes from reports submitted by the operators to PHMSA, Corrective Action Orders issued by PHMSA and Failure Investigation Reports issued by PHMSA. The authors did not have the time or resources to confirm the accuracy of this information. Most dates and times are taken from the incident report filed by operators.

Tennessee Gas Pipeline Company (El Paso); 83,487 MSCF

On November 21, 2011 a leak occurred on Segment 63-1D of Tennessee Gas Pipeline Company's Line 100 System located near Batesville, Mississippi. The incident occurred in the pipeline ROW and released approximately 83,487 MSCF of natural gas. The gas ignited and continued to burn for several hours. The local authorities evacuated approximately 20 homes. There were no reported injuries or fatalities.

At approximately 8:33 p.m. Central Standard Time (CST) on November 21, 2011, the operator of the Batesville Compressor Station detected a change in the pressure of Line 100-1. The compression station operator immediately notified gas control and his supervisor of that abnormal condition.

At approximately 8:45 p.m. CST, personnel activated the emergency shutdown system at the Batesville CS, which automatically closed the mainline block valves on all four of the Line 100 System pipelines at that location. The Batesville CS is approximately 2.39 miles upstream of the rupture site. At approximately 9:20 p.m. CST, personnel manually closed MLV 64-2, the first mainline block valve on Line 100-2 downstream of the rupture site. At approximately 9:30 p.m. CST, personnel manually closed MLV 64-1, the first mainline block valve on Line 100-1 downstream of the rupture site. The closure of MLV 64-1 isolated the ruptured section of Line 100-1.

The valve upstream of the rupture was remotely controlled and the downstream valve was manual. Closure of these valves resulted in the isolation of approximately 9.16 miles of pipeline.

According to documentation, SCADA was the incident identifier. The leak was reported as occurring 16 minutes prior to the identification time of the incident. Based on identification time of 08:30 am, the pipeline was shut down in 60 minutes.

This incident was a leak from a welded sleeve.

Tennessee Gas Pipeline Company (El Paso); 79,000 MSCF

At approximately 8:45 a.m. EST on November 16, 2011, a failure occurred on Tennessee Gas Pipeline Company's 36-inch natural gas pipeline, Line 200-4 in mainline valve section 205-4 in

Morgan County, Ohio, approximately four miles southeast of Glouster. The rupture occurred within the pipeline ROW. It was a circumferential rupture.

According to incident documentation, SCADA was in-place and functional but was not the initial identifier of the incident. Notification from the public was initial identifier of the incident. The release ignited and exploded.

The upstream valve used to isolate the rupture was manual and the downstream valve was automated. The closure of these valves isolated approximately 15.6 miles of pipeline. It took the operator approximately 67 minutes to shut down the pipeline once the rupture was identified. This time is based on the data submitted by the operator to PHMSA and present in the data examined in this study.

The incident did cause injury according to the PHMSA CAO but this is not recorded in the incident report reviewed in this study.

Transcontinental Gas Pipe Line Company, LLC; 61,700 MSCF

At approximately 3:08 p.m. Central Standard Time (CST) on December 3, 2011, Transcontinental Gas Pipeline Company's 36-inch diameter Line C ruptured at MP 817.77 and released approximately 61,700 MSCF of natural gas. The incident occurred within the pipeline ROW. The release ignited and exploded.

At approximately 3:08 p.m. CST, personnel in the Houston Control Center received indications of a possible rupture on pipeline and immediately notified the local operations manager. The local operations manager responded and provided visual confirmation of the rupture and fire at MP 817.77. SCADA is reported as the identifier of this incident.

At approximately 3:25 p.m. CST, the local operations manager closed the main line manual block valve (Valve 90- C-10) on Line C, located about 15 miles downstream of Compressor Station 90. At about that same time, another employee closed the side gate valve (Valve 90-C-0) on Line C that is located at Compressor Station 90. The closure of these two valves isolated the affected segment. The length of segment isolated was 151 miles according to the incident report.

The pipeline was shut down within approximately 38 minutes of the rupture.

TransCanada Northern Border, Inc.; 50,555 MSCF

On July 20, 2011, at approximately 7:15 PM MDT, a rupture occurred on the TransCanada Bison Pipeline at MP 16.2 in Campbell County, Wyoming. The Incident resulted in the release of approximately 50,555 MSCF of natural gas in a rural area. There were no fires, injuries, or evacuations as a result of the failure.

The pipeline began operating at the beginning of 2011.

The incident occurred within the pipeline ROW. According to the incident report, a SCADA system was in-place and detected the rupture. The initial identifier was given as the SCADA. The upstream and downstream valves were automatic.

The incident identification time was given as 08:15 pm. The pipeline shut down time was given as 7:40 pm on the same day. It is possible that the pipeline was shutdown in 15 minutes.

The block valves isolated 18.3 miles.

Pacific Gas & Electric Company; 47,600 MSCF

This was a tragic event and is well known within the industry. The rupture of PG&E's 30-inch-diameter gas transmission line known as Line 132 occurred in a residential area in San Bruno, California on September 9, 2009 and released approximately 47,600 MSCF of natural gas. The National Transportation Safety Board (NTSB) has produced a report on this incident, which includes details of the event and apparent causes. For a description of the sequence of events leading up to and following the rupture, the reader is referred to the NTSB report.

SCADA data indicate that the rupture occurred about 6:11 p.m., when the pressures on Line 132 upstream of Martin Station (7 miles downstream from the rupture site) rapidly decreased from a high of 386 psig. At the same time, a pressure of 386.4 psig was recorded at Half Moon Bay (located about 10 miles upstream of the rupture). By 6:15 p.m., Martin Station generated the first low pressure alarm for Line 132, followed 20 seconds later by another alarm (150 psig). These low-pressure alarms occurred while SCADA operator D was on the phone with a SCADA operator at the Brentwood facility, who alerted him to the low pressures. By 6:36 p.m., the Line 132 pressure at the Martin Station was 50 psig. The pressures in Lines 101 and 109, which are interconnected to Line 132, also decreased but at a slower rate than Line 132.

Incident records show that the line was shut down at 9:30 pm; 3 hours and 19 minutes after SCADA indicated an issue with the pipeline. The time recorded for the incident identifier is 6:18 pm. The time to shut down the pipeline based on date and time of the incident identifier is 3 hours and 12 minutes. The valves upstream and downstream of the release site were manual. Closing the valves was a significant contributor to the time taken to shut down the pipeline.

Southern Natural Gas; 41,176 MSCF

This rupture released 41,176 MSCF of natural gas. The rupture occurred on the ROW of Southern Natural Gas' 24-inch diameter 2nd North Main Pipeline, Center Ridge Gate to Louisville segment, near Highway 14. A PHMS Failure Investigation Report and a Corrective Action Order were issued for this incident.

The Failure Investigation Report states that the SCADA system "low alarm" indicating the release and phone calls from operator field personnel reporting the release occurred simultaneously.

Within 26 minutes of the reported time of the rupture, the release location was isolated by closing manual isolation valves upstream and downstream of the rupture.

Natural Gas Pipeline Company of America (KMI); 34,455 MSCF

At approximately 2:00 a.m. CDT on June 6, 2012, a rupture occurred at Natural Gas Pipeline Company of America's Compressor Station 154 located at MP 52 of their 26-inch diameter pipeline in Gray County, Texas, approximately four miles east of the town of Laketon. The escaping gas ignited, leaving a crater approximately 30 feet in diameter and burning approximately two acres of an agricultural. The fire also burned two utility poles and associated transformers and required State Highway 152 to be shut down for several hours. The rupture resulted in the release of approximately 34,455 MSCF of natural gas.

Respondent experienced a sudden pressure drop on the OE #1 pipeline, requiring shut down of the 26-inch diameter pipeline system. Pampa local law enforcement contacted Respondent's Gas Control 800 number and reported a fire in the vicinity of a compressor station in a rural farming area.

Following the failure, automated valves closed upstream and downstream of the failure site isolating approximately 3.3 miles of pipeline and the main fire self-extinguished after about two hours, although a smaller fire resulting from valve leakage continued to burn for about seven hours.

According to documentation, the in-place SCADA system was functional and operational at the time of the rupture and it provided the initial notification of the pipeline failure and confirmation of the rupture. The operator reports that identification of the incident and pipeline shutdown occurred simultaneously, approximately 8 minutes after the rupture occurred.

Tennessee Gas Pipeline Company; 14,980 MSCF (below average)

This incident consisted of a leak in Tennessee Gas Pipeline's (TGP) 30-inch diameter, carbon steel, 100-2 pipeline in Natchitoches, Louisiana, which released 14,980 MSCF of natural gas. The leak occurred approximately 1.4 miles downstream of the TGP Compressor Station 40. The TGP system is monitored by gas control in Houston, Texas. The pipeline system consists of 4 lines, in 2 ROWs as they leave the Natchitoches Station.

A Failure Investigation Report and Corrective Action Order were issued with respect to this incident.

On Tuesday, November 30, 2010 a loud noise was reported to Tennessee Gas Pipeline (TGP) by a member of the general public in the vicinity of TGP pipeline facilities in Natchitoches, Louisiana. Personnel from the Natchitoches Station responded immediately to shut in the systems and identify the location. Upon initial investigation, TGP operations personnel found a gas leak in the 100-2 pipeline, on operator-controlled property. Visual examination revealed that the leak was coming from a crack in a wrinkle bend. No ROW or maintenance work was being performed (or had been performed) in the area of the incident when the incident occurred. No warning or abnormal situation occurred prior to the failure.

Following the emergency response, TGP isolated Line 100-2 from MLV 40-2 to MLV 41-2 (both manual valves). The pipeline was shut down approximately 70 minutes after the leak was identified. SCADA did not detect or confirm this release. The incident identifier was a member of the public.

3.9 Incident Reporting for the Natural Gas and Other Gas Distribution Industry

3.9.1 Natural Gas and Other Gas Distribution Incidents

For gas distribution, all 276 incidents were evaluated. The release classifications are different to those for gas transmission systems and it was considered appropriate to evaluate all 276 incident reports. Table 1 shows only 30 incidents were related to "utility ROW or easement" and associated with pipe body. Table 1 also shows that when incidents on private and public land are incorporated there are 260 incidents. Hence, all 276 incidents were included in the evaluation.

In reviewing all 276 incidents between January 1, 2010, and July 2012, the origin of a leak can be in metal and plastic pipes as well as from meters and regulators and other appurtenances. Therefore, the data presented here cover a wider range of operating conditions than those reviewed for hazardous liquid and gas transmission pipelines. There are no case studies for these gas distribution releases.

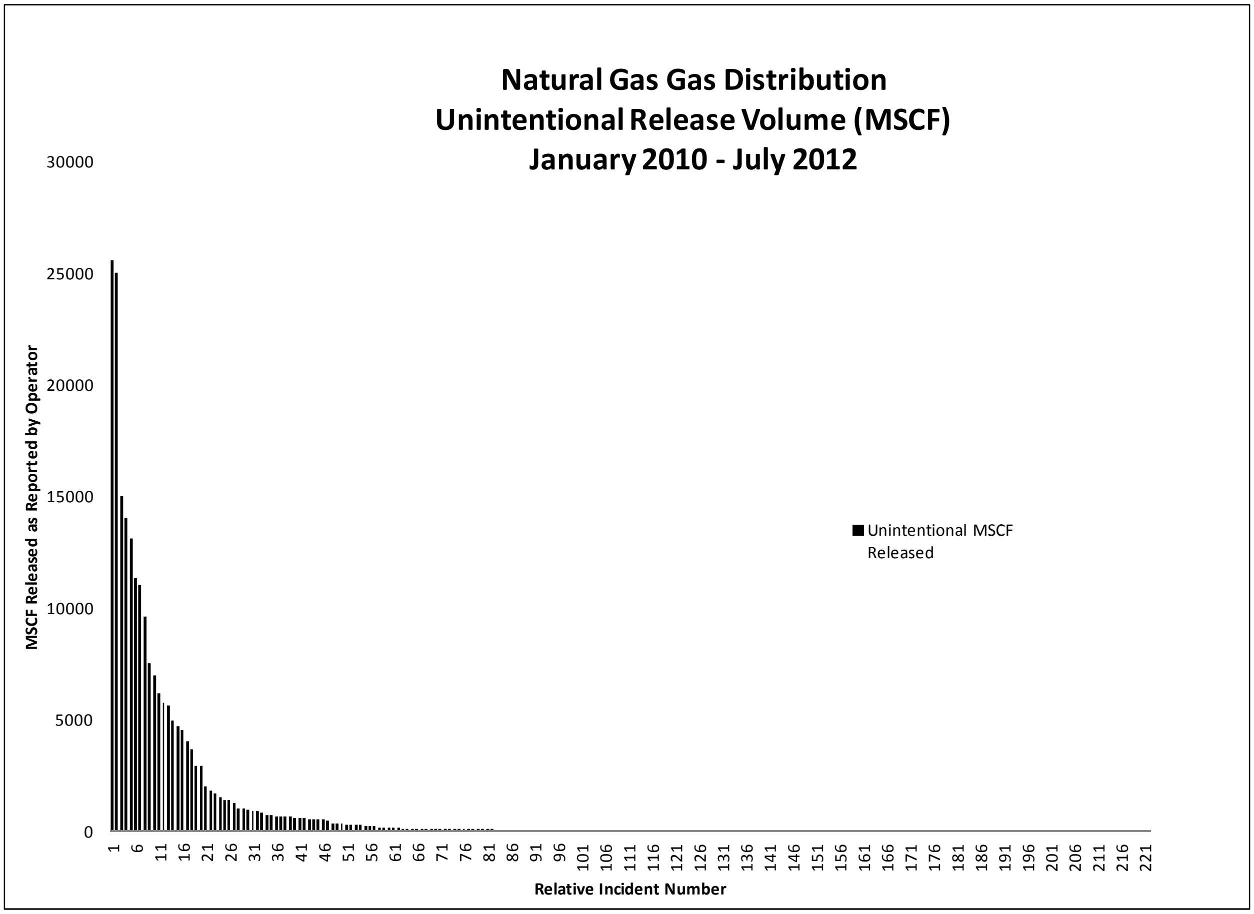


Figure 3.34 Gas Distribution Releases, January 2010 to July 2012

Figure 3.34 shows the reported releases volumes (in MSCF) for all 276 incidents. Most of the release volumes do not show because of the scale used for the maximum size of volume released. Most of the gas distribution releases are of a small quantity.

Of the 272 incidents reported, 29 of them had less than 1 MSCF of unintentional release of gas reported or there was no volume reported.

The maximum reported release volume was 25,555 MSCF. The average of the release volumes reported was 975 MSCF. The total release volume reported for the 276 incidents is 216,564 MSCF. The 276 incident reports came from 113 different operators.

186 of the 276 releases ignited (67.4% of the total number of releases) and 71 of the 186 resulted in an explosion (25.7% of the total); the percentage of ignition is very high and it might be caused to the proximity of populated areas.

Gas distribution networks are not required to have a CPM system. For distribution, incident reports operators only to only identify the status of the system SCADA, as in gas transmission. Table 3.11 summarizes the data provided in the incident reports for whether:

1. A SCADA system was operational at the time of the incident.

2. The SCADA was functioning when the incident occurred.

3. The SCADA information assisted in the detection of the incident.

4. The SCADA information assisted in the confirmation of the incident.

A SCADA system was in place for 60 of the incidents (21.7%). At the time of the incident, all 60 of the SCADA systems are reported to be functional and only 13 (4.7%) assisted in the detection of the release. For 216 of the incidents (78.3%), the operators reported that a SCADA was not in place at the time of the incident.

Table 3.11 Above Average Gas Transmission/Gathering Releases, Initial Identifier

	# of Reports	% of Total Reports
SCADA System in Place	60	21.7%
SCADA System NOT in Place	216	78.3%
SCADA System in Place BLANK-No Data	0	0.0%

	# of Reports	% of Total Reports	% of Reports where SCADA was In Place
SCADA System Operating at Time of Accident	61	22.1%	101.7%
SCADA System Functional at Time of Accident	61	22.1%	101.7%
SCADA Assisted in Detection of Accident	13	4.7%	21.7%
SCADA Assisted in Confirmation of Accident	10	3.6%	16.7%

The above SCADA statistics are illustrated on Figure 28 but related to the MSCF released into the environment; it shows the MSCF released where SCADA was either functional, not functional or where information on SCADA was not reported. Figure 3.35 shows that SCADA was not functional for the three largest volumes releases.

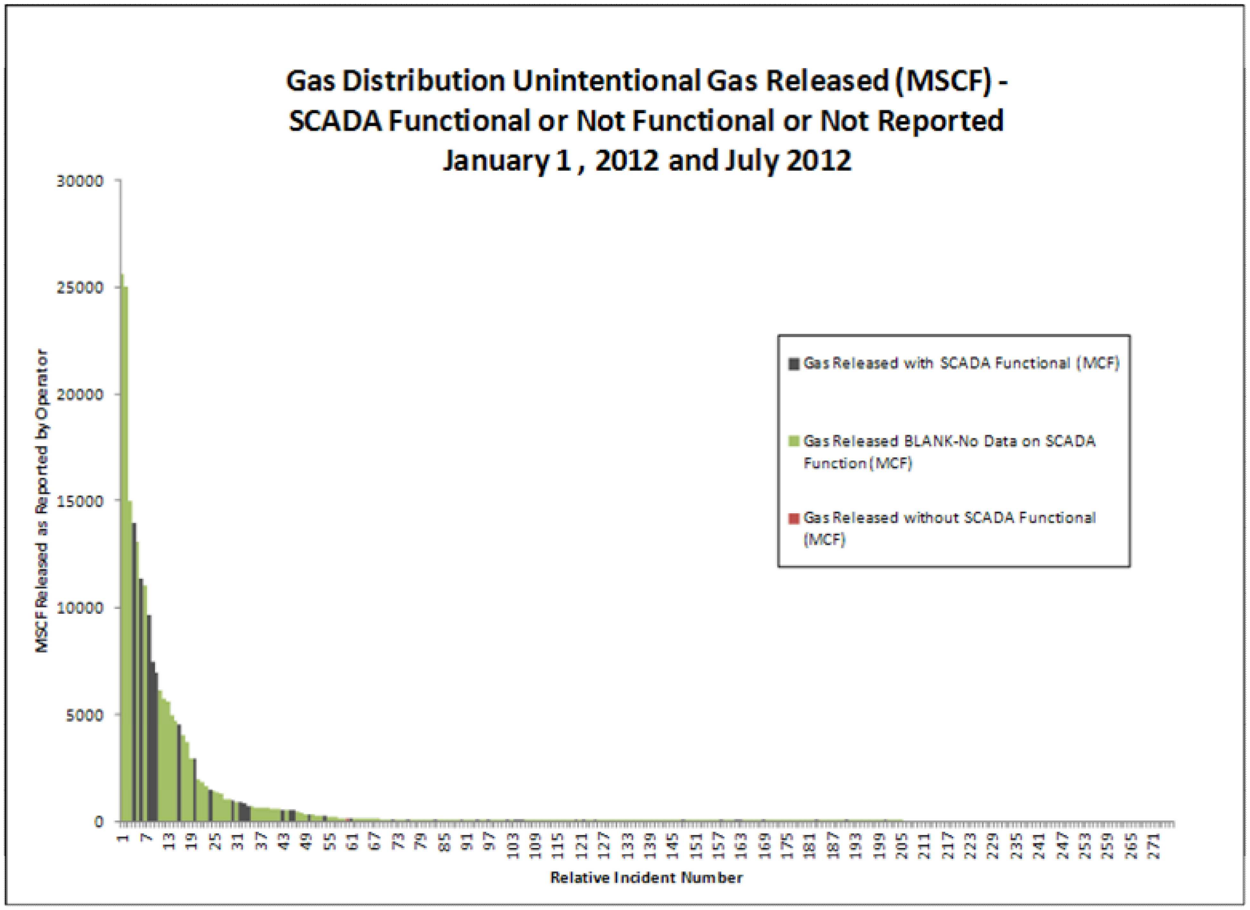


Figure 3.35 Gas Distribution Releases, SCADA Detail

Figure 3.36 shows the release volumes that were initially detected by SCADA and those where SCADA was not the initial identifier of the release. It is shown that in only one case (the 9th largest) the SCADA system was the initial identifier of the gas release.

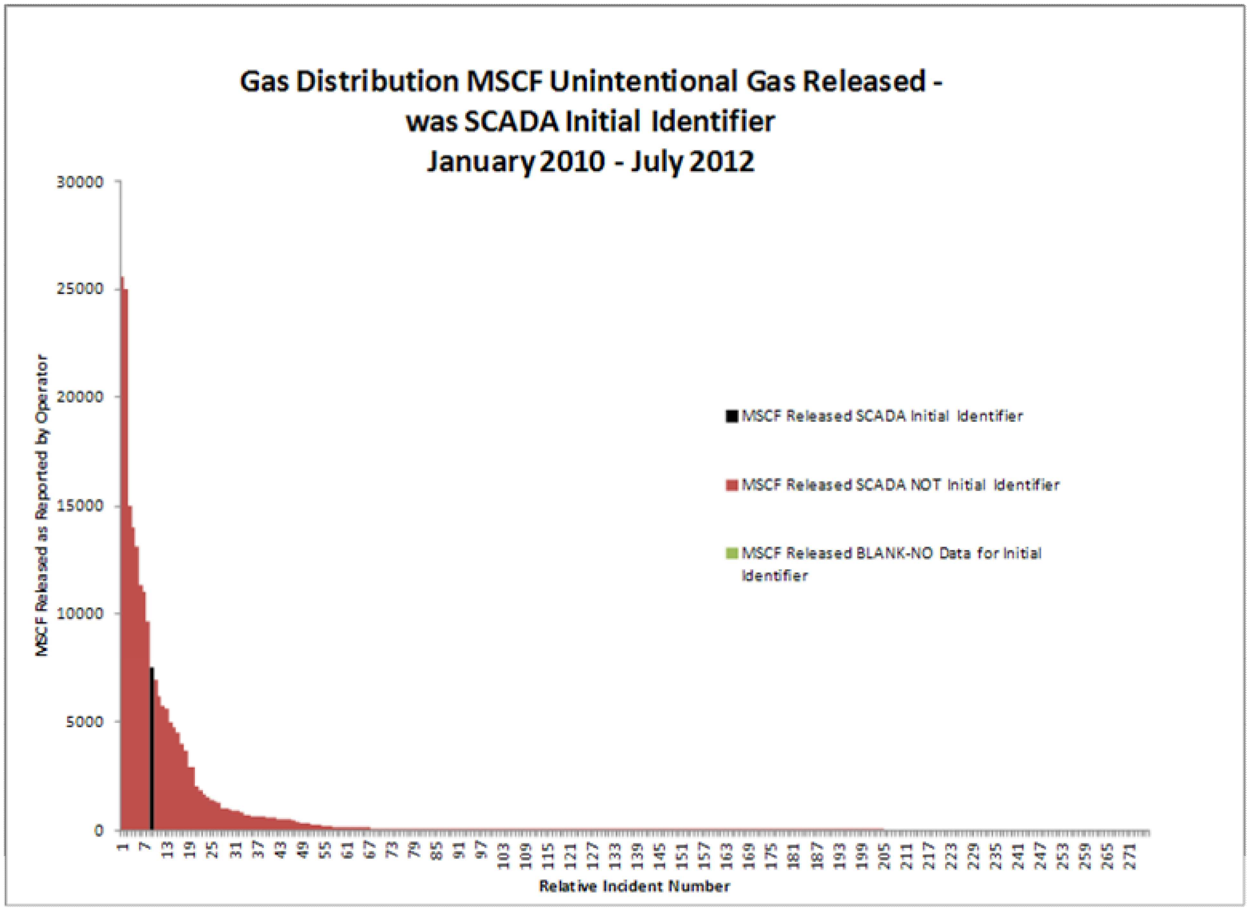


Figure 3.36 Gas Distribution Releases, SCADA Initial Identifier

Figure 3.37 presents a pie-chart showing all of the means by which a control room was notified of the release of all 276 incidents:

1. Pipeline control and non-control room personnel and contractors (19%)
2. The public (64%)
3. A third party (12%)
4. Other (5%)

It can be noted that more than a two thirds of the releases in gas distribution are discovered by the public and that the pipeline operators or contractors discover less than 20% of all releases.

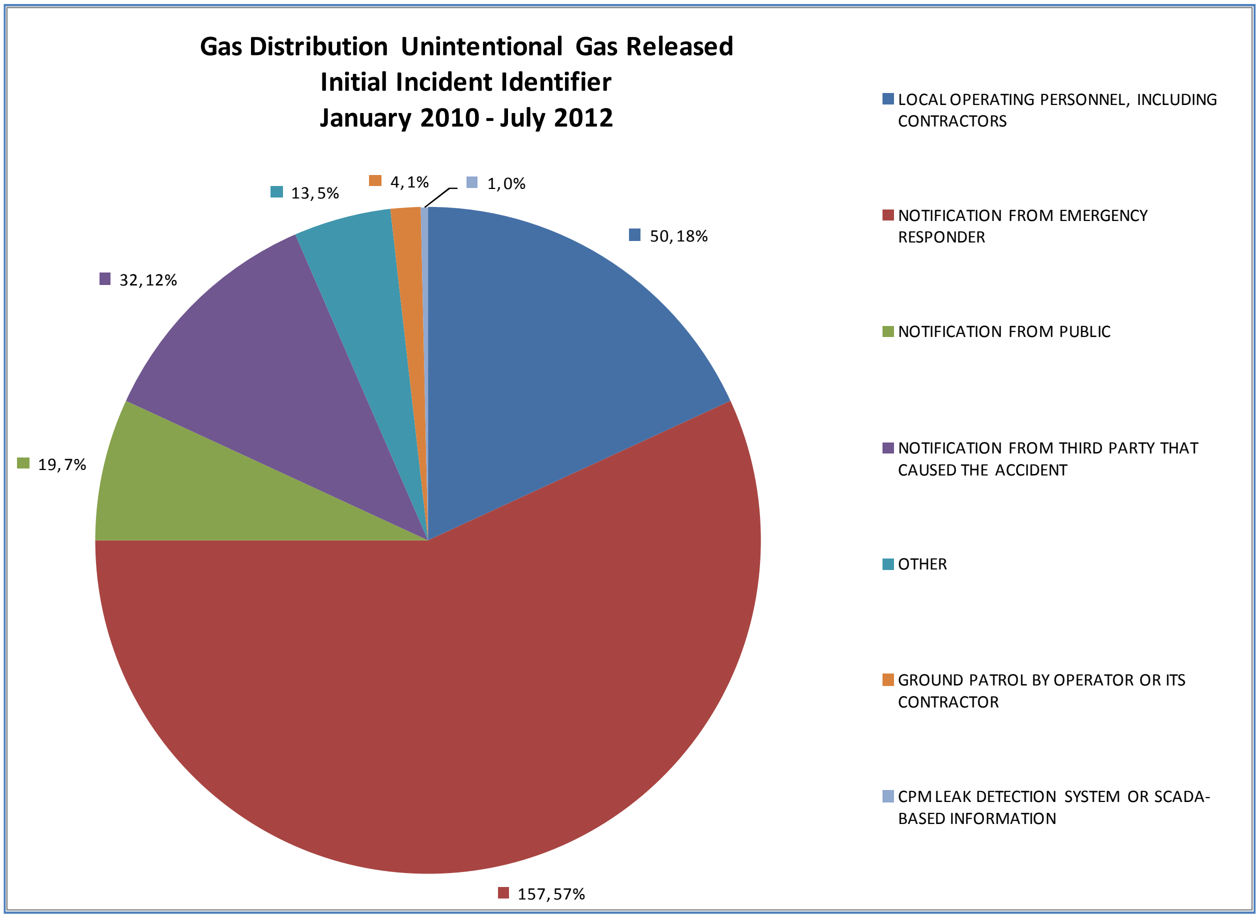


Figure 3.37 Gas Distribution Releases, Initial Identifier

The date on which the operator became aware of the release was not recorded on 8 of the 276 incidents reports; 3 of these 8 reports also fail to report the time of shutdown of the line.

It was possible to calculate the time to arrive on site after the time of initial identification by the operator for 266 incidents of the 276 total, as shown in Figure 3.38. For 48 of these incidents the time to arrive on site is reported as Zero minutes. For 206 of the incidents the time to arrive on site was reported between 1 minute and one hour. For 7 of these incidents the time to arrive on site was reported between 1 and 2 hours and only four incidents have a time to arrive on site above 2 hours. The reported times for arriving on site for the two largest releases were 5 and 0 min.

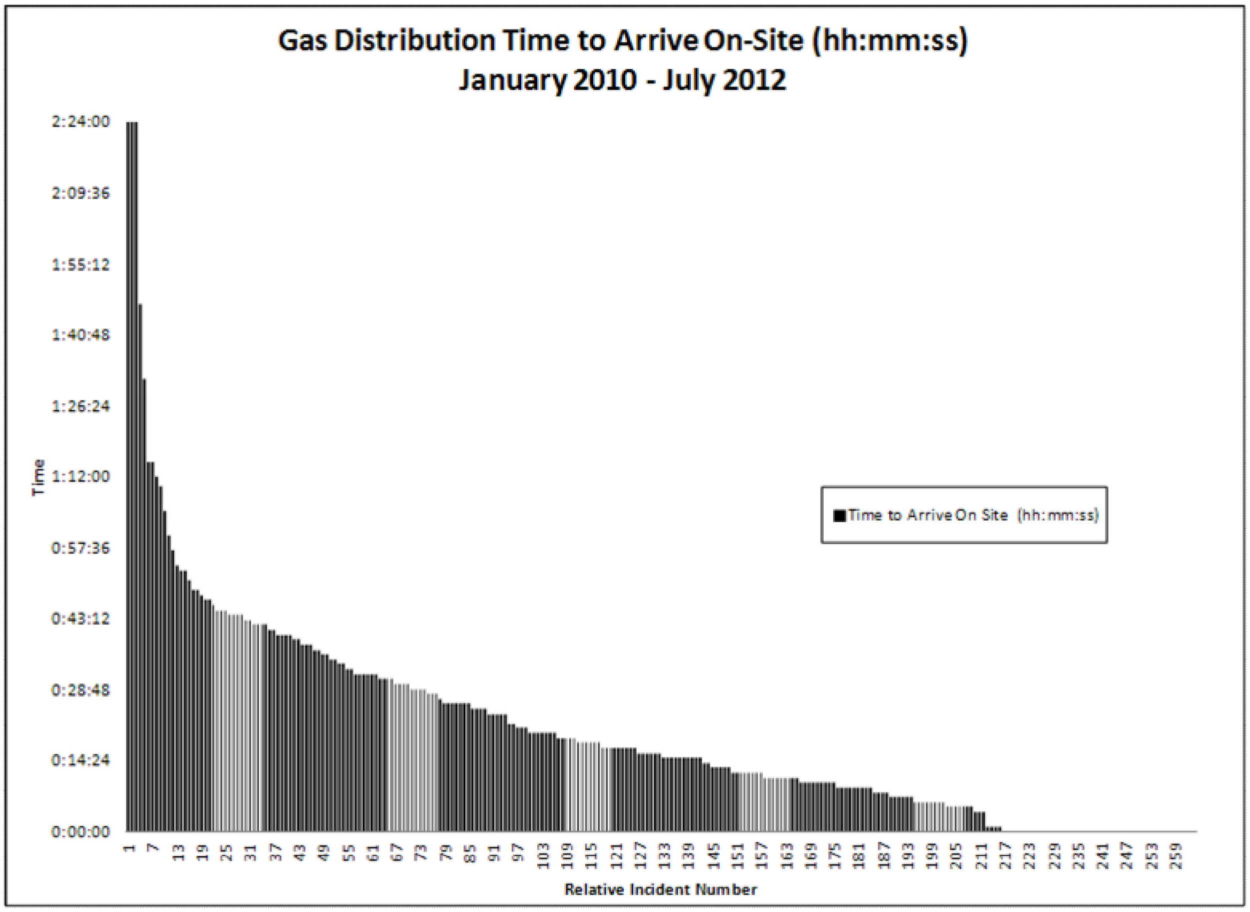


Figure 3.38 Gas Distribution Releases, Response Times

The average time to arrive on-site with and without SCADA functional was determined and for the instances where no data about SCADA functionality was provided by the operator. This data is shown in Figure 3.39. The average time to respond for those incidents where SCADA was functional is 0.4 hours, lower than the value for Gas Transmission. Where SCADA was not functional (most of the incidents), the average response time was 0.2 hours (same value as in Gas Transmission). The average response time was 3.9 hours where SCADA information was not available.

	Average Response Time (hours)
Time to Respond with SCADA Functional	0.4 hrs
Time to Respond without SCADA Functional	0.2 hrs
Time to Respond BLANK-No Data on SCADA Function	3.9 hrs

	Gas Released
Gas Released with SCADA Functional	57,118
Gas Released without SCADA Functional	157
Gas Released BLANK-No Data on SCADA Function	137,124

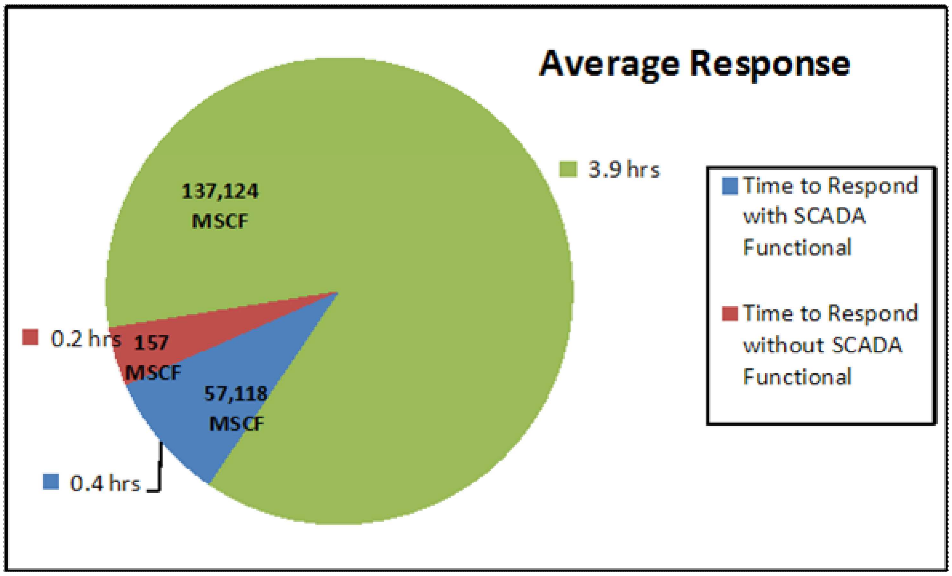


Figure 3.39 Gas Distribution Releases, Response Times, SCADA Detail

TASK 3 APPENDIX A: HAZARDOUS LIQUID CASE STUDIES CASE STUDIES (11)

HAZARDOUS LIQUID CASE STUDY 1			
INCIDENT DESCRIPTION		**LOCATION INFORMATION**	
PHMSA Incident ID [FIR]	20100181 [None]	**State**	Michigan
Corrective Action Order	3-2010-5008H	**ZIP Code**	49068
Date / Time of Incident	7-26-2010 / 1141	**City**	Marshall
Operator Name / ID	Enbridge Energy / 11169	**County or Parish**	Calhoun
Pipeline Category	Liquid Trans	**Pipeline / Facility Name**	Line 6B
Leak Class	Other	**Segment Name / ID**	
Commodity Released	Crude Oil	**Location of Incident**	Pipeline Right of Way

CONSEQUENCE INFORMATION	
Unintentional Release Volume	843,444 Gallons
Total Fatalities	0
Total Injuries Requiring Inpatient Hospitalization	0
Resulted Shutdown of Line	Unknown
Did Commodity Ignite?	No
Did Commodity Explode?	No
Number of General Public Evacuated	61
TIMELINE	
Local time operator identified Incident	7-26-2010 / 1141
Local time operator resources arrived on site	7-26-2010 / 1141
Local Time and Date of Shutdown	N/A
Elapsed Time From Detection to Shutdown (mins)	0

INCIDENT IDENTIFICATION	
How was the Incident initially identified for the Operator?	Public
Was a SCADA-based system in place on the pipeline or facility involved in the Incident?	Yes
Was it operational?	Yes
Was it fully functional?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection of the Incident?	No
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident?	Yes
Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	Yes
Was it operational?	Yes
Was it fully functional?	No
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	No
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	Yes
Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator	$725,000,000

INCIDENT SUMMARY (from PHMSA Corrective Action Order)

At approximately 9:45 a.m. CDT on July 26, 2010, Respondent discovered that a rupture occurred on its Line 6B hazardous liquid pipeline, resulting in the release of an estimated 19,500 barrels of crude oil. The failure occurred at Mile Post (MP) 608, approximately one mile south of the town of Marshall, Michigan. Marshall is located approximately half-way between the cities of Kalamazoo and Jackson, Michigan. The incident was reported to the National Response Center (NRC Report No. 948903).

Spilled oil from Respondent's pipeline entered the Talmadge Creek and the Kalamazoo River. Emergency responders closed two nearby county roads. Various state and federal agencies including the Environmental Protection Agency, U.S. Coast Guard, and the Michigan Department of Environmental Quality are deploying boom and taking other response and collection measures. Spilled oil has migrated as far downriver as Augusta, Michigan.

HAZARDOUS LIQUID CASE STUDY 1
Line 6B was last re-assessed for corrosion in June, 2009 with Ultrasonic Technology and prior to that in October, 2007 with Magnetic Flux Leakage technology. On July 15, 2010 Respondent notified PHMSA of an alternative remediation plan for metal loss anomalies found in this survey to consider pipe replacement instead of repair. Enbridge further notified PHMSA that the alternative remediation method would result in exceeding the allowable timeframe to complete remediation.

HAZARDOUS LIQUID CASE STUDY 2			
INCIDENT DESCRIPTION		**LOCATION INFORMATION**	
PHMSA Incident ID [FIR]	20100021 [None]	**State**	North Dakota
Corrective Action Order	3-2010-5001H	**ZIP Code**	58265
Date / Time of Incident	1-8-2010 / 2338	**City**	Neche
Operator Name / ID	Enbridge Energy / 11169	**County or Parish**	Pembina
Pipeline Category	Liquid Trans	**Pipeline / Facility Name**	Line 2
Leak Class	Rupture	**Segment Name / ID**	MP 774.18
Commodity Released	Crude Oil	**Location of Incident**	Pipeline Right of Way

CONSEQUENCE INFORMATION	
Unintentional Release Volume	158,928 Gallons
Total Fatalities	0
Total Injuries Requiring Inpatient Hospitalization	0
Resulted Shutdown of Line	Yes
Did Commodity Ignite?	No
Did Commodity Explode?	No
Number of General Public Evacuated	0
TIMELINE	
Local time operator identified Incident	1-8-2010 / 2338
Local time operator resources arrived on site	1-9-2010 / 0220
Local Time and Date of Shutdown	1-8-2010 / 2341
Elapsed Time From Detection to Shutdown (mins)	3

INCIDENT IDENTIFICATION	
How was the Incident initially identified for the Operator?	Operator Controller
Was a SCADA-based system in place on the pipeline or facility involved in the Incident?	Yes
Was it operational?	Yes
Was it fully functional?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection of the Incident?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident?	Yes
Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	Yes
Was it operational?	Yes
Was it fully functional?	Yes
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	No
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	Yes
Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator	$4,194,715

INCIDENT SUMMARY (from PHMSA Corrective Action Order)

At approximately 11:37 p.m. local time, on January 8, 2010, a rupture occurred on Respondent's Line 2, resulting in the release of approximately 3000 barrels of crude oil. The failure occurred at Mile Post (MP) 774, approximately 1.5 miles northeast of the town of Neche, North Dakota.

At 11:38 p.m., a low-suction alarm initiated an emergency station cascade shutdown. At 11:40 p.m., the Gretna station valve began closing. At 11:44 p.m., the Gretna station was isolated. At 11:49 p.m., Line 2 was fully isolated from the Gretna to Donaldson pump stations.

HAZARDOUS LIQUID CASE STUDY 3			
INCIDENT DESCRIPTION		**LOCATION INFORMATION**	
PHMSA Incident ID [FIR]	20100220 [15823]	**State**	New York
Corrective Action Order	1-2010-500SH	**ZIP Code**	12131
Date / Time of Incident	8-27-2010 / 1630	**City**	Gilboa
Operator Name / ID	TE Products / 19237	**County or Parish**	Schoharie
Pipeline Category	Liquid Trans	**Pipeline / Facility Name**	P-41
Leak Class	Other	**Segment Name / ID**	Watkins to Selkirk
Commodity Released	HVL (LPG/NGL)	**Location of Incident**	Pipeline Right of Way

CONSEQUENCE INFORMATION	
Unintentional Release Volume	137,886 Gallons
Total Fatalities	0
Total Injuries Requiring Inpatient Hospitalization	0
Resulted Shutdown of Line	Yes
Did Commodity Ignite?	No
Did Commodity Explode?	No
Number of General Public Evacuated	23
TIMELINE	
Local time operator identified Incident	8-27-2010 / 1630
Local time operator resources arrived on site	8-27-2010 / 1700
Local Time and Date of Shutdown	8-27-2010 / 1700
Elapsed Time From Detection to Shutdown (mins)	30

INCIDENT IDENTIFICATION	
How was the Incident initially identified for the Operator?	Public
Was a SCADA-based system in place on the pipeline or facility involved in the Incident?	Yes
Was it operational?	Yes
Was it fully functional?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection of the Incident?	No
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident?	Yes
Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	Yes
Was it operational?	Yes
Was it fully functional?	Yes
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	No
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	Yes
Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator	$1,811,756

INCIDENT SUMMARY (from PHMSA Corrective Action Order)
At approximately 5:17 p.m. EDT, on August 27, 2010, a failure occurred on TEPPCO's 8-inch Line P-41 at Mile Post (MP) 133.9 along Keyserkill Road in Gilboa, New York (Schoharie County), resulting in a release of propane causing the evacuation of local residents in a three- mile area ("Failure"). Local residents first detected the Failure and phoned the operator. The incident was reported to the National Response Center (NRC Report No. 952328) at 6:52 p.m. EDT on August 27, 2010.

HAZARDOUS LIQUID CASE STUDY 4			
INCIDENT DESCRIPTION		**LOCATION INFORMATION**	
PHMSA Incident ID [FIR]	20100163 [n/a]	**State**	Georgia
Corrective Action Order	None	**ZIP Code**	30824
Date / Time of Incident	7-5-2010 / 1040	**City**	Thomson
Operator Name / ID	Dixie Pipeline / 3445	**County or Parish**	McDuffie
Pipeline Category	Liquid Trans	**Pipeline / Facility Name**	Dixie Pipeline
Leak Class	Mechanical Puncture	**Segment Name / ID**	120
Commodity Released	HVL (LPP/NGL)	**Location of Incident**	Pipeline Right of Way

CONSEQUENCE INFORMATION	
Unintentional Release Volume	130,368 Gallon
Total Fatalities	1
Total Injuries Requiring Inpatient Hospitalization	1
Resulted Shutdown of Line	Yes
Did Commodity Ignite?	Yes
Did Commodity Explode?	Yes
Number of General Public Evacuated	1
TIMELINE	
Local time operator identified Incident	7-5-2010 / 1040
Local time operator resources arrived on site	7-5-2010 / 1227
Local Time and Date of Shutdown	7-5-2010 / 1052
Elapsed Time From Detection to Shutdown (mins)	

INCIDENT IDENTIFICATION	
How was the Incident initially identified for the Operator?	CPM/SCADA
Was a SCADA-based system in place on the pipeline or facility involved in the Incident?	Yes
Was it operational?	Yes
Was it fully functional?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection of the Incident?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident?	Yes
Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	No
Was it operational?	--
Was it fully functional?	--
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	--
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	--
Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator	$524,275

INCIDENT SUMMARY

On Monday, July 5, 2010, at approximately 10:40 am Eastern Daylight Savings Time (EDT), a rupture occurred on the Dixie Pipeline Company (Dixie) 8-inch diameter propane pipeline at milepost (MP) 817.11 in Thomson, McDuffie County, Georgia. The release occurred at 390 Stagecoach Road, which was a 20-acre property with a pond, two mobile homes, and a storage building all surrounded by a wooded area. One passenger car (a Jeep) was on the premises at the time of the rupture.

The pipeline rupture occurred when the 390 Stagecoach Road property owner, Paul McCorkle, struck the 8-inch propane pipeline with his bulldozer while grading a dirt road along the edge of the pond. The strike punctured the pipe and created a 9-inch (longitudinal) by 5-inch (at its widest point) hole that allowed propane to escape and form a vapor cloud over the pond and lower lying areas of the property. The released propane caused injury to Paul McCorkle that later required medical attention.

HAZARDOUS LIQUID CASE STUDY 4
Immediately after striking the pipe, Paul McCorkle left the accident scene. He went to his nearby residence where he called 911 at 10:45 am to report he had struck the Dixie pipeline with a bulldozer. Paul McCorkle's son, Jason McCorkle, who lived in a mobile home on the property also called 911 from his cellular phone (within 60 seconds of his father's call) to report the ruptured pipeline. Jason McCorkle was standing outside of his mobile home approximately 150 yards north of the rupture when he made his call. During Jason McCorkle's 911 call, the propane ignited and exploded, killing the young man. The ensuing fire destroyed one of the two mobile homes on the property, the storage building, the Jeep and the bulldozer. The fire also ignited several brush fires within the surrounding wooded area. At approximately 10:40 am, five minutes before Paul McCorkle's 911 call, Dixie's Supervisory Control and Data Acquisition (SCADA) system received two "Pressmon" alarms due to a rapid pressure decrease in the pipeline between the Norwood Pump Station (MP 806.39) and the Appling Pump Station (MP 831.76). These pump stations were located immediately upstream and downstream of the rupture location (MP 817.11). At approximately 10:46 am, Dixie's pipeline controllers shut down the pumps at several upstream pump stations and opened an upstream spur to decrease flow to the rupture area; a few minutes later the controllers shut motor operated valves to isolate the Norwood to Appling pipeline segment. At 10:56 am, a Stagecoach Road resident who lived east of the accident notified Dixie of a possible pipeline explosion and provided Dixie with the accident location. Through coordination with the Stagecoach Road resident, the McDuffie County Sheriff's office and the McDuffie County Fire Service, Dixie was able to secure the closure of the manual shut-off valves at Ridge Road and Washington Road, further isolating (i.e. reducing in length) the affected pipeline segment. The McDuffie County Fire Service arrived at the accident scene at 10:56 am and received mutual aid from surrounding county fire departments as well as the Georgia Forestry Commission to assist in controlling the structure and woodland/brush fires. Upon arriving at the accident scene, Dixie advised the McDuffie County Fire Service to allow the propane to continue to burn at the rupture site. After the McDuffie County Fire Service gained complete control of the woodland/brush and structure fires, they directed their efforts to monitoring the immediate area around the large flame at the propane leak for secondary fires. On July 6, the fire went out due to lack of fuel. At that time, PHMSA, Dixie, and Georgia State agencies began their respective accident investigations. The cause of the rupture was mechanical damage caused by a third party. Paul McCorkle, the bulldozer operator did not call the Georgia Utilities Protection Center (GA 811) to have the pipeline or any other utilities located prior to his mechanized digging, which is required by Georgia State law.

HAZARDOUS LIQUID CASE STUDY 5			
INCIDENT DESCRIPTION		**LOCATION INFORMATION**	
PHMSA Incident ID [FIR]	20120041 [None]	**State**	Ohio
Corrective Action Order	3-2012-5002H	**ZIP Code**	44090
Date / Time of Incident	1-12-2012 / 2218	**City**	Wellington
Operator Name / ID	Sunoco Pipeline / 18718	**County or Parish**	Lorrain
Pipeline Category	Liquid Trans	**Pipeline / Facility Name**	Fost-HUDS-8
Leak Class	Leak	**Segment Name / ID**	Fostoria to Hudson
Commodity Released	Gasoline	**Location of Incident**	Pipeline Right of Way

CONSEQUENCE INFORMATION	
Unintentional Release Volume	81,900 Gallons
Total Fatalities	0
Total Injuries Requiring Inpatient Hospitalization	0
Resulted Shutdown of Line	Yes
Did Commodity Ignite?	No
Did Commodity Explode?	No
Number of General Public Evacuated	70
TIMELINE	
Local time operator identified Incident	1-12-2012 / 2218
Local time operator resources arrived on site	1-13-2012 / 0107
Local Time and Date of Shutdown	1-12-2012 / 2222
Elapsed Time From Detection to Shutdown (mins)	4

INCIDENT IDENTIFICATION	
How was the Incident initially identified for the Operator?	CPM/SCADA
Was a SCADA-based system in place on the pipeline or facility involved in the Incident?	Yes
Was it operational?	Yes
Was it fully functional?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection of the Incident?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident?	Yes
Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	Yes
Was it operational?	Yes
Was it fully functional?	Yes
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Yes
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	Yes
Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator	$15,000,005

INCIDENT SUMMARY (from PHMSA Corrective Action Order)

At approximately 10:18pm EST on January 12, 2012, Sunoco discovered that a failure had occurred on the Affected Pipeline, resulting in the release of an estimated 2,780 barrels of unleaded gasoline. The failure occurred at Mile Post 56 in the town of Wellington, Ohio. The incident was reported by Sunoco to the National Response Center at 1:02am on January 13, 2012 (NRC Report No. 1000262).

The accident occurred in a parking lot in a high consequence area (HCA) about 20 miles south of Lake Erie. As a result of the failure, emergency responders evacuated approximately 50 individuals from nearby homes. As of January 17, 2012, the homes remained evacuated.

After discovering the failure, Respondent's personnel initiated an emergency shut-down of the entire Affected Pipeline. Respondent's personnel then isolated the line by closing various isolation valves and stopping individual pumping units.

HAZARDOUS LIQUID CASE STUDY 5
At the time of the incident, the estimated operating pressure at the failure site was 1102 psig. The maximum operating pressure (MOP) of this line segment is 1200 psig and the discharge pressure at the Norwalk station, approximately 17 miles upstream of the failure site, was reported to be 1199 psig. The Affected Pipeline was last assessed for corrosion in 2007 with Hi-Resolution Magnetic Flux Leakage inline inspection technology.

HAZARDOUS LIQUID CASE STUDY 6			
INCIDENT DESCRIPTION		**LOCATION INFORMATION**	
PHMSA Incident ID [FIR]	20110262 [FIR]	**State**	Montana
Corrective Action Order	5-2011-5017H	**ZIP Code**	59044
Date / Time of Incident	7-1-2011 / 2240	**City**	Laurel
Operator Name / ID	Exxon Mobil / 4906	**County or Parish**	Yellowstone
Pipeline Category	Liquid Trans	**Pipeline / Facility Name**	Silvertip to Billings 12-inch
Leak Class	Rupture	**Segment Name / ID**	Edgar to Laurel
Commodity Released	Crude Oil	**Location of Incident**	Pipeline Right of Way

CONSEQUENCE INFORMATION	
Unintentional Release Volume	63,378 Gallons
Total Fatalities	0
Total Injuries Requiring Inpatient Hospitalization	0
Resulted Shutdown of Line	No
Did Commodity Ignite?	No
Did Commodity Explode?	No
Number of General Public Evacuated	40
TIMELINE	
Local time operator identified Incident	7-1-2011 / 2345
Local time operator resources arrived on site	7-2-2011 / 0010
Local Time and Date of Shutdown	No Shutdown Time Reported
Elapsed Time From Detection to Shutdown (mins)	No Shutdown Time Reported

INCIDENT IDENTIFICATION	
How was the Incident initially identified for the Operator?	Public
Was a SCADA-based system in place on the pipeline or facility involved in the Incident?	Yes
Was it operational?	Yes
Was it fully functional?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection of the Incident?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident?	Yes
Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	Yes
Was it operational?	Yes
Was it fully functional?	Yes
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Yes
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	Yes
Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator	$135,000,000

INCIDENT SUMMARY (from PHMSA Corrective Action Order)

On July 1, 2011 at approximately 10:40 p.m. MDT a reportable accident occurred on the Silvertip line, resulting in the release of approximately 750-1000 barrels of crude oil into the Yellowstone River (the Failure). The Silvertip Pipeline is a 12-inch diameter pipeline approximately 69 miles in length that transports crude oil from the company's Silvertip Station near Elk Basin, Wyoming, to the ExxonMobil refinery in Billings, Montana.

The Failure occurred between Mile Posts 20.7 and 21.0 in the vicinity of the city of Laurel, Montana (Failure Site).

The Failure was reported to the National Response Center (NRC Report No. 981503) on July 2, 2011, at approximately 12:19 a.m. MDT.

In response to the Failure, ExxonMobil shut down the pumps at Silvertip Station at approximately 10:47 p.m., MDT, on July 1, 2011.

HAZARDOUS LIQUID CASE STUDY 6
ExxonMobil initially closed the Laurel block valve (1067) at approximately 10:57 p.m., reopened it at 11:07 p.m., and then finally closed it at 11:28 p.m. Finally, ExxonMobil closed the block valve located south of the Yellowstone River at approximately 11:36 p.m. on July 1, 2011. This operational timeline is based on control center timelines provided by ExxonMobil and converted to Mountain time by PHMSA staff. The accident did not cause any known injuries but approximately 140 people were initially evacuated. Water intakes for the City of Billings are located immediately downstream of the pipeline crossing and had to be temporarily shut down. ExxonMobil performed an in-line inspection (ILI) of the Silvertip Pipeline in 2005 and 2009. Between June 6-10, 2011, PHMSA reviewed the raw ILI data and found no integrity-threatening pipe defects in pipe materials in the area of the Yellowstone River crossing.

HAZARDOUS LIQUID CASE STUDY 7			
INCIDENT DESCRIPTION		**LOCATION INFORMATION**	
PHMSA Incident ID [FIR]	20100287 [None]	**State**	Louisiana
Corrective Action Order	4-2010-5017H	**ZIP Code**	70668
Date / Time of Incident	11-16-2010 / 1646	**City**	Vinton
Operator Name / ID	Shell Pipeline / 31174	**County or Parish**	Calcasieu
Pipeline Category	Liquid Trans	**Pipeline / Facility Name**	Earth to East Houston
Leak Class	Rupture	**Segment Name / ID**	Sulpher Station to Pt. Neches 22”
Commodity Released	Crude Oil	**Location of Incident**	Pipeline Right of Way

CONSEQUENCE INFORMATION	
Unintentional Release Volume	43,260 Gallons
Total Fatalities	0
Total Injuries Requiring Inpatient Hospitalization	0
Resulted Shutdown of Line	Yes
Did Commodity Ignite?	No
Did Commodity Explode?	No
Number of General Public Evacuated	Unknown
TIMELINE	
Local time operator identified Incident	11-16-2010 / 1715
Local time operator resources arrived on site	11-16-2010 / 1715
Local Time and Date of Shutdown	11-16-2010 / 1646
Elapsed Time From Detection to Shutdown (mins)	Shutdown Reported Prior to Incident

INCIDENT IDENTIFICATION	
How was the Incident initially identified for the Operator?	CPM/SCADA
Was a SCADA-based system in place on the pipeline or facility involved in the Incident?	Yes
Was it operational?	Yes
Was it fully functional?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection of the Incident?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident?	Yes
Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	Yes
Was it operational?	Yes
Was it fully functional?	Yes
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Yes
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	Yes
Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator	$989,000

INCIDENT SUMMARY (from PHMSA Corrective Action Order)

On November 16, 2010, a failure occurred on the Houma-to-Port Neches segment of the pipeline system near Vinton, Louisiana, resulting in the release of approximately 1,000 barrels of crude oil. The accident occurred on the Houma-to-Port Neches segment of the affected pipeline near Vinton, Louisiana, approximately 10 miles downstream from Sulphur Station. Shell’s Houma-to-Houston pipeline system is approximately 300 miles in length and transports crude oil from Houma, Louisiana to Houston, Texas.

The Houma-to-Port Neches segment is 22-inch diameter pipeline constructed in 1952 from API 5L X-52 seamless and double submerged arc-welded seam line pipe.

PHMSA became aware of the accident on November 16, 2010, when the agency received NRC Report #960033. PHMSA

HAZARDOUS LIQUID CASE STUDY 7
initiated an investigation of the accident, which involved communication with Shell personnel, on-site investigations at the failure location, and a review of records at Shell offices in Houston. The Houma-to-Houston pipeline typically operates in a steady state operation between 800 to 900 psig. The MOP of the pipeline system is 1050 psig. The discharge pressure at the time of the accident was 840 psig at Sulphur Station. Shell performed an inline inspection (ILI) of the pipeline in 2007 using Magnetic Flux Leakage and Caliper tools. The grading report from the ILI did not provide any indications of a required repair at the location of the failure, however, a review of the raw ILI data shows an indication of corrosion was present on the pipeline joint where the failure occurred. Because a failure occurred approximately three years after the graded ILI report indicated no actionable indication, there is valid cause for concern about other potential sites along the affected pipeline that may have been assessed in a similar manner and should be reevaluated and investigated for the threat of failure.

HAZARDOUS LIQUID CASE STUDY 8			
INCIDENT DESCRIPTION		**LOCATION INFORMATION**	
PHMSA Incident ID [FIR]	20100201 [None]	**State**	Indiana
Corrective Action Order	3-2010-5010H	**ZIP Code**	46320
Date / Time of Incident	8-17-2010 / 0948	**City**	Hammond
Operator Name / ID	AMOCO/395	**County or Parish**	Lake
Pipeline Category	Liquid Trans	**Pipeline / Facility Name**	White Oak to Chicago O'Hare
Leak Class	Leak	**Segment Name / ID**	White Oak to Manhattan South
Commodity Released	Refined Products	**Location of Incident**	Pipeline Right of Way

CONSEQUENCE INFORMATION	
Unintentional Release Volume	38,640 Gallons
Total Fatalities	0
Total Injuries Requiring Inpatient Hospitalization	0
Resulted Shutdown of Line	Yes
Did Commodity Ignite?	No
Did Commodity Explode?	No
Number of General Public Evacuated	8
TIMELINE	
Local time operator identified Incident	8-17-2010 / 0949
Local time operator resources arrived on site	8-17-2010 / 1000
Local Time and Date of Shutdown	8-17-2010 / 0949
Elapsed Time From Detection to Shutdown (mins)	

INCIDENT IDENTIFICATION	
How was the Incident initially identified for the Operator?	Public
Was a SCADA-based system in place on the pipeline or facility involved in the Incident?	Yes
Was it operational?	Yes
Was it fully functional?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection of the Incident?	No
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident?	No
Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	Yes
Was it operational?	Yes
Was it fully functional?	Yes
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	No
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	No
Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator	$13,184,000

INCIDENT SUMMARY

BP is the owner or operator of a 38-mile-long pipeline that transports refined petroleum products through 10-inch and 12-inch pipe from the White Oak Pump Station in Lake County, Indiana, Milepost (MP) 0, to the Manhattan Pump Station in Will County, Illinois, MP 38 (Affected Pipeline Facility).

On August 17, 2010, at 2:58 p.m. CST, BP notified the NRC that it had found petroleum product in a storm sewer at the corner of 175th Street and White Oak Avenue in Hammond, Indiana. BP also informed the NRC that the Affected Pipeline Facility was located in the vicinity of the release site.

HAZARDOUS LIQUID CASE STUDY 8
The intersection of 175th Street and White Oak Avenue in Hammond, Indiana, is in a "high consequence area" under 49 C.F.R. §§ 195.450 and 195.452, and is within approximately one to two blocks of an interstate highway. On August 19, 2010, at 5:12 p.m. CST, BP notified the NRC that the Affected Pipeline Facility had failed at the above location, resulting in the release of approximately 90 barrels of gasoline and diesel fuel into the sewer system.

HAZARDOUS LIQUID CASE STUDY 9			
INCIDENT DESCRIPTION		**LOCATION INFORMATION**	
PHMSA Incident ID [FIR]	20110335 [None]	**State**	Iowa
Corrective Action Order	3-2011-5009H	**ZIP Code**	51040
Date / Time of Incident	8-13-2011 / 0209	**City**	Onawa
Operator Name / ID	Enterprise Products / 31618	**County or Parish**	Monona
Pipeline Category	Liquid Trans	**Pipeline / Facility Name**	West Leg Loop Red Line
Leak Class	Other	**Segment Name / ID**	Line ID 428
Commodity Released	Refined Products	**Location of Incident**	Pipeline Right of Way

CONSEQUENCE INFORMATION	
Unintentional Release Volume	34,356 Gallons
Total Fatalities	0
Total Injuries Requiring Inpatient Hospitalization	0
Resulted Shutdown of Line	Yes
Did Commodity Ignite?	No
Did Commodity Explode?	No
Number of General Public Evacuated	0
TIMELINE	
Local time operator identified Incident	8-13-2011 / 0216
Local time operator resources arrived on site	8-13-2011 / 0330
Local Time and Date of Shutdown	8-13-2011 / 0219
Elapsed Time From Detection to Shutdown (mins)	3

INCIDENT IDENTIFICATION	
How was the Incident initially identified for the Operator?	Operator/ Controller
Was a SCADA-based system in place on the pipeline or facility involved in the Incident?	Yes
Was it operational?	Yes
Was it fully functional?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection of the Incident?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident?	Yes
Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	Yes
Was it operational?	Yes
Was it fully functional?	Yes
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	No
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	No
Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator	$7,657,195

INCIDENT SUMMARY (from PHMSA Corrective Action Order)

On August 13, 2011, a failure occurred on Enterprise’s West Leg Red Line hazardous liquid pipeline that crosses underneath the Missouri River approximately eight miles west of Onawa, Iowa (“Failure”).

The incident was reported to the National Response Center on August 13 at 04:23 a.m. CDT. The suspected failure location is inaccessible due to flooding. Enterprise updated the initial report to the National Response Center at 8:14 a.m. CDT (Report No. 985813) and 10:09 a.m. CDT (NRC Report No. 985822), on August 13, 2011.

The West Leg Red Line is an 8-inch diameter pipeline, approximately 536 miles in length, which transports natural gas liquids from Conway, Kansas, to Pine Bend, Minnesota (Red Line). The West Leg Blue Line is an 8-inch diameter pipeline, approximately 471 miles in length, which transports propane (HVL) from Conway, Kansas, to Mankato, Minnesota (Blue Line)

HAZARDOUS LIQUID CASE STUDY 9
within the same right-of-way as the Red Line. At approximately 1:57 a.m. CDT, on August 13, 2011, a release occurred on the Red Line. Although no released product has been detected, Enterprise reported 3,351 barrels released, based on the volume of product between block valves initially closed at Mile Post (MP) 269 and MP 280 (Whiting Station). The failure occurred near MP 271 approximately eight miles west of Onawa, Iowa, in Monona County. At approximately 1:57a.m. CDT on August 13, 2011, discharge pressure at Enterprise's Whiting Pump Station (downstream of failure site) began to drop. The pump unit gas turbine dropped out at 2:09 a.m. on Under Speed Shutdown. A low suction pressure shutdown alarm occurred at 2:14 a.m. Enterprise's control center staff noted the sudden drop in pressure on the Red Line. In response to the Failure, Enterprise's operations control center (OCC) shut down the Red Line at 2:19 a.m. by remotely closing a block valve located at MP 269 west of the Missouri River Channel. Another remotely operated block valve located at MP 271, east of the Missouri River Channel, was inoperable. Electrical service to this block valve was cut off in June 2011 due to high water. As a result, the OCC closed the remotely operated valve at Whiting Station (MP 280) at 2:29 a.m. No fires, injuries, or evacuations were reported as a result of the Failure. The toll bridge across the Missouri River had been closed previously due to flooding. The Affected Pipelines impact one or more "High Consequence Areas," as defined under 49 C.F.R. 195.450, and the site of the Failure along the Missouri River is located adjacent to State Route 175 in Monona County, Iowa. The Red Line pipe in the area of the Failure was replaced in 1993, in conjunction with a project to remove all three pipelines from the toll bridge. The replacement pipe consists of 8.625-inch diameter, 0.277-inch wall thickness, Grade X-42 line pipe manufactured by Lone Star Steel, and 8.625-inch diameter, 0.172-inch wall thickness, Grade X-60 line pipe manufactured by Ipsco Steel. The pipe is coated with Plastic Tape, and cathodic protection is provided by an impressed current cathodic protection system. At the time of the incident, the pressure of the Red Line pipeline was 748 psig at the Greenwood pump station discharge. The maximum operating pressure (MOP) in the area of the Failure is 1354 psig.

HAZARDOUS LIQUID CASE STUDY 10			
INCIDENT DESCRIPTION		**LOCATION INFORMATION**	
PHMSA Incident ID [FIR]	20100146 [15723]	**State**	Utah
Corrective Action Order	5-2010-5032H	**ZIP Code**	84113
Date / Time of Incident	6-12-2010 / 0742	**City**	Salt Lake City
Operator Name / ID	Chevron / 2731	**County or Parish**	Salt Lake
Pipeline Category	Liquid Transmission	**Pipeline / Facility Name**	Red Butte Creek
Leak Class	Other	**Segment Name / ID**	Rangely to Salk Lake Crude System
Commodity Released	Crude Oil	**Location of Incident**	Pipeline Right of Way

CONSEQUENCE INFORMATION	
Unintentional Release Volume	33,600 Gallon
Total Fatalities	0
Total Injuries Requiring Inpatient Hospitalization	0
Resulted Shutdown of Line	Yes
Did Commodity Ignite?	No
Did Commodity Explode?	No
Number of General Public Evacuated	0
TIMELINE	
Local time operator identified Incident	6-12-2010 / 0742
Local time operator resources arrived on site	6-12-2010 / 0905
Local Time and Date of Shutdown	6-12-2010 / 0742
Elapsed Time From Detection to Shutdown (mins)	

INCIDENT IDENTIFICATION	
How was the Incident initially identified for the Operator?	Public
Was a SCADA-based system in place on the pipeline or facility involved in the Incident?	Yes
Was it operational?	Yes
Was it fully functional?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection of the Incident?	No
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident?	No
Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	No
Was it operational?	--
Was it fully functional?	--
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	--
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	--
Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator	$441,000

INCIDENT SUMMARY
Chevron Pipe Line (CPL) Controller was notified of the spill Saturday morning by the Salt Lake City Fire Department and CPL immediately shut down the pipeline. CPL dispatched emergency response teams to manually close the valve upstream from the leak site and began containment response. CPL notified all appropriate federal, state, and local emergency response agencies. Preliminary visual observations of the damaged pipeline appear consistent with damage caused by an electrical arc, and we are working with Rocky Mountain Power Company to develop a testing protocol to analyze the pipeline to help determine the cause of the accident.

HAZARDOUS LIQUID CASE STUDY 11			
INCIDENT DESCRIPTION		**LOCATION INFORMATION**	
PHMSA Incident ID [FIR]	20110331 [None]	**State**	Texas
Corrective Action Oder	3-2011-5010H	**ZIP Code**	76365
Date / Time of Incident	8-12-2011 / 1220	**City**	Henrietta
Operator Name / ID	Magellan Pipeline / 22610	**County or Parish**	Clay
Pipeline Category	Liquid Trans	**Pipeline / Facility Name**	Orion System
Leak Class	Leak	**Segment Name / ID**	Orion N. 12 inch
Commodity Released	Refined Products	**Location of Incident**	Pipeline Right of Way

CONSEQUENCE INFORMATION	
Unintentional Release Volume	29,988 Gallons
Total Fatalities	0
Total Injuries Requiring Inpatient Hospitalization	0
Resulted Shutdown of Line	No
Did Commodity Ignite?	No
Did Commodity Explode?	No
Number of General Public Evacuated	0
TIMELINE	
Local time operator identified Incident	Time Not Reported
Local time operator resources arrived on site	Time Not Reported
Local Time and Date of Shutdown	No Shutdown Time Reported
Elapsed Time From Detection to Shutdown (mins)	No Shutdown Time Reported

INCIDENT IDENTIFICATION	
How was the Incident initially identified for the Operator?	CPM/SCADA
Was a SCADA-based system in place on the pipeline or facility involved in the Incident?	Yes
Was it operational?	Yes
Was it fully functional?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection of the Incident?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident?	Yes
Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	Yes
Was it operational?	Yes
Was it fully functional?	Yes
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	No
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	No
Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator	$831,750
INCIDENT SUMMARY	

TASK 3 APPENDIX B: NATURAL GAS AND OTHER GAS TRANSMISSION CASE STUDIES CASE STUDIES (8)

NATURAL GAS AND OTHER GAS TRANSMISSION CASE STUDY 1			
INCIDENT DESCRIPTION		**LOCATION INFORMATION**	
PHMSA Incident ID	20110396	**State**	Mississippi
Corrective Action Order	2-2011-1010H	**ZIP Code**	38606
Date / Time of Incident	11-21-2011 / 2014	**City**	Batesville
Operator Name / ID	Tenn. Gas Pipeline / 19160	**County or Parish**	Panola
Pipeline Category	Gas T&G	**Pipeline / Facility Name**	100-1
Leak Class	Leak	**Segment Name / ID**	63-1D
Commodity Released	Natural Gas	**Location of Incident**	Pipeline Right of Way

CONSEQUENCE INFORMATION	
Unintentional Release Volume	83,487 MCF
Total Fatalities	0
Total Injuries Requiring Inpatient Hospitalization	0
Resulted Shutdown of Line	Yes
Did Commodity Ignite?	Yes
Did Commodity Explode?	No
Number of General Public Evacuated	71
TIMELINE	
Local time operator identified Incident	11-21-2011 / 2030
Local time operator resources arrived on site	11-21-2011 / 2045
Local Time and Date of Shutdown	11-21-2011 / 2130
Elapsed Time From Detection to Shutdown (mins)	60

INCIDENT IDENTIFICATION	
How was the Incident initially identified for the Operator?	SCADA
Was a SCADA-based system in place on the pipeline or facility involved in the Incident?	Yes
Was it operational?	Yes
Was it fully functional?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection of the Incident?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident?	Yes
Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	Unknown
Was it operational?	Unknown
Was it fully functional?	Unknown
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Unknown
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	Unknown
Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator	$734,698

INCIDENT SUMMARY (PHMSA Corrective Action Order)

On November 21, 2011, one of the four parallel pipelines in the Line 100 System ruptured near Batesville, Mississippi, resulting in the release of natural gas. The escaping natural gas ignited and formed into a fireball that continued to burn for the next several hours. The local authorities evacuated approximately 20 homes. There were no reported injuries or fatalities.

At approximately 8:33 p.m. Central Standard Time (CST) on November 21, 2011, the operator of the Batesville CS detected a change in the pressure of Line 100-1. The operator immediately notified gas control and his supervisor of that abnormal condition.

At approximately 8:41 p.m. CST, escaping natural gas from Line 100-1 at Valve Section 63-1, Station 126+43 ignited and formed into a fireball. Line 100-1 has a wrinkle bend with a pressure-containing sleeve at that location.

At approximately 8:45 p.m. CST, TGP personnel activated the emergency shutdown system (ESD) at the Batesville CS, which

NATURAL GAS AND OTHER GAS TRANSMISSION CASE STUDY 1
automatically closed the mainline block valves on all four of the Line 100 System pipelines at that location. The Batesville CS is approximately 2.39 miles upstream of the rupture site. At approximately 9:20 p.m. CST, TGP personnel manually closed MLV 64-2, the first mainline block valve on Line 100-2 downstream of the rupture site. At approximately 9:30 p.m. CST, TGP personnel manually closed MLV 64-1, the first mainline block valve on Line 100-1 downstream of the rupture site. The closure of MLV 64-1 isolated the ruptured section of Line 100-1. At approximately 11:15 p.m. CST, the local authorities extinguished the fire at Line 100-1, Valve Section 63-1, Station 126+43.

NATURAL GAS AND OTHER GAS TRANSMISSION CASE STUDY 2			
INCIDENT DESCRIPTION		**LOCATION INFORMATION**	
PHMSA Incident ID [FIR]	20110393 [None]	**State**	Ohio
Corrective Action Order	3-2011-1018H	**ZIP Code**	45732
Date / Time of Incident	11-16-2011 / 0841	**City**	Glouster
Operator Name / ID	Tennessee Gas / 19160	**County or Parish**	Morgan (Home Twp.)
Pipeline Category	Gas T&G	**Pipeline / Facility Name**	200-4 Line
Leak Class	Rupture	**Segment Name / ID**	205-4
Commodity Released	Natural Gas	**Location of Incident**	Pipeline Right of Way

CONSEQUENCE INFORMATION	
Unintentional Release Volume	79,000 MCF
Total Fatalities	0
Total Injuries Requiring Inpatient Hospitalization	0
Resulted Shutdown of Line	Yes
Did Commodity Ignite?	Yes
Did Commodity Explode?	Yes
Number of General Public Evacuated	6
TIMELINE	
Local time operator identified Incident	11-16-2011 / 0848
Local time operator resources arrived on site	11-16-2011 / 0950
Local Time and Date of Shutdown	11-16-2011 / 0955
Elapsed Time From Detection to Shutdown (mins)	67

INCIDENT IDENTIFICATION	
How was the Incident initially identified for the Operator?	Public
Was a SCADA-based system in place on the pipeline or facility involved in the Incident?	Yes
Was it operational?	Yes
Was it fully functional?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection of the Incident?	No
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident?	No
Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	Unknown
Was it operational?	Unknown
Was it fully functional?	Unknown
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Unknown
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	Unknown
Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator	$1,883,770

INCIDENT SUMMARY (PHMSA Corrective Action Order)

Line 200 Pipeline System is composed of four parallel lines, namely, Lines 200-1, 200-2, 200-3, and Line 200-4, which are generally located within a common right-of-way.

At approximately 8:45 a.m. EST on November 16, 2011, a failure occurred on Respondent's 36-inch natural gas pipeline, Line 200-4 in mainline valve section 205(Failure). The failure occurred in Morgan County, Ohio, approximately four miles southeast of Glouster, Ohio. The Failure was reported to the National Response Center at 10:21 a.m. EST on November 16, 2011 (NRC Report No. 995666).

The release and ignition of an undetermined amount of gas produced a fireball that destroyed two homes and one other structure, damaged three other homes and caused three injuries. The two homes that were destroyed were approximately 200 ft and 540 ft from the failure location. Another home was also evacuated.

NATURAL GAS AND OTHER GAS TRANSMISSION CASE STUDY 2
The Failure was in a Class 1 rural location. At the Failure site, the Line 200-4 pipeline was constructed in 1963 of 36-inch x 0.344-inch wall thickness, grade API-5L X60, DSAW seam, manufactured by National Tube. It has a coal tar enamel coating and an impressed current cathodic protection system. The Line 200-4 pipeline was constructed in sections from 1962 to 1968, which includes pipe by National Tube and other manufacturers using similar girth welding processes. The pipeline in the area of the Failure was last hydrostatically tested in 1971 to a test pressure of 1,042 psig.

NATURAL GAS AND OTHER GAS TRANSMISSION CASE STUDY 3			
INCIDENT DESCRIPTION		**LOCATION INFORMATION**	
PHMSA Incident ID [FIR]	20110392	**State**	Alabama
Corrective Action Order	2-2011-1011H	**ZIP Code**	36782
Date / Time of Incident	12-3-2011 / 1507	**City**	Sweetwater
Operator Name / ID	Transcontinental Gas Pipeline Co. / 19570	**County or Parish**	Marengo
Pipeline Category	Gas T&G	**Pipeline / Facility Name**	
Leak Class	Rupture	**Segment Name / ID**	
Commodity Released	Natural Gas	**Location of Incident**	Pipeline Right of Way

CONSEQUENCE INFORMATION	
Unintentional Release Volume	61,700 MCF
Total Fatalities	0
Total Injuries Requiring Inpatient Hospitalization	0
Resulted Shutdown of Line	Yes
Did Commodity Ignite?	Yes
Did Commodity Explode?	Yes
Number of General Public Evacuated	0
TIMELINE	
Local time operator identified Incident	12-3-2011 / 1508
Local time operator resources arrived on site	12-3-2011 / 1525
Local Time and Date of Shutdown	12-3-2011 / 1545
Elapsed Time From Detection to Shutdown (mins)	37

INCIDENT IDENTIFICATION	
How was the Incident initially identified for the Operator?	SCADA
Was a SCADA-based system in place on the pipeline or facility involved in the Incident?	Yes
Was it operational?	Yes
Was it fully functional?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection of the Incident?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident?	Yes
Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	Unknown
Was it operational?	Unknown
Was it fully functional?	Unknown
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Unknown
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	Unknown
Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator	$2,310,000

INCIDENT SUMMARY (PHMSA Corrective Action Order)

Transco is a 10,000-mile natural gas pipeline system that originates in South Texas. It receives natural gas in the Gulf Coast and Appalachia areas and delivers that product to consumers in the Southeast, Mid-Atlantic, and Northeastern United States, including metropolitan areas in Pennsylvania, New Jersey, and New York. Transco is composed of either three or five parallel, looped pipelines (Lines A-E) that are generally located in a common right-of-way (ROW).

At approximately 3:08 p.m. Central Standard Time (CST) on December 3, 2011, Line C (36-inch, MAOP of 800 psig) ruptured at MP 817.77.

- The force of that rupture created a crater in the ground that is approximately 79.5-feet wide, 55-feet long, and 14.25-feet deep and propelled a 47-foot, 3-inch piece of buried pipe more than 200 feet away from the point of

NATURAL GAS AND OTHER GAS TRANSMISSION CASE STUDY 3
impact. • The rupture also resulted in the release of an unknown quantity of natural gas, which ignited and burned for several hours. • MP 817.77 is in a Class 1 location. • Line C was installed in 1964 and constructed with API 5L X-60 pipe as manufactured by National Tube with a double submerged arc weld longitudinal seam. • The actual operating pressure of Line C at the time of the rupture was 795 psig. • In October 2011, WPLP performed an inline inspection (ILI) of Line C from Compressor Station 80 to Compressor Station 100 and of Line B from Compressor Station 90 to Compressor Station 100. WPLP has not yet received the reports from these ILI runs. • At approximately 3:08 p.m. CST, personnel in the Houston Control Center received indications of a possible rupture on Transco and immediately notified the local operations manager. The local operations manager responded and provided visual confirmation of the rupture and fire at MP 817.77. • At approximately 3:25 p.m. CST, the local operations manager closed the main line block valve (Valve 90- C-10) on Line C, located about 15 miles downstream of Compressor Station 90. At about that same time, another WPLP employee closed the side gate valve (Valve 90-C-0) on Line C that is located at Compressor Station 90. The closure of these two valves isolated the affected segment.

NATURAL GAS AND OTHER GAS TRANSMISSION CASE STUDY 4			
INCIDENT DESCRIPTION		**LOCATION INFORMATION**	
PHMSA Incident ID [FIR]	20110294 [None]	**State**	Wyoming
Corrective Action Order	5-2011-1004H	**ZIP Code**	82716
Date / Time of Incident	7-20-2011 / 1930	**City**	Gillette
Operator Name / ID	TransCanada Northern Border Inc. / 32487	**County or Parish**	Campbell
Pipeline Category	Gas T&G	**Pipeline / Facility Name**	Bison Pipeline
Leak Class	Rupture	**Segment Name/ID**	MLV 0 –MLV17
Commodity Released	Natural Gas	**Location of Incident**	Pipeline Right of Way

CONSEQUENCE INFORMATION	
Unintentional Release Volume	50,555 MCF
Total Fatalities	0
Total Injuries Requiring Inpatient Hospitalization	0
Resulted Shutdown of Line	Yes
Did Commodity Ignite?	No
Did Commodity Explode?	No
Number of General Public Evacuated	0
TIMELINE	
Local time operator identified Incident	7-20-2011 / 2015
Local time operator resources arrived on site	7-20-2011 / 2015
Local Time and Date of Shutdown	7-20-2011 / 1940
Elapsed Time From Detection to Shutdown (mins)	Shutdown Reported Prior to Incident

INCIDENT IDENTIFICATION	
How was the Incident initially identified for the Operator?	SCADA
Was a SCADA-based system in place on the pipeline or facility involved in the Incident?	Yes
Was it operational?	Yes
Was it fully functional?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection of the Incident?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident?	Yes
Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	Unknown
Was it operational?	Unknown
Was it fully functional?	Unknown
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Unknown
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	Unknown
Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator	$6,700,000

INCIDENT SUMMARY (PHMSA Corrective Action Order)

The Bison Pipeline (301-mile, 30-inch) transports natural gas from Wyoming's Powder River Basin to the Northern Border pipeline system in Morton County, North Dakota, and passes through southeastern Montana and southwestern North Dakota. On July 20, 2011, at approximately 7:15 PM MDT, a failure occurred on the Affected Pipeline in Campbell County, Wyoming, at MP 16.2, resulting in the release of natural gas in a rural area. There were no fires, injuries, or evacuations as a result of the failure.

The Affected Pipeline was hydrostatically pressure-tested in 2010 and 2011 to establish an MAOP of 1480 psig. The pressure at the location of the failure at the time of the Incident, as provided by Respondent, was 1340 psi. Other segments of the Affected Pipeline are operated at a higher alternative MAOP. An in-line inspection for both magnetic flux leakage and

NATURAL GAS AND OTHER GAS TRANSMISSION CASE STUDY 4
deformation on the Affected Pipeline in mid-July 2011. The results are not yet available.

NATURAL GAS AND OTHER GAS TRANSMISSION CASE STUDY 5			
INCIDENT DESCRIPTION		**LOCATION INFORMATION**	
PHMSA Incident ID [FIR]	20100070 [None}	**State**	California
Corrective Action Order	None	**ZIP Code**	94066
Date / Time of Incident	9-9-2010 / 1811	**City**	San Bruno
Operator Name / ID	Pacific Gas & Electric / 15007	**County or Parish**	San Mateo
Pipeline Category	Gas T&G	**Pipeline / Facility Name**	L132
Leak Class	Rupture	**Segment Name / ID**	
Commodity Released	Natural Gas	**Location of Incident**	Pipeline Right of Way

CONSEQUENCE INFORMATION	
Unintentional Release Volume	47,600 MCF
Total Fatalities	8
Total Injuries Requiring Inpatient Hospitalization	51
Resulted Shutdown of Line	Yes
Did Commodity Ignite?	Yes
Did Commodity Explode?	Yes
Number of General Public Evacuated	0
TIMELINE	
Local time operator identified Incident	9-9-2010 / 1813
Local time operator resources arrived on site	9-9-2010 / 1841
Local Time and Date of Shutdown	9-9-2010 / 1930
Elapsed Time From Detection to Shutdown (mins)	77

INCIDENT IDENTIFICATION	
How was the Incident initially identified for the Operator?	SCADA
Was a SCADA-based system in place on the pipeline or facility involved in the Incident?	Yes
Was it operational?	Yes
Was it fully functional?	No
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection of the Incident?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident?	Yes
Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	Unknown
Was it operational?	Unknown
Was it fully functional?	Unknown
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Unknown
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	Unknown
Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator	$375,363,000

INCIDENT SUMMARY (NTSB Accident Report NTSB/PAR-11/01)
On September 9, 2010, about 6:11 p.m. Pacific daylight time, a 30-inch-diameter segment of an intrastate natural gas transmission pipeline known as Line 132, owned and operated by the Pacific Gas and Electric Company, ruptured in a residential area in San Bruno, California. The rupture occurred at mile point 39.28 of Line 132, at the intersection of Earl Avenue and Glenview Drive. The rupture produced a crater about 72 feet long by 26 feet wide. The section of pipe that ruptured, which was about 28 feet long and weighed about 3,000 pounds, was found 100 feet south of the crater. The Pacific Gas and Electric Company estimated that 47.6 million standard cubic feet of natural gas was released. The released natural gas ignited, resulting in a fire that destroyed 38 homes and damaged 70. Eight people were killed, many were injured, and many more were evacuated from the area.

NATURAL GAS AND OTHER GAS TRANSMISSION CASE STUDY 6			
INCIDENT DESCRIPTION		**LOCATION INFORMATION**	
PHMSA Incident ID [FIR]	20100002 [15077]	**State**	Mississippi
Corrective Action Order	2-2010-1002H	**ZIP Code**	39339
Date / Time of Incident	1-6-2010 / 0432	**City**	Louisville
Operator Name / ID	Southern Nat. Gas/18516	**County or Parish**	Winston
Pipeline Category	Gas T&G	**Pipeline / Facility Name**	2nd North Main
Leak Class	Rupture	**Segment Name / ID**	Center Ridge Gate to Louisville
Commodity Released	Natural Gas	**Location of Incident**	Pipeline Right of Way

CONSEQUENCE INFORMATION	
Unintentional Release Volume	41,176 MCF
Total Fatalities	0
Total Injuries Requiring Inpatient Hospitalization	0
Resulted Shutdown of Line	Yes
Did Commodity Ignite?	No
Did Commodity Explode?	No
Number of General Public Evacuated	0
TIMELINE	
Local time operator identified Incident	1-6-2010 / 0432
Local time operator resources arrived on site	1-6-2010 / 0444
Local Time and Date of Shutdown	1-06-2010 / 0458
Elapsed Time From Detection to Shutdown (mins)	26

INCIDENT IDENTIFICATION	
How was the Incident initially identified for the Operator?	Operator Personnel
Was a SCADA-based system in place on the pipeline or facility involved in the Incident?	Yes
Was it operational?	Yes
Was it fully functional?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection of the Incident?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident?	Yes
Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	Unknown
Was it operational?	Unknown
Was it fully functional?	Unknown
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Unknown
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	Unknown
Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator	$406,699

INCIDENT SUMMARY (PHMSA Corrective Action Order)
ON JANUARY 6 2010 SOUTHERN NATURAL GAS (SNG) COMPANY OPERATIONS PERSONNEL AT THE LOUISVILLE (MS) COMPRESSOR STATION ADVISED SNG GAS CONTROL THAT MEMBERS OF THE GENERAL PUBLIC HAD REPORTED A LOUD NOISE NEAR HIGHWAY 14 WEST OF LOUISVILLE MS. GAS CONTROL SAW A CORRESPONDING PRESSURE DROP VIA THE SCADA SYSTEM. A FAILURE HAD OCCURED ON SNG'S 24 INCH 2ND NORTH MAIN PIPELINE. SNG FIELD PERSONNEL WERE DISPATCHED TO CLOSE VALVES FOR ISOLATION OF THE FAILURE SITE AND TAKE THE AFFECTED SEGMENT OF PIPELINE OUT OF SERVICE.

NATURAL GAS AND OTHER GAS TRANSMISSION CASE STUDY 7			
INCIDENT DESCRIPTION		**LOCATION INFORMATION**	
PHMSA Incident ID	20120066	**State**	Texas
Corrective Action Order	4-2012-1011H	**ZIP Code**	79065
Date / Time of Incident	6-6-2012 / 0247	**City**	Pampa
Operator Name / ID	Nat. Gas Pipeline Co. of America /13120	**County or Parish**	Grey
Pipeline Category	Gas T&G	**Pipeline / Facility Name**	OE#1
Leak Class	Rupture	**Segment Name / ID**	--
Commodity Released	Natural Gas	**Location of Incident**	Pipeline Right of Way

CONSEQUENCE INFORMATION	
Unintentional Release Volume	34,455 MCF
Total Fatalities	0
Total Injuries Requiring Inpatient Hospitalization	0
Resulted Shutdown of Line	Yes
Did Commodity Ignite?	Yes
Did Commodity Explode?	No
Number of General Public Evacuated	0
TIMELINE	
Local time operator identified Incident	6-6-2012 / 0255
Local time operator resources arrived on site	6-6-2012 / 0300
Local Time and Date of Shutdown	6-6-2012 / 0255
Elapsed Time From Detection to Shutdown (mins)	0

INCIDENT IDENTIFICATION	
How was the Incident initially identified for the Operator?	SCADA
Was a SCADA-based system in place on the pipeline or facility involved in the Incident?	Yes
Was it operational?	Yes
Was it fully functional?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection of the Incident?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident?	Yes
Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	Unknown
Was it operational?	Unknown
Was it fully functional?	Unknown
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Unknown
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	Unknown
Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator	$117,000

INCIDENT SUMMARY (PHMSA Corrective Action Order)

At approximately 2:00 a.m. CDT on June 6, 2012, Respondent experienced a sudden pressure drop on the OE #1 pipeline, requiring shut down of the line. Pampa local law enforcement contacted Respondent's Gas Control 800 number and reported a fire in the vicinity of a compressor station in a rural farming area.

The failure occurred downstream of Compressor Station 154 located at Mile Post (MP) 52 in Gray County, Texas, approximately four miles east of the town of Laketon.

The escaping gas ignited, leaving a crater approximately 30 feet in diameter and burning approximately two acres of an agricultural area including two 500-gallon plastic tanks used to store liquid fertilizer. The fire also burned two telephone poles

NATURAL GAS AND OTHER GAS TRANSMISSION CASE STUDY 7
and associated transformers and required State Highway 152 to be shut down for several hours. Following the failure, automated valves closed upstream and downstream of the failure site and the main fire self-extinguished after about two hours, although a smaller fire resulting from valve leakage continued to burn for about seven hours. The pipeline remains out of service.

NATURAL GAS AND OTHER GAS TRANSMISSION CASE STUDY 8			
INCIDENT DESCRIPTION		**LOCATION INFORMATION**	
PHMSA Incident ID [FIR]	20100106 [15341]	**State**	Louisiana
Corrective Action Order	4-2010-1007H	**ZIP Code**	71457
Date / Time of Incident	11-30-2010 / 1450	**City**	Natchitoches
Operator Name / ID	Tennessee Gas / 19160	**County or Parish**	Natchitoches
Pipeline Category	Gas T&G	**Pipeline / Facility Name**	Line 100-2
Leak Class	Rupture	**Segment Name / ID**	40-2D
Commodity Released	Natural Gas	**Location of Incident**	Operator-Cont. Prop.

CONSEQUENCE INFORMATION	
Unintentional Release Volume	14,980 MCF
Total Fatalities	0
Total Injuries Requiring Inpatient Hospitalization	0
Resulted Shutdown of Line	Yes
Did Commodity Ignite?	No
Did Commodity Explode?	No
Number of General Public Evacuated	0
TIMELINE	
Local time operator identified Incident	11-30-2010 / 1450
Local time operator resources arrived on site	11-30-2010 / 1600
Local Time and Date of Shutdown	11-30-2010 / 1600
Elapsed Time From Detection to Shutdown (mins)	70

INCIDENT IDENTIFICATION	
How was the Incident initially identified for the Operator?	Public
Was a SCADA-based system in place on the pipeline or facility involved in the Incident?	Yes
Was it operational?	Yes
Was it fully functional?	Yes
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection of the Incident?	No
Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident?	No
Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	Unknown
Was it operational?	Unknown
Was it fully functional?	Unknown
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Unknown
Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	Unknown
Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator	$116,000

INCIDENT SUMMARY
A loud noise was reported to Tennessee Gas Pipeline (TGP) by a member of the general public in the vicinity of TGP pipeline facilities in Natchitoches, Louisiana. Upon initial investigation, TGP operations personnel found a natural gas leak in the 100-2 pipeline. Visual examination revealed that the leak was coming from a crack in a wrinkle bend. The crack was 1/2" wide and propagated for a length of 50.5" around the circumference of the pipeline. Metallurgical analysis revealed that the crack in the wrinkle bend was likely due to concentrated mechanical stresses coming from external stresses from probable shifting of the surrounding soil, triaxial state of stresses inherent to in-service wrinkle bends (geometric), and internal line pressure from normal pipeline operations.

4.0 TASK 4: TECHNOLOGY FEASIBILITY

4.1 Leak Detection Systems Technology

4.1.1 Background

PHMSA is required, under the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, to report to Congress on leak detection systems utilized by operators of hazardous liquid pipeline facilities and transportation-related flow lines.

The report shall include:

- An analysis of the technical limitations of current leak detection systems, including the ability of the systems to detect ruptures and small leaks that are ongoing or intermittent, and what can be done to foster development of better technologies; and
- An analysis of the practicability of establishing technically, operationally, and economically feasible standards for the capability of such systems to detect leaks, and the safety benefits and adverse consequences of requiring operators to use leak detection systems.

Furthermore, the National Transportation Safety Board (NTSB) most recently issued the following safety recommendation to PHMSA in their San Bruno Pipeline Accident Report, PAR-11-01:

> **NTSB Recommendation P-11-10:**
>
> *Require that all operators of natural gas transmission and distribution pipelines equip their supervisory control and data acquisition systems with tools to assist in recognizing and pinpointing the location of leaks, including line breaks; such tools could include a real-time leak detection system and appropriately spaced flow and pressure transmitters along covered transmission lines.*

This Technology Review is intended to provide material for PHMSA to address the technical and engineering issues related to the congressional mandate and NTSB recommendation.

4.1.2 Objectives

Task 4 of the PHMSA Leak Detection Study includes the following objectives:

- A technical study of the state-of-the-art and current industry practices.
- A comparison of LDS methods to determine whether current systems (or multiple systems) are able to adequately protect the public and environment from pipeline leaks and incidents:
  - Legacy equipment currently utilized by operators
  - Ability to retrofit legacy systems
  - Benefits and drawbacks of LDS methods
  - Ability to detect small/intermittent leaks
- Identification and explanation of current technology gaps

In particular, with regard to gas pipelines, we reviewed SCADA system tools to assist in recognizing and pinpointing the location of leaks, including line breaks; including real-time leak detection systems and appropriately spaced flow and pressure transmitters along covered transmission lines.

The approach to this technical review is two-fold. It covers the purely technical engineering analysis components of Task 4, including:

- An analysis of the current state-of-the-art and accepted best practices.
- Ability to retrofit legacy systems, benefits and drawbacks of LDS methods, and ability to detect small/intermittent leaks, from a technical and theoretically practical point of view
- An identification of major current technology gaps

It also includes a study of actual operator technology choices and current industry practices, summarizing direct contacts with industry operators and technology suppliers.

4.2 Previous Work

This report is an update to the Leak Detection Technology Study for the PIPES Act (H.R. 5782) published by the U.S. Department of Transportation on December 31, 2007.

This update does not provide any issues that replace issues identified in the 2007 study, but rather provides an update of technical, operational, and economic considerations that appear to implemented today. Most developments in the technology of leak detection over the past four years have been in the areas of:

- The deployment of External systems' sensors in different packages

- The use of different algorithms in computational pipeline monitoring (CPM) to compute physical properties and effects more accurately and efficiently
- The emergence of “Hybrid” systems that incorporate more than one individual technology

There have been no new formal standards from the primary industry standards bodies. However, there have been joint industry research programs from the Pipeline Research Council International (PRCI). The most important is an evaluation of external leak detection systems (February 2011) based upon laboratory tests, covering specifically distributed temperature sensing (DTS) and acoustic sensing. The report contains remarks from the technology suppliers regarding the issues identified with the technologies, and the field measurements, in the appendix.

Current joint industry research at PRCI includes:

- Field-testing of Acoustic external leak detection systems, due for reporting late 2013
- A theoretical study to update the API 1149 standard for internal leak detection systems performance, due mid 2014

Given that most underlying technology has remained largely stable, this report provides a different perspective from the 2007 PIPES Act Study. In summary:

- This report avoids broad numerical or qualitative estimates of performance for each technology. It is our opinion that any such tables tend to be misleading. For example, sensitivity in Internal systems are expressed in percentage of total flow, and for External systems in terms of absolute leak size, or leak rate. Depending on the application, different measures may be appropriate.

- We emphasize current gaps and the practical actual current state of utilization of each technology, rather than aiming for a comprehensive catalogue of approaches.

- We try to simplify the treatment of External systems by classifying them by: (i) The physical principle that is used; (ii) How the sensors are packaged and deployed; and (iii) How the system is utilized for leak detection. This helps to avoid a lengthy catalogue of different devices as in the 2007 Study, and emphasizes how the technologies can be engineered into a tailored solution.

- Internal LDS are categorized more thoroughly. A major confusion in the industry is related to the precise definition, in practice, of the various methods listed in the API 1149 standard (See Task 7). In particular, Real Time Transient Models represent only one category of technologies in API 1149 (See Task 7), but in practice they are implemented in many different ways.

- LDS are *engineered systems*. This means that precisely the same technology, applied to two different pipelines, can have very different results. Even very simple technology, applied carefully, can yield very useful leak detection. Conversely, complex technologies are not a silver bullet for delivering excellent performance. Therefore, we emphasize both *systems* and *technologies*.

4.3 Current State-of-the-Art

4.3.1 Introduction

For over a decade, pipeline industry research has consistently indicated that the best opportunities to mitigate accidents and subsequent leaks are through prevention measures such as aggressive controller training and strict enforcement of safety and maintenance programs.

The same research consistently indicates that the next most effective 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 stakeholder and general public confidence. This increase in confidence is a real, economic advantage. Through reduced assumed risk in operations, the pipeline asset value is increased. More predictable, safer operations improve investor value.

Paragraphs that are highlighted with a side bar contain key concepts that are important to understand and should be remembered while reading the rest of the report.

4.3.2 Industry Standards and Best Practices

For the liquids pipeline industry, three API publications form the basis of currently accepted recommended best practices in leak detection:

- API 1130 (2002): Computational Pipeline Monitoring for Liquid Pipelines. 2nd Edition (November, 2002). American Petroleum Institute.
- API 1149 (1993): Pipeline Variable Uncertainties and Their Effects on Leak Detectability. 1st Edition (November, 1993). American Petroleum Institute.
- API 1155 (1995): Evaluation Methodology for Software Based Leak Detection Systems. 1st Edition (February, 1995). American Petroleum Institute. (This has now been

withdrawn as a standard. Relevant sections of API 1155 are now included in Annex C of the latest edition API 1130 dated September 2007)

These recommended practices are not new. API 1130 was largely intended as an update to API 1155. PRCI is currently funding an update to API 1149, for adoption by the API in the 2014 – 2015 timeframe.

There are no corresponding recommended best practices for gas pipelines from AGA or the Gas Technology Institute. Furthermore, there are no definite industry standards for leak detection as there are for instrumentation, safety equipment, metering, etc.

Neither the API nor the AGA have systematically researched or developed best practices for external sensor-based leak detection.

4.3.3 Impact of Regulation

Since July 6, 1999, under 49 CFR Part 195, DOT-OPS requires all controllers of hazardous liquids pipelines engaged in pipeline leak detection known as computational pipeline monitoring (CPM) to use, by reference and with other information, API 1130: Computational Pipeline Monitoring.

Noteworthy sections of this rule include 195.2 which defines CPM; 195.3 which incorporates API 1130 into Part 195; Subpart C Design Requirements (195.134) which outlines the requirement for a CPM system; and Subpart F Operation and Maintenance (195.444) which outlines compliance with API 1130.

This regulation also requires (as do other, more recent regulations) many categories of hazardous liquids pipelines to, at a minimum, perform some form of continual leak detection based upon a volume accounting principle. This is one of the forms of CPM defined by API 1130. This has made at least an elementary CPM based leak detection system very common in the liquids pipeline industry.

By contrast, natural gas pipeline operators are not required to install any form of leak detection system, nor indeed any form of continual pipeline monitoring, on their systems. Correspondingly far fewer gas pipelines are equipped with leak detection systems.

4.3.4 Sources / Origins of Technologies

It is notable that very few leak detection technologies for oil and gas pipelines were developed within the oil and gas industry. Original research and development in this area continues to lag other industries – as a proportion of overall industry size – to this day. Instead, most technologies have been adopted from other process industries that require fluid movement.

Storage

Leak detection for inventory protection and security of supply pre-date safety and environmental protection objectives by perhaps half a century. Military leak detection systems for protecting storage of fuel oil date back to the 1940's.

Today, the U.S. Environmental Protection Agency (EPA) regulates leak detection in storage vessels of hazardous liquids. Standard EPA/530/UST-90/010 of March 1990 specifically covers Pipeline Leak Detection Systems.

The EPA regulations differ from those covered by DOT-OPS in that they formally recognize two categories of leaks and that one or more leak detection system(s) must be used to identify both:

- A large release that occurs over a short time; and
- Small amounts of products that are released over a long period of time.

There is also a formal incorporation of a statistical methodology, which compensates for random errors in measurement and metering, and the impact of operations.

Chemical Process Industries

Petrochemical plants and refineries are typically much more tightly controlled than transportation pipelines. They also have to operate to generally much smaller operational tolerances. Leak detection systems within these plants are taken very seriously and, for example:

- Multiple, redundant, and complementary leak detection systems are common engineering practice;
- Highly sensitive external hydrocarbon sensors are installed routinely; and
- Accurate mass metering is routinely used for CPM, rather than much less complex flow metering

Water Industry

Although in general water pipelines are less hazardous than petroleum, there are applications where a water spill can cause great damage to facilities – around sensitive electronics, for example. The water industry is the origin of at least two highly sensitive sensor technologies: acoustic emissions sensing and electrical cable sensors.

Nuclear Industry

The requirements of the nuclear industry are perhaps even more stringent than those of the chemical industry. They share the requirement for very fast detection of leaks in their steam piping systems. We note that this industry is perhaps the origin of the real-time transient model approach to CPM in the pipeline industry. At least one current supplier of real-time transient models for oil and gas pipelines still develops software with origins in nuclear power applications.

4.3.5 Quantifying Performance

The method of leak detection selected for a pipeline depends on a variety of factors, including pipeline characteristics, product characteristics, instrumentation and communications capabilities, and economics. Pipeline systems vary widely in their physical characteristics and operational functions, and no one leak detection method is universally applicable or possesses all the features and functionality required for perfect leak detection performance. Perhaps worse, exactly the same leak detection method or system, applied to two different operating pipelines, will perform in different ways and with different measures of performance.

The first unusual feature of leak detection systems, compared with most other subsystems used on a pipeline, is that they do not have nameplate or rated performance measures that can be used universally across all pipelines. This is particularly true of CPM where computer software, program configuration, and parameter selection all contribute, in unpredictable ways, to overall performance.

A second notable feature is that many performance measures present conflicting objectives. For example, leak detection systems that are highly sensitive to small amounts of lost hydrocarbons are naturally also prone to generating more false alarms.

To an almost unique degree compared with other instrumentation and control, the performance of a leak detection system depends critically on the quality of the engineering design, care with installation, continuing maintenance, and periodic testing. Differences in any one of these factors can have a dramatic impact on the ultimate value of a leak detection system.

4.3.6 Leak Detection as Risk Management

Modern systematic risk analysis, using international best practices such as ISO-31000, recognizes two forms of assumed risk from leaks in the operation of a pipeline: the probability of a leak occurring; and the impact that the leak will have once it has occurred.

A leak detection system has no effect in reducing the likelihood of a leak occurring. At the same time, pipeline maintenance, inspection, security, and other leak prevention measures can never reduce the probability of a leak to zero. Given there is always a likelihood of a leak occurring, a leak detection system is the first line of defense in reducing its impact, mostly by limiting the size of the eventual total spill.

Leak detection is the first line of defense in the sense that it triggers all other impact mitigation measures that an operator should plan for, including safe flow shutdown, spill containment, cleanup, and remediation. Given that it is the first trigger for all mitigation, a leak detection system that prioritizes rapid detection and high sensitivity is particularly valuable. At the same time, a leak detection system that is too sensitive and provides too many false alarms for standard operating practices can mask a leak by conditioning the operator over time to assume an alarm is false. This can substantially degrade the mitigation value of leak detection, especially for larger leaks.

We emphasize in the next Task that leak detection systems are a combination of people, processes and technology. Leak detection systems are never autonomous technologies. The true leak detector is the Controller (i.e. people) and the technology and associated processes only truly take a supporting role.

The API Standard 1160: Managing System Integrity for Hazardous Liquid Pipelines, First Edition, November 2001, covers this in Section 10, Mitigation Options: 10.3 Detecting and minimizing unintended pipeline releases:

> *In the event of an unintended release from within a pipeline system, the consequences can be minimized by:*
>
> - *Reducing the time required for detection of the release.*
> - *Reducing the time required to locate the release.*
> - *Reducing the volume that can be released.*
> - *Reducing the emergency response time.*

This reflects both the API best practices, and the standards view, that leak detection is an integral part of risk-based asset integrity management.

4.3.7 Performance Measures

4.3.8 General Issues

Before attempting to categorize all possible performance measures, we summarize the major performance categories for leak detection. As mentioned in the comments on quantifying performance above, many of these performance objectives conflict with each other:

- Continuous operation, versus intermittent or scheduled operation
- Ability to perform well during steady-state operations, versus transient conditions
- Ability to detect leaks in shut-in conditions
- Ability to detect small, gradual leaks

- Ability to estimate the leak position

Most studies of leak detection performance also emphasize two factors that are difficult to quantify or compare, but are perhaps the most important:

- *Reliability*: this means that the system must correctly report any real alarms, but it is equally important that the system does not generate false alarms. Indeed, too many false alarms generate a hazard by themselves, since the operator may lose confidence in the system altogether, and therefore may ignore even the correct alarms.
- *Robustness*: the system must continue to operate in non-ideal circumstances. For example, in case of a transducer failure it must detect the failure and continue to operate (possibly with necessary compromises such as reduced sensitivity).

It is important to be specific about *redundancy*, in the sense of providing backup systems to improve reliability and robustness. Redundant instrumentation is required in principle, but in practice the requirement for redundant equipment is frequently relaxed. This may happen either because the risk of damage to life and property is relatively low, or because instruments at substations effectively provide back-ups for each other.

Redundant signal paths and communication are always recommended, however. This is primarily because the risk of failure of communications is considerably higher than instrumentation, and in part because one communications channel can carry multiple measurement streams.

The leak detection system itself should always be redundant, by using multiple techniques that differ from each other and therefore compensate for any inherent weaknesses they do not share.

It is worth noting that in Germany, the Technical Rule for Pipeline Systems (TRFL) covers:

- Pipelines transporting flammable liquids;
- Pipelines transporting liquids that may contaminate water; and
- Most pipelines transporting gas

It requires these pipelines to implement an LDS, and this system must at a minimum contain these subsystems:

- Two independent LDS for continually operating leak detection during steady state operation. One of these systems or an additional one must also be able to detect leaks during transient operation, e.g., during start-up of the pipeline. These two LDS must be based upon different physical principles.
- One LDS for leak detection during shut-in periods.

- One LDS for small, creeping leaks.
- One LDS for fast leak localization.

Most other international regulation is far less specific in demanding these engineering principles. It is very rare in the U.S. for an operator to implement more than one monolithic leak detection system.

Perhaps the first specifications of performance were defined in the recommended practice, API 1155: Evaluation Methodology for Software Based Leak Detection Systems, first published in 1995. This added two additional criteria:

- *Sensitivity* is a composite measure of the size of a leak that a system is capable of detecting, and the time required for the system to issue an alarm in the event that a leak of that size should occur.
- *Accuracy* covers estimation of leak parameters such as leak flow rate, total volume lost, type of fluid lost, and leak location within the pipeline network.

These parameters are still regarded as the most important, but we remark that API 1130 has superseded API 1155 and adds a number of other factors that are discussed below. Finally, we discuss below how Leak Detection *Systems* must include the pipeline controller and the operational procedures the controller follows. The discussion in this section only covers the technology component of the system, and the other equally important components are explored in Sect. 5 below.

4.3.9 Categorization of Solutions

There are two broad families of leak detection systems, named in the API 1149 recommended practice:

- *Internal* systems use measurement sensors providing flow or pressure readings, and perform calculations to estimate the state of the fluids within the pipe.
- *External* systems use dedicated instrumentation equipment, typically located externally to the pipe, to detect escaped fluids.

Because all Internal leak detection involves some form of computation, it is often referred to interchangeably with CPM. However, technically speaking, API 1130 regards CPM as only one of three broad classes of Internal systems.

To these two categories of automated, continuous leak detection systems, it is usual to add visual and instrumented Inspection. This is covered, in part, by API 570: Inspection, Repair, Alteration, and Rerating of In-Service Piping Systems.

We repeat that it is good engineering practice for a leak detection *system* to comprise separate *subsystems* including Internal, External, and Inspection technologies. They should be carefully selected and engineered to complement each other.

4.3.10 Internal Systems

API 1130 is devoted to Internal systems, and further subdivides them into these groups:

1. Regular or Periodic Monitoring of Operational Data by Controllers:
    a. Volume balance (over/short comparison)
    b. Rate of pressure / flow change
    c. Pressure point analysis
    d. Negative pressure wave method
2. Computational Pipeline Monitoring (CPM)
    a. Mass balance with line pack correction
    b. Real time transient modeling
    c. Statistical pattern recognition
    d. Pressure / flow pattern recognition
    e. Negative pressure wave modeling / signature recognition
3. Data Analysis Methods
    a. Statistical methods
    b. Digital signal analysis

It is important to remember that although API 1130 is devoted to liquid pipelines many techniques apply well to gas pipelines also, in principle. Because of the much greater compressibility of gas, however, their practical implementation is usually more complex and difficult.

1.a Volume Balance

The mass balance method is based on the equation of conservation of mass. In the steady state, the mass entering a leak-free pipeline will balance the mass leaving it. In the more general case, the difference in mass at the two ends must be balanced against the change of mass inventory of the pipeline. Any additional mass imbalance indicates a leak.

Basic volume balance leak detection uses only volume flows and volume inventory as an approximation to this principle. This is simply done since flow meters are often already installed on a pipeline at the receipt and delivery points. Suppose that a leak is allowed to continue for a long period, the mass entering and leaving the pipeline increases indefinitely. The mass inventory of the pipeline, on the other hand, remains within a fixed range – and in reasonably steady conditions that range is actually quite narrow.

Over any finite period *T* this is only an approximation. We must therefore set a detection limit or threshold, below which an apparent imbalance may be the result of neglecting the inventory. This threshold is a function of the balancing period *T*.

The time period *T* must be sufficiently long for the flow in and out of the pipeline to be large in comparison with the change in pipeline inventory. In many cases, a very large value will be required, as for example:

- Start-up of a pipeline
- Change of pressure at inlet or outlet, even if the change is small
- Product change
- Most gas pipelines, most of the time

1.b Pressure/Flow Monitoring

A leak changes the hydraulics of the pipeline, and therefore changes flow or pressure readings after some time. Local monitoring of pressure or flow at only one point can therefore provide simple leak detection.

The pressure/flow monitoring method does not require telemetry, since local monitoring of pressure or flow rate is sufficient. It is only useful in steady state conditions, however, and its ability to deal with gas pipelines and multi-product liquid pipelines is extremely limited. It does not provide good sensitivity, and leak localization is not possible.

If a leak occurs, the pressure in the pipeline will fall by a small amount. As pressure sensors are almost always installed, it is natural to use them for leak detection. The pressure in the pipeline is simply compared against a lower limit after reaching steady state conditions. When the pressure falls below this lower limit, a leak alarm is raised.

This method is often called pressure point analysis (PPA), although this is technically different; see below.

The sensitivity of the pressure monitoring method depends on the leak location. Near the inlet and the outlet of the pipeline, a leak leads to little or no change in pressure. This can be compensated by flow monitoring, where the flow is measured for change. The two methods can be combined.

This form of leak detection is by far the most common CPM method in the pipeline industry. If a SCADA system is installed then limit alarms (high/low pressures and flow rates) are nearly always implemented. This by default implements Internal leak detection by Pressure/Flow monitoring. Some SCADA systems go several steps further; for example, by monitoring limits on the rate of pressure and/or rates, or rate change divided by pressure change.

Recall the major weaknesses of this method:

- In gas systems, a downstream leak may have almost no effect on flow rate
- In general, pressures in a gas system require a very large leak to have any effect on pressure
- Near the inlet and the outlet of the pipeline, a leak leads to little or no change in pressure.
- Flow rates and pressures near any form of pumping or compression will generally be insensitive to a downstream leak

1.c Pressure Point Analysis

We remark above that pressure point analysis (PPA) in its simplest form is simply an alarm triggered by abrupt pressure drop at a point sensor. However, it is technically a trademarked statistical analysis technique of EFA Technologies, Inc. and overlaps with the Data Analysis method 3.a – Statistical Methods.

The pressure readings are sampled discretely in time via SCADA or locally, and are treated over two different time windows. Each moving window contains a different fixed number of sample points at any one time: N_o, N_1

This gives two estimates of the average pressure at any time, using the moving average estimator:

$$\hat{\mu}_o(k) = \hat{\mu}_o(k-1) + \frac{p(k) - p(k - N_o + 1)}{N_o}$$
$$\hat{\mu}_1(k) = \hat{\mu}_1(k-1) + \frac{p(k) - p(k - N_1 + 1)}{N_1}$$

To test whether these two are statistically different, so that there is a significant change in average pressure, PPA uses the statistic:

$$t = \frac{(\hat{\mu}_o(k) - \hat{\mu}_1(k))}{\sqrt{\frac{N_o - N_1}{N_o - 1} \cdot \frac{\sigma}{N_1}}}$$

Where σ is estimated from the time-series. This statistic has a Student-t distribution and can therefore be compared against standard tables to yield a level of confidence in a change.

As we discuss below, this approach is distinct from the traditional fixed threshold alarming approach. With PPA, there is no pre-defined threshold for the change in pressure required to sound an alarm. Rather, a level of confidence in *any* change in average pressure is required.

1.d Negative Pressure Wave Method

Using several pressure transducers along the pipeline, the negative pressure drop Δp due to a leak can be observed as a wave propagating with wave speed *a* through the pipeline, both downstream and upstream of the point of the leak. This method is popular since existing pressure instrumentation can be used, where available, so retrofit requirements are minimal.

Assuming isentropic flow without friction, the pressure wave amplitude is given by $\Delta p = -\rho \cdot a \cdot \Delta v$ where ρ denotes fluid density, *a* is the speed of sound, and Δv describes the flow amplitude caused by a sudden leak. There are in fact two forms of wave:

- An immediate, high-amplitude wave caused by the sudden onset of the leak; and
- An enduring, but much lower amplitude standing wave caused by the initial pulse.

The initial pulse is short-lived. Therefore, this method is most sensitive when the pressure is monitored tens or hundreds of times per second using specialized electronics. Normal SCADA data acquisition frequencies can only reliably detect the second, lower amplitude waves.

A threshold for the rate of change of Δp at the sensors based upon this equation triggers an alarm. It can especially be used to localize a leak. We remark that it is generally poor as a leak detection method in its simplest form, since the threshold Δp is often close to the normal level of pipeline noise and even the instrument accuracy, so it is typically only used together with mass balance to add some measure of leak localization.

The negative pressure wave method is able to detect leaks in steady state as well as in shut-in condition. It is only able to detect leaks reliably in relatively steady state conditions, and small variations in pressure can easily lead to false alarms. Negative pressure wave methods are most useful in liquid pipelines, as pressure waves are quickly attenuated in gas pipelines.

There is overlap with the CPM method 2.d – Pressure / Flow Pattern Recognition. One of the most widely used implementations of this technique is a method that, apart from dedicated high-frequency data acquisition, adds pattern recognition to this algorithm to identify only changes in pressure that are wave-like, of wave speed *a*. With these additions, the technique is a highly sensitive standalone leak detection and localization method.

2.a Mass Balance with Line Pack Correction

Unlike basic volume balance, compensated mass balance takes account of changes in pipeline inventory. The mass inventory of a short section of pipeline depends critically on the product density and the diameter of the pipe. Both density and pipe area may vary along the pipeline. To calculate the exact inventory over the entire pipeline, it is necessary to integrate the density profile.

It is impractical to determine the density profile along the pipeline directly. All practical methods are based on initially determining the temperature and pressure profile, and then applying an equation of state that allows the density to be calculated as a function of temperature and pressure. For products with multiple components such as crude oil and natural gas, additional variables such as molecular weight or density at reference conditions are required.

The density of crude oil and most common refined products can be calculated according to the Manual of Petroleum Measurement Standards, Chapters 10 and 11, also known as API 2540. Natural gas densities can be calculated according to the AGA publication AGA-8 of 1992.

Three main methods are used to determine the pressure and temperature profile:

1. Direct measurement of pressure and temperature. A number of pressure and temperature transmitters must be installed sufficiently closely. The readings are interpolated between the sensors to perform the integration.
2. Determination with the help of a simple, steady state model. In liquid pipelines, a linear decrease in pressure can be assumed along the pipeline; and the temperature of the fluid can be assumed to equal ground temperature for long pipelines.

3. Computation with the help of a real-time transient model (RTTM). The most accurate method is to use a pipeline model that covers transient as well as steady state conditions. This allows the temperature and pressure to be determined at every point and corresponds to the CPM Method 2.b.

2.b Real-Time Transient Modeling (RTTM)

Using and solving the complete fluid mechanical equations of motion for the physical state of the fluid in real time, it is possible to eliminate transient effects introduced by:

- Fluid compressibility and pipe wall elasticity, and
- Temperature dependence of the density.

US Patent 4,308,746 (1982): Liquid Pipeline Leak Detection was filed in 1979, so this concept is not new.

RTTM LDS can be used during transient pipeline operation, e.g., during start-up of a pipeline; this is especially useful for gas pipelines, where greater compressibility results in severe transients.

Nevertheless, the gas pipeline industry, with exceptions , tends to avoid RTTM. Implementation tends to be complex, and a poorly configured and calibrated RTTM will inevitably provide very low reliability.

An RTTM can be used to detect leaks in several ways, but the two most common are generally:

1. Deviation analysis: A set of the measurements taken from SCADA on the pipeline can be compared with the simulated values calculated from the RTTM. If there is a significant deviation, a leak alarm will be given.
2. Model compensated mass balance: The RTTM can be used to calculate the line fill in real-time. The imbalance subsequently can be compared with a threshold to establish the leak alarm state.

2.c Statistical Pattern Recognition

The degree of statistical involvement varies widely with the different methods in the API classification of internally based systems. Above, we describe pressure point analysis (PPA), which has been assigned to pressure/flow monitoring methods; it might equally be assigned to statistical analysis methods. In essence, any leak detection method that depends on a measurement or calculated value exceeding a threshold can benefit from the application of statistical hypothesis testing or decision theory.

The underlying physical principle that it uses is the simplest volume balance method. Using this imbalance *R(t)* as above, the statistical approach asks the question: is the imbalance at this time *t* likely to be on average the old value μ or has it increased to $\mu + \Delta\mu$? This is a statistical hypothesis question, and is approached using the Sequential Probability Ratio Test (SPRT). The ratio is:

$$\lambda_k = log\left(\frac{R_k}{R_{k-1}}\right)$$

An alarm is definitely called if $\lambda > A$ - there is certainly no alarm if $\lambda < B$ - and no decision is made if $B < \lambda < A$.

If we define:

$$A = \frac{\alpha}{1-\beta}; 1/B = \frac{\beta}{1-\alpha};$$

then α, β represent the confidence intervals for identifying a leak, and of missing a leak, respectively.

In practice, α, β are rarely specified up-front. The system is set up to run on the pipeline for a length of time (usually 2 – 3 weeks) and under various transient conditions. Operations are assumed to be normal (free of leaks) during these periods. The confidence intervals are adjusted so that under these normal operations no alarms are sounded.

To estimate the size of leak, and/or specify the threshold as a percentage of flow – i.e., what is $\Delta\mu$ – the theoretical result that assumes all errors are normally distributed is used:

$$\lambda(k) = \lambda(k-1) + \frac{\Delta\mu}{\sigma^2}\left(R(k) - \mu - \frac{\Delta\mu}{2}\right)$$

To use this formula, values of σ, μ have to either be assumed, or estimated from a sample of the $R(k)$. Then, the imbalance $\Delta\mu$ can be derived.

In summary, this entire technique is not tied to a fixed percentage imbalance in order to sound an alarm. Rather, a statistical confidence interval is set which allows for the natural transients on the pipeline during operations.

2.d Pressure / Flow Pattern Recognition

The essence of this category of solutions is to go beyond statistics and to apply pattern classification theory either directly to measurements or to calculated values (like imbalances). In pipeline LDS the most common techniques that are used are:

- Maximum entropy classifier
- Naive Bayes classifier
- Neural networks

A common implementation adds pattern recognition to a basic PPA algorithm to identify only changes in pressure that are wave-like, and of the correct wave speed *a* for the pipe and fluid. This technique uses Fourier analysis followed by a maximum entropy classification. To achieve this, the pressure sensors are sampled and analyzed at far greater rates than normal SCADA scans using dedicated field processing units (FPUs). The processed data are then communicated to the other FPUs and to the host.

2.e Negative Pressure Wave Modeling

A few RTTM explicitly model the hydraulic response that would be expected from a sudden leak to compare this response against the measured pressures, to find a match, and to estimate the size and location of the leak. This requires specialized modeling algorithms and numerical techniques, since the transient pressure wave varies on a much faster timescale and is much weaker than most of the other hydraulics in the pipeline.

A widely used implementation of this method is SimSuite, trademarked by Telvent USA.

3.a Statistical Methods

Statistical LDS use statistics from operational data to detect a probable leak. This leads to the opportunity to optimize the decision if a leak exists in the sense of chosen statistical parameters. However, it does make demands on measurements. They need to be steady state, in a statistical sense, for example. All errors are assumed to be random, unbiased, and taken from a distribution that does not change.

Statistical LDS use methods and processes from decision theory and from hypothesis testing. We have already cited two examples above: the PPA method implemented by EFA Technologies, Inc. and the ATMOS Pipe system.

A particularly interesting feature of this approach is that several different statistical leak alarms can be combined systematically using a Bayes approach. As an example, both PPA and mass balance leak detection can be implemented using confidence intervals in a leak being present, rather than pre-fixed thresholds. If the two methods are run in parallel, then the two confidence measures can be combined to give a single, much more reliable one.

3.b Digital Signal Analysis

Most measurements that are made on a pipeline come from analog devices like pressure transducers and flow meters. However, they are typically sampled by the control and / or SCADA systems and so they only become available to the LDS as a time-series of digitized signals.

Digital signal analysis (or processing, DSP) is used for various purposes in pre-processing measurements and also for detecting leaks via associated pattern recognition, for example:

- Digital filtering removes spikes and other outliers in measurements that may lead to false alarms
- Entropy measurement rapidly identifies when a data stream changes in nature
- Drift and trend detection can identify very slow but systematic changes in a measurement, or an imbalance

Combined Methods

There is no reason why several different Internal leak detection methods should not be implemented at the same time. In fact, a basic engineering robustness principle calls for at least two methods that rely on entirely separate physical principles.

As an example, the Extended-RTTM system trademarked by Krohne Industries, USA uses an RTTM in conjunction with several other API 1130 techniques:

- A classical RTTM generates deviations between measured and estimated flow based on the RTTM deviation analysis. A leak signature analyzer uses the deviations as input. It assigns the pipeline to one of two classes: class “no leak” and class “leak.” This forms an online pattern recognition scheme with a feature generation module (deviations analysis) and a leak signature analysis module.
- Neglecting model errors and assuming appropriate measurement noise characteristics, the deviations are stationary normal distributed process variables. This allows a number of textbook statistical methods to be used properly, since all assumptions about the nature of the errors are met.
- Leak localization is also a redundant scheme. Both a classical pressure gradient analysis, and negative pressure wave modeling are deployed simultaneously.

The combined methods need not be packaged within the same system. For example, it is routine to combine a compensated material balance system that detects leaks well and estimates the size of the leak, with an entirely separate PPA that, while being poor at leak detection, will nevertheless provide an estimate of the position of the leak.

4.3.11 External Systems

External leak detection is both very simple – relying upon routinely installed external sensors that rely upon at most seven physical principles – and also confusing, since there is a wide range of packaging, installation options, and operational choices to be considered.

Whereas there is at least a set of API recommended practices to follow and to cite when recommending an Internal system, there is no such guideline with External systems. This often requires the engineer to make original design decisions, without the support of an engineering standard to quote.

External leak detection sensors depend critically on the engineering design of their deployment and their installation. A sensor placed in the wrong location can quite easily miss an escaping plume of hydrocarbons. The number and density of placement of sensors needs to be weighed against requirements. Poorly installed sensors can perform orders of magnitude worse than laboratory specifications.

It is useful to categorize these systems by three dimensions:

1. The physical principle that is used
2. How the sensors are packaged and deployed
3. How the system is utilized for leak detection

As we remarked earlier, there are relatively few physical principles that are actively and commonly used for hydrocarbon leak detection on pipelines:

1. Sensing of the acoustic emissions of a leak
2. Sensing lost product with a fiber optic cable, specially treated to change refractive index when wet with hydrocarbons
3. Sensing strain and/or temperature change due to a leak with a fiber optic cable
4. Utilizing conductive cables whose resistance and/or AC impedance change when wet with hydrocarbons

5. Sensing hydrocarbons using permeable tubes that are swept with gas that is tested chemically for traces of contamination
6. Detecting hydrocarbon vapors with chemical testers
7. Detecting hydrocarbon vapors via optical methods

Most of these physical principles can be deployed using sensors in at least a couple of these packages:

a) Instrumentation attached to the pipeline
b) Point sensors
c) Continuous sensors, typically in the form of a cable
d) Hand or vehicle carried tools
e) Tools launched internally to the pipeline

Similarly, they can be utilized in several operational modes:

i. Permanent installation with continual sampling
ii. Permanent installation with periodic / intermittent sampling
iii. Periodic or on-demand deployment, typically as part of a manual inspection program

An example using this scheme would be an airborne LIDAR camera that is used in monthly gas pipeline leak survey patrols would be 7.d.iii – an optical method, in a vehicle carried camera, deployed periodically. Similarly, an on-line acoustic sensor array for an oil terminal would be 1.a.i – an acoustic method, permanently attached to the pipeline, with continual sampling.

Industry and Regulatory Opinions

It is notable how External systems are regarded by different sections of the industry. Natural gas pipelines almost exclusively utilize External systems, the most popular being atmospheric sensing, hydrocarbon vapor testing, and acoustic methods. Because of the extreme line pack effects in gas pipelines, they are generally suspicious of Internal methods.

The U.S. EPA has commissioned a number of reviews of performance of point chemical sensors of liquids and gas. One of the earliest, EPA-510-S-92-801 of May 1988, stated that even at that time the sensors could deliver:

- Sensitivities to 250 ppm vapor concentrations and one-quarter inch layers of hydrocarbon liquids floating on water

- Specific rejection of non-hydrocarbon vapor and liquid
- Detection times as low as 15 seconds, with nearly all technologies responding within one minute
- Elementary retrofit procedures

Therefore, even in 1988, these point sensors were delivering sensitivity and time to detection far ahead of any Internal system. Since then the technologies have only improved in performance.

4.3.12 Current External LDS Solutions

The table below illustrates how, according to the classification scheme above, the main External solutions in use today are deployed. This does not mean that other physical principles, packages, or means of operation are not possible – these are simply the current state of industry practice and commercial availability of systems.

Table 4.1 Currently Available External Systems

	a. Attached Instrumen-tation	b. Point Sensors	c. Cables	d. Human / Vehicle Tools	e. Internal Tools
1. Acoustics	i	i		iii	iii
2. HC Sensing FO		i	i	iii	
3. Temp Sensing FO			i		iii
4. Liquid Sensing Cable		i, ii	i	iii	
5. Vapor Sensing Tube			i		
6. Vapor Sensors		i, ii		iii	
7. Vapor Cameras		i, ii		iii	

i. Permanent installation with continual sampling
ii. Permanent installation with periodic / intermittent sampling
iii. Periodic or on-demand deployment, typically as part of a manual inspection program

Many External leak detection systems – particularly those that are deployed in an array to measure a distribution over space of a physical property – are calibrated upon commissioning to form a “baseline map”. This means that if there are any existing hydrocarbons in the environment, they are built into the initial calibration and no longer affect detection. At the same time, systems that rely upon comparison with a baseline map are generally not sensitive to pre-existing leaks.

4.3.13 General Descriptions

1. Acoustics

Acoustic sensors are used in four main ways:

1. Attached to the pipeline, and potentially tapped into the line as well, in an array and monitored continually as part of a system
2. Positioned very close to, or attached to, the pipeline as standalone sensors
3. Used as aids to human external surveys of the pipeline, as probes for leak sounds
4. Used within “intelligent pigs” or “smart balls” as leak sensors, deployed during routine internal surveys of the pipeline

The principle of operation of all these systems is that any leak causes a sound that lies within a specific frequency range depending on the fluid. The frequency and the amplitude also depend on the size of the leak, but not by much. All leak detection acoustic sensors incorporate filtering to at least remove all sound that does not fall within the frequency range. They also filter out all random (white) noise.

Acoustic systems are deployed with multiple acoustic sensors attached to the pipeline. These are often simply physically mounted on the external wall of the pipe, but can sometimes be tapped into the pipe itself. It is important to avoid confusion with the Negative Pressure Wave / “Acoustic” Wave Internal leak detection method. That technique utilizes pressure sensors and detects the pressure wave in the fluid itself, not an acoustic frequency signal. Two closely spaced sensors are installed at each end of the section of pipe that is to be protected (much as with the negative pressure wave method). These cancel out any sound arriving from outside the protected section, to improve sensitivity. Sensors are spaced within the protected section according to requirements, but up to a maximum of around 200 feet apart. Any leak sound that is identified can be localized accurately by interpolation. The performance of these systems depends critically upon the signal processing algorithms that reject extraneous noise, identify very faint leak sounds, and locate the leak.

Standalone sensors are used as point detectors of sounds from a leak. They can be strapped to the pipeline, or driven into the ground near a buried pipeline. Their performance is of course less than expected from a complete array of continually monitored sensors, but they are still often useful and far easier to install.

Similarly, acoustic sensors can be implemented as probes, used in walking surveys of the pipeline to listen for leaks. This is a very traditional use of the technology, and is routine with water pipelines.

Acoustic sensors are often used as part of the instrument package in an intelligent pig. It is important to note that they are able to detect pinhole leaks that a normal induction device would miss. They are also used within smart balls, which are much smaller (less than the pipe diameter) free-rolling balls with an internal instrument package. These can be launched and retrieved in non-piggable lines from standard flange fittings. They roll with the flow of the fluid and therefore do not require a substantial rate, as with a conventional pig that requires a pressure differential.

When used as an internal device, acoustic sensors are extremely sensitive since they pass right by the leak itself where the sound is greatest. An on-board data logger tracks the recorded sound against location data from locators placed outside the pipe, and this is downloaded and analyzed once the smart ball is retrieved from its run.

Acoustic systems can be used effectively on both liquids and natural gas systems.

2. Hydrocarbon Sensing Fiber Optics

With this technology, fiber optic sensing probes are driven into the soil beneath or adjacent to the pipeline. In the presence of hydrocarbons, the patented covering of the sensor changes its refractive index. This change is registered optically by the sensor and converted to a parts-per-million reading of hydrocarbons.

This same fiber optic cable can also be laid alongside the pipeline as a continual sensor, and the location of any changes in its refractive index can be measured using pulsed laser.

The probe need not be permanently mounted. It is also often used as a hand-held probe that is pushed into the soil near the buried pipeline to sense spills during a human inspection survey.

This technology is notable in that it is covered by a closely held patent and therefore not available from many sources.

These systems can be used effectively on both liquids and natural gas systems.

3. Temperature Sensing Cables

Distributed temperature sensing (DTS) using fiber optic cables originated and is widely used in down-hole formation evaluation and casing integrity / leak detection in production wells in the upstream industry. Fiber optic cables naturally change refractive index when subjected to the very slightest strain, and therefore also to very small changes in temperature. Pulsed laser is used to locate the position of this change in refractive index. The most common installation is a continuous cable laid alongside the pipeline as a continual sensor.

It is also used as part of the instrument package in intelligent pigs and smart balls, since they provide very sensitive tracking of temperature change.

This technology can be used effectively on both liquids and natural gas systems.

4. Liquid Sensing Cables

Liquid sensing cables are typically buried beneath or adjacent to a pipeline and are specifically designed to reflect changes in electrical properties, both DC resistance and AC impedance, by contact with hydrocarbon liquids.

To monitor AC impedance changes, safe energy pulses are continuously sent by a microprocessor through the cable. The pulses are reflected and returned to the microprocessor. Based on the specific installation of the cable, a baseline reflection map is stored in the memory of the microprocessor. When a leak occurs, the cable is saturated with fluid. The fluid alters the impedance of the sensing cable, which in turn alters the reflection pattern returning to the microprocessor. The change in signal pattern causes the microprocessor to register a leak alarm at the location of the altered impedance.

Monitoring DC resistance changes is simpler. A very low-current supply measures resistance, which drops to nearly zero when the cable is wet with hydrocarbon. In this case, it is not possible to locate the leak.

Specific cable types are chosen for each application based on the specific fluid being monitored. The cables need not be long, or be buried alongside the pipe, and other typical applications include:

- Cables driven vertically into the ground periodically or at points of high risk adjacent to a buried pipeline, as point sensors.
- Short cables pulled through the casing pipe at road crossings, culverts, etc.
- As moisture probes, used in manual leak surveys, for testing damp areas near the pipeline.

This technology cannot be used effectively on gas pipelines.

5. Vapor Sensing Tubes

The vapor sensing tube leak detection method involves the installation of a secondary conduit along the entire length of the pipeline. The conduit may be a small-diameter perforated tube attached to the pipeline or it may completely encompass the pipeline, allowing the annular headspace to be tested. Air gas samples are drawn into the tube and analyzed by hydrocarbon vapor sensors to determine the presence of a leak. Because of the logistical problems associated with any system that must be installed along the entire length of a pipeline, vapor-sensing tubes are usually only employed on short lines. However, they are extremely sensitive and reliable and so they are popular in local, highly critical applications.

Vapor sensing tubes can be used effectively on both liquids and natural gas systems.

6. Chemical Vapor Sensors

Hydrocarbon gas sensing systems, as point chemical sensors or "noses," are common in petrochemical and refining plants, and at plants used on natural gas pipelines.

Tracers or chemical markers may be added to the product being monitored so that it may be identified from naturally occurring background vapors.

When these sensors are used as hand carried probes, they are "electronic noses."

In the liquids industry, hydrocarbon gas sensing systems are more frequently used in storage tank systems, but can also be applicable to pipelines. When a liquid seeps into the soil, vapors migrate into the surrounding soil pore spaces. Probes are arranged in the soil so that a vacuum may be applied to them. The soil vapors are collected for laboratory or field analysis. When hydrocarbon tracers or markers are encountered during analysis of the vapors, it can be surmised that a leak has occurred.

Vapor detectors can be used effectively on both liquids and natural gas systems. This is because oil spills release vapors in the hundreds of ppm range, and these sensors are sensitive enough to detect them (see the report EPA-510-S-92-801 of May 1988 referenced above).

7. Optical Methods

Most hydrocarbon vapors resonate to light in the medium infrared spectrum. Although many other atmospheric imaging techniques have been tried (microwave radar, visible light, etc.) the most widely used today are active and passive infrared imaging.

Optical methods can be deployed as permanently mounted cameras that monitor the air above the pipeline, or as mobile cameras that are handheld, mounted on road vehicles, or airborne. When permanently mounted, they can either rely on a human operator to examine the images, or automatic pattern recognition can continually seek the image of a hydrocarbon plume.

Periodic airborne surveys are extremely common for natural gas pipelines. They are also mandated for liquids pipelines in Alaska.

Active systems illuminate the air with infrared light and either detect backscatter to the source (also called LIDAR), or absorption between the source and the detector. Passive systems simply image the air with a camera.

The main technical challenge is to improve sensitivity, primarily by filtering the wavelengths and only searching for the specific hydrocarbons in the product. Nearly all systems at least filter the overall bandwidth to include hydrocarbons. We also point to multispectral technology that processes the image in frequency and can filter to the exact spectrum of each hydrocarbon component. These are useful in petrochemical plants where multiple hydrocarbon compounds may be present.

Optical methods can be used effectively on both liquids and natural gas systems.

4.3.14 General Performance of LDS

We remarked above that exactly the same leak detection system, deployed on two different pipelines, delivers different performance. Therefore, it is only possible to present general indications of the relative strengths and weaknesses of each of the technologies discussed.

Furthermore, since no engineering system is perfectly reliable, there are always tradeoffs between conflicting objectives in a leak detection specification.

API 1155: Evaluation Methodology for Software Based Leak Detection Systems was first published in 1995; it defines the four performance criteria that concern most operators: sensitivity, reliability, accuracy, and robustness. Reliability is further split into the probability of detecting a leak given that a leak does in fact exist (misses), and the probability of incorrectly declaring a leak given that no leak has occurred (false alarms).

Even though API 1155 is directed towards the liquids pipeline industry, and to software based LDS, there is absolutely no reason why exactly the same performance indicators in API 1155 should not be used for External LDS systems. This is the approach suggested here since it allows for an integrated assessment of all LDS technologies with a common set of metrics.

False Alarms – there is always a conflict between the desire for greater sensitivity and the requirement to minimize false alarms. Virtually every physical effect that is used to detect leaks may be duplicated by another non-leak event. For example:

- Mass balance LDS are at the mercy of metering and SCADA. If a meter loses accuracy beyond the threshold used in the mass balance, then there is no way that the LDS can differentiate between this meter error and a leak.
- Acoustic LDS carefully filter all noise on the pipeline and in the fluid only to react to the specific spectrum of a leak sound. However, just exactly the wrong mechanical vibration, at the wrong point of the pipe, with a harmonic exactly within the acoustic tuning range, would be indistinguishable from a leak.
- A sudden drop in pressure in the pipeline might trigger a PPA Internal LDS, either because of a leak or because of a normal pump shutdown.

As a rule, it is difficult to get false alarms from External systems that directly sample for hydrocarbons. Either the hydrocarbons are present outside the pipe, or not. Nevertheless, even here "detection" might be biogenic gas, vapor from traffic or machinery or other emissions, and not originate from a leak in the pipeline at all, thus generating a false alarm.

Especially with Internal LDS, false alarms are often a tradeoff with sensitivity. With a higher threshold for detection, fewer random and transient effects will have an impact on the imbalance or pressure deviations. Of course, this also affects reliability by increasing the probability of misses.

Sensitivity – this is defined as a composite measure of the size of a leak that a system is capable of detecting, and the time required for the system to issue an alarm in the event that a leak of that size should occur. This relationship is particularly important for Internal systems and is discussed at length in API 1130 and API 1149.

For long leak detection times, for any Internal LDS, the minimum leak that can be detected converges asymptotically to a minimum limit value, the smallest possible leak detection rate. This value mainly depends only on the accuracy of the flow meters and is therefore essentially independent of the LDS method used. A more sophisticated Internal system – a detailed RTTM, for example – will indeed reduce the time to detect a leak of a given size definitively. However, the absolute minimum size leak that can be detected will always be dominated by the instrument accuracy.

This is one of the main weaknesses of an Internal LDS. It is rare to find flow metering systems that have cumulative uncertainties better than about ~ 1%. Therefore, the absolute best sensitivity of an Internal system is of this magnitude. On a 100,000 BBL/day pipeline, this means that leaks of the order of ~ 1,000 BBL/day are invisible to these LDS.

By contrast, External systems (for all their other potential drawbacks) can detect spills in the few hundreds of ppm vapor, or tens of barrels of liquid (see, for example, the EPA-510-S-92-801 of May 1988 report referenced above). Furthermore, there is no issue with the time to detection: once the concentration (spill size) threshold is reached, detection is practically instantaneous. Some External systems, like the pigs and balls, can detect pinhole-sized (microliter per second) leaks.

Accuracy – it is noteworthy that whereas an Internal system can typically estimate a number of the size and location parameters of a leak, External systems can typically only estimate location.

A mass balance system of any kind can estimate the size of a leak. As with the time to detect an imbalance, the accuracy of this estimate improves with time the longer that the leak continues. Pressure based systems cannot estimate leak size. The best that an External system can do is perhaps to indicate the relative severity of a spill.

A mass balance system cannot estimate the position of a leak, and for this reason is typically backed up by another principle that includes pressure. An RTTM combines both principles into one, and therefore can estimate leak position quite well.

External LDS can locate a leak according to the packaging and deployment:

- A continuous cable system is usually rated to locate a leak to within 1% - 3% of the cable length, between detectors.
- Similarly, an array of acoustic sensors is usually rated to locate a leak to within 3% of the sensor spacing.
- An array of point sensors depends critically on their individual sensitivity. For example, soil analyzers may not be sensitive enough to provide more than one reading, in which case interpolation for position may be impossible.
- Camera based systems can show location quite well, to within visual accuracy.
- Tools like pigs and balls can locate a leak to within one yard since they pass right by it.

Robustness – even though an Internal system may rely upon a relatively simple, basic principle like mass balance, it is quite a complex overall system. For a mass balance system to work, it requires robust metering, robust SCADA and telecommunications, and a robust computer to perform the calculations. Each of these subsystems is individually quite complex.

It is quite possible for a poor measurement or SCADA system to fail or under-perform and make the LDS inoperable. For this reason, it is good practice to provide redundant backup for all the subsystems that the leak detection relies upon.

External systems are essentially standalone instrumentation and therefore can be analyzed as individual subsystems. They need backup and redundancy in their own right.

Apart from system availability issues, robustness is a function of not relying upon only one physical principle. As an example, if only acoustic LDS are deployed on a pipeline, then a rare but specific vibration will affect every single alarm on the pipeline. The same is true of Internal systems – if only material balance LDS are used on the pipeline, then any meter failure will affect them all. Therefore, it is good engineering practice to insist on physical redundancy:

At least two leak detections systems should be used, each of which utilizes an entirely different physical principle from the other.

4.3.15 Multiple Performance Objectives

It has to be understood that certain objectives – high sensitivity versus few false alarms, for example – are naturally contradictory. Good engineering accepts and works with this. As an example, a complete leak detection system might include several subsystems (perhaps quite different) that:

- Work to a high degree of sensitivity and reliability during steady-state operations
- Continue to work in transient conditions, perhaps with less sensitivity
- Only cover highly critical specific sections (maybe quite short – rivers, roads, towns, etc.) of the pipeline with a high degree of sensitivity
- Provides leak detection of some form while the pipeline is shut in
- Can detect small, gradual leaks, even if relatively slowly
- Estimates the leak position, even perhaps with poor detection capability (like PPA, for example)

A system of this kind generates at least five alarms:

- A low tolerance alarm that should be ignored during transient operations, but respected otherwise
- An alarm that is to be respected even during transient operations
- Alarms at points of high criticality that are always respected
- These three alarms go offline during shut-ins, and another separate system comes online
- A long-term gradual leak report can be examined weekly by engineering

For this to work, we remark that a very good degree of pipeline operator training and education is important so that the scope, validity, and purpose of each subsystem are understood clearly.

4.3.16 Other Performance Factors

The API 1130 recommended practice adds a number of other performance issues that pipeline operators are required to consider when deploying LDS. These apply equally well to gas pipelines:

Personnel Training and Qualification – some LDS are extremely simple to understand, and others are very difficult. In general the concepts of sensitivity and reliability for an Internal system are hard to explain and the training required to master a detailed RTTM might be quite extensive. At the same time, this is critical. An LDS that is misunderstood or ignored by the operators is useless.

System Size and Complexity (including Batch Line Factors) – a complex networked system with many frequent operational changes will naturally present more imbalances than a simple, steady state pipeline. It is therefore important for the operator to be realistic about the likely sensitivity of an Internal system in these situations and perhaps to provide more backups.

Detecting Pre-existing Leaks – most LDS assume that upon commissioning there are no leaks, for initial calibration. This includes Internal LDS and most sensor systems. Only direct in-line tools are truly effective in detection of pre-existing leaks. Also, static hydro-tests are effective, which is why Integrity Management Programs usually require these periodically.

Detecting a leak in pipelines under a *Slack Condition During Transients*; *Transient Flow Conditions*; and *Multiphase Flow* – all make Internal systems less sensitive. In fact, it becomes almost essential to perform some kind of detailed physical modeling to get the mass balance calculation correct. A particular difficulty with any kind of multiphase flow is that the metering accuracy is far poorer and therefore the theoretically best-case sensitivity of the LDS is accordingly rather less. By contrast, most External systems are immune to these factors. It is often more cost-effective simply to avoid Internal systems in favor of sensor based LDS when these three factors are significant.

Retrofit Feasibility – most LDS are practical options for a new pipeline construction, while several are much less practical solutions for retrofit on an existing pipeline. Any significant engineering on an old pipeline may, in fact, compromise its integrity.

We remarked above that this is in fact not the enormous issue for External LDS that it is often supposed to be – only cable sensors that need to be buried close to the pipeline are difficult to retrofit. It should also be remarked that for a good Internal LDS, metering of a good accuracy is necessary and that this of course adds to the retrofit cost and complexity.

Testing – all LDS are required to be tested at least once every five years according to 49 CFR 195 and annually in Canada according to the CSA Z662. In fact, they should be tested even more frequently and preferably by direct removal of fluid from the pipeline at a variety of locations. This is an operational procedural requirement and an added cost that must be considered. In particular, physical removal of fluids – particularly gases – from a pipeline must be accomplished with due care not to create polluting releases into the environment. This requires specialized equipment, including test regulators, meters, and vacuum vessels, designed to protect the environment.

Cost – and more importantly cost-justification, is a difficulty with all safety related systems in engineering. Since LDS are not directly able to generate revenues or improve profits they are difficult to value. Other considerations include a consideration of purchase and installation versus long-term full-lifecycle costs. As an example, an RTTM solution is rather less expensive to implement than a full acoustic array on a long pipeline. However, over a five-year horizon the manpower, training, and testing requirements including probable software and SCADA upgrades typically make an RTTM far more expensive.

Maintenance – maintenance requirements, as already noted, are both a cost and human resources issue. An important factor is the impact of the lack of, or poor, maintenance on a LDS. Many systems stop working altogether while others continue to work with impaired performance.

4.4 Benefits and Drawbacks of LDS Methods

Following the general categorizations and performance metrics described above, a general benefit and drawback matrix can be developed for LDS methods. This assessment can only be a general guideline since every pipeline is quite different in size / complexity and operational requirements. However, the tables below attempt this high-level assessment:

4.4.1 Internal Systems

In general terms, all Internal systems share these common benefits and drawbacks. Probably the main three benefits of these technologies are:

- They are widely used and most rely upon easily understood physical principles. Some of the possible exceptions are pattern recognition, statistics, and DSP, but the objectives and physical principles are still easily explained, if not perhaps the mathematics itself.

- Many of these techniques utilize measurement that is already on the pipeline and / or provide benefits and tools that are useful beyond LDS. For example, metering and SCADA systems are usually already present. Volume balance is a useful check on metering. An RTTM can be used for operational optimization, planning, predictive modeling, and other functions that are very valuable in their own right.
- They are rapidly deployed and provide a fast, procedural path to regulatory compliance. There are many recommended practices (for liquids pipelines) with procedures that describe design, implementation, and operations explicitly.

With regard to the second benefit, this is often the source of the common remark that Internal LDS are "less costly." They are only less costly if the metering and SCADA has been paid for and perhaps an RTTM has already been paid for by operations. Therefore, the total cost for leak detection is shared among many functions and requirements.

The main three drawbacks are:

- Most methods are completely dependent on the quality of the support subsystems: metering, SCADA, computers, and telecommunications. The overall system is therefore quite complex. In addition, the sensitivity of these LDS is limited to the accuracy of the meters – no Internal LDS using 1% accuracy meters can ever detect a leak smaller than 1% of flow.
- Line pack effects, especially during transients, cause frequent volume imbalances and potentially many false alarms. These are particularly bad for gas pipelines.
- The value of threshold for an alarm, and therefore the sensitivity, is often chosen fairly arbitrarily and as a tradeoff against false alarms. All alarm thresholds (except with statistical systems) are a percent of total flow. Recall that a 1% of flow rate is considered good, given current flow meter technology. Therefore, on a 100,000 BBL/day pipeline, *any* Internal system is blind to leaks of the order of 1,000 BBL/day.

The table below adds some more details for the individual Internal system categories as defined above and in API 1130:

Table 4.2 Benefits / Drawbacks of Internal Systems

	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.

	Internal System	Benefits	Drawbacks
3.a)	**Statistical Methods**	Reduce false alarms by introducing statistical degree of confidence. Can combine multiple alarm signals consistently.	Still relies upon a physical principle - measurement or calculated 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.

4.4.2 External Systems

In general terms, all External systems share these common benefits and drawbacks. Probably the main three benefits of these technologies are:

- External systems, when engineered and deployed well, are typically much more sensitive than Internal systems. Whereas an Internal system's sensitivity is limited by the accuracy of metering to a percentage of flow rate, most External systems (when deployed carefully) can detect spills or emissions in the few barrels or ppm.
- They are relatively immune to pipeline operational changes and transients, which plague Internal systems. For systems with slack line flow, often shut-in, contain multiphase fluid, or have very transient operations, this is critical.
- External LDS are mostly standalone, simple instrumentation systems that do not rely upon the complexities of ancillary metering, pressure sensors, etc. There are exceptions; for example, acoustic sensor arrays are complicated electronic systems. In most cases, External systems can be deployed as standalone protection for high-consequence sections of the pipeline.

With regard to the first benefit, recall that this is subject to the earlier observation that External systems' performance depends critically on design and installation factors, so the actual as-built sensitivity may not always be as good as the ideal case. Internal methods may have faster response times, and smaller spill volumes, but they may not detect the same sized leak. Recall that Internal methods are themselves dependent on flow measurement instrumentation accuracy and repeatability and those are the primary limits to overall sensitivity and reliability, not the method itself.

The main three drawbacks are:

- External systems require individual engineering design. Whereas Internal LDS are often single computer programs – that nevertheless require configuration and tuning – External

LDS need to be designed, with sensors located critically, performance estimated individually, and are often built to order from several component subsystems.

- There is no systematic procedural approach or regulation that provides guidance to the operator in selecting, engineering, and operating External systems.
- As a rule, External systems are only useful as leak detection systems. They do not have any of the added operational benefits that many Internal systems provide, except in a few cases, for example, fiber optics, where an operator could use the same cables for telemetry, cameras, threat prevention, etc.

With regard to this last drawback, this is often the source of the common remark that External LDS are "expensive." This is because they only serve a leak detection function, and their total cost falls to this department. The metering, SCADA, communications, and computing that are shared with or passed on to other functions with Internal systems cannot usually be shared with another department.

Table 4.3 below adds some more details for the individual External system categories as defined above:

Table 4.3 Benefits / Drawbacks of External Systems

	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.

	External System	Benefits	Drawbacks
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.

	External System	Benefits	Drawbacks
iii.	**Periodic or on-demand deployment**	Zero installation requirement.	Only intermittent service, as part of an inspection program, e.g., for slow leaks.

4.4.3 Ability to Retrofit Legacy Systems

With Internal systems, recall that they rely upon metering, instrumentation (pressure and temperature), and telecommunications (if the leak detection is to be continual). Given these components, implementing most Internal LDS is relatively non-invasive and requires no field installation. They are simply connected to the SCADA and configured and tuned on a computer.

A few exceptions include dedicated pressure wave signature pattern recognition systems that do require the installation of field processing units. However, they can usually utilize current pressure transmitters and so sensor installation on the line is avoided.

However, also recall that the ideal, maximum sensitivity of any Internal LDS is driven by the accuracy of the metering. If the legacy metering is low accuracy, then it may need to be replaced. In addition, if the telemetry only allows very basic on-demand readings, then it may need to be upgraded to provide reliable 30 second to5 minute scans. The replacement of flow meters and of pressure sensors on an old line is an invasive procedure, and requires careful testing after installation to make sure that they have not themselves caused new leaks.

In the benefits and drawbacks table for External systems above, it is notable that many External LDS have practically zero installation requirements. For example, a multispectral infrared camera can be mounted on a pole near the pipeline without even going close to the line or coming into contact with it. At the other extreme, a few External systems are more difficult to install and potentially labor-intensive or risky to retrofit:

- Continuous cables for long sections of pipeline to provide complete coverage need to be laid alongside the line in the same trench. This requires invasive excavation for retrofit.
- Some acoustic sensors require tapping into the line to listen for the fluid wave. Still this procedure is no more invasive than installing a pressure sensor. This is also typically at an exposed point of the pipeline, such as at a valve or meter station.

This limits the practicality of retrofitting most cable-based External solutions to short sections of high-consequence line. For example, a road crossing usually has the pipeline contained within a protective casing pipe. It is simple to pull a liquid sensing tube through the casing, and to secure it next to the pipeline. This provides practical and sensitive leak protection for the riskier road crossing.

Other factors that do need to be considered with the retrofit of External systems appear throughout the benefits and drawbacks table above:

- Soil mounted hydrocarbon sensors can only be installed above the pipeline if the operator has the rights and access to the ground above the line.
- Fixed cameras can only protect sections of pipeline that are within their clear line of sight.
- Sensors can only be permanently attached at exposed points of the pipeline.

At the same time, there are common misconceptions with regard to the practicality of retrofitting other, attractive solutions:

- Internal in-line acoustic tools for leak detection are either carried by intelligent pigs, or also by small smart balls. Pigs require the installation of launchers and receivers, and can only travel along relatively straight and relatively high-pressure lines. On the other hand, smart balls are not full-diameter tools, and roll with the flow and/or gravity rather than pushed by pressure. They can be launched and retrieved from simple flanged fittings bolted on at valve stations. They are therefore practical for a large class of older, smaller diameter, non-uniform and non-straight pipelines.
- At river crossings, it is not necessary for hydrocarbon sensors or cables to be attached to the pipeline. Instead, it is practical to deploy floating sensors above the pipeline route. These are entirely safe to shipping. They are also, paradoxically, extremely sensitive since hydrocarbons find their way to the water surface much more quickly than through soil.

4.4.4 Small/Intermittent Leaks

It is actually customary to define "small" leaks as those leaks that are physically undetectable by any Internal system. Therefore, they fall into the category of leaks that are smaller than ~ 1% of total flow of the pipeline, which is the current practical limit of accuracy of state-of-the-art flow meters and pressure sensors.

It is perhaps possible to reduce this measure by one order of magnitude, to about ~ 0.1% of total flow, by using dedicated pressure analysis systems with pattern recognition. However, this starts to be extremely difficult and complex.

Therefore, almost by definition, small leaks cannot be found using Internal methods.

With External systems, the one technology specifically designed to identify and locate very small leaks is the in-line acoustic sensor tool, carried either by a pig or by a smart ball. These devices are rated to detect pinhole size leaks as low as 0.03 gallons per minute. Location accuracy is rated to +/- 10 feet. This is an “intermittent” not a “continual monitoring” technology since it only finds leaks when it is launched manually.

Perhaps the next most sensitive LDS – by rating, under ideal conditions – is a permanent, acoustic sensor array. The performance of these systems most definitely depends on the pipeline, how many sensors are deployed, the specific algorithms used for leak detection, and other factors. However, they are rated to a sensitivity of 0.1 gallons per minute, with location accuracy rated to +/- 2% of sensor spacing. They are also a “continual monitoring” method, and therefore suitable for leaks that are sporadic as well as small.

Most other sensors are rated in terms of a concentration of hydrocarbons in the soil, water, or atmosphere. This is sometimes difficult to relate to actual leak rate or spill size, depending on the environment. For example, quite a large leak in a line that is buried deep in heavy soil may take a long time to reach the surface where a liquid sensor may be mounted. The vapor from this very small surface pool may take even longer to reach parts-per-million concentrations for a vapor sensor. Similarly, very fast-moving water at a river crossing may disperse small leaks away from a floating sensor. Nevertheless, the suppliers’ test ratings of most hydrocarbon sensors are in the range:

- Vapor sensors: concentrations of 100 ppm in soil or the atmosphere
- Liquid sensors: time-dependent, but given time as low as 0.01 gallon in direct contact. Floating in water, 10 ppm.
- Cameras: between 10 – 100 ppm at the horizon, better when closer

4.5 Major Current Technology Gaps

Perhaps the main difficulty expressed by operators with their current generation of LDS is the problem of false alarms. This is not an issue of the LDS not functioning; rather, it is the difficulty that a number of otherwise normal operational changes on or near the pipeline can cause exactly the same physical effects that the LDS uses to detect leaks. The word “false” often gives the impression that this is a failing of a specific leak detection system. Rather, it is an inherent difficulty with any technology that relies upon any physical side effect of a leak for its detection.

Some examples:

- The classical problem with Internal mass balance systems is that an imbalance in flow can be caused quite normally if the line is packing or unpacking fluid. Any significant change in pressure at a location on the pipeline can have this effect.
- Early versions and some legacy hydrocarbon vapor sensors were sensitive to all hydrocarbons. Biogenic sources of methane (for example, fertilizer, decaying grass, and livestock) produce hydrocarbons indistinguishable from those in the pipeline.
- Distributed temperature sensors rely on changes in temperature that may be caused by leaks, but may also be caused by natural geothermal or atmospheric cooling and heating.

Therefore, the challenge is to eliminate as many extraneous explanations, beyond there being a leak, for the basic physical effect that each LDS utilizes.

A related problem, specific to Internal systems, is that many of them depend upon configuration and tuning, where thresholds are set almost by experiment in order to reduce the number of “false alarms” to a level acceptable to the operator and his control room. This requires expertise, but also leads to unpredictable as-implemented performance. Therefore, the challenge is to design systems that “self-tune” and “self-calibrate” against pipeline operations in the field. A number of the methods, described above, that use statistics, pattern recognition, and DSP already seek to do this.

A related issue with External systems is they are still often quite difficult and specialized to select, engineer, and deploy. Better basic packaging of “solutions,” for example, a bolt-on acoustic array for short sections of pipe or loading terminals that provides a rated performance and resembles a normal safety system, would help avoid the confusion of many operators.

Many operators also remark on the state of industry recommended practices in the area of leak detection:

- The two “bibles” of liquid leak detection systems are API 1149 (1993) and API 1130 (2002). An update of API 1149 is currently in preparation, but will not be ready until at least 2014.
- The API 1149 update will include natural gas pipelines. However, the current edition does not, and to date there has never been a recommended practice for the gas pipeline industry.
- Similarly, there is very little guidance on External systems from an operator’s perspective. It appears based on our review the last public guidance is in the Technical Review of Leak Detection Technologies for Crude Oil Transmission Pipelines by the

Alaska Department of Environmental Conservation (2000). Most EPA tests and surveys are older still.

This is unfortunate, since operators of large infrastructure require systematic procedures. It is often difficult and expensive to have to re-develop internal standards and practices, and they would benefit from a cross-industry starting point as to technical best available technology, and best engineering practices.

Related to this is a lack of a widely-accepted systematic procedure, similar to and perhaps based upon ISO 31000 that helps an operator to express the degree of risk that his selected LDS is mitigating and whether or not this constitutes adequate protection.

4.6 Operator and Developer Opinions and Current Practice

This section of the Technology Review focuses on the information received during direct conversations with pipeline operators and with leak detection technology suppliers.

The interviews covered nine liquids pipeline companies – including two smaller crude oil and petroleum products pipelines; five gas transmission pipelines; and five gas distribution pipelines.

Three of the gas transmission companies also had distribution operations within their company. Within the gas distribution pipelines, we focused solely on the *Intermediate Pressure Systems* – transporting gas from the City gates to local reducing stations for domestic, commercial and industrial end-users. At medium and low pressures the U.S. EPA sets leak detection standards. This report does not explore the particular requirements of that segment of the industry.

A total of twelve technology suppliers were interviewed, covering Computational Pipeline Modeling (CPM, four suppliers); Acoustic and Pressure Wave Analysis (four suppliers); Fiber optic cables (two suppliers); Hydrocarbon sensors (two suppliers); and Thermal imaging (two suppliers). Note that two of these suppliers develop multiple technologies.

The technology part of the interviews covered three purely technical issues:

1. Technology in place at present
2. Performance of current systems and current technology “gaps”
3. Retrofit capability, and plans for retrofitting and improving current technology

4.6.1 Summary

Dominant LDS – All operators that we contacted stated that the most widespread actual current leak detection is by Pressure/Flow monitoring. For gas transmission pipelines, this is in fact pressure monitoring since flow measurement is widely spaced. For gas distribution at intermediate pressure, this normally means flow measurement since pressures are rarely monitored. In addition, all but one of the liquids pipeline operators also implements a Volume Balance CPM.

This is in part because all the operators that we contacted require SCADA for operational purposes, and/or was regulated by the DOT under 49 CFR 195.

Where ASVs are in use by gas pipeline operators, the only leak detection principle utilized is pressure measurement.

Other CPM LDS – A number of liquids pipeline operators also used other forms of CPM on sub-sections of their overall assets. These are summarized in the chart below:

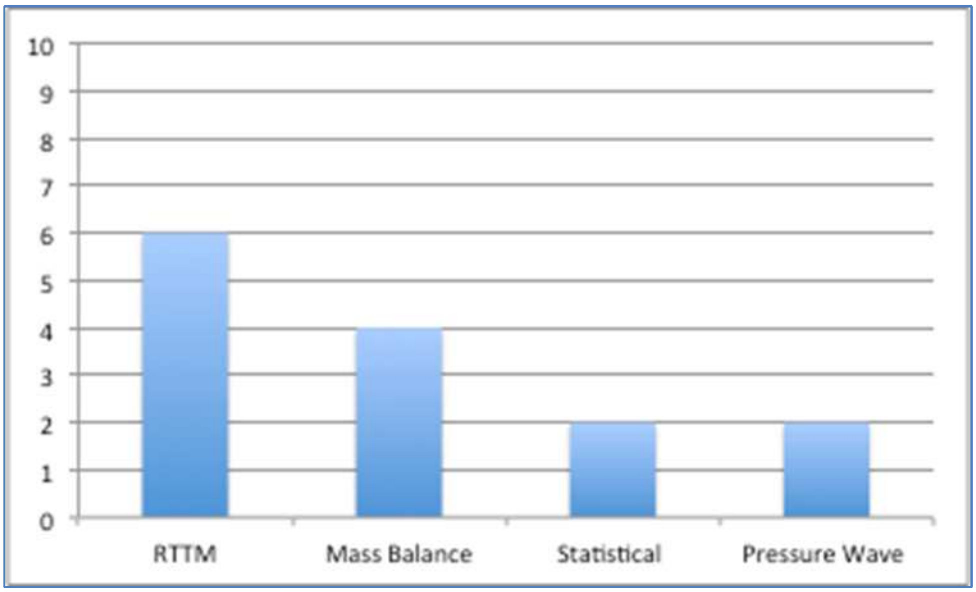


Figure 4.1 Users of "Advanced" CPM Techniques in Liquids Pipelines, from Sample

External LDS – Only three External leak detection technologies were in active use, and all operators referred to these implementations as “pilots” or “experimental”:

1. Floating hydrocarbon sensors – used at river crossings – 2 operators
2. Fiber optic sensors, DTS and DAS – 1 operator
3. Acoustic sensors (used individually, not in an array) – 4 operators: 2 liquids, 2 gas transmission

Technology Suppliers, Installed Base – We also contacted a number of technology suppliers and asked for approximate numbers of separate pipeline where their technology is deployed in the U.S. The totals from our selected set are summarized below:

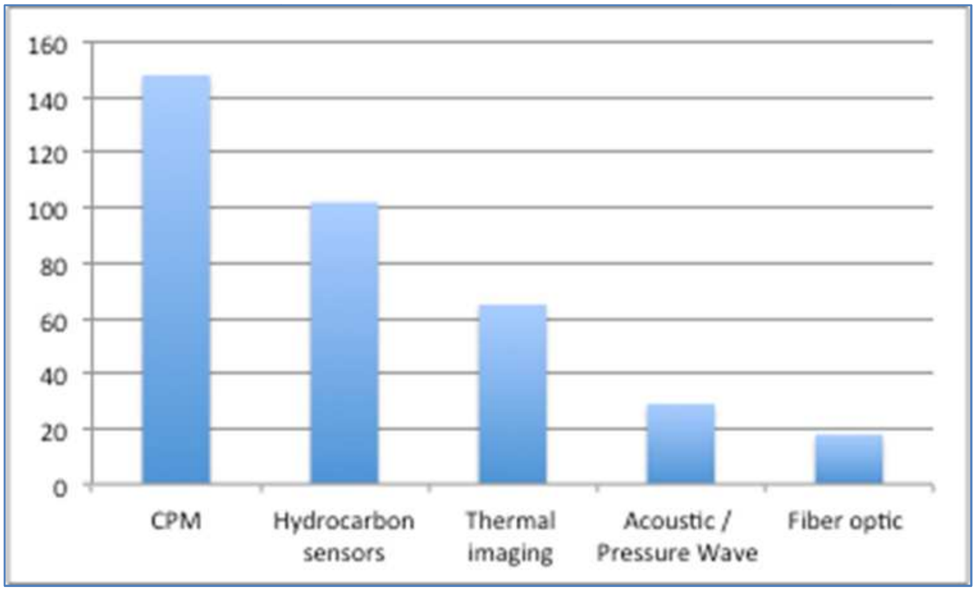


Figure 4.2 Total Pipelines with LDS Installations by Technology, from Sample

These are substantial numbers and provide evidence that a large number of pipelines beyond our survey group are actually using technologies beyond simple Pressure/Flow monitoring.

Performance – The most used leak detection technique, Pressure/Flow monitoring, was acknowledged by all operators not to be generally a sensitive method. It is effective only for large ruptures, and even then not consistently so.

Six out of the nine liquids operators (67%) seek to assess this impact on Pressure/Flow monitoring sensitivity. However, none of the operators (0%) actively install extra flow and pressure measurement with the single objective of improving leak detection sensitivity.

With CPM systems, sensitivity and other measures of performance are directly limited by the accuracy of the flow metering. The same six out of the nine liquids operators (67%) seek to assess this impact on CPM sensitivity. However, none of the operators (0%) actively install extra or improved flow measurement with the single objective of improving leak detection sensitivity.

The general comment from those operators who are piloting External systems is that their performance depends critically on the design of the application and on the quality of the installation.

4.6.2 Technology Gaps

Standardization and certification was universally regarded as an issue. Operators seek standard solutions that give guaranteed levels of performance, according to some certification. No current leak detection technology provides this level of predictability. A similar gap may be described by the desire of pipeline owners to operate, not engineer, their systems. Based on feedback from the interviews, technologies that require extensive design analysis and engineering tend to be troublesome for operators.

Leak detection systems all generate *"False" Alarms*, as discussed above, simply because they actually alarm a physical effect that may be due to a leak or may be due to a number of other non-leak events. Based on feedback from the interviews, this distinction does not appear to interest the operator, who simply wants to know whether it is a leak or not.

All the operators that were interviewed pointed out that the installation of extra pressure sensors and metering was expensive, for a wide variety of regulatory and compliance reasons. Similarly, External sensors often required permits and procedures for installation whose cost far exceeded that of the instrumentation itself.

The "last mile" for many liquids pipelines may be quite short and connect the main pipeline to a tank farm, terminal, or other third-party receipt. These short lines are not suitable for most Internal technologies because operations on these lines is at the control of a third party and therefore pressures and rates are unpredictable. These lines are often idle, which makes flow-based leak detection impossible. Similarly, it is hard to install External sensors since the land typically belongs to a third party.

Pipelines often have relatively short sections where leak detection is far more critical than in others. Examples include: river crossings (even small emissions are carried long distances); road crossings (vibration, immediate contact with moving machinery); hospitals, schools and other low-mobility areas (limited escape capability). There is a need for a certified, dedicated *point solution* that is pre-designed and pre-configured for each of these common situations.

Retrofit Capability – Technically, practically any of the solutions described above can be retrofitted safely and effectively on an existing pipeline. Operators point out that the issues with retrofit are not really technical. The true difficulty is the high cost of permitting, installing, testing and maintaining any additional equipment on a regulated pipeline. This is explored in more detail in our economic analysis below.

Retrofit and Improvement Plans – Not many of the operators interviewed had substantial leak detection systems improvement plans. *None of the gas distribution operators* had leak detection improvement plans.

Two out of the five *gas transmission companies* plan to upgrade their pressure monitoring with Pattern Recognition CPM. The remaining three operators have no plans to improve leak detection or instrumentation.

Five of the nine *liquids operators* have no substantial leak detection improvement (as opposed to maintenance) programs. The remaining four cite these improvement programs:

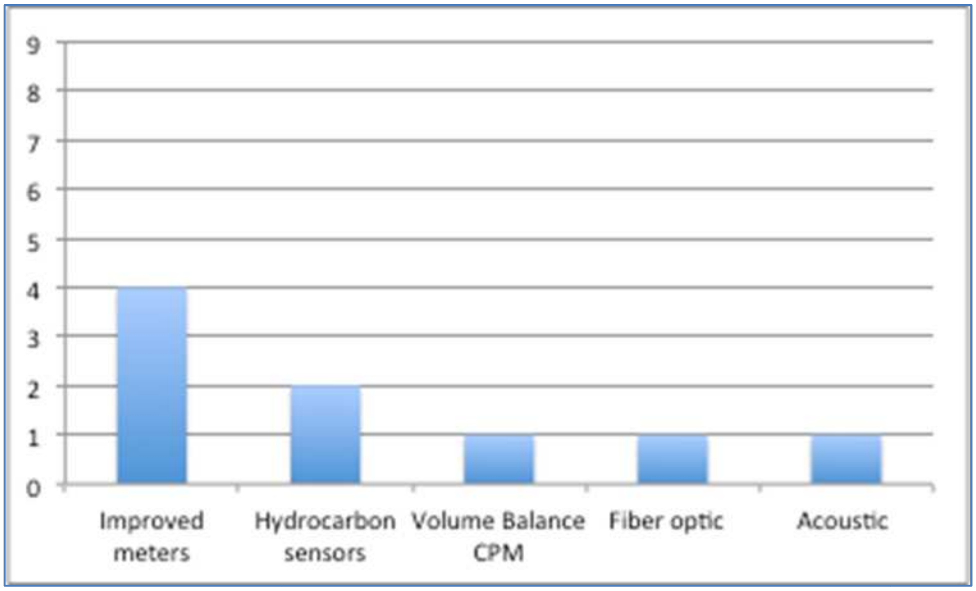


Figure 4.3 Retrofit Programs by Technology, from Sample

4.7 Current Technology

4.7.1 Hazardous Liquids Pipelines

In part because all the pipelines that were interviewed are subject to 49 CFR 195 regulations, all but one of the smaller liquids pipelines used some form of CPM. This smaller operator is currently in the process of implementing a Volume Balance CPM, perhaps with Statistical Analysis. Their actual current leak detection is by Pressure/Flow monitoring.

Similarly, since all these pipelines require SCADA for operations, Pressure/Flow monitoring is universally claimed as a form of leak detection. We do not have hard data on how carefully alarms are set, so we expect this to provide at best large rupture detection and all interviewed operators conceded this.

Within these CPM systems, the technology used breaks down as:

1. Volume Balance 8 (89%)
2. Pressure/Flow monitoring 9 (100%)

3. Mass balance with line pack correction 4 (44%)
4. Real-Time Transient Modeling (RTTM) 6 (67%)
5. Statistical Pattern Recognition 2 (22%)
6. Negative Pressure Wave Modeling 2 (22%)

Note that in these counts:

- A single larger operator often uses more than one technique, depending on the individual pipeline system.
- By contrast, a larger operator with multiple lines sometimes does not have leak detection on all sections. This is discussed below at more length.

Only three External leak detection technologies were in active use, and all operators referred to these implementations as “pilots” or “experimental”:

1. Floating hydrocarbon sensors – used at river crossings – 2 operators
2. Fiber optic sensors, DTS and DAS – 1 operator
3. Acoustic sensors (used individually, not in an array) – 2 operators

These low counts may simply reflect our choice of operators for interview. Conversations with the suppliers seem to indicate a larger total number of installations.

4.7.2 Gas Transmission Pipelines

All five gas transmission pipelines interviewed use SCADA and therefore Pressure/Flow monitoring was universally claimed as a form of leak detection. Given the highly transient nature of gas pipeline operations we expect this to provide at best large rupture detection and all interviewed operators conceded this.

Furthermore, most reliable measurement on the gas transmission pipelines was based on pressure. These pressure measurements are typically at major valve stations and compression facilities. Good quality flow measurement is only available, for commercial reasons, at injection and delivery points, which are usually quite far apart on transmission lines. The focus of these measurements is to calculate Lost and Unaccounted for Natural Gas (L&U), which is an application that is far too coarse to provide leak detection. The leak detection is therefore actually Pressure monitoring.

Two operators also use Acoustic wave analysis. These were referred to as “specialized” applications, both in remote and high-consequence areas. This technology was otherwise not widely utilized.

We discussed Automated Shut-off Valves (ASVs) as part of the interviews, since an ASV incorporates some form of leak detection in order to trigger a shutoff. All interviewed operators used ASVs and universally the leak detection principle was Pressure monitoring.

Three of the five operators use RTTM of their pipelines, and two are in the process of building an RTTM of their systems. However, only two out of the five routinely use the RTTM in the control room during operations. It is not clear from them whether or not the RTTM is used in leak detection – although clearly they would be able to identify large ruptures. The main purpose of the RTTM is for operations and capacity optimization via modeling.

The only External leak detection technology used by this group is LIDAR, and even this is only from aircraft during mandatory pipeline inspection surveys. Hydrocarbon sensors are used in local applications – at compression facilities, for example – as safety devices.

In summary:

1. Leak detection is universally by Pressure monitoring (100%)
2. Two operators (40%) use Acoustic systems in “specialized” applications, although not as a rule throughout their systems
3. Perhaps two operators (40%) use RTTM, although this is not certain

4.7.3 Gas Distribution Pipelines

All five gas distribution pipelines interviewed use SCADA on their Intermediate pressure systems and therefore Pressure/Flow monitoring was universally claimed as a form of leak detection. In contrast to high-pressure transmission, most reliable measurement on the Intermediate pressure pipelines was of flow measurement, for commercial reasons, at supply and delivery points. The leak detection is therefore actually Flow monitoring.

Given that Flow rate is maintained by the supplier in Intermediate pressure operations we expect this to provide at best large rupture detection and all interviewed operators conceded this.

Two of five operators used ASVs and universally the leak detection principle was Pressure monitoring.

Four of the five operators use Real-Time Transient Modeling (RTTM) of their pipelines but they are used strictly for training, planning and capacity optimization via modeling. They explicitly do not use the RTTM in leak detection.

One operator uses Acoustic technology in especially high-consequence areas, but describes this as a “Pilot”.

In summary:

1. Leak detection is universally by Flow monitoring (100%)
2. Two operators (40%) use ASVs and the leak detection principle is Pressure monitoring
3. One operator (20%) uses Acoustic sensors, but describes this as a “Pilot”.

4.7.4 Technology Suppliers

Technology developers and suppliers were asked to provide approximate numbers of currently installed and operational leak detection systems that they provided at least in part, within the U.S. In summary:

1. Computational Pipeline Modeling (Material Balance and RTTM) – 148
2. Acoustic and Pressure Wave Analysis – 29
3. Fiber optic cables – 18
4. Hydrocarbon sensors – 102
5. Thermal imaging – 65

These numbers represent individual pipelines where they have supplied the systems. Therefore, a single pipeline might have, for example, a large number of individual hydrocarbon sensors.

These figures were not verified nor validated, and it is important to note these potential sources of over-estimation:

- Within CPM, as noted earlier, many RTTM are not actually used in practice for leak detection. Similarly, line balancing is often simply a metering or Lost and Unaccounted for Natural Gas application. Therefore, we expect only a fraction of these installations to be genuine leak detection applications.
- With most External technologies, the applications tend to be “tactical” – at facilities, specific road or river crossings, and at points of extreme consequence. Therefore, it is likely that many of the counted installations are actually on the same pipeline, and also unlikely that they represent end-to-end leak detection on an entire pipeline.
- With thermal imaging, by far the majority of applications are for hand-held visual patrol cameras. In this case it is hard to identify which pipeline each patrol camera belongs to.
- It is difficult to assess – especially with newer technologies – whether these systems are used operationally or whether they are trials or pilots.

- With sensor technologies, including fiber optic cables, we do not have a breakdown of whether they are packaged as point sensors, continuous cables, intermittently sampled or continually monitored.

Nevertheless, these are substantial numbers and provide evidence that a large number of pipelines beyond our survey group are actually using technologies beyond simple Pressure/Flow monitoring.

4.8 Performance and Technology Gaps

4.8.1 Performance

In general, operators mostly use whatever measurements are currently installed on the pipeline, for other commercial or operational reasons, and seek to utilize them for leak detection as well.

All the operators interviewed summarized their performance goals as being set by two factors:

1. Regulations – for example, 49 CFR Part 195 or 49 CFR Part 192
2. Internal Company Standards – which usually focus on metering and then by implication cover line balancing and Lost and Unaccounted for Gas (L&U) issues

The sensitivity performance targets are usually in terms of percentage of total flow. This can result in very large undetected spill volumes. However, this is consistent with an approach driven by regulation and metering standards.

Performance of Pressure/Flow monitoring with liquids systems can be very good, but it is unpredictable. A few examples:

- A leak downstream of a flow meter will cause practically no change in that flow measurement.
- A leak near the end of a line with pumps will cause practically no pressure drop, nor any measurable pressure wave.
- A leak at the middle of a line will cause only minimal pressure changes at the ends.

Therefore, performance is strictly related to the placement, density and quality of measurement.

Six out of the nine liquids operators (67%) seek to assess this impact on Pressure/Flow monitoring sensitivity. However, none of the operators (0%) actively install extra flow and pressure measurement with the single objective of improving leak detection sensitivity.

With CPM systems, sensitivity and other measures of performance are directly limited by the accuracy of the flow metering. The same six out of the nine liquids operators (67%) seek to assess this impact on CPM sensitivity. However, none of the operators (0%) actively install extra or improved flow measurement with the single objective of improving leak detection sensitivity. The one exception is the single smaller operator who currently has no CPM. In this case, entirely new metering is being commissioned to give the best price / performance possible within their context.

We remarked above that two operators are "Piloting" External leak detection systems. Their performance – even for the same technology – varies widely. The general comment is that their sensitivity depends critically on the design of the application and on the quality of the installation.

Gas transmission operators generally model their systems thoroughly and all five of our samples (100%) have developed probable minimum and maximum pressures and flow rates for a wide variety of scenarios. These are used to set the alarm limits. However, none of these operators appear to know what the leak volume or rate going beyond these limits – i.e. the sensitivity – would be.

The two gas transmission operators using Acoustic systems are convinced that these systems are sensitive – unfortunately, because they tend to react quite often to non-leak acoustic signals. Therefore, they tend to produce many "false" alarms that reduce their overall effectiveness.

The gas distribution operators were not able to provide a measure of the effectiveness of their measurement systems in terms of ability to detect leaks.

Most leak detection in this sample of operators cannot locate leaks once they are detected. The exceptions are among the liquids pipelines:

1. Two operators are using pressure wave modeling
2. A number of operators (67%) are using RTTM, but it is not clear how widespread its use is for leak detection

All the Technology Suppliers that were interviewed expressed the same opinions on technical performance as described in Part I – Technical Assessment above.

4.8.2 Technology Gaps

Many of the issues that were raised in terms of gaps or industry requirements contain Operational and Economic elements. There is therefore some overlap with those studies below. However, we list below the current issues with leak detection technology and systems that were expressed in one form or another by every one of the operators that we interviewed.

Standardization and Certification

Although none of the operators was especially in favor of mandatory standards that they would be expected to follow, they were all in favor of systems that were standardized, and certified to work to a certain minimum level of performance.

A good comparison is with industrial instrumentation, where a limited set of clearly defined instruments is rated for performance within a consistent set of categories. For example, any engineer can quote an ISA–37.16.01 calibration of a pressure sensor, and any other engineer knows exactly what is meant. Not so with leak detection systems, which are essentially all designed, calibrated and perform individually.

Technology suppliers feel this impact since operators appear continually to be *piloting* or *testing* their systems, and not committing to larger-scale operational deployments. This is often because the results of a pilot are difficult to quantify, compare or test against other options. We note below under Technology Gaps that perhaps a certification standard should be adopted so suppliers can truly sell a product that meets an industry-wide certification.

This is a technology limitation, since even if the effort were to be made to categorize every possible performance measure and uncertainty factor in leak detection, it would still be the case that exactly the same technology, applied to two different pipelines, will yield a different result.

The impact on operators is that they fear investing in leak detection systems, with potentially little benefit to show from them and no way to truly measure success in a standardized way. The result of this technology gap is that leak detection is implemented cautiously, and incrementally, on measurement and other systems that are already in place and self-justified.

False Alarms

Leak detection systems all generate “False” alarms, as discussed in the Technical Assessment above, simply because they actually alarm a physical effect that may be due to a leak or may be due to a number of other non-leak events. This distinction does not interest the operator, who simply wants to know whether it is a leak or not.

This makes leak detection systems unique – any other technology in industrial automation that regularly generated false alarms would not survive long.

This is again a technology limitation, since all leak detection systems in widespread use today rely on a pressure and flow response that may be due to a leak, or may equally be due to measurement errors, or operational transients. Even most of the External leak detection systems are prone to error. Only a sensor that covered the entire wall of the pipe and was immune to all fluids except the ones within the pipe could be expected to approach zero false alarms.

The impact on operators is that often they set the thresholds for a leak alarm so wide that the sensitivity of the detection suffers. Although there are no false alarms any more, *there are also very few alarms of any kind* so at best only large ruptures are reported.

Installation Requirements

All the operators that were interviewed pointed out that the installation of extra pressure sensors and metering was expensive, for a wide variety of regulatory and compliance reasons. Similarly, External sensors often required permits and procedures for installation whose cost far exceeded that of the instrumentation itself.

Nearly all leak detection systems rely on some measurement from the pipeline, and from either within the pipe or as close to the pipe as possible. Furthermore, the more measurements are made the better the quality of the leak detection. The technology challenge is therefore to extract the maximum performance from as few instruments and sensors as possible.

The impact on operators is that technologies that require performing extensive physical works on the pipeline are severely disadvantaged.

Operate vs. Engineer

Operators universally pointed out that they are in the business of operating their infrastructure – they are not engineering companies themselves. Most engineering of any kind is outsourced to contractors.

Of the pipeline companies that we interviewed:

- Only two out of 19 independently explored leak detection technologies in-house. Of these two, one has relatively recently stopped doing original research into new technologies and so both now limit themselves to testing third-party technology.
- Six out of 19 belong to Joint Industry Projects (JIPs) that both develop and test leak detection technology. However, only a handful of such projects are in progress at present. The pipeline companies that we interviewed could name three such JIP sponsored leak detection development projects, and two of these were tests or evaluations of existing technology.
- As we discuss below in operational issues, most companies have at most one engineer dedicated to leak detection, and even the biggest ones have no more than six.

Closely related is the confusion and lack of understanding of technical options. Pipeline operators are impatient with highly convoluted descriptions of leak detection systems, their applicability and their performance. This sentiment is similar to the desire for standards and certifications referred to above.

The technical gap here is that practically all leak detection systems require individual engineering design. The performance of all current leak detection systems depends critically on design, configuration, installation, testing and commissioning. We are a long way from a situation where leak detection systems are simply installed and operated.

The result is that operators themselves are not disposed to carrying out these design studies. Equally, technology suppliers are not always disposed to carry out turnkey deployments including design, configuration, testing and commissioning. They are more interested in supplying the base technology.

Short Lines

Nearly all pipeline operators claim almost total leak detection coverage of their systems, except for the “last mile” for many liquids pipelines that may be quite short and connect the main pipeline to a tank farm, terminal, or other third-party receipt.

These short lines are not suitable for CPM since it is not practical to install metering at their far end. Many other Internal technologies are difficult to implement because operations on these lines is at the control of a third party and therefore pressures and rates are unpredictable. These lines are often idle, which makes flow-based leak detection impossible. Similarly, it is hard to install External sensors since the land typically belongs to a third party. In all cases, engineering design is technically required but is difficult since (a) there are no standard solutions to imitate; and (b) there are sometimes hundreds of such lines, making one-by-one solutions impractical.

The technical need here is for a leak detection technique that requires only limited measurement at one end and that can nevertheless function through highly transient operations and shutdown conditions. The closest candidate at present is Acoustic technology, but even two out of the four Acoustics suppliers that we interviewed doubted that current systems could be relied upon for error-free operation in this environment. They are in any case very expensive in terms of miles of leak detection coverage per dollar cost.

The result is that operators currently often do not implement leak detection on these short terminal lines.

Point Solutions

This is again discussed in much more detail below under operational considerations, but most pipelines have relatively short sections where leak detection is far more critical than in others. Examples include: river crossings (even small emissions are carried long distances); road crossings (vibration, immediate contact with moving machinery); hospitals, schools and other low-mobility areas (limited escape capability).

This is similar to the requirement for standardized systems, but the need is for a certified, dedicated system that is pre-designed and pre-configured for one of these common situations. Most technologies and leak detection systems are "generic" in the sense that they are purposely developed to cover as many technical challenges, physical situations and options as possible. However, certain point solutions are so frequently necessary that ease and confidence of deployment become more important.

Currently, most operators do not provide specific solutions for areas of extremely high consequence as described here. Rather, they continue to rely on an end-to-end solution, which may of course have improved performance because of the HCA.

Price / Performance

This is a compound, and not entirely technological, issue. Two apparently very similar leak detection systems from two different suppliers often nevertheless vary in price substantially. Many of the operators that we interviewed quoted a spread of at least two-fold in quotations they receive for the implementation of apparently the same leak detection system. Technology suppliers actually have a very narrow spread of baseline prices, so the difference is really in design, how much leak detection is being implemented, and the level of effort that is being proposed in configuration, installation and testing.

Therefore, this issue is a combination of:

- Standards and certifications, since it is hard to compare two systems systematically
- Installation, since at least half the cost of a system is installation, not equipment or technology

This technological gap would therefore be covered if the standardization and installation requirements could be solved. There would remain the cost-justification issue, discussed in the economic analysis below, but at least price-performance assessments could be made more systematically.

4.9 Retrofit Capability and Improvement Plans

4.9.1 Capability

Technology suppliers all pointed out that technically nearly all solutions could be retrofitted to an existing pipeline.

The main category where retrofit is more difficult is cable-based technology. However, only one cable, the permeable vapor-sensing tube, requires placement directly below the pipeline. This can be difficult if a pipeline is already buried. Both the fiber optic cable suppliers, including temperature sensing cables, were specific in stating that their cables do not need to be buried next to the pipeline. A shallow separate trench, or even placement on the surface, is sufficient to provide a good level of leak detection. This was confirmed by one liquids pipeline operators, who is testing this technology at present.

Operators, by contrast, point out that the issues with retrofit are not really technical. Although the expressed concerns are not to damage an old pipeline by installing new equipment or performing trenching works, the true difficulty is the high cost of permitting, installing, testing and maintaining any additional equipment on a regulated pipeline. This is explored in more detail in our economic analysis below.

4.9.2 Improvement Plans

Out of the pipeline operators whom we interviewed, a large number had no improvement plans at all:

- Five out of nine (55%) liquids operators will remain as they are, and upgrade only if there is a separate improved metering requirement.
- Only two out of five gas transmission companies plan to upgrade their pressure monitoring with Pattern Recognition CPM. The remaining three operators (60%) have no plans to improve leak detection or instrumentation.
- All the gas distribution companies (100%) have no plans.

Most gas operators are currently heavily involved in safety and emergency response programs, including RCVs and ASVs, and so this may explain the lack of initiative in leak detection.

The remaining four liquids operators are currently planning to upgrade these technologies:

1. Improved meters, including ultrasonic and other newer technologies – 4 operators. These operators are not, however, performing these upgrades only for the purpose of improved leak detection
2. An upgrade to Volume Balance CPM – 1 operator

3. Floating hydrocarbon sensors – used at river crossings – 2 operators
4. Fiber optic sensors – 1 operator
5. Acoustic sensors (used individually, not in an array) – 1 operator

5.0 TASK 5: OPERATIONAL FEASIBILITY

5.1 Objectives

Leak detection systems, as *systems*, involve people, processes and technology. Task 4 above dealt with the purely technological issues, while people and processes are equally important to the success of effective leak detection.

Task 5 of the PHMSA Leak Detection Study includes the following objectives:

- A technical study of recommended best operational procedures and current industry practices.
- Consideration of reliability, availability and maintainability
- Risk assessment and benefit assessment
- Testing, maintenance, training and qualification, and continual improvement

The approach to this operational review is two-fold. It covers the purely technical engineering analysis components of Task 5, including:

- An analysis of the current standards and accepted best practices.
- Current operational regulations and guidelines

It also includes a study of actual operator choices and current industry practices, summarizing direct contacts with industry operators and technology suppliers.

5.2 Leak Detection Operational Principles

In principle, a prudent operator should consider at least seven major issues related to leak detection.

The first major topic is *Risk Analysis*, which also defines the anticipated *value* of leak detection as a means of reducing the consequence of a loss of containment. As with any safety system, the value of leak detection is measured as its ability or potential to reduce the residual level of risk in operating the pipeline. It also defines what the value of accepted, assumed risk from leaks is in the operation of the pipeline. Best practices ask for clarity and transparency in the units in which the level of risk is expressed.

Given the requirements from the assumed risk study, the next major step is *Front-End Design*, where an actual *performance* of a theoretically ideally installed and operated technology, as well as its *cost*, is evaluated. This technical study provides input back into the risk analysis, so that an actual as-built risk reduction benefit is estimated.

These first two steps define a systematic *cost-benefit analysis*. This is explored further in the next Task of the report, below.

Several operational procedures need to be developed pending installation and commissioning of the systems:

- A *Testing Program*, which will verify upon commissioning and periodically thereafter that the anticipated performance and therefore benefits are in fact being provided.
- A *Maintenance Program* appropriate to the technology used and to the environment and operations of the pipeline.
- *Procedures* that ensure that personnel (including controllers and relevant supervisors and field personnel if a control room exists or any personnel involved with leak detection in general if there is no control room) utilize the results of the leak detection system appropriately, to maximize its effectiveness.
- A *Training Program* to ensure controllers and other personnel understand the design basis of the system and its expected uncertainties.

Best practices also ask for a form program of *Continual Improvement*. This may include a periodic review and repetition of all the steps above.

5.2.1 Applicable Operational Codes and Standards

Unlike with purely technical issues related to leak detection, where there are recommended best practices from the API, there are few industry groups who recommend best practical procedures for leak detection.

For liquids pipelines, minimum safety standards for leak detection are described in the 49 CFR 195. These regulations are prescriptive in some aspects, but are also performance based in nature and provide some flexibility and engineering judgment in describing overall objectives, and requiring a demonstration of a process, strategy and methodology. Some of the key elements include, for leak detection systems:

- Design Criteria for CPM Systems based upon the API RP 1130
- Written Operations and Maintenance procedures
- In particular: Responding to, investigating, and correcting deviations from normal operating conditions
- Testing, at least once every five years
- Record Keeping, and Retention
- Formal Controller Training in leak detection

The major mandatory clauses are under Sect. 195.452(i)(3), among which:

- An operator must have a means to detect leaks on its pipeline system
- An operator must evaluate the capability of its leak detection means
- Leak detection analysis should include the impact of sudden significant failures, as well as smaller leaks that may take longer to detect

There are no corresponding regulatory guidelines for gas pipelines.

The Canadian Standards Association (CSA) also has a standard Z662 that makes a leak detection system mandatory on a liquids pipeline. Its Annex E is written as a recommended best practice for the procedures to use in implementing leak detection as a system. Some of its main recommendations are more prescriptive than the 49 CFR 195:

- Operating companies should establish a procedure whereby *a material balance is made* for all liquids transported. In other words, CPM at least by material balance is mandatory, and Pressure/Flow Monitoring is insufficient.
- Operating companies shall establish acceptable tolerances for material balance deviations … deviations in excess of acceptable tolerances *shall result in immediate initiation of a shutdown procedure* unless such deviations can be explained and verified by independent means.
- The *uncertainty in the receipt and delivery metering* used in the material balance calculation … shall not exceed 5% per five minutes, 2% per week, or 1% per month.
- A record of daily, weekly, and monthly material balance results shall be *kept for a minimum period of six months*. Records pertaining to maintenance, internal auditing, and testing shall be *retained for five years*.
- Occasions when the leak detection system was inoperative because of equipment or system failures exceeding 1 h in duration *shall be audited*
- The leak detection system *shall be tested annually* to demonstrate its continued effectiveness. Preferably, *this should be done by the removal of liquid* from the pipeline.
- Personnel responsible for interpreting and responding to the leak detection system shall receive training in: liquid *pipeline hydraulics* as applied to each pipeline segment and as affected by related operational procedures; *the leak detection method used* on each pipeline segment and the interpretation of results; *the effects of system degradation* on leak detection; and the contents and interpretation of a *leak detection manual*.

In addition, minimum values for the material balance summation window and frequency of comparison are set forth in a table, according to the impact of the location, type of fluid transported and the maximum flow rate.

5.2.2 Internal Standards

Many pipeline companies also have internal standards that set additional minimum standards. The main area where additional relevant standards are specified is measurement. Since flow measurement is critical to CPM by material balance they have a direct impact on leak detection.

Internal standards that specify a maximum acceptable metering uncertainty for material balance – as in the third main CSA Z662 mandatory standard above – are particularly useful. This uncertainty can be used directly in the API RP 1130 procedure to estimate theoretically best-case leak detection sensitivity for CPM by material balance in a procedural way.

Internal standards are important since with leak detection “one size does not necessarily fit all”. Therefore, industry standards must invariably be tailored to the requirements of the individual pipeline.

5.2.3 Risk Analysis

Both the 49 CFR 195 and the CSA Z662 cited above require a risk analysis of loss of containment from the pipeline as a first step in setting objectives for the performance of leak detection. The procedures explicitly ask for a consideration of the consequence of a release in High Consequence Areas (HCA) as well as the likelihood of a failure.

For example, in 49 CFR 195.452(i)(2), an operator is asked to “evaluate the likelihood of a pipeline release occurring and how a release could affect HCAs”. In short, both the probability of a leak, and the consequence of this leak if it occurs, should be evaluated

The precise method used for this risk analysis is left to the operator. There are in general very many formats and procedure for a risk analysis, but two are frequently used in the pipeline industry:

A the International Standards Organization (ISO) standard no. 31000 cover risk analysis in general, and addresses general sound principles. It is accompanied by ISO/IEC/FDIS 31010: Risk management – Risk assessment techniques (2009). This provides descriptions and recommendations for 31 different techniques. Some general principles to highlight include:

- Risk assessment is not static – it has to be updated regularly since the environment is changing and certain risks increase over time, while others can decrease through mitigation or changes in circumstances.
- Risks can be complex in themselves, made up of several cumulative risks. These include for example several unwanted events happening simultaneously.

- Risks should be expressed in understandable terms, and the units in which the level of risk is expressed should be clear.

This final point is important, since in one form or another the risk reduction from leak detection is the benefit from its investment. In this regard, risk assessments fall into two main categories:

- *Absolute* risk assessment, where a definite unit of measure is used for the consequences and the risks. This might be dollars per year, or similar.
- *Relative* risk assessment, where a scoring or ranking scheme is used instead for each consequence. Therefore, risks are simply ranked but do not express an absolute level.

Another general issue, which is pervasive in pipeline integrity management, is that total risk is the product of a probability of failure times the consequence of that failure. Leak detection has no effect at all on the probability of a leak. It can, however, mitigate the consequences of a leak dramatically. Therefore leak detection systems are *consequence mitigation measures*, and not probability reduction measures like inspection, maintenance and repair. Since risk is the product of probability and consequence, they nevertheless reduce total risk just as importantly as other integrity management measures.

The ASME also has two standards specifically addressed at pipeline integrity management: B31.8 Gas Transmission and Distribution Piping Systems, and B31.4 Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids. These standards are very detailed in the area of inspection, maintenance and mechanical repair – all of which are the primary probability reduction measures for a pipeline. However, they both contain sections describing risk analysis practice (which is, however, very light on consequence mitigation). In particular they identify a category of threat called *Time-Independent* where almost no amount of inspection and maintenance will reduce the threat probability. With these threats the only possible mitigation is via consequence reduction, in part by leak detection.

The leak detection system, once installed on a pipeline, itself becomes part of the pipeline and therefore part of its overall risk profile. Poorly performing, maintained, tested or operated leak detection systems actually have the potential to degrade to overall risk of operations of the pipeline.

5.2.4 Benefit and Performance Analysis

The 49 CFR 195.452(i)(3) explicitly requires the operator to: “evaluate the capability of its leak detection means and modify, as necessary.” For liquids pipelines, the accepted standard is the API RP 1130 procedure, which is also codified into 49 CFR Part 195.134.

Similarly, CSA Z662 Annex E, Sect. E.3.1 asks for a technical evaluation of the performance of the leak detection system.

In any case, it is prudent for the operator to know exactly what the as-built performance of the leak detection system is likely to be, both before deployment and during operations. These performance estimates can then be used back at the risk analysis stage to yield an as-built value of assumed risk from containment loss.

As we remark in the Technical Review above, a performance study (commonly called a Leak Sensitivity Study, LSS) can be performed for any form of leak detection, whether Internal or External. Except for 49 CFR 195 regulated pipelines the choice of procedure is left up to the operator.

5.2.5 Testing

The 49 CFR Part 195.444 also requires periodic testing of the leak detection system, at least once every five years. Similarly, the CSA Z662 Annex E, Sect.E.4.3 asks that: "the leak detection system shall be tested annually to demonstrate its continued effectiveness. Preferably, this should be done by the removal of liquid from the pipeline."

The purpose of periodic testing is to:

- Ensure that the leak detection system is meeting its design performance targets in terms of sensitivity, accuracy, reliability and robustness.
- Measure actual performance.
- Ensure the continued effectiveness of the system over time.

The testing has to be of the entire *system*. Therefore, both the technology and control room operators should be tested.

There is a preference for testing by actual removal of fluid from the pipeline, or "draw test". On all pipelines and perhaps especially on gas systems, this requires at a minimum special connections on the pipeline, test regulators and meters, and vacuum vessels or a vacuum truck. On a gas pipeline specialized equipment is needed to avoid escape of methane into the atmosphere. These tests might be unannounced, so that controller reactions to the alarms can also be tested.

Simulated testing is far less expensive, but of course less reliable. It can involve artificially modifying SCADA values or metering factors to see whether Internal leak detection notices these anomalies. It can also involve using simulated values from a transient hydraulics model. The controller tests can similarly be performed on a simulation trainer.

A closely related issue is *Auditing*. Any failure of a test, but also any other failure of the system, should be recorded and a post-mortem analysis should be performed. Transparency is essential since reliability and robustness are items to be tested as well.

5.2.6 Maintenance

In general, maintenance is made up of inspection; regular, preventive maintenance to mitigate probability of failure; and calibration, where original factory specifications are maintained. Leak detection technologies themselves require minimal maintenance. However, when considered as *systems* they have multiple points of potential weakness, and hence maintenance requirements.

In general, system components have maintenance requirements that go from high to low, according as:

- They contain consumable fluids and chemicals. Only a few direct sensing External leak detection technologies require this.
- They contain moving parts. Many forms of flow meter contain moving parts, for example, and require periodic calibration.
- They contain electronics and software. Computers used for CPM, for example, require very regular IT maintenance.
- They are inert, physical sensors. Most External technologies are in this category and require minimal maintenance.

Since flow metering is often a central part of most Internal leak detection systems, the second item – flow meter calibration – is by far the most laborious part of the system's maintenance. We also highlight the computational part of most Internal technologies, which rely on computers and software. Personal computer technology usually has maintenance requirements far greater than most industrial automation and need special attention.

Maintenance is required since it reduces the risk of failure of the leak detection system. Therefore, it is a central part of the design of the system and contributes to overall risk reduction. It is also one of the main elements of total lifecycle cost and should therefore be considered carefully during technology selection.

5.2.7 Control Room Procedures

As with many items of industrial automation and control, the human operator is often the weakest component of the system. This is recognized, for example, in the 49 CFR 195.446 Control Room Management standards that emphasize the key part the control room, and not just the SCADA technology, is critical to safe operations. In the Incident Analysis in Task 3 above, a large number of serious losses occur not because the leak detection system fails to give an alarm, but because the controller fails to take appropriate actions in response or the process of validation takes too long.

In part, this is due to the “false alarm” issue described in the Technical Review above. Leak detection alarms may be due to many other reasons apart from a leak. Therefore, most alarm response involves a period of alarm investigation during which the controller checks a variety of issues that may have triggered the alarm instead. These might include:

- Highly transient operations in the field that were not notified to the control room
- Meter or instrument maintenance or failure
- Valve or pump / compressor operation in the field not notified to the control room
- SCADA, communications or IT failure

Once the most probable alternative sources of the alarm are eliminated, a mandatory shutdown sequence should begin. The better operational procedures specify a time limit to the investigation, so that under no circumstances does a leak alarm persist for more than a given length of time without a definite alternative cause.

Recall that there is enormous economic value in stopping a leak early, since even 1% of flow rate in a major pipeline is a very large continuing release. However, a pipeline shutdown is also commercially damaging. With gas distribution, it might also be dangerous since as a direct energy source it may be supplying many thousands of people with life-sustaining heat and power. For this reason, a carefully designed alarm response plan is critical.

These Procedures are called for by 49 CFR Part 195.402:

- Sect. (d)(1): Responding to, investigating, and correcting … deviation from normal …
- Sect. (e)(4): Taking necessary action … to minimize the volume released

Some specific items that should be covered include:

- Actions should be based on documented work practices and/or covered in guidance or training material
- Integration of emergency response procedures
- Assurance for the restoration of any mute/disable functions that are used during certain operational modes
- If procedures require such contact (with a supervisor) before action, assurance that any required supervision is always promptly available for contact
- Adequate guidance in documented work processes: authority and responsibility
- Corporate directive or policy on authority and responsibility

The CSA Z662 Annex E, Sect.E.3.1 is explicit: “Material balance deviations in excess of acceptable tolerances shall result in immediate initiation of a shutdown procedure … “

There are no similar standards for a gas pipeline, but the principles remain much the same.

The shutdown procedure itself requires care. On a high-rate liquids pipeline it is very dangerous to close all valves instantly since doing so will cause a large pressure hammer effect and perhaps rupture the pipe itself. Careful shutdown must be designed by hydraulic analysis and can take many minutes to complete. This is not an issue with gas, where valves can be shut as fast as necessary. It is still necessary to know exactly which valves will isolate which sections of the pipeline.

5.2.8 Controller Training

All pipeline controllers are required to undergo training and to be qualified in the operations of their pipeline, by law. This training is typically a combination of theory, simulation-based training and on-the-job-training alongside an experienced controller (piggybacking).

Controllers are also required to receive training on their leak detection systems. This is required under 49 CFR Part 195.444, where operator actions: “should be based on documented work practices and/or covered in guidance or training material”.

At a minimum, controllers need to know the expected performance thresholds and operating window of applied leak detection system.

The CSA Z662 Annex E, Sect.E.5.1 and E.5.2 is explicit about the content of the training:

- The detailed physical description of each pipeline segment and the characteristics of all liquids transported;
- Liquid pipeline hydraulics as applied to each pipeline segment and as affected by related operational procedures;
- The leak detection method used on each pipeline segment and the interpretation of results;
- The effects of system degradation on the leak detection results; and
- The contents and interpretation of the leak detection manual.

This leak detection manual must explicitly contain:

- A system map, profile, and detailed physical description for each pipeline segment;
- A summary of the characteristics of each service fluid transported;

- A tabulation of the measurement devices used in the leak detection procedure for each pipeline segment and a description of how the data are gathered;
- A list of special considerations or step-by-step procedures to be used in evaluating leak detection results;
- Details of the expected performance of the leak detection system under normal and line upset conditions; and
- The effects of system degradation on the leak detection results.

5.2.9 Continual Improvement

Leak detection is a technology area where advances are constantly being made – notably in other industries – and where the environment is changing. Building and human development around pipelines that once were remote, aging infrastructure and increasing environmental awareness are just a few issues that constantly increase the requirements for leak detection.

It is therefore important for all engineering operating companies to adopt Continual Improvement programs that challenge operations and engineering to change and to improve over time. Leak detection systems are just one area where continual improvement is encouraged.

This attitude, particularly in large organizations, is often confused with "Management of Change" – equally important, but more focused on controlling (perhaps limiting) any changes to internal standards or procedures via a system of approvals and checks. Continual Improvement programs are rather directed at deliberately modifying accepted internal standards or procedures for a defined benefit.

5.2.10 Other General Issues

A particular difficulty with leak detection is identifying who "owns" the leak detection system. A technical manager or engineer in charge is typically appointed, but he is rarely empowered with global budgetary, manpower or strategic responsibilities. Actual ownership of this business area can fall to:

- Metering – especially when leak detection is by volume balance. Of course, this means that all leak detection will continue to be by volume balance.
- Instrumentation and Control – specifically the SCADA group. Likewise, this ensures that leak detection will continue to be by pressure and flow monitoring.
- Information Technology – especially for CPM, since computers and software are central.

A similar difficulty is that, although leak detection is fundamentally a risk reduction measure, the Corporate Risk Department rarely interacts with operations, and may perhaps not even evaluate leak detection in their models.

Leak detection system complexity or high cost does not necessarily translate to better performance. Without a focus on all three: technology, people and procedures, a single "weak link" can render the overall system useless. In particular even very simple technologies can be very effective, if they are backed up by highly skilled operators and well-designed procedures. Design choices need to be balanced with available and committed operating and maintenance resources.

After implementation, field crews will also likely be affected by a need for more instrument maintenance.

5.3 Operator and Developer Opinions and Current Practice

This section of the Operational Review focuses on the information received during direct conversations with pipeline operators and with leak detection technology suppliers.

The interviews covered nine liquids pipeline companies – including two smaller crude oil and petroleum products pipelines; five gas transmission pipelines; and five gas distribution pipelines. These were the same ones interviewed about technology issues.

The individuals at these operators were for the majority of the cases engineering and operations staff at the managerial or higher level. Only three discussions were held with executives. Therefore, it should be understood that these are very much "working engineering" opinions and may not reflect companies' strategic directions very well.

A total of twelve technology suppliers were interviewed, covering Computational Pipeline Modeling (CPM, four suppliers); Acoustic and Pressure Wave Analysis (four suppliers); Fiber optic cables (two suppliers); Hydrocarbon sensors (two suppliers); and Thermal imaging (two suppliers). Note that two of these suppliers develop multiple technologies.

The operational part of the interviews covered six purely technical issues:

1. Internal standards at the operator
2. Risk analysis processes
3. System selection, design and value assessment processes
4. Testing, Maintenance
5. Control room procedures and Controller training
6. Continual improvement
7. Responsibility and Empowerment for leak detection systems

The technology developers were asked for general comments, but also specifically:

1. Their views on value assessment with regard to their own technologies
2. Maintenance requirements
3. Operator adoption of new technologies

5.3.1 Summary

Standards – very few operators develop independent, internal standards explicitly directed a leak detection technology. Three of the liquids operators (33%) have such standards, and none of the gas operators. External recommended practices and Federal Regulations make up the large majority of the standards in continual use.

Risk (Requirements) Analysis – most requirements analysis, in terms of absolute risk, is done outside the technical groups. Leak detection performance input was asked for at only four of the total 19 companies interviewed.

Value (Performance Benefit) Assessment – Four of the nine liquids operators do perform leak sensitivity studies in-house. The remainder relies on performance predictions supplied by their technology vendors. None of the gas operators assess their capability to detect a leak in-house.

Testing, Maintenance – all operators relied on the supplier of the SCADA system, and/or of the CPM software to provide the necessary maintenance. Maintenance of associated field equipment was not assigned to the leak detection or operations teams.

Two out of nine liquids operators perform testing by actual physical draw tests as a matter of course on most lines. The remainder verifies functionality by providing deliberately bad readings through SCADA, deliberately mis-calibrating the meters, or other devices. None of the gas pipeline operators had a systematic program for testing their ability to detect leaks.

Controller Procedures and Training – A written response procedure to an alarm (of any kind) is enforced at 17 out of the 19 operators. However, a specific written response procedure for a leak alarm is enforced at 6 out of 19 operators (all of them liquids operators). Among these, a procedure that sets a mandatory time limit to shutdown, following a leak alarm is mandated at 3 operators.

All operators have written controller procedures, training and qualification programs. However, the specific leak detection systems training content is generally vague. Three liquids operators specifically produced a Leak Detection Manual.

Continual Improvement – Four liquids operators do have continual improvement plans, mostly related to metering. Only two of the gas companies have active instrumentation improvement plans. Only one company out of the sample is testing advanced technologies with a potential for use beyond one years' time.

Responsibilities – of the pipeline operators that we interviewed, approximately one-third (six out of 19) had dedicated staff responsible for leak detection. The personnel that we talked with are given working budgets for a period of between one year and five years. Therefore, actual investment in leak detection has to be taken out of additional departmental responsibilities (metering, SCADA, Information Technology) that can only be increased on a long timeframe.

5.3.2 Internal Standards

Among the nine liquids operators:

- Three (33%) had specific internal standards related to metering, when used for line balance. These went beyond compliance with 49 CFR 195.
- An additional three (33%) had internal metering and instrumentation standards that went beyond standard API recommended practices. However, these did not mention any leak detection-related issues.
- The remainder admitted that compliance with 49 CFR 195 was their operational objective.

Among the gas operators, none had specific internal leak detection standards. Three gas transmission operators have internal metering standards that go beyond AGA recommended practices – however, these do not mention line balancing explicitly.

These responses follow, almost exactly, the replies to questions related to the existence of a formal Leak Detection Manual, a separate topic discussed under Training, below.

5.3.3 Risk Analysis Processes

Recall that most operator personnel contacted were in engineering and operations. None of these personnel contacted are involved in formal operations risk analysis at their companies. Of the total 19 companies surveyed, at only four have technical staff been asked for inputs like expected speed of detection or maximum spill size for a risk analysis. Nearly all operators surveyed did believe that their companies had a Corporate Risk Department, but all but one do not know or won't comment on whether corporate risk takes leak detection into account.

There were two interesting exceptions:

- Among the smallest liquids pipeline operators surveyed, one company is promoting advanced and systematic leak detection as a corporate differentiator to investors. Therefore, it is not so much a risk mitigation technology as a stability and operational excellence issue in this one instance.
- Among the gas distribution companies, there is one that runs complex models of the likelihood of methane concentrations in market areas becoming explosive. At this operator, this is a central engineering function. It falls short of a complete risk analysis, but it is certainly a major part of one.

5.3.4 Value Assessment

Liquids operators are required under 49 CFR 195 to assess their leak detection systems for suitability in protecting HCAs, and are directed to use API RP 1130 to do so. Nevertheless, of the nine liquids operators surveyed:

- One in fact does not have any leak detection system at present, so the question does not apply.
- Four other operators confess to never having performed an LSS in house. They rely on the estimates provided by the vendors.
- The remaining four perform theoretical performance calculations in-house and use them to pre-screen technical options and to rank them by performance.

Gas operators universally were not asked to assess the performance of their current, or potential future, leak detection systems.

5.3.5 Testing and Maintenance

With regard to maintenance, all operators relied on the supplier of the SCADA system, and/or of the CPM software to provide the necessary maintenance. Only one operator used to perform serious internal maintenance on its SCADA system, and is now moving towards outsourcing this function.

Maintenance of associated field equipment was never directly the responsibility of the leak detection function. Rather, instrumentation, control and metering were responsible for their maintenance. This was also true of the one gas transmission operator with acoustic leak detection on specialized sections. Although the acoustic emissions system has the sole function of detecting leaks, the instrumentation group maintains it.

Testing of liquids systems is mandated by 49 CFR 195 and all operators comply. However, only two out of nine operators perform testing by actual physical draw tests as a matter of course on most lines. The remaining operators take a relaxed view, regarding “testing” as a verification that the system is up and running. This may be by providing deliberately bad readings through SCADA, deliberately mis-calibrating the meters, or other devices.

None of the gas pipeline operators had a systematic program of testing their ability to detect leaks.

5.3.6 Controller Procedures and Training

Responses to questions about controller procedures and training were very confusing. All operators have written controller procedures, training and qualification programs. The difficulty is that the elements related to leak detection specifically are vague.

Only the three liquids operators, cited under the Internal Standards topic above, specifically produced a Leak Detection Manual as referred to in CSA Z662.

A more specific question was: does your company have a written procedure that a controller must follow, that defines the validations to be made and sets a firm time limit for the validation? These responses can be summarized:

- Written response procedure to an alarm (of any kind) – 17 out of 19 operators
- Different written response procedure for a leak alarm – 6 out of 19 operators (all liquids operators)
- A procedure that sets a mandatory time limit to shutdown, following a leak alarm – 3 out of 19 operators

5.3.7 Continual Improvement

Out of the pipeline operators whom we interviewed, a large number had no improvement plans at all for LDS:

- Five out of nine (55%) liquids operators will remain as they are, and upgrade only if there is a separate improved metering requirement. The remaining four (45%) do have continual improvement plans, mostly related to metering.
- Only two out of five gas transmission companies have active instrumentation upgrade plans. The remaining three operators (60%) have no plans to improve leak detection or instrumentation.
- All the gas distribution companies (100%) have no plans.

Most gas operators are currently heavily involved in safety and emergency response programs, including RCVs and ASVs, so this may explain the lack of initiative in improving leak detection effectiveness. This is troublesome as the two interact and are important for an overall effective system; for example, RCVs and ASVs rely on an LDS to generate the response signal.

5.3.8 Responsibility, Empowerment

Of the pipeline operators that we interviewed, approximately one-third (six out of 19) had dedicated staff responsible for leak detection. This was also occasionally called *loss control* and *containment management.*

- Liquids operators: four out of nine operators have dedicated leak detection teams. The remainder has metering teams, who by implication also manage line and inventory balancing.
- Gas transmission operators: all have Lost and Unaccounted for Gas (LUFG) technical personnel. This is not really leak detection, but it can be used to identify medium-large leaks in the system by metering. Two out of five transmission operators assigned leak detection to the LUFG team, as part of the operations group. The remainder assigned leak detection to the SCADA group, which resided in Information Technology.
- Gas distribution operators: all the distribution operators assigned leak detection responsibilities to the SCADA group, administered within Information Technology.

In short, none of the gas pipeline operators we interviewed assign a specific job function to leak detection.

In terms of numbers of personnel, among liquids operators: one company had five leak detection experts, one had three, and two had two each. Recall that metering teams handled line balancing at the other five companies.

In terms of empowerment, the personnel that we talked with are given working budgets for a period of between one year and five years. This is discussed in more detail in the next section of this report. Therefore, actual investment in leak detection has to be taken out of additional departmental responsibilities (metering, SCADA, Information Technology) that can only be increased on a long timeframe. There is correspondingly more focus on leak detection improvement at companies where dedicated staff is assigned to the task and can manage budgets independently.

5.4 Technology Developers

It is significant that the attitudes of technology developers in the sample set that we surveyed, and in the three areas of Value, Maintenance and Technology adoption, were all very similar.

5.4.1 Value Assessment

Perhaps obviously, all technology suppliers regarded their solutions as high-value in absolute terms. More relevant is that they assessed value by comparison with similar technologies used in other industries, for example:

- Simulation of fluid dynamics and operations is widely used in highly critical applications like nuclear reactors, construction, and aerospace.
- Fatigue monitoring on bridges and other large structures regularly uses acoustic monitors and other monitoring methods also used by External leak detection technologies.
- Chemical plants and other process industries use leak detection intensively.

In these industries, the same technologies are more expensive and have higher perceived value. This argument was universal among our survey sample.

5.4.2 Maintenance Requirements

In general, CPM technology suppliers all regarded the maintenance required on their part of a total Internal leak detection system as minimal, as compared with the maintenance required on the metering, instrumentation and SCADA.

Similarly, most External sensors were regarded as robust and far less maintenance-intensive than metering or other moving equipment.

It must be remembered that, in our survey, most maintenance is in any case delegated to the suppliers so it is perhaps not surprising that they find this activity simple.

5.4.3 Operator Adoption of New Technologies

Technology suppliers tend to take a pessimistic view of the operational reasons that operators adopt new technologies. Their view is that external pressure is nearly always required. Either regulation or external standards are the only certain levers to encourage the introduction of new techniques.

6.0 TASK 6: ECONOMIC FEASIBILITY

6.1 Objectives

Leak detection systems, in common with all purchases by major corporations, require cost justification. Many of the above Tasks already touch on cost-benefit analysis:

- Tasks 4 and 5 cover performance assessment, and briefly on how risk reduction is estimated.
- Task 5 covers the full-lifecycle cost elements as well as organizational and people requirements.

Task 6 of the PHMSA Leak Detection Study includes the following objectives:

- A technical study of principles of cost-benefit analysis of leak detection for pipelines.
- Absolute budget allocation principles
- Relative cost-benefit ranking

The principles of cost benefit analysis for deploying leak detection systems on new and existing pipeline systems are covered. Typical cost elements for equipping a new, and retrofitting an existing, pipeline system are listed as a guideline – covering the technical options presented in Task 4 above but focusing on SCADA and CPM based leak detection, as is the norm today.

The cost benefit is based on the lifetime operational cost of the system. Variables including the benefits to the public and surrounding environment are assessed. These are markedly different for pipelines that are situated within HCAs.

The approach to this economic review is two-fold. It covers the purely technical economic analysis components of Task 6 above. It also includes a study of actual operator choices and current industry practices, summarizing direct contacts with industry operators and technology suppliers.

6.2 Economic Principles

Any for-profit company has a number of stakeholders, who all have an interest in its economic success. These include but are not limited to: Investors, Managers, Employees, Customers, and the Community where the business is run. Each of the stakeholders has particular objectives and demands for the company, and the company owes each of them its regard. To simplify greatly:

- Investors ask for a maximized and reliable return on their investment

- Managers are tasked with setting and meeting measurable performance metrics for the company
- Employees seek an improved quality of life through remuneration and personal development
- Customers benefit from the products or services supplied by the company
- The Community seeks an improved environment from the presence of the company within its society

Leak detection systems – in common with all safety systems – affect all stakeholders in slightly different ways:

- Investors are assured of a more reliable return on investment, through the reduction in the risk of financial damages.
- Similarly, Managers can deliver more reliable performance.
- Employees can work in safer environments
- The Community has a reduced risk of having to deal with serious safety and environmental hazards

In brief, these all translate to a reduction in the *risk* of a leak (or any other safety-related incident). Conversely, it is an increase in the *reliability* of the overall business.

A Risk is a probability-weighted cost, and is defined in various forms depending on the application. In our context, it is useful to think of:

Risk = (Probability of the cost being due) * (Economic impact of the cost) / (Unit time)

Applying common units, this might be rated as: Expected $ cost / year. If the total cost of remedying a given leak is C, and the probability of this leak occurring in a given year is P, then the Risk is P * C.

6.2.1 Risk Reduction

The final corporate Exposure = Risk – Reduction. This represents the amount of risk that remains after risk reduction measures have been applied. Exposure may also be referred to as Threat, Liability, etc.

The Assumed Risk is the final accepted level of Exposure once the selected Mitigation is applied. It is also called Asset Liability, which is a stronger term to remind operators that the possibility of enduring undetected leaks is a continuing liability to their pipeline assets.

6.2.2 Risk Management

Any business can in principle manage its Asset Liability in one of four ways:

- Avoidance – in our context, withdrawal from the pipeline industry in order to avoid any chance of ever dealing with a leak incident.
- Sharing – via insurance against incidents, or by outsourcing operational functions. This does happen in the pipeline industry. However, the insurance and outsourcing companies certainly do perform accurate risk analysis and are sure to assume third-party risk only for a profit.
- Retention – this refers to the policy of doing nothing, avoiding any immediate investments, and maintaining instead a contingency fund to pay for potential disasters.
- Reduction – rationally mitigating risks by investment in systems, so that the assumed risk is acceptable.

6.2.3 Cost-Benefit

The economic benefit from a leak detection system is gained from a reduction in the consequential cost, or *Consequence* of the leak. The leak detection system cannot reduce the *Probability* P, which is the domain of mechanical safety, inspection, maintenance and repair.

The total lifecycle cost of the system is (Capital Expenditure) + (Annual Operational Expenditure)*Lifetime. Over a sufficiently long period of time, this is dominated by Annual Operational Expenditure (OPEX). Therefore, the total lifetime cost-benefit approaches: OPEX / Risk

6.2.4 Other Benefits

During interviews with operators, we did identify two interesting alternative, but non-quantifiable, justifications for leak detection:

Among the smallest liquids pipeline operators, one company is promoting advanced and systematic leak detection as a corporate differentiator to investors. Therefore, it is not so much a risk mitigation technology as stability, leading-edge practices, and operational excellence issue. One of the larger liquids operators publicizes its leak detection as an operational excellence issue also.

Among the gas distribution companies, there is one that runs complex models of the likelihood of methane concentrations in market areas becoming explosive. In this case, leak detection becomes a means to regulate methane concentrations and is explicitly a safety system for fire and gas containment.

6.2.5 Observations

Any two analysts assessing risk will almost certainly reach different results and values for the risks. Techniques for assessing risk are described in Task 5 above, but nevertheless even exactly the same technique will yield different values. However, the *orders of magnitude* for the risk are surprisingly consistent, given the same data.

Since most leaks in hazardous petroleum fluids pipelines can have high consequences, even small probabilities of occurrence lead to substantial risk. Since the OPEX of these systems is low, the theoretical lifetime cost-benefit (OPEX/Risk) is very high. This is not controversial and applies to all safety-related systems.

6.2.6 Practical Issues

Despite the theory above, most operators do not consider a long lifecycle in their cost-benefit calculations. Rather, they apply a timeframe of between 1 and 5 years to their investments. Then, the cost-benefit (since OPEX is relatively low) is more like:

CAPEX / (Between 1 and 5 * Risk)

Since the Capital Expenditure (CAPEX) is frequently quite high, this radically increases the cost-benefit.

Leak detection systems are *not* currently described as safety-related systems. This means that the risk and risk reduction calculations are rarely performed in practice. If a reduction to risk is not analyzed, there is simply no economic way to calculate cost-benefit.

6.2.7 New Installation vs. Existing Retrofits

We observed above in Task 4 that there are few technical difficulties to retrofitting existing pipelines with most technologies. The difficulties are economic and practical.

Installing equipment, of any kind, on a new development is an activity that can be integrated within the overall construction project. It is also relatively easy to integrate with the overall project construction CAPEX, especially since these costs are far lower than most other hardware and labor components of a pipeline.

Installing equipment on an existing pipeline is more difficult. Separate Authorizations for Expenditure (AFEs) have to be processed, the budget has to be found from a cyclical budget cycle, installation has to be coordinated with an operations schedule and safety and regulatory issues have to be addressed. For some technologies, excavation of the pipeline may be necessary, which is an activity operators prefer to avoid for practical reasons. With older pipelines, works of any kind can uncover or cause multiple unintended integrity management difficulties.

Therefore, operators tend to use the term “retrofit” to mean leak detection using whatever equipment is already installed on the pipeline. Beyond installation of equipment on the pipe itself, there is essentially no difference in the economics of the “host” or central processing system of a new installation vs. a retrofit.

6.2.8 Impact of Regulation

The economic impact of regulation is that it applies definite economic constraints on investment. Specifically, it obliges a company either to comply with the regulations – often involving an investment – or to avoid compliance and carry the risk of a fine or other sanctions.

In risk analysis terms, if the consequences of non-compliance (fines and other sanctions) are C, and the annual risk of being audited by the regulator are P, then this is a normal Risk = P * C. The consequence can be mitigated by the appropriate annual investment I, so that the cost-benefit of compliance is I / P * C. Greater sanctions C and better enforcement P make this cost-benefit lower. Greater compliance requirements I increase the cost-benefit.

More importantly, if the investment I actually achieves other operational improvements – including reducing other levels of risk – the cost-benefit is dramatically lower.

This coldly calculated cost-benefit does not take into account the extremely bad image that deliberate non-compliance creates among stakeholders. It especially affects those investors who value reliable, predictable operations.

6.2.9 Safety-Related Systems

It is interesting to explore systems that are officially classified as safety-related, even though we emphasize that leak detection systems are not classified as such. The intent of these systems is to meet a specified, low level of assumed risk with very high reliability and robustness.

This classification is technical, not semantic. Of course leak detection relates to safety and to health. However, it is never technically classified as such.

Once classified as safety-related, systems automatically must meet engineering standards that are far greater than normal systems – even when they are dealing with hazardous liquids and natural gas. It is interesting that even in the petroleum industry many offshore pipelines are classified as safety-related. Nuclear plants and the machinery sector, to name but a couple, rely heavily on functional safety to achieve safety for the equipment that cause the hazards.

Because electronics and computers are used extensively, as with SCADA and CPM, the IEC has developed a specific standard, IEC 61508, for safety systems. It is interesting that many pipeline SCADA systems are in fact IEC 61508 compliant since the suppliers have to cover many other industries.

Fire and Gas (F&G) Systems are essentially just dedicated atmospheric sensing External leak detection systems, engineered to a far higher standard than usual in the pipeline industry.

Of course, meeting the more stringent standards carries a cost in terms of more equipment and more engineering. In essence, the cost-benefit analysis is conceded to justify a higher cost simply by this description.

6.3 Cost Elements of Leak Detection Systems

It is useful to gain some insight into the order-of-magnitude costs and benefits involved with leak detection systems. We emphasize that costs vary widely, and so do benefits – especially as perceived by the operator. Prices from suppliers vary by many multiples depending on the volume, product lifecycle, buyer and season. Similarly costs for services vary widely depending on geographical location, certification requirements, in-house vs. outsource choices, to name only a few. These variations can be as high as a factor of ten in some cases.

We focus on the two main forms of leak detection in actual frequent use today: SCADA monitoring and CPM by volume balance. Other technologies as presented in Task 4 above are then analyzed separately. One issue with the economics of SCADA and CPM systems is that they usually rely on systems (SCADA and metering) that are already in place. The economics therefore fall into two categories: no current SCADA and metering, and piggybacking existing systems.

We also aim to estimate a cost benefit based on the lifetime operational cost of the system. This is also difficult since the risks of leaks and their consequences vary enormously between pipelines. New pipelines, for example, generally have rather lower risks of leaks; and even within HCAs the consequences of a leak near drinking water reservoirs are much higher than near only navigable water.

Nevertheless, we use a single benchmark benefit value based upon global U.S. historical performance, and a separate benchmark benefit based on a multiple of the average economic damage in an HCA compared with the average. The use of this single benefit value masks the fact that more sensitive technologies have higher value in terms of reducing spill size and therefore damages. Their higher cost is balanced against the same average benefit, artificially depressing their ROI.

This analysis can, at best, offer an order-of-magnitude illustration of which solutions are viable, and does illustrate that certain technologies offer extremely high returns on investment. The reader is invited to imitate this analysis for his own particular operational situation and with cost values more appropriate to his own reality.

6.3.1 Approach

We first calculate costs from a basic table that represents a general, order-of-magnitude set of unit costs for the components of a leak detection system. A difficulty is that these unit costs come in a wide variety of units. Nevertheless, we attempt a basic bill of materials for a notional grossly "average" pipeline:

- A liquids pipeline 400 miles long. This is the total U.S. hazardous liquids network length of 148,622 miles, over 350 DOT-registered companies.
- A gas transmission pipeline 300 miles long. This is the total U.S. gas transmission network length of 301,896 miles, over 981 DOT-registered companies.

Also, we provide costs for a basic leak detection system only. A prudent operator will prefer to invest in more equipment and systems than we define here.

Any pipeline operator will also need to perform a specific, targeted benefits analysis for their own pipeline based upon the physical realities of their systems, their environment, and their own corporate risk tolerance policies. To yield an order of magnitude figure for the annual dollar assumed risks from leak damages, we use an estimate based upon global, total U.S. property damage over the last ten years and various other assumptions detailed below. We encourage the reader not to use this methodology for any specific pipeline, but rather to view this approach as explaining how annual assumed risks are at least in the $100,000's per average 400-mile pipeline.

About a ten-year historical timeframe is probably appropriate for seeking historical averages, since there have been years during the last decade with unusually large property damage in a single year (2005, and 2010 were particularly bad years with over $1.1 Billion in a single year). At the same time, property damage is generally increasing, and it is to be expected that aging infrastructure will tend to fail more often, so this will probably lead to an under-estimate of averages.

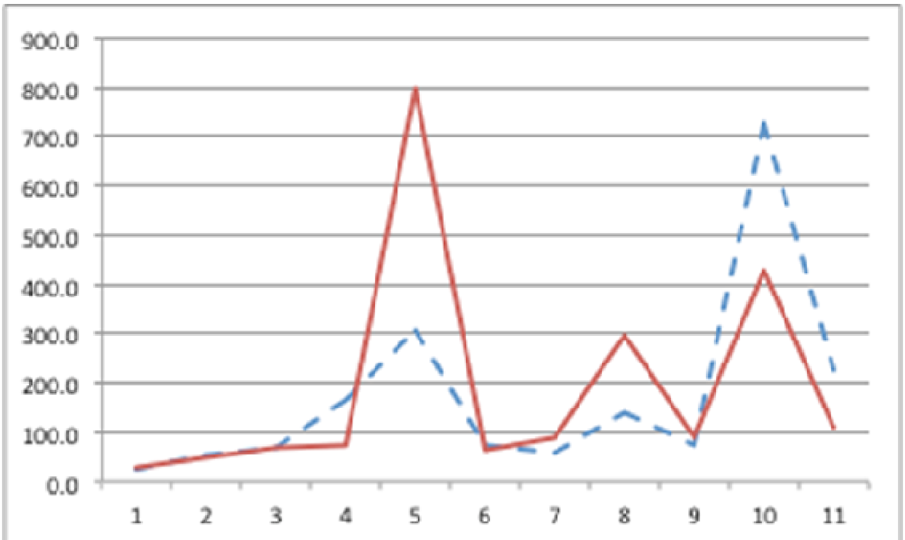


Figure 6.1 Annual property damage, $ millions, 2001 – 2011 Liquids pipelines are the dashed line, and gas pipelines are the solid line

There have been 201 major incidents (in an HCA or with volumes over 1,000 gallons) related to liquid leaks in the U.S. over the last ten years that were reportable to DOT. The "average" pipeline therefore has a 57% probability of experiencing a major leak, with consequences over the $1 million range, in a ten-year period.

We then have to assess a similarly gross "average" risk reduction benefit from reduction in incidents. Our first simplification is to assume that over the period 2001 – 2011 at least 90% of the property damage caused by pipeline incidents was caused by loss of containment on the pipeline. The remainder would be caused by other industrial accidents. Property damage would then total:

- Liquids pipeline industry: $1.7 Billion over 2001 – 2011.
- Gas pipeline industry: $1.9 Billion over 2001 – 2011.

This represents a direct economic damage to the public. It does not necessarily represent a cost to the pipeline company, but at this level of detail we additionally assume that nearly all these costs fall to the pipeline company. Therefore, again taking gross averages, the annual damages per notional average pipeline is:

- Liquids pipelines: $490,000 per notional 400-mile pipeline, per year.
- Gas pipelines: $190,000 per notional 300-mile pipeline, per year.

It is unrealistic to make the assumption that improved leak detection would have eliminated this property damage completely. The probability of these leaks occurring bears no relation to leak detection. Rather, by accelerating leak containment, it reduces the consequential damage.

Without any idea about the engineering specifics of the pipelines, we further assume that a leak detection system might have reduced these costs by a factor of 75%. Our final risk reduction, or leak detection systems' benefit, figures are then:

- Liquids pipelines: $370,000 per 400-mile pipeline, per year, in risk reduction.
- Gas pipelines: $144,000 per notional 300-mile pipeline, per year, in risk reduction.

This final step might perhaps be misleading. More sensitive, reliable, and costly leak detection systems should increase this factor. Cheaper systems should reduce this factor, and in fact may not provide significant risk reduction at all. Therefore, our cost-benefit below suffers from a fixed benefit for all technical options while the costs vary.

Finally, a big issue is whether the spill occurs in an HCA or not. Clearly in an HCA total remediation of the spill is often impossible, or takes an extremely long time. Places of outstanding environmental value can be affected for a longtime. In any case, costs of remediation are substantially higher since the tolerance for any remaining hydrocarbons in the environment is much lower. No hard data for the costs of cleanup in an HCA, relative to the average, are available to our knowledge. However, we estimate that they are at least 2 – 3 times as high and probably more.

It is worth recalling all the assumptions behind these figures:

- All pipelines are equal and are distributed among U.S. operators evenly.
- At least 90% of all property damage over the period 2001 – 2011 was due to loss of containment on the pipeline.
- All the property damage was borne by the pipeline company.
- Any leak detection, or improved leak detection, could have reduced these costs by a factor of 75%. This figure is estimated by reference to the historical data analysis in Section 3 above.
- Fines, and other sanctions that are aggravated by not having implemented leak detection, are not included and would increase these risks.
- Similarly, general business damages like lost transportation capacity and infrastructure repairs are not included and would increase these risks.
- Damages in an HCA are approximately 3 times as high, economically, as the average.

We repeat, readers are encouraged to repeat this analysis for their specific pipelines, using the actual percentage figures and cost basis appropriate to their situation and operational targets.

6.3.2 Intangible Costs

There is no way to assess an economic impact from loss of life, but there were a total of 165 fatalities and 680 injuries in the pipeline industry over 2001 – 2011. These were surely not all due to leak events. In any case, this level of loss of life in many other transportation industries would probably call for safety-instrumented systems.

The dollars per year risk reduction argument is appropriate for very large systems. If, on the other hand, absolute ability to contain any spill rapidly is a corporate objective, which is the case for many smaller operators, who might be put out of business entirely by larger unhandled spills. It is more appropriate to use the 57% probability of experiencing a major leak within ten years as the correct value measure. In this view, leak detection might be closer to 5.7% of total operational budget.

The final intangible cost that we highlight is the impression made both to the general public and to investors in particular that the operator is not in control of his assets. To a point, occasional leaks and other failures are conceded as accidents as long as they are relatively infrequent. Not knowing for several hours that the leak has even occurred and struggling to contain it appears as carelessness. The economic impact to the operator in terms of investor confidence and share value may be much higher than the direct property damages.

6.3.3 Unit Pricing

We repeat that many of these unit costs are only order-of-magnitude indications, valid at the time of writing, and subject to large practical deviations (Table 6.1).

Table 6.1 Indicative Unit Costs

Component	Unit Price	Unit	Clarifications
SCADA metering system	$100,000	Turnkey	Average price, turnkey, for a 500-mile pipeline. Metering only, no control
Internal systems, software and commissioning:			
Pressure Wave	$250,000		Requires pressure sensors
Material Balance	$250,000		
RTTM	$500,000		
External systems, hardware, installed:			
Acoustic sensors	$1,000,000	Turnkey	Requires fiber communications
Fiber-Optic Cable	$5,000	Per Mile	
Cable sensors	$50,000	Per Mile	
Point sensors	$2,000	Per Sensor	Every 150 ft./ 35 per mile.
Host LDS processor	$20,000	Per Host	
Host IT systems	$20,000	Per Host	
Other field hardware:			
Meter	$50,000	Per Meter	
Pressure sensor, installed	$15,000	Per Sensor	
Communications stations	$100,000	Per Station	
Field works:			Extremely variable
Meter Installation	$30,000		
Trenching works	$1,500	Per Mile	
Maintenance, support			
Meter proving	$20,000	Per Meter, Per Year	
CPM Systems maintenance	18%	Of Base Cost	Typically includes system upgrades
Internal engineering	$200,000	Per Person, Per Year	Fully loaded. Extremely variable

6.3.4 Conceptual Systems, Capital Cost

We examine four prototype leak detection configurations:

1. SCADA monitoring of pressure and flow
2. CPM using material balance
3. Negative pressure wave monitoring
4. RTTM
5. External systems:
    a. Acoustic
    b. Fiber Optic Cable
    c. Liquid Sensing Cables
    d. Point Hydrocarbon Sensors

To simplify presentation, we provide costs for a single 400-mile pipeline, gas or liquid. This simplification does not change the orders of magnitude significantly.

The first scenario that we analyze studies full-length coverage of the pipeline by External technologies. This is unusual, it is much more common to provide coverage only for sensitive sections of the pipeline using External technology.

The second scenario studies only sensitive area coverage of the pipeline by External technologies. We have to assume how much of the pipeline is sensitive, and as an order-of-magnitude estimate we apply a 10% estimate. In real situations, the operator would make this assessment with both a risk analysis and a budget in mind. In this situation, complete pipeline coverage is still required, so a CPM would also be required.

1. SCADA monitoring – if the SCADA system is already installed, for an average 300 – 400 mile pipeline about 6 months of internal engineering time will be required for a suitable design and implementation of appropriate alarms. Otherwise, a turnkey SCADA system will also need to be installed. Recall, it is unusual not to have a separately justified SCADA system in place.

2. Material Balance – if appropriate metering is already in place, only software (installed and configured) and host IT systems will be required. Otherwise, we suggest that about 4 meter stations, with pressure readings, and appropriate communications, are appropriate for a 300 – 400 mile pipeline. Recall, it is unusual not to have a separately justified metering system in place.

3. Negative Pressure Wave – if appropriate pressure monitoring is already in place, a monitoring system (installed and configured) and host IT systems will be required. Otherwise, we suggest that about 4 instrument stations, with pressure readings, and appropriate communications, are appropriate for a 300 – 400 mile pipeline. Recall, it is unusual not to have a separately justified pressure monitoring system in place.

4. RTTM – we assume that an appropriate flow and pressure monitoring is already in place, since otherwise it is unlikely that an operator would be considering this option. The appropriate software and host IT systems will be required. We also recommend at least half a full-time equivalent internal resource to manage this project.

5.a. Acoustic Systems – we have estimated a complete acoustic sensor array system. If an entire-pipeline fiber communications network is not present (which is usually the case) a fiber communications system also needs to be installed.

5.b. Fiber Optic Cable – the cost is made up of the actual laying of the fiber optic cable – in a trench above or very close to the buried pipeline – and of the sensing electronics systems and Host. Where there already is a communications cable near the pipe, the former cost is not necessary. In a new construction, the additional trenching costs are not necessary.

5.c. Liquid Sensing Cables – are similar to fiber optic cables, except that it is unlikely that a cable will already be present. Note that this solution only applies to liquids pipelines.

5.d. Point Hydrocarbon Sensors – the cost is made up of the sensors, at about 35 per mile, and of the associated electronics systems and Host.

First Scenario

In this scenario, predictably, many External solutions that depend on the length of the pipeline are very expensive (Table 6.2).

Table 6.2 - System Capital Costs - Full Pipeline Coverage

		Equipment	Labor	Total
1	SCADA monitoring of pressure and flow		$100,000	$100,000
	If SCADA is required:	$100,000	$100,000	$200,000
2	CPM using material balance	$270,000		$270,000
	If metering is required	$930,000	$120,000	$1,050,000
3	Negative pressure wave monitoring	$270,000		$270,000
	If pressure monitoring is needed	$730,000		$730,000
4	RTTM	$520,000	$100,000	$620,000
5	External systems:			
a.	Acoustic,	$3,000,000		$3,000,000
	If fiber is already in place	$1,000,000		$1,000,000
b.	Fiber Optic Cable,	$2,040,000	$600,000	$2,640,000
	If suitable fiber is already in place	$40,000		$40,000
	New construction	$2,040,000		$2,040,000
c.	Liquid Sensing Cables	$20,040,000	$600,000	$20,640,000
	New construction	$20,040,000		$20,040,000
d.	Point Hydrocarbon Sensors	$210,020,000		$210,020,000

Second Scenario

In this scenario, only 10% of the pipeline is covered at sensitive sections by an External technology. Their costs are therefore much lower, but recall that end-to-end leak detection is still needed using one of the Internal methods (Table 6.3).

Table 6.3 - System Capital Costs - 10% HCA Coverage Only

		Equipment	Labor	Total
1	SCADA monitoring of pressure and flow		$100,000	$100,000
	If SCADA is required:	$100,000	$100,000	$200,000
2	CPM using material balance	$270,000		$270,000
	If metering is required	$930,000	$120,000	$1,050,000
3	Negative pressure wave monitoring	$270,000		$270,000
	If pressure monitoring is needed	$730,000		$730,000
4	RTTM	$520,000	$100,000	$620,000
5	External systems:			
a.	Acoustic,	$1,200,000		$1,200,000
	If fiber is already in place	$1,000,000		$1,000,000
b.	Fiber Optic Cable,	$240,000	$60,000	$300,000
	If suitable fiber is already in place	$40,000		$40,000
	New construction	$240,000		$240,000
c.	Liquid Sensing Cables	$2,040,000	$60,000	$2,100,000
	New construction	$2,040,000		$2,040,000
d.	Point Hydrocarbon Sensors	$21,020,000		$21,020,000

6.3.5 Operational Costs

External systems have virtually no operating cost. According to our model, only the Host systems have a recurring 18% annual maintenance that includes upgrades. All External technologies therefore have a fixed, negligible $7,200 annual operating cost.

The one area where costs vary widely is the price of internal company IT maintenance. Here we assume that this recurring cost is covered by the general IT maintenance of the control room.

Therefore, the main continuing operational costs are with Internal systems that require software more intensively. These are summarized as follows (Table 6.4).

Table 6.4 - System Operating Costs

		Maintenance	Labor	Total
1	SCADA monitoring of pressure and flow			
	If SCADA is required:	$18,000		$18,000
2	CPM using material balance	$48,600		$48,600
	If metering is required	$200,600		$200,600
3	Negative pressure wave monitoring	$48,600		$48,600
	If pressure monitoring is needed	$120,600		$120,600
4	RTTM	$93,600	$100,000	$193,600

6.3.6 Cost-Benefit Analysis

The tables above give an indication in terms of simple orders of magnitude of the most attractive choices for an operator.

Our earlier discussions justified risk reduction on the order of:

- Liquids pipelines: $370,000 per year, and $1.1 million in HCAs per year.
- Gas pipelines: $144,000 per year, and $432,000 in HCAs per year.

A rapid pre-screening shows that all technologies except probably complete coverage with continuous hydrocarbon sensing cables and point sensors are on the table as economically viable options.

Our model defines systems that have theoretically infinite lifespans, since components that require upgrades or replacement are accounted for via an 18% annual OPEX requirement. Nevertheless, the tables below show a return on investment analysis for each technical option over a three, five and ten year lifetime (Table 6.5 and Table 6.6). We remark that many pipelines' lifetimes are in fact in the fifty-year or more range, but ten years is about the limit for most engineering ROI calculations.

Under our two scenarios:

1. Scenario 1 – External LDS options are used to cover the entire pipeline.
2. Scenario 2 – External LDS options cover only 10% of the pipeline, and are backed up by an Internal CPM system. This is more credible as an engineering solution.

Any option that has no economic benefit is left blank.

Table 6.5 - ROI (Multiples) for Technical Scenario 1

	Liquids Pipeline			
		Three Year	Five Year	Ten Year
1	SCADA monitoring of pressure and flow	11.10	18.50	37.00
	If SCADA is required:	4.37	6.38	9.74
2	CPM using material balance	2.67	3.61	4.89
	If metering is required	-	-	1.21
3	Negative pressure wave monitoring	2.67	3.61	4.89
	If pressure monitoring is needed	1.02	1.39	1.91
4	RTTM	-	1.16	1.45
5	External systems:			
a.	Acoustic,	-	-	1.23
	If fiber is already in place	1.11	1.85	3.70
b.	Fiber Optic Cable,	-	-	1.40
	If suitable fiber is already in place	27.75	46.25	92.50
	New construction	-	-	1.81
Liquids Pipeline in HCA				
		Three Year	Five Year	Ten Year
1	SCADA monitoring of pressure and flow	33.00	55.00	110.00
	If SCADA is required:	12.99	18.97	28.95
2	CPM using material balance	7.94	10.72	14.55
	If metering is required	2.00	2.68	3.60
3	Negative pressure wave monitoring	7.94	10.72	14.55
	If pressure monitoring is needed	3.02	4.13	5.68
4	RTTM	2.75	3.46	4.30
5	External systems:			
a.	Acoustic,	1.10	1.83	3.67
	If fiber is already in place	3.30	5.50	11.00
b.	Fiber Optic Cable,	1.25	2.08	4.17
	If suitable fiber is already in place	82.50	137.50	275.00
	New construction	1.62	2.70	5.39

Gas Pipeline				
		Three Year	Five Year	Ten Year
1	SCADA monitoring of pressure and flow	4.32	7.20	14.40
	If SCADA is required:	1.70	2.48	3.79
2	CPM using material balance	1.04	1.40	1.90
	If metering is required	-	-	-
3	Negative pressure wave monitoring	1.04	1.40	1.90
	If pressure monitoring is needed	-	-	-
4	RTTM	-	-	-
5	External systems:			
a.	Acoustic,	-	-	-
	If fiber is already in place	-	-	1.44
b.	Fiber Optic Cable,	-	-	-
	If suitable fiber is already in place	10.80	18.00	36.00
Gas Pipeline in HCA				
		Three Year	Five Year	Ten Year
1	SCADA monitoring of pressure and flow	12.96	21.60	43.20
	If SCADA is required:	5.10	7.45	11.37
2	CPM using material balance	3.12	4.21	5.71
	If metering is required	-	1.05	1.41
3	Negative pressure wave monitoring	3.12	4.21	5.71
	If pressure monitoring is needed	1.19	1.62	2.23
4	RTTM	1.08	1.36	1.69
5	External systems:			
a.	Acoustic,	-	-	1.44
	If fiber is already in place	1.30	2.16	4.32
b.	Fiber Optic Cable,	-	-	1.64
	If suitable fiber is already in place	32.40	54.00	108.00
	New construction	-	1.06	2.12

Table 6.6 - ROI (Multiples) for Technical Scenario 2

Liquids Pipeline				
		Three Year	**Five Year**	**Ten Year**
1	SCADA monitoring of pressure and flow	11.10	18.50	37.00
	If SCADA is required:	4.37	6.38	9.74
2	CPM using material balance	2.67	3.61	4.89
	If metering is required	-	-	1.21
3	Negative pressure wave monitoring	2.67	3.61	4.89
	If pressure monitoring is needed	1.02	1.39	1.91

4	RTTM	-	1.16	1.45
5	External systems:			
a.	Acoustic,	-	1.08	1.89
	If fiber is already in place	-	1.22	2.11
b.	Fiber Optic Cable,	1.55	2.28	3.50
	If suitable fiber is already in place	2.44	3.35	4.65
	New construction	1.69	2.46	3.71
c.	Liquid Sensing Cables	-	-	1.30
	New construction	-	-	1.32
Liquids Pipeline, HCA				
		Three Year	**Five Year**	**Ten Year**
1	SCADA monitoring of pressure and flow	33.00	55.00	110.00
	If SCADA is required:	12.99	18.97	28.95
2	CPM using material balance	7.94	10.72	14.55
	If metering is required	2.00	2.68	3.60
3	Negative pressure wave monitoring	7.94	10.72	14.55
	If pressure monitoring is needed	3.02	4.13	5.68
4	RTTM	2.75	3.46	4.30
5	External systems:			
a.	Acoustic,	2.04	3.21	5.62
	If fiber is already in place	2.33	3.64	6.26
b.	Fiber Optic Cable,	4.61	6.77	10.42
	If suitable fiber is already in place	7.24	9.95	13.82
	New construction	5.03	7.30	11.04
c.	Liquid Sensing Cables	1.31	2.10	3.85
	New construction	1.34	2.15	3.93
Gas Pipeline				
		Three Year	Five Year	Ten Year
1	SCADA monitoring of pressure and flow	4.32	7.20	14.40
	If SCADA is required:	1.70	2.48	3.79
2	CPM using material balance	1.04	1.40	1.90
	If metering is required	-	-	-
3	Negative pressure wave monitoring	1.04	1.40	1.90
	If pressure monitoring is needed	-	-	-
4	RTTM	-	-	-
5	External systems:			
a.	Acoustic,	-	-	-
	If fiber is already in place	-	-	-
b.	Fiber Optic Cable,	-	-	1.36
	If suitable fiber is already in place	-	1.30	1.81
	New construction	-	-	1.45

Gas Pipeline, HCA				
		Three Year	Five Year	Ten Year
1	SCADA monitoring of pressure and flow	12.96	21.60	43.20
	If SCADA is required:	5.10	7.45	11.37
2	CPM using material balance	3.12	4.21	5.71
	If metering is required	-	1.05	1.41
3	Negative pressure wave monitoring	3.12	4.21	5.71
	If pressure monitoring is needed	1.19	1.62	2.23
4	RTTM	1.08	1.36	1.69
5	External systems:			
a.	Acoustic,	-	1.26	2.21
	If fiber is already in place	-	1.43	2.46
b.	Fiber Optic Cable,	1.81	2.66	4.09
	If suitable fiber is already in place	2.84	3.91	5.43
	New construction	1.98	2.87	4.34
c.	Liquid Sensing Cables	-	-	1.51
	New construction	-	-	1.55

6.3.7 Observations

In an engineering application, any investment that yields factors of 1.5 – 2 ROI is usually regarded as valuable. At the ten-year horizon, nearly all the technologies pass this threshold for a liquids pipeline. At this time horizon, average gas pipelines may only consider basic CPM, but even pressure wave monitoring is cost-effective. Gas pipelines in HCAs can economically consider most technologies.

Certain technologies stand out, as being so potentially cost-effective that almost no operator should overlook them:

- Even if an entire SCADA metering system also needs to be procured, pressure/flow monitoring has a high ROI.
- As long as metering is present, CPM is also economical. However, a complete and accurate metering system just for the purpose of material balancing is rarely economic.
- Similarly, if pressure monitoring is already present, pressure wave analysis is cost-effective. However, a complete and accurate instrumentation system just for the purpose of pressure wave analysis is rarely economical.
- If the pipeline already has fiber optic cable in the right-of-way, or if the construction is new, fiber optic technology has a high ROI. Any separate trenching work to lay cable typically reduces the economics, however.

- Because of their relatively low OPEX requirements, External systems are worth consideration when a ten-year time horizon is used. This would especially be the case with a new construction.
- Just because liquid sensing cables and point sensors are expensive when deployed on 40-mile stretches of pipeline does not mean that they should not be seriously considered for shorter sections of truly critical areas: river, road and town crossings for example. Our simplistic calculations overlook their potential sensitivity and potential for reliability.

6.4 Operator and Developer Opinions and Current Practice

This section of the Economic Review focuses on the information received during direct conversations with pipeline operators and with leak detection technology suppliers.

The interviews covered 19 total pipelines, made up of: nine liquids pipeline companies – including two smaller crude oil and petroleum products pipelines; five gas transmission pipelines; and five gas distribution pipelines. These were the same ones interviewed about technology issues.

The individuals at these operators were for the majority of the cases engineering and operations staff at the managerial or higher level. Only three discussions were held with executives. Therefore, it should be understood that these are very much “working engineering” opinions and may not reflect companies’ corporate views very well.

A total of twelve technology suppliers were interviewed, covering Computational Pipeline Modeling (CPM, four suppliers); Acoustic and Pressure Wave Analysis (four suppliers); Fiber optic cables (two suppliers); Hydrocarbon sensors (two suppliers); and Thermal imaging (two suppliers). Note that two of these suppliers develop multiple technologies.

The economic part of the interviews covered six purely technical issues:

1. How are leak detection budgets allocated
2. What is the budget cycle
3. What is the cost-benefit approach
4. Risk management processes
5. Impact of regulation

6.4.1 Summary

There is strong evidence that much of the above theoretical exposition of principles is not actively used by the industry today.

Leak Detection Budgets – the opinion of the large majority of interviewees was that overall leak detection budgets are driven by an honest desire to meet regulations and industry standards, but no more. In order to secure a program budget from the board, a case has to be made that it is necessary to meet an external standard or obligation.

Although all the companies did have a corporate risk analysis group, our group of interviewees did not include any personnel from these groups. Our interviewees were mostly of the opinion that leak detection was not considered a significant consequence mitigation measure at the corporate level. Only four interviewees have been asked for inputs like expected speed of detection or maximum spill size for a risk analysis.

Only one liquids operator maintains a five-year leak detection improvement budget that is driven by an internal excellence program.

Budget Cycles – the personnel that we talked with are given working budgets for a period of between one year and five years. Therefore, actual investment in leak detection has to be taken out of additional departmental responsibilities (metering, SCADA, Information Technology) that can only be increased on a long timeframe.

Cost-Benefit Approach – none of the interviewees are asked to justify a total budget in terms of a cost-benefit. However, they are all regularly asked to rank potential technical options in terms of costs and benefits. Despite this, a large number reported that even very cost-effective options are often excluded if they do not follow accepted internal procedures. Following a tried and tested approach is usually valued more highly than cost-benefit.

Risk Management – only one smaller operator used to outsource operations and leak detection, and now no longer does so. However, three gas distribution operators know that their corporation carries liability insurance specifically against “pipeline losses”, and all the other distribution company interviewees expected that they had leak insurance.

Impact of Regulation – all the companies that we interviewed follow regulations without fail, and indeed are grateful since they are the one sure way to secure investment budgets from the board. The attitude of the technology developers was explicit. They consider that regulation alone is largely responsible for the adoption of their products, at any price.

6.4.2 Leak Detection Budgets

All the 19 companies do have a corporate risk analysis group. However, our set of interviewees did not include any personnel from these groups. Most of our contacts were of the opinion that leak detection was not considered as a significant consequence mitigation measure at the corporate level.

Four interviewees out of 19 have been asked for inputs like expected speed of detection or maximum spill size for input to a risk analysis.

Most of our contacts, 16 out of 19 total companies, were of the opinion that corporate leak detection budgets are driven by a commitment to meet regulations and industry standards, but no more. In order to secure a program budget from the board, a case has to be made that it is necessary to meet an external standard or obligation. Therefore, the academic justification for leak detection in terms of consequence mitigation is not widely believed.

One liquids operator maintains a five-year leak detection improvement budget that is driven by an internal excellence program. However, this is a relatively small sum, about 5% of the regular maintenance budget for leak detection systems.

6.4.3 Budget Cycles

The personnel that we talked with are given working budgets for a period of between one year and five years. The distribution of durations of the regular budget cycle taken from our sample is shown in the chart below:

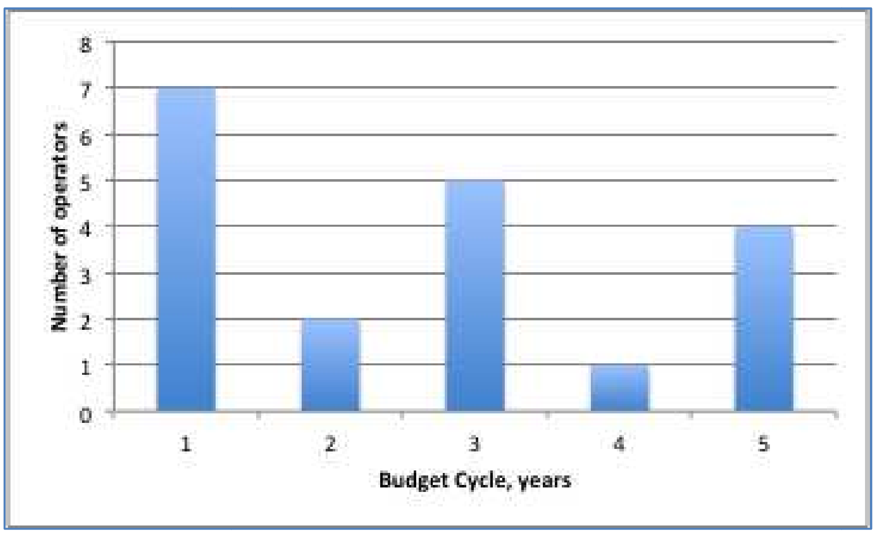


Figure 6.2 Distribution of Budget Cycles

Recall from the Task 5 interviews above that most of these leak detection engineers work in departments related to, but not dedicated to, leak detection. Therefore, actual investment in leak detection has to be taken out of additional departmental responsibilities (metering, SCADA, Information Technology) that can only be increased over a long timeframe.

Emergency appropriations are possible in the middle of a budget cycle, but they are only made from a contingency fund, to provide funding for an unexpected obligation of some kind.

6.4.4 Cost-Benefit Approach

All the technical personnel that we interviewed are regularly asked to rank potential technical options in terms of costs and benefits. A large minority actually complains of being asked to write formal, cost-justified approval requests for small and obviously essential repairs and maintenance. However, we were not able to speak with corporate management, who set the overall loss control budgets and contingencies.

Despite this, a large number reported that even very cost-effective options are often excluded if they do not follow accepted internal procedures. Following a tried and tested approach is usually valued more highly than cost-benefit. Therefore, risk of waste, that is, adopting a technical approach that fails totally, is considered worst of all.

Technology providers do try to demonstrate a reasoned cost-benefit analysis in their marketing. As we point out in the economic theory above, the full-lifecycle cost-benefit of a safety-critical system is, in general, demonstrably very low. They also try to demonstrate comparisons with other industries with similar metrics. In these industries, the same technologies are more expensive and yet have lower perceived cost-benefit. This view was universal among our survey sample.

6.4.5 Risk Management

Outsourcing

Only one smaller operator in our group used to outsource operations and leak detection, and now no longer does so. However, they report that this practice is uncommon. The usual model is that a small operator will ask a larger business partner to adopt operational responsibilities for them, either for a flat fee or in exchange for transportation capacity. The reason that the outsourcing business model was abandoned in this one case was that control over risk was being lost, and that in the case of any incident the owner, not the operator, would be liable in any case.

Insurance

Insurance coverage against leaks appears to be quite common among gas distribution companies. Three of our gas distribution contacts know that their corporation carries liability insurance specifically against “pipeline losses”, and all the other distribution company interviewees expected that they had leak insurance.

The other categories, gas transmission and liquids transportation, do not appear to carry insurance, or at least our contacts were not sure.

6.4.6 Impact of Regulation

All our contacts reported that their companies follow regulations without fail, as a matter of policy.

Technical personnel indeed are grateful since regulations are the one sure way to secure investment budgets from the board. The technology developers are all convinced. They consider that regulation alone is largely responsible for the adoption of their products, at any price. If compliance is at issue, the cost-benefit arguments go away.

7.0 TASK 7: ANALYSIS OF LEAK DETECTION STANDARDS

7.1 Leak Detection in Pipelines

Leak detection in pipelines is important for a number of reasons. Some of them are:

1. Public Safety
2. Environmental Impact
3. Operational Efficiency
4. Compliance with Federal and State Regulations
5. Business/ Commercial

Pipeline Companies/ Operators employ several leak detection methodologies. Some of these are listed below:

1. Physical Inspection (including aerial aircraft/ helicopter, foot patrol, motor vehicle/ ATV)
2. External hardware sensors
3. Computational pipeline monitoring (CPM)
4. Supervisory control and data acquisition (SCADA)

7.2 Liquids Pipelines

There are many standards and recommended practice documents for Hazardous Liquids Pipelines. Four of these standards are analyzed and summarized in this report. They are:

1. API 1130
2. API 1149
3. CSA Z662 Annex E (Canada)
4. TRFL (Germany)

7.2.1 Leak Detection and Current Standards for Liquid Pipelines:

Currently various standards exist that address the issue of leak detection in liquids pipelines. Some of these standards include:

- API 1130 (*Computational Pipeline Monitoring for Liquids*)
- API 1149 (*Pipeline Variable Uncertainties and Their Effects on Leak Detectability*)
- API 1161 (*Guidance Document for the Qualification of Liquid Pipeline Personnel*)
- API 1164 (*Pipeline SCADA Security*)

- API 1165 (*Recommended Practice for Pipeline SCADA Displays*)
- CSA Z662 Annex E (*Recommended practice for liquid hydrocarbon pipeline system leak detection*) (Canada)
- TRFL (*Technical Rule for Pipeline Systems*) (Germany)
- API 1155 *Evaluation Methodology for Software Based Leak Detection Systems* has been withdrawn by API but some of its important parts have been retained as Annex C in API 1130.

7.2.2 API 1130 (*Computational Pipeline Monitoring (CPM) for Liquids*)

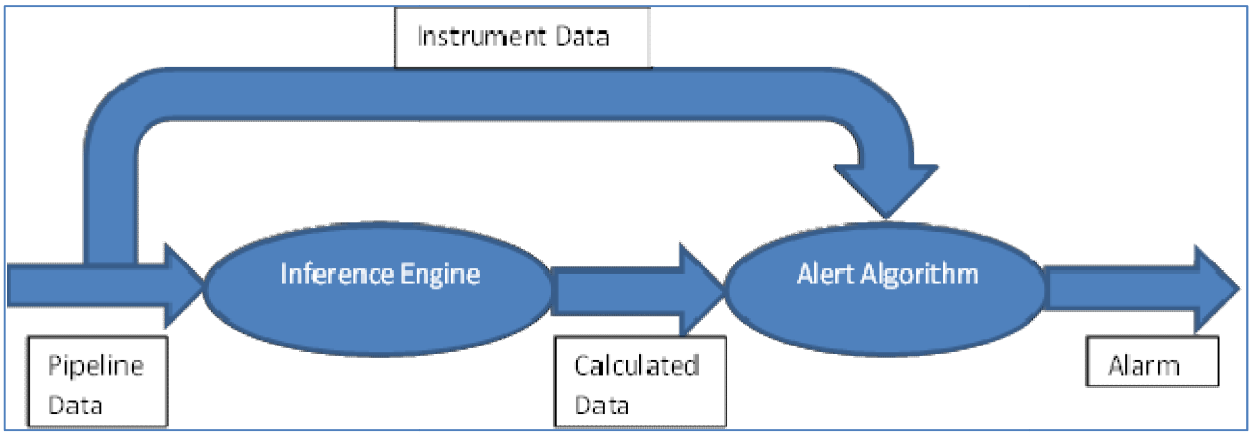


Figure 7.1 Typical CPM System per API 1130

API 1130 defines Computational Pipeline Monitoring (CPM) as "an algorithmic monitoring tool that alerts the Pipeline Controller to respond to a detectable pipeline hydraulic anomaly (perhaps both while the pipeline is operating or shut-in) which may be indicative of a commodity release." API 1130 is a widely referenced industry document on CPM systems for leak detection in liquid pipelines; however, it does not apply to natural gas pipelines.

CPM refers to software based algorithmic monitoring tools utilized by Pipeline Operators to enhance their capabilities to recognize hydraulic anomalies on pipelines. There are numerous methods of leak detection in pipelines; however, as per API definition CPM only refers to the software based algorithmic tools that are utilized for the purposes of leak detection in pipelines.

An ideal CPM system would assist the Pipeline Operator by issuing an alarm and presenting data and related analysis once certain thresholds and limits have been reached in the pipeline system. Title 49 Code of Federal Regulations Part 195 Section 195.444 (this and other relevant code sections listed later in this report) clearly says "Each computational pipeline monitoring (CPM) leak detection system installed on a hazardous liquid pipeline transporting liquid in single phase (without gas in the liquid) must comply with API 1130 in operating, maintaining, testing, record keeping and dispatcher training of the system."

CPM systems and alarms are complex and require a lot of knowledge and training for their interpretation. Pipeline Operators should be continuously trained and re-trained so they can correctly interpret CPM alarms.

It is also important to note that API 1130 was written specifically for single phase liquid pipelines. Some parts of API 1130 may not apply to pipelines with intermittent or permanent slack line flow or on pipelines that are shutdown or are in shut-in conditions. API 1130 supports liquid onshore or offshore trunkline systems but can also be applied to other select piping systems.

API 1130 and Regulations

API 1130 First and Second Editions were published in 1995 and 2002 respectively. API 1130 Recommended Practice First Edition was published in 2007. During the Second Edition, Federal leak detection regulations were established for High Consequence Areas (HCAs).

API 1130 has been referenced and mentioned in several federal regulations. There are references to API 1130 in Department of Transportation (DOT) and Pipeline and Hazardous Materials Safety Administration (PHMSA) regulations through Title 49 Code of Federal Regulations (CFR) Part 195. Section 195.2 includes CPM definitions and Section 195.444 clearly says that each computational pipeline monitoring (CPM) leak detection system must comply with API 1130 in operating, maintaining, testing, record keeping and dispatcher training. All CPM references in 49 CFR Part 195 are listed below.

- 195.2 Definitions, Computation Pipeline Monitoring
- 195.134 Design Requirements, CPM Leak Detection
- 195.444 Operation and Maintenance, CPM Leak Detection
- 195.452(i)(1) Integrity Management, General Requirements
- 195.452(i)(3) Integrity Management, Leak Detection
- 195.452(i)(4) Emergency Flow Restricting Devices

A High Consequence Area (HCA) is currently defined in § 195.450 as a commercially navigable waterway, a high population area, or any other populated area. Some of these HCAs include areas with high population density, sole source drinking water supplies, and ecological resources that are unusually sensitive to environmental damage. PHMSA currently regulates approximately 173,000 miles of hazardous liquid pipelines. Approximately 76,000, or 44%, of these miles are in areas that could affect an HCA. The IM requirements specify how pipeline operators must identify, prioritize, assess, evaluate, repair and validate, through comprehensive analyses, the integrity of hazardous liquid pipelines that, in the event of a leak or failure, could affect HCAs within the United States.

The regulation, 49 CFR 195.452(i)(3), requires an operator to have a means to detect leaks on the sections of its pipeline system that could affect HCAs. An operator must also evaluate and modify its leak detection system to protect HCAs. An operator's evaluation must, at least, consider the following factors: length and size of the pipeline, type of product carried, the pipeline's proximity to the HCA, the swiftness of leak detection, location of nearest response personnel, leak history and risk assessment results. The IM regulations, Appendix C to Part 195, also specify that the location of pipeline segments as it relates to the ability of the operator to detect and respond to a leak is a risk factor to be considered when establishing the frequency of assessment.

Although 49 CFR 195.452 states that liquid pipelines in HCAs must have means of detecting leaks, there are no specific requirements for the type of leak detection that must be implemented.

Operators must also assess the relevance of any leak detection system and make any and all improvements necessary to protect HCAs.

49 CFR regulations are further elaborated by PHMSA in a Frequently Asked Questions (FAQ) page on their website. This FAQ page provides further guidance to operators on how to interpret and implement 49 CFR 195. Section 9 of these FAQs specifically talks about leak detection, EFRD (Emergency Flow Restricting Device) and additional risk controls. Since EFRDs are devices that can limit the amount of product released as a result of a leak or rupture, section 9.2 of the FAQs lists the criteria that operators should use to determine whether such devices are required for HCAs protection. PHMSA leaves it up to the operators to make their decision based on considerations of several factors. Some of the factors per PHMSA website include:

- The swiftness of leak detection and pipeline shutdown capabilities
- The type of commodity carried
- The rate of potential leakage
- The volume that can be released
- Topography or pipeline profile
- The potential for ignition
- Proximity to power sources
- Location of nearest response personnel
- Specific terrain between the pipeline and the HCA
- Benefits expected by reducing the spill size

FAQ 9.2 states "An operator is required to install an emergency flow restricting device if the operator determines one is needed to protect an HCA".

FAQ 9.4 lists several factors for operator leak detection considerations; operators must protect HCAs. PHMSA recommends the evaluation must include the following factors:

- The length and size of the pipeline
- Type of product carried
- The pipeline's proximity to the HCA
- The swiftness of leak detection
- Location of nearest response personnel
- Leak history
- Risk assessment results

Other factors for the operators' consideration listed include:

- System operating characteristics (steady state operation, high transient pressure and flow)
- Current leak detection method for HCAs
- Use of SCADA
- Thresholds for leak detection
- Flow and pressure measurement
- Specific procedures for lines that are idle but still under pressure
- Specific consequences related to sole source water supplies regarding additional leak detection means
- Testing of leak detection means, such as physical removal of product from the pipeline to test the detection
- Any other characteristics that are part of the system leak detection

49 CFR 195.452 (i)(3) simply states that an operator must have means to detect leaks on its pipeline systems but it does not specify how. The factors listed above in FAQ 9.4 must be considered by the operator in its evaluation of the capability of leak detection means.

Since 49 CFR 195.134 and 195.444 require that each CPM system complies with API 1130, section 9.6 of the FAQS discusses this matter further. An operator can detect leaks in many ways and must conduct a risk analysis as per 195.452 (i) (2) in order to identify the need for additional preventive and mitigative measures. Similarly per 195.452 (i) (3) utilizing the results of the risk analysis, leak detection capabilities must be evaluated. An operator must determine if modifications to its leak detection means are needed to improve the operator's ability to respond to a pipeline failure and protect HCAs. An operator may determine, on an individual pipeline segment basis, that a CPM system is needed to meet this need. If a CPM system is employed, its implementation and operation must satisfy the requirements of 195.134/444, which reference certain aspects of API 1130.

FAQ 9.7 lists actions that are both preventative and mitigative for protection of HCAs and stresses the importance of conducting risk analysis for HCA segments again. Some of the recommended actions are:

- Implementing damage prevention best practices
- Enhanced cathodic protection monitoring
- Reduced inspection intervals
- Enhanced training
- Installing EFRDs
- Modifying the systems that monitor pressure and detect leaks
- Conducting drills with local emergency responders
- Other management controls

Some of the risk factors to be considered in risk analysis per PHMSA are:

- Design and construction information
- Maintenance and surveillance activities
- Operating parameters and history
- Right of way information
- Information about the population and the environment near the pipeline
- Terrain surrounding the pipeline segment, including drainage systems such as small streams and other smaller waterways that could act as a conduit to the HCA
- Elevation profile
- Characteristics of the product transported
- Amount of product that could be released
- Possibility of a spillage in a farm field following the drain tile into a waterway
- Ditches alongside a roadway the pipeline crosses
- Physical support of the pipeline segment such as by a cable suspension bridge
- Exposure of the pipeline to operating pressure exceeding established maximum operating pressure.

PHMSA also recommends that the operator not wait until after a baseline assessment has been conducted to perform a risk analysis. This is because a baseline assessment could take several years for some segments. Risk analysis should be re-visited once a baseline assessment has been conducted, incorporating the results of the assessment and identifying the remaining significant risks and their subsequent prevention and mitigation. This risk analysis as well as preventative and mitigative actions for the identified significant risks is recommended to be done within one year of the baseline assessment. PHMSA also recognized that some actions might be quick to implement while others may be complex and require considerable time; hence this is just a recommendation.

FAQ 9.10 provides some guidelines on third party damage to pipelines. Although operators have no direct control over third parties, there are a number of actions operators can take or are required to take to reduce or prevent third party damage. As part of a comprehensive risk analysis required by 195.452(f) and 195.452(i), PHMSA expects pipeline operators to determine the risk associated with third party damage to pipeline segments that affect HCAs. However PHMSA does not prescribe any method and leaves it up to the operator. PHMSA requires the operator to take actions to reduce the risk of third party damage in HCAs. Some of the actions and factors to be considered are already discussed above.

Although PHMSA puts great emphasis on leak detection on HCA segments, non-HCAs must also have means to detect leaks. Appropriate Preventative and Mitigative actions should be taken once significant risks have been identified on all pipeline segments.

API 1130 Recommended Practice First Edition 2007 states on high consequence areas:

“Within regulations, there may be a specific reference to CPM or leak detection. The reference may also be indirect as in the regulatory requirement for the closing of remote valves (or activation of flow restricting devices) where a CPM system may be used as one of the triggers for that activation, particularly in high consequence areas.

CPM systems may be employed when the requirement states:

- A Pipeline Operator must have a means to detect leaks on its pipeline system and to protect high consequence areas.
- The Pipeline Operator must evaluate the capability of its leak detection means and modify it as necessary to provide a sufficient level of protection (i.e., the CPM may be adjusted to account for the operational mode or characteristics of the pipeline segment including shut-in). Ideally, factors such as length and size of the pipeline, type of product carried, the pipeline’s relationship to high consequence areas, the swiftness of leak detection, the location of nearest response personnel, the pipeline’s leak history, and risk assessment results, must be considered.”

The EPA's regulations for underground storage tanks require owners and operators to check for leaks on a routine basis using one of a number of detection methods (40 CFR Part 280, Subpart D).

In order to ensure the effectiveness of these methods, the EPA has set minimum performance standards for equipment used to comply with the regulations. For example, after December 22, 1990, all systems that are used to perform a tightness test on a tank or a pipeline must be capable of detecting a leak as small as 0.10 gallons per hour with a probability of detection of at least 95% and a probability of false alarm of no more than 5%. It is up to tank owners and operators to select a method of leak detection that has been shown to meet the relevant performance standard.

Leak Detection Technology

In API 1130, leak detection technology is broken down into two systems. They are called Externally based leak detection systems and Internally based CPM systems. API 1130 does not consider externally based leak detection systems as CPM systems because they do not operate on algorithmic principles of physical detection of an escaping commodity. These systems and sensors are listed below:

Externally based leak detection systems:

1. Fiber optic hydrocarbon sensing cables
2. Dielectric hydrocarbon sensing cables
3. Acoustic emissions detectors
4. (4) Hydrocarbon (Vapor) sensors

Similarly, API 1130 defines Internally based CPM systems as systems that utilize field sensor data that monitor internal and sometimes external pipeline parameters. CPM systems may look at all possible measured data such as temperature, pressure, viscosity, flow rate, density etc.

Internally based leak detection systems (CPM):

API 1130 also lists the types of internally based CPM systems. Some of those are listed below:

1. Line balance methods (line balance, volume balance, modified volume balance, compensated Mass balance)
2. Real time transient model (RTTM)
3. Pressure/ Flow monitoring
4. Acoustic / Negative pressure wave

5. Statistical analysis

CPM systems often utilize two technologies; conservation of mass or mass balance methods; and signature recognition methods. There is no universal CPM technology or technique that can be applied to all the pipeline systems. Pipeline Operators may apply one or more suitable CPM techniques to cover all pipeline conditions. API 1130 also lists CPM systems features quite extensively for selection considerations. Since all pipeline systems are different, the order of preference for these features will be different for each Pipeline Operator. Some of the most commonly desired CPM systems features include accurate alarming, high sensitivity to leaks, and timely detection of leaks. API 1130 also lists four performance metrics for an ideal performance of a CPM system. These four metrics are reliability, sensitivity, accuracy and robustness of a CPM system.

According to a PRCI/SWRI study and a survey of leak detection system manufacturers/ providers and users/operators, almost all operators utilized CPM systems as their primary leak detection systems. Hence API 1130 due to its references in federal and state codes and its extensive guidance on CPM systems becomes a very important document for pipeline operators to follow.

CPM Infrastructure

API 1130 provides a detailed account of all the infrastructure supports required by a CPM system, since a CPM system is not a stand-alone system. These infrastructure supports are illustrated in Figure 7.2.

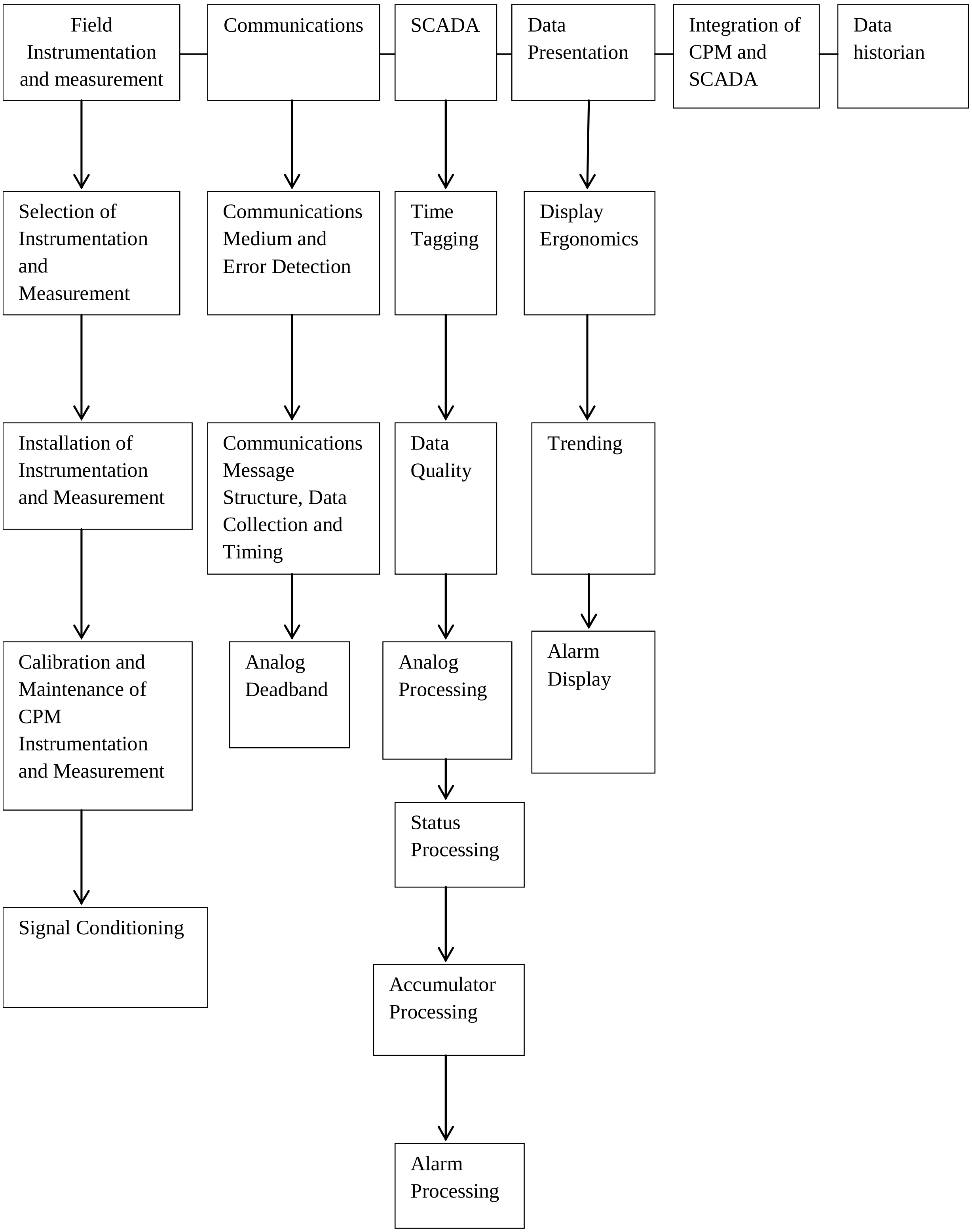


Figure 7.2 Infrastructure Supports for CPM provided by API 1130

API 1130 Section 6 describes in detail the recommended practice for CPM Operation, Maintenance and Testing. CPM systems contain an inference engine and an alert algorithm as shown in Figure 8-1 previously. The inference engine uses hydraulic calculations or it may calculate data to infer the pipeline parameters. The alert algorithm considers inferred data and/or actual data and may issue an alarm if a limit is exceeded. API 1130 goes into great detail about the types of alarms and CPM systems; however, it does not inform the Pipeline Operator on how to do threshold calculations to determine if certain limits have been reached. API 1149 details the pipeline variables and their effects on leak detectability by calculations and the use of tables.

Alarms in API 1130

API 1130 describes an alarm as "In the context of CPM, an alarm is an automated or manual signal or other presentation of data concerning an abnormal or emergency event on the pipeline to the pipeline Controller (via a SCADA system Pipeline Controller interface, a separate interface, or manual tabulation sheets). An alarm could be triggered by many causes including equipment or data failure, an abnormal operating condition or a commodity release". Therefore, all CPM alarms must be thoroughly investigated by the Pipeline Controller/ Operator.

API 1130 recommended practice divides CPM alarms into three categories:

1. Data Failure Alarms
2. Irregular Operating Condition Alarms
3. Possible Commodity Release Alarms

However, many CPM systems issue just one type of alarm. Hence any and all alarms should be thoroughly evaluated by the Pipeline Controller.

Section 6.2 in API 1130 is about CPM System Testing. It states "Testing of CPM systems is performed to establish a baseline of achieved performance for new CPM systems, or when there are changes to the CPM or the pipeline system that warrant re-evaluation of system performance, or for periodic evaluation of actual system performance." Testing of the CPM system is necessary to establish whether the system is performing as expected and if it will alarm in the case of a leak or release. All the subsections in Section 6.2 provide a framework for CPM system Testing. Sections 6.3 and 6.4 in API 1130 provide guidelines on Operating Issues and CPM System Data Retention respectively.

API 1130 and the Role of the Pipeline Operator

API 1130 Section 6.5 emphasizes the need for Pipeline Operator Training and Retraining. Since CPM systems are not perfect by any means, a well-trained and educated Pipeline Operator is essential in correctly interpreting the CPM alarms and making the right decisions.

API 1130 lists the following areas that the Pipeline Controller/ Operator need to be trained in. The more detailed Operator training guidance is provided in API 1161. In order to use a CPM system effectively and properly a Pipeline Operator needs to get properly trained in the following areas (only as related to the CPM system):

1. Hydraulics
2. Alarming/ Performance
3. Data Presentation
4. Instrument Failure
5. Validating CPM Alarms
6. Line-pack Change (Online)
7. Trending
8. CPM System Operation
9. Abnormal Functions
10. Other Leak Detection Techniques

API 1130 has supplemental information in the form of three Annexes; Annex A talks about CPM thresholds whereas Annex B goes in depth describing types of Internal Based CPM systems. Annex C, as mentioned before, has some pertinent text from now withdrawn API 1155 and mostly talks about the Reliability, Sensitivity, Accuracy and Robustness of a leak detection system.

API 1130 Limitations/ Gaps

1. API 1130 is a guidance document/ recommended CPM practice for liquid pipelines only. It does not address natural gas pipelines.
2. API 1130 is not all inclusive. It recommends that the Pipeline Controllers/ Operators have an intimate knowledge of the pipeline and should use other standards for additional information.
3. API 1130 is written for single phase, liquid pipelines. For lines with slack line flow, the Pipeline Operator has to be cautious regarding which parts of the API 1130 to apply.

4. When the line is shutdown (shut-in conditions), API 1130 may or may not apply.
5. There are many CPM methodologies and there is no particular universal methodology that can be applied to all pipelines. Every pipeline system is unique and has its own set of conditions. One or more CPM systems may be applied to a pipeline to cover all the unique design and operating conditions. Detectable limits must be determined and validated on a system by system or segment by segment basis.
6. CPM system is not a stand-alone system and requires considerable interpretation and analysis. Pipeline Operator must be thoroughly trained and re-trained in CPM system related technical areas as described earlier. API 1130 does not go into great detail about that. Pipeline Operators also need to reference API 1161 for more information.
7. API 1130 does not replace other pipeline integrity standards and procedures, only complements them.
8. CPM has a detection threshold below which commodity release detection cannot be expected. Other techniques, such as visual inspection, may be considered in addition to CPM.
9. Other methods that can detect a commodity release are not ruled out by this recommended practice.

7.2.3 API 1149 (Pipeline Variable Uncertainties and their Effects on Leak Detectability)

Leak detectability is a measure of how small and how quickly a leak can be detected. For any pipeline system, it is useful to know the leak detectability as well as the sensitivity of leak detectability with respect to the variables involved. API 1149 is a very detailed and thorough report on different pipeline variables and their effects on leak detectability and can be utilized to estimate theoretical leak detectability of a pipeline with a specified configuration and instrumentation.

API 1149 states "Software-based methods use a supervisory control and data acquisition (SCADA) system to obtain field data. The data is then analyzed by mathematical algorithms to detect the onset of a leak in real-time. These algorithms are based on mass balance, mass balance with line fill correction, and transient flow analyses, which includes simulations, pattern recognition, and pressure change monitoring. Fluid properties, pipeline parameters, instrumentation performance, SCADA characteristics, and states of flow are the variables used in the algorithms. The magnitude of and the uncertainty in these variables determine the leak detectability."

API 1149 is a very detailed report on pipeline variable uncertainties and leak detectability. It provides a step by step procedure and database for calculating leak detectability. It also provides examples and field trial results. Similarly, a procedure to establish the sensitivity of leak detectability and application examples is also given.

Algorithmic leak detection systems can be divided into three components:

1. Mathematical algorithms.
2. Pipeline variables.
3. Operator training and experience.

The mathematical algorithms are based on physics and abide by the conservation principles of mass, momentum and energy. Pipeline variables are the parameters pertaining to SCADA systems, instrumentation, fluid properties, physical attributes of pipelines, pressure, temperature, and rate of flow. Leak detectability is complicated because algorithms are merely approximations whereas pipeline variables are hard to ascertain.

The objectives of API 1149 are to provide a quantitative analysis of the effects of variables on leak detectability using common software based leak detection methods. API also provides a step by step procedure and a data base to evaluate leak detection potential of a given pipeline with specified instrumentation and SCADA capabilities. Upgrading individual variables and hence improved leak detectability can also be studied and determined in this study.

API 1149 also states “The utility of the results from this study is to enable users (i.e., pipeline companies to determine the achievable level of leak detection for a specific pipeline with a specific set of instrumentation and SCADA system. The results also help users to understand the sensitivity of leak detectability with respect to the variables involved.”

API 1149 addresses three types of software based leak detection methods:

1. Mass balance.
2. Mass balance with line fill correction.
3. Transient flow analysis.

API 1149 is applicable only to liquids such as crude oils, gasoline, jet fuel and fuel oil. The chapters’ description below is more or less taken and referenced from API 1149 standard itself.

API 1149 Chapter 2 is about the physical basis for leak detection. It describes principle of mass conservation and Newton’s second law of motion and their application to liquid flow in pipelines.

Chapter 3 describes variables and uncertainty levels. It studies the relationships between density, temperature and pressure for liquids. It also discusses different pipeline variables, process measurements and SCADA systems. It also describes and lists ranges of variables, level of uncertainties and overall uncertainty estimation.

Chapter 4 is about line fill and its uncertainty. It shows methods of computing line fill and the sensitivity of line fill with respect to the independent variables.

Chapter 5 is about leak detectability for steady state flow based on the principle of mass conservation. It also establishes a procedure and data bases for leak detection by volumetric mass balance. For any given pipe size and length, the size of the minimum detectable leak, expressed as a fraction of a reference flow rate, is viewed as a function of response time. It also develops the data bases for the rates of change of line fill with temperature and pressure. A step by step procedure for leak detectability is also established in this chapter.

Chapter 6 is about field trials pertaining to steady state flow. In this chapter non-repeatability in measurements due to instrumentation and fluctuations in pressure and flow are discussed.

Chapter 7 pertains to ranking of variables and their sensitivities. It generalizes the expression for leak detectability using the ratio of the response time over a residence time. This generalization allows the size and length of pipelines to enter the leak detectability formulation.

Chapter 8 is about transient modeling and system characterization.

Chapter 9 deals with line fill correction for transients and addresses the uncertainty in line fill change induced by transient flow.

Chapter 10 deals with leak detection by mass conservation and law of motion. It also establishes a method of leak detection by transient flow simulations.

Chapter 11 is about field trials and transient flow. It presents field trial results for the leak detection method by transient flow simulations.

API 1149 Applicability

API 1149 deals with uncertainties of various elements in the pipeline and how they affect the leak detectability. It uses a simple mass balance technique to calculate a theoretical leak detection limit by taking into consideration instrument inaccuracies and physical characteristics of a pipeline.

The main process variables of leak detection are flow rate, pressure, temperature and reference mass density. Usually the flow rate, pressure and temperature in a pipe segment are sampled periodically by a SCADA system. Similarly, pipeline system parameters are diameter, length, pipe wall thickness, pipeline elevation profile, Young's modulus of elasticity and the thermal expansion co-efficient of the pipe material.

Some Pipeline Operators utilize API 1149 calculations to determine the leak detectability and establish thresholds. API 1149 allows Pipeline Operators to establish and determine theoretical detectable limits. The rather detailed and sometimes cumbersome API 1149 formulas and calculations can be programmed into a spreadsheet, all the inputs are entered and results can be obtained by simply clicking a button. Some typical inputs from above are:

- Variable uncertainties such as Flow, Pressure and Temperature etc
- Pipeline data such as Temperature and Line fill
- Pipeline station data such as Discharge Pressure etc

Similarly, the results obtained will typically be:

- Leak detectability and size (min)
- Volume uncertainty values in dVs, dVtnlfc, dVtlfc

Where dVs is steady state volume uncertainty, dVtnlfc is volume uncertainty with no line fill correction and dVtlfc is volume uncertainty with line fill correction.

API 1149 Chapter 5 describes all these equations and calculations in detail. Although API 1149 provides a step by step procedure and tables to calculate these values, some of the calculations can be rather tedious to do. Entering these formulas and table values into a spreadsheet can be a rather valuable tool for the Pipeline Operator.

Leak detection sensitivity>=Steady state uncertainty + Transient uncertainty

Where Steady state uncertainty= Uncertainties in flow, temperature and pressure

Transient uncertainty= Uncertainty caused by transient conditions in a pipeline

API 1149 Benefits

API 1149 has been used quite extensively by pipeline operators and its pros and cons have been established. Some of the benefits of the standard as identified by the operators are listed below:

- Is able to perform programmatically, i.e., its equations and calculation can be programmed into a spreadsheet

- It is system independent
- Is capable of predicting future detectability for instrumentation improvements and additions
- It aids in the understanding of the effects of instrument uncertainties to leak detection
- It is a relatively quick method to determine a very rough estimate of mass balance leak detection performance that can be achieved based on specific pipeline parameters and instrumentation
- Results obtained by its application can be very useful in gaining confidence in vendor estimates of achievable performance.

API 1149 Limitations/ Gaps

API 1149 shortcomings as identified by pipeline operators are given below:

- It is a highly theoretical standard
- It is only valid for steady state conditions
- It does not reflect state estimation
- It is valid only for mass balance systems (Only considers leak detection via mass balance technique)
- More applicable to steady state than to transient operating conditions
- It only considers very basic transient estimation
- Its results are based on theoretical estimation of leak detection based on accumulation of measurement uncertainties
- API 1149 only covers the following fluids: oil, refined products. It does not cover natural gas and HVLs.
- Its results can vary based on co-efficients used to determine uncertainties; therefore it should only be used as a basis for further, specific leak detection system testing.

7.2.4 CSA Z662-2011 Annex E

Canadian Standards Association CSA Z662 Annex E Recommended Practice for liquid hydrocarbon pipeline system leak detection is an informative document which focuses entirely on material balance methods for leak detectability. It states “ it is not the intent of this Annex to exclude other leak detection methods that are equally effective. Regardless of the method of leak detection used, operating companies shall comply as thoroughly as practical with the record retention, maintenance, auditing, testing and training requirements of this Annex”.

This standard applies to all the Pipeline Operators not only in Canada but a lot of the trans-border pipelines between the U.S. and Canada need to comply as well.

This standard emphasizes the need to establish a procedure for making material balance for the entire product transported. While designing a material balance technique, operators should consider all the physical and operational factors that can influence the material balance system and establish tolerances based upon normal operating conditions. Any deviation in excess of acceptable tolerances should result in a shutdown unless the well trained and experienced operator can explain and justify such deviations. "It is the responsibility of the operator to establish tolerances that do not result in too many false leak indications, while providing reasonable assurance that a leak will be detected".

The rule also states "All pipeline segment receipts and deliveries should be measured. Under normal operating conditions, the uncertainty in the receipt and delivery values used in the material balance calculation, including uncertainties attributable to processing, transmission, and operational practices, shall not exceed 5% per five minutes, 2% per week, or 1% per month of the sum of the actual receipts or deliveries. To meet these requirements, the uncertainty in the individual receipt and delivery measurements under installed operating conditions shall not exceed 2% of the actual measurements, except where individual measurements are obtained by tank gauging performed according to custody transfer practices. Notwithstanding such requirements, a less stringent individual measurement may be used where it is technically demonstrated that overall leak detection effectiveness can be equal to or better than that achieved when such requirements are met. Pipeline equipment shall be installed to ensure that only liquid is normally present in the pipeline segment, unless the material balance procedure compensates for slack-line flow".

This standard recommends all daily, weekly and monthly material balance results be kept for 6 months and reviewed appropriately for evidence of small shortages below established tolerances.

Maintenance, Auditing and Testing per CSA Z662 Annex E

CSA Z662 Annex E emphasizes the need for establishing procedures and properly maintaining all instrumentation and systems that affect the leak detection system.

Internal audits on the performance of leak detection system should be carried out so that any deviation from the optimal performance can be detected and remedial action taken. Audit records should be kept for important incidents such as detectable leaks that were not detected by the system or were ignored and not acted upon by operator responsible for material balance. Also, the occasions where the leak detection equipment or system downtime exceeded one hour should also be noted.

"The leak detection system shall be tested annually to demonstrate its continued effectiveness." This should be done by removing liquid from the pipeline. The test records should include:

- Date, time and duration.
- Method, location, and description of the leak.
- Operating conditions at time of test.
- Details of any alarms triggered by the test.
- Analysis of the performance of leak detection system and operating personnel during the test.

Just like API 1130 and API 1149, CSA Z662 Annex E Section E.5 lays great emphasis on the need and importance of employee training and knowledge, without which any such systems and practices would be futile.

7.2.5 TRFL (*Technical Rule for Pipeline Systems*) (Germany)

It is worth noting that in Germany, the Technical Rule for Pipeline Systems (TRFL) covers:

- Pipelines transporting flammable liquids.
- Pipelines transporting liquids that may contaminate water, and
- Most pipelines transporting gas.

It requires these pipelines to implement an LDS, and this system must at a minimum contain these subsystems:

- Two independent LDS for continually operating leak detection during steady state operation. One of these systems or an additional one must also be able to detect leaks during transient operation, e.g. during start-up of the pipeline. These two LDS must be based upon different physical principles.
- One LDS for leak detection during shut-in periods.
- One LDS for small, creeping leaks.
- One LDS for fast leak localization.

Most other international regulation is far less specific in demanding these engineering principles. It is very rare in the U.S. for an operator to implement more than one monolithic leak detection system. Since German standards do not apply to US or Canadian Operators, it is unlikely that any North American Operators are utilizing them.

7.3 Natural Gas Pipelines

7.3.1 Leak Detection in Gas Pipelines

Currently there are not many standards for leak detection in gas pipelines. However, many principles and factors of the liquid leak detection systems standards can be applied to gas systems as well. After the San Bruno incident in 2010, leak detection regulation/ standards for gas pipelines might be forthcoming. The gas pipeline industry currently has its own safety procedures and processes and conferences are held regularly where operators express their desire to have a zero incident policy emulating the policies of other such industries i.e. the airline industry. The importance of having a safety culture in the member companies is often emphasized. Company safety culture has to be led from the top by corporate executives who should be the ones prioritizing and promoting safety at all meetings and companywide communications. The need for a senior safety manager who is accountable and answerable to all the safety issues of the organization is also important. PHMSA desires good risk assessment programs within operators that are truly investigative and results oriented. However, in light of San Bruno, more prescriptive regulations might be coming forth by PHMSA.

The Interstate Natural Gas Association of America (INGAA) responded to the DOT/PHMSA notice of comment "Pipeline Safety: Public comment on leak and valve studies mandated by the pipeline safety, regulatory certainty, and job creation act of 2011, Docket No PHMSA-2012-0021", on April 30, 2012.

Section 8 of this act directs that the Secretary of Transportation conduct an analysis of "the technical limitations of current leak detection systems, including the ability of the systems to detect ruptures and small leaks that are ongoing or intermittent, and what can be done to foster development of better technologies", and also " the practicability of establishing technically, operationally and economically feasible standards for the capability of such systems to detect leaks, and the safety benefits and adverse consequences of requiring operators to use leak detection systems". In its response INGAA reiterated its goals of zero incidents and highlighted several efforts its member companies have made to prevent leaks and ruptures. It also stressed the need to perform risk analysis to determine and prioritize leaks, especially the small ones. Some INGAA operators classified small leaks as hazardous while others did not. INGAA suggested subjecting all small leaks to a risk-based analysis. They also argued that the current data does not support that leaks are precursors to rupture and that leak and rupture prevention rather than detection are more desirable. They also cited conflicting viewpoints among their own members that leak detection models were useful in preventing leaks and ruptures in gas pipelines. "INGAA believes that these leak detection models do not reduce risk or reliably detect leaks on natural gas transmission systems due to the compressible nature of natural gas, the complexities of pipeline systems and transient gas flow, and the inherit, industry-available tolerances within measurements and other transducers that provide input into such models. Experience has shown that real time models do not have the necessary capabilities to overcome the large challenges of detecting gas leaks given available technologies and therefore do not reduce risk for natural gas transmission pipelines".

Similarly one INGAA operator argued for the benefits for using external sensors whereas another argued against it. INGAA mostly sided with the later view point.

Therefore, given the complex nature of natural gas transmission pipelines and the extreme difficulty in modeling and monitoring them, INGAA argued, leak detection is not likely to reduce the occurrence of ruptures. INGAA also argued against NTSB's recommendation to PHMSA that they require all operators of natural gas transmission and distribution pipelines to equip their SCADA systems with tools to assist in recognizing and detecting the location of leaks. At present the suggested SCADA tools lack the reliability and credibility needed for a leak detection system in gas pipelines, INGAA said. They also put forward the idea that applying a risk-based approach to leak detection management that involves the development of systems and technology and not immediate deployment is a better way to go as far as leak detection in natural gas pipelines is concerned.

7.4 Gaps in Liquids Standards

Unlike natural gas pipelines, there are established standards for liquids pipelines. API 1130, API 1149 and CSA Z662 are well established standards commonly used by pipeline operators. These standards serve as guidance and recommended practice documents throughout the industry. API 1130 is incorporated by reference in 49 CFR 195 as a guidance and compliance document. However API 1130 addresses liquids pipelines only and does not address natural gas pipelines specifically. It also recommends using other related standards and hence is not the only recommended document. There could be complications in using API 1130 if the lines have slack line flow since the standard works best for single phase liquid pipelines. Similarly there might be complications in using it under shut-in conditions.

Since July 6, 1999, under 49 CFR Part 195, DOT requires all controllers of hazardous liquids pipelines engaged in CPM pipeline leak detection systems to use, by reference and with other information, American Petroleum Institute (API) document API 1130: Computational Pipeline Monitoring.

Noteworthy sections of this rule include § 195.2 which defines CPM; §195.3 which incorporates API 1130 into Part 195; Subpart C Design Requirements (§ 195.134) which outlines the requirement for a CPM system; and Subpart F Operation and Maintenance (§ 195.444) which outlines compliance with API 1130.

This, and other more recent, regulation also requires many categories of hazardous liquids pipelines to, at a minimum, perform some form of continual leak detection based upon a volume accounting principle. This is one of the forms of CPM defined by API 1130. This has made at least an elementary CPM based leak detection system very common in the liquids pipeline industry.

Task 4 of this project addressed specifically the technology gaps in existing leak detection systems. Nine liquids pipeline operators, five gas transmission and five gas distribution pipeline operators were interviewed. Because of 49 CFR 195 all but one operator used some form of CPM system. The one remaining smaller operator was also in the process of implementing a CPM system. By regulation all operators who use CPM systems must comply with API 1130. Hence API 1130 principles are widely applied by the liquid operators.

API 1130 based CPM systems consist of the following:

1. Line balance methods (Line, Volume, Mass balance etc)
2. Real time transient model (RTTM)
3. Pressure/ Flow monitoring
4. Acoustic/ Negative pressure wave
5. Statistical analysis

The operators polled utilized CPM as follows:

1. Volume balance 8 (89%)
2. Pressure/ Flow monitoring 9 (100%)
3. Mass balance with line pack correction 4 (44%)
4. Real time transient modeling (RTTM) 6 (67%)
5. Statistical pattern recognition 2 (22%)
6. Negative pressure wave monitoring 2 (22%)

This shows that some operators use more than one CPM technique. There are many CPM methodologies and there is no particular universal methodology that can be applied to all pipelines. API 1130 leaves it up to the operator to utilize the methodology that best suits them since each pipeline system is unique and has its own set of conditions. All these pipelines used

SCADA for operations and Pressure/ Flow monitoring was universally claimed as the method for leak detection. We do not know how carefully alarms were set and API 1130 is vague on this subject as well, therefore, we expect these to provide at best large rupture detection and all interviewed operators conceded this.

Another criticism of CPM system is that it is not a stand-alone system and requires considerable interpretation and analysis. Pipeline operators must be thoroughly trained and re-trained in CPM systems and their related technical areas. Operators also need to reference API 1161 for this purpose because API 1130 does not go into great details about that. CPM systems as described in API 1130 have a detection threshold below which commodity release detection cannot be expected. Therefore the operators would still have to rely on other methods such as aerial and visual inspections etc.

There were also issues with standardization and certification in the operators' survey. Although none of the operators was especially in favor of mandatory standards that they would be expected to follow, they were all in favor of systems that were standardized, and certified to work to a certain minimum level of performance.

A good comparison is with industrial instrumentation, where a limited set of clearly defined instruments is rated for performance with a consistent set of categories. For example, any engineer can quote an ISA-37.16.01 calibration of a pressure sensor, and any other engineer knows exactly what that means. Not so with leak detection systems, which are essentially all designed, calibrated and perform individually.

This is a technology limitation, since even if the effort were to be made to categorize every possible performance measure and uncertainty factor in leak detection, it would still be the case that exactly the same technology, applied to two different pipelines, will yield a different result. The current standards do not tell us how to address these issues.

The impact on operators is that they fear investing in leak detection systems (external or internal), with potentially little benefit to show from them and no way to truly measure success in a standardized way. The result of this technology gap is that leak detection is implemented cautiously and incrementally, on measurement and other systems that are already in place and self-justified.

Both API 1149 and CSA Z662 have limitations as well. API 1149 is meant only for mass balance systems and steady state conditions. It is also a highly theoretical standard that is more applicable to steady state than transient conditions. Its results can vary based upon co-efficients used to determine uncertainties. Pipeline Research Council International (PRCI) is currently funding an update to API 1149, for adoption by the API, in 2014-2015 timeframe.

Similarly, although CSA Z662 Annex E tells the operator that the testing of the leak detection system be done annually to demonstrate its continued effectiveness, it is directed only at systems that use material balance techniques.

7.5 Gaps in Natural Gas Best Practices/ Standards

As mentioned before, there are several industry standards and recommended practice documents for leak detection in liquid pipelines. There are no corresponding recommended best practices for gas pipelines from the American Gas Association or Gas Technology Institute. Furthermore, there are no definite industry standards for leak detection as there are for instrumentation, safety equipment, metering etc.

Neither the API nor the AGA have systematically researched or developed best practices for external sensor based leak detection. Therefore, natural gas pipelines are not required to install any form of leak detection system, nor indeed any form of CPM on their systems. Correspondingly, far fewer gas pipelines are equipped with leak detection systems.

It is important to remember that, although the API 1130 is devoted to liquid pipelines, practically all these techniques apply equally well to gas pipelines also. Because of the much greater compressibility of gas, however, their practical implementation is usually more complex and delicate.

All five natural gas transmission pipeline operators interviewed in task 4 used SCADA and therefore Pressure/ Flow monitoring was universally used as a form of leak detection. Given the highly transient nature of gas pipelines we expect this to provide at best large rupture detection and all interviewed operators conceded this.

The most reliable measurement on the gas transmission pipelines was based on pressure. These pressure measurements are typically at major valve stations and compression facilities. Good quality flow measurement is only available, for commercial reasons, at injection and delivery points, which are quite far apart on transmission lines. The focus of these measurements is to calculate lost and unaccounted for natural gas, which is an application that is far too coarse to provide leak detection.

All five gas distribution pipelines operators interviewed in task 4 use SCADA on their intermediate pressure systems and therefore Pressure/ Flow monitoring was universally claimed as a form of leak detection. In contrast to high pressure transmission, most reliable measurement on the intermediate pressure pipelines was of flow measurement, for commercial reasons, at supply and delivery points. The leak detection is therefore actually flow monitoring.

Given that flow rate is maintained by the supplier in the intermediate pressure operations we expect this to provide at best large rupture detection and all interviewed operators conceded this.

7.6 References

API 1130 (Computational Pipeline Monitoring for Liquids). API Recommended Practice 1130. First Edition, September 2007.

API 1149 (Pipeline Variable Uncertainties and Their Effects on Leak Detectability). A report prepared for the American Petroleum Institute. API Publication 1149. November 1993.

CSA Z662-2011 Annex E.

Docket No. PHMSA-2012-0021. INGAA comments (Leak Detection). April 30, 2012.

Pipeline Research Council International (PRCI)/Southwest Research Institute (SWRI) (PRCI/SWRI). Detection of small leaks in liquid pipelines: Gap study analysis of available methods. February 2007.

Pipeline Research Council International (PRCI)/Battelle: Human Factors Analysis of Leak Detection and Response Scoping Study. February 2007.

U.S. Department of Transportation (DOT), Pipeline and Hazardous Materials Safety Administration (PHMSA). Hazardous liquid integrity management: FAQs. http://primis.phmsa.dot.gov/iim/faqs.htm

U.S. Department of Transportation (DOT), Pipeline and Hazardous Materials Safety Administration (PHMSA). Title 49 CFR Part 195. Available online via electronic code of federal regulations website at http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&tpl=%2Findex.tpl.

U.S. Environmental Protection Agency. Standard Test Procedures for evaluating leak detection. Methods: Pipeline leak detection systems. EPA/530/UST-90/010 March 1990.