PHMSA

Final Report No. 17-119

Improving Leak Detection System Design, Redundancy and Accuracy Natural Gas Pipelines Report

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July 18, 2017

Kiefner

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on

IMPROVING LEAK DETECTION SYSTEM DESIGN, REDUNDANCY AND ACCURACY FOR NATURAL GAS PIPELINES

PHMSA PROJECT DTPH-5614H00007

PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

(PHMSA)

July 18, 2017

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Executive Summary

This is the Final Report for the PHMSA project, *Improving Leak Detection System Design, Redundancy and Accuracy*. The scope of this report is for Natural Gas (and other gas) Pipelines. A separate document has been prepared for Hazardous Liquid Pipelines. This report is divided into two parts: Part I contains the Summary Report which is meant to provide the reader with an overview of the process; Part II contains a more detailed version. Both have been prepared as standalone documents. There is also a separate document containing Appendices which provides additional depth and guidance.

The mission of this project was the development of a set of recommendations, expert guidance, and basic tools that will:

- Be accessible to all operators (including the smaller ones);
- Reduce the extended and laborious front-end engineering for implementing a Leak Detection Systems (LDS); and
- Standardize the approach to designing an appropriate Leak Detection System (LDS) for pipelines.

The emphasis is on improving the accessibility of and on effort reduction in LDS technology. The results are primarily intended as source documents and expert guidance for use in operations. They are also potentially a reference for developers of pipeline procedures and best practices.

It was not intended that this project alone produce recommended practices or standards. Similarly, no software development or development of mathematical algorithms was intended.

The overall list of five issues that are addressed (also called "Tasks") covers:

1. An approach that improves the ability of the industry to design and engineer fit-for-purpose LDS for a wide range of pipeline systems more reliably and more rapidly;
2. Improving the reliability and accuracy of LDS by developing a standard methodology for technology selection and engineering;
3. Systematic predictions of performance;
4. Specification and quantification of the impact of installation, calibration and testing of LDS on their performance; and
5. Retrofit issues.

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Acronyms

Ac	Accuracy
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASV	Automatic shutoff valve
BAT	Best available technology
BP	Business Process
CBA	Cost-benefit analysis
CFR	Code of Federal Regulations
CPM	Computational Pipeline Monitoring
CRM	Control Room Management
DOT	Department of Transportation (U.S)
EFRD	Emergency Flow Restriction Device
FEED	Front-end Engineering Design
FEL	Front-end Loading
FMEA	Failure Modes and Effects Analysis
HC	Hydrocarbon
HCA	High Consequence Area
HVL	Highly volatile liquid
IEC	International Electro-technical Commission
ILI	Inline inspection
IM	Integrity Management
IMP	Integrity Management Program
IPO	Input-Process-Output
ISO	International Standard Organization
LD	Leak detection
LDCE	Leak Detection Capability Evaluation
LDS	Leak Detection System
LVL	Low volatile liquid
MAOP	Maximum allowable operating pressure
NETL	National Energy Technology Laboratory (U.S. Department of Energy)
PC	Project Charter
PM	Project Manager
PPP	Pre-project planning
RCA	Root Cause Analysis
ROI	Return on investment
ROW	Right-of-way

Rp	Reliability
Ro	Robustness
RP	Recommended Practice (API)
SCADA	Supervisory Control and Data Acquisition
Se	Sensitivity
TOR	Terms of Reference
TQM	Total Quality Management

Part I – Summary

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1 About the Project

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3. Systematic predictions of performance;
4. Specification and quantification of the impact of installation, calibration and testing of LDS on their performance; and
5. Retrofit issues.

1.1 Overall Flowchart

A leak detection (LD) engineer generally follows the process shown in Figure I-1 in the design, implementation and operation of LDS. It is important to understand that the process is continual and not a single, terminated effort.

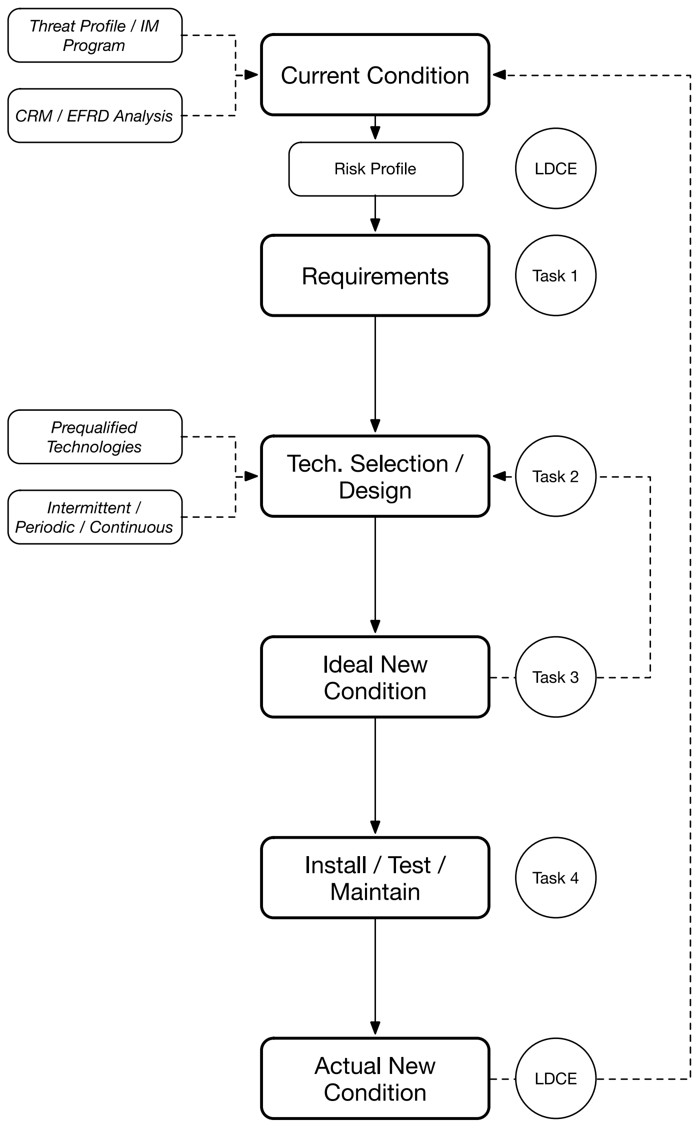

Figure I-1 - Overall Engineering Process Flowchart

The main steps in the lifecycle and evolution of the LDS are listed in the boxes in the middle of the chart. They are named using terms common in engineering practice.

The "Ideal New Condition" refers to the proposed, designed and evaluated on paper – new LDS.

The Risk Profile of the pipeline is a "living document" which changes during the lifecycle of the LDS and the pipeline. It corresponds closely to the word "Condition" in the flowchart. The desired new Risk Profile is the essential component in defining the Requirements for an LDS.

To the right of each of the steps, in a circle, is the primary Project Task which relates to that step. The LDCE is the Leak Detection Capability Evaluation. This is a risk-based assessment of the performance of the LD, given its requirements and constraints. The LDCE is covered in Task 1, but is highlighted in the flowchart where it is most important. Task 5 (Retrofit) is common to all the steps – there will be retrofit issues related to each step.

Items to the left (with titles in italics) are generally *inputs* to the LD engineer, perhaps from another engineering group, or an item of policy defined as a business / corporate objective. The LD engineer should ideally have input to these items, but they are often not a *primary* responsibility – although it is always recommended to address them as a team:

- The threat profile (the likelihood profile), and IM program are often managed by the Asset Integrity Management group. At the same time, LDS contribute to the reduction of risk (by reducing the consequences of the leak) and therefore can usefully refine the IM program.
- Control Room Management and Emergency Flow Restriction Device (EFRD) placement are also often managed by the operations group. At the same time, LDS contribute to the reduction of risk (by reducing the consequences of the leak) and therefore can be useful in refining the selection of EFRD and applicable CRM procedures.
- Pre-qualified technologies that can be used within the organization are frequently selected on a relatively long timeframe, and include corporate purchasing issues, policies and other business issues. At the same time, LD engineers certainly contribute to this selection process. Any pre-qualified technology must include with an agreed performance evaluation procedure, which allows the LD engineer to perform a system design systematically.
- The decision as to whether to implement 24/7 continuous monitoring, intermittent monitoring, or periodic surveys is also generally a policy. LD engineers certainly contribute to this decision, but the operations and management groups often make a final decision and manage these processes.

Note the major feedback loops:

- The “Actual New Condition” logically becomes the new “Current Condition” after placing a new or modified LDS in service. This emphasizes the continual improvement nature of engineering LDS.
- During Design, several proposed “Ideal, New” LDS might be proposed so their respective expected performance might be iteratively evaluated. In fact, more than one LDS technology may be recommended to be run in parallel.
- Continual maintenance and testing is very important in the improvement of an LDS. During maintenance, actual performance of system components and the system as whole is assessed. If the initial design is flawed because the engineers do not understand the required maintenance requirements for various technologies and sensors, the technology may never perform as expected and may not be the correct selection for the pipeline system.

1.2 General Advice

It is possible to perform each step of the overall process in great detail, and indeed for large, complex and highly critical pipeline systems *it is*. However, for simple systems even basic considerations might be sufficient.

> The important element is to document each step of the process, and to explain in clear engineering language what recommendations were made and decisions taken.[1]

> There is no “correct” or “minimal” performance requirement for an LDS. It is, however, important to justify clearly why a certain performance standard was recommended and it is important to be sure that an installed LDS actually performs and meets this standard.

Similarly, there is no “correct” or “recommended” technology or technique for LD. The simplest of techniques, like visual inspection by patrols, might be appropriate in many cases. Again, the important element is to justify the technique used with reference to stated requirements and in light of business, operational and technical constraints.

> It is strongly recommended to implement a “defense-in-depth” approach, by using multiple distinct LDS techniques in synergy. For example, a complete LD approach might include:

[1] Key points are emphasized using a left bar.

1. Periodic inspection (line surveys, hydrostatic tests, ILI, etc.) for extremely small losses;
2. Intermittent surveys (visual / instrumented visual inspection, for example) for small losses;
3. Continual external monitoring by instrument for critical sections;
4. Computational Pipeline Monitoring for medium sized losses; and/or
5. Pressure and Flow monitoring for large, sudden ruptures.

Any one of these alone is a valid LDS of a certain performance profile. However, any combination of these provides much better coverage of the entire leak size / time to detection / criticality spectrum of potential leaks.

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2 Deliverables

The Summary Report contains the overall framework of LD engineering. The Summary is primarily a description of principles which apply to both liquid and gas pipelines. However, all remaining reports are divided into two distinct branches - liquids and gas. The intention is to avoid any confusion between the two industries as well as to be technically correct for each subject. Both Liquids and Gas have a Base Report. Generally, this should be the only document needed in order to understand the results of the project. Much more detailed Task Reports are also maintained and are available as Appendices.

Closely related is a set of Tools that help the operator understand and manage the overall process. They are Excel spreadsheets and do not involve detailed calculations or software. Note that they are intended as models / templates and cannot cover every pipeline or operational situation – operators are expected and encouraged to modify them according to their own situation and requirements. The overall organization of these deliverables is shown in Figure I-2.

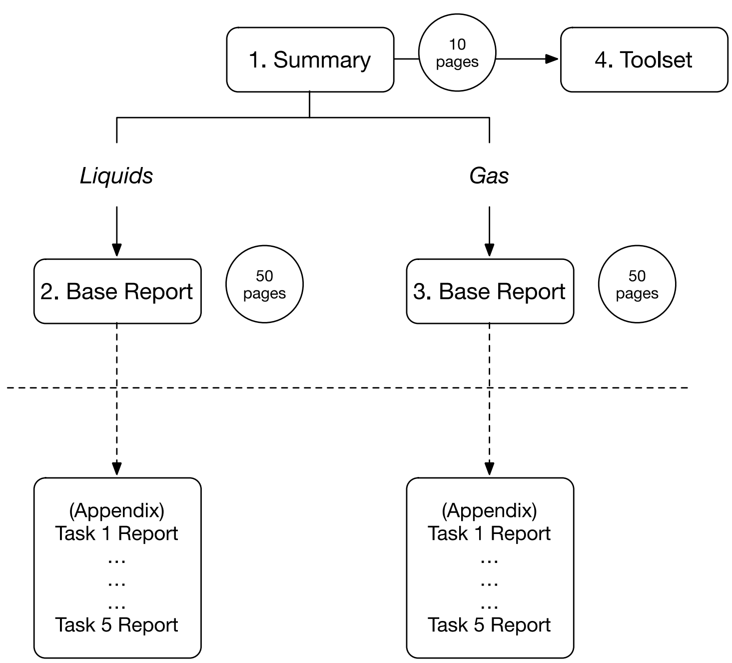

Figure I-2 - Deliverables

2.1 Toolset

The Toolset that is provided includes:

1. LDCE Templates
2. Requirements / Considerations
3. Technology Selection - with performance prediction and alignment with requirements
4. Actual Condition Monitoring (Testing / event tracking)

The LDCE templates are an example of how priorities based on the likelihood of and the consequence and impact of the failure events can be calculated using a risk-based approach. The Technology Selection template applies a scoring approach to evaluating the relative suitability of different LD technologies. The other two templates are intended to be *tracking / organization* tools rather than *calculation* tools.

2.1 Organization

The approach to organizing this Summary Report and the Base Reports is by using a description of:

1. Guidance – what are the applicable recommended practices (RP), standards, and other guidance documents?
2. Protocol – what are the steps / procedures to take?
3. Recommendations
4. Output – what are the expected results?

3 The Process

3.1 Approach

The overall approach to engineering and operating an LDS begins with the development of a set of objectives for leak detection. Therefore, the first task results in a reasonably specific set of performance requirements for the system to be built.

Best practices encourage a *risk-based* approach to developing requirements; in other words, to engineer the system to reduce the risk of a loss of containment to an acceptable level. The results of the risk analysis must then be refined to express precise requirements, as well as constraints, in terms of engineering parameters.

3.1.1 Risk Profile

A Leak Detection System is a key tool to reduce the consequence of a potential loss of containment on the pipeline. The justification, the engineering and the operation of an LDS must all align with the requirements for risk reduction. Regulations, recommended practices and industry guidance encourage a risk-based approach to pipeline operations and the management of LDS as part of a holistic risk-based Integrity Management Plan.

A Risk Profile for the pipeline may be developed using a tool similar to the Template LDCE (Leak Detection Capability Evaluation) that is included in the toolset. The inputs are:

1. A Likelihood (or threat, probability) of failure, which is generally an input from the Integrity Management team at the pipeline company
2. A Consequence (or impact) of a loss of containment, which is a function of the potential loss size, HCA location, environment and other physical and operational parameters. One of the more important factors is the overall performance of the LDS that is used in mitigating the loss.

The product of the likelihood and consequence of a loss is the composite risk.

3.1.1.1 *Guidance*

DOT 49 CFR 192 (natural gas pipelines) provides not only the minimum requirements for a risk-based assessment of leak detection requirements, but also contains valuable advice. This includes references to other advisory documents.

API RP 1130 *Computational Pipeline Monitoring for Liquid Pipelines,* Appendix C, lists the major performance factors in an LDS that can affect the consequences of a failure. API RP 1160 describes how LDS fit in to the overall Integrity Management Program (IMP) of a pipeline and synergies with failure prevention strategies. API RP 1173: *Pipeline Safety Management System Requirements,* Chapter 7: *Risk Management,* is also a valuable source of advice. API 1175 Sections (6), (7) and (Annex A, B) also describes how an overall Leak Detection Program is managed and contributes to an overall IMP.

ASME B31.8S *Gas Transmission and Distribution Piping Systems* (Supplement) contains a useful list of many of the common factors that contribute to the likelihood of failure.

How well LDS alarms are presented to and processed by the controller is a key risk reduction factor. This is discussed at length in, for example, API RP 1168 *Pipeline Control Room Management* and API RP 1167 *Pipeline SCADA Alarm Management*.

3.1.1.2 *Protocol*

The evaluation of the overall risk profile of a pipeline is an integral part of the pipeline's IMP, as described in 49 CFR 192 (natural gas pipelines) and API 1160.

3.1.1.3 *Recommendations*

Root Cause Analysis (RCA) and other previous incident analyses help to provide a clearer picture of the most important / common causes, locations and sizes of a leak. These can be supplemented by industry-wide studies of historical incidents (see for example ASME B31.8). Often the Integrity Management team has a Failure Modes and Effects Analysis (FMEA) available that states threat (likelihood) and consequence very clearly.

It is also useful to diagram threats (likelihoods) and consequences, showing barriers to failure (for example, maintenance, and inspection) as well as mitigations to the consequences (for example, better LDS, EFRD and control room procedures). See for example ISO 31000:2009 - IEC 31010:2009, and the bow-tie diagram in particular.

There needs to be some validation of the API RP 1149 sensitivity curves and other performance metrics with physical tests as part of a system-wide LDS validation. This is part of Task 4 (Installation, Calibration and Testing).

3.1.1.4 *Output*

The risk profile shows the general level of risk that is assumed on each pipeline subsystem or section. This includes a ranking of areas of particular risk. It also demonstrates the mitigating effect of the LDS performance parameters upon consequence. This is useful in assessing the relative benefit of different potential LDS as well as the benefit of the current LDS.

3.1.1.5 *Summary*

Referring to the overall Flowchart in Figure I-1, the process is summarized in Table I-1.

Table I-1 - Risk Profile Summary

Guidance	49 CFR 192
	API 1130 Appendix C
	API 1160, API 1173 (7)
	ASME B31.8 (Supplement)
	API 1175 (6)(7)(Annex A, B)
Protocol	IMP / Risk Program
Recommendations	RCA, Incident look-back, FMEA
	Industry Threats, Barrier Model
Output	Likelihoods, Consequences, Risk, Fitness-for-purpose

3.1.2 Requirements and Constraints

The requirements are expressed formally in terms of (at least): Sensitivity (Se), Robustness (Ro), Reliability (Rp), and Accuracy (Ac). Each of these LD performance parameters is an input to the LDCE and must all align with the stated requirements for risk reduction. Constraints include both operational constraints (e.g. personnel, service profile, commercial and environmental issues) and resource constraints (e.g. budget and time).

3.1.2.1 *Guidance*

API 1130 provides an exhaustive list of both operational constraints and of performance measures for a pipeline LDS. API 1155 is a predecessor to API 1130 and – although technical superseded by it – provides much of the same information more compactly and in an easier to understand format, although it has been withdrawn by API and is not maintained. Much of API 1155 is formally incorporated in Appendix C of API 1130.

API 1149 provides a specific approach and formulas for estimating the performance of the important Computational Pipeline Monitoring (CPM) Class of LDS. Note that the original publication only covered liquids, simple pipelines and a few of the factors involved. The 2015 update covers all fluid types, networked systems, and multiple uncertainty factors. It includes details for estimating non-CPM systems as well.

API 1175 describes how assessing requirements and ensuring that they are met is managed within an overall LDP. In addition:

1. API 1164 covers Pipeline SCADA Security and how it relates to LDS,
2. API 1165 covers Pipeline SCADA Displays and how they relate to LD,
3. API 1167 covers Alarm Management and how to process / act upon LD alarms,
4. API 1168 covers Pipeline Control Room Management and how the controller reacts to an alarm.

3.1.2.2 *Protocol*

Generally, although there are many terms for this, the process of assessing requirements, enforcing / measuring their compliance, and continually improving them, is part of Process Quality Programs or Total Quality Management (TQM).

3.1.2.3 *Recommendations*

Historical Incidents, Business Process (BP) and Enterprise issues drive a large number of not only the requirements statements but will also dictate a large number of constraints on the analyses. Even though these are not purely engineering / technical, they should be documented clearly.

A Cost-Benefit Analysis (CBA) in the company-accepted form is a very useful addition to any requirements analysis. It provides a purely business case for accepting a certain requirements standard.

A “Must Perform as Intended” policy going forward into deployment also helps to ensure that unrealistic / unattainable requirements are not specified at this stage. This helps to clarify many of the constraints in clear terms.

The decision on whether to provide 24 x 7 continuous LD is an important one. It is not always a requirement – low-criticality, low-impact lines may not need it at all. Also, it might be either a requirement (24 x 7 continuous LD is needed on this line because…) or a constraint (corporately, all lines in all systems will have 24 x 7 continuous LD…)

3.1.2.4 *Output*

The primary results of the requirements analysis are:

1. Target Performance Criteria (Se, Ro, Rp, Ac). (Any pre-qualified technology set will include a performance prediction protocol, so that a system can later be designed to meet these criteria.)
2. Engineering Constraints (staff, capital, qualified technologies, regulatory requirements, etc.)
3. Operational Constraints (transient conditions, slack line operations, etc.)

The engineering and operational constraints will also, during design, help eliminate technologies from the pre-qualified set.

3.1.2.5 *Summary*

Referring back to the overall Flowchart (Figure I-1), the LD Requirements of the pipeline is summarized in Table I-2:

Table I-2 - LD Requirements Summary

Guidance	API 1130 (4.2)(5)(6)
	API 1149, API 1155
	API 1175 (6)(7)(8)(10)(12)
	API 1164, API 1165, API 1167, API 1168
Protocol	Process Quality / TQM
Recommendations	Incidents, BP, Enterprise
	Cost-Benefit Analysis (CBA)
	Must Perform as Intended
	FMEA, 24 x 7 continuous LD
Output	Target Performance Criteria (Se, Ro, Rp, Ac)
	(Any qualified technology set will include a performance prediction protocol)
	Engineering Constraints (staff, capital, qualified technologies, regulatory requirements, etc.)
	Operational Constraints (transient conditions, slack line operations, etc.)

3.2 LDS System Design and Engineering

Careful design is important so that the final, as-built LDS meets the requirements and constraints, and therefore delivers the appropriate reduction in the level of risk of a spill.

3.2.1 Guidance

The technology used need not always be complex. The most widely-used techniques with liquids pipelines are visual inspection, pressure / flow monitoring by SCADA, and material balance. With natural gas pipelines the techniques include visual inspection, use of gas detectors or tracer gases, and pressure / flow monitoring by SCADA. The important element is to discuss and document the suitability of the technique to the stated requirements in terms of target performance criteria (Se, Ro, Rp, Ac). The techniques can be divided into two categories: Internal and External.

The most widespread Internal techniques, that utilize measurements of fluid properties internal to the pipe, include:

- Pressure / Flow Monitoring by SCADA. This alarms when abnormal pressures and/or flow rates (or their rate of change) are observed.
- Periodic Leak Surveys, either using pressure or hydrostatic tests. For many pipelines, these are mandatory although at long time intervals.
- Material Balance, which balances flow into and out of a section of pipe, against an estimated rate of change of line pack.

These methods account for the great majority of Internal systems in use. Others that are also used in difficult or particularly sensitive applications are listed in API RP 1130.

The most widespread External techniques that utilize measurements or sensors external to the pipe, include:

- Visual inspection by regular patrol. In fact, this is perhaps the most widespread LDS technique of all. The inspection may be by naked eye, camera (including infrared), or the use of specialized sensors. The patrol may be at the surface or aerial, on foot, surface vehicle, airplane, drone, etc.
- Periodic leak surveys, using in-line tools.
- Hydrocarbon or tracer chemical detection, either as part of a periodic survey or installed permanently at locations of particular sensitivity.

There are many other External sensors available, and we highlight acoustic emissions and thermal emissions as techniques that are becoming more common. They are listed exhaustively in the Appendix Report of Task 2: Methodology for Technology Selection and Engineering.

3.2.2 Protocol

Generally, the technologies that may be implemented on a specific LD project are listed by the corporation, in a *qualified technology list* (or similar). This includes non-technical issues such as pre-qualified vendors, price and cost structures, corporate standard policies, etc. With each of these qualified technologies will come a set of RPs as well as standard procedures for design, performance estimation, and deployment.

Similarly, most operators have a set of engineering best practices, which would be followed during any LDS engineering project.

3.2.3 Recommendations

The selection of a technology is by no means the only way to achieve performance. An important technique that can be used to improve technological shortcomings is to utilize several technologies in parallel, as well as to use several leak indicators in parallel. In fact, almost without realizing it, most pipelines already employ a variety of LDS techniques in parallel:

1. Hydrostatic testing is mandatory on some pipelines on a periodic basis. This is perhaps an extreme on the issue of speed of detection. However, it is also extremely sensitive, detecting even small seeps.
2. The pipeline will also generally be patrolled; this is often mandatory. The patrols might be as frequent as daily for unique situations, such as within an aquifer. Of course, only a fairly large leak will be visible to a patrol, but the speed is 24 hours.
3. A CPM system might be installed, and even if it is quite rudimentary it can detect losses smaller than those visible on the surface within 24 hours. Conversely, it might detect rather larger leaks more rapidly than 24 hours.

In this way the composite performance coverage is far more widespread than that of any one single technology. In this simple example the three technologies function relatively independently of each other, with each one separately declaring an individual alarm. Note also that the simultaneous declaration of potential leak alarms, perhaps with relative weights or reliabilities, to the pipeline controller is a powerful method for engineering redundancy into the system. This is discussed at length in several Control Room Management (CRM) publications such as API RP 1168 *Pipeline Control Room Management* and API RP 1167 *Pipeline SCADA Alarm Management*.

3.2.4 Output

Generally, at the end of this stage a Front-end Engineering Design (FEED) is completed that includes a system design (including technologies and equipment specifications), a baseline budget (capital, manpower, and time), and a high-level timetable for action.

3.3 LDS Performance Prediction

Prediction of the performance of an LD system is only an estimate, made using assumptions and assessments of operational factors, of the *potential* ultimate effectiveness of the system. Nevertheless, it is an essential part of any requirements analysis, specification and design process. Even just the exercise of listing and estimating the potential performance factors and their impact is valuable.

3.3.1 Guidance

Absolutely accurate prediction of LD effectiveness is never possible. However, relative rankings of expected performance certainly are, so that technology and design pre-screenings can be performed efficiently. In all cases, as-built testing of the system will also be needed; predicted, rated performance can never substitute for field tests as a measure of quality.

Only one industry procedure, the API Publication 1149, exists for predicting the performance of internal, CPM systems only. Other estimates of performance, including widely-used techniques like visual inspection, are much more dependent on the specific application and are discussed at more length in the Appendix Report of Task 3: Systematic Predictions of Performance.

3.3.2 Protocol

Recall that technologies that may be implemented on a specific LD project are listed by the corporation in a *qualified technology list* (or similar). With each of these qualified technologies will come a set of standard procedures for prediction of performance. The *standardization* of the methods used to predict or estimate performance is just as important as their accuracy.

3.3.3 Recommendations

The level of detail and effort that is made in predicting performance depends on the application. The estimates need not be extremely complex, but should be clearly explained and should be repeatable and consistent.

In certain situations it is quite acceptable to state the prediction in general terms such as "Likely to be High / Low," "Up to 100%," or similar – rather than undertake a lengthy complex calculation of uncertain quality.

It is quite common for designs with, for example, excellent nominal sensitivity to have poor robustness. Therefore, the design trade-offs should all be examined.

3.3.4 Output

At least all four "standard" measures, Sensitivity, Accuracy, Robustness and Reliability, should be assessed.

The assumptions, procedures, and estimates that are made in the predictions should be stated clearly.

3.4 Installation / Testing / Maintenance

Continual maintenance and performance testing is critical to the success of an LDS. Training of personnel is also a critical element for success. Maintenance, Testing, and Training can be tracked using a tool similar to the Template that is part of the toolset.

3.4.1 Guidance

API 1175 provides a detailed description of how Installation / Testing / Maintenance as well as Training fit within an overall LDP. Furthermore, API 1130 provides explicit guidance for CPM systems.

Robustness and Reliability are critical, but difficult items to measure and test. Procedures within reliability-centered maintenance aim specifically to test under low-reliability conditions and to actively seek out difficult situations where performance is poorest. This is particularly important in mission-critical systems (such as LDS) where testing only in "common" or "routine" situations almost certainly yields good results.

3.4.2 Protocol

Ideally, these items are written into the corporate Testing Procedures and Training Programs.

Continual system tuning procedures for systems (such as CPM) that depend upon thresholds and threshold tuning are recommended. This is discussed in detail in API 1175.

3.4.3 Recommendations

Using a Failure Modes and Effects Analysis (FMEA) framework that updates threat and consequence systematically is recommended. Knowing how and when the LDS might fail and how this threatens the pipeline is central to this analysis.

It is also recommended to track performance in the categories of Vendor (specifications) vs. Predicted (e.g. API 1149) vs. Actual (Tested -- by date, over lifetime).

It is important to track, test, and maintain all "touching" equipment (meters, sensors, SCADA, etc.)

Testing and maintenance should be time- and condition-based. This is consistent with a reliability-centered maintenance policy as described earlier in this report.

3.4.4 Output

The primary output is actual, tested (as opposed to specified or estimated) performance. This is part of the actual, current condition of the pipeline.

This also provides a measure of the fitness-for-purpose of the LDS, and its alignment with stated requirements.

3.4.5 Summary

Referring back to the overall Flowchart (Figure I-1), for the Installation / Testing / Maintenance of the pipeline leak detection systems point of view, the process is summarized in Table I-3:

Table I-3 - Installation, Testing, and Maintenance Summary

Guidance	API 1175 (10)(11)(12.3)(12.4)
	API 1130
	Reliability-centered maintenance
Protocol	Testing Procedures, Training Programs
	Continual system tuning procedures
Recommendations	FMEA
	Vendor (specifications) vs. Predicted (e.g. API 1149) vs. Actual (Tested -- by date, over lifetime)
	"Touching" equipment (meters, sensors, SCADA, etc.)
	Time and condition based
Output	Actual tested performance
	Fitness-for-purpose / alignment with requirements

3.5 Retrofit Issues

Retrofit refers to the implementation of an LDS on a pipeline that has already been built and is either completely ready for operation or is already in service. There may or may not already be other LDS on the pipeline, so one issue is how the new retrofit LDS might affect the existing systems. Many issues are considerably simpler when the LDS can be designed and implemented as part of the total pipeline construction project.

Note that there is a “gray area” between these clear-cut distinctions where a pipeline might be undergoing a change in service – a reversal, change in product type, etc. – or a substantial environmental change. The *physical pipeline* might have already been built, but the requirements for LD might be entirely new.

Retrofit issues have an impact on most material in previous Tasks of this PHMSA project:

- Risk Analysis, Requirements Definition and Design are all affected if the pipeline is already built and in operation.

- Technology selection and engineering are affected since some technologies are simple to retrofit, while others are more complicated.
- Predictions of performance are affected by the operating regimes of the pipeline.
- Installation on an operating pipeline can be considerably more difficult than on a new construction.

Retrofit issues can also be categorized into these major areas:

- Applicability and suitability. Certain technologies might be difficult to install on an existing pipeline, and some might even be impossible. Difficult installations might take a long time, present project risks, and carry a high cost in terms of resources.
- Safety. Certain installations might be hazardous on a pipeline in operation. Similarly, if the pipeline is very old then it might have an impact on its integrity.
- Operational impact. The installation may adversely affect operations, and the new LDS might degrade performance or efficiency of current systems.
- Legal, contractual and/or regulatory. For example, access to a right-of-way may be restricted by land rights, and construction on an existing pipeline might need to be permitted. Change in service may affect the regulations around inspection intervals. A regulatory review for LD as part of a retrofit is generally recommended if substantial design changes are made.

Not all technologies have substantial retrofit issues. Many Internal LDS, when all the necessary instrumentation has already been installed and is in operation, generally have very low impact on a pipeline in operation. Similarly, a new program of visual inspection has almost no effect on pipeline transportation operations.

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Part II – Natural Gas Pipelines

LIST OF FIGURES

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1 General Principles

It is possible to perform each step of the overall process in great detail, and indeed for large, complex and highly critical pipeline systems, it may be necessary. However, for simple systems even basic considerations might be sufficient. The important element is the documentation of each step of the process to some extent and the explanation in clear engineering language what recommendations were made and decisions taken. There is no “correct” or “minimal” performance requirement for an LDS. However, it is important to justify clearly why a certain performance standard was recommended and it is also important to be sure that an installed LDS actually performs and meets this standard.

Similarly, there is no “correct” or “recommended” technology or technique for LD. The simplest of techniques, like visual inspection by patrols, might be appropriate in many cases. Again, the important element is to justify the technique used with reference to stated requirements and in light of the business, operational and technical constraints.

It is strongly recommended to implement a “defense in depth” approach by using multiple distinct LDS techniques in synergy. For example, a complete LD approach might include:

1. Periodic inspection (line surveys, hydrostatic tests, ILI, etc.) for extremely small losses;
2. Intermittent surveys (visual / instrumented visual inspection, for example) for small losses;
3. Continual external monitoring by instrument for critical sections;
4. Computational Pipeline Monitoring for medium sized losses; and/or
5. Pressure and Flow monitoring – including fully automated shutoff valves – for large, sudden ruptures.

Any one of these alone is a valid LDS of a certain performance profile. However, any combination of these provides much better coverage of the entire leak size / time to detection / criticality spectrum of potential leaks.

1.1 Note on API Documentation and References

In this report, a number of American Petroleum Institute (API) technical publications and recommended best practices are cited. The API generally focuses on the oil industry and liquids pipelines. However, many of the principles and guidance in these publications apply equally well to natural gas pipelines and so the reader is encouraged to refer to them when possible.

2 Approach

The overall approach to engineering and operating an LDS begins with the development of a set of objectives for leak detection. Therefore, the first task results in a reasonably specific set of performance requirements for the system to be built.

Best practices encourage a *risk-based approach* to developing requirements; in other words, to engineer the LDS in order to reduce the risk of a loss of containment to an acceptable level. The results of the risk analysis must then be refined to express precise requirements, as well as constraints, in terms of engineering parameters.

2.1 Risk Profile

The approach to engineering leak detection systems is based on a Risk-Based Analysis that assesses benefits, requirements and objectives in terms of risk reduction. A Risk Profile, representing the current and potential future condition, for the pipeline may be developed using a tool similar to the Template LDCE (Leak Detection Capability Evaluation) that is attached to this report. The inputs are:

1. A Likelihood (or threat, probability) of failure, which is generally an input from the Integrity Management team at the pipeline company.
2. A Consequence (or impact) of a loss of containment, which is a function of the potential loss size, HCA location, environment and other physical and operational parameters. One of the more important factors is the overall performance of the LDS that is used in mitigating the loss.

The product of the likelihood and consequence of a loss is the composite risk.

2.1.1 Guidance

DOT 49 CFR Part 192 (natural gas pipelines) provides not only the minimum requirements for a risk-based assessment of leak detection requirements, but also contains valuable advice. This includes references to other advisory documents.

API 1130 Appendix C lists the major performance factors in an LDS that can affect the consequences of a failure. API 1160 describes how LDS fit in to the overall Integrity Management Program (IMP) of a pipeline and synergies with failure prevention strategies. API RP 1173: *Pipeline Safety Management System Requirements,* Chapter 7:

Risk Management, is also a valuable source of advice. API 1175 (6)(7)(Annex A, B) also describes how an overall Leak Detection Program is managed and how it contributes to an overall IMP.

ASME B31.8 (Supplement) is useful because it lists many of the common factors that contribute to the likelihood of failure. Note that this advisory document is written in the context of natural gas pipelines although the principles apply equally well to all pipelines.

How well LDS alarms are presented to and processed by the controller are key risk reduction factors. This is discussed at length in for example API RP 1168 *Pipeline Control Room Management* and API RP 1167 *Pipeline SCADA Alarm Management*.

2.1.2 Protocol

The evaluation of the overall risk profile of a pipeline is an integral part of the pipeline's IMP, as described in 49 CFR 192 (natural gas pipelines) and API 1160.

2.1.3 Recommendations

Root Cause Analysis (RCA) and other previous incident analyses help provide a clearer picture of the most important / common causes, locations, and sizes of leaks. These can be supplemented by industry-wide studies of historical incidents (for example ASME B31.4). Often the Integrity Management team has a Failure Modes and Effects Analysis (FMEA) available that states threat (likelihood) and consequence very clearly.

It is also useful to diagram threats and consequences, showing barriers to failure (such as maintenance and inspection) as well as mitigations to the consequences (for example, better LDS, EFRD and control room procedures). See for example ISO 31000:2009 - IEC 31010:2009, and the bow-tie diagram in particular.

2.1.4 Output

The risk profile shows the general level of risk that is assumed on each pipeline subsystem or section. This includes a ranking of areas of particular risk. It also demonstrates the mitigating effect of the LDS performance parameters upon consequence. This is useful in assessing the relative benefits of different potential LDS as well as the benefit of the current LDS.

2.1.5 Summary

The process for the Risk Profile / Condition of the pipeline from a leak detection requirements point of view is summarized in Table I-1 of Part I – Summary.

2.2 The Engineering Process

The overall LDS engineering process contains several sub-tasks, but overall it can be summarized (with details below) as follows:

Table II-1 - Overall LDS Engineering Process

Input	Required	The Project Charter
	Recommended	Company and/or Industry Recommended Practices (RP) Project risk management plan
	Useful	Applicable Regulations and interpretation of their impact
Process	Required	A systematic five-step engineering plan, including at least (or equivalent): 1. Requirements; 2. Design; 3. Implementation; 4. Verification; and 5. Maintenance. Analysis of the appropriate Continual Improvement cycle for the technology that is selected.
	Recommended	Periodic internal and/or Peer Reviews
	Useful	ISO, PMI or other project management standards
Output	Required	(Matching the Project Charter) A System for the detection of loss of containment on the pipeline that meets the detailed Requirements developed during the project. Includes: 1. Trained *People* to operate the LDS; 2. An operational *Procedure* for how to operate the LDS; and 3. A *Technology* tool to assist in leak detection. Closeout of the Project Charter.
	Recommended	Timetable for LDS review and continual improvement.
	Useful	Reporting that details compliance with applicable RPs and regulations

2.3 Input

2.3.1 Project Charter

The minimum necessary input to an LDS engineering project is the Project Charter (PC).

It is often also called the project definition or project statement, and is a statement of the scope, objectives, and participants in a project. It provides a preliminary delineation of roles and responsibilities, outlines the project objectives, identifies the main stakeholders, and defines the authority of the project manager. It serves as a reference of authority for the future of the project. Terms of Reference are usually part of the project charter.

2.3.2 Terms of Reference

The PC often either contains, or is replaced by, a Terms of Reference (TOR) for a project. To a great extent they overlap. A typical TOR will include:

1. Vision, objectives, scope and deliverables (i.e. what has to be achieved)
2. Stakeholders, roles and responsibilities (i.e. who will be involved)
3. Resource, financial and quality plans (i.e. how it will be achieved)
4. Work breakdown structure and schedule (i.e. when it will be achieved)

Success factors/risks and restraints are also an important part of a standalone TOR.

2.3.3 Recommended Practices

It is recommended that any applicable company engineering standards, or industry recommended practices, should be identified as input to the project. Often these are part of the Directions concerning the solution in the PC, but if not they are strongly recommended as additional input. Industry RPs are listed in Table I-1, but the operator may well have general engineering best practices that it would like to see followed and these are best identified at the onset of the project.

2.3.4 Integrity Management

It is widely recommended that leak detection be considered as part of a comprehensive Integrity Management Program (IMP). (See for example API 1160, ASME B31.4, or 49 CFR 192.) Therefore explaining how the project contributes to the overall company IMP plan is strongly recommended.

2.3.5 Project Risk Management

It is recommended that any applicable company PM standards or industry recommended practices be identified as input into the project. Often these are part of the PC but, if not, they are very useful input to the project.

2.3.6 Applicable Regulations

Including any applicable Regulations that relate to this project is only ranked as *useful*. It is not required since any complete Requirements Analysis will certainly identify compliance with any applicable regulations as a key requirement.

Identifying Regulatory constraints at this stage has a mixed impact. It is useful, up front, to state engineering requirements or constraints that will affect or constrain engineering design decisions. For example, it might be useful to cite 49 CFR 192 as a form of best practice or standard. What is not very useful is to state, either as a Reason, Objective, or Design constraint, something similar to: *Compliance with 49 CFR 192*.

2.4 Process

2.4.1 Project Plan

The basis of the Process is a plan. It is important for the Inputs, Processes, and Outputs of each step of the plan to be specified. Again, the guidance provided in the chapters below may be used, or any other Input-Process-Output (IPO) plan appropriate to the operator.

Project Management is an advanced discipline in itself. The other components of the Plan are at the discretion of the Project Manager (PM). The rest of the Plan is also deliberately standardized for any kind of project, not just LDS, and therefore not a focus of this document.

2.4.2 Continual Improvement Lifecycle

Especially for high-technology solutions, it is critical that one of the results of the Requirements and Design stages be to identify the lifecycle of the solution. For an LDS a continual improvement review is very dependent on the technology selection, and it is required to identify its likely future frequency. This is because it has a direct impact not only on the initial project, but also on the total lifetime cost of ownership of the system to the operator.

2.4.3 Peer Reviews

The periodic involvement of experts who are not directly and continually involved in the project is recommended as part of the overall project management. This is particularly important in all high-technology projects including LDS.

2.4.4 Standardized PM Procedures

Highly standardized PM procedures are useful but not essential to LDS projects. Their advantage is that they reduce the risk of failure – sometimes considerably, especially for large projects – but they do add significant overhead in terms of PM time. Very often significantly “lighter” procedures are sufficient and appropriate, especially for smaller projects.

2.4.5 Performance Prediction and Measurement

Perhaps the best current explanation of the difference between performance prediction (i.e. a priori estimation) and measurement (i.e. a posteriori inference) is due to Van Reet (2014)[2], as follows:

Performance targets define the expectation of a pipeline operator for a leak detection technology or the specific implementation of a leak detection technology on a particular pipeline. Performance targets for a technology are used primarily when selecting which technologies to have available in a leak detection program and for initial selection of candidate technologies for a particular pipeline. Performance targets for a particular pipeline are appropriate for making the final selection of technologies for an asset and for evaluating continual improvement possibilities. Performance targets can be determined by estimation or observation of the system performance.

Performance *estimation* (part of Requirements Analysis) uses detailed knowledge of the technology and considers how the inputs to and operational environment of the system affect its performance. API 1149 is an example of this approach applied to leak detection systems (primarily CPM-based, but applicable to many other techniques). Performance estimation is more appropriate where detailed and specific knowledge of the asset, the leak detection system, and the operations are available. This implies assets that are in place or that have a detailed design available so that the specifics of the implementation are known. It also implies that the methodologies of the leak detection system are known in sufficient detail to apply techniques such as uncertainty analysis.

Note that as part of any qualified technology set comes a corresponding set of performance estimation procedures. Part of the definition of a *qualified* technology is indeed that its performance is predictable, and the procedures for its estimation are well-accepted.
There needs to be some validation of the API 1149 sensitivity curves and other performance metrics with physical tests as part of a system-wide LDS validation. This is part of Task 4 – Impact of Installation, Calibration and Testing.

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[2] Van Reet, J. D. (2014) Unpublished communication

2.5 Output

2.5.1 Objective

A typical statement of the objective of an LDS project might be: A system designed to detect loss of containment on the pipeline, consisting of:

1. Trained *People* (and the training program) to operate the LDS;
2. An operational *Procedure* (appropriately documented) for how to operate the LDS; and
3. A *Technology* tool to assist in leak detection.

The pipeline refers to the specific operator's pipeline system that is to be protected by LDS.

2.5.2 Project Charter Closeout

It is required to issue some form of Final Report that looks back to the original Project Charter or Terms of Reference, and itemizes how each of the line items were covered (or unavoidably changed) during the project.

2.5.3 Review Schedule

It is recommended to include, either separately or as part of the Final Report, a timetable for future continual improvement reviews of the LDS. The continual improvement implications of the technology selection are already a required deliverable of the Design process, but it is recommended to explicitly set dates, or triggers, when a subset of the project stakeholders will reconvene for a continual improvement review.

2.5.4 Regulatory, Procedural and RP Compliance Reporting

It is useful, although it will have little impact on the project outcome or the performance of the LDS itself, to report formally on compliance with applicable regulations, company procedures, and industry recommended or best practices.

The project team is generally best placed to report on these issues, especially given the Requirements analysis, and this documentation is often useful to the pipeline operator's administration.

2.6 Requirements and Constraints

The Requirements and the Constraints for LD for the pipeline may be tracked and documented using a tool similar to the Template that is attached to this report. The requirements are expressed at least in terms of: Sensitivity (Se), Robustness (Ro), Reliability (Rp), and Accuracy (Ac). Each of these LD performance parameters is an input to the LDCE, and must all align with the stated requirements for risk reduction.

Constraints include both operational constraints (e.g. personnel, service profile, commercial and environmental issues) and resource constraints (e.g. budget and time).

2.6.1 Guidance

API 1130 provides an exhaustive list of both operational constraints and of performance measures for a pipeline LDS. API 1155 is a predecessor (and is technically superseded) but it provides the same information in perhaps more compact and easier to understand form, although it has been withdrawn by API and is not kept current. Much of API 1155 is also included in API 1130, Appendix C.

API 1149 provides a specific approach and formulas for estimating the performance of the important Computational Pipeline Monitoring (CPM) class of LDS. Note that the original publication only covered liquids, simple pipelines and a few of the factors involved. The 2015 update covers all fluid types – including natural gas, networked systems and multiple uncertainty factors. In particular, in order to analyze a natural gas pipeline for CPM performance, the 2015 update is *required*. It also includes the principles for the estimation of many non-CPM LDS as well.

API 1175 describes how assessing requirements and ensuring that they are met is managed within an overall LDP. In addition:

1. API 1164 covers Pipeline SCADA Security and how it relates to LDS.
2. API 1165 covers Pipeline SCADA Displays and how they relate to LD.
3. API 1167 covers Alarm Management and how to process / act upon LD alarms.
4. API 1168 covers Pipeline Control Room Management and how the controller reacts to an alarm.

2.6.2 Protocol

Generally, although there are many terms for this, the process of assessing requirements, enforcing / measuring their compliance, and continually improving them, is part of Process Quality programs or Total Quality Management (TQM).

2.6.3 Recommendations

Historical Incidents, Business Process (BP) and Enterprise issues drive a large number of not only the requirements statements but will also dictate a large number of constraints on the analysis. Even though these are not purely engineering / technical, they should be documented clearly.

A Cost-Benefit Analysis (CBA) in the company-accepted form is a very useful addition to any requirements analysis. It provides a purely business case for accepting a certain requirements standard.

A "Must Perform as Intended" policy going forward into deployment also helps to ensure that unrealistic / unattainable requirements are not specified at this stage. This helps to clarify many of the constraints in easier language.

The decision on whether to provide 24/7 continuous LD is an important one. It is not always a requirement – low-criticality, low-impact lines may not need it at all. Also, it might be either a requirement (24/7 continuous LD is needed on this line because…) or a constraint (corporately, all lines in all systems will have 24/7 continuous LD…)

2.6.4 Output

The primary results of the requirements analysis are:

1. Target Performance Criteria (Se, Ro, Rp, Ac). Any pre-qualified technology set will include a performance prediction protocol, so that a system can later be designed to meet these criteria.
2. Engineering Constraints (staff, capital, qualified technologies, regulatory requirements, etc.)
3. Operational Constraints (transient conditions, slack line operations, etc.)

The engineering and operational constraints will also, during design, help eliminate technologies from the pre-qualified set.

2.6.5 Summary

The process for the LD Requirements of the pipeline is summarized in Table I-2 of Part I – Summary.

2.6.6 The Requirements Process

The Requirements process contains several sub-tasks, but overall it can be summarized (with details below) as follows:

Table II-2 - Requirements Process

Input	*Required*	Risk Analysis Project Charter, in particular: Objective, Limitations, Directions, Out-of-scope, Target benefits
	Recommended	Technology selection pre-screening
	Useful	Costs of Loss of Containment Events
Process	*Required*	FEL-2 With conceptual alternatives Analysis of impact on risk Analysis of impact on operations Preliminary Project Planning
	Recommended	Potential alternatives rejected, with reasons
	Useful	Cost Benefit Analysis
Output	*Required*	FEL-2 Conceptual design selection Performance measures (expected and required) FEL-2 Risk-based Cost-Benefit Impact on operations Preliminary Project Plan
	Recommended	Updated benefits from PC
	Useful	FEL-2 Risk-based Cost Benefit Analysis

2.6.7 Front-End Loading

This document uses Front-end loading (FEL) terminology for the initial stages of a project. Many other frameworks and terminologies are in wide use but can generally be translated into FEL language as necessary.

FEL is also referred to as pre-project planning (PPP), front-end engineering design (FEED), feasibility analysis, conceptual planning, programming/schematic design and early project planning. It is perhaps the most frequently used process for conceptual development of projects in hydrocarbons industries such as upstream, midstream, petrochemical and refining.

Front-end loading includes robust planning and design *early* in a project's lifecycle (the front end of a project), at a time when the ability to influence changes in design is relatively high and the cost to make those changes is relatively low. It is divided into three stages:

1. FEL-1 covers the preliminary stages that were discussed as overall project inputs in the last chapter, specifically the development of the Project Charter and budget. The budget is not expected to be more than about +/- 100% accurate.
2. FEL-2 covers preliminary (conceptual) ideas. This includes general potential solutions, and very high-level architectures. Each of these is listed and analyzed for potential resource requirements, expected performance, and cost-benefit. None of these is expected to be more than about +/- 50% accurate.
3. FEL-3 covers detailed specifications. This includes purchase-ready major equipment specifications, drawings, a definitive resource requirements estimate (about +/- 15% accurate), and a detailed implementation plan.

FEL is usually followed by purchases and implementation. Frequently the supplier or contractor is then asked to follow FEL-3 with a detailed design appropriate to the supplier's own technologies and procedures which are constrained to be within about +/- 15% of the FEL-3 detailed specification.

2.6.8 Cost-Benefit of an LDS

It is strongly recommended to include a Cost-Benefit Analysis as part of the requirements. Indeed, achieving a certain benefit at a given cost is a common and recommended component of the Requirements. Cost-Benefit, for the purposes of this discussion, differs from a Return on Investment (ROI) only in that an ROI is expressed in terms of capital expenditure vs. cash returns whereas a Cost-Benefit Analysis can be more qualitative or relative (although should still be expressed numerically). Often, it becomes *the only* or at least the central Requirements Analysis for LDS.

Calculating an ROI for most engineering projects is simplified by an evident source of additional business revenues that can be attributed to the activity. New equipment, sections of line, or control systems allow the pipeline to transport more products to or for more customers and so translate into increased cash revenues. In common, to a certain degree, with safety systems and maintenance projects, LDS are usually justified in terms of reducing the consequential damage from a failure.

Leak detection systems – in common with all safety systems – affect 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 track and ensure performance more reliably.
- Employees can work in safer environments.
- The Community has a reduced risk of having to deal with serious safety and environmental hazards from a loss of containment.

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.

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3 Systems Design and Engineering

Careful design is important so that the final, as-built LDS meets the requirements and constraints and therefore delivers the appropriate reduction in the level of risk of a spill. Generally, it involves three steps: choosing technology(-s) / approach(-s) to LDS, designing their implementation, and planning their installation, deployment and operation.

3.1 Technology Selection

The technology used need not always be complex. The most widely-used techniques with natural gas pipelines are visual inspection, use of gas detectors or tracer gases, and pressure / flow monitoring by SCADA. The important element is to discuss and document the suitability of the technique to the stated requirements in terms of target performance criteria (Sensitivity, Robustness, Reliability and Accuracy).

In classifying LDS technologies, a handful of publications continue to provide the most consistent listing of currently available techniques. For Internal methods, the API RP 1130 provides perhaps the most useful categorization of Internally Based CPM techniques. Appendix C provides descriptions of types of internal-based CPM systems and lists eight separate techniques. They rely essentially on four physical effects, and the last technique, B.3 *Statistical Analysis*, can in fact be used as a Comparison method against the baseline with any one of these physical effects.

Table II-3 - API RP 1130 CPM Systems

Guidance	API 1130 (4.2)(5)(6)
	API 1149, API 1155
	API 1175 (6)(7)(8)(10)(12)
	API 1164, API 1165, API 1167, API 1168
Protocol	Process Quality / TQM
Recommendations	Incidents, BP, Enterprise
	Cost-Benefit Analysis (CBA)
	Must Perform as Intended
	FMEA, 24/7 continuous LD
Output	Target Performance Criteria (Se, Ro, Rp, Ac)
	(Any qualified technology set will include a performance prediction protocol)
	Engineering Constraints (staff, capital, qualified technologies, regulatory requirements, etc.)
	Operational Constraints (transient conditions, slack line operations, etc.)

For External LDS techniques, there are at least two main publications of general use:

1. Technical Review of Leak Detection Technologies – State of Alaska ADEC best available technology (BAT) review (2004). This review is for liquids LDS, and Volume I focuses on pipeline applications.
2. Technology Status Report on Natural Gas Leak Detection in Pipelines, prepared for U.S. Department of Energy National Energy Technology Laboratory (DE-FC26-03NT41857)

The major External physical effects used are:

- Temperature change at the site of a leak due to a fluid loss. This is both due to a difference in temperature between the pipeline fluid and the environment, and Joule-Thomson cooling at the site particularly for HVL and natural gas.
- Acoustic sound (possibly sub- or super-audible frequency) due to the nozzle effect at the leak.

- Electromagnetic (including visible light and/or infrared) scattering, reflection or radiation by the released plume of hydrocarbons.
- Physical / chemical reaction with the released hydrocarbons – typically in a sensor.

The correspondence between External techniques and their primary physical principle can be listed as follows[3].

Table II-4 - NETL External LDS Methods

Technique	Description	Physical Principle
Acoustic sensors	Detects leaks based on acoustic emissions	Acoustic
Gas / HC Vapor sampling	Flame Ionization (natural gas) or other HC vapor detector	Physical / chemical reaction
Soil monitoring	Detects tracer chemicals added to gas pipe line	Physical / chemical reaction
Lidar absorption	Absorption of a pulsed laser monitored in the infrared	Infrared scattering
Diode laser absorption	Absorption of diode lasers monitored	Infrared scattering
Broad band absorption	Absorption of broad band lamps monitored	Infrared scattering
Evanescent sensing	Monitors changes in buried optical fiber	Temperature
Millimeter wave radar systems	Radar signature obtained above pipe lines	Microwave scattering
Backscatter imaging	Natural gas illuminated with CO2 laser	Light scattering
Thermal imaging	Passive monitoring of thermal gradients	Infrared radiation
Multi-spectral imaging	Passive monitoring using multi-wavelength infrared imaging	Infrared radiation

[3] Technology Status Report DE-FC26-03NT41857, National Energy Technology Laboratory

3.2 Classification of Techniques

Although they are generally used interchangeably, the terms technology and technique have important implications:

- A technology is (primarily) a physical principle or device that is used for the purpose of leak detection.
- A technique is (primarily) a means of packaging and/or deploying the technology in the field as part of an overall LDS.

In the industry, engineers tend to think of three main layers to a technique: Internal vs. External, Continual vs. Intermittent, and Automated vs. Manual.

1. Internal methods rely on measurements on the fluids within the pipe – pressures, flow rates, temperatures, etc. External methods rely on measurements of conditions outside the pipe – hydrocarbon content, temperature, sound, etc.
2. Continual methods provide a continual monitoring (in time) of the probability of a loss. Intermittent methods provide periodic but "snapshot" checks of the probability of a loss.
3. Automated techniques, once installed, rely on SCADA to provide a constant stream of data without the need for manual collection. Manual techniques require human intervention or operation for data and/or information collection.

Table II-5 - Classification of LD Techniques

Guidance	API 1130 (4.1, 4.2), also (5)(6)
	API 1149, API 1155
	API 1175 (6), also (7)(8)(10)(12)
	API 1164, API 1165, API 1167, API 1168
Protocol	Process Quality / TQM
Recommendations	Incidents, BP, Enterprise
	Cost-Benefit Analysis (CBA)
	Must Perform as Intended
	FMEA, 24/7 continuous LD
Output	Target Performance Criteria (Se, Ro, Rp, Ac)
	(Any qualified technology set will include a performance prediction protocol)
	Engineering Constraints (staff, capital, qualified technologies, regulatory requirements, etc.)
	Operational Constraints (transient conditions, slack line operations, etc.)

Some particular techniques are quite widely used and therefore merit special discussion.

3.2.1 Visual Inspection

Visual inspection is generally an External technique however, depending on how it is performed, its other dimensions can very. For example:

- Periodic patrolling by land vehicle is intermittent, and manual. However, note that it might embody several technologies. The inspection might be visual, or it might use cameras (including IR cameras), or even sensors (hydrocarbon detectors, etc.).
- Periodic patrols by an un-manned drone are intermittent, but automated in the sense that the data collection is automated – although the data analysis itself is generally by a human analyst.

- Segments of pipeline or pipeline corridors that are monitored by permanently installed video cameras (including IR cameras) represent continuous monitoring. However, the alarm is generally due to a human analysis of the video feed.

Leak detection that relies on a call-in by members of the public is a particular form of a manual and intermittent technique. Operators should appreciate the critical role members of the public can play in assisting with leak detection, and it should be incorporated as part of a comprehensive public awareness program. At the same time, operators should not rely solely on members of the public as a means of leak detection. If a member of the public does call it in, operators should use that as an opportunity to see why other aspects of their system did not pick it up first and how it can be improved to prevent future instances.

3.2.2 Hydrostatic Testing

When a pipeline is shut down periodically, filled with water, oil or gas at high pressure, and physically monitored for tightness over a fixed period, the technique is clearly manual and intermittent. It is also formally an Internal technology since it relies on monitoring pressure during the test.

ASME B31.4 requires this testing to ensure tightness and strength. High pressure liquid pipelines are tested for strength by pressurizing them to at least 125% of their maximum allowable operating pressure (MAOP) at any point along their length. Test pressures need not exceed a value that would produce a stress higher than yield stress at test temperature (see also 49 CFR Part 192 Subpart J).

Leak testing is performed by balancing changes in the measured pressure in the test section against the theoretical pressure changes calculated from changes in the measured temperature of the test section.

3.2.3 "Smart" Pigs / Balls

Often sensors are installed in "intelligent" pigs, or rolling "balls", that are launched inside the pipe and carried within the pipe by the fluid flow. They find losses by being in close contact with the pipe wall. These are manifestly intermittent techniques – they only detect a loss while in the pipe. However, although they record data automatically (usually into a data logger) the analysis of the data requires a trained technician. It therefore crosses the automated / manual distinction. Similarly, because it is inside the pipe it is tempting to call the technique "Internal" – although it utilizes External sensors.

It is recommended to categorize this technique as External, Intermittent, and Automated.

3.2.4 Automatic Shutoff Valves

Automatic shutoff valves (ASVs) include valves that are triggered by mechanical alarms (for example, earthquakes or third-party damage), excess pressure or flow, or by detecting a rupture in the pipeline. In this latter case, they are in fact a combination of a dedicated single-point measurement LDS and a valve that is automatically closed in response to an alarm. They are intended to provide very fast containment, wherever this containment is safe, in response to obvious rupture incidents.

The LDS principles that are most widely used by ASVs are:

- Monitoring or flow and/or pressure change, or rate of change. This accounts for the large majority of systems.
- Negative pressure wave monitoring
- Acoustic emissions monitoring

The first and second are standard CPM techniques, and are described in API RP 1130. Acoustic monitoring is described below under External technologies.

3.3 Major LDS Techniques

The technologies in regular use fall into two main categories. Internal methods rely on measurements on the fluid itself within the pipe such as fluid flow rate, pressure and temperature. These are often called Computational Pipeline Monitoring (CPM) techniques since a computer calculation based upon these measurements is generally required. External methods use specialized sensors outside the pipe wall to detect the impact of the leak on the external environment of the pipe. There are also some crossover techniques; for example, in-line pigs or balls carrying external sensors but within the pipe.

The most widespread Internal techniques include:

- Pressure / Flow Monitoring by SCADA. This alarms when abnormal pressures and/or flow rates (or their rate of change) are observed.
- Periodic leak surveys, either using pressure or hydrostatic tests. For many pipelines, these are mandatory although at long time intervals.

- Material Balance, which balances flow into and out of a section of pipe, against an estimated rate of change of line pack.

These methods account for the great majority of Internal systems in use. Others also used in difficult or particularly sensitive applications are listed in API RP 1130.

The most widespread External techniques include:

- Visual inspection by regular patrol. In fact, this is perhaps the most widespread LDS technique of all. The inspection may be by naked eye, camera (including infrared), or using specialized sensors. The patrol may be at the surface or aerial, on foot, surface vehicle, airplane, drone, etc.
- Periodic leak surveys using in-line tools.
- Hydrocarbon or tracer chemical (including odorants) detection, either as part of a periodic survey or installed permanently at locations of particular sensitivity.

There are many other External sensors available, and we highlight acoustic emissions and thermal emissions as techniques that are becoming more common. These are listed exhaustively in the report of Task 2: Methodology for Technology Selection and Engineering.

3.4 Engineering for Performance

The selection of a technology is by no means the only way to achieve performance. An important technique that can be used to improve technological shortcomings is to utilize several technologies in parallel as well as to use several leak indicators in parallel. In fact, almost without realizing it, most pipelines already employ a variety of LDS techniques in parallel:

1. Hydrostatic testing is mandatory on some pipelines on a periodic basis. This is perhaps one extreme of the issue of Speed of detection. However, it is also extremely sensitive, detecting even small seeps.
2. The pipeline will also generally be patrolled; this also is often mandatory. The patrols might be as frequent as daily for unique situations. Of course, only a fairly large leak will be visible to a patrol, but the speed is 24 hours.
3. A CPM system might be installed though these are more common on liquids pipelines. Even if it is quite rudimentary, it can detect losses smaller than those visible on the surface within 24 hours. Conversely, it might detect rather larger leaks more rapidly than 24 hours.

The composite Performance Quadrant for this scheme might then look like this:

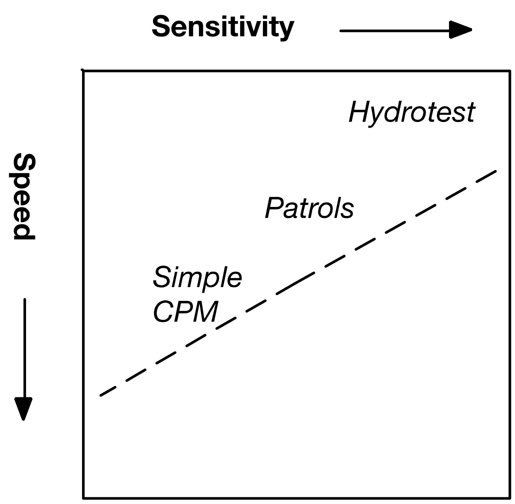

Figure II-3 - Composite LDS Performance

In this way, the composite performance coverage is far more widespread than that of any one single technology. In this simple example the three technologies function relatively independently of each other with each one separately declaring an individual alarm. Note also that the simultaneous declaration of potential leak alarms, perhaps with relative weights or reliabilities, to the pipeline controller is a powerful method for engineering redundancy into the system. This is discussed at length in several Control Room Management (CRM) publications, for example API RP 1167 (still in development) Alarm Management.

Just as an example, when the controller is certain that the pipeline should be in stable, steady state operation then a combination of these alarms – roughly in increasing order of confidence – might increase the confidence in the likelihood of a loss:

1. Short-term, one-minute imbalance in material (i.e. CPM method C.4)
2. Medium-term, five-minute imbalance in volume (i.e. CPM method C.2)
3. Rate of change of pressure threshold, over a minute (i.e. CPM method C.6)
4. Low-pressure threshold (i.e. CPM method C.6)

A carefully designed display enunciating these four different CPM technologies is a powerful engineering technique for multiplying their effectiveness.

For more detailed guidance on the design and engineering a fit-for-purpose LDS refer to Appendix A.

4 Performance Prediction

Prediction of performance is an a priori estimate, made using assumptions and estimates of operational factors, of the potential ultimate effectiveness of the system. Nevertheless, it is an essential part of any requirements analysis, specification and design process. Even just the exercise of listing and estimating the potential performance factors and their impact is valuable.

Absolutely accurate prediction effectiveness is never possible. However, relative rankings of expected performance certainly are, so that technology and design pre-screenings can be performed efficiently. In all cases, as-built testing of the system will also be needed; predicted, rated performance can never substitute for field tests as a measure of quality.

The level of detail and effort that is made in predicting performance also depends on the application. The estimates need not be extremely complex, but these central principles should be maintained:

- At least all the four "standard" measures: Sensitivity, Accuracy, Robustness and Reliability, should be assessed. It is quite common for designs with excellent nominal sensitivity to have poor robustness. Therefore, the design trade-offs should all be examined.
- The assumptions, procedures, and estimates that are made in the predictions should be stated clearly. For example, it is quite acceptable to use gross estimates ("High, Medium and Low") when a certain parameter is unknown and this is made explicit. It is less acceptable to use apparently precise estimates ("56 C +/- 10%") when in fact the values are not actually well known.
- Certain situations where a good prediction can almost never be made are highlighted below. In these situations, it is quite acceptable to state the prediction in general terms such as "Likely to be High / Low," "Up to 100%," or similar – rather than undertake a lengthy complex calculation of uncertain quality.

4.1 What is the "Performance" of an LDS?

It is useful to concentrate on four main issues as highlighted by the API RP 1130: Sensitivity, Accuracy, Robustness and Reliability.

- Sensitivity is a composite measure of the smallest leak that can be detected, and the least amount of time that it takes to detect it. Therefore, generally it is a table or graph of detectable leak sizes against detection time.
- Accuracy is the precision with which indicators provided by the LDS are estimated. This depends on the LDS. Some LDS may provide estimates of leak size, leak location, etc. – and some may not. If they do, the accuracy of estimation is a composite measure the amount of time available to estimate it. Therefore, generally it is a table or graph of accuracy against estimation time.
- Reliability is the percentage of time that the LDS functions as specified and designed, while all operational and environmental design parameters apply. In other words, the ability to function without false positives or negatives assuming that conditions are as specified in the design.
- Robustness is the ability of the LDS to function correctly even when unexpected events occur outside its design range.

There are other, more complex performance measures and factors and they are listed in detail in API RP 1130 Appendix C.

4.2 Performance Estimation Procedures

Only for a number of Internal, Computational Pipeline Monitoring (CPM) techniques are there prescribed technical publications that provide step-by-step procedures for performance estimation. The original 1993 API publication 1149 applies well to Material Balance CPM techniques, with the following limitations:

- Tables are only provided for crude oils and LVL products.
- Only pipeline length, diameter and liquid API gravity are provided as pipeline parameters. A single uniform, straight and horizontal pipeline is assumed.
- Also, only the impact of flow, pressure and temperature measurement is assessed.

It is a useful reference for explaining basic principles, but the actual performance estimation procedure cannot be used for natural gas pipelines. The updated 2015 API publication 1149 provides much more flexibility although it is rather more complex. It allows analysis of most CPM techniques, pipelines and fluid types, and in particular allows performance estimation on natural gas pipelines.

There needs to be some validation of the API 1149 curves or other performance metrics with physical withdrawal tests for system-wide LDS validation. This is part of Appendix C.

There are, however, no standardized procedures for the analysis of External systems. The approaches for these are described in the next sections are suggested but are not part of a formal industry best practice.

For more detailed guidance on LDS Performance Prediction
refer to Appendix C.

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5 Installation / Testing / Maintenance

Continual maintenance and performance testing is critical to the success of an LDS. Personnel training is also a critical element for success. Maintenance, Testing and Training can be tracked using a tool similar to the Template that is attached to this report.

5.1 Guidance

API RP 1175 provides a detailed description of how Installation / Testing / Maintenance as well as Training fit within an overall LDP. Furthermore, API RP 1130 provides explicit guidance for CPM systems.

Robustness and reliability are critical, but difficult items to measure and to test. Procedures within reliability-centered maintenance aim specifically at testing under low-reliability conditions and to actively seek out difficult situations where performance is poorest. This is particularly important in mission-critical systems (like LDS) where testing only in “common” or “routine” situations almost certainly yields good results.

5.2 Protocol

Ideally, these items are written into the corporate Testing Procedures and Training Programs.

Continual system tuning procedures for systems (like CPM) that depend upon thresholds and threshold tuning are recommended. This is discussed in detail in API 1175.

5.3 Recommendations

Using a Failure Modes and Effects Analysis (FMEA) framework that updates threat and consequence systematically is recommended. Knowing how and when the LDS might fail, and how this threatens the pipeline, is central to this analysis.

It is also recommended to track performance in the categories of Vendor (specifications) vs. Predicted (e.g. API 1149) vs. Actual (Tested -- by date, over lifetime).

It is important to track, test and maintain all "touching" equipment (meters, sensors, SCADA, etc.).

Testing and maintenance should be time and condition based. This is consistent with a reliability-centered maintenance policy described earlier.

5.4 Output

The main output is actual, tested (as opposed to specified or estimated) performance. This is part of the actual, current condition of the pipeline.

This also provides a measure of the fitness-for-purpose of the LDS and its alignment with stated requirements.

5.5 Summary

From the Installation / Testing / Maintenance of the pipeline leak detection systems point of view, the process is summarized in Table I-3 of Part I – Summary.

For more detailed guidance on the Installation, Testing, and Maintenance of an LDS refer to Appendix D.

6 Retrofit Issues

Retrofit refers to the implementation of an LDS on a pipeline that has already been built and is either completely ready for operation or is already in service. There may or may not already be other LDS on the pipeline, so one issue is how the new retrofit LDS might affect the existing systems. This is in contrast with a situation where the pipeline is a "greenfield" development. Many issues are considerably simpler when the LDS can be designed and implemented as part of the total pipeline construction project. Note that there is a "gray area" in between these clear-cut distinctions where a pipeline is undergoing a change in service – a reversal, change in product type, etc. – or a substantial environmental change.

Retrofit issues have an impact on most material in previous Tasks of this PHMSA project:

- Risk Analysis, Requirements Definition and Design are all affected if the pipeline is already built and in operation.
- Technology selection and engineering are affected since some technologies are simple to retrofit, while others are more complicated.
- Predictions of performance are affected by the operating regimes of the pipeline.
- Installation on an operating pipeline can be considerably more difficult than on a new construction.

Retrofit issues can also be categorized into these major areas:

- Applicability and suitability. Certain technologies might be difficult to install on an existing pipeline, and some might even be impossible. Difficult installations might take a long time, present project risks, and carry a high cost in terms of resources.
- Safety. Certain installations might be hazardous on a pipeline in operation. Similarly, if the pipeline is very old then it might have an impact on its integrity.
- Operational impact. The installation may adversely affect operations, and the new LDS might degrade performance or efficiency of current systems.
- Legal, contractual and/or regulatory. For example, access to a right-of-way might be restricted by land rights, and construction on an existing pipeline might need to be permitted. Change in service may affect the regulations around inspection intervals. A regulatory review for LD as part of a retrofit is generally recommended if substantial design changes are made.

Not all technologies have substantial retrofit issues. We shall discuss later how Internal LDS, when all the necessary instrumentation has already been installed and is in operation, generally have very low impact on a pipeline in operation. Similarly, a new program of visual inspection has almost no effect on pipeline transportation operations.

6.1 Widely-Used LDS Technologies

The most widely-used LDS Technologies for natural gas pipelines are:

1. External: Visual inspection by patrol, with or without instrumentation like infrared cameras and gas sensors
2. Internal: Monitoring of pressure and/or flow, and/or their rate of change
3. Internal: Material balance

In addition, although they are currently not widely used, Automatic Shutoff Valves (ASVs) might become frequent candidates for retrofit on certain categories of natural gas lines in the future for regulatory reasons and also as the technology becomes more reliable. Essentially, these are mainline valves that incorporate pressure and/or flow rate monitoring for standalone LD and line isolation.

Generally, none of these methods involve serious retrofit issues. In fact, Risk Analysis, Requirements Definition and Design might all be helped (although this is not guaranteed) if the pipeline is already built and in operation, with a known and recorded history. Therefore, the discussion in this section is mostly for reference only.

6.1.1 Visual Inspection

The applicability and suitability of visual inspection to existing pipelines in operation is good. In fact, operational history indicating sections of the line with particular weakness or risk can help to direct the patrols. Although visual patrols are almost always done by aircraft, it may perhaps be difficult for foot patrols to access the pipeline right of way for inspection purposes, in which case access roads, gates, etc. might need to be built. This is unusual since access is almost always designed into the pipeline construction for regular maintenance purposes.

Of course, the safety of the patrols should be guaranteed and since the patrollers are human consequences can be serious. However, this issue is not particularly more serious in a retrofit than in a new build.

Operational impact is usually minimal in any case, and not more serious in a retrofit than in a new build.

6.1.2 Pressure / Flow Monitoring

The only situation where retrofit of a pressure / flow monitoring LDS might be invasive on the pipeline is if suitable instrumentation and SCADA, power, or telecommunications have not already been installed. Nevertheless, installation of pressure sensors is usually not unreasonably difficult (although installing good flow metering can be complicated). Instrument installation might prove to be difficult if sensors prove to be necessary along long sections of buried pipe, or other situations where many excavations are necessary. If there is no existing SCADA, power, or telecommunications system then this might be a fairly involved installation; however, this issue is not more serious in a retrofit than in a new build.

Installation of pressure sensors is usually quite safe[4] and does not require a pipeline shutdown (although flow meter installation may require a shutdown). Therefore, operational impact is usually minimal. The one exception might be for very old pipe where the pipe wall might not be very stable. In those situations, the installation might lead to metal fatigue and actually cause a leak rather than help to prevent it.

6.1.3 Material Balance

The issues with this technique are similar to those with pressure / flow monitoring. As above, providing suitable instrumentation and measurement, and a SCADA system are present, then issues are minimal from a technical/software point of view. Organization, people, training, and procedures may nevertheless pose significant issues.

Retrofit of flow metering can be laborious. Many flow meters (even those of custody transfer quality) are not particularly effective for material balance calculations. Therefore, it is imperative to evaluate the likely performance of the LDS using the measured performance of existing flow metering. This can be accomplished using standard methodologies such as the API Publication 1149. If the likely performance is lower than required, then new metering must be installed.

Installation of new flow metering is not especially invasive although it may present facilities availability challenges. A metering facility often requires new space, which might be difficult to come by. A new site can require access and power posing more

[4] U.S. EPA Natural Gas STAR: Using Hot Taps for In-Service Pipeline Connections (October 2006)

complications. It might require a brief shutdown of sections of pipeline to install the meter loops, but this is a routine operation. The equipment can be expensive and if the metering station is remote then it can require substantial manpower and other resources.

6.1.4 Automatic Shutoff Valves

ASVs are usually designed to operate independently and therefore without the need for SCADA. However, there are several very good reasons to connect the ASV to the control center via SCADA; for example: self-testing, monitoring of the recorded pressures, status checking, etc. For these reasons, the SCADA issues in Sect. 4.2 might also apply.

ASVs are fundamentally in-line valves and their installation therefore requires an equivalent pipeline shutdown (or equivalent bypass operation), testing and certification. They also specifically require reliable power supply. They are generally fail safe so any interruption in their power supply will result in a closure and shutdown of the pipeline.

6.2 Impact on LD Engineering

It is important to remember that there are several types of potential retrofits. For example:

- The line may be built but not in operation (reactivation). Many of the advantages that might result from an operational history might then not be available.
- The previous operation might have been in a different regulatory environment (converting gas to liquid or state to DOT). In this case, a number of specific requirements that might not already have been applicable become newly important.
- Less relevant operational changes (e.g. line reversal, increase in throughput, etc.) might have caused the re-design, in which case only minor re-configurations are needed.

6.2.1 Risk Analysis, Requirements and Design

Risk Analysis, Requirements Definition and Design might all be helped if the pipeline is already built and in operation, with a known and recorded history. In Risk Analysis, threat factors are usually much better defined, for example:

- Results from previous testing/inspection
- Leak History
- Known integrity, corrosion or condition of pipeline
- Cathodic protection and damage prevention checking history

These, and many other factors, are assumed “perfect” with a new build and this can lead to a false sense of security.

Design is also to some extent helped by an actual knowledge of the as-built configuration of the pipeline. At the early stages of pipeline construction, these are still sometimes subject to change.

Above all, however, requirements often need to be relaxed since technology selection and installation needs restrict the options available and therefore the feasible overall performance of the LDS.

6.2.2 Technology Selection

Retrofit restrictions are often driven by the feasibility or practicality of retrofitting equipment onto the pipeline. Technologies that require no installation of equipment onto or near the pipe have no such issues. The main examples cited above include visual inspection by patrol.

Otherwise, it is necessary first to assess whether the equipment already installed on the line is sufficient for the technology used and the performance required. This applies mostly to Internal technologies, where a prediction of performance using currently known instrumentation parameters can be used. If additional instrumentation or better metering is needed to meet required performance targets, then the feasibility or practicality of retrofitting these devices will become a factor.

With many External sensors that need to be close to or at the pipe wall, a new installation is always required. In these cases, sensor placement density is often an issue. The frequency of sensor placement often means multiple excavations and taps into the line.

6.2.3 Predictions of Performance

In the few cases where a systematic prediction of performance of the LDS is possible, generally using API Publication 1149, it is generally helped if the associated instrumentation is already installed and in operation, with a known and recorded calibration and proving history.

Of course when additional instrumentation and metering proves necessary, only manufacturer specifications for their performance can be used.

Recall from Task 3 – Systematic Predictions of Performance, that generally External systems' performance is difficult to predict. In those situations, a retrofit implementation is no easier or harder to estimate than a new build.

6.2.4 Installation

Certain technologies might be difficult to install on an existing pipeline, and some might even be impossible. Difficult installations might involve:

- High resource requirements in terms of time, manpower and cost
- Project risk
- Safety issues
- Operational impact

In summary, these might be due to:

- Extensive and/or frequent digs. These might be needed to install densely spaced sensors at the pipe wall, or in order to lay a cable near the pipe.
- Access and/or rights to install equipment above the surface on the ROW.
- Installation of any equipment (for example, metering) that requires a pipeline shutdown.
- Difficulties in testing the system reliably once the LDS is installed.

For more detailed guidance on Retrofitting refer to Appendix E.

7 References

PHMSA Project DTPH-5614H00007: *Improving Leak Detection System Design, Redundancy and Accuracy* Reports:

- Task 1: Design and Engineering Process
- Task 2: Methodology for Technology Selection and Engineering
- Task 3: Systematic Predictions of Performance
- Task 4: Impact of Installation, Calibration and Testing
- Task 5: Retrofit Issues

49 CFR 192 – Code of Federal Regulations, Title 49; Part 192: Transportation of Natural and Other Gas by Pipeline.

49 CFR 195 – Code of Federal Regulations, Title 49; Part 195: Transportation of Hazardous Liquids by Pipeline.

American National Standards Institute (ANSI) ANSI/PMI 99-001-2008.

API 1130 (2007) – Computational Pipeline Monitoring for Liquid Pipelines. Third Edition, Reaffirmed in 2012, American Petroleum Institute.

API 1149 (1993) – Pipeline Variable Uncertainties and Their Effects on Leak Detectability. First Edition, November 1993, American Petroleum Institute.

API 1155 (1995, now superseded, mostly incorporated in API 1130 Appendix C) – Evaluation Methodology for Software Based Leak Detection Systems. First Edition, February 1995, American Petroleum Institute.

API 1160 (2013) – Managing System Integrity of Hazardous Liquids Pipelines. September 2013, American Petroleum Institute.

API 1168 (2015) – Pipeline Control Room Management, Second Edition, February 2015, American Petroleum Institute.

API RP 1173 (2014) Pipeline Safety Management System Requirements, First Edition, June 2014, American Petroleum Institute.

API RP 1175 (2013) – Pipeline Leak Detection, First Edition, December 2015, American Petroleum Institute.

ASME B31.8 (S) – Supplement to the standard, a Commentary, for Managing System Integrity of Gas Pipelines, 9/30/2014.

ASME B31.4 – Pipeline Transportation Systems for Liquids and Slurries, ASME Code for Pressure Piping, 3/31/2016.

Construction Industry Institute (2012). CII Best Practices Guide, ver. 4.

Institute of Electrical and Electronics Engineers (IEEE) 1490-2011.

ISO 19011:2011 – Audits of Quality Management Systems

ISO 21500:2012 – Guidance on Project Management

ISO 31000 – Risk Management: Principles and Guidelines

ISO 31030 – Risk Management: Risk Assessment Techniques

ISO 9000:2005 – Basic Concepts and Language

ISO 9001:2008 – Requirements of a Quality Management System

ISO 9004:2009 – Making a Quality Management System more Efficient and Effective

ISO 19011:2011 – Guidelines for Auditing Management Systems

PMI Knowledge Center at: www.pmi.org/Knowledge-Center.aspx

PMI Project Management Body of Knowledge (PMBOK); Fifth Edition (2013)

Project Auditors: “PDRI: A Simple Tool to Measure Scope Definition” at: www.projectauditors.com

SAVE International – American Society of Value Engineering at: www.value-eng.org

Notes

API RP 1130 References

There are many references to the API RP 1130 (and the API RP 1155 – superseded by API RP 1130). The reader should remember that the current official Recommended Practice is the Third Edition (2007), reaffirmed in 2012. There are several evolutions of this publication:

- API 1155 Evaluation Methodology for Software Based Leak Detection Systems. First Edition (February 1995) - Replaced by API RP 1130. Therefore, this is no longer even an API official publication. However, it is referred to since it is compact, well-written and a useful introductory text.
- Much of API 1155 is incorporated in Appendix C of API RP 1130.
- API RP 1130 First Edition, November 2002 is referred to only as the baseline RP, primarily to emphasize that these practices are by now almost fifteen years old.
- API RP 1130 Computational Pipeline Monitoring for Liquids. The Third Edition (2007), reaffirmed in 2012, is the current Recommended Practice. Note that the "reaffirmation" did not change any of the text.

ASME B31.8 References

For leak detection threat analysis, there are several references to the Supplement to the ASME Standard "Gas Transmission and Distribution Piping Systems". The document ASME B31.8S is officially a "supplement" to this Standard and therefore is not, in of itself, a Standard at all.

The reports liberally use terms interchangeably for "Supplement", like "Commentary", "Remarks", etc.

Also note that the current applicable standard ASME B31.8 is the August 2016 edition. The reader might note, however, that the *Supplement's* text has not changed since the original, 2006 version.

PHMSA and DOT Sources of Recommendations

Note that the CFR is not officially a source of technical recommendations. Also, the Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC) of PHMSA does not serve an industry technology advisory role any longer. The reader is advised instead to refer to the PHMSA set of FAQs' at:
https://primis.phmsa.dot.gov/iim/faqs.htm