PHMSA

Final Report No. 17-152

Improving Leak Detection System Design, Redundancy and Accuracy

Natural Gas Pipelines: Appendices

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IMPROVING LEAK DETECTION SYSTEM DESIGN, REDUNDANCY AND ACCURACY

APPENDICES:

NATURAL GAS PIPELINES

PHMSA PROJECT DTPH-5614H00007

PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION (PHMSA)

July 18, 2017

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Improving Leak Detection System Design, Redundancy and Accuracy – Appendices for Natural Gas Pipelines

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1 Introduction

The objective of this first topic is to develop:

An approach that improves the ability of industry to design and engineer fit-for-purpose leak detection systems (LDS) for a wide range of pipeline systems more reliably and more rapidly.

The first step in such an approach is a systematic assessment of LDS requirements. This approach is via systematic Risk Analysis of the impact of a leak along the pipeline.

Together with the requirements analysis there also needs to be guidance as to appropriate solutions – or combinations of solutions – for each risk, operational and engineering pipeline situation.

This report is intended as source documentation and expert guidance for use in operations, and a potential reference for developers of pipeline standards and developers of recommended best practices. It is not intended as a standalone recommended practice; rather, it is a summary of current practice and a starting point for perhaps extensive customization for the purposes of individual operators.

The first part of the Appendix includes a description of the process and commentary. The second part of the report includes templates, examples and other tools to assist with its implementation.

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2 Context

2.1 Objectives of the Project

This PHMSA Project DTPH-5614H00007 is directed at the development of a set of recommendations, expert guidance, and draft procedures that will:

- Standardize the approach to designing an appropriate LDS for pipelines,
- Be accessible to all operators (including the smaller ones), and
- Try to reduce the extended and laborious front-end engineering.

The results are intended as:

- Source documents and expert guidance for use in operations, and
- A reference for developers of pipeline best practices.

The issues, with the exception of a future topic that specifically addresses retrofit, apply to new pipelines, new LDS on existing pipelines, and continual improvement to existing LDS. Generally, the scope includes:

- Gas, Oil, Liquids Products (including HVL) and Gas Products – with the issue being to try to unify processes and procedures appropriate to each.
- Offshore and onshore, buried and surface, river and road crossings.
- New (Greenfield) construction as well as existing (Brownfield) retrofit / improvement are both to be considered carefully.
- Gathering, Transmission, and "last mile" Delivery lines. However, low-pressure gas distribution systems are *not* included. Similarly, "inside the facility fence" piping is *not* included.

Of particular note is the distinct difference between operations, requirements and technologies in the Liquids and Gas industries – which is why we have prepared separate reports for gas and liquids.

2.2 Project vs. Program Management

Although there is definite overlap in these definitions, it is useful to distinguish between:

- Leak Detection *Programs* (ideally, part of an overall Integrity Management Program, IMP) that provide general principles; overarching goals, methodologies, and procedures; and company-wide policies. They are primarily intended to apply equally across all assets in a company.
- Leak Detection *Projects* that are tactical, specific deployments of LDS on a given pipeline asset.

It is also worth emphasizing that a Leak Detection *Project* may in fact refer to an asset that consists of multiple individual pipelines. For example, "all terminal lines under two miles in length" might be the subject of a single project, consisting of many dozens of lines. It is usually inappropriate to repeat very similar repetitive analysis, process and documentation many dozens of times – it is generally better in these cases to aim rather for a certain level of standardization.

Similarly, the two terms become the same when the pipeline operator may only own a few distinct pipelines. Even a portfolio of a few dozen short distribution lines is small enough that the LDS Program might in fact be a single Project.

Generally, the discussion in this and the other reports is tactical, and refers to practical pipeline LDS *projects* (with the understanding that these may include a collection of individual lines). LDS *program* management is an active and substantial area of development by organizations like the API, AOPL, and others.

2.3 Scale

With all the reports and guidance developed within this project, it is worth remembering that their application is expected to be appropriate and aligned with the size and importance of the pipeline assets for which they are used.

Generally, the overall discussion is intended to cover the broadest and most complex applications, for completeness. However, it is not by any means suggested that the same level of detail, process and documentation will be appropriate for short, single lines and smaller operators. The reader is encouraged to select the ideas and templates that are most useful to his particular application and to customize these at will.

In part to demonstrate this attitude, templates and examples are included with this task report specifically directed towards the simplest scenarios as well.

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3 Design and Engineering Framework

It is an objective of this work to standardize the design and engineering of LDS so that, as far as possible, they are approached in the same way as any other engineering project at a pipeline company.

The framework presented here is a very typical example of the overall process of an engineering project. However, the intention is for the operator to translate this guidance to match the specific practices at the pipeline company.

Broadly speaking, the engineering process is a series of steps that engineers follow to come up with a solution to a problem. Many times the solution involves designing and building a tangible product (like a machine, tool or computer code) that meets certain criteria or accomplishes a certain task. Engineers do not always follow the engineering process steps in order, one after another. It is very common to design something, build it, test it, find a problem, and then go back to an earlier step to make a modification or change to the design. This way of working is called *iteration*.

A common representation of the engineering process is often called the *Waterfall Process*. It consists of five high-level independent and roughly consecutive steps as illustrated (slightly modified) in the following figure:

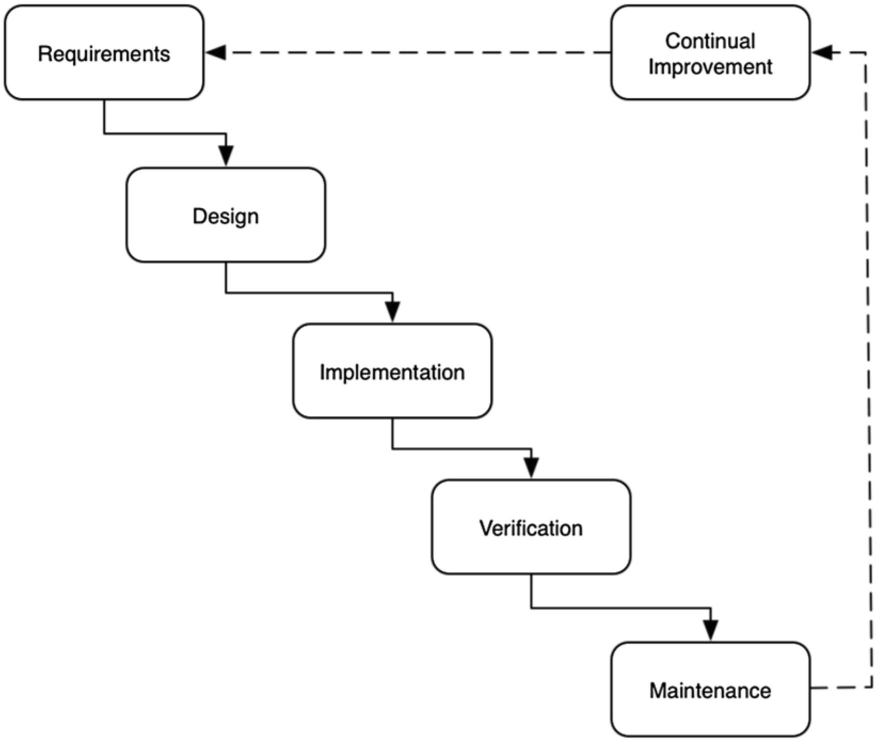

Figure A-1 - Waterfall Process

In this process, the major steps are:

- Requirements: The starting point for the entire process is a clear definition of the requirements and expected outcome of the LDS project.

- Design: Given the explicit requirements, the Design phase explores and then selects a specific technical solution in order to fulfill these objectives.

- Implementation: This takes the engineering design and assembles it for the application.

- Verification: Refers to the testing and validation that the as-built solution accomplishes the requirements.

- Maintenance: On a continual basis, testing, maintenance and re-verification is required to ensure that the as-built solution continues to accomplish the requirements.

- Continual Improvement: This is only occasionally added to the typical Waterfall Process. However, particularly where the operational environment of the pipeline, as well as the selection of potential technology solutions, is changing rapidly, potential new requirements and / or design options should be explored periodically.

Note that with LDS the Continual Improvement "loop" and its relationship with ongoing verification and maintenance is particularly significant. As described below in the final two chapters, Continual Improvement need not involve major technological or system upgrades; rather, it usually involves tuning or adjusting parameters and processes (such as alarm settings) in light of actual recorded LDS performance. These adjustments may be quite frequent especially when an LDS has just been commissioned.

Each of these steps is discussed in more detail below. At this stage, note the following comments and clarifications:

3.1 Remarks and Comments

Many sections contain "Remarks and Comments" which are notes on the body of the report. They are intended to address frequently asked questions on the content.

Even with the name "Waterfall" the overall process is rarely performed in an entirely linear fashion in practice. For example, it is not rare for the requirements to be modified after an engineering design feasibility study identifies some of them to be impractical. Similarly, during implementation it is not rare for the design to be modified in light of realities that only become evident during field installation. In this way, there is usually some iteration between steps in the process (and certainly within each step).

Nevertheless, it is good practice for the completed project to be documented as if it *had* been a step-wise procedure – in the sense that the finalized stage documentation and verifications should refer to the final, as-delivered solution.

The Waterfall process is by no means the only one for engineering in widespread use. It is presented as a framework to organize the guidance below. However, most other engineering methodologies can to some extent be translated into the language used here.

A popular alternative approach, for example, is the *Iterative Process* sketched in the following figure:

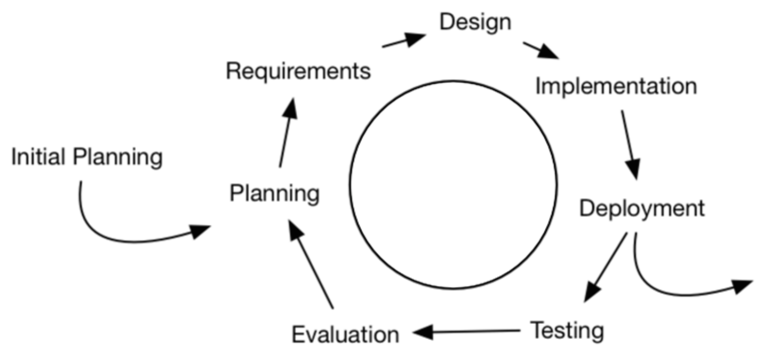

Figure A-2 - Iterative Process

This process diagram has the advantage of making the issue of Continual Improvement quite explicit. At the same time, note how many of the same terms are used for the steps in the process, and how they can be translated readily into the Waterfall in Figure A-1.

Similarly, the scope of each step varies between descriptions and implementations of the process. For example, Figure A-1 refers only to "Verification" whereas Figure A-2 divides this step into Testing and Evaluation. "Design" is, similarly, quite often divided into Analysis and Design. Again, these differences can generally be translated into the Waterfall in Figure A-1 without ambiguity.

A frequent overlap is between Implementation and Verification. There are usually several verification or testing stages during implementation, for example unit tests and integration testing, long before the final verification of the solution. This is discussed in more detail in the Implementation chapter below. Generally, this document takes the position that Verification applies to the complete, candidate solution, with respect to the complete set of Requirements. However, many other interpretations are equally valid.

3.2 Processes, Programs, Methodologies and Techniques

Methods (or technologies, techniques, etc.) are tools that seek to define a relationship between the measures taken to maintain the system integrity and the consequences in the event of a release through a variety of data and assumptions about how the system is designed, constructed, operated, and maintained, as well as the environmental and external factors that can affect risk. Methodologies "predict" the value of the output variable (e.g., environmental impact) based on the input values of more easily measured or evaluated variables (e.g., instrumentation, flow rate measurement, SCADA, sensors, etc.). The quality of the prediction is dependent on the quality of the inputs and the soundness of the logical relationships inherent in the method used to evaluate the input and output conditions.

It is important to distinguish between a risk mitigation *process* and a risk assessment *method*. Risk assessment is the estimation of risk (including the estimation of LDS effectiveness) for the purposes of decision-making. Risk *management* is the overall process (or program, procedure, etc.) that includes the risk assessment, maintenance activity and reintegration of data into subsequent risk assessments. Risk assessment methods can be very powerful analytical tools to integrate data and information, and help understand the nature and locations of risks along a pipeline. However, risk assessment methods alone should not be relied upon to establish risk, nor solely determine decisions about how risks should be addressed.

Risk assessment *methods* should be used as part of a *process* that involves knowledgeable, experienced personnel that critically review the input, assumptions, and results. This review should integrate the risk assessment output with other factors not considered by the tool, the impact of key assumptions, and the impact of uncertainties created by the absence of data or the variability in assessment inputs before arriving at decisions about risk and actions to reduce risk.

3.3 Input, Process, and Output

The overall framework, and each of its individual steps, is described here using the *Input, Process and Output* (IPO) formalism. There are many other ways of describing an engineering system in general but, as with the framework itself, these differences can generally be translated into an IPO structure without ambiguity. The output of one step is usually at least a sub-set of the input of the next step.

This document also divides each set of inputs, processes and outputs into three categories: Required, Recommended and Useful. These categories can be described as:

- Required: an item that is essential to the dataset or the process;
- Recommended: an item that, while technically not essential, will improve the quality of the solution substantially; and
- Useful: an item that will improve the quality of the solution, but may even quite often be omitted for practical reasons.

This is summarized in the following table:

Table A-1 - IPO Requirements Matrix

	Required	Recommended	Useful
Input	Data that is needed before any processing can be performed.	Data that allows better or more detailed processing.	Data that might, for example, provide crosschecks or validation of the results.
Process	The minimum level of work required, so that the objectives are met.	Additional work that substantially improves the product.	Additional work that might improve the quality of the product, for example by adding robustness or reducing uncertainty.
Output	The stated objective of the process.	Additional results or outcomes that allow for a better solution.	Additional results that might, for example, provide crosschecks or additional validation.

At the very highest level the major IPO for the Waterfall Process is shown in the following diagram. Each subsequent chapter contains a more detailed explanation of the IPO of the sub-processes (or *phases*):

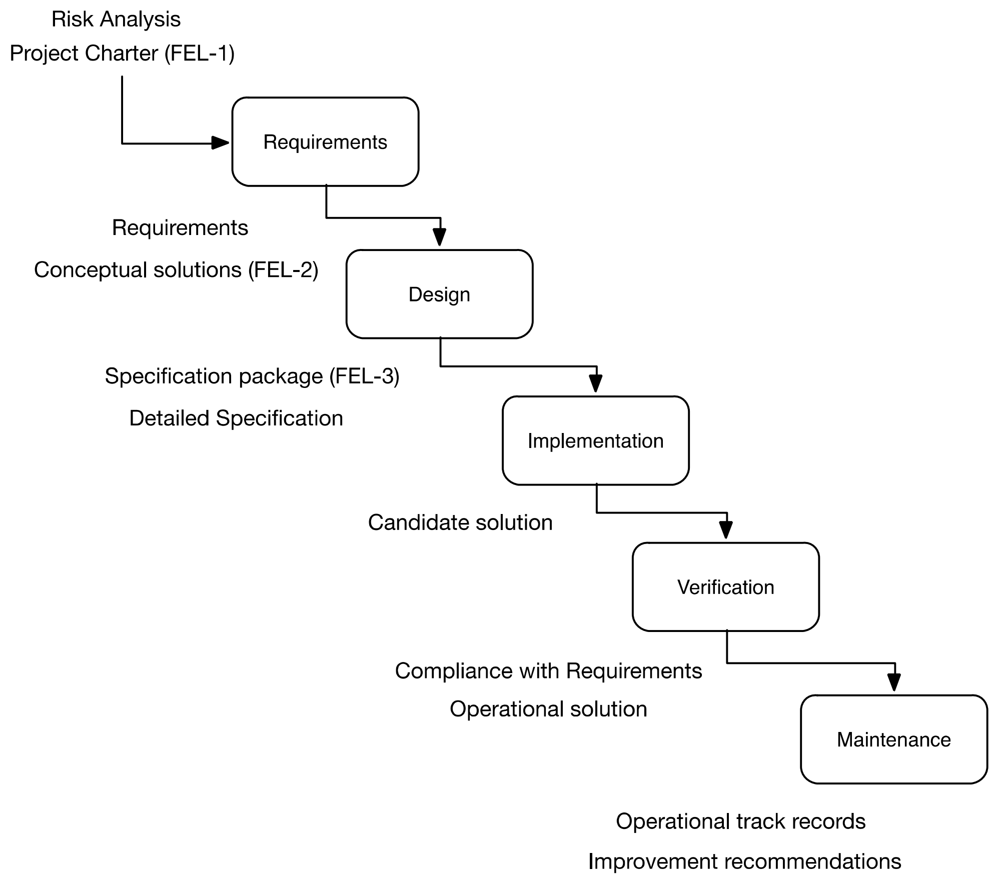

Figure A-3 - High-level IPO for Each Phase

3.3.1 Remarks and Comments

Very often, the "Output" is referred to as the *Objectives*. In practice, an IPO model is actually built in reverse order; the first step is in fact to define the outputs (objectives, end products) of the process. The necessary steps (processes) in order to generate the outputs are then described, and finally the pre-requisites (inputs) to these steps are stated.

The definition of required, recommended and useful can be highly controversial. It is also difficult to make this distinction universally for all projects, applications and industries. Therefore, it is fully expected that an operator will modify these specifications to suit the specific environment and expectations of a given project or set of projects.

3.4 Project Risk Management

Few complex engineering projects follow their initial plan exactly. In fact, an alarming number fail altogether for a wide variety of reasons. The risks of a project failure increase dramatically with high-technology solutions. There are a number of strategies available for mitigating project risk, and a good source for these is the Project Management Institute (PMI) and the International Standards Organization (ISO). Some typical examples include:

- Highly recommended are periodic internal and / or external Peer Reviews of the project;
- Checkpoints and off-ramps – in other words, milestones where it is acceptable to re-plan or even cancel the project depending on a review of progress; and
- Contingency plans and other "plan B" strategies, particularly useful with very new technologies.

These strategies apply generally to all Project Management, so this document does not define or to recommend how an operator manages project risk. However, the procedure will nevertheless include a minimal set of project risk management.

3.5 Documentation

In general, consistent documentation is a valuable tool for ensuring the quality and repeatability of any engineering process. Document management is in itself a major, standalone practice of Project Management. It is not the purpose of this study to define or to recommend how an operator maintains engineering records. However, the procedure will nevertheless include a minimal set of mandatory documentation.

Any input data should be recorded and stored, so that all steps can be repeated or reviewed if necessary. This is particularly important at the beginning of the Requirements stage. This is because the initial inputs to the requirements analysis will drive the entire remainder of the project, and it is critical to be able to recall the basis for these fundamental decisions many years, perhaps, later.

The process used should be recorded and stored (perhaps including any analytical or other tools that were utilized) so that it can be repeated, or checked, or verified. Of course, this is particularly important during Verification and Maintenance, where perhaps several different teams might be involved and it is critical to be able to recall performance measures many years, perhaps, later.

Finally, all outputs should be recorded. For example, a formal as-built description of the product is critical so that a review of success, and a baseline for continual improvement, can be available. It is common, in practice, for documentation of the process to be part of the output documentation.

3.6 Unique Elements of an LDS Project

Many of the steps of the engineering workflow are common to all engineering projects. However, LDS projects have certain elements that make them unique. These unique features are discussed in far more detail below but for now it is worth noting the main areas of focus:

- Requirements: It is typically possible to justify an engineering project on the basis of a pre-approved cost-benefit analysis, or on the basis of an urgent operational necessity. LDS requires different treatment since it neither generates immediate economic benefits, nor is it vital to operating a pipeline efficiently. Rather, the requirements are in terms of reduced risk of operations, safety and environmental considerations, and engineering best practices. Another particular difficulty with expressing requirements for an LDS is that their measures of performance are complicated. There is no one simple measure – like horsepower for an engine, or accuracy of an instrument – that can be stated as a requirement for an LDS.[1]

- Design: Among the challenges in designing an LDS is the novel and rapidly changing technology set available for building a solution. The available potential technical solutions often include candidates with a degree of implementation and project risk. Therefore, the designer is often faced with a choice between potentially high-performance designs, with a higher probability of failure, and lower-performance traditional designs. In addition, the technology set changes on a much more rapid cycle than for the rest of routine pipeline engineering.[2]

- Implementation itself is generally very similar to most other engineering disciplines. One feature (which is by no means unique to LDS) is that it often requires a *range* of engineering specializations; for example, many LDS require a combination of software, instrumentation, and telecommunications disciplines.[3]

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[1] This issue is sufficiently complex that an entire Task 3 of this project is devoted to Systematic predictions of performance for LDS

[2] This issue is sufficiently complex that an entire Task 2 of this project is devoted to Methodology for technology selection and engineering for LDS

[3] This issue is sufficiently complex that an entire Task 4 of this project is devoted to Impact of installation, calibration and testing.

There are also particular difficulties in retrofitting an LDS to a legacy pipeline without risking operations.

- Verification of an LDS shares with the Requirements that their measures of performance are complicated. Given the complexity of these measures, it can be difficult to design validations and tests that specifically measure these performance metrics fairly and accurately.

- Maintenance of an LDS shares with Design the difficulties of novel and changing technologies. Sometimes the technology itself has a lifespan shorter than the design life of the as-built LDS. Therefore, maintenance procedures can require constant adjustment. Similarly, inspection and continuing testing share the challenges of Verification, particularly in measuring performance metrics fairly and accurately, and on a repeatable basis.

- Continual Improvement presents the same challenges as most high-technology applications. The pace of change is sufficiently rapid that many pipeline operators find that the technology changes much more rapidly than other pipeline sub-systems. Therefore, a particular effort is usually needed to keep pace with technological improvements in LDS.

The following table is intended to help summarize these issues, by listing them and pointing to the sources for further detailed discussion.

Table A-2 - Project Issues that are Particular to LDS

Requirements	• Risk-based cost-benefit objectives • Specification of expected performance • Prediction of expected performance • Technology selection	Chapter 4 below Task 3 Task 3
Design	• Redundant / high-availability architectures • Technology selection	Task 2
Implementation	• Range of disciplines • Impact of installation on performance • Retrofit challenges	Task 4 Task 3
Verification	• Measurement of specified performance	Task 3
Maintenance	• Impact of testing and maintenance on performance • Impact of installation on performance	Task 4 Task 3

The reader who is specifically interested in LDS issues – and who already has a grasp of the more general Project Management processes – is recommended to focus on the sub-sections listed in the following table:

Table A-3 - Sub-Sections Devoted Specifically to LDS Technology

Sub-Section	Section Number
Recommended Practices	4.2.3
Integrity Management	4.2.4
Applicable Regulations	4.2.6
Continual improvement lifecycle	4.3.2
Performance prediction and measurement	4.3.5
Regulatory, Procedural and RP compliance reporting	4.4.4
Cost-Benefit of an LDS	4.8
Risk Analysis	4.9
Typical pipeline escalation and impact factors	4.9.3
Threats vs. Consequence in LDS	4.9.7
Technology selection pre-screening	4.10.3
Impact on operations	4.11.2
Formal Performance Requirement	4.12.2
Buy vs. Build	5.3
Impact on operations	5.5.3
LDS-specific concerns	5.6
Particular LDS issues	6.4
Maintenance process	8
Continual improvement	9

3.7 Differences between Gas and Liquids Pipelines

It is noted above that the overall Engineering Process for LDS is generally the same, regardless of whether the project is for a gas or liquid; retrofit or new construction; or for a small or large system.

However, it is worth remembering that there are substantial differences in the details of the solutions that are available, and that can be developed, between the gas and liquids industries. Some of the more notable ones include:

Table A-4 - Project Issues that Differ between Gas and Liquids

Requirements	• Risk factors (specification and thresholds) for leaks and cost-benefit objectives • Specification and also levels of expected performance • Applicable Technology set
Design	• Technology selection and engineering for different objectives
Implementation	• Impact of installation on performance • Meter-based vs. external sensor-based
Verification	• Measurement of performance and testing procedures
Maintenance	• Tuning of gas vs. liquids LDS • Frequency of upgrades

3.8 Differences between Large and Small Pipelines

Similarly, the *overall* Engineering Process for LDS is generally the same, regardless of whether the project is for a small or large system. Naturally, there will be large differences in the scale and level of detail used to plan and execute an LDS depending on the size and complexity of the pipeline. For example:

- The output of the requirements and design phases for a low-consequence, short and low-volume line can be a brief, one-page document. It may even state simply that a dedicated LDS is not needed (for example, if there is already an established surveillance program for the asset).

- Implementation and Verification for smaller systems might be performed as part of another larger project (again as an example, it might be delegated to an asset security project)

However, it is still recommended to maintain a record of all five of the engineering process phases as they relate to LDS specifically, so that the unique requirements of leak detection are not missed or under-served.

3.8.1 Remarks and Comments

In practice, a common issue with many pipeline systems is the "last mile" segments. These are the generally quite short gathering or distribution lines, from the main transportation network to facilities (which may even be owned by third parties).

Although individually these lines may be less than a few miles long, there can be dozens or hundreds of them to take into account.

Carrying out a complete LDS analysis and engineering process for every one of these short lines is usually prohibitively time-consuming in terms of process, management and engineering time. In these situations, it is common to address an entire collection or sub-set of these short lines as a single project. As far as possible, they are normalized into "typical" lines, and engineering solutions are developed for them as a group. Task 2 of this project, devoted to Methodology for technology selection and engineering for LDS, explores this approach further.

4 The LDS Engineering Process

4.1 Summary

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

Table A-5 - 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 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

4.2 Input

4.2.1 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.

Various descriptions of a PC are used, but for this document the necessary content of the PC is at least:

Table A-6 - Contents of a Project Charter

Reason	(Optional) A statement of the reason for the project. Examples include: risk reduction of operations; improved environmental protection and safety; or integrity management improvements.
Objective	The stated Objective of the LDS project. 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. Detailed Requirements for the LDS will be developed during the project, and the LDS shall demonstrate achievement of these stated requirements.
Constraints / Resources	Limitations on the resources available to the project: in terms of time, investment capital, people, infrastructure, technologies, etc.
Directions	(Optional) These Directions concerning the solution are constraints on the design. For example, any relevant binding company policies or RPs might be cited here. Rarely, a specific technical solution is also dictated (but see notes on this issue below).
Stakeholders	The identities of the main stakeholders are specified. It is strongly recommended that their respective Responsibilities and Authorities should be identified clearly.
In-Scope / Out-of-Scope	(Optional) These in-scope and out-of-scope items are constraints on the design, usually intended as a clarification so that unnecessary objectives are not even considered right from the start.
Project Risk Management	(Optional) A statement of how risks in the project execution will be handled. At this stage, high-level statements are sufficient such as citing corporate or standard practices.
Communication Plan	(Optional) A high-level statement of how project documentation will be handled and, as appropriate, which stakeholders will be involved.
Target Benefits	(Optional) Recall that for LDS the exact measurable performance benefits are very difficult to specify and are unlikely to be included in the PC. However, these can relate to the Reason for the project above: for example halving overall relative operational risk; environmental protection of all High-Consequence Areas; or 30% reduction in the likelihood of any loss exceeding a certain size.
Budget / Spending Authority	The total budget corresponds to the constraint on capital resources above, but it may be further detailed into, for example, internal vs. external spending, quarterly / annual availability, IT / instrumentation / communications, etc. Critically, the respective Responsibilities and Authorities to spend of each stakeholder should be identified clearly.

Note that the development of the Project Charter is often referred to as the first step (FEL-1) of the three-step Front-End Loading (FEL) process. The FEL process is described in the Requirements section below.

4.2.2 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 take part in it)
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.

4.2.3 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 (line item 4) of the PC, but if not they are strongly recommended as additional input.

There are not many RPs applicable specifically to LDS. Some of the few that are available include (technically for liquids pipelines only):

- API 1149 (1993): Pipeline Variable Uncertainties and Their Effects on Leak Detectability. 1st Edition (November, 1993). American Petroleum Institute.

- API 1130 (2002): Computational Pipeline Monitoring for Liquid Pipelines. 2nd Edition (November, 2002). American Petroleum Institute.

- API 1155 (1995, now superseded): Evaluation Methodology for Software Based Leak detection Systems. 1st Edition (February, 1995). American Petroleum Institute.

- API 1160 (2013): Managing System Integrity of Hazardous Liquids Pipelines (September, 2013) American Petroleum Institute. This is much less specific to LDS but does cover Risk Analysis and potential LDS methods.

The ASME also publishes the ASME B31.8 (S) as a supplement to the standard, a Commentary only, for Managing System Integrity of Gas Pipelines. It includes valuable minimum set of leak consequence factors to consider as well as a list of potential leak detection methods.

These recommended practices are not new. API 1130 is largely intended as an update to API 1155. As a comment, API 1155 and also despite its title API 1130 can be used in large part for natural gas pipelines, and with LDS techniques other than Computational Pipeline Monitoring (CPM), as well.

However, 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.

4.2.4 Integrity Management

It is widely recommended that leak detection should be considered as part of a comprehensive Integrity Management Program (IMP). See for example API 1160, ASME B31.8 (S), or the 49CFR 195. Therefore, it is strongly recommended to explain how the project contributes to the overall company IMP plan as well.

4.2.5 Project Risk Management

It is recommended that any applicable company PM standards, or industry recommended practices, should be identified as input to the project. Often these are part of the PC (line item 7) but if not, they are very useful input to the project.

It is very common, for example, for a project to authorize just the requirements and preliminary design stages up-front, and then to have a major checkpoint where a decision to go forward is made. Several templates are available from:

- The PMI Knowledge Center, which has a whole section on Risk Management
- ISO 31000:2009 Risk Management – Principles and Guidelines

4.2.6 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.

It is not even recommended since 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 state:

The pipeline is located entirely in an HCA (High Consequence Area) and therefore (see the 49 CFR 195.134) special consideration will need to be paid to appropriate higher-performance leak detection systems.

In this regard, the 49 CFR 195 is being cited 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 195

This typically has a chilling effect on the engineering project in general: at a minimum it focuses attention on bare compliance with the letter of the law. Worse, it is all too easy to copy relatively simple solutions just known to pass the letter of the regulation, without stretching the design team to seek an optimal LDS. By contrast, requiring compliance with the industry RP API 1130 provides far more space for design decisions, while automatically providing compliance via 49 CFR 195.3.

4.3 Process

4.3.1 Project Plan

The basis of the Process is a plan. The overall structure of the plan is the scope of this study and this document. This might usefully follow the Waterfall Process of Figure A-1 above, or any other similar structure appropriate to the operator.

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 IPO 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 this document does not focus on them.

A useful set of guidelines and templates is provided by the PMI, in the Guide to the Project Management Body of Knowledge (PMBOK), a book that presents a general set of standard terminology and guidelines for project management. The Fifth Edition (2013) is the document resulting from work overseen explicitly by the PMI. Earlier versions have been recognized as standards by:

- The American National Standards Institute (ANSI, ANSI/PMI 99-001-2008); and
- The Institute of Electrical and Electronics Engineers (IEEE 1490-2011).

The project plan typically covers topics used in the project execution system and includes the following main aspects:

- Scope Management
- Requirements Management
- Schedule Management (based on the Waterfall or similar stated process)
- Financial Management
- Quality Management
- Resource Management
- Stakeholders Management
- Communications Management
- Project Change Management
- Risk Management
- Procurement Management

4.3.2 Continual Improvement Lifecycle

Especially for high-technology solutions, it is critical for one of the results of the Requirements and Design stages 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 on the initial project, but on the total lifetime cost of ownership of the system for the operator. As a few rough examples:

- Most CPM based LDS rely on software, and commercial software typically has a release / update cycle. The operator should at least review whether an update is required at every new software publication.

- Certain pressure wave CPM methods rely on very sensitive pressure transducers. Recently, these transducers have been approximately doubling in accuracy every two years or so. The operator should at least review whether a pressure sensor upgrade is useful every two years.

- Material balance CPM methods depend on a definition of the topology and supply/delivery points on the pipeline. If any new points are added to the pipeline, the CPM will have to be reviewed.

This issue is sufficiently complex that it is discussed in detail in Task 2 of this project, which is devoted to Methodology for technology selection and engineering for LDS. It is also the subject of the API Recommended Practice 1160, Chapters 12 and 13, which emphasize a continual program evaluation and management of change process.

4.3.3 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.

The reviews typically take place at major milestones or decision points. Examples include:

- Verifying the stated Requirements;

- Concurring with the Design and Technology Selection;

- Checking the testing and Validation of the as-built system; and

- At closeout, for example to identify lessons learned and final compliance with the Requirements.

Many pipeline operators have internal Subject Matter Experts (SME) in LDS, who are ideal for these reviews. Alternatively, external engineering consultants or laboratory staff with LDS SMEs can be employed.

4.3.4 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.

The main sources for these standardized PM procedures have already been referred to above:

- The PMI, through its Knowledge Base and the PMBOK; and
- ISO 21500:2012 – Guidance on project management, ISO 31000:2009 – Risk Management, and others from the International Standards Organization.

4.3.5 Performance Prediction and Measurement

Task 3 covers Systematic predictions of performance, and Task 4 covers the Impact of installation, calibration and testing, in much more detail. However, even at this high level it is important to focus both on the specific importance of attempting to predict performance of the LDS, and of observing its actual performance once built in the field.

Currently, perhaps the best 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)[4], 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 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 CPM leak detection systems. 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

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

methodologies of the leak detection system are known in sufficient detail to apply techniques such as uncertainty analysis.

Some advantages of estimation are that it:

- Can be done before a leak detection system is put in place.
- Allows comparison of different leak detection systems for an asset.
- Provides prediction of the effects of changes to the configuration or operation of the asset or of the leak detection system.

Some disadvantages of estimation are:

- It is a theoretical exercise that is not perfectly accurate, and the accuracy of the estimation is generally not known.
- When comparing different leak detection systems if the difference in accuracy of the estimations is of the same order as the difference in the estimated accuracy it provides no basis for selection and can even be misleading.
- The configuration of the asset must be known in great detail, including items such as accuracy and precision of inputs that are difficult to obtain or assess.
- The methodology of the technique used for leak detection must be known in detail, this may not be available for proprietary technologies.
- Derivation of the uncertainty relations for a leak detection technique is a challenging exercise and requires a thorough understanding of the mathematics and statistics of uncertainty analysis.

Performance *observation* (part of continual System Verification) bases performance targets on analysis of historic performance of the technology and/or testing designed to establish the performance of the technology. Performance observation techniques are more appropriate where detailed knowledge of the asset, the operation, or the leak detection technology is not known or when the true performance of an existing asset needs to be determined.

Some advantages of observation are that:

- It provides a definitive result for the performance.

- It accounts for as-built, real-world conditions.

Some disadvantages are that:

- It does not identify factors limiting the performance.
- It does not provide predictive information on how changing the configuration or operation of the system will affect performance.

These two methods of determining performance targets are not exclusive. As an example observation of the performance of a CPM leak detection system on a specific asset provides the definitive measure of the performance of the system. A performance estimation technique such as API 1149 must be used to estimate the performance that can be expected if the operation or configuration of the asset is to be changed. An API 1149 analysis might also be used to determine if the observational performance is expected or if the observed performance indicates a problem with the system. As always, sound engineering practice and experience must be used when deciding whether a difference in the estimated and observed performance of a system should be attributed to inaccuracies inherent to the estimation procedure or if additional investigation is warranted.

A special case of using the two techniques together is to use observed performance to 'tune', or reverse engineer, the inputs to the estimation technique to cause it to calculate the observed performance. There are many pitfalls to this practice that should be considered.

The number of independent observations must at least exceed the number of inputs to the estimation procedure to provide a unique solution. Recorded SCADA data is highly correlated and so SCADA scans cannot be considered independent observations.

Without great care such an exercise can produce inputs to the estimation procedure that will match the observations used to tune the system but will not produce correct results when used to estimate the performance of the system with new operations or configurations.

Both estimation and observation are useful to determine, or at least estimate, the performance of a specific technology applied to a specific asset. They can also be applied to make generalizations about the performance of a leak detection technology by performing the analysis for many pipelines with common characteristics, such as all those that use a specific technology. For instance an operator may deduce that their uncompensated volume balance CPM achieve X% sensitivity versus Y% for their compensated volume balance. Such a finding is obviously a simplification since each pipeline in reality has a unique performance, but generalized metrics can be useful in many instances such as making an initial choice of technology for an asset.

4.4 Output

4.4.1 Objective

This matches the Objective stated in the PC (line item 2).

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.

Note how it is required for the project to include all three of People, Process and Technology issues. It is *not recommended* to divide these up between projects or teams; for example, to have project "A" for a technical solution, driven by engineering, project "B" for controller training, driven by H.R., and project "C" for LDS response procedures, driven by operations.

Development of detailed Requirements for the LDS *is an objective of the project*. Logically, achievement of these stated requirements, and demonstration of this achievement using repeatable engineering tests, is also an objective.

4.4.2 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.

4.4.3 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.

4.4.4 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.

4.5 Requirements Process

4.6 Summary

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

Table A-7 - Requirements Process

Input	*Required*	• Risk Analysis • Project Charter, in particular: Objective, Limitations, Directions, Out-of-scope, Target benefits
	Recommended	• Technology selection pre-screening
	Useful	• Financial Risk Analysis

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	• Return on Investment estimation

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 Return on Investment

4.7 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:

4. 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 more than about +/- 100% accurate.
5. 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.
6. FEL-3 covers detailed specification. 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 his own detailed design, appropriate to his own technologies and procedures, which are constrained to be within about +/- 15% of the FEL-3 detailed specification.

4.7.1 Remarks and Comments

As usual, the precise definitions of the FEL steps, and when they take place, vary considerably. The operator is encouraged to modify these to suit his own specific project and internal requirements. For the purposes of this document:

- FEL-1 consists primarily of the development of a Project Charter, and so is an Input to the overall process;

- FEL-2 consists of a conceptual exploration of solution alternatives, with a view to developing alternatives and practical performance targets. It is therefore primarily a detailed Requirements analysis exercise.

- FEL-3 (detailed specification) is then part of the Design phase.

For alternative definitions, definitions, and templates that can be used as appropriate to modify this process, some sources include:

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

- Project Auditors: "PDRI: A simple tool to measure scope definition".

- SAVE International – American Society of Value Engineering

The development of conceptual design alternatives this early on during Requirements analysis is sometimes controversial. It is, however, consistent with maximizing analysis at the front end of the project. The reason for having at least a set of conceptual design alternatives available at the end of Requirements analysis is that this also allows a (conceptual) study of cost-benefit and a better statement of expected performance.

This whole FEL process is also meant to be *creative*. Especially at the FEL-2 stage, it is expected that a wide variety of alternatives should be explored and brainstormed.

4.8 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. Perhaps a more accurate term is *Loss Detection Capability Evaluation* (LDCE).

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 risk of failure and consequential damage.

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 monitor 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. In this context, it is useful to think of:

Risk = (Probability of the cost being due) * (Economic impact of the cost) / (Unit time)

The economic impact can be relative and assigned a relative numerical score, or explicit in terms of dollar value. If the total cost of remedying a given leak is C, and the probability of this leak occurring in a given year is P, then the Risk is P * C.

A relative (score-based or ranking-based) risk can be used to estimate a Cost-Benefit in relative terms. An absolute Financial Risk might be rated as: Expected $ cost / year. This allows an ROI in dollar terms to be estimated. Note, however, that this is extremely rare in practice in the pipeline industry, and is generally limited to downstream operations.

4.9 Risk Analysis

There are a number of techniques used to estimate the probability and impact of failure, and the numerical product of these is the total Risk. These notes refer to two documents from the International Standards Organization (ISO) from 2009 that cover Risk Analysis:

- ISO 31000: Risk Management – Principles and Guidelines
- ISO 31030: Risk Management – Risk Assessment Techniques

The same principles and techniques have been adopted by the pipeline industry, but mainly with the objective of providing a framework for inspection and maintenance – see for example the API RP 580/581 – Advanced Risk Based Inspection.

A summary of ISO 31000 by the Institute of Risk management (IRM) of the U.K. is also useful as a practical document to understand the principle and concepts at a high level. It is the view of the ISO that:

“Organizations manage risk by identifying it, analyzing it and then evaluating whether the risk should be modified by risk treatment in order to satisfy their risk criteria. Throughout this process, they communicate and consult with stakeholders and monitor and review the risk and the controls that are modifying the risk in order to ensure that no further risk treatment is required.”

This implies that there are established – and communicated, consultative – organizational risk criteria. That is, maximum *absolute* levels of risk.

"Although the practice of risk management has been developed over time and within many sectors in order to meet diverse needs, the adoption of consistent processes within a comprehensive framework can help to ensure that risk is managed effectively, efficiently and coherently across an organization. The generic approach described in this International Standard provides the principles and guidelines for managing any form of risk in a systematic, transparent and credible manner and within any scope and context."

In other words, standardization helps with diversity of applications, efficiency, consistency and credibility.

Independent of the risk assessment method used, all techniques incorporate the same basic components:

1. Identify potential events or conditions that threaten the system's integrity.
2. Determine risk represented by these events or conditions by determining the likelihood of a release and the consequences of a release.
3. Rank risk assessment results.
4. Identify and evaluate risk mitigation options (both net risk reduction and benefit/cost analyses)
5. Integrate maintenance project data (i.e., a feedback loop)
6. Re-assess risk

Ultimately, it is the responsibility of the operator to choose the risk assessment method that best meets the requirements of the risk assessment task. Therefore, it is in the best interest of the pipeline operator to develop a thorough understanding of the various risk assessment methods in use and available, as well as the respective strengths and limitations of the different types of methods, before selecting a long-term strategy. A variety of different approaches to risk assessment have been employed in the pipeline as well as other industries. The major differences among approaches are associated with:

- The relative "mix" of knowledge, data, or logic / algorithms;

- The complexity and level of detail; and

- The nature of the output (probabilistic versus relative measures versus absolute levels of risk).

4.9.1 Vocabulary

It is important to use a consistent vocabulary in order to communicate concepts clearly between stakeholders, and across disciplines. Some of the more subtle distinctions include (references in parentheses are to the ISO document):

Risk is often characterized by reference to potential **events** (2.17) and **consequences** (2.18), or a combination of these.

Risk is often expressed in terms of a combination of the **consequences** of an event (including changes in circumstances) and the associated **likelihood** (2.19) of occurrence.

Uncertainty is the state, even partial, of deficiency of information related to, understanding or knowledge of an event, its consequence, or likelihood.

Risk attitude is an organization's approach to assess and eventually **pursue, retain, take or turn away** from risk (2.1)

Risk treatment can involve various approaches, including:

- Removing the risk source (2.16) such as removing a line from service;
- Changing the likelihood (2.19) such as maintenance or inhibiting corrosion. This mechanism is called a **control**;
- Changing the consequences (2.18) such as by detecting a leak early – potentially using an LDS – and shutting it down fast – perhaps with an Emergency Flow Restriction Device (EFRD). This is called **mitigation**; and
- Retaining the risk by **informed decision** that involves communicating this decision and identifying this risk.

4.9.2 Techniques

ISO 31000 only recommends principles and a vocabulary. The purpose of ISO 31010 is to present a set of methodologies and techniques for implementing these principles. Table A.1 describes all the methods in ISO 31010 and where / when they can be used.

The most widely used in engineering integrity management is the bow-tie diagram, Sect. B.21

The bow tie is drawn as follows:

1. A particular **Risk** (say, a leak at a given location of a certain size) is identified for analysis and represented as the central knot of a bow tie.
2. **Causes** (and perhaps **sub-causes**) of the event are listed considering sources of risk (or hazards in a safety context).
3. The mechanism by which the source of risk leads to the critical event is identified.
4. Lines are drawn between each cause and the event forming the left-hand side of the bow tie – the **Fault Tree**. Factors that might lead to **escalation** can be identified and included in the diagram – for example, increasingly corrosive fluids, changes in operating regime, etc.
5. **Barriers** that should prevent each cause leading to the unwanted consequences can be shown as vertical bars across the line. Where there were factors causing escalation, barriers to escalation can also be represented. The approach can be used for positive consequences where the bars reflect 'controls' that stimulate the generation of the event.
6. On the right-hand side of the bow tie, the **Event Tree**, different potential **Consequences** of the risk are identified and lines drawn to radiate out from the risk event to each potential consequence. These might for example be a release of a certain total volume at a certain point.
7. Barriers to the consequence are depicted as bars across the radial lines. The approach can be used for positive consequences where the bars reflect **Controls** that **Mitigate** the generation of consequences. These might include rapid shutdown of a leaking pipe.
8. **Recovery** involves returning to the original state, such as cleanup of the escaped fluids.
9. Management functions that support controls (such as training, ILI and visual inspection, and of course Leak Detection) can be shown under the bow tie and linked to the respective control.

When pathways are independent, the probability of a particular consequence or outcome is known and a figure can be estimated for the effectiveness of a control. However, in many situations, pathways and barriers are not independent and controls may be procedural, so the effectiveness unclear. Quantification is often more appropriately carried out using Fault Tree Analysis (FTA) and Event Tree Analysis (ETA).

This is almost always the case. FTA is described in Sect. B.14 and ETA is described in Sect. B.15.

In short, Prevention Barriers are applied to reduce the *threat likelihood* (for example, ILI, corrosion inhibitor, maintenance, etc.) Mitigation measures reduce the *impact of the consequence*, once it has occurred (for example, leak detection and emergency shutdown).

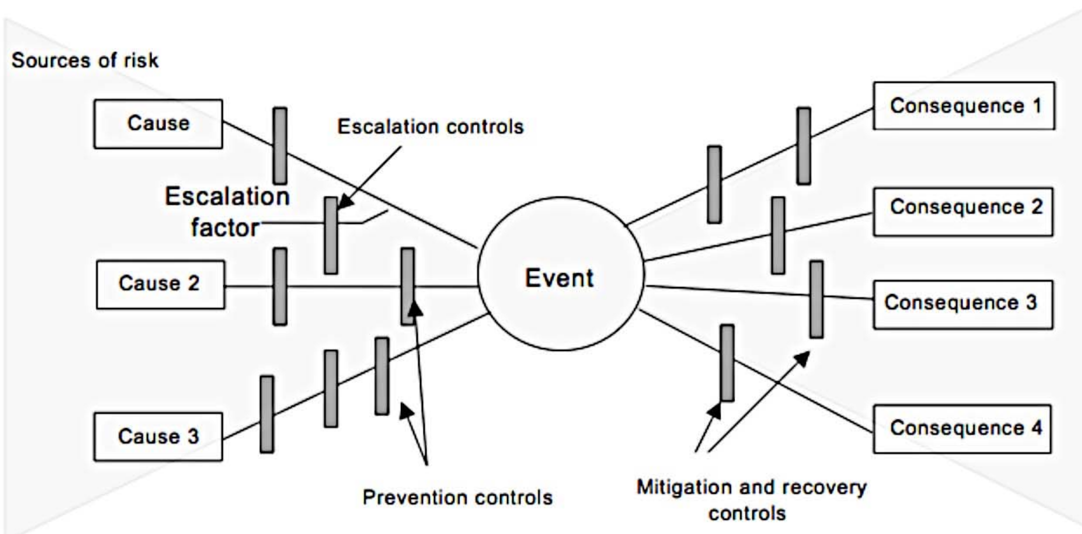

Figure A-4 - Bow-tie Diagram (ISO 31010)

4.9.3 Typical Pipeline Escalation and Impact Factors

The primary factors are listed in the 49 CFR 195 (liquids pipelines) and also in industry recommended practices like the ASME B31.8 Supplement (gas pipelines) and API RP 1160 (liquids pipelines). It is worth recalling that according to the U.S. DOT periodic reports on *the State of the National Pipeline Infrastructure* nearly all the failure causes for line pipe are corrosion, material/weld failures, and excavation damage. Incorrect operation also contributes to failures in a substantial number of smaller systems. These reports also provide percentages of all incidents where failures were due to each of these three causes. Other useful sources for the percentages of incidents due to each cause include the API Incident Database, as well as the periodic PHMSA Incident Analysis Reports.

ASME B31.8 Supplement (2006) – For gas pipelines, the ASME publishes a Commentary, as a supplement to the ASME B31.8 standard, for Managing System Integrity of Gas Pipelines. It is of note that the majority of the principles (if not the details) apply equally well to liquids pipelines also.

Chapter 3 of this Commentary provides, in particular, a minimum set of possible Consequence calculations that can be applied during a Risk Analysis. They also list the following minimal set of factors to consider:

- Population density
- Proximity of the population to the pipeline (including consideration of manmade or natural barriers that may provide some level of protection)
- Proximity of populations with limited or impaired mobility (e.g., hospitals, schools, child-care centers, retirement communities, prisons, recreation areas), particularly in unprotected outside areas
- Property damage
- Environmental damage
- Effects of un-ignited gas releases
- Security of gas supply (e.g., impact resulting from interruption of service)
- Public convenience and necessity
- Potential for secondary failures

Chapter 5 also describes a Risk Analysis process tailored to gas pipeline systems, and consistent with the ISO standards.

It is generally much more difficult to assign a quantitative impact measure for a gas release than for a liquids release. With liquids, it is common practice (49 CFR 195, API RP 1160, and other procedures) to scale the impact of a release directly with its volume. In the case of natural gas, some of the other factors to consider include (49 CFR 192, ASME B31G (S), and others):

- Depending on the transported gas density, the release may either settle above the ground around the line (for example, CO2 and many HVLs in gas state), or it may vent upwards into the atmosphere (for example, industrial methane).
- If the region around the loss is relatively well ventilated, even quite large losses will disperse rapidly. However, if the surrounding area is enclosed it may either be trapped above (when lighter than air) or below (when heavier than air). This

might create either a suffocation / choking hazard, or an ignition hazard, depending on the situation.

- Some gases (like methane) are quite difficult to ignite and require a specific air-to-fuel ratio. Others (like most HVL) are easily combustible.

In short, the impact of a release might range from quite small and fairly independent of rate of release (for example, a methane line in open countryside) to extreme, and essentially catastrophic in most cases (for example, a butane line running under schools, airports, or other populated areas). In many cases, speed of detection has to be substantially higher than in liquids pipelines. In others, it is sufficient to perform routine air quality surveys.

API Recommended Practice 1160 (2013) – For liquids pipelines, the API publishes a RP for Managing System Integrity of Hazardous Liquids Pipelines. It is of note that the majority of the principles (if not the details) apply equally well to gas pipelines also.

It contains an Informative Annex F describing potential leak detection methods. Annex A provides a normalized list of threats to pipeline integrity. Both threats and consequences are covered in Chapter 10. The threats are generally in the categories of:

- Third-party Damage
- Brittleness and Cracking in Line Pipe
- Weather and Outside Forces
- Corrosion (internal and external)

Table 7 and Chapter 10.6 also cover leak detection methods for liquids lines.

Code of Federal Regulations – *For liquids pipelines*, the 49 CFR 195 rule requires an operator to include a process in its program for identifying which pipeline segments could affect a high consequence area and to take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area (see §§ 195.452 (f) and (i).) Thus, an operator will need to consider how each pipeline segment could affect a high consequence area (HCA). The primary source for the listed risk factors is a US DOT study on instrumented Internal Inspection devices (November 1992). Other sources include the National Transportation Safety Board, the Environmental Protection Agency and the Technical Hazardous Liquid Pipeline Safety Standards Committee.

1. Terrain surrounding the pipeline.
2. Drainage systems such as small streams and other smaller waterways that could serve as a conduit to a high consequence area.
3. Crossing of farm tile fields. An operator should consider the possibility of a spillage in the field following the drain tile into a waterway. Crossing of roadways with ditches along the side. The ditches could carry a spillage to a waterway.
4. The nature and characteristics of the product the pipeline is transporting (refined products, crude oils, highly volatile liquids, etc.) Highly volatile liquids (e.g. Butane) become gaseous when exposed to the atmosphere. A spillage could create a vapor cloud that could settle into the lower elevation of the ground profile.
5. Physical support of the pipeline segment such as by a cable suspension bridge. An operator should look for stress indicators on the pipeline (strained supports, inadequate support at towers), atmospheric corrosion, vandalism, and other obvious signs of improper maintenance.
6. Operating conditions of the pipeline (pressure, flow rate, etc.).
7. Exposure of the pipeline to an operating pressure exceeding the established maximum operating pressure.
8. The hydraulic gradient of the pipeline.
9. Normal Flow Rate
10. The diameter of the pipeline, the potential release volume, and the distance between the isolation points.
11. Potential physical pathways between the pipeline and the high consequence area.
12. Response capability (time to respond, nature of response). Large Leaks Only 2hrs / Small Leaks 24hrs
13. Potential natural forces inherent in the area (flood zones, earthquakes, subsidence areas, etc.)
14. Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.
15. Results from previous testing/inspection. (See § 195.452(h).)
16. Leak History.
17. Operating Temperature
18. Known corrosion or condition of pipeline. (See § 195.452(g).)
19. Cathodic protection history.
20. Current Hydro Interval
21. Type and quality of pipe coating (disbonded coating results in corrosion).
22. Age of pipe

23. Product transported (highly volatile, highly flammable and toxic liquids present a greater threat for both people and the environment)
24. Pipe wall thickness
25. Size of pipe (higher volume release if the pipe ruptures).
26. Location related to potential ground movement (e.g., seismic faults, rock quarries, and coal mines); climatic; geologic (landslides or subsidence)
27. Security of throughput (effects on customers if there is failure requiring shutdown).
28. Time since the last internal inspection/pressure testing.
29. With respect to previously discovered defects/anomalies, the type, growth rate, and size.
30. Operating stress levels in the pipeline (% of SMYS).
31. Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly impede access for spill response or any other purpose).
32. Non-standard or other than recognized industry practice on pipeline installation (e.g., horizontal directional drilling; very old pipe without weld inspections; etc.).

For gas pipelines, the 49 CFR 192 rule similarly requires an operator to take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area, and to maintain an Integrity Management Program. The guidance in this rule is conveniently summarized in Appendix E to Part 192: *Guidance on Determining High Consequence Areas and on Carrying Out Requirements In The Integrity Management Rule*.

The major categories of threat of failure follow Part 195 closely: External Corrosion, Internal Corrosion, and Third-Party Damage. Table E.II.I summarizes not only the requirements of the rule, but also potential threat-reduction measures:

1. Direct Assessment:
2. Electrical Surveys, or other ILI Survey
3. Pressure Testing
4. Integrated Data Reviews
5. Leak Repair and Inspection Records
6. Fluid Removal and Analysis (for corrosive properties)

Mitigation of consequences is much less thoroughly covered, in particular leak detection. Leak surveys (periodic patrolling of the line with methane gas detectors or other means) are cited, but these are really considered as early warning of a more serious leak. However, Figure E.I.A provides a general method for assessing when a pipeline is in an HCA, based upon a Potential Impact Radius (PIR, also Blast Radius, Hazard Area Radius, etc.):

PIR = 0.69 *d*SQRT (P) – Where: d = diameter of the pipe (inches) and P = pressure (psi)

The factor 0.69 was recommended by, among others, the Gas Research Institute (now the Gas Technology Institute, GTI). A pipeline *Class Location* helps to define what an HCA is. In essence, Class 3 and 4 areas are places where there would be greater human injury potential from a pipeline incident and therefore require more vigorous inspection / protection regimes. They are determined by the number of buildings within 660 feet on each side of a pipeline per sliding mile, as follows:

- Class 1 – 10 or fewer buildings.
- Class 2 – more than 10 but less than 46 buildings.
- Class 3 and 4 locations – more than 46 buildings, *and any buildings with high occupancy* (churches, schools, etc.).

4.9.4 Pipeline Leak Detection by Visual and Instrumented Patrols

Especially with gas pipelines, but also in many smaller rate liquids pipeline systems (including gathering and distribution lines), leak detection is often accomplished by human patrols, visually or using manual instrumentation.

For gas pipelines, depending on the Class Location described above, the 49 CFR 192 Subpart M (Maintenance, par. 705 and 706) describes binding minimum frequency (but not technique used) with which these surveys are to be carried out. Apart from Class Location, whether the gas is odorized or not is a factor in determining this minimum frequency. The regulation does make a distinction between *Patrols* and *Leak Surveys*, but does not specify the form or technique to be used.

For liquids pipelines, the 49 CFR 195.412 specifies an inspection frequency specifically for rights-of-way and river crossings, where those crossings constitute an HCA and therefore fall under the rule. Patrolling the entire line within an HCA is not required as for gas lines.

4.9.5 Remarks and Comments

Leak detection – for slower, gradual losses – by *Patrols* and/or *Leak Surveys* is an effective method that should always be considered as part of the overall LDS technique portfolio.

There is often a lack of precision in what *Patrols* and/or *Leak Surveys* mean exactly and what is their *purpose*. For example, the 49 CFR regards them as a primarily maintenance activity. In practice, they might actually be the only form of LDS on a pipeline.

To add precision to the procedures used by an operator, generally it is important to specify at least: (a) the frequency; (b) the technique used (for example, purely line-of-sight visual, infrared camera, methane gas detector, etc.) and (c) some estimate of the sensitivity (minimum release rate and/or volume) that the technique affords. With these minimal added details it is possible to analyze patrols and leak surveys just as any other LDS.

Generally inspection and maintenance departments assume responsibility for the entire practice of assessing the *threat* of failure likelihood. This is often as part of a Risk-Based Asset Management Program (cf. API 580/581, API 1160, ASME B31.8, etc.) When this is done, it is nearly always best for the leak detection engineer to adopt the threat likelihood figures directly from the RBA program. All of the above discussion then simply becomes informative.

4.9.6 Typical Pipeline Leak Mitigation and Recovery Controls

The 49 CFR (and other publications) generally emphasizes two main mitigation controls in the bow-tie diagram above:

- Leak Detection – also implicitly including alarms and response; and
- Emergency Flow Restriction Devices (EFRD), which are intended to stop the losses rapidly.

Recovery controls also include EFRD – since the very first step in recovering the "as-new" state of the pipeline is to stop the damage – but they tend to focus on environmental cleanup, pipe repair, and testing of the repairs. These Business Continuity Management (BCM) activities are not usually the focus of leak detection engineering. However, EFRD are definitely part of leak detection design, since the total time to stopping the loss is expressed in the 49 CFR as:

Total response time = Time to detection (LDS) + Time to respond (operators / controllers) + Time to shutoff (EFRD)

It is therefore pointless having an LDS that is highly sensitive and fast to detection, when either the control room procedures allow an alarm to be ignored for longer periods, and/or it is difficult and/or slow to shut off the region of pipe that is releasing fluid.

4.9.7 Threats vs. Consequence in LDS

It is worth repeating that LDS are central to the mitigation of consequences of a leak, but play no part in the prevention of leaks. At the same time, any situation where the threat of failure is higher increases the value of an LDS. The API RP 1160 and ASME B31.8 (S) emphasize that threat and consequence management are highly inter-connected and should be considered together as part of an Integrity Management Plan.

However, *organizationally* the detailed modeling of the threats to a pipeline is often handled separately from safety systems and consequence management. Therefore, it is quite common for an LDS project to adopt the same threat probabilities that have been calculated for, say, corrosion management and inspection purposes. It is then not necessary or appropriate for the LDS team to re-compute failure probabilities.

On the other hand, the calculation of the impact of an LDS on the consequence of a leak once it has happened *most definitely is* a leak detection responsibility. Other organizations (for example, health and safety systems) within the company may already have established assessment procedures for mitigation assessments, and it might be wise to adopt these procedures as well.

4.9.8 Process

Volume 2 of this report includes an example worked risk assessment worksheet and commentary. A typical relative risk ranking process takes the following three steps:

1. A Threat of failure is computed (or adopted), which is an aggregate, weighted score evaluated using for example the threat factors 1 – 32 listed above. The relative weightings used are at the discretion of the operator and are chosen in accordance with the operator's priorities and opinions relating to threat of failure mitigation.

2. A Consequence of failure is computed, which is itself a product of a directly computed potential release volume, and a consequence per barrel factor. The potential release volume is the sum of the volume pumped into the ground (active release) before the leak is detected, and the volume that will drain into the ground even after a shutdown (drainage volume). The former is primarily a function of the line volume, nominal flow rate and leak detection performance / times. The latter is a function of terrain and pipeline profile. The relative weightings used for the consequence per barrel are at the discretion of the operator and are chosen in accordance with the operator's priorities and opinions relating to consequences of a failure.

3. The Total Risk is then the product of the Threat and the Consequence scores, appropriately scaled to give (in our model) a number roughly between 0 and 100.

The exact process itself is specified neither in 49 CFR 195 nor in other industry recommended practices. However, it is an objective to use all the inputs 1 – 32 listed above appropriately, and also to build Threat and Consequence rankings in accordance with the operator's priorities and operations.

4.10 Input

4.10.1 Risk Analysis

Going into the requirements phase, at least the following elements of the Risk Analysis should be available, in order to be able to track the consequence mitigation of the LDS project to be tracked consistently:

1. The risk analysis model, which ideally matches the corporate risk management standard, so that the project can be tracked and compared against similar safety and environmental projects; and
2. An analysis of the status quo using the model that is the baseline against which improvements due to the LDS can be measured. This is either in relative terms, a weighted risk score of current operations without LDS improvements, or a direct financial assumed risk in $ / year due to leaks. In the former case, cost-benefits can be estimated due to the LDS improvements and in the latter a ROI also.

4.10.2 Project Charter

This is discussed in the preceding chapter and is a fundamental input to the overall project. Particularly relevant to Requirements are:

- Objective – this will automatically be one of the Requirements,
- Limitations, Directions, Out-of-scope items – these will constrain any of the potential alternatives to be explored, and
- Target benefits – these will be the initial benefits (at least partially expressed in terms of risk reduction) and represent a minimum cost-benefit that must be achieved.

4.10.3 Technology Selection Pre-screening

It is recommended, but not essential, to perform an initial pre-screening of potentially applicable technologies. This can be a part of the process itself, but there is value in having both:

- A list of available technologies that are useful for LDS, and
- A sub-set of this list of technologies very unlikely to be applicable to this project, for up-front and uncontroversial practical and policy reasons. This helps to reduce the list of potential alternatives, and focus attention on the most likely to create benefits.

4.10.4 Financial Risk Analysis

As noted above, if the baseline risk analysis is in absolute financial terms then this is useful for the eventual calculation of an ROI.

4.11 Process

4.11.1 FEL-2 Analysis

The conceptual FEL-2 analysis should be executed with the objective of providing:

- Solution alternatives – in many situations there is truly only one practical and economic solution. However, it is important to avoid "tunnel vision" and this stage of the analysis is intended to be creative and iterative. It is better to explore multiple alternatives at this stage, and then discard them later during FEL-3, than never to explore them at all.

- Alternatives that use multiple technologies in a redundant architecture to improve robustness and reliability. This issue is important enough that it is discussed in detail in Task 2 – Methodology for technology selection and engineering, of this study.

During the FEL-2 stage, the team (or perhaps many teams) develops multiple alternatives that meet the business objective. It is important to outline for each alternative, to allow a single alternative to be chosen, at least:

- Basic Conceptual Engineering
- Budget and Time Estimates (+/- 40 to 50 %)
- Benefits (impact on risk reduction)

It is important to recall that at the end of FEL-2, the project gatekeepers will identify and choose only one of the alternatives to develop during FEL-3. Closeout of Requirements needs one alternative to be selected, and the business to decide to spend the necessary money to develop the project scope, schedule, and estimate further.

4.11.2 Impact on Operations

It is also important to study each solution as a complete system, including requirements on personnel and operations. This is a particular requirement of LDS. A particular area of operational concern regards the overlap with EFRD strategies and operations. The LDS itself is worthless if it does not contribute to the overall emergency shutdown and this has a major effect on operational procedures.

4.11.3 Preliminary Project Plan

Part of the FEL-2 engineering is a high-level and preliminary project plan. This must be consistent with the standards and objectives expressed in the Project Charter, and it will depend on the alternatives that are analyzed. These plans are used as one element in alternative selection, and also as the basis for a definitive plan during FEL-3.

4.11.4 Reporting of Rejected Alternatives

It is recommended to report formally on all potential alternatives rejected, with reasons. This is not essential, and often it is overlooked with the objective of selecting just one alternative in mind. However, it is useful in project reviews, look-backs and also in future projects as a source of lessons learned.

4.11.5 ROI Estimation

If an absolute risk analysis methodology is being used, it is useful to estimate the ROI of each alternative option as well. This has the benefit of providing a fairly standardized way of ranking the options and selecting the best one.

4.12 Output

4.12.1 FEL-2 Design Selection

At the end of Requirements, the project gatekeepers will identify and choose only one of the alternatives to develop.

Closeout of Requirements needs one alternative to be selected, and the business to decide to spend the necessary money to develop the project scope, schedule, and estimate further. This selection defines:

- Conceptual design and technology selection
- Performance measures (expected)
- Risk-based Cost-Benefit
- Impact on operations
- Preliminary Project Plan

4.12.2 Formal Performance Requirement

It is generally required, as part of the Closeout of Requirements, to describe formally the performance requirement of the final, as-built system. The manner in which they are expressed, and the metrics to be used, depend on the operator and vary widely. However, a measure of success must be stated explicitly at this point, as well as a means by which it will be tested.

4.12.3 Updated Project Charter

It is common for minor updates to be made at the end of Requirements analysis. Some elements that might be adjusted include the Objectives, Budget, Timetable, and Target Benefits.

5 Design Process

5.1 Summary

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

Table A-8 - Design Process

Input	*Required*	• FEL-2 Conceptual design selection • Preliminary Project Plan
	Recommended	• Target performance measures
	Useful	• Financial Risk Analysis

Process	*Required*	• FEL-3 Detailed specification and plan • (As applicable) Detailed engineering • Supplier selection and procurement
	Recommended	• (As applicable) Contractor-generated detailed engineering
	Useful	• Budget and cost-benefit update

Output	*Required*	• Final detailed design • Updated expected performance measures • Updated Budget and Cost-Benefit • Impact on operations • Updated Project Plan
	Recommended	• Updated Risk Analysis
	Useful	• Updated ROI

Note how this phase of the overall process is quite similar to most engineering projects. Refer to the end of this chapter for a summary of the main recommended items for attention specific to LDS projects.

5.2 Input

Recall that the Design phase generally involves a go / no-go decision step, during which the alternatives explored during FEL-2 are studied and a definite solution alternative is chosen. This alternative comes with a basic +/- 50% statement of resources required, and an estimate of expected performance. The other elements of input to the Design phase are the outputs of Requirements.

5.3 Buy vs. Build

The Design process is generally quite different if performed internally or if an external contractor is used. Very often with LDS an external contractor handles at least some of the project, so this document is generally structured with this probability in mind. However, there is no reason why an operator cannot build a high-performance LDS internally, and so it is quite acceptable for the procedure in this document to be modified accordingly.

At the same time, is strongly recommended that stakeholders within the operator's company should perform at least FEL-1 through FEL-3. It is difficult to outsource the responsibility for these activities to a third party.

5.4 Process

5.4.1 FEL-3 Process

The goal of FEL-3 is to develop a set of engineering documents (design basis package) that incorporate site-specific conditions and a plan for executing the project, such that reliable cost and schedule estimates can be established. Typically at the FEL-3 stage the cost estimates reflect an accuracy of between +/- 20% accuracy. The product of this phase will allow a detailed package to be presented at the authorization gate. The specific deliverables for the FEL-3 analysis include:

- Detailed Equipment Specification
- Procurement Plan
- Detailed Scope of Work (including quantities)
- Schedules including Critical Path, Resource Loading, etc.
- AFE-Grade Estimate (+/- 20% accuracy)

At the end of FEL-3 the project is authorized and the project team receives funding to move into detailed engineering and planning. Also, the design basis package is expected to be sufficient to include in Requests for Proposal (RFP) during procurement.

5.4.2 Detailed Engineering

There are, as discussed earlier, broadly two approaches:

- The operator can manage detailed engineering in-house, and this is common if general management of the Implementation is performed directly by the operator. In this case, detailed engineering may only be a small incremental update (if at all) to the FEL-3 detailed specification.

- General management of the project can be assigned to a contractor. In this case it is common to ask the contractor to develop his own detailed engineering plan, based on the FEL-3 detailed specification. Generally, this is not allowed to deviate by more than the +/- 20% accuracy of the design basis package. This approach has the advantage of committing the contractor to a detailed specification that he himself has written, and is appropriate to his technology and procedure sets.

5.4.3 Procurement

The results of the FEL-3 process include an RFP-grade design basis package. Other components of the procurement process are very dependent on operator practices, including supplier selection, bidding process, itemization of the supply, etc.

5.4.4 Budget Updates

It is certainly useful to maintain an as-purchased budget figure, and to reflect this actual expenditure in budget updates. This similarly updates the initial cost-benefit analysis.

5.5 Output

5.5.1 Detailed Design

At the end of this Design stage, Implementation can begin on the basis of a tight engineering specification:

- System / Equipment Specification

- Detailed Scope of Work

- Acceptance Criteria

- Project Plan with Schedules

- Final Budget with Milestones and Payment Schedules

5.5.2 Risk Analysis Update

The project team should verify that the System / Equipment Specification and / or the Acceptance Criteria, however they are stated, are consistent with the stated benefits of the project in terms of reduced risk. This will generally involve re-running the risk model initially built during Requirements.

5.5.3 Impact on Operations

It is important for the specification to include impact on:

- Personnel, including training and any hiring requirements; and
- Operations, including integration with other systems and procedures.

It is similarly essential for the System Specification to include inspection, testing and maintenance requirements for the LDS.

5.6 LDS-Specific Concerns

While most of this chapter contains guidance similar to any engineering discipline or project, it is important to highlight the following outputs, which are particularly relevant or challenging to LDS projects:

1. Specification of LDS performance is a complex issue. For this reason, the entire Task 3 of this study is devoted to Systematic prediction of performance. It is, at the same time, central to achieving quantifiable objectives in terms of reduced risk, and to measure success of the project. Therefore, it is critical within the System Specification to be as precise as possible about the expected nominal LDS performance using an agreed set of metrics.

2. Acceptance Criteria should be based on measuring these expected LDS performance metrics before putting the LDS in operation. Therefore, part of the final test suite will need to be designed to provide repeatable and uncontroversial measurement of these metrics. This task is just as complex as defining the metrics themselves.

3. The issue of how to link Acceptance Criteria to the project objectives in the Project Charter is quite difficult. Whereas the Project Charter might use language like "halving overall assumed risk of a leak in an HCA" as an objective, the engineering specification might use language like "detecting leaks creating

clouds of concentration greater than "X" ppm of gas". The project team needs to verify and agree that the engineering specification will meet the expectations of the Project Charter.

4. Task 5 of this study is entirely devoted to the Impact of installation, calibration and testing on LDS. Inspection, testing and maintenance requirements for the LDS, which are part of the System Specification, will depend heavily on these factors. Similarly, the recommendations of Task 5 will cover appropriate tests during Implementation, and during Verification below.

5. Retrofit projects often require specific project plans since they are executed on running equipment and plant. This is detailed at length in Task 3 of this study. In general, the Project Plan is harder to design and to track since the impact on and coordination with operating assets is rather greater.

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6 Implementation Process

6.1 Summary

The Implementation process is mostly quite similar to all engineering projects. This chapter focuses on a summary of the main recommended items for attention specific to LDS. It can be summarized (with details below) as follows:

Table A-9 - Implementation Process

Input	*Required*	• Detailed design • Project Plan
	Recommended	
	Useful	

Process	*Required*	• System build • Preliminary acceptance tests (unit, integration, factory, site, etc. tests)
	Recommended	
	Useful	

Output	*Required*	• Built system, ready for Verification • Deviations log
	Recommended	• Implementation history / log
	Useful	

6.2 Acceptance Testing

It is generally a bad idea to wait until the entire solution has been assembled before beginning to test it to ensure that mistakes have not been made. Successful implementations rely on identifying and correcting build errors early on, where the impact of the mistakes is far smaller.

These tests are specified as part of any sound Project Plan. They are part of the schedule, and are often intermediate checkpoint milestones in the project.

The acceptance test suite is run against the supplied input data or using an acceptance test script to direct the testers. Then the results obtained are compared with the expected results. If there is a correct match for every case, the test suite is said to pass. If not, the system may either be rejected or accepted on conditions previously agreed between the sponsor and the builder. This conditional acceptance is here called a Deviation.

The objective is to provide confidence that the delivered system will meet the business objectives of both sponsors and users. The final acceptance test is generally the same as the subsequent Verification phase. It is for this reason that often Implementation and Verification are considered as one single process, with frequent iterations between the two.

A principal purpose final Verification testing is that, once completed successfully, and provided certain additional (contractually agreed) acceptance criteria are met, the sponsors will then sign off on the system as satisfying the contract (previously agreed between sponsor and manufacturer), and deliver final payment.

Apart from the final Verification testing, there might be a number of intermediate, earlier tests. Some common ones include (with wide variations in their naming):

Typical types of acceptance testing include the following:

- *Factory acceptance testing*. This is often called user acceptance testing in other industries. It is the testing done by factory users before the product or system is moved to its destination site.

- The users at the site may then perform *Site acceptance testing*. Many other industries refer to these as alpha, beta and field-testing as well.

- *Operational acceptance testing*. Also known as operational readiness testing, this refers to the checking done to a system to ensure that processes and procedures are in place to allow the system to be used and maintained. This may include checks done to back-up facilities, procedures for disaster recovery, training for end users, maintenance procedures, and security procedures.

- *Regulation acceptance testing*. Here a system is tested to ensure it meets governmental, legal and safety standards.

6.3 Project Logs

It is rare for any implementation to go exactly according to plan. It is recommended to maintain a project history or log of any deviations from the plan, and certainly any deviations from the stated project scope, for a number of reasons:

- To help in final Verification, so that the project team can understand any deviations from stated objectives, acceptance criteria, or other items in the Project Charter.
- To explain any extensions of project resources.
- As a resource for future projects, as a source of lessons learned.

6.4 Particular LDS Issues

A number of issues relating specifically to LDS have already been raised in earlier phases of the project. Those that apply particularly to the Implementation phase include:

- Acceptance testing criteria should be based on measuring expected LDS performance metrics and specification of LDS performance is itself a complex issue. Therefore, part of the acceptance test suite(s) will need to be designed to provide repeatable and uncontroversial measurement of these metrics. This task is just as complex as defining the metrics themselves.

- Task 5 of this study is entirely devoted to the Impact of installation, calibration and testing on LDS. Implementation in general will depend heavily on these factors. Similarly, the recommendations of Task 5 will cover appropriate tests during Implementation, and during Verification below.

- Retrofit projects often require particular care in Implementation, and make testing more complicated and invasive to perform. This is detailed at length in Task 3 of this study. In general, the Implementation is harder to perform and to track since the impact on and coordination with operating assets is rather greater.

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7 Verification Process

7.1 Summary

The Verification process is mostly quite similar to all engineering projects. This chapter focuses on a summary of the main recommended items for attention specific to LDS. It can be summarized (with details below) as follows:

Table A-10 - Verification Process

Input	*Required*	• Detailed Specification • Project Plan
	Recommended	• Requirements
	Useful	

Process	*Required*	• Repeatable and quantitative testing
	Recommended	• Re-tests • Confirmation of requirements
	Useful	

Output	*Required*	• Signoff records
	Recommended	• Re-test records and commentary
	Useful	

Recall that a number of tests, as called for in the Project Plan, may well have already taken place during the Implementation phase. These might include User, Factory, Site, Operational and Regulatory Acceptance Testing. These are all, technically, verification activities, but for the purposes of this document Verification is meant to be the final acceptance of the completed LDS before placing it in service.

The actual test procedures and measurable outcomes for acceptance will have already been established in the Detailed Specification. The timetable and logistics for their execution will already have been established in the Project Plan. It is useful to refer right back to the Requirements analysis as well, to ensure once more that the Verification meets the stated measurable performance requirements.

The validation policy must be that it is:

- Quantitative as far as possible. That is to say, numerical measurements of performance should be made. For example, the minimum size leak rate that can be detected over a one-hour period during actual removal of fluid from the line.

- Repeatable. In other words, does not require specialized tools or custom equipment but rather tools and methods readily accessible to the operator so that they can be repeated at any time.

- Transparent. The verification process has to be readily understandable, and understood by all stakeholders. Similarly, the precise process, when it was executed and its outcomes must be recorded.

It is also recommended to repeat the tests, and perhaps to have these re-tests performed by an entirely different team. This simply adds to the scientific reliability of the verifications. Furthermore, it is worth returning to the Requirements analysis, in order to perform one final check that the stated measurable performance requirements have been met.

API RP 1160 (2013), among others, also identify particular elements of a successful validation process, including being:

- Structured. The underlying methodology should be structured to provide a thorough, repeatable analysis.

- Allocated adequate resources. Appropriate personnel and adequate time must be allotted to fit the detail level of the validation.

- Experience-based. The frequency and severity of past events (in the subject or a similar system) should be considered and continually added to the knowledgebase for verification.

- Predictive. The assessment should be investigative in nature, seeking to identify previously failures, but also focus on the potential for future mishaps, including scenarios that may never have happened before.

- Able to provide for and identify means of feedback. Validation is an iterative process. Actual field events and data collection efforts should be used to validate (or invalidate) assumptions made.

At the end of Verification, appropriate signoffs must be obtained from all stakeholders, since the LDS will now become part of the overall pipeline system. It is also recommended that observations and a log of comments should be part of the Verification outputs since continual testing (see below under Maintenance) will be required and these can contribute to overall LDS lessons learned.

7.2 Remarks and Comments

Recall that the LDS is a complete *system*. All three of people, processes and technology must work for it to be successful. Therefore, Validation must generally include:

- Testing of the operators in the use of the LDS,
- Testing of the procedures implemented upon a leak alarm in the control room, and
- Testing of the technology in the field that issues alarms.

The *operational readiness* – in other words, the robustness – of the LDS should be tested specifically. Such test might, for example, include randomly disconnecting components of the LDS (meters, instruments, sensors or power supplies) and observing the actual impact.

Recall from the Design phase that the design is strongly recommended to include redundancy (ideally using multiple physical principles) and backup systems. These operational readiness tests are a direct verification of these design principles.

Frequently an entirely separate verification is made that any applicable regulations or standards are met by the as-built system. This generally requires minimal actual measurement or testing, but the corporate administration frequently signs off on the LDS as with any other industrial control system with a potential HS&E impact.

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8 Maintenance Process

8.1 Summary

The Maintenance process is mostly quite similar to all engineering projects. This chapter focuses on a summary of the main recommended items for attention specific to LDS. It can be summarized (with details below) as follows:

Table A-11 - Maintenance Process

Input	*Required*	• Requirements • Detailed Specification
	Recommended	
	Useful	

Process	*Required*	• Testing • Tuning • Physical Maintenance
	Recommended	• Random testing
	Useful	

Output	*Required*	• Testing and Failure records • Maintenance record
	Recommended	• Performance logs
	Useful	

All engineering systems require maintenance, and LDS are no exception. LDS also have the particular requirements of:

- Continual testing: essentially a periodic re-verification of performance. The frequency of this re-testing is generally stated up-front in the Requirements, and is certainly part of the detailed specification. It is often the subject of regulation, particularly for liquids lines.

- Tuning: many operational parameters in an LDS (particularly, the thresholds for calling alarms) are adjusted in the light of performance during regular operations. The tuning procedures are part of the detailed specification.

Even with computer-based CPM LDS, there is still a hidden physical maintenance requirement for the meters and instruments upon which the computations depend.

As with Verification, continual testing must be repeatable and quantitative. In fact, it is mandatory in many regulations for detailed and systematic records of the periodic tests to be maintained. Furthermore, as with most pipeline sub-systems, any abnormal performance of the LDS – for example, false alarms that are inexplicable or missed leaks – must be documented formally.

It is recommended also to perform random testing, and failure testing, from time to time, to assess the robustness of the LDS. This tests not only the resilience of the technology to random events, but also the reactions of the control room operators and of the procedures that they have been given to follow.

Task 5 of this study is entirely devoted to the Impact of installation, calibration (i.e. tuning) and testing on LDS. Much greater detail on these issues can be found there.

8.2 Remarks and Comments

There is often a practical difficulty in organizing LDS tests, simply because LDS span many departments at a pipeline company. Operations are affected since tests may involve actual physical leak simulations. Instrumentation and control are involved through the meters, instruments, sensors, and flow control. The control room is involved through the operators.

Similarly with maintenance, a CPM system involves at least IT (software, computers and networking); engineering (meters, instruments, sensors, and flow control); SCADA; and operations (control room training / testing). It is often practically challenging to synchronize all these maintenance activities appropriately.

Calibration and tuning of an LDS also include calibration of meters and instruments upon which it relies. This may be overlooked – gradual deteriorations in performance of many CPM LDS are actually due to drifting over time of input measurements.

The API RP 1130 (2002) is a valuable source – specifically for liquids pipelines using a CPM LDS technology, but useful for many other LDS as well – for maintenance and testing best practices. Chapter 6 covers, in about fifteen pages, all the essentials of: Operations, Testing, Data Retention; Controller Training; and Documentation.

9 Continual Improvement

9.1 Summary

Continual improvement is particularly important for LDS. It can be summarized (with details below) as follows:

Table A-12 - Continual Improvement

Input	*Required*	• Requirements analysis • Company policies
	Recommended	• Detailed Specification
	Useful	

Process	*Required*	• Periodic reviews • Triggered reviews
	Recommended	
	Useful	

Output	*Required*	• Recommendations for Requirements re-analysis
	Recommended	
	Useful	

By far the most frequent form of "Continual Improvement" in LDS is a regular program of re-verification and re-tuning of the system, rather than a significant technological or systemic overhaul. However, for the purposes of this exposition, these regular programs are described above under Maintenance – in part, to emphasize their regular and frequent nature.

Continual improvement (CIP) is in many ways an attitude more than a formal process. It is a stated policy of continuing to strive for a better solution and not to settle for "good enough". For this reason, it is often expressed up front in the Requirements documentation, or in company-wide policies, or both.

There are two main reasons for at least some measure of CIP with LDS:

- LDS are usually very specific to a given pipeline system. If any change is made to the pipeline, the LDS may well degrade or even cease to function at all. A

good detailed specification will generally state precisely what changes in the pipeline will necessitate a change in the LDS.
- The technology cycle of LDS is rapid. Even with classical RTTM CPM systems, there are at least software updates on an annual basis. These updates often come with new and useful features that should be exploited. Similarly, novel instruments and sensors are being developed continually.

For this reason, a CIP cycle is called for both:

- On a "triggered" basis, when an operational or physical change is made to the pipeline that will affect the LDS; and
- On a periodic basis, according to the policies and requirements of the operator.

Generally, a CIP recommendation calls for a review of the initial Requirements phase. The entire LDS engineering process is not necessarily repeated (unless a complete replacement is recommended) but only those sub-processes necessary to accomplish the recommended improvements.

9.2 Remarks and Comments

There is a substantial management science literature on CIP. Generally, it is expressed in three principles:

1. The core principle of CIP is the continual adjustment of / reflection upon processes. (Feedback)
2. The purpose of CIP is the identification, reduction, and elimination of suboptimal processes. (Efficiency)
3. The emphasis of CIP is on incremental, continual steps rather than giant leaps. (Evolution)

Improvements are therefore based on many small changes rather than the radical changes of a wholesale system replacement. This effort is therefore actually aimed at reducing total lifetime cost of ownership.

As the ideas come from the stakeholders and users themselves, they are less likely to be radically different, more practical, and therefore easier to implement. These small improvements are less likely to require major capital investment than major process changes

Similarly, CIP ideas come from the talents of the in-house workforce, as opposed to using consultants or engineering contractors – any of which could be very expensive. It has the organizational impact of encouraging stakeholders and users of the LDS to take ownership of the system over the long-term.

In general Management Science, CIP is often included under an overall Quality Program. Quality Management standards that incorporate CIP in the ISO 9000 family include:

- ISO 9000:2005 – covers the basic concepts and language
- ISO 9001:2008 – sets out the requirements of a quality management system
- ISO 9004:2009 – focuses on how to make a quality management system more efficient and effective
- ISO 19011:2011 – sets out guidance on internal and external audits of quality management systems.

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10 Template Basic Risk Assessment System

10.1 Method

There are a number of Risk Assessment techniques, and the operator should feel free to use the technique that is best suited to his particular pipeline asset. The operator should most certainly tailor the sources of likelihood of failure, impact of failure and the controlling factors – as well as the precise algorithm that is used to combine with them – appropriately for his particular needs.

The purpose of this template is to illustrate a basic risk assessment system, and focuses on how it can be used to evaluate the potential benefits of an improved LDS. It may, depending on the application, either be too detailed (including for example a number of factors that are unknown, or irrelevant) or not detailed enough (for example, in an extremely sensitive high-risk environment). However, it can at least be used as a starting point for a useful, analytical treatment.

10.2 General Principles

Regardless of the details of the process, it is recommended for each risk assessment to have the following features:

- As far as possible, to be *quantitative*. As explained below, the procedure will probably include at least some elements of relative ranking or scoring – which are by their own nature at least partly subjective. However, it is most useful when a specific increase in any given parameter leads to a quantifiable change in risk. For instance, when a specified change in LDS performance leads to a specific percentage change in risk.

- To be *transparent*, so that the algorithms taking the inputs to generate risk figures can be reproduced and/or modified.

- Similarly, to be *flexible*. It is important for the important factors to be considered, but also not to include a multitude of tangential issues, nor to slant the analysis towards over-emphasizing certain issues. It is quite easy for one analyst to use an algorithm that emphasizes certain issues (for example, inspection and maintenance) while another emphasizes others (for example, safety and containment controls).

10.3 Template Method

The Template uses as its basis two documents from the International Standards Organization (ISO) from 2009 that cover Risk Analysis:

- ISO 31000: Risk management – Principles and guidelines
- ISO 31030: Risk management – Risk assessment techniques

Some of the more important terms used include (references in parentheses are to the ISO 31000 document):

Risk is characterized by reference to potential events (2.17) and consequences (2.18), or a combination of these.

Risk is expressed in terms of a combination (usually the multiplication product) of the *consequences* of an event (including changes in circumstances) and the associated *likelihood* (2.19) of occurrence.

- Likelihood of a failure / leak is the probability of the leak occurring, within a certain timeframe. This might be measured in expected number of leaks per year, for example.
- Consequence of a failure / leak is the impact, or cost, of that specific leak. This might be measured in dollars of cost, opportunity-cost, time or other appropriate penalty measure.

There are two very distinct approaches to the assessment of Risk:

- The Relative Risk Ranking approach – in this situation, only relative scores are assigned to likelihoods, consequences, and risks. So for example, if threat A is assessed to be twice as serious as threat B, then A is assigned a likelihood of 2 and B a likelihood of 1.
- The Absolute Risk Ranking approach – in this situation, an attempt is made to assign actual measurable values to likelihoods and consequences (which need not be very accurate and may be +/- 100% estimates). For example, all likelihoods are in terms of a per-year failure rate and consequences are assigned a financial penalty.

Very valuable requirements and design decisions for LDS using either approach. This Template takes a specifically *Relative* Risk ranking approach.

Table A.1 in ISO 31010 describes all the methods and where / when they can be used. The Template uses the bow-tie diagram technique, Sect. B.21. The bow-tie is drawn as follows:

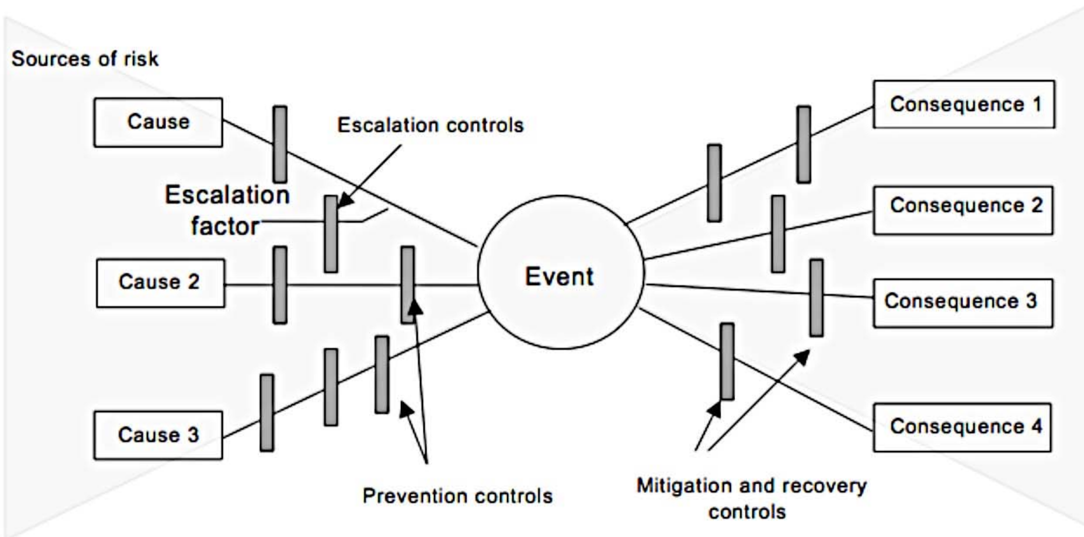

Figure A-5 - Bow-tie Diagram (ISO 31010 Sect. B.21)

A particular Risk Event (say, a leak at a given location of a certain size) is identified for analysis and represented as the central knot of a bow tie.

Causes (and perhaps sub-causes) of the event are listed considering sources of risk (or hazards in a safety context) on the left. The mechanism by which the source of risk leads to the critical event is identified, and lines are drawn between each cause and the event forming the left-hand side of the bow tie – the Fault Tree.

Factors that might lead to escalation can be identified and included in the diagram – for example, increasingly corrosive fluids, changes in operating regime, etc. Similarly, Barriers or Controls that help to prevent each cause leading to the unwanted consequences can be shown as vertical bars across the line.

On the right-hand side of the bow tie, the Event Tree, different potential Consequences of the risk are identified and lines drawn to radiate out from the risk event to each potential consequence. These might for example be a spill of a certain total volume at a certain point. Barriers to the consequence are depicted as bars across the radial lines. The approach can be used for positive consequences where the bars reflect Controls that Mitigate the generation of consequences. These might include rapid shutdown of a leaking pipe.

Management functions that support controls (such as training, ILI and visual inspection, and of course Leak Detection) can be shown under the bow tie and linked to the respective control.

When pathways are independent, the probability of a particular consequence or outcome is known and a figure can be estimated for the effectiveness of a control. This is rarely the case in the real world, but for the purposes of this Template, each threat and consequence is taken to be independent and the probabilities add, subtract and multiply in a simple manner.

10.4 Overview of the Spreadsheet

The Spreadsheet is organized as follows:

- The first tab is for Raw Data. It is useful to isolate all the inputs to the model on one tab so that they are evident. The Raw Data includes all the Causes, Escalation Factors, Controls, and Consequences related to the identified risks.
- The second tab estimates scores for the Likelihood of each Cause (with escalation factors and controls) leading to a leak.
- The third tab estimates scores for the Consequences (with mitigation factors and controls) resulting from a leak.
- The fourth tab shows the cumulative Risk (Likelihood multiplied by Impact), including associated graphics and reports.

The Template is pre-populated with arbitrary data for a hypothetical pipeline asset consisting of forty lines each carrying liquid petroleum products. This is to assist with the exposition below only. The operator is encouraged to delete the example data before beginning his own analysis. Also, we explain below a number of factors to consider when the pipelines carry natural gas or other fluids.

Note that the spreadsheet itself does not generate the graphical bow-tie diagram by itself, although one can easily be drafted using the content of the template.

10.5 Step 1: System and Risk Definition

Perhaps the most important step is defining the pipeline system and its sub-systems precisely. In terms of the bow-tie diagram, this defines the complete set of bowties, each with a central "knot" corresponding to a specific leak event.

Referring to the Template spreadsheet with its example dataset, and its first tab with Raw Data, each row of input corresponds to a separate potential leak event. The example assigns a row to each separate line in a hypothetical refinery distribution system. Therefore, the analysis will be performed to the level of detail of assigning just one risk score to each delivery line.

Some alternative situations might include:

- A very long pipeline might be segmented into individual one-mile (or so) sections, and the leak risk would then be calculated mile-by-mile along the line.
- A hybrid gathering / transmission / distribution system might first divide the system into three sub-systems. The gathering and distribution sub-systems might be handled line-by-line as in the example, while the longer transmission system would be analyzed mile-by-line.
- Certainly, if any line or sub-section has distinctly different characteristics – for example, passes through an area with particularly high consequence or changes diameter significantly – then it should be analyzed as a separate row.
- Similarly, if the elevation profile of the line varies dramatically then it is worth segmenting it into shorter sections in order to capture this profile more accurately. The "drainage volume" (see below) of a section of pipe depends strongly on the elevation difference between its beginning and its end.
- Conversely, if the line is carrying natural gas or a HVL then the size of the release depends far more on depth of cover than on elevation profile. It may then be possible to work with much longer sections of pipe, even when the overall line is long.

10.6 Step 2: Define the Consequence Factors

The Consequence Factors that are considered might be as few as one: the size of the release in barrels, for example. In the example dataset in the template, Raw Data tab, Columns C – P contain several consequence factors that are taken directly from the 49 CFR §§ 195.452 (f) and (i). This is not necessarily with the intention of ensuring compliance with the rule – rather, this source is a technically well though-out summary of generally significant consequence factors for liquids lines.

The primary factors are also in industry recommended practices like the ASME B31.8 Supplement (gas pipelines) and API RP 1160 (liquids pipelines).

The primary source for the example risk factors is a US DOT study on instrumented Internal Inspection devices (November 1992). Other sources include the National Transportation Safety Board, the Environmental Protection Agency and the Technical Hazardous Liquid Pipeline Safety Standards Committee.

A comment row above the factor description assigns a broad category to each factor:

- ENV – An Environmental factor
- OPS – A factor due to Operations
- ENG – An Engineering, construction, maintenance or inspection factor

Summarizing the columns:

1. Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.

The next four factors relate to the need to protect HCAs, and particularly the need to avoid a release into a waterway that can potentially spread the hydrocarbons over a large area. They are generally only relevant to liquids releases. For gases, the contour of the land is still important since a release may gather at a lower elevation point of the ground profile – see factor no. 6 below.

2. The contour of the land profile and if it could allow the liquid from a release to enter a high consequence area. An operator can get this information from topographical maps such as U.S. Geological Survey quadrangle maps.

3. Drainage systems such as small streams and other smaller waterways that could serve as a conduit to a high consequence area.

4. Crossing of farm tile fields and the possibility of a spillage in the field following the drain tile into a waterway.

5. Crossing of roadways with ditches along the side. The ditches could carry a spillage to a waterway.

The sixth factor is critical, and may indicate completely different risk models for different classes of pipelines:

6. The nature and characteristics of the product the pipeline is transporting (refined products, crude oils, highly volatile liquids, etc.) Highly volatile liquids become gaseous when exposed to the atmosphere. A spillage could create a vapor cloud that could settle into the lower elevation of the ground profile. Flammability of the fluid is also an important consideration.

The seventh factor is perhaps more of a threat indication, but a release impact can be compounded by mechanical failure as well:

7. An operator should look for stress indicators at physical supports of the pipeline segment (such as by a cable suspension bridge). Strained supports, inadequate support at towers, atmospheric corrosion, vandalism, and other obvious signs of improper maintenance.

The next six factors relate to the physical dimensions of the pipeline, and operating conditions. There is some overlap between them – for example, potential release volume can be calculated from diameter and length between isolation points; also, hydraulic gradient can be estimated from flow rate. With all these factors, the analyst should be explicit whether average (usual or nominal) figures are used (for example, the normal operating flow rate) or whether worst-case (maximum or rated) figures are used (for example, the peak flow rate).

8. Operating conditions of the pipeline (pressure, flow rate, etc.).

9. Exposure of the pipeline to an operating pressure exceeding the established maximum operating pressure.

10. The hydraulic gradient of the pipeline, psi/ft. or flow rate, bbl or mscf /hr.

11. Pipe wall thickness (thicker walls give a better safety margin)

12. Diameter of pipe (higher volume release if the pipe ruptures).

13. Potential release volume (bbl or mscf), and / or the distance between the isolation points.

The fourteenth factor is in addition to the first four, and is really intended to cover any other possible routes for a spill to reach an HCA:

14. Potential physical pathways between the pipeline and the high consequence area.

The final factor is central to Leak Detection. It is the primary "what-if" factor that can be adjusted in order to assess the connection between LDS performance and assumed risk. Importantly, "response capability" can be defined in many ways, and this is discussed at more length below. In this example, the time in hours to isolate a leak is estimated, for large, obvious leaks defined as larger than 10% of flow rate, and the remaining small, less obvious leaks. For gases, this size might be better expressed as a concentration range (ppm) or overall release volume (mcf)

15. Response capability (time to respond, nature of response). Large Leaks > 10% flow / Small Leaks < 10% flow

10.6.1 Response Capability

Generally, response capability can be expressed by the length of time for a given size leak at a given location to be isolated. The nature of response can also be relevant.

The time to isolation can be divided into three components:

1. The time to detect or recognize the release. This is strongly a function of the leak detection system in use. If only visual inspection by routine patrols is used this time may be days or longer. If advanced technology is used it may be a matter of minutes. It is also most often a function of the size of the leak; larger leaks can usually be detected more rapidly.
2. The time to react to this information. This is a function of pipeline operations procedures; it corresponds to the time taken by the control room operator to receive the alarm, to assess it, and then to initiate action to isolate the leak.
3. The isolation time. This is a function of the flow control equipment installed on the pipeline. If it is equipped with automated EFRDs this time can be a matter of seconds; if isolation valves are manual then it may be a matter of hours before a field technician can reach the valve site to operate the shut down.

The LDS technology will not of itself affect time to react or to isolate. However, the people component of the LDS system is central to the time to react factor. An EFRD effectiveness and benefit analysis is central to the isolation time factor.

For LDS analysis, the time to detect the release is one of the most important factors discussed in detail in Task 4: Systematic predictions of performance. At this stage it is important to note that in general:

The time to detection may depend on the rate of the loss (either an absolute rate, or as a percentage of the normal pipeline flow rate); the absolute size of the loss; a minimum concentration of hydrocarbons in the environment; or other measures. As examples:

- Most material balance based LDS have a sensitivity specified as time to detection for a loss of a given percentage of the normal pipeline flow rate.
- Generally, visual inspection by patrols can detect a certain minimum spill size where an odor is evident or vegetation begins to die.
- Most external hydrocarbon sensors (gas detectors for example) detect a minimum concentration of lost hydrocarbons in the environment (the air or the soil).

Therefore, when analyzing risk it is important to be explicit about how the time to detection is being measured. In the example Template, it is specified as a function of percentage of the normal pipeline flow rate.

Even then, short of providing a complete curve of time vs. percentage, several approximations can be made. In the example Template, two broad categories are assumed: less and greater than ten percent. It is equally valid to, say, define small (< 5%) medium (5% - 15%) and large (> 15%) ranges, or even just a single worst-case figure.

10.7 Step 3: Define the Threat Factors (Causes)

The Threat Factors that are considered might be as few as one: the age of the pipeline, for example. In the example dataset in the template, Raw Data tab, Columns R – AI contain several threat factors that are taken directly from the 49 CFR § 195.452(e). This is not necessarily with the intention of ensuring compliance with the rule – rather, this source is a technically well though-out summary of generally significant causes of failure for pipelines.

The primary factors are also in industry recommended practices like the ASME B31.8 Supplement (gas pipelines) and API RP 1160 (liquids pipelines).

By assigning weights or values to the risk factors, and using risk indicator tables, an operator can determine the priority for assessing pipeline segments, beginning with those segments that are of highest risk, that have not previously been assessed.

Summarizing the columns:

1. Results from previous testing/inspection. These might be positive results (no defects found) or negative (widespread corrosion found).

2. Leak History. For example, number of previous leaks. This applies generally only to segments of pipe that were not replaced following a leak incident.

3. Operating Temperature

4. Known corrosion or condition of pipeline. Similar to no. 1 above but may include other indications.

5. Cathodic protection checking history. For example, CP audits, AC mitigation etc.

6. Current Hydro-test Interval

7. Type and quality of pipe coating (disbonded coating results in corrosion).

8. Age of pipe (older pipe shows more corrosion—may be uncoated or have an ineffective coating) and type of pipe seam. (See Age of Pipe risk table.)

9. Location related to potential ground movement (e.g., seismic faults, rock quarries, and coal mines); climatic; geologic (landslides or subsidence).

10. Potential natural forces inherent in the area (flood zones, earthquakes, subsidence areas, etc.)

11. Security of throughput (effects on customers if there is failure requiring shutdown). This is actually both a threat factor and a consequence factor. However, there is no question that a constraint on being able to shut down the line – for example, a strategic natural gas pipeline supplying a large urban area – is a constraint on the value of LDS.

12. Time since the last internal inspection/pressure testing (months)

13. With respect to previously discovered defects/anomalies, the type, growth rate, and size.

14. Operating stress levels in the pipeline. This is usually expressed as a percentage of the pipe material specified minimum yield strength (SMYS).

15. Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly impede access for spill response or any other purpose).

16. Physical support of the segment such as by a cable suspension bridge.

17. Non-standard or other than recognized industry practice on pipeline installation (e.g., horizontal directional drilling).

Note that each of these factors essentially relates to a potential Cause of a leak, and either represents an escalation factor, or a prevention factor.

10.8 Step 4: Define a Likelihood Value from the Causes

A systematic procedure for using the threat factors in the Raw Data tab to yield a combined threat of a leak is given in the Likelihood tab.

Note that this algorithm is entirely at the discretion of the Operator. It is also a central topic of detailed Integrity Management engineering. The algorithm presented here is extremely simple, but at the same time it is not the central purpose of this analysis, which is mostly directed at LDS factors. The LDS has no effect on the Likelihood of a leak. In fact in practice it is possible for a completely separate pre-calculated list of Likelihood estimates to be given to him by Integrity Management specialists.

The algorithm used in the Template simply uses a weighted sum of a set of scores that are assigned to each factor that is present:

Likelihood = Sum, from 1 – 17 of each of the leak factors: (Factor) * (Weight)

The Weights for each factor are listed at the top of the Worksheet, and the calculation is laid out in columns for each row corresponding to the subsystems in the asset. Some of the Weights are in tables to cover various ranges or values of the factors. In this example, we have:

Leaks caused by Corrosion:		
Prevention Controls:		
	Testing/inspection	Factor 1 if pigged, factor 2 if dug / externally inspected.
	Cathodic protection	Factor if CP checked last year
	Coating	Factor 1 if FBE, factor 2 if CTE
Escalation Factors:		
	Leak History	Factor added for each previous leak
	Known corrosion	Factor added for known corrosion (Note 1)
	Known corrosion type, growth rate, and size	Factor multiplied by % wall loss added
	Temperature	Factor added for high-temp service
	Age	Factors for: pre-1949, pre-1970 and since 1970
Leaks caused by Mechanical Failure:		
Prevention Controls:		
Escalation Factors:		
	Ground movement	Factor added for ground movement risk
	Natural forces	Factor added for each potential natural event
	Operating stress levels	Factor multiplied by % SMYS loss added
	Non-standard installation	Factor added for each non-standard procedure
	Physical supports	Factor added for each span (Note 2)
Leaks from all causes:		
Prevention Controls:		
	Hydro-testing	Factor subtracted if line is hydro tested

	Time since last internal inspection/pressure testing	Factor added per month since last hydro test
Escalation Factors:		
	Particular difficulty to detect and respond to a leak	Factor added (Note 3)
	Security of supply	Factor multiplied by line flow rate added (Note 4)

Note that:

1. There is often dispute about whether having "known corrosion" might in fact be better than not having any information on corrosion at all. Known corrosion may then actually be a positive factor, so long as it is not severe – and in any case there is a penalty applied for the corrosion extent right below. This example uses a very small factor here and relies on the corrosion extent penalty more.
2. Simply the fact that the pipeline is supported rather than buried is not necessarily a risk factor – certain supported spans may indeed more mechanically secure than certain dug and covered installations. Therefore, it is important to specify that these supports place extra strain on the pipe beyond the average of the asset, and also that the factor is chosen not to exaggerate this risk.
3. Any particular difficulty to detect and respond to a leak may appear to be completely unrelated to the threat of a leak occurring and should really be a Consequence factor. This is a good example of how risk assessment terminology is not perfectly systematic. In practice, calling this factor a threat or consequence makes little difference, since the two are multiplied anyway to yield a compound risk. Simply to maintain the language in 49 CFR § 195.452(e) this example puts this factor under threats.
4. Any particular restrictions on shutting down a segment of pipeline may equally appear to be completely unrelated to the threat of a leak occurring and should really be a Consequence factor. In this example the risk is purely commercial, and scales with the hourly throughput of the line. However, in situations where delivery is safety related (as with many natural gas supplies) the factor may well be a single, numerically large penalty.

10.9 Step 5: Define a Consequence Value from the Factors

A systematic procedure for using the consequence factors in the Raw Data tab to yield a combined impact of a leak is given in the Consequence tab.

Note that this algorithm is entirely at the discretion of the Operator. It is also where the LDS has the main effect, on the Consequence of a leak.

The algorithm used in the Template regards the Consequence of a leak as directly proportional to the size of the release. The size of the release is the sum of:

1. The Active Leak, which is the volume pumped into the ground before the leak is detected and shut down, at some fraction of the normal flow rate:

   Active Leak (bbl) = (Leak Flow Rate, bbl/hr.) * (Time to Isolation, hrs.)

2. The Static Leak, which is the volume that will drain into the ground, once the segment has been isolated. In this algorithm the worst-case situation is used, where the entire contents of the pipe segment – between isolation points – is lost to the environment.

Again, with natural gas a different leak model will be needed, and the Consequence may not be assessed as a simple linear function of the total leak volume.

A compound Consequence Factor then multiplies this total leak volume, which is simply a weighted sum of a set of scores that are assigned to each impact that is present:

Consequence Factor = Sum, from 1 – 15 of each of the impact factors: (Factor) * (Weight)

The Weights for each factor are listed at the top of the Worksheet, and the calculation is laid out in columns for each row corresponding to the subsystems in the asset:

- The example considers any one of these situations as equivalent to being in an HCA:
    - In an HCA
    - Drainage to an HCA
    - Water leading to HCA
    - Field irrigation to HCA

    - Ditch to HCA
    - Other pathways to HCA
- Fluid Type
- Weak Support Infrastructure
- Abnormal High Pressure

The factors listed above are used to estimate the total potential spill size:

- Potential Drainage Volume
- Total Isolation Time:
    - Large Leaks > 10% flow
    - Small Leaks < 10% flow
- Normal Flow Rate

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11 Template Basic Risk Assessment (Gas)

Because – particularly for the consequence factors – risk assessment for gas pipelines is technically quite different from liquids, an example for a gas system is also provided. The detailed description of the methodology, factors and multipliers is not repeated in this section, so the reader is advised to review the earlier liquids template description above first in order to understand the basics.

The example data is synthetic (as opposed to the liquids system above, which contains actual data) and in fact is a copy of the first example with representative gas flow values substituted. As such, it might be an example of a hypothetical medium/intermediate-pressure (10 – 200 psi) distribution ring[5].

11.1 Security of Supply

The Threat Factors and calculations are left the same as for the liquids lines, except for the particular issue of security of supply. With a liquids system, loss of supply in itself is not usually life threatening or a substantial public nuisance. It is therefore generally sufficient to weight it as a purely commercial loss proportional to lost dollar value of throughput.

With a gas supply system there are similar purely commercial losses for most industrial supplies, but there may also be a substantial public safety or harm factor too – for example, due to loss of heating during severe weather. The calculation of the security of supply factor, and how it contributes to the total likelihood / consequence calculation, is therefore quite complicated.

In this example – and this is the most simple of cases – the criticality of the supply is simply graded as Low, Medium and Severe. Then, the volume of gas that might be lost during any interruption is multiplied by the criticality factor to give one component of the impact.

11.2 Gas Concentration vs. Leak Rate / Volume

A major topic of the report for Task 2: Methodology for Technology Selection and Engineering is how both (a) the performance of a gas LDS; and (b) the impact of a gas leak; really depend more on leaked gas concentration in the environment rather than

[5] Recall that (low-pressure) gas distribution systems are beyond the scope of this study.

the rate or volume of the leak. It is quite possible for a quite large loss of gas, in a well-ventilated environment, both to be quite hard to detect but also to be relatively harmless to the immediate environment (over the short term). It is equally possible for a very small leak in a confined space to generate easily detectible but also potentially very hazardous / explosive concentrations, quite rapidly.

This example template avoids this issue by using only qualitative scaling factors that multiply loss volumes. More complicated risk models and/or environmental concentration side calculations are recommended for more critical applications.

11.3 Consequence Calculation

As before, we emphasize that the calculation of the consequences of a leak is very variable and subject to the individual operator's requirements, objectives and policies.

For this example, a very simple calculation is performed that divides consequence into three components:

- Straightforward volume of release. This incorporates a number of factors, but embodies the assumption that generally a larger release has a higher impact than a smaller release, all else being equal. The total volume released is taken as the worst case: the most gas that will be pressurized into the atmosphere before detection and shutdown, plus the total line-pack stored in the line that will then vent to the environment.
- Collection / Concentration potential. This applies only if it is possible for a leak to accumulate in a confined space. In that case, any leaked plus vented volume is included in a concentrated gas volume calculation.
- Lost supply. This corresponds to the loss of supply during restoration of service. It is itself weighted according as the supply is low, medium or severely critical.

A compound Weighted Volume Impact score is then found by weighting these volumes:

Total Weighted Volume Impact = (Factor 1)*(Volume of Potential Release) + (Factor 2)*(Volume of Potential Collection) + (Factor 3)*(Volume of Lost Supply)

This Impact is then multiplied, as before, by an environmental consequence score that is generally independent of the size of the leak to give a total consequence.

Several issues make the calculation of volumes and other inputs to these estimates more difficult than for liquids:

A detectable leak volume, for gas, is often measured in ppm of concentration in the environment, rather than in an absolute or relative flow rate or volume as for liquids. Therefore, the "simple volume of release" calculation is quite complicated and depends on the topography of the line, environment, pressures and flow rates just to list a few factors.

Similarly, the concentration potential calculation is made more difficult since the hazard does not really scale directly with the potential gas cloud volume. Rather, there are several regimes, which might be handled with a more complex risk model, that include at least:

- Up to a certain minimum concentration in the environment, methane is relatively harmless.
- Within a given – but quite narrow – concentration band, it has a risk of serious explosion. This is partially covered in the PIR calculation, but the probability of an explosion occurring at all is quite a complicated estimate of concentration.
- Beyond a certain concentration – and if there are humans at risk – there is a high risk of sudden suffocation. Here, the issue is that of achieving this minimum concentration, more than this level is no more or less hazardous.

Once again, it is concentration of the loss, rather than the volume, that is critical.

Finally, note that the Security of Supply issue is also quite often binary rather than an issue that scales linearly with lost volume. In certain situations, any loss of supply at all is critical. In that case, a fairly complicated algorithm that makes truly difficult decisions about the relative severity of Security of Supply vs. Public Safety has to be built.

11.4 Improvement Scenarios

It is possible to use even this elementary kind of consequence model to at least estimate the impact of a number of leak detection and mitigation practices:

- Time to detection – as well as time to shutdown, which can be very rapid for gas lines – can be reduced, in order to reduce the total volume of release.
- Potential for collection can be reduced significantly if particularly sensitive, localized LDS can be installed near potential collection points.

- Providing contingency plans for re-routing gas in the event of a leak shutdown can reduce lost supply.

12 Template Basic Project Charter

There are a number of Project Charter formats, and the operator should feel free to use the layout that is best suited to his particular pipeline asset. The operator should most certainly tailor the requirements, budgets and other controlling factors – as well as the precise description of the project – appropriately for his particular needs.

The purpose of this template is to illustrate a basic project charter, and focuses on the minimum level of detail and consensus required to initiate a project. It is described under the overall LDS engineering process in volume 1 of the report. The template itself is in Word format, with a "fill-in-the-blanks" style and embedded comments. A minimal table of contents for this Project Charter is reproduced in the table below:

Table A-13 - Project Charter Template Contents

1. INTRODUCTION
1.1. Purpose of Project Charter
2. PROJECT AND PRODUCT OVERVIEW
3. JUSTIFICATION
3.1. Business Need
3.2. Public and Business Impact
3.3. Strategic Alignment
4. SCOPE
4.1. Objectives
4.2. High-Level Requirements
4.3. Major Deliverables
4.4. Boundaries
4.5. Directions
5. DURATION
5.1. Timeline
5.2. Executive Milestones
6. BUDGET ESTIMATE
6.1. Funding Source
6.2. Estimate

13 Program Evaluation (Verification) Template

This document is intended to be a "live" or tracking document, continually subject to dated changes as needs, the environment, and engineering concepts evolve.

This document is intended to capture all the essential elements of a continual improvement process, while being understandable at a high level by engineering management. Therefore, detailed engineering (for example, the detailed designs and component specifications) need only be included by reference here (see the example wording below). Also, a number of elements in this template are recommended for *any* part of an Integrity Management Plan. For example, the API RP 1160 already calls for Headings 1 and 2, the Initial Data and Risk Assessment. If these elements have already been completed elsewhere, then they are best incorporated by reference rather than duplicated.

The entries *all* should be dated. An objective of this management document is to track progress and to ensure that verification is systematic and programmed. With this in mind, it is often useful to provide two "views" of the same data, ideally generated automatically from the same source:

- View 1: Categorical, where activities are listed by category (and dates are attached); and
- View 2: Chronological, where activities are listed by date (and descriptions are attached).

A policy decision to make is what level of upgrade / re-design warrants replacing this document with an entirely new one – as opposed to including it in the original as any other continual update. Maintaining a single document helps to emphasize the continuity of an LDS strategy, but it can also create lengthy and hard-to-read reports over time.

As with all the examples and templates specific entries, headings and wordings are the responsibility and at the discretion of the operator. However, a useful minimal set of entries in these documents is given in the following Table:

Table A-14 - Template Program Evaluation Headings

1. Initial Data
1.1. Changes to Initial Data
2. Initial Risk Assessment (RA)
2.1. Updates to RA (multiple, with reasons)
3. Statement of Initial LDS Requirements
3.1. Updates to LDS Requirements, with reasons
4. Initial Technology Selection
4.1. Initial alignment with LDS Requirements
4.2. Technology selection updates
5. Initial System Design
5.1. Initial alignment with LDS Requirements
5.2. System design updates
6. Initial as-built System
6.1. SAT results: Alignment w/ Design
7. System Modification
7.1. Calibration or tuning
7.2. Re-configuration (i.e. replaced / removed / added components)
7.3. Upgrade (i.e. same design, improved components)
7.4. Substantial re-design (i.e. new technology, approach, design). This generally triggers updates to 2 – 6 above, in which case include references.
8. Periodic Testing
8.1. Test Protocol (frequency, type of test, expected result with respect to design)
8.2. Test Protocol Changes
8.3. Results – anomalies
8.4. System Modification impacts (include reference to 7 above)
9. Periodic Review
9.1. Review Protocol (frequency, type of review, expected outcomes)
9.2. Review Protocol Changes
9.3. System Modification impacts (include reference to 7 above)
10. Special Review
10.1. Reason, and System Modification impacts (include reference to 7 above)

14 Management of Change Template

It is important to be able to track changes made *and also changes requested, proposed or just conceived*, to an LDS. There is a certain amount of overlap with the Program Evaluation system described just above, except that it is much more specific and focuses on actual modifications to the LDS.

Recall that the LDS includes the technology, associated processes, and people factors (training, responsibilities, etc.). Management of Change (MOC) can affect any one of these major categories as necessary. Useful templates are available from the PMI and are covered in the PMBOK (2013) and elsewhere. However, it is to be emphasized that MOC for LDS is not just an issue during Implementation and Commissioning, but is a full-lifecycle activity to track changes to the LDS over its lifetime of operations.

As with all the examples and templates specific entries, headings and wordings are the responsibility and at the discretion of the operator. In addition, nearly all organizations will already have an MOC system in place, which should be adapted for LDS use. However, a useful minimal set of entries in these documents is given in the following table:

Table A-15 - MOC Template Contents

1. Change No. – Each change request is assigned a reference number. A "request" may include even just ideas for improvement, or be as generic as a new system requirement.
2. Change Type – This may be a design, scope, schedule or other type of change. It is recommended to use a systematic list of types, and a useful list might reflect the Engineering Process itself: Scope; Requirements; Design; Implementation; Verification; etc.
3. Description of Change – The change request should be described in detail. It is strongly recommended that a justification should be included, or at least a reference to a study analyzing the change.
4. Requestor – Who initiated the change request?
5. Date Submitted – When was the request submitted?
6. Date Approved – When was the request approved?
7. Status – Is the change request open, closed or pending? Has it been approved, denied or deferred? It is often useful to include "last action" or some more detail, like: "open – under detailed analysis by xxx due mm/dd".
8. Comments – This section may describe why the change request was rejected, deferred or provide any other useful information.

Appendix B – Technology Selection

LIST OF TABLES

LIST OF FIGURES

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1 Introduction

The objective of this second Appendix is:

Improving the reliability and accuracy of LDS by developing a standard methodology for technology selection and engineering.

As such, it addresses both: a standard methodology for technology selection, and engineering strategies (including in particular redundant, synergic, and backup systems), for improving the reliability and accuracy of LDS.

This report is intended as source documentation and expert guidance for use in operations, and a potential reference for developers of pipeline standards and developers of recommended best practices. It is not intended as a standalone recommended practice; rather, it is a summary of current practice and a starting point for perhaps extensive customization for the purposes of individual operators.

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2 Overview

The approach to addressing the objectives of this Task is to divide the topic into two major areas.

The first major area is Technology Selection. Within this area, the main components are:

1. Definitions, Categorizations and Essential Considerations. Basic diagramming tools are developed and described that are intended to communicate the main features of a given technology.
2. A Technology "Roadmap" that expresses the suitability, maturity and practicability of a given technology
3. How to provide a translation to the Requirements Analysis; how a technology selection affects the Requirements

The first task is to define a categorization of technologies, and to define a map (or matrix) of Applications / Performance / Suitability / Maturity / Project Risk.

A basic guideline review of available technologies is provided, and this includes a high-level technical description, principles of operation, their categorization, and intended application. It also gives a baseline assessment of requirements in terms of resources (and capital), expertise (human) and maintenance.

The second major are is Engineering Principles. This area comprises:

1. Improving and "Tailoring" Sensitivity, Accuracy, Repeatability
2. Improving Robustness and Availability using the strategies of redundancy, failover / backup, etc.

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3 Technology Selection

3.1 Leak Detection Methods

A general process for leak detection is as follows:

Pipeline fluid loss → Physical effect → Transmission of the physical effect → Detection or measurement of the effect → Comparison vs. a baseline or threshold → Alarm

Figure B-1 - The Process of Leak Detection

The components can be summarized as:

The physical effect or *signal* is a change in the pipeline's conditions (either operational or environmental) triggered by the leak. It might be physical or chemical – for example, a change in methane concentration in the surrounding atmosphere. Note here that there are two major families of LDS technologies: Internal methods rely on physical changes inside the pipe, while External methods mostly rely on changes to the environment outside the pipe.

Only rarely is the physical effect measured right at the location of the fluid loss. In most cases, it is transmitted over some distance to the measurement or detection system.

Also, in most cases a baseline or background normal measurement, or threshold, is used rather than an absolute zero-tolerance alarm setting. For example, only a temperature variation near the pipeline substantially greater than a recorded normal daily cycle would usually trigger an alarm.

One way of categorizing LDS technologies in terms of strengths and weaknesses is to focus on the following parameters:

Table B-1 - Components of an LD Technology

Transmission	The impact of how difficult or unreliable the transmission of the physical effect is between the fluid loss and the measurement.
Detection	The "ideal case" sensitivity and speed of the measurement device.
Signal Noise	The impact of a widely varying baseline of "normal" measurements.

Some examples to illustrate this distinction:

A traditional material balance CPM system uses the *physical effect* of a rate of change of line fill. A leak causing this change will have to *transmit* the effect along the entire length of pipe between two flow meters; similarly, any pressure and density changes will need to travel the distance between two sensors. The *detectability* is a function of the meters' and sensors' accuracy. The *baseline* against which this rate of change of line fill is compared becomes more varied (the threshold increases) when background line fill changes are occurring due to normal transient operations of the pipeline.

A temperature sensing fiber optic cable system uses the *physical effect* of a change in temperature at a point of fluid loss due to both: fluid vs. ambient temperature differential, and Joule-Thomson cooling effects. A leak causing this change will have to *transmit* the temperature change to the cable, along the pipe wall and perhaps through the soil or atmosphere. The *detectability* is a function of the cable's accuracy as measured in the laboratory. The *baseline* against which this temperature change is compared becomes more varied (the threshold increases) when background temperature changes around the pipeline are greater.

An infrared camera system again uses the *physical effect* of a change in temperature at a point of fluid loss due to both: fluid vs. ambient temperature differential, and Joule-Thomson cooling effects. Specific hydrocarbons also radiate with a specific spectrum, which may be used to improve reliability. A leak causing this change will have to *transmit* the temperature change to the camera through the soil and then through the atmosphere. The *detectability* is a function of the camera's accuracy – as well as perhaps the reliability due to spectral processing – as measured in the laboratory. The *baseline* against which this temperature change is compared becomes more varied as background infrared emissions (thermal sources) increase.

In each of these examples:

- The shorter, more reliable and less prone to disturbance the transmission path, the better. As a very broad generalization, Internal methods where the transmission path is inside the pipe present a more insulated and reliable transmission path than External methods, which are affected by the relatively uncontrollable pipeline external environment.
- The better the quality of the measurement, the better the detectability. Here by contrast some of the External sensors available have better ratings than most flow meters used in Internal CPM methods. However, the environment of the

transmission path mentioned above often outweighs this better laboratory specification.

- The more stable the baseline, the better. Therefore, generally stable pipeline operations and calmer environmental conditions make leak detection easier.

It is useful to place a given technology using Tornado Diagrams. For example, for a CPM LDS system on a well-instrumented liquids pipeline during relatively stable operations, the relative impact of the parameters is roughly as follows:

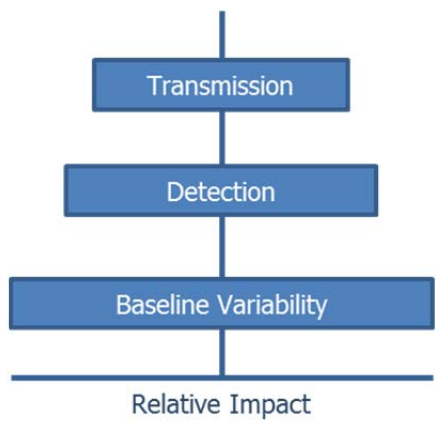

Figure B-2 - Uncertainty Tornado Diagram - CPM for Liquids

By reference to the API publication 1149, there is a rough correspondence:

1. Transmission – number and spacing of instrumentation
2. Detection – accuracy of flow meters and instruments
3. Signal – transient effects

With a gas pipeline, the baseline variability is considerably greater, even during relatively stable operations, and achieving similar flow meter accuracies is more difficult:

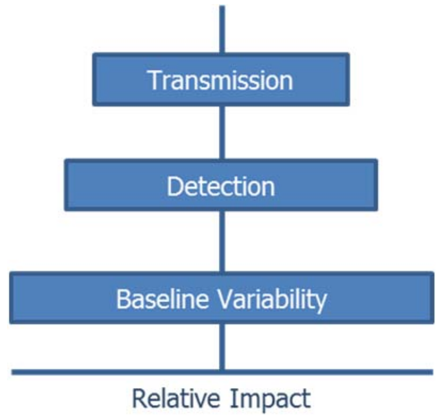

Figure B-3 - Uncertainty Tornado Diagram - CPM for Gas

Also, purely as a guideline, with External sensors the signal (affected by the environment) and transmission path tend to dominate much more:

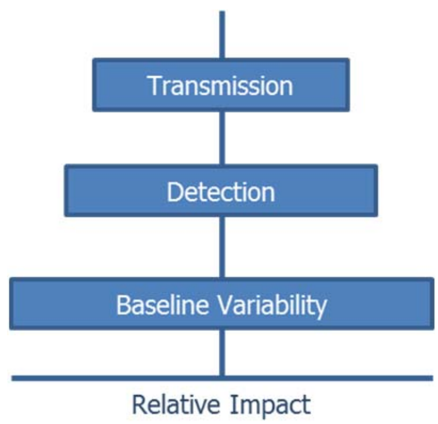

Figure B-4 - Uncertainty Tornado Diagram – External Sensor

Note that forthcoming reports in this study will address several key related issues:

- Task 3: Systematic predictions of performance, will address how all the individual performance factors can be combined systematically in order to provide a composite expected performance.
- Task 4: Impact of installation, calibration and testing, will cover the physical effect transmission issue (via installation planning), the signal issue (via calibration and testing) and the quality of measurement issue (via testing).
- Task 5: Retrofit, is strongly affected by transmission effects.

3.2 Classification of Technologies

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: description of types of internal-based CPM systems, lists eight separate techniques. They rely essentially on four physical effects, and the table below summarizes their interplay:

Table B-2 - API RP 1130 CPM Systems

API RP 1130 Method	Physical Principle
C.1 Line Balance	Conservation of mass
C.2 Volume Balance	
C.3 Modified Volume Balance	
C.4 Compensated Volume Balance	
C.5 Real-Time Transient Modeling	Conservation of mass and energy
C.6 Pressure/Flow Monitoring	Pressure inversely proportional to flow (Bernoulli's Law)
C.7 Acoustic/Negative Pressure Wave	Speed of sound in fluids

The last technique, C.8 Statistical Analysis, can in fact be used as a Comparison method against the baseline with any one of these physical effects.

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 is as follows:

Table B-3 - 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

3.3 Classification of Techniques

Although they are generally used interchangeably, the terms technology and technique have slight 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.

This is sketched in the table below, with some example entries intended to illustrate the division:

Table B-4 - Classification of LD Techniques

	Internal		**External**	
	Continuous	**Intermittent**	**Continuous**	**Intermittent**
Automated	On-line CPM methods	Daily volume imbalances	Fiber optic monitoring	Smart pigging
Manual		Hydro-tests	Monitoring by cameras	Periodic patrols

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

3.3.1 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.

3.3.2 Hydro-testing

When a pipeline is shut down periodically, filled with water, 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.

3.3.3 "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.

3.4 Transmission Effects

For Internal methods, the API RP 1130 techniques all essentially analyze sections of pipe between meters and instruments that measure the properties of the fluid flow. In this sense, the physical principle is "transmitted" over the distance between meters and instruments. As before, these can be summarized as follows:

Table B-5 - Transmission Effects, CPM Systems

API RP 1130 Method	Transmission Effect
C.1 Line Balance	Conservation of mass contained in a section of pipe bounded by meters.
C.2 Volume Balance	
C.3 Modified Volume Balance	
C.4 Compensated Volume Balance	
C.5 Real-Time Transient Modeling	Conservation of mass and energy, by sections of pipe bounded by meters.
C.6 Pressure/Flow Monitoring	Sections of pressure sensor / flow meter pairs. Even just one pressure sensor will work in principle, but then the entire line fill has to transmit the pressure change.
C.7 Acoustic/Negative Pressure Wave	Sections of pressure sensor pairs.

The corresponding considerations for External sensors are as follows:

Table B-6 - Transmission Effects, External Systems

Technique	Description	Transmission Effect
Acoustic sensors	Detects leaks based on acoustic emissions	Acoustic sound must travel along the pipe wall and perhaps also soil and atmosphere.
Gas / HC Vapor sampling	Flame Ionization (natural gas) or other HC vapor detector	Natural gas must travel through soil and the atmosphere to the detector, without too much dissipation.
Soil monitoring	Detects tracer chemicals added to gas pipe line	Tracer must travel through soil and the atmosphere to the detector, without too much dissipation.
Lidar absorption	Absorption of a pulsed laser monitored in the infrared	Gas plume must achieve a minimum concentration to absorb sufficient light, without too much dissipation.
Diode laser absorption	Absorption of diode lasers monitored	Gas plume must achieve a minimum concentration to absorb sufficient light, without too much dissipation.
Broad band absorption	Absorption of broad band lamps monitored	Gas plume must achieve a minimum concentration to absorb sufficient light, without too much dissipation.
Evanescent sensing	Monitors changes in buried optical fiber	Temperature plume must travel through soil to the detector.
Millimeter wave radar systems	Radar signature obtained above pipe lines	Gas plume must achieve a minimum concentration to absorb sufficient energy, without too much dissipation.
Backscatter imaging	Natural gas illuminated with CO2 laser	Gas plume must achieve a minimum concentration to absorb sufficient energy, without too much dissipation.
Thermal imaging	Passive monitoring of thermal gradients	Temperature plume must be concentrated enough to become visible.
Multi-spectral imaging	Passive monitoring using multi-wavelength infrared imaging	Temperature plume must be concentrated enough to become visible.

We remark below that transmission effects, together with signal variability, are among the most serious sources of false alarms / poor reliability.

3.5 Signal Variability

For Internal methods, the API 1149 publication identifies transient operations of the pipeline (i.e. unsteady flow conditions) as a major source of uncertainty in these forms of CPM LDS. By contrast, environmental conditions outside the pipe (with the possible exception of ambient temperature) have a very small impact on the baseline flow conditions. These can be summarized as follows:

Table B-7 - Signal Issues, CPM Systems

API RP 1130 Method	Signal Issues
C.1 Line Balance	Compression / expansion of mass contained in a section of pipe bounded by meters.
C.2 Volume Balance	
C.3 Modified Volume Balance	
C.4 Compensated Volume Balance	
C.5 Real-Time Transient Modeling	Compression / expansion of mass and loss / gain of energy, in sections of pipe bounded by meters.
C.6 Pressure/Flow Monitoring	Ordinary pressure changes due to transient operations.
C.7 Acoustic/Negative Pressure Wave	

Recall that C.8 Statistical Methods can be used to "filter" extraneous or very transient changes, and seek only statistically significant deviations from the baseline.

Correspondingly, the considerations for External sensors are nearly always environmental, but independent of the flow conditions and operations of the pipeline:

Table B-8 - Signal Issues, External Systems

Technique	Description	Signal Issues
Acoustic sensors	Detects leaks based on acoustic emissions	Ambient sound / vibration (can be tuned to partially reject this). Attenuation of sound by soil, groundwater, etc.
Gas / HC Vapor sampling	Flame Ionization (natural gas) or other HC vapor detector	Ambient sources of gas (e.g. biogenic). Soil or atmospheric (e.g. wind) dispersal of methane.
Soil monitoring	Detects tracer chemicals added to gas pipe line	Soil or atmospheric (e.g. wind) dispersal of tracer.
Lidar absorption	Absorption of a pulsed laser monitored in the infrared	Other atmospheric absorbers of light (e.g. clouds, birds). Soil or atmospheric (e.g. wind) dispersal of methane.
Diode laser absorption	Absorption of diode lasers monitored	Other atmospheric absorbers of light (e.g. clouds, birds). Soil or atmospheric (e.g. wind) dispersal of methane.
Broad band absorption	Absorption of broad band lamps monitored	Other atmospheric absorbers of light (e.g. clouds, birds). Soil or atmospheric (e.g. wind) dispersal of methane.
Evanescent sensing	Monitors changes in buried optical fiber	Ambient sources of temperature (e.g. sun, climate). Soil / groundwater temperature dispersal.
Millimeter wave radar systems	Radar signature obtained above pipe lines	Ambient sources of EM radiation (e.g. industrial). Soil / groundwater gas dispersal.
Backscatter imaging	Natural gas illuminated with CO2 laser	Ambient sources of thermal radiation (e.g. industrial). Soil / groundwater gas dispersal.
Thermal imaging	Passive monitoring of thermal gradients	Ambient sources of temperature (e.g. sun, climate). Soil / groundwater temperature dispersal.
Multi-spectral imaging	Passive monitoring using multi-wavelength infrared imaging	Ambient sources of thermal radiation (e.g. industrial). Soil / groundwater gas dispersal.

3.6 Detection Sensitivity

Recall that detection sensitivity is the ideal case, laboratory measured, sensitivity of the measurement device being used as part of the LD technique. It is degraded both by the transmission path for the physical effect to reach it from the point of fluid loss, and is limited by the variability of the baseline against which it is being compared.

For Internal methods, the API 1149 publication identifies and explains how the accuracy of the measurement device contributes to sensitivity, generally as a percentage of bulk flow within a given time. Very broad guidelines (with excellent metering, better than 1% accuracy) *ideal cases* (absolutely stable flow) can be summarized as follows:

Table B-9 - Detectability Issues, CPM Systems

API RP 1130 Method	Detectability Threshold
C.1 Line Balance	About 5% - 10% within 5 min.
C.2 Volume Balance	About 2% - 10% within 5 min.
C.3 Modified Volume Balance	About 2% - 5% within 5 min.
C.4 Compensated Volume Balance	About 1% - 5% within 5 min.
C.5 Real-Time Transient Modeling	1% within about 1 min.
C.6 Pressure/Flow Monitoring	About 10% - 15% within 5 min.
C.7 Acoustic/Negative Pressure Wave	1% within 10 sec.

Recall internal methods are very sensitive to operational conditions. If flow rates and pressures are themselves varying by much more than 1%, the detectability threshold is meaningless.

By contrast External sensors are nearly always rated in terms of an absolute sensitivity at the sensor. Therefore, these guideline figures are strictly in laboratory conditions, in a neutral environment. Recall that environmental factors can enormously degrade this sensitivity, but these ratings are independent of the flow conditions and operations of the pipeline:

Table B-10 - Detectability Issues, External Systems

Technique	Description	Detectability Threshold
Acoustic sensors	Detects leaks based on acoustic emissions	-20 – -70 dB
Gas / HC Vapor sampling	Flame Ionization (natural gas) or other HC vapor detector	25 ppm
Soil monitoring	Detects tracer chemicals added to gas pipe line	25 ppm
Lidar absorption	Absorption of a pulsed laser monitored in the infrared	~ 100 ppm (depends on power)
Diode laser absorption	Absorption of diode lasers monitored	~ 100 ppm (depends on power)
Broad band absorption	Absorption of broad band lamps monitored	~ 100 ppm (depends on power)
Evanescent sensing	Monitors changes in buried optical fiber	Resolution of 1 m with accuracy to within ±1°C
Millimeter wave radar systems	Radar signature obtained above pipe lines	~ 100 ppm (depends on power)
Backscatter imaging	Natural gas illuminated with CO2 laser	~ 100 ppm (depends on power)
Thermal imaging	Passive monitoring of thermal gradients	About 50 ppm / 10 m.
Multi-spectral imaging	Passive monitoring using multi-wavelength infrared imaging	About 50 ppm / 10 m.

Recall external methods are very sensitive to transmission / signal noise conditions. If, for example, background temperatures are themselves varying by much more than ±1°C, the detectability threshold of ±1°C of a temperature sensor is meaningless. Similarly, quite a large loss of methane might, in a strong wind, never achieve a 50-ppm *at the sensor* detectability threshold.

Note how the specification of sensitivity is different according to the kind of sensor that is used. Even similar acoustic sensors, for example, will have different characteristics depending on the frequency range being monitored. A major part of Task 3: Systematic predictions of performance, will address how they contribute to a composite expected LDS performance.

3.7 Major Performance Factors

The API publication 1149 highlights several key issues that are most relevant to the selection and performance of a given technology, summarized below:

Table B-11 - API 1149 Major Performance Factors

1. Rate of False Alarms and Misses
2. Instrument Accuracy
3. Personnel Training and Qualification
4. System Size and Complexity (Including Batch Line Factors)
5. Leak Size vs. Leak Flow Rate
6. Response Time
7. Leak Location Estimation
8. Release Volume Estimation
9. Detecting Pre-existing Leaks
10. Detecting a Leak in Shut-in Pipeline Segments
11. Detecting a Leak in Pipelines under a Slack Condition During Transients
12. Sensitivity to Flow Conditions
13. Multiphase Flow
14. Robustness
15. Availability
16. Retrofit Feasibility
17. Testing
18. Cost
19. Maintenance

The 49 CFR 195 specifically calls for consideration of these factors in assessing a liquids pipeline LDS. Gas pipelines are not subject to the same level of specific instruction; however, these factors are still relevant to natural gas to varying degrees.

As an illustration, a typical Internal CPM system might be (partially) assessed as follows:

Table B-12 - Major Performance Factors, CPM Systems

1.	Rate of False Alarms and Misses	Manageable for liquids, can be high for gas. Specific numerical methods are available from API 1149 to assess this.
2.	Instrument Accuracy	Flow meters often need careful calibration.
4.	System Size and Complexity (Including Batch Line Factors)	Generally, only one inlet / one outlet pipelines can be covered. Batch operations degrade performance.
5.	Leak Size vs. Leak Flow Rate	Sensitivity is expressed as a percentage of total flow. Leak size is not measured.
6.	Response Time	Depends on the flow rate of the leak.
7.	Leak Location Estimation	Difficult
8.	Release Volume Estimation	Difficult
9.	Detecting Pre-existing Leaks	Difficult
10.	Detecting a Leak in Shut-in Pipeline Segments	Difficult
11.	Detecting a Leak in Pipelines under a Slack Condition During Transients	Generally not possible
12.	Sensitivity to Flow Conditions	Batch operations and transients on the pipeline degrade performance.
13.	Multiphase Flow	Generally not possible
14.	Robustness	Relatively good if well engineered
15.	Availability	Relatively good if well engineered
16.	Retrofit Feasibility	If metering is available, no fieldwork is required.

With a specific LDS technology, both a more precise and a more detailed analysis should be done. However, a similar generic External system might be (partially) assessed as follows:

Table B-13 - Major Performance Factors, External Systems

1.	Rate of False Alarms and Misses	No detailed numerical methods are available to assess this. Highly situation-dependent.
2.	Instrument Accuracy	Not an issue.
4.	System Size and Complexity (Including Batch Line Factors)	Not an issue.
5.	Leak Size vs. Leak Flow Rate	Leak size is measured. Leak flow rate is difficult to estimate.
6.	Response Time	Almost immediate, once threshold sensitivity is achieved.
7.	Leak Location Estimation	Good
8.	Release Volume Estimation	Good
9.	Detecting Pre-existing Leaks	Good – although it is possible to miss these if they are included in the baseline calibration
10.	Detecting a Leak in Shut-in Pipeline Segments	Good
11.	Detecting a Leak in Pipelines under a Slack Condition During Transients	Good
12.	Sensitivity to Flow Conditions	Insensitive
13.	Multiphase Flow	Insensitive
14.	Robustness	Highly situation-dependent
15.	Availability	Relatively good if well engineered
16.	Retrofit Feasibility	Fieldwork is nearly always required

3.8 Performance Factors Quadrant

In common with many other engineering design issues, LDS performance factors are often a trade-off against each other. It is generally very difficult to achieve high performance in all 19 of the categories of Table B-11.

This issue is discussed in much more detail in the forthcoming Task 3: Systematic predictions of performance. Some examples of well-known trade-offs in performance include:

With Internal CPM systems, the API 1149 publication describes how Sensitivity is generally at the expense of Reliability (Rate of False Alarms and Misses), and Accuracy is generally at the expense of Speed of Detection. This is also discussed in API RP 1130. A highly sensitive CPM, with very low thresholds for detection, will tend to declare more false alarms as transient or unexpected operating scenarios are encountered, inconsistent with the low threshold. Similarly, an early alarm will tend to give less accurate estimates of position and release volume; these estimates improve with time.

With External sensor systems, Sensitivity is generally at the expense of Retrofit Feasibility. Ideally, most sensors are best positioned right next to the pipe, or even attached to it, at frequent intervals. While this may be feasible during original construction, it may be difficult once the pipeline is in operation. Robustness is also often at the expense of Sensitivity: highly sensitive sensors also tend to be the most delicate.

At this stage, where a technology pre-screening is called for, it is useful to express these issues in a Performance Factors Quadrant. This is modeled upon the Gartner Group's Magic Quadrant research methodology for technology providers. It is useful to think of at least a few models for LDS with perhaps the most frequently used being Sensitivity against Reliability:

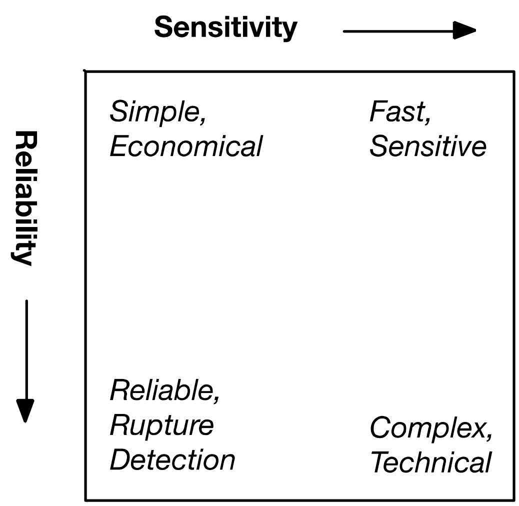

Figure B-5 - Quadrant for Sensitivity / Reliability

A similar diagram might apply to Accuracy against speed:

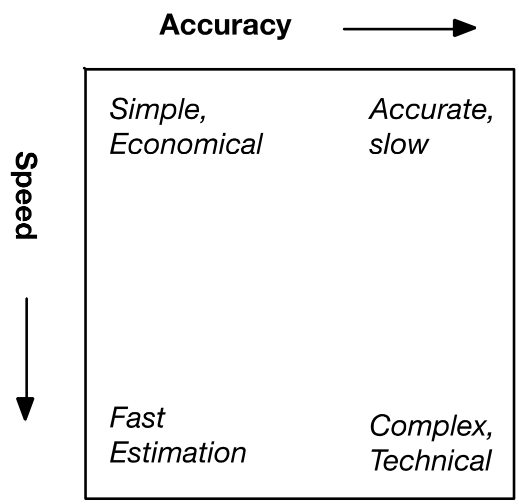

Figure B-6 - Quadrant for Accuracy / Speed

3.9 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. These are discussed in much more detail in the Engineering Approach section of this report. However, it is useful to look at one example at this stage to explain how a single technology does not need to be dismissed entirely because it does not meet all the requirements listed in Table B-11.

In fact, almost without realizing it, most pipelines already employ a variety of LDS techniques in parallel:

1. Hydro-tests are often mandatory on a five-year cycle. This is perhaps one 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 also is often mandatory. The patrols might be as frequent as daily. 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.

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

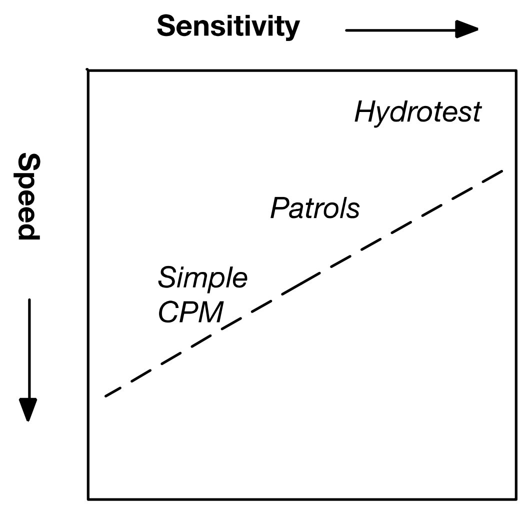

Figure B-7 - Composite LDS performance

In this way, the composite performance is far more widespread than any one single technology's.

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 his 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.

4 Technology Matrix

From the last section, it is evident that there are many potential combinations of physical leak detection principles and their deployment either as a continuous or intermittent, and automated or manual, technology.

Nevertheless, there are certain combinations that dominate, and in this section there is a focus on the leak detection technologies listed below. The first table lists Internal Methods in wide use:

Table B-14 - Internal Technologies Considered

• On-line CPM methods	Continuous	Automated
• Periodic (daily, weekly, etc.) volume imbalance	Intermittent	Automated
• Hydro-testing	Intermittent	Manual

The second table lists the External Methods in wide use:

Table B-15 - External Technologies Considered

Periodic patrols:	Intermittent	Manual
Purely visual		
Gas / HC Vapor sampling		
Using Thermal Imaging		
Soil monitoring		
Cable monitoring:	Continuous	Automated
DTS / DAS		
Point sensor monitoring:	Continuous	Automated
Acoustic sensors		
Gas / HC Vapor sampling		
Soil monitoring		
Monitoring by cameras:	Continuous	Manual
Thermal imaging		
Multi-spectral imaging		
Smart Pigging:	Intermittent	Automated
Acoustic sensors		

Note again that this is not meant to be an exhaustive list of all LD technologies; rather, this is a working list, for this section, that represents the majority of technologies and their uses within the pipeline industry.

4.1 Technology Suitability Factors

There are many possible factors that might be used in deciding whether a given technology is suitable for a given application or project. However, it is useful to focus on these principal factors:

1. Suitability – is the technology suitable to the physical and environmental environment of the pipeline at all.
2. Application – in other words, is the technology practically applicable to the pipeline situation.
3. Performance – can the technology function to the required level of performance in the physical and operational environment of the pipeline
4. Maturity – how mature is the technology, in terms of how likely is it to work as intended without continual updates, reconfigurations, etc.
5. Project Risk – closely related, the likelihood of a failure of the technology, or of it performing well below its expected rating.
6. Requirements – specifically in terms of resources (and capital), expertise (human) and maintenance.

4.2 Technology Selection Process

In broad summary, a general selection process might proceed as follows:

1. A list of candidate technologies is prepared. Tables 14 and 15 above might be used as a starting point for this.
2. The suitability of each technology is a pre-screening step. Tables B-5 – B-10 and B-17 – B-18 list the major performance issues of a number of technologies. If any of these issues is particularly marked, then the technology will probably not perform at all well. For example, if the pipeline is often in a highly transient state, perhaps with slack flow, basic volume balance should not pass this step.
3. Applicability is similar, but adds in practical considerations about the actual pipeline environment, operations and physical configuration. A good example is retrofit feasibility, as discussed in the API publication 1149 and Table B-11. A highly suitable technology may nevertheless be impractical to retrofit and therefore not apply well.

4. Performance is then estimated, for the specific pipeline using each technology. Precise measures of this performance are addressed in Task 3: Systematic predictions of performance. However, an initial estimate or ranking of performance can be made using Tables B-12 and B-13.
5. The maturity of each technology is assessed, and this may – depending on corporate or other strategic policies – be a deciding factor. As a matter of policy, a pipeline may decide that only well-tested technologies apply at all – in which case this step might belong at the Suitability stage.
6. General project risk then uses technology maturity as a component, but adds in factors of complexity, time to deployment, difficulty of testing and similar issues.
7. Finally, resource, expertise and maintenance requirements provide a final ranking for the selection of technologies.

It is to be emphasized that no technology will be perfectly suitable in all these categories. Likewise, no technology will be completely useless, although certainly after step 3 several will probably be assessed as unlikely to perform well. It is recommended to at least follow 2 – 3 technology options right through to the end since the Engineering Approach described below allows a set of perhaps sub-standard technologies to be combined into a well-performing overall system.   This process can be illustrated in a flow chart as follows:

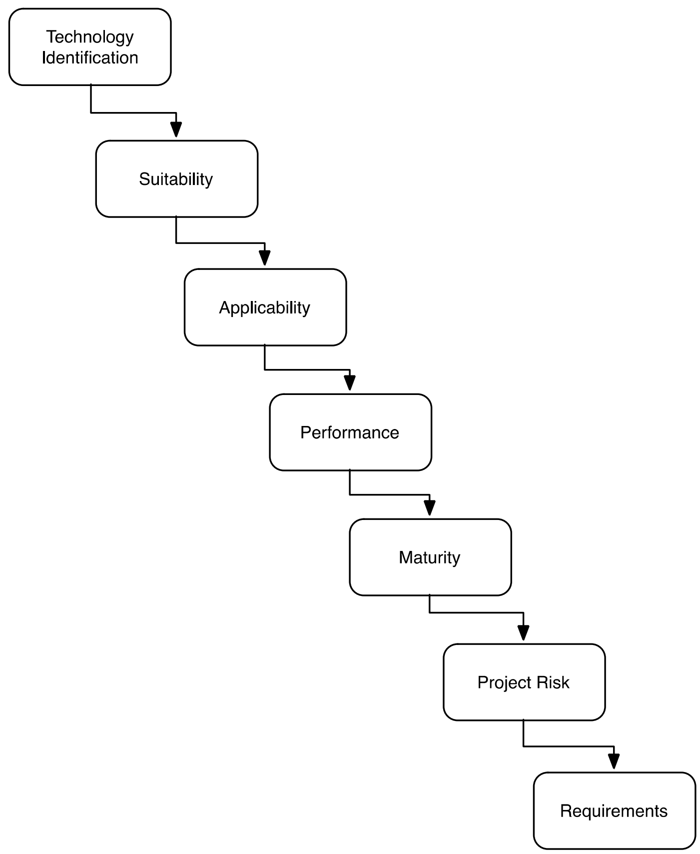

Figure B-8 - General Technology Selection Process

Since, as described above, most of the first four steps are covered elsewhere in this and other reports, the focus of the rest of this section is on assessing technology maturity, project risk, and requirements.

4.3 Technology Maturity

Generally, Maturity can be defined in the context of LDS technology as the level of predictability, effectiveness, and control[6].

1. Predictability can be measured as its ability to produce repeatable, consistent results.
2. Effectiveness can be measured as delivering a consistent level of performance.
3. Control refers to its ability to be managed within general engineering frameworks.

[6] US Department of Defense Software Engineering Institute (SEI)

In this framework, a predictable technology can be used and, given inputs such as the pipeline configuration, operations, and environment, its performance can be predicted reliably. Predictable technologies are examined in detail in Task 3: Systematic predictions of performance. Experimental or relatively young technologies do not usually have systematic performance prediction algorithms. Therefore, the operator cannot implement these with a good degree of confidence in their ultimate success.

Effective technologies are sufficiently mature that their use, application and implementation have been optimized and are generally competitive with other mature techniques. Prototype technologies that are still being "tweaked" may require rapid replacement as more data on their performance metrics are collected.

Controllable technologies allow any engineer or operator to deploy them and to manage them according to public, generally accepted best practices. Technologies that are not controllable require custom, "Black Box" deployments in the hands of few dedicated experts.

4.3.1 Maturity vs. Age

A technology may be long-standing, but still be relatively immature (and vice-versa). For example, many hydrocarbon sensor technologies and infrared imaging technologies have been used for decades in process plants – petrochemicals and refineries. In those industries, these technologies are highly predictable, effective, and manageable. However, there is far less of a track record with these technologies in the multiple-mile pipeline industry.

Nevertheless, a useful screening tool remains some measure of where the technology lies on its overall lifecycle. One way of expressing this is on the scale of Prototype, Early Adoption, Multiple Adoption, General Acceptance, and (perhaps) Obsolescence. This table summarizes some quick-look measures of how to place a given technology on this scale:

Table B-16 – Maturity vs. Age

Stage	Number of Installations (pipeline industry)	Timeframe	Predictability	Effectiveness	Control
Prototype	None	Less than a year	Experimental	Unknown	Custom Implementation
Early Adoption	Less than a dozen	Few years	Still being assessed	Unpredictable	Multiple releases / versions
Multiple Adoption	Multiple dozen	Several years	Accepted guidelines	Predictable performance	Standard versions available
General Acceptance	Industry wide	Years - decades	Guidelines, recommended practices, etc.	Highly predictable performance	Standard engineering practices
Obsolescence		Decades		Better technologies acknowledged	

4.3.2 Maturity vs. Applicability

One important distinction to be made is against applicability. This is why, in the general process of Figure B-9, applicability is assessed first. It is quite possible for a technology *never* to be predictable, effective, or manageable in certain situations.

As an example, CPM Internal LDS techniques are highly mature. They are predictable (API 1149, 1130 and other prediction tools exist), effective (widely used with excellent results), and manageable (several packaged commercial packages exist, as well as best practice documents). However, for pipelines that are, for example, often in slack line conditions (liquids) or are often in highly transient operations (gas) they do not apply very well. This does not mean that they are immature in the gas pipeline industry – it simply means that they only apply to certain classes of gas pipeline.

4.3.3 Maturity vs. Performance

For a technology to be mature its performance must be *predictable* – however, this does not mean that it will necessarily perform *well*. This is why, in the general process of Figure B-9, performance is assessed later. If it is generally impossible to predict the performance of a given technology, it will never make it past the maturity test in the overall technology selection process.

4.4 Capability Maturity Model

There are not many standard engineering methodologies available for a consistent, algorithmic assessment of the maturity of a techniques or product. Practically speaking, the basic three-category approach outlined at the beginning of this section is often sufficient for a pipeline operator assessing the maturity of a LD technology set.

One good general approach, however, is the Capability Maturity Model (CMM, a registered service mark of Carnegie Mellon University, CMU) a development model created after study of data collected from organizations that contracted with the U.S. Department of Defense, through their Software Engineering Institute (SEI), who funded the research. The term "maturity" relates to the degree of formality and optimization of processes, from ad hoc practices, to formally defined steps, to managed result metrics, to active optimization of the processes.

The model's aim is to improve existing software-development processes, but it can also be applied to other processes. It involves five aspects:

1. Maturity Levels: a 5-level process maturity continuum - where the uppermost (5th) level is a notional ideal state where processes would be systematically managed by a combination of process optimization and continuous process improvement.
2. Key Process Areas: a Key Process Area identifies a cluster of related activities that, when performed together, achieve a set of goals considered important.
3. Goals: the goals of a key process area summarize the states that must exist for that key process area to have been implemented in an effective and lasting way. The extent to which the goals have been accomplished is an indicator of how much capability the organization has established at that maturity level. The goals signify the scope, boundaries, and intent of each key process area.
4. Common Features: common features include practices that implement and institutionalize a key process area. There are five types of common features: commitment to perform, ability to perform, activities performed, measurement and analysis, and verifying implementation.
5. Key Practices: The key practices describe the elements of infrastructure and practice that contribute most effectively to the implementation and institutionalization of the area.

4.4.1 CMM Maturity Levels

There are five levels defined along the continuum of the model and, according to the SEI: "Predictability, effectiveness, and control of an organization's software processes are believed to improve as the organization moves up these five levels. While not rigorous, the empirical evidence to date supports this belief".

1. Initial (chaotic, ad hoc, individual heroics) - the starting point for use of a new or undocumented repeat process.
2. Repeatable - the process is at least documented sufficiently such that repeating the same steps may be attempted.
3. Defined - the process is defined/confirmed as a standard business processes.
4. Managed - the process is quantitatively managed in accordance with agreed-upon metrics.
5. Optimizing - process management includes deliberate process optimization/improvement.

Within each of these maturity levels are Key Process Areas which characterize that level, and for each such area there are five factors: goals, commitment, ability, measurement, and verification. These are not necessarily unique to CMM, representing generically the stages that any technology, product or organization must go through on the way to becoming mature.

The model provides a theoretical continuum along which process maturity can be developed incrementally from one level to the next:

1. Level 1 - Initial (Chaotic). It is characteristic of processes at this level that they are (typically) undocumented and in a state of dynamic change, tending to be driven in an ad hoc, uncontrolled and reactive manner by users or events. This provides a chaotic or unstable environment for the processes.
2. Level 2 – Repeatable. It is characteristic of processes at this level that some processes are repeatable, possibly with consistent results. Process discipline is unlikely to be rigorous, but where it exists it may help to ensure that existing processes are maintained during times of stress.
3. Level 3 – Defined. It is characteristic of processes at this level that there are sets of defined and documented standard processes established and subject to some degree of improvement over time. These standard processes are in place (i.e., they are the AS-IS processes) and used to establish consistency of process performance across the organization.
4. Level 4 – Managed. It is characteristic of processes at this level that, using process metrics, management can effectively control the AS-IS process (e.g., for software development). In particular, management can identify ways to adjust and adapt the process to particular projects without measurable losses of quality or deviations from specifications. Process Capability is established from this level.

5. Level 5 – Optimizing. It is a characteristic of processes at this level that the focus is on continually improving process performance through both incremental and innovative technological changes/improvements.

At maturity level 5, processes are concerned with addressing statistical common causes of process variation and changing the process (for example, to shift the mean of the process performance) to improve process performance. This would be done at the same time as maintaining the likelihood of achieving the established quantitative process-improvement objectives.

4.5 Project Risk

Task 1: Design and engineering approach, addresses how LDS project risk is assessed, managed and tracked through the course of an LDS deployment project. This section focuses on how the technology selection has an impact on project risk. At this level, there are four major components of technology-related risk:

1. Maturity of the technology, as described above: predictability, effectiveness, and control.
2. Complexity – this refers to the general complexity of the technique in general. The technology may be effective, but if it is highly complex then the risk of its failure to deploy is far greater.
3. Contingency / Dependence – some LD technologies are totally self-contained, and some rely heavily on the support of other sub-systems. The more highly dependent the technology is on third-party systems, the higher the unintended risk.
4. Testability – the more easily a technology can be tested, particularly if it can be partially tested during implementation, the more easily mistakes can be avoided thus reducing risk.

Of course, there are many other sources of project risk (organizational, financial, business, operations, etc.) but from a purely technology selection perspective these are useful categories to work with.

4.5.1 Complexity

The complexity of a technology is a relative measure of how much expertise is required to understand and manage it, as well as the number of subsystems involved and the criticality of their inter-dependencies.

As an example, a human foot patrol using visual inspection is not complex. It involves one component (the inspector) with a fixed inspection program, schedule and procedure. The level of expertise required of the inspector is relatively low as well. A real-time transient model CPM Internal LDS, on the other hand, is relatively complex. It requires instrumentation, metering, telemetry, a SCADA system, substantial software, and computer hardware. In addition, it requires expert engineers both to implement and to maintain.

4.5.2 Contingency

The degree of dependence of the technology on third-party systems naturally increases the (unintended) risk of failure. This is usually a qualitative measure, although a complete risk analysis that includes the number of contingencies and all their corresponding risks of failure can be performed in extreme cases.

This source of project risk also affects operational risk: in this context, the project risk applies because the third-party systems may fail to be implemented. During operations, they may fail to perform.

To take the same example, human foot patrol using visual inspection has almost no contingency. The inspector can be deployed almost independently of any other system on the pipeline. With the RTTM LDS, however, if a SCADA system is not deployed, is late, or is over-budget then the RTTM project will unavoidably suffer the same fate.

4.5.3 Testability

The issue of system validation is covered in detail elsewhere, particularly:

- Task 1: Design and engineering approach – addresses Validation as a key component in the overall waterfall process.
- Task 4: Impact of installation, calibration and testing – details how testing affects all phases of an LDS lifecycle, including the implementation project risk.

At this stage, the implementation project risk is reduced substantially if the chosen technology is easily tested. This is because the probability of ultimate, operational success is much greater if the implementation can reliably test performance, using tests that reliably predict long-term operational performance. Another factor is that the system might be unit tested during implementation, long before the entire system is assembled and put through final validation.

Testability is also a subset of the Predictability and Control issues discussed above, under the context of assessing Maturity. An immature technology will probably not be easy to test.

4.6 Technology Requirements

The API publication 1149 highlights several key issues that are most relevant to the selection of a given technology, and they are summarized in Table B-11 above. At this stage, the four relevant ones include:

- Testing
- Cost
- Maintenance

Note also that factor Retrofit Feasibility is an important issue in deciding the Applicability of the technology.

4.6.1 Testing

Testing has already appeared above in other contexts:

- Technology maturity depends on the existence of established testing procedures
- Project risk is reduced if testing can be performed easily during implementation

In this context, long-term continual / periodic testing requirements are meant. That is to say, the ongoing lifetime testing needs: technical, operational and cost. For example, with CPM methods it may be necessary to test the system periodically using physical withdrawal of fluid from the pipeline (see, for example, 49 CFR 196.112). In that case, equipment will be needed for the safe and reliable withdrawals on a periodic basis. It may be necessary to install this equipment permanently on the pipeline. Similarly, external hydrocarbon sensing cameras will need some way to be tested by (safe and contained) release of vapors near the pipeline.

These operational testing requirements can be difficult to design, and can also contribute substantially to the long-term cost of ownership of the technology.

4.6.2 Cost and Maintenance

Clearly, other factors being equal, lower-cost technologies are preferable. However, it is important for this cost to represent the total cost of ownership (TCO) of the system, including maintenance requirements. It is common to compare technologies by setting a time horizon (five or ten years, for example) so that all the costs involved are examined.

As an example, a basic mass balance CPM system can appear very attractive since it is cheap and fast to implement initially. However, it is entirely dependent on a very high level of meter accuracy, and the monthly proving of the associated metering should really be included. Equally, the testing of the system by physical withdrawal adds to the TCO. By contrast, External systems have higher initial costs but are generally much less expensive to operate.

Note that, in order to save time, a high-level and approximate cost estimate is often used at the Applicability stage of Technology Selection. It is useful to be able to eliminate, early on, technologies that will undoubtedly exceed the available budget.

5 Engineering Approach

LDS are at least in part related to reliable and safe operations of a pipeline. Therefore, the design and engineering of LDS are strongly related to reliability and safety engineering principles.

Some specialized disciplines of engineering that apply to basic LDS principles include:

- Reliability engineering – including the closely related areas of safety engineering / system safety
- Reliability, Availability and Maintainability (RAM)
- Robust control systems engineering

5.1 Key Performance Objectives

The API publication 1149 highlights several key issues that are most relevant to the selection and performance of a given technology, and these are summarized in Table B-11 above. However, it is useful to concentrate on four main issues: Sensitivity, Accuracy, Robustness and Reliability.

Sensitivity and Accuracy are generally limited by the technology that is used, but they can be adjusted to suit the application that is being addressed. We have already noted that the API 1149 publication describes how Sensitivity is generally at the expense of Reliability (Rate of False Alarms and Misses), and Accuracy is generally at the expense of Speed of Detection. This is also discussed in API RP 1130. A highly sensitive CPM, with very low thresholds for detection, will tend to declare more false alarms as transient or unexpected operating scenarios are encountered, inconsistent with the low threshold. Similarly, an early alarm will tend to give less accurate estimates of position and release volume; these estimates improve with time.

There is also a subtle tradeoff between Reliability and Robustness. In principle, Reliability refers to the ability of a system to function under stated, bounded conditions for a specified period of time. Robustness, understood as the ability of a system to resist change without adapting its initial stable configuration, is a perhaps stronger attribute that acknowledges that there will be situations where the stated, bounded system conditions – perhaps quite often – and that the system is generally expected to operate for as long as possible.

Exactly how these indicators are measured or expressed is discussed in much more detail in the forthcoming Task 3: Systematic predictions of performance. For now, the focus is much more on the principles and definitions involved.

5.1.1 Sensitivity

In general, sensitivity is the threshold at which a detector – in this application, a leak detector – can reliably detect a given event or signal, within a given time of the event. From this definition itself, it is obvious that a careful definition of "reliably" and "time" needs to be made. Similarly, the "given event" must be described carefully for sensitivity to have a good meaning.

A few comments:

1. A detector is often not instantaneous – in fact this is common. A particular feature of CPM methods of leak detection is that they tend to become more sensitive (for the same reliability) over a longer sampling period. This relationship is often discussed – notably in API publication 1149. External sensors often require a minimum (but fixed) sampling period.
2. The threshold may also be expressed in different ways. For example, CPM methods often have a minimum detectability threshold expressed as a percentage of total flow lost. By contrast, many external systems have an absolute volume loss threshold.
3. The reliability is typically made in terms of a degree of confidence – i.e. the detection is correct a given percentage of times that it is made.

A common expression of sensitivity might be "ability to measure a loss flowing at a rate of x% of bulk flow rate (the threshold), "within ten minutes" (the time) "with a 90% level of confidence" (the reliability).

Note that this definition includes a measure of reliability. Another very common approach is to cite sensitivity as an absolute measure and the reliability quite separately (see the definition below). In that case, sensitivity is a function of reliability and not really a fixed value.

5.1.2 Accuracy

Accuracy is similarly the degree of confidence in a measurement of any kind. The way that this "degree of confidence" is expressed is again central to this definition. A good source for a thorough description of how Accuracy is the ANSI/API Manual of Petroleum

Measurement Standards (MPMS) – refer in particular to Chapter 3. Accuracy is technically expressed as a Bias (a mean, systematic average deviation from the actual value) and a Precision (the standard deviation of random errors from the actual value).

Accuracy can refer to discrete measurements (Bias as a mean over or under reporting and Precision as a S.D. of these erroneous measures) or continuous measurements (as in classical metering theory).

An LDS itself has Accuracy in a discrete sense, which is technically a bias towards over or under alarming a leak. The API RP 1130 lists this accuracy separately, classifying it as "Rate of False Alarms and Misses". It also discusses this as an attribute of Reliability. Accuracy in the continuous sense might apply to an LDS that makes estimates of, for example, the volume of the loss and/or the location of the loss.

Note that accuracy is frequently a function of time to a measurement. For example, most CPM systems estimate the location of a leak, and the volume of fluid lost, more accurately given more time. Similarly, many external sensors are more accurate in estimating the concentration of hydrocarbons if given longer to perform the measurement.

5.1.3 Reliability

Reliability, or Dependability, describes the ability of a system or component to function under stated conditions for a specified period of time. In the context of LDS, this can usefully be thought of as the confidence in an alarm or a detection being made, given that the entire system including the pipeline is in the "normal range" of conditions for which the LDS was designed.

Therefore, careful definitions of the "stated conditions" and the "period of time" are important.

The term "reliability" is often used as a concept that includes availability and maintainability (RAM). Reliability in its purest form is more concerned with the probability of a failure occurring over a specified time interval, whereas availability is a measure of something being in a state (mission capable) ready to be tasked (i.e., percentage uptime). Maintainability is the parameter concerned with how the system in use can be restored after a failure. Availability combines the reliability with the maintainability to a mission-capable state to give a probability of the system being online over an unlimited period of time.

This is sometimes overlooked in an LDS – there is technically also a maintainability of the system, which may be as simple as re-setting a false alarm as quickly as possible after a failure, or switching over to a backup LDS.

A common expression of reliability might be the number of inaccurate loss alarms (i.e. false alarms and misses) as specified in the design (failure of the system) "under steady state operations" (the stated conditions) over "one year" (the period of time).

5.1.4 Robustness

Robustness is defined as "the ability of a system to resist change without adapting its initial stable configuration". Another way of viewing this is as a form of reliability without the key restrictions of "stated conditions" and the "period of time".

The requirement of "without adapting its initial stable configuration" is important. It means that there is no need for manual operator intervention, or re-configuration / re-setting, during any periods of change.

Sources vary as to whether the "ability to resist change" includes a minimum performance requirement (i.e. the system must still be working at a perhaps reduced performance level) or whether this simply means that the system "sleeps" during severe changes and returns to normal operation transparently.

Note that this requirement can occasionally be at the expense of availability (i.e. reliability). If the system truly does "sleep" during unplanned changes, then it is no longer available. Therefore, it is robust but less reliable.

The API RP 1130 recognizes this issue, and provides also a key observation that robustness is generally at the expense of sensitivity and vice-versa. The example that is cited in API RP 1130 is as follows:

> System I: This system employs a sensitive leak detection algorithm. The system is normally very reliable, but will frequently generate alarms during normal pipeline operations.
>
> System II: This system employs an alternative algorithm that is somewhat less sensitive than that of System I, but generates only a fraction of the alarms.

System III:	This system employs the same sensitive leak detection algorithm as System I, but inhibits leak detection during pipeline operations that can cause it to generate alarms.

System IV:	This system normally employs the same sensitive leak detection algorithm as System I, but switches to the less sensitive algorithm of System II when it senses conditions that generate alarms.

A Reliability – Sensitivity square for these four systems might be sketched as below:

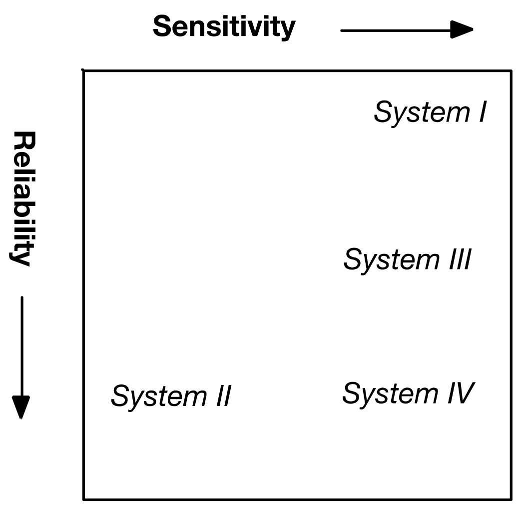

Figure B-9 - API 1130 Example Speed vs. Reliability

An Availability – Robustness square for these four systems might be sketched as below:

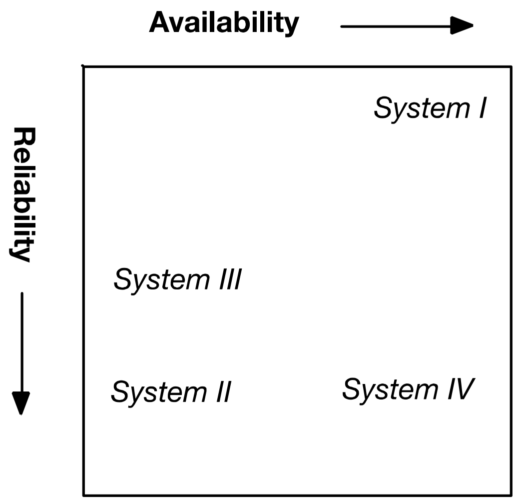

Figure B-6 - API 1130 Example Availability vs. Reliability

5.1.5 Summary of Performance Measures

Specifically in the context of LDS, API RP 1130 provides a one-sentence summary of each of the performance measures as follows:

- Sensitivity is the combined measure of the size of leak that a system is capable of detecting, and the time required for detection
- Accuracy relates to estimation parameters such as leak flow rate, total volume lost, and leak location
- Reliability is the probability of detecting a leak, given that a leak does in fact exist, and the probability of incorrectly declaring a leak, given that no leak has occurred
- Robustness is a measure of ability to continue to function and provide useful information, even under changing conditions of pipeline operation

From a design perspective, it is important to remember the trade-offs that are made between these four objectives. Perhaps the most important are:

- Sensitivity against Speed
- Sensitivity against Varying Conditions
- Accuracy against Speed
- Reliability against Sensitivity
- Reliability against Speed

- Reliability against Varying Conditions
- Robustness against Availability

In the context of LDS, it is common to express the reliability as "rate of false alarms and misses." The reliability trade-offs (4 – 6 in the list) are more usually expressed as:

- False alarms increasing, and Misses decreasing, with Sensitivity
- False alarms and Misses decreasing with Time
- False alarms and Misses increasing with Varying Conditions

5.2 Reliability and Robustness

In this sub-section, perhaps the least discussed two performance objectives are explained. This is unusual, since in most branches of engineering, including instrumentation and measurement, reliability and robustness are among the most studied features of a system.

Recall that for an LDS:

- Reliability can be thought of as the probability of detecting an actual loss, and the probability of making a false alarm
- Robustness is a measure of ability to continue to function under widely changing pipeline operational conditions

However, in an attempt to "harmonize" terminology with general engineering practice, Reliability and Robustness will be used as names in what follows.

The major features of Reliability and Robustness of an LDS can be summarized in this table:

Table B-17 - Reliability and Availability Attributes

Feature	Description	Strategies
Robustness		Technological and Human Redundancy
Reliability	*Includes caveats of:*	Physical, Human Redundancy
	Stated conditions	
	Period of Time	
Availability	*Includes constraints of:*	
	Verification / Validation	System Commissioning
	Maintainability	System Design
	Testability	Supporting Diagnostics
	Re-Start Time	Procedures

The rest of this section discusses these attributes in more detail, but briefly:

Robustness is the hardest level to achieve – it requires both an unlimited period of operation, and an ability to handle unspecified operational conditions. The strategies that may be used to improve these constraints include providing redundancy in technology and in human factors.

Reliability is predicated upon tighter specifications. It also benefits from physical redundancy in the design, and from human factors.

Availability includes the ability to recover from failures – both "hard" faults where the LDS stops working altogether, and failures of performance like false positives and missed losses. Human factors including testability, diagnostics and control room procedures are strategies to improve availability.

5.2.1 Engineering for Reliability

Reliability may be defined in the following ways:

- The idea that an item is fit for a purpose with respect to time
- The resistance to failure of an item over time

- The probability of an item to perform a required function under stated conditions for a specified period of time
- The durability of an object

Many engineering techniques are used in reliability engineering, such as:

- Reliability hazard analysis,
- Failure mode and effects analysis (FMEA),
- Failure modes, mechanisms, and effects analysis (FNMEA),
- Fault tree analysis (FTA),
- Human error analysis,
- Reliability testing,
- Statistical uncertainty estimations

Because of the large number of reliability techniques, their expense, and the varying degrees of reliability required for different situations, most projects develop a reliability program plan to specify the reliability tasks that will be performed for that specific system.

Essentially, a systematic Risk Analysis is performed on the system, with a view to assessing: Modes and Likelihood of Failure, Consequences of Failure, and Likelihood Reduction / Mitigation Measures. This Risk Analysis is extremely similar to the procedure used to specify requirements for the LDS itself, based upon risks of losses along the pipeline. The difference is that this analysis applies to risks of failure of the LDS rather than the pipe.

5.2.2 Major / Common Failure Modes

A detailed description of LDS technologies, including their strengths and weaknesses, has already been provided in earlier PHMSA studies[7]. However, an understanding of the main weaknesses in terms of operating conditions and other physical factors is important for reliability analysis, and can be summarized in this table:

[7] PHMSA PHM2012101 Leak Detection Systems Study, Task 4 (2012)

Table B-18 - LDS Technology Failure Modes

Technology	Failure Modes
Internal Methods	
Imbalance / CPM	Instrumentation, SCADA, Transient Operations
Pressure / Flow Monitoring	SCADA, Transient Operations
Pressure Wave	Abrupt Transients, Instrumentation
External Methods	
Visual Inspection (Unaided)	Soil, Weather, Light
Acoustic sensors	Abrupt Transients, Background Noise
Gas / HC Vapor sampling	Weather, Soil, Biogenic / Background Sources
Soil monitoring	Soil, Biogenic / Background Sources
LIDAR absorption	Weather, Soil, Biogenic / Background / Light Sources
DTS / DAS	Soil, Weather, Installation, Local Surface Disturbances
Radar systems	Weather, Soil, Biogenic / Background / Electromagnetic Sources
Broadband imaging	Weather, Soil, Biogenic / Background / Thermal Sources
Multi-spectral imaging	Weather, Soil

5.2.3 Mean Time before Failure

Detailed measures of Reliability in the context of an LDS will be suggested in Task 3: Systematic predictions of performance. For now, it is important to note that provision of only quantitative minimum targets (e.g. MTBF values/ Failure rates) is not sufficient for various reasons:

a. The fact that the requirements are probabilistic – in other words, there will not in practice be *zero* failures before the "specified" MTBF.
b. The extremely high level of uncertainties involved for showing compliance with all these probabilistic requirements. For example, in order to achieve just one fault per year with 24/7 operations, the probability of failure can only be 10E-09.
c. Reliability can be measured only very late in the project, since at very high MTBF a statistically significant sample size is only achieved after a very long time – perhaps many years.

Note also the issue related with defining “failure”. With an LDS, the failure mode where a false alarm is called is arguably much less severe than a missed, serious spill. This is not captured in a “raw” single MTBF value.

5.2.4 Availability

The maintainability requirements address the costs of repairs as well as repair time. Testability (not to be confused with test requirements) requirements provide the link between reliability and maintainability and should address detectability of failure modes (on a particular system level), isolation levels and the creation of diagnostics (procedures).

In the context of LDS, Maintainability refers to the ability of an operator to recover from a failure of the LDS to call alarms accurately. A couple of examples might be:

1. Referring to the API RP 1130 example cited above, Systems I and II only differ by the degree of sensitivity set on the LDS. If this detection threshold is easily re-set by the operator following an unacceptably high number of false alarms, then average Availability might still be acceptable. By contrast, if the alarm threshold is absolutely fixed, then reliability will always be low.
2. If an External field sensor is difficult to reach (perhaps buried or in a remote location) then if it ever fails at all it may take a long time to repair. This added time to repair has to be taken into account when assessing overall availability.

Testability in the context of LDS refers to the ease with which the operator can rapidly verify an alarm, at least partially. For example, referring again to the API RP 1130 example cited above, System I is far more reliable if the operator has knowledge of the transient / stable state of operation of the pipeline. If he does know that the pipeline is in a transient condition, then he can “Test” the alarm more reliably; conversely if he has no knowledge of operations then the alarms are far less reliable.

Another feature of Testability is the speed with which the actual presence or absence of a leak can be verified. This generally involves efficient communications with field personnel who are able to confirm loss containment rapidly.

Diagnostics and diagnostic procedures might include:

- Related displays showing pipeline state (pressures and flow rate) trends, or even more specialized LD plots as described in the next section.

- Control Room Procedures (CRM) that specify and script the tests and diagnostics that an operator should perform before accepting an alarm as probably valid.

5.2.5 Corroborating Tests / Testability

Recall that Testability of an LDS is in two parts:

- Corroboration by the operator that the alarm passes a number of diagnostic tests, eliminating known probable failure modes of the LDS (for example, transient operations) and is therefore credible
- Rapid confirmation of the actual presence or absence of a leak, generally by efficient communications with field personnel

This is not to be confused with system testing requirements, which are discussed below and in much more detail in Task 4: Impact of installation, calibration and testing.

Operator diagnostics include:

- Verification of pipeline operational parameters that are known to have an impact on the reliability of the LDS
- Specialized displays that are at least partially analytical, to provide direct corroboration of the possibility of a leak

A robust SCADA system is of great benefit in providing input to the first strategy. Trends of measured pipeline conditions can assist in identifying transient pressure, flow and / or temperature conditions that may cause LDS failure. Also of great benefit is the ability to communicate with the field rapidly in order to discover transient operations that are not reported by SCADA.

Specialized diagnostic displays[8] are tailored to the specific technology that is being used. A first common example applies to CPM Imbalance methods, which in their basic form have a weakness in not including line pack effects. However, it is at least known that a positive value of in/out flow balance – an expansion effect – will lead to a negative rate of change of line pack. Conversely, a negative balance physically must lead to a positive rate of change of line pack. To exploit this fact, a graph that tracks over / short against change (or rate) in calculated line pack should normally always follow a 45-degree trend-line. Particular deviations from the "standard" trend can be visualized due to, for

[8] This example is courtesy of Simulations, Inc. / Energy Solutions International

example, incorrect bulk modulus, slack flow, flow meter bias / drift and also probable leaks.

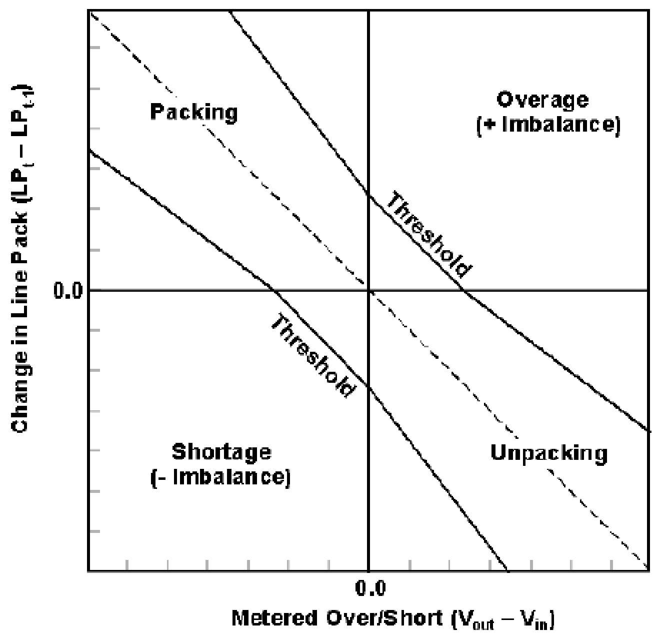

Figure B-11 - Example CPM Diagnostic Plot

A second common display is Flow Balance minus Packing Rate. Normally, as discussed above, this should be zero or close. When overlaid against flow, pressure and temperature this provides a useful tool to differentiate between system errors and probable leaks. Many other ways of exploiting calculated line pack as a diagnostic tool in validating alarms are used by controllers.

With External LDS, additional SCADA readings that identify the potential weaknesses of the LDS technique are similarly valuable. For example, with a distributed temperature sensor (fiber optic cable) a common fault mode is for a localized environmental temperature spike to mimic a leak. Therefore, a related display of all known temperature readings on the pipeline, plus perhaps ambient weather readings and soil conditions, are very useful.

5.2.6 Procedures

The value of an LDS is far greater when supported by various Human Factors. In general, reliability engineering recognizes that humans perform some tasks better, and machines perform others better. Furthermore, human errors in management and the organization of data and information or the misuse or abuse of items may also contribute to unreliability. This is the core reason why high levels of reliability for complex systems can only be achieved by following a robust systems engineering process with proper planning and execution of the validation and verification tasks. It also includes careful organization of data and information sharing and creating a "reliability culture" in the same sense as having a "safety culture" is paramount in the development of safety critical systems.

Alexander (2003)[9] gives a useful summary of four key points that apply to LDS:

- Incorporate useful leak detection screens into daily operations -
- Avoid complicating the controller's life
- Include leak detection system features as part of operator training
- Keep the leak detection system configuration current

In summary, the system should be engineered not only to be reliable, but also to be usable and part of 24/7-operations interaction with the pipeline.

5.2.7 System Validation and Verification

One major feature of Task 4: Impact of installation, calibration and testing is the System Testing for reliability. This is a complicated task, but at this stage it is important to note that even at the design stage it must be possible to allow testing, and to specify appropriate tests for reliability. The purpose of reliability testing is to discover potential problems with the design as early as possible and, ultimately, provide confidence that the system meets its reliability requirements.

It is not always feasible to test all system requirements. Some systems are prohibitively expensive to test; some failure modes may take years to observe; some complex interactions result in a huge number of possible test cases; and some tests require the use of limited test ranges or other resources. In such cases, different approaches to testing can be used, such as (highly) *accelerated life testing*, design of experiments, and *simulations*.

These apply specifically to LDS in the form of deliberately performing tests in difficult (upset) pipeline conditions, and performing hydraulic simulator based Leak Sensitivity Studies (LSS).

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[9] Alexander, C.S. (2003) "Successful Leak Detection Systems: Taking Ownership" presented at ENTELEC, April 2003

A key aspect of reliability testing is to define "failure". Although this may seem obvious, there are many situations where it is not clear whether a failure is really the fault of the system. Variations in test conditions, operator differences, weather and unexpected situations create differences between the customer and the system designer. One strategy to address this issue is to use a *scoring conference process*. A scoring conference includes representatives from the customer, the developer, the test organization, the reliability organization, and independent observers. The scoring conference process is defined in the statement of work. Each test case is considered by the group and "scored" as a success or failure. This scoring is the official result used by the reliability engineer.

As part of the requirements phase, the reliability engineer develops a *test strategy* or *plan* with the customer. This is described in detail in Task 1 procedures. The test strategy makes trade-offs between the needs of the reliability organization, which wants as much data as possible, and constraints such as cost, schedule and available resources. Test plans and procedures are developed for each reliability test, and results are documented.

5.2.8 Reliability vs. Safety Engineering

Reliability engineering differs basically from safety engineering with respect to the kind of hazards that are considered.

There are “Type 1” and “Type 2” failures that reliability seeks to eliminate. In the LDS context these are broadly speaking false positives and misses.

False positives are ultimately only concerned with cost. It relates to all Reliability hazards that could transform into incidents with a particular level of loss of revenue for the company or the customer. These can be cost due repair costs, man hours, (multiple) re-designs, interruptions to normal operations and many other indirect costs.

Missed leaks are safety engineering, on the other hand, which is more specific and regulated. It relates to very specific and system safety hazards that could potentially lead to severe accidents and is primarily concerned with loss of life, loss of equipment, or environmental damage. The related system functional reliability requirements are sometimes extremely high. It deals with unwanted dangerous events (for life, property, and environment) in the same sense as reliability engineering, but does normally not directly look at cost and is not concerned with repair actions after failure / accidents (on system level). Another difference is the level of impact of failures on society and the control of government.

There is a strong tradeoff in LDS between the need for smooth, less costly operations (avoiding false positive alarms) and the need for safe operations (reducing the number of missed loss incidents). This is a classic example of reliability vs. safety tradeoff.

5.2.9 Reliability vs. Quality

The everyday usage term "quality of a product" is loosely taken to mean its inherent degree of excellence. In industry, this is made more precise by defining quality to be "conformance to requirements at the start of use". Assuming the product specifications adequately capture customer or (rest of system) needs, the quality level can now be precisely measured by the fraction of units shipped that meet the detailed product specifications (six-sigma process).

However, Quality is a snapshot at the start of life of a system or product, and mainly related to control of product specifications. Reliability is more of a system level motion picture of the day-by-day operation for many years. Time zero defects are manufacturing / build / commissioning mistakes that escaped final test / Quality Control. The additional defects that appear over time are "reliability defects" or reliability fallout.

These reliability issues may just as well occur due to inherent design issues, which may have nothing to do with non-conformance product specifications. Items that are produced perfectly, according all product specifications, may fail over time due to any failure mechanism.

In theory, all items will functionally fail over infinite time. The Quality level might be described by a single "percentage defective." To describe reliability fallout a probability model that describes the percentage fallout *over time* is needed. This is known as the life distribution model.

5.3 Redundant System Design

Reliability design begins with the development of a (system) model. Reliability and availability models use block diagrams and fault trees to provide a graphical means of evaluating the relationships between different parts of the system. These models may incorporate predictions based on failure rates taken from historical data. While the (input data) predictions are often not accurate in an absolute sense, they are valuable to assess relative differences in design alternatives.

The most important fundamental initiating causes and failure mechanisms are vital inputs to the reliability model. Even with an LDS, failure mechanisms are generally:

1. Technological – this relates to a basic inability of the technology being used to function under certain conditions
2. Physical – in other words, due to the environment of the system
3. Human – this relates to perfectly human mistakes that have no purely technological solution. However, it also relates to the human capacity to recognize common-sense faults that cannot be automated.

An example of technological limitation is sensitivity under ideal physical conditions. However well implemented, Internal CPM technologies are limited (in sensitivity) by the accuracy of the metering and sensors that are used. By contrast, External LDS are generally extremely sensitive under ideal conditions.

With all LDS technologies, there are areas of weakness and of strength. Internal CPM technologies are generally weakest during periods of transient pipeline operations, whereas External LDS are generally immune to the flow of the fluid within the pipe. By contrast, CPM technologies are generally immune to environmental conditions (ambient temperatures, wind, climate) whereas External LDS are enormously affected by these. This is an example of physical limitation.

Human factors are, as described above, both a benefit and a drawback. There will always be situations where a true alarm is ignored or dismissed by a human controller. There will equally be situations where a relatively poor CPM LDS is made much stronger by using well-trained and experienced human operators, together with carefully designed diagnostic tools.

5.3.1 Redundancy

One of the most important design techniques is redundancy. This means that if one part of the system fails, there is an alternate success path, such as a backup system. By creating redundancy, together with a high level of failure monitoring and the avoidance of common cause failures, even a system with relative bad single channel (part) reliability, can be made highly reliable on system level.

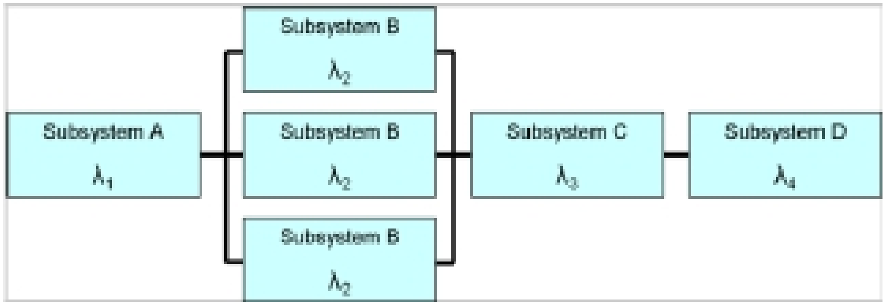

Figure B-12 - Example Redundant System

The overall system sketched above shows a 1 out of 3 (1 oo 3) redundantly designed subsystem. The overall system might be described as a 1 – 3 – 1 – 1 redundancy scheme. Conceptually, suppose that P(A), P(B), P(C) and P(D) are the probabilities of failure of each subsystem. Then, if the system fails when any one subsystem does so, the total probability of failure is dominated by the "weakest link" i.e. the largest of P(A) – P(D).

In this example, suppose that this weakest link is subsystem B. Then, with a triple-redundant scheme as shown, in order for B to fail, all three subsystems must fail simultaneously. The probability of this happening is $P(B)^3$ – which is generally far smaller than P(B).

5.3.2 Redundancy for Robustness

Strictly speaking, if the three "B" subsystems are identical, only reliability has been improved. The basic limitations in terms of operating conditions and of time are still present and robustness may not be affected.

However, it is quite possible to choose the subsystems quite differently (or to make a mix) in which case they provide a redundancy that potentially extends the operational and time range. In this way, a system that originally was limited in robustness becomes more robust.

5.3.3 Voting System

It is important to note that there are a number of ways to implement this redundancy. Some examples are:

- Parallel operations – all three subsystems "B" are on all the time. A voting system (generally) chooses the majority, consensus output between the three and uses that.

- Hot standby – all three subsystems are on, or at least in complete operational readiness, all the time. However, only one of the subsystems is actually in use. A voting system decides if the output is at fault, and based on that decision the output may be switched over to another one of the subsystems.
- Cold standby – only one subsystem is on. If the voting system decides that the output is at fault, another one of the subsystems is started up and is used.

In the context of an LDS, some subsystems will of course have one of these "standard" voting systems – for example, the SCADA, telecommunications and instrumentation systems will almost certainly incorporate some level of this basic engineering redundancy. More difficult is the issue of how to deal with multiple LDS subsystems, each of which might use different technologies and incorporate different and competing technological, physical and human constraints. It is difficult to automate a voting procedure in most cases.

How, for example, to vote between, say:

- A normal pressure profile in the pipeline – indicating normal containment;
- A local temperature spike at milepost 102 – indicating perhaps a loss there;
- A flow imbalance over a five-hour period that is normal;
- A flow imbalance over a one-hour period indicating a loss of line pack; but
- A corresponding negative rate of change in calculated line pack.

Generally, the only way that this can be accomplished consistently and successfully is to implement some sort of human decision-making and/or procedure or policy that reconciles these five loss indicators.

5.3.4 Example LDS Architecture

In order to illustrate how these principles might apply to a LDS, suppose that a total integrated scheme consists of the following components:

1. Four-year hydro-test
2. Annual In-Line Acoustic Pig
3. Twice weekly visual patrol
4. Fixed surface hydrocarbon sensors
5. Daily flow imbalance
6. Hourly flow imbalance
7. Five minute flow imbalance

Consider just the first of these in isolation. The sensitivity vs. speed quadrant would be similar to this one: very high sensitivity but extremely long time to detection (four years).

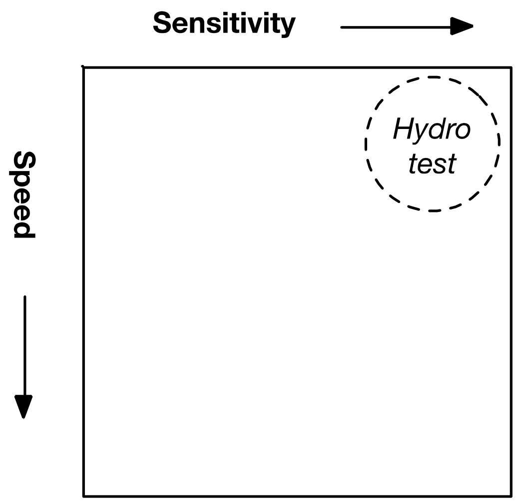

Figure B-13 - Hydro-test only LDS Quadrant

This does not cover much of the overall "space" of potential Speed / Sensitivity requirements. However, a sketch of all seven methods taken together might look like this:

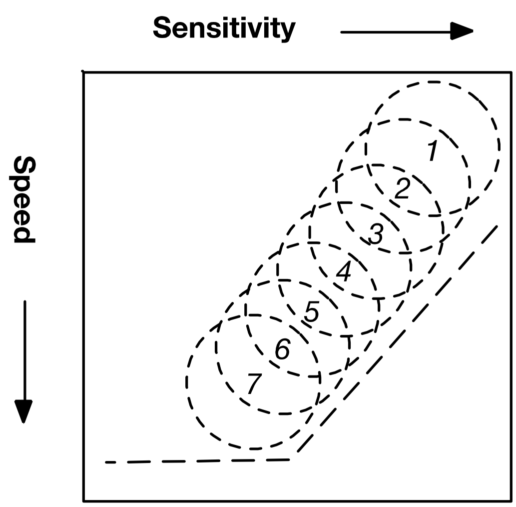

Figure B-14 - Hybrid LDS Quadrant

In this way, using the principle of redundancy covers much of the upper-left of the quadrant. This greatly improves the overall Robustness of the overall system.

Appendix C – Predictions of Performance

LIST OF TABLES

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1 Framework

The basic framework for analyzing a generic LDS technology is taken from Task 2: Methodology for Leak Detection Systems Technology Selection and Engineering, which is summarized here for convenience.

The loss itself is only rarely directly detected and measured. The one major exception is perhaps visual inspection where the inspector directly sees the loss itself. Most other techniques rely on:

1. A physical effect, or *signal*, induced by the loss of fluid;
2. The transmission of this signal to a detector;
3. The detection of the transmitted signal.

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

The physical effect generating the signal will usually be stronger the greater the rate or volume of the loss is. The first task in analyzing performance is to assess how efficiently a loss of fluid from the pipe wall generates the signal that is used by the technique. Generally the sequence is as follows:

1. Assess the amplitude of the signal at the source (i.e. at the leak location) as a function of leak rate, leak volume, or other physical driving factor(s).
    a. Sensitivity will be a function of the expected / estimated amplitude
    b. Accuracy is a function of the uncertainty in this estimate
    c. Robustness and Reliability are a function of how often a signal will not be generated at all during a leak, or conversely may be generated in the absence of a leak for other physical reasons. Recall, Robustness includes all potential operational and environmental situations, while Reliability includes only the design operational environment.

2. Assess the impact of the attenuation and noise during transmission of the signal to the detector.
    a. Sensitivity is degraded as the signal is attenuated.
    b. Accuracy is degraded as noise during the transmission increases uncertainty.

c. Robustness and Reliability are a function of how the signal-to-noise ratio becomes too low for reliable detection; conversely, how the noise becomes strong enough to generate a false alarm.

3. Estimate the sensitivity and other performance factors of the detector itself.
   a. Sensitivity of the detector is usually either specified by the designer / manufacturer, or can be measured in the laboratory or field. However, the form of this specification will depend on the kind of signal being used.
   b. Accuracy will similarly be the rated ability of the detector to measure the amplitude of the signal (apart from simple detection).
   c. Robustness and Reliability of the detection instrument are also usually either specified by the designer / manufacturer, or can be measured in the laboratory or field.

1.1 Combining Performance Measures

The evaluation of sensitivity is generally the most rigorous of the performance measures. It is usually easiest to begin with the sensitivity of the detector, then assess the signal that would be needed – after attenuation by the transmission path – and finally to assess what magnitude of loss would be required to generate that signal.

As an example, in visual inspection, a patrol might be able to identify a concentration of X ppm of natural gas at the surface, in clear weather and in areas where there is little ground cover. For X ppm concentration to appear on the surface, Y MMSCF would have to be released into the ground from the pipe, taking into account dispersion of the oil into the ground, absorption deeper down into the soil, and dispersion of the surface cloud into the atmosphere. For a signal of Y MMSCF at the leak point, a sustained flow rate of Y / H MMSCF per hour would be required for H hours.

The evaluation of accuracy is less systematic, and will involve a different procedure depending on the value being measured. It is perhaps easiest to work with uncertainties rather than accuracies. When the uncertainties are large it is usual to add them together; when they are small they can be combined by root-mean-square.

To use the same example, a patrol might be able to estimate the size of a gas cloud to +/- A MMSCF by inspection. Uncertainties in the soil composition, depth and nature of cover, and other environmental factors might make the diffusion calculation only accurate to +/- B MMSCF. However, there is no uncertainty in the purely physical Y / H MMSCF per hour loss rate calculation. In this example, since A and B will probably be quite large, the combined inaccuracy in release rate estimation will be +/- (A + B). If A and B were relatively small, a more appropriate combined uncertainty would be the RMS: +/- $\sqrt{A^2 + B^2}$

Reliability and Robustness are best combined using the principle of "weakest link". The detector itself usually has a good industrial-grade reliability. It may or may not have a good robustness depending on how it is packaged, deployed and maintained. The transmission path also has a reliability which might include known situations where the signal never reaches the detector with sufficient intensity, as well as a robustness that includes unforeseen physical difficulties. Finally, the generation of the signal by the leak may be more or less reliable.

Using the same example, the patrol may be unable to see any surface contamination at night, and therefore reliability would be 50% at best. It may also be unable to see any surface contamination during bad weather, so robustness would include a forecast of percentage of days where this happens. The diffusion calculations might assume perfectly uniform soil and/or zero wind, so the reliability of this calculation includes an assessment of how heterogeneous the soil really is. Robustness would include situations where perhaps solid rock stops a loss reaching the surface at all. Perhaps the only reliable part of the chain is that a fluid loss at a sustained rate will indeed always cause a volume loss. The combined measures would use the worst of the values from signal creation, transmission, and detection.

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2 Internal LDS Methods

2.1 Leak Detection Methods

There are two broad families of leak detection systems, named in the API 1130 recommended practice:

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

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

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

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

For Internal methods, the API RP 1130 provides perhaps the most useful categorization of Internally Based CPM techniques. Appendix C: description of types of internal-based CPM systems, lists eight separate techniques. They rely essentially on four physical effects, and the following table summarizes their interplay:

Table C-1 - API RP 1130 CPM Systems

API RP 1130 Method	Physical Principle
C.1 Line Balance	Conservation of mass
C.2 Volume Balance	
C.3 Modified Volume Balance	
C.4 Compensated Volume Balance	
C.5 Real-Time Transient Modeling	Conservation of mass and energy
C.6 Pressure/Flow Monitoring	Pressure inversely proportional to flow (Bernoulli's Law)
C.7 Acoustic/Negative Pressure Wave	Speed of sound in fluids

The last technique, C.8 Statistical Analysis, can in fact be used as a Comparison method against the baseline with any one of these physical effects.

It is important to remember that, although the API RP 1130 is technically devoted to liquid pipelines, practically all these techniques apply in principle to gas pipelines also. Because of the much greater compressibility of gas, however, their practical implementation is usually rather more complex and delicate.

2.1.1 Volume Balance

The mass balance method is based on the equation of conservation of mass. In the steady state, the mass entering a leak-free pipeline will balance the mass leaving it. In the more general case, the difference in mass at the two ends must be balanced against the change of mass inventory of the pipeline. Any additional mass imbalance indicates a leak. The uncertainty in this calculation is discussed at length in API publication 1149, but in brief summary:

$$|Q_{in} - Q_{out}| \leq dQ_m + \frac{dV_s}{T}$$

In other words, the difference in material flow rates into and out of a segment of pipe is bounded by:

- The inaccuracy in the measurement of mass flow rate, dQ_m, plus
- The change in line pack in the pipe segment, dV_s, over the period of time T

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

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

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

- Start-up of a pipeline
- Change of pressure at inlet or outlet, even if the change is small

2.1.2 Pressure/Flow Monitoring

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

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

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

This method is often called Pressure Point Analysis (PPA), although this is technically different; see below.

The sensitivity of the pressure monitoring method depends on the leak location. Near the inlet and the outlet of the pipeline a leak leads to little or no change in pressure.

This can be compensated by flow monitoring, where the flow is measured for change. The two methods can be combined.

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

Recall the major weaknesses of this method:

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

2.1.3 Pressure Point Analysis

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

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

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

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

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

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

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

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

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

2.1.4 Negative Pressure Wave Method

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

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

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

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

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

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

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

2.1.5 Mass Balance with Line Pack Correction

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

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

Natural gas densities can be calculated according to the American Gas Association's publication AGA-8 of 1992.

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

1. Direct measurement of pressure and temperature. A number of pressure and temperature transmitters must be installed sufficiently closely. The readings are interpolated between the sensors in order to perform the integration.
2. Determination with the help of a simple, steady state model. In gas pipelines a quadratic decrease in pressure can be assumed along the pipeline; and the temperature of the fluid can be assumed to equal ground temperature for long pipelines.
3. Computation with the help of a Real-Time Transient Model (RTTM). The most accurate method is to use a pipeline model that covers transient as well as steady state conditions. This allows the temperature and pressure to be determined at every point and corresponds to the CPM Method 2.b.

2.1.6 Real-Time Transient Modeling (RTTM)

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

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

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

Nevertheless, the gas pipeline industry – with the exception of larger, more sophisticated operators – tends to avoid RTTM. Their implementation tends to be complex, and a poorly configured and calibrated RTTM will inevitable provide very low reliability.

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

1. Deviation analysis: A set of the measurements taken from SCADA on the pipeline can be compared with the simulated values calculated from the RTTM. If there is a significant deviation, leak alarm will be given.

2. Model Compensated Mass Balance: The RTTM can be used to calculate the line fill in real-time. The imbalance subsequently can be compared with a threshold to establish the leak alarm state.

2.1.7 Statistical Pattern Recognition

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

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

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

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

If we define:

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

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

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

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

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

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

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

2.1.8 Pressure / Flow Pattern Recognition

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

- Maximum entropy classifier
- Naive Bayes classifier
- Neural networks

One of the most widely used implementations of this technique is trademarked ATMOS Wave by ATMOS International, Inc., and adds pattern recognition to a basic PPA algorithm in order to identify only changes in pressure that are wave-like, and of the correct wave speed *a* for the pipe and fluid. This technique uses Fourier analysis followed by a maximum entropy classification. To achieve this, the pressure sensors are sampled and analyzed at far greater rates than normal SCADA scans using dedicated field processing units. The processed data are then communicated to the other FPUs and to the host.

2.1.9 Negative Pressure Wave Modeling

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

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

2.1.10 Statistical Methods

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

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

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

2.1.11 Digital Signal Analysis

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

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

- Digital Filtering removes spikes and other outliers in measurement that may lead to false alarms
- Entropy Measurement rapidly identifies when a data stream changes in nature

- Drift and trend detection can identify very slow but systematic changes in a measurement, or an imbalance

2.2 Major Performance Factors

The API RP 1130 highlights several key issues that are most relevant to the selection and performance of a given technology, summarized and re-organized below:

Table C-2 - API RP 1130 Major Performance Factors

1. Measures of Performance
a. Rate of False Alarms and Misses
b. Response Time
c. Robustness
d. Availability
e. Leak Location Estimation Accuracy
f. Leak Size or Leak Flow Rate Estimation Accuracy
g. Release Volume Estimation Accuracy
2. Factors that Affect Performance
a. Instrument Accuracy and Placement
b. System Size and Complexity (Including Batch Line Factors)
c. Detecting Pre-existing Leaks
d. Detecting a Leak in Shut-in Pipeline Segments
e. Detecting a Leak in Pipelines under a Slack Condition During Transients (for liquids only)
f. Sensitivity to Flow Conditions
g. Fluid Type
h. Multiphase Flow
3. Operational Requirements
a. Personnel Training and Qualification
b. Retrofit Feasibility
c. Testing
d. Cost
e. Maintenance

The 49 CFR 195 specifically calls for consideration of these factors in assessing a liquids pipeline LDS. Gas pipelines are not subject to the same level of specific instruction in the 49 CFR 192; however, these factors are still relevant to natural gas to varying degrees.

The earlier API RP 1155 actually focuses only on four main measures of performance:

- Sensitivity is the combined measure of the size of leak that a system is capable of detecting, and the time required for detection. Some LDS technologies – notably material balance – inherently involve a tradeoff between sensitivity and time to detection; others do not.

- Accuracy relates to estimation parameters such as leak flow rate, total volume lost, and leak location. Similarly, there is often a tradeoff between accuracy and time to calculation.

- Reliability is the probability of detecting a leak, given that a leak does in fact exist, and the probability of incorrectly declaring a leak, given that no leak has occurred

- Robustness is a measure of ability to continue to function and provide useful information, even under changing conditions of pipeline operation

For this reason, the next sub-sections concentrate on just these four factors.

From a design perspective, it is important to remember the trade-offs that are often made between these four objectives. Perhaps the most important are:

- Sensitivity against Speed
- Sensitivity against Varying Conditions
- Accuracy against Speed
- Reliability against Sensitivity
- Reliability against Speed
- Reliability against Varying Conditions
- Robustness against Availability

In the context of LDS, it is common to express the reliability as "rate of false alarms and misses." The reliability trade-offs (4 – 6 in the list) are more usually expressed as:

- False alarms increasing, and Misses decreasing, with Sensitivity
- False alarms and Misses decreasing with Time

- False alarms and Misses increasing with Varying Conditions

2.2.1 Uncertainty of an LDS

We use the term Uncertainty rather than Sensitivity of an LDS, even though they tend to be used interchangeably in the industry. Uncertainty is a predictable and measurable degree of confidence that a given indicator (or "metric") of a CPM is reliable. The threshold for alarm set by the system designer, on the other hand, generally drives sensitivity. A low threshold ("sensitivity") will tend to generate False Alarms, while a high threshold will tend to Misses.

Recall the fundamental uncertainty relationship of API publication 1149 described above:

$$|Q_{in} - Q_{out}| \leq dQ_m + \frac{dV_s}{T}$$

When plotted as a function of time T to detection, this represents a hyperbolic curve that decays with time. Recall that this bound on accuracy is only valid in steady-state conditions. In transient scenarios dV_s itself may be a complex function of time and the second term may not decay with time nearly as predictably.

Sensitivity according to API publication 1155 (which was superseded by API RP 1130) is therefore defined as a composite measure of both the size of leak that an LDS is capable to detect $(Q_{in} - Q_{out})$, and the time T required for the system to issue an alarm. Minimum detectable leak rate and leak detection time depend on each other. Smaller minimum leak detection rates require longer leak detection times, and larger minimum leak detection rates permit smaller leak detection times. The performance of an LDS is best described using an Operational Characteristic Plot as this example:

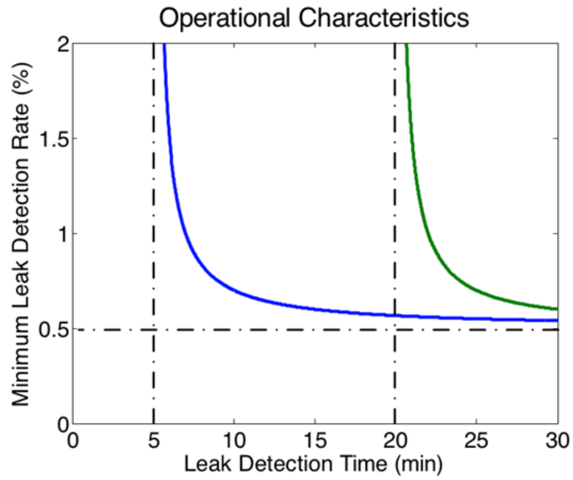

Figure C-1 - Material Balance Operational Characteristics Plot

In this example:

- LDS no. 1 (in blue) uses a five-minute averaging window, and LDS no. 2 (in green) uses a 20-minute averaging window. Neither system will show any response earlier than a complete averaging cycle.

- Both LDS use the same meters, and the long-time asymptotic uncertainty of 0.5% represents the combined uncertainty dQ_m in measurement.

In order to draw the curves in Figure C-1, it is important to know estimates of dQ_m and of dV_s. The procedure for estimating these is discussed at length in API publication 1149, but briefly:

- $d\mathrm{Q}_\mathrm{m}$ is estimated as the cumulative accuracy of the metering used in the LDS. This is the root-mean-square of their individual accuracy.

- dV_s is estimated from tables provided in the API publication 1149, which were computed for a range of crude oils through LVL petroleum products.

A recent 2015 update to API publication 1149 also describes how to estimate dV_s for other fluid types and particularly for natural gases, pipeline configurations, and in transient situations.

Ultimately, although this plot is numerical and soundly based in physical principles, it does not actually represent a completely reliable prediction of the sensitivity of the LDS in practice. It is prudent always to set alarm thresholds appropriately higher than these curves in order to minimize the number of false positives.

However, these plots have tremendous value in quantifying the relative sensitivity of different LDS designs. For example, in Figure C-1, LDS no.1 is evidently a more sensitive design than LDS no. 2.

2.2.1.1 Rate of False Alarms and Misses

The performance curve of Figure C-1, despite its sound physical basis, does not translate readily to a measure of false alarm rate or of rate of missed leaks. It is tempting to use the curves as firm boundaries, where any imbalance above the curve is definitely a leak and any below is within physical inaccuracy. However, this is never the case for at least two major categories of reasons:

1. Even in a completely steady operational state (dV_s constant) the rated accuracy dQ_m of the instrumentation is a statistical measure only of how often a measurement will be within a given tolerance of the true value. Therefore, there is always a probability of an actual reading exceeding the tolerance dQ_m used in the equations.
2. In practice, a pipeline is never in a completely steady operational state. Especially in gas pipelines, even small changes in pressure and temperature can produce changes in line pack that dominate the idealized equations.

Both these effects are difficult to measure precisely and so the *prediction* of a rate of false positives / negatives is generally impossible. However, note that it is possible (and is a recommended best practice) to *deduce* the rate of false positives / negatives from historical performance of an LDS, once it has been put into service. This is discussed in more detail later in Task 4: Impact of installation, calibration and testing.

2.2.1.2 Sensitivity vs. Time to Detection

The basic volume balance method of API publication 1149 manifestly has a defined inverse relationship between sensitivity to leaks and the time to detection. Therefore, sensitivity is only expressed as a function of time.

Note, however, that even other Internal methods need not have the same relationship (even if generally higher sensitivities are available given longer time to detection). For example, any technique that actively seeks to estimate the line pack change dV_s will result in a time to detection that is much better than hyperbolic, $1/T$. This includes Compensated Mass Balance and RTTM methods. The only way to evaluate the sensitivity and time to detection of these methods is to use the 2015 updated API 1149 procedures, or alternatively to use the LDS itself in offline parametric study simulations (*Leak Sensitivity Studies*, or LSS).

Some of the other methods – particularly the pressure and flow monitoring techniques, including PPA, SPRT and others – may not be particularly sensitive, but they have a practically fixed, constant time to detection. Generally, their time to detection is the longest averaging period involved in the algorithm.

2.2.2 Accuracy

LDS may provide additional leak information like leak location, leak size and leak rate. The validity of these leak parameter estimates constitutes another measure of performance referred to as accuracy.

The best way to evaluate the accuracy and time to evaluation of Internal methods is to use the 2015 updated API 1149 procedures, or alternatively to use the LDS itself in offline parametric study simulations (LSS).

Note that many LDS techniques provide no estimate at all of additional leak information, and therefore have zero accuracy.

2.2.3 Robustness

Robustness (according to API 1155) is defined as a measure of the LDS ability to continue to operate and provide useful information, even under changing conditions of pipeline operation, or in situations where data is lost or suspect. An LDS is considered to be robust if it continues to function under these less than ideal conditions.

Robust LDS typically are able to tolerate sensor failures using some kind of redundancy evaluation. In other words, even when all the inputs to the CPM algorithm may be suspect, at least some approximation is still being made.

Robust LDS are also able to tolerate operational conditions of the pipeline normally outside the scope of the technique. For example, a simple volume balance CPM is not designed for transient pipeline operations. However, if it is backed up by another LDS technique that is insensitive to flow conditions then it can continue to operate even under transient conditions. This strategy of using physical redundancy is in fact one of the main ones used for improving Robustness, and is discussed at more length in Task 2: Methodology for Technology Selection and Engineering.

Robustness can be estimated as the percentage of the time during which the pipeline and the data acquisition systems are operating as required by the LDS technology. It is therefore fundamentally a measure of percentage uptime.

It is wise to disable or otherwise suspend alarms from the LDS outside its known performance envelope in order to avoid false positives. However, this does not of itself improve Robustness (just Rate of False Alarms).

As a side note, with Internal systems it is not uncommon for False Alarms to be due *primarily* to a lack of Robustness (flow meter, sensor, communications, etc. failures) rather than to the sensitivity of the system as designed.

2.2.4 Reliability

According to API 1155, Reliability is the probability of detecting a leak, given that a leak does in fact exist, and the probability of incorrectly declaring a leak, given that no leak has occurred – within the design parameters of the system. In this sense, it is equivalent to the "Rate of False Alarms and Misses" measure of API RP 1130, and discussed in Sect. 4.2.1.1

We repeat that, with Internal systems it is not uncommon for False Alarms to be due *primarily* to a lack of Robustness rather than to the Reliability of the system as designed.

2.2.5 Factors that affect Performance

2.2.5.1 Instrument Accuracy and Placement

Instrumentation accuracy is key to the performance of all Internal LDS techniques. For example, it appears directly in the API 1149 procedure as the uncertainty dQ_m in measurement. Ultimately, this represents the absolute baseline accuracy that can be expected from an LDS.

Placement is also critical. For example, leak detection by Volume Balance is by segment contained between two flow meters. The longer the segment, the greater the potential line-pack changes dV_s. This relationship is not simple; for example, lines that are generally in steady state may require fewer balancing segments, while more transient lines might benefit from more.

The tables given in API publication 1149 are in terms of segment length. Therefore, the impact of different instrument spacing on the Operational Characteristics of Figure C-1 can be assessed.

2.2.5.2 System Size and Complexity (Including Batch Line Factors)

It is important to recall that the procedures in API publication 1149 are only valid for a single homogeneous fluid within the pipeline. Batch products pipelines are beyond its scope.

Similarly, by definition Balancing CPM techniques pre-suppose an inlet and an outlet to the pipeline (although there may be branches between – but no sources or sinks). This makes them difficult to apply to networked systems, except as a collection of point-to-point lines.

The best way to evaluate the accuracy and time to evaluation of Internal methods in large, complex and multi-product systems is to use the updated updated API 1149 procedures, or alternatively to use the LDS itself in offline parametric study simulations (LSS).

We have already remarked that longer the pipeline, the greater the potential line-pack changes dV_s.

2.2.5.3 Pre-existing Leaks

Basic volume balance techniques cannot easily identify a pre-existing leak. These appear as a systematic constant imbalance and are therefore indistinguishable from a meter measurement bias.

On the other hand, techniques that do estimate line-pack changes dV_s can be used since the imbalance is distinctively non-constant and inconsistent with flow rate and pressure changes. This is discussed at more length in the 2015 updated API 1149 procedures.

2.2.5.4 Detecting a Leak in Shut-in Pipeline Segments

Similarly, basic volume balance techniques cannot be used in shut-in segments, since there is nothing to balance. Again, techniques that monitor pressure of estimate line-pack changes dV_s can be used since the imbalance appears as a line pack drop. This is discussed in the 2015 updated API 1149 procedures.

2.2.5.5 Detecting a Leak in Pipelines under a Slack Condition During Transients

Slack line flow (SLF, or "channel flow") is a notoriously difficult situation to model since the slack region has all the characteristics (in terms of volume-pressure-temperature) of a leak. Standard channel flow only occurs in liquid pipelines where the fluid vaporizes locally, but essentially the same effect can occur in a gas pipeline where condensation occurs – for example, very cold pipelines at low pressure. In these situations it is very hard to perform reliable volume-based LDS.

2.2.5.6 Sensitivity to Flow Conditions

It has already been remarked above in Sect. 4.2 that any transient situations, where line-pack changes dV_s are not constant but are quite complicated functions of time, make basic balancing methods ineffective. In these situations, techniques like RTTM that track dV_s as a function of time are needed.

2.2.5.7 Fluid Type

The API publication 1149 only includes tables for dV_s ranging from crude oils to gasoline. HVL products and gases are not included. At least in part, this is because of their much greater compressibility and therefore dependence on pressure and temperature.

The best way to evaluate the accuracy and time to evaluation of Internal methods with natural gas systems is to use the 2015 updated API 1149 procedures, or alternatively to use the LDS itself in offline parametric study simulations (LSS).

In all cases, the potential line pack rate of change is much higher with natural gas systems. Therefore, essentially all CPM systems will have higher levels of uncertainty with these fluids.

2.2.5.8 Multiphase Flow

Multiphase flow, perhaps due to condensates in a gas line, is inherently difficult to predict and to model, and is unsuited to basic CPM methods. This is discussed in the 2015 updated API 1149 procedures.

2.3 Framework for Internal CPM Systems

With Internal LDS, in practice it is much more efficient to apply recommended practices – particularly API Publication 1149 and API RP 1130 – directly. However, as an illustration of the principle, it is useful to understand how the framework applies.

2.3.1 Material Balance

Material Balance CPM Methods relay on the physical principle of the conservation of mass:

(Mass flow rate into the pipe) – (Mass flow rate out of the pipe) = (Rate of change of the Mass stored in the pipe)

In practice, the technique uses the integrated form of this principle:

Mass into, less mass out of the pipe, accumulated over a period of time = Total change of the Mass stored in the pipe, over this same period of time

In steady flow, the right-hand-side should be zero. Note that in practice, instead of mass at flowing conditions, volumes normalized to standard pressure and temperature are usually used in the calculations.

With Imbalance CPM LDS, the system can be divided into:

1. A signal, caused by a loss of material at the leak. This signal is the Total change of mass stored in the pipe over a period of time, which – if there is a loss – will be a growing negative value.
2. This change of mass at the location of the leak has to propagate to the ends of the pipe, where it will affect the mass into and out of the line.
3. The detection / measurement of mass flow rates is complicated by the fact that usually only volume flow rates at flowing conditions are measured directly. Therefore, detection is by volume rate measurement plus correction for density of some form using a calculation based on actual pressure(s) and/or temperature(s). Detection accuracy of flow meters is, roughly speaking, a +/- percentage of actual flow rate.

2.3.2 Sensitivity

The signal is, for this technique, very directly related to the size of the leak. The "total change of mass in the pipe" is exactly equal to the mass flow rate of the loss, times the accumulation period. Equivalently, it is exactly the total mass volume of the loss.

However, the mass stored in the pipe over the entire length of the line is subject to the compressibility of the fluid and the capacity of the line fill to absorb this very local loss of mass temporarily. This effect is explained and calculated in API Publication 1149. Two items are important:

1. The longer the line and the more compressible the fluid, the greater the attenuation over short periods of time this loss of material is subject to. Also, the uncertainty due to line fill decays inversely with time.

2. The rate of attenuation is a function not of simply the rate of the leak, but is a function of leak rate as a fraction of the bulk flow rate of the line.

Note also that API Publication 1149 discusses and tabulates the attenuation for steady state flow. Transient flow greatly degrades performance – however, in this framework we treat transient flow as a Reliability issue.

Finally, detection is performed using mass flow rate metering (either directly, or by correcting volume flow rates). The accuracy of flow meters is, roughly speaking, a +/- percentage of actual flow rate. Therefore, a statistically significant difference in flow in against flow out is also a +/- percentage of bulk flow rate.

Very roughly speaking, API Publication 1149 then combines these elements to give:

Sensitivity, percent of bulk flow = (No uncertainty due to the creation of the signal) + (Uncertainty due to compressibility / line pack) / Time + (Accuracy of the metering)

2.3.3 Accuracy

Very similarly, the detection is a measurement of total mass lost. In this sense:

- The physical effect is exactly the total mass loss.
- The line fill and its capacity to absorb the mass loss by compression adds uncertainty to the measurement. The uncertainty due to line fill decays inversely with time.
- The accuracy of flow meters is, broadly speaking, a +/- percentage of actual flow rate.

Similarly speaking, API Publication 1149 then combines these elements to give:

Accuracy, percent of bulk flow, in measuring the mass lost = (No uncertainty due to the creation of the signal) + (Uncertainty due to compressibility / line pack) / Time + (Accuracy of the metering)

2.3.4 Reliability and Robustness

The major issue with material balance CPM is its ability to function reliably during transient operational conditions. There are two issues:

1. In the fundamental material balance equation itself, the "Total change of the Mass stored in the pipe, over a period of time" is only zero in steady state.

Therefore, setting zero as the target imbalance is no longer valid – at least for short times.

2. The line pack uncertainty is no longer a predictable, smoothly decaying function of time. In fact, for particular transients it may be a constant or growing uncertainty.

To issue number one, only some form of more detailed physical modeling – for example, an RTTM – can provide some estimate of the actual target total change of mass in the line during a transient. Similarly, some sort of more detailed physical modeling beyond the tables computed in API Publication 1149 is necessary to estimate the transient line pack uncertainty.

Generally speaking, the worst-case scenario is to assess:

1. Reliability of the CPM will only include conditions of steady state flow. Then, the overall LDS reliability is the combined reliability of the Measurement System, SCADA, and the computer.
2. Robustness of the CPM will include the proportion of the time where the pipeline is operated outside the regime of assumed steady state flow.

Of course, this calculation can be refined for situations where an RTTM is used, or else where some form of reduced sensitivity is used to reduce false alarms.

2.3.5 Pressure and Flow Monitoring

Pressure and/or Flow Monitoring is probably the most widely-used form of Internal CPM and is explicitly listed as a standard LDS technique in API RP 1130. However, the API Publication 1149 does not explicitly define a procedure for its assessment and so this framework can help in its absence.

- The signal is either: (a) the drop in pressure at the location of a leak, or (b) the loss of material at the leak.

- This pressure drop and/or un-metered loss has to reach the instruments via the fluid between them and the associated fluid mechanics.

- The pressure sensor is usually rated in +/- pressure units, while the flow meter is rated by a +/- percentage of actual flow rate.

2.3.5.1 Pressure Signal and Hydraulics

In order to estimate the pressure and/or flow rate profile in the pipe, some form of physical modeling is needed. If good precision is required then it will be necessary to use a complete, transient mathematical model of the physics of the flow. However, for a simpler analysis it is often sufficient to employ a simplified model that assumes a quadratic pressure profile between sources and sinks.

These assumptions critically assume that: flow is steady state, the pipe is uniform with a constant friction factor, the temperature profile is linear, and the gas is in subsonic and isentropic flow.

The applicable simplified version of Bernoulli's equation is:

$$P_1^2 - P_2^2 = C\,Q^2\,L$$

where P represents the pressure, Q represents the volume flow rate, and L is the distance between the pressure measurements. The constant C is a function of fluid properties and the pipe dimensions and friction factor. The most practical way to estimate the constant(s) C is to use field measurements between two pressure sensors at a known flow rate in steady state conditions.

The impact of a leak in the pipe is sketched in Figure C-:

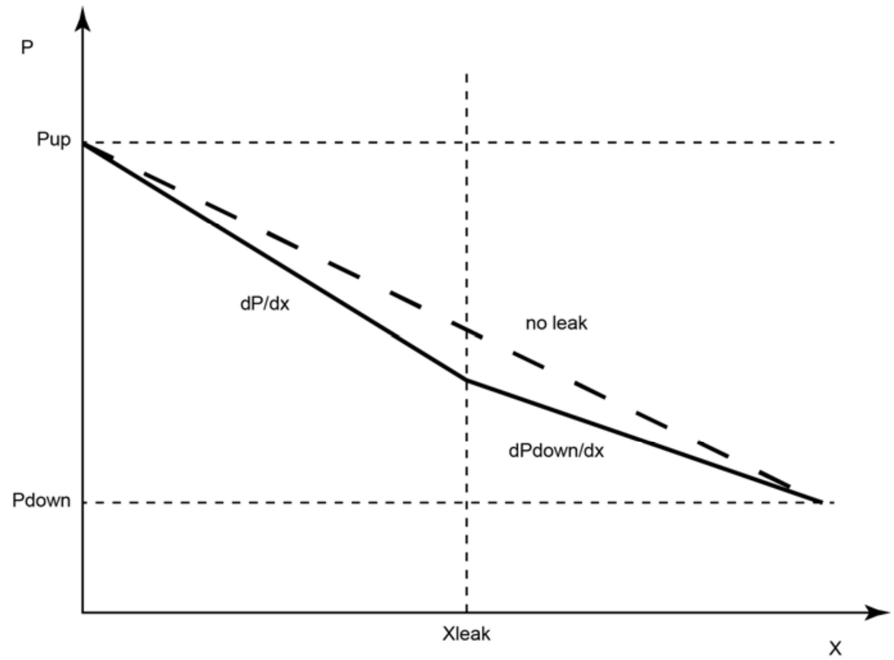

Figure C-2 - Pressure Profile from a Leak

The diagram will have more curved quadratic pressure profiles as the gas is more compressible. This basic diagram can be used to estimate the pressure profile with a loss at Xleak as follows:

- The "no-leak" pressure profile is drawn using the operating flow rate Q and the coefficient C estimated from normal condition flow tests.
- For a hypothetical leak at a location Xleak of rate Qleak, upstream of Qleak the flow rate will be (Q + Qleak). Therefore the upstream pressure profile slope will be: $C\ (Q + Qleak)^2$
- Downstream of Qleak the flow rate will be (Q - Qleak). Therefore the downstream pressure profile slope will be: $C\ (Q - Qleak)^2$

Note how there is not just one pressure profile regardless of the location of the leak; in fact, the dependence of pressure on leak location is a popular technique for leak location. Therefore, multiple scenarios for different leak rates and positions usually must be run. Other practical considerations include:

- Which pressure points (if any) are held fixed, perhaps by a pressure controller or large supply / delivery. In the sketch, the two ends of the pipe have a fixed pressure; however, only one might be fixed.

- Where the pressure measurement(s) for leak detection is being made. Generally, the closer the sensor is to the leak, the more sensitive it will be.

In each case, the signal at the detector is the difference between the pressure with a leak (solid lines) and the "no leak" profile (dotted line). This represents the minimum resolution of measurement that a pressure sensor would need to have, for a given operating flow rate and for a given size and location of leak.

2.3.5.2 Time to Detection

When a loss first occurs, then the flow will by definition not be in steady state at all for a certain period of time. This period might be quite short for incompressible fluids, or quite long for compressible flow and long pipelines. Therefore it is important to remember that all the discussion using Bernoulli's equation is only valid at long times from the onset of the leak, once the flow has regained steady state. Estimation of short-time sensitivity will require more careful transient physical modeling, with an RTTM for example.

2.3.5.3 Pressure Reliability and Robustness

Except for very large losses, pressure monitoring and most definitely the simplified analysis described here will fail in conditions of transient flow. Only some form of more detailed physical modeling – for example, an RTTM – can provide some estimate of the actual target change in pressure in the line during a transient. Similarly, some sort of more detailed physical modeling is necessary to estimate the pressure threshold uncertainty.
Generally speaking, the worst-case scenario is to assess:

1. Reliability of the CPM will only include conditions of steady state flow. Then, the overall LDS reliability is the combined reliability of the Measurement System, SCADA, and the computer.
2. Robustness of the CPM will include the proportion of the time where the pipeline is operated outside the regime of assumed steady state flow.

2.3.5.4 Flow Signal and Hydraulics

When only a single flow rate is being monitored it is difficult to apply the principle of conservation of mass unless some sort of assumption can be made about flow control upstream of the leak. Therefore, in practice one of several assumptions are made:

- The flow rate upstream (or downstream) is constant: perhaps it is a large supply or delivery, or it is regulated by a set-point controller.
- The pressure upstream is constant: perhaps at a compressor station or regulator.

Note that generally (perhaps not always) pressure control downstream of the single flow meter will not help in leak detection since the upstream pressure will be able to compensate for the reduced flow.

When a constant upstream or downstream flow rate is given, then effectively this method becomes the material imbalance method. The assumed fixed flow rate is then virtually a second meter with constant reading and perfect accuracy.

If the pressure upstream is held fixed, then the upstream flow rate has to rise to (Q + Qleak) to compensate. Then, the flow rate everywhere downstream of the leak will be (Q - Qleak) and the flow meter simply needs to have the resolution to measure a variation of Qleak.

3 External LD Techniques

The main forms of External LD were categorized Task 2: Methodology for Leak Detection Systems Technology Selection and Engineering, which is summarized here for convenience.

The main forms of the Signal that are used are:

- The volume of released fluid itself. Notably, this is the signal that is used in visual inspection.
- A change in temperature due to the loss of fluid.
- The generation of sound at the point of loss of fluid.

The Transmission of the signal may involve one or more of the following:

- The surrounding ground environment: coating, insulation, soil, water table, etc. This might be to the surface, or it might be to a buried detector.
- Along the pipe wall itself. This is usually to a detector clamped to the pipe wall.
- Through the atmosphere. If the detector relies on atmospheric sampling, visual instruments or is airborne then this adds to the attenuation in the ground.

Detectors follow the form of the signal closely:

- Visual or optical / electromagnetic detection
- Temperature sensors; packaged either as point detectors or continuous cables
- Acoustic sensors; packaged either as point detectors or continuous cables that are tuned to acoustic waves or stress / strain.

Estimation of the performance of any External LDS needs to take all three of these issues into account.

3.1 Detection

The main forms of detection used in External LDS were introduced in Task 2: Methodology for Leak Detection Systems Technology Selection and Engineering. It is important, when analyzing a specific, real-world External LDS technology, to be specific and detailed about the actual detector being used and its rating. However, as a guideline the detectors used in the most common External LDS can be described as in Table C-:

Table C-3 - Detection of External LDS Techniques

Technique	Description	Physical Principle	Rating
Visual / Naked Eye	Either direct inspection of hydrocarbon loss, or of its impact (e.g. vegetation loss, soil discoloration, etc.)	Light reflection	Volume or Concentration – near or at the surface
Acoustic sensors	Detects leaks based on acoustic emissions	Acoustic	Acoustic Pressure (dB) or Signal-to-Noise ratio (dB) at the correct wavelength(s)
Gas / HC Vapor sampling	Flame Ionization (natural gas) or other HC vapor detector	Physical / chemical reaction	Concentration
Soil monitoring	Detects tracer chemicals added to gas pipe line	Physical / chemical reaction	Concentration
Lidar absorption	Absorption of a pulsed laser monitored in the infrared	Infrared scattering	Concentration – in the path of the laser beam
Diode laser absorption	Absorption of diode lasers monitored	Infrared scattering	Concentration – in the path of the laser beam
Broad band absorption	Absorption of broad band lamps monitored	Infrared scattering	Concentration – in the path of the lamps
Evanescent sensing	Monitors changes in buried optical fiber	Temperature	Temperature accuracy (+/- C)
Millimeter wave radar systems	Radar signature obtained above pipe lines	Microwave scattering	Concentration – in the path of the radar beam
Backscatter imaging	Natural gas illuminated with CO2 laser	Light scattering	Concentration – in the path of the laser beam
Thermal imaging	Passive monitoring of thermal gradients	Infrared radiation	Sensitivity (lux / F at HC wavelengths)
Multi-spectral imaging	Passive monitoring using multi-wavelength infrared imaging	Infrared radiation	Sensitivity (lux / F at HC wavelengths)

Note that in this table, the majority of the ratings mean a given physical value at the location of the detector itself. For example, the temperature rating of a DTS cable means an accuracy and precision at the cable surface. However, many ratings include the notation that the measurement might be remote. For example, laser monitoring in general depends mostly on the concentration of the hydrocarbon in the air above the pipeline, rather than physically at the laser source or receiver.

For complete detail, both the rating and the location of where this rating applies, should be made clear. Note also that:

1. Visual inspection on its own strictly speaking always depends on a concentration of hydrocarbons relative to the environment. Only when the hydrocarbons do not disperse – for example, in a pool of oil – is it simpler to work with volumes released. However, if there is any dispersion effect at all then even a gas cloud of a great volume can be unrecognizable if, say, it is carried away by a strong wind.
2. Acoustic sensors have varying sensitivity according to the frequency of the sound being heard, and this frequency will depend on the composition of the hydrocarbon. It is important for the rating to be at this frequency. Also, given the background noise present on all pipelines it is often most useful to specify an SNR in dB rather than a straightforward minimum detectable pressure in dB.
3. Infrared image sensors have varying sensitivity according to the wavelength being imaged, and this wavelength will depend on the composition of the hydrocarbon. It is important for the rating to be at this wavelength.

3.2 Transmission

Signal transmission is usually the single most important factor in the overall performance of an External LDS.

It is once again important, when analyzing a specific, real-world External LDS technology, to be specific and detailed about the actual transmission mechanism between the signal and its detection. Some estimate of the attenuation of the signal (for sensitivity calculations), and the addition of noise (for both sensitivity and reliability calculations) along this path should be made. Note that in practical LDS deployments, the transmission effects tend to dominate overall performance in most cases.

Remembering that the actual transmission mechanism between the signal and its detection is highly technology and implementation-specific, the main effects can be grouped into:

1. Convection / diffusion of the signal to the point of detection.
2. Attenuation of the signal with distance.
3. Noise.

Bear in mind that there might also be multiple paths to the detector. For example, gas may need to travel both through the soil, and then through the atmosphere, to form a cloud detectable by infrared imaging. Also, an acoustic wave may travel both along the pipe wall and in surrounding soil or water to reach the sensor.

Table C- summarizes how each form of transmission effect applies to the most common External technologies. This is only a guideline; recall that when analyzing a specific, real-world External LDS the actual transmission mechanism between the signal and its detection should be detailed more exactly.

Table C-4 - Transmission of External LDS Techniques

Technique	Description	Transmission Assessment
Visual / Naked Eye	Either direct inspection of hydrocarbon loss, or of its impact (e.g. vegetation loss, soil discoloration, etc.)	Fluid migration to the surface or to a point that is visible. Noise consists of other contaminants or effects that reach the same point, and make visibility difficult.
Acoustic sensors	Detects leaks based on acoustic emissions	Transmission of sound along the pipe, and through the environment. Ambient acoustic noise.
Gas / HC Vapor sampling	Flame Ionization (natural gas) or other HC vapor detector	Fluid migration to the surface and through the atmosphere. Noise consists of other contaminants or effects that reach the same point.
Soil monitoring	Detects tracer chemicals added to gas pipe line	Fluid migration through the soil. Rarely, similar tracers might be naturally present as noise.
Lidar absorption	Absorption of a pulsed laser monitored in the infrared	Fluid migration to the surface and through the atmosphere. Noise consists of contaminants in the atmosphere that absorb the laser.
Diode laser absorption	Absorption of diode lasers monitored	Fluid migration to the surface and through the atmosphere. Noise consists of contaminants in the atmosphere that absorb the laser.
Broad band absorption	Absorption of broad band lamps monitored	Fluid migration to the surface and through the atmosphere. Noise consists of contaminants in the atmosphere that absorb the light.
Evanescent sensing	Monitors changes in buried optical fiber	Transmission of sound and temperature through the environment. Ambient acoustic and thermal noise.
Millimeter wave radar systems	Radar signature obtained above pipe lines	Fluid migration to the surface and through the atmosphere. Noise consists of contaminants in the atmosphere that absorb the radar.
Backscatter imaging	Natural gas illuminated with CO2 laser	Fluid migration to the surface and through the atmosphere. Noise consists of contaminants in the atmosphere that reflect the light.
Thermal imaging	Passive monitoring of thermal gradients	Temperature migration to the surface and through the atmosphere. Noise consists of thermal interference in the atmosphere.
Multi-spectral imaging	Passive monitoring using multi-wavelength infrared imaging	Temperature migration to the surface and through the atmosphere. Noise consists of thermal interference in the atmosphere.

3.2.1 Convection / Diffusion

A point source of any fluid, from a leak for example, migrates in complicated ways through its environment. For those detectors that rely upon a certain concentration of fluid in the environment it is therefore important to understand how this migration takes place and its impact on the concentration in the background.

Generally, the hydrocarbon may need to migrate through the soil and/or through the atmosphere. Whereas the physical principles are the same, the rate of convection and of diffusion through the two media are quite different. Note that these effects can dominate the performance of the LDS completely. Convection due to strong winds or currents can rapidly degrade even a large concentration of hydrocarbons at the site of the leak. Even without any convection, diffusion alone can reduce strong surface-level concentrations to undetectable levels at a few dozen feet of altitude.

Practically speaking, diffusion in the atmosphere is routinely estimated using the tools from the U.S. EPA[10] designed to model pollution from a source at the surface in the atmosphere. AERSCREEN is the recommended screening model based on the more complete but complex AERMOD tool. The model will produce estimates of "worst-case" 1-hour concentrations for a single source, without the need for hourly meteorological data, and also includes conversion factors to estimate "worst-case" 3-hour, 8-hour, 24-hour, and annual concentrations.

The U.S. EPA[11] also has a number of similar tools for the assessment of diffusion from a point source under the ground. Practically speaking, the most used is FOOTPRINT, which is in fact more than generally needed for simple transport estimates since it includes chemical degradation over long periods of time of the hydrocarbons in the organic soil. However, it is suitable for the purposes of estimating surface concentrations of hydrocarbon simply by setting the chemical reaction parameters to zero. FOOTPRINT can also be used for dispersion underwater.

The first effect is diffusion. When concentration is low somewhere compared to the surrounding areas (e.g. a local minimum of concentration), the substance will diffuse in from the surroundings, so the concentration will increase. Conversely, if concentration is high compared to the surroundings (e.g. a local maximum of concentration), then the substance will diffuse out and the concentration will decrease. The net diffusion is proportional to the second derivative of concentration, and also of a diffusion coefficient. Tables of appropriate diffusion coefficients for hydrocarbons in air, water and in soils are available from the U.S. EPA[12].

[10] Available free to the public at: http://www.epa.gov/ttn/scram/dispersion_screening.htm
[11] Available free to the public at: http://www2.epa.gov/water-research
[12] See: http://www.epa.gov/athens/learn2model/part-two/onsite/estdiffusion.html and related sites

The second effect is convection (or advection). The concentration at a given location can change because of the bulk flow. For example, if there is a strong wind then a cloud of hydrocarbons will be broken up rapidly by the bulk flow of air. Therefore, another important input to the models is the expected wind speed and/or groundwater flow / water current.

3.2.2 Temperature

The same equations that describe the Convection / Diffusion of concentrations of fluid apply to temperature gradients. However, whereas there are usually no large sinks for the hydrocarbons in the environment, there are often large ambient sinks for temperature near a pipeline. These take two forms:

1. Strong background temperature gradients; these are treated similarly to convection.
2. Large cold or warm masses, which are treated as additional sources or sinks of temperature. These might be a water table or moving equipment, for example.

The EPA Convection / Diffusion Screening Models can also be used when estimating temperature gradients, with the addition of these type (2) sources or sinks.

3.2.3 Attenuation of Radiation

Any detector that relies on radiation – specifically, light, infrared, microwave or acoustic pressure – will be subject to attenuation with distance different from convection and diffusion. There are two basic attenuation profiles associated with External LDS: linear and radial. In linear attenuation, the radiated wave is planar and the attenuation is directly proportional to the distance from the source. Common examples of this are conduction of sound along a steel pipe, or laser light in a beam.

By contrast, radial waves decay as the square of the distance from the source. Examples of this are visual inspection, imaging by camera, or emissions from unfocused lamps.

In each case, the coefficient of attenuation depends strongly on the medium along which the wave travels. For example, electromagnetic waves in a vacuum have an intensity inversely proportional to the square of distance (coefficient = 1). A very cloudy atmosphere can have a coefficient of proportionality many orders of magnitude greater. Similarly, bare steel pipe in free space especially at the correct tuned frequency can actually amplify a source of sound. By contrast, buried or insulated pipe can attenuate the amplitude by several orders of magnitude.

Generally, the only way to be quite sure of the level of attenuation is by direct measurement at the site. A controlled source of the signal is used under controlled conditions to simulate the signal from a leak and the attenuation is measured directly. This can then be extrapolated to different distances or signal strengths according to whether the radiation is linear or radial. This is covered later in more detail under Task 4: Impact of installation, calibration and testing. In summary, if the attenuation follows the linear relationship $R = C/x$ or the radial law $R = C/x^2$ then the attenuation A is measured over a known distance L. Then, the coefficient C is either AL or AL^2 respectively.

3.2.4 Noise

Except in a complete vacuum, any transmission path will add noise to the signal to some extent. To overcome this, External LDS are often calibrated to ignore background, natural LD signals. A "Map" of the signals received with no leaks under various conditions is built, and only deviations from this map are considered as a valid signal. This is covered later in more detail under Task 4: Impact of installation, calibration and testing.

Noise has two effects:

1. In a system calibrated to ignore background noise, the SNR will be reduced and therefore the sensitivity will be degraded.
2. Otherwise, the background noise may be interpreted as a false alarm, indistinguishable from a leak.

The form of this noise depends on the detector. For example, biogenic methane might affect an ionization detector just as well as a natural gas loss. The noise effect is highly location and application dependent and may also be seasonal. For this reason, the only effective way of assessing and dealing with it is the calibration process.

3.3 Signal Generation

Recall that the signal can usually be:

- The volume of released fluid itself.
- A change in temperature due to the loss of fluid.

- The generation of sound at the point of loss of fluid.

An assessment of the efficiency of the generation of each of these signals might include factors like:

- An assumed or estimated flow rate through the hole from the pipe.
- The physical size of the hole.
- The location, shape or other geometric attributes of the hole.

The issues related with signal include:

- The volume of released fluid is simple to estimate, given a leak flow rate, or equivalently a percent of bulk flow rate. This might be sufficient in design estimation, but sometimes it is not known what a "typical" leak flow rate might be. It is then less easy to calculate volume released given a hole size, pipeline pressure and other parameters.
- The change in temperature induced locally by a fluid loss depends in general both upon the flow rate of the loss, and the size of the hole. Worse still, it depends upon whether flow is supersonic or subsonic, and particularly on the fluid properties, so that the form of the equations differ. Direct estimation of the temperature change in certain regimes can be very difficult.
- The amplitude of the noise generated locally by a fluid loss also depends both upon the flow rate of the loss, and the size (and in fact the shape) of the hole. Again, it depends upon supersonic or subsonic flow, and on the fluid properties, making the equations difficult.

3.3.1 Volume

It is elementary to deduce the release volume from the release flow rate. This is one reason why most recommended practices use this parameter as the design basis for performance estimation. It is also perhaps the most useful measure of how rapidly the volume of the loss will grow with time.

However, it is sometimes important to evaluate volume as a function of the actual size of the leak. Discussion in the API RP 1130 refers, for example, to a classification of leaks into pinholes, seeps, medium-sized leaks and ruptures. Fairly arbitrarily, these are classified as roughly less than 1%, 1% - 5%, 5% - 10%, and over 10% of bulk flow rate, respectively. This is arbitrary since, for example, a "pinhole" (about a 1mm hole size) on a very high pressure interstate transmission line can easily lose 10% of bulk flow.

If the requirement is to estimate a loss flow rate only from a hole size, the source of most of the equations is the theory of orifice plates. An idealized orifice plate resembles a perfect circular hole on the wall of a flowing pipe, with the important difference that not all the bulk flow is forced through the orifice.

Most practical orifice assessment procedures follow the same Reader-Harris/Gallagher (1998) equation for the coefficient of discharge for sharp-edged orifice plates. They are formalized in the international standard ISO 5167[13]. An enormous simplifying factor is that whereas an orifice enclosed within a pipe has bounding walls, an orifice on the wall of an infinite pipe has no flow boundary and therefore the ratio $\beta = d/D$ of orifice to pipe wall diameter can be assumed zero. Then, according to ISO 5167, the mass flow rate through the hole is:

$$q_m = 0.5961 \ {}^{\pi}/_{4} \ \varepsilon \, d^2 \sqrt{2 \, \rho \, \Delta p}$$

In short, this is proportional to the square of the hole diameter and the square root of the pressure drop. It is common to assume that (at least for relatively small holes) the pressure drop is approximately line pressure less ambient pressure. This gives a convenient if approximate direct relationship between mass flow rate and hole diameter squared.

The expansibility factor should be noted. For incompressible fluids, $\varepsilon = 1$, but generally:

$$\varepsilon = 1 - 0.351 \left[1 - \left(\frac{P_2}{P_1} \right)^{1/\kappa} \right]$$

The isentropic exponent κ is usually approximated by the specific heat ratio. For a light, natural gas this factor can be *very* small[14]. This means that even large diameter holes in a natural gas pipeline can have a remarkably low leakage rate.

Note that these equations are subject to many simplifying assumptions:

[13] ISO 5167:2003 Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full.
[14] In fact, with the equation as written, it can be negative. To avoid this situation, most standards require the pressure ratio to be less than 0.75 in order to apply it.

- Hole diameter much smaller than pipe diameter (so that it is effectively planar)
- Hole in a long, uniform section of pipe (so that it is effectively infinite)
- Leak does not change the pressure of the fluid or environment substantially (constant pressure drop)

… and others. However, it is a very useful order-of-magnitude closed form relationship that illustrates trends very well.

A final comment is that the equations assume subsonic flow, and with incompressible fluids the flow can often become supersonic if the pipeline flow is large and so is the rupture. However, in situations where the hole diameter is rather smaller than the pipe diameter, it is generally accepted that a square-edge (not a nozzle) opening will never produce supersonic flow[15].

3.3.2 Temperature

In most practical cases, the temperature change at the external pipe wall due to a leak is mostly due to the difference in temperature between the outside, ambient temperature and the warmer fluid inside which is escaping. There is also a usually smaller effect from the fact that the escaping fluid expands into the lower ambient pressure and lose (or sometimes gain) temperature (hydrocarbon gases generally cool).

For estimating the first effect, estimates of the internal fluid temperature and the external ground (or other environmental) temperature are needed. The first can usually only be found from pipeline flow modeling of some form. It becomes closer to the ambient temperature as the distance from sources of heat increases. The difference between the two can vary substantially, for example:

- In short subsea lines the fluids from production wells might be at several hundred degrees while the surrounding seawater is cold.
- In long natural gas pipelines, in bare steel pipe, the fluid can have a temperature close to the surroundings.

Especially in this second example, it is also useful to estimate the cooling of an escaping gas due to the rapid drop of pressure. An idealized situation is the Joule–Thomson

[15] Cunningham, R.G. (1951) "Orifice Meters with Supercritical Compressible Flow" Transactions of the ASME, Vol. 73, pp. 625-638

effect[16], which is the temperature change of a fluid when it is forced through a valve or porous plug while kept insulated so that no heat is exchanged with the environment. This adiabatic (no heat exchanged) assumption can be quite poor in the real-life environment of a leak; however, it does provide a good upper limit and a useful order-of-magnitude estimate.

In summary, the change in temperature for a given change in pressure (with constant enthalpy) is approximately:

$$\Delta T/_{\Delta P} = \frac{V}{c_P}\,(\alpha T - 1)$$

Here V is the volume of the fluid, c_P is the heat capacity at constant pressure, and α its coefficient of thermal expansion. This is notably greater as the fluid is more compressible, and has less thermal capacity – both are the case for natural gases.

When the fluid has a temperature very close to the surroundings, this temperature drop can be the dominant effect.

3.3.3 Sound

Sometimes leakage of fluid may make a sound which can be detected. The amplitude of the sound created by the leak is unfortunately both relatively unreliable, and also difficult to predict analytically. LDS that rely on sound generation are generally rated with extreme sensitivities so that even the smallest unexpected sound can be detected.

Often, it is the sound of the internal flow of the fluids which is now more audible in the environment due to the hole – rather than the sound of the escaping fluid – which is the actual signal being heard.

A major difficulty with the sound from a leak is its unpredictability. For example, even quite a large opening in a pipe wall that is correctly shaped and oriented longitudinally can generate almost no noise. Conversely, a small hole in high-pressure gas pipeline flow can produce a loud sonic wave.

Experimental studies of the amplitude of the sound caused by a leak have been carried out by Battelle Institute, CFER, and the Southwest Research Institute. However, the range of parameters in these studies are necessarily limited so may not apply to all

[16] R. H. Perry and D. W. Green (1984). Perry's Chemical Engineers' Handbook. McGraw–Hill. ISBN 0-07-049479-7

possible pipeline applications or leak types. Many academic and laboratory studies of the noise caused by a nozzle or jet have been published; however, they are hard to extrapolate to pipeline leaks.

As a general rule-of-thumb the acoustic amplitude follows the same trends as the Joule-Thomson effect. It will increase as:

- The Mach number (flow rate as a fraction of sonic velocity) increases
- The pressure differential increases

However, a simple and useful closed-form equation like with the Joule-Thomson effect is not available, even with many simplifying assumptions.

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Appendix D – Installation, Calibration, Testing

List of Tables

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1 Framework

Most material in previous Tasks of this project has been related strictly to LDS technology, design and engineering issues. Here, we begin to consider how leak detection is a sustained program of activities and issues that cover technologies, people and processes.

The idea of leak detection as a program is described and explored at length in the API Recommended Practice 1175 (2015) *Pipeline Leak Detection Program Management*[17]. Note also that related issues in personnel training are also a critical element for success. Other key guidance, protocols, recommendations and the desired output of the process are listed in Table D-:

Table D-1 - Installation, Testing and Maintenance Summary

Guidance	API RP 1175 (10)(11)(12.3)(12.4)
	API RP 1130
	Reliability-centered maintenance
Protocol	Testing Procedures, Training Programs
	Continual system tuning procedures
Recommendations	FMEA
	Vendor (specifications) vs. Predicted (e.g. via modeling) 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

[17] Throughout this work, the American Petroleum Institute and its publications are widely referenced. Although they relate principally to liquids pipelines, many of the principles and recommendations relate equally well to gas pipelines.

1.1 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 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 (like LDS) where testing only in "common" or "routine" situations almost certainly yields good results.

1.2 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 RP 1175.

1.3 Recommendations

Using a Failure Modes and Effects Analysis (FMEA) framework, that updates threats and consequences systematically. 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. via modeling / simulation) 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 (as opposed to a routine, scheduled check basis). This is consistent with a reliability-centered maintenance policy described earlier.

1.4 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.

1.5 Regulatory Issues

For gas pipelines the 49 CFR 192 does not include specific leak detection provisions (unlike the liquids pipeline industry.) However, API RP 1130 recommendations for testing are still mostly valid as guidance for any pipeline. These include notably the need to record and to maintain records of:

- The Date and Time of the test(s).
- Location of test(s).
- Test Method. Note that a particular test method is not prescribed, but testing by "physical withdrawal of fluid" (i.e. a live actual leak test) is generally dangerous and not advisable for gas pipelines.
- Parameters of the test.
- Operating Conditions (e.g. steady state operations, transient operations, standstill, etc.)
- Alarms Triggered during the test.
- Analysis of the performance of the system (i.e. how well did the LDS as a whole perform)

Furthermore, API RP 1130 emphasizes the use of testing and the related records as a proactive continual improvement exercise, which suggests testing as often as practical and using records from as far back in time as possible in an effort to maximize efficiency.

1.6 Particular Gas Pipeline Issues

Since it is generally hazardous to withdraw gas from a pipeline system – particularly since most LDS are scoped to detect large ruptures – when reading API publications, the option of testing by actual hazardous fluid withdrawal should be discounted in general.

In general, gas pipeline operators should be mindful of possible safety and environmental consequences related to all testing, calibration and training issues. Often, this reduces the number of technical options available.

Finally, since most natural gas pipeline LDS strategies rely upon inspections and/or pressure and flow monitoring, it is worth emphasizing that nevertheless these forms of LDS also require testing, calibration and training to the same degree as more complicated forms of technology.

2 Testing

General guidance for the execution of a testing program can be found in API RP 1175 Chapter 7.

All LDSs, since they are engineering systems, should be tested, for a variety of practical reasons:

- As discussed in Task 2: Systematic predictions of performance, testing is a type of performance observation which can be used to establish *actual* performance.
- Testing is to ensure that a leak that is within the design capabilities of a system to detect can be detected and an alarm is in fact generated.
- To provide a realistic setting for leak detection training.

Testing on a gas pipeline can almost never be safely accomplished by actual withdrawal of hazardous fluid from a pipeline. Pipeline operators should be mindful of possible safety and environmental consequences of withdrawal testing when establishing their testing plan. This usually only leaves the option of using various means of simulation.

The exact procedure for simulating leaks depends on the leak detection technology but may, for instance, be done by altering measurements or other inputs to the system.

2.1 General Considerations

Pipeline operators should first create a detailed test plan to document the purpose of the test(s), the methods that will be employed, and the process and procedures that should be followed. LDS tests should be rigorous and be planned and executed using sound engineering and technical judgment regarding issues such as test methods employed, service fluid loss rates (when this test method is used), and situations to be simulated. The test plan should be consistent with the operational and safety policies of the pipeline operator.

For some types of leak detection, effective testing may be difficult (e.g. when third party reporting is involved) but can still be effective. The evaluation should use a checklist that ensures that the evaluation is consistent and thorough. API RP 1162[18] provides a detailed description of evaluation and a checklist for Public Awareness Programs (i.e.

[18] This recommended practice is also endorsed by INGAA as part of its own public awareness program.

third party reporting). This checklist may be modified to apply to similar evaluation of other methods.

API RP 1130 and CSA Z662 (in Annex E, which is an informative reference in this document) have sections concerning testing for CPMs. Much of these documents can also be applied to other leak detection methods, including externally-based technologies. Both documents recommend:

- Verification testing when a new LDS is initially installed, and
- Periodically thereafter for various reasons.

It is not necessary to test a LDS on every new asset on which it is installed if it is expected that previous tests on other pipelines are sufficient to guarantee the functioning of the system on the new pipelines.

Testing should be performed to cover all operating regimes (shut in, packing, unpacking, etc.) if the leak detection method is capable of and intended to function in those regimes.

Where practicable, the LDS should be tested to an alarm state. LDS tests may be announced or unannounced at the Control Center. The pipeline operator may use the unannounced test as an opportunity to evaluate Pipeline Controller response and Control Center procedures along with LDS performance. In this case, the scenario should continue right up to the point where a decision is made to shut down the pipeline.

When the test is announced, the pipeline operator should determine the potential for a reduced level of pipeline monitoring capability and for the misdiagnosis of a leak alarm during any type of LDS test.

If the LDS technology self-tests, this does not meet the criteria for periodic re-testing or change-driven testing (although this is a useful feature in general).

Operational use of a LDS, such as the successful detection of an actual leak, can be an acceptable substitute for periodic re-testing if it demonstrates the continued effectiveness of the LDS. Analysis of the leak and of the LDS performance during the incident may help to validate LDS capability.

The pipeline operator should be alert to the possibility of an actual leak that might occur simultaneously with the LDS test and that a leak might be undetected during the test interval.

The most effective test method for the particular pipeline and leak detection method should be chosen. The test method and testing parameters should be chosen to be representative of all normal pipeline operating conditions and failure modes, and be capable of being repeatable. Where practicable, leak location and leak rate should be varied between test events to evaluate both sensitivity and accuracy. Also, pipeline operations should be varied between test events to evaluate robustness. Reliability should be evaluated before, during, and after every test event.

Test records for each test should always be documented. The records should include the reasons for the test(s), the test parameters and methodology, as well as the test results. The records of as many as possible, but at least two previous, tests should be retained for purposes of comparison.

The API RP 1130 recommends that the test report should include

- Date, time and location
- Testing method and test parameters
- Operating conditions at the time of the test
- Details on any alarms triggered by the test
- Analysis of the performance of the system

2.2 Installation Testing

Initial testing (after a new installation) of the LDS is performed to establish a baseline of achieved performance for the new system. This is typically a verification test (see below) aimed at verifying that the initial performance meets the stated requirements from a system design perspective.

2.3 Continual / Periodic Testing

Additional testing may occur when there are changes to the LDS, or the pipeline system, or the system environment that warrant re-evaluation of system performance (change-driven testing). The LDS can also be tested simply for periodic assurance of actual system performance (periodic testing).

Prior to testing, careful planning should be considered as to the reasons for the test and methods that will be employed, and the process and procedures that will be followed. The test should be careful to ensure it achieves the desired results.

LDSs should be re-tested following significant changes to ensure that the performance of the system is not affected. Pipeline operators should use their discretion to decide what constitutes a significant change that may affect the leak detection. Examples of significant changes include, for example:

- Major pipeline or software configuration changes or addition of features — abnormal pipeline operating conditions
- New versions of any associated software
- Instrument and measurement additions or changes
- SCADA system updates

The decision to perform change-driven testing should be based upon individual analysis of possible effect on performance and on a line-by-line basis. Consideration should be made as to how to document, if necessary, this analysis. In the case of pipeline configuration changes, testing similar to initial or periodic testing should be considered. Other changes may be tested using an actual leak event data set, a data set from a leak test, a test simulation or other off-line system testing.

In all cases, the persons responsible for the particular LDS should determine which method is best suited to test the system following significant changes.

The results of change driven testing may not be recorded in test records. However, when the test is documented such tests may be considered a periodic re-test and should set the start of a new testing interval.

2.4 Evaluation and Verification Testing

Evaluation testing is performed to determine the true capabilities of a LDS and generally involves *testing to failure*. That is to say repeated tests are used to find the point at which the system is no longer effective. This can be quite expensive in terms of time and resources required. This type of testing might be done with a new leak detection technology or for a new implementation of the technology to a specific pipeline.

Testing a new technology might be part of a pilot testing program to include it in the certified technology set of a pipeline operator. Because it is the most time and resource intensive type of leak detection testing, it is often done in collaboration with industry groups, regulators, academia, and LDS vendors.

Testing for a new implementation of a technology to a specific pipeline, since it applies to a specific operator and asset, should be performed by the individual pipeline operator. Since it is more limited in scope it is less burdensome that testing a completely new technology but is still a significant effort. This type of testing is used to establish performance targets and may not be necessary if these targets can be determined by other means.

Verification testing differs from evaluation testing in that the goal is simply to test to success. That is to say that a LDS should detect and enunciate a leak it is expected to be able to detect. While these tests may still be challenging to perform, typically a single test is all that is required. A Site Acceptance Test (SAT) or similar commissioning test after installation of an LDS is usually a verification test.

All pipeline LDSs or methods should have a verification test on a periodic basis to ensure they are functioning as expected. The testing interval will be established by the pipeline operator but in any case it is not recommended to exceed 5 years from the previous test. Pipeline operators should use sound engineering judgment to determine if verification testing of a technology on one pipeline can be generalized to the same technology on other pipelines. API RP 1130 allows such generalization for CPM LDSs.

2.5 Testing the Training Program

Training is covered below, and also in API RP 1175 Chapter 10. In general, testing for/evaluating effectiveness of training closely resembles verification testing in that the intent is to test for success. The desired outcome is that the system declares a leak alarm so that the controller, analyst, or other user can effectively acknowledge and respond to the alarm.

2.6 Continual Improvement

Suggestions for improvement to testing should be captured and forwarded to the Improvement Planning and Process for consideration.

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3 Training

Training programs are covered in API RP 1175 in Section 10, as well as several other sources listed below. An effective training program has the potential to greatly reduce the consequences of a pipeline leak, particularly at the Control Center.

A pipeline operator's personnel and external stakeholders who interact with any part of its LDS should receive appropriate initial training, retraining and refresher / recurring training.

The level, content, method, frequency and testing of the training should be based on the roles and functions of the individuals and to support the pipeline operator Culture and Strategy. Training metrics should be established to ensure training effectiveness.

It is important to make a clear distinction between LDS training and pipeline Operator Qualification (OQ).

Nevertheless, the training recommended here may serve as one of the sources for the Knowledge Component of the Control Center OQ tasks that reference LDSs in API RP 1161: *Recommended Practice for Pipeline Operator Qualification (OQ)*. However, completion of the OQ training does *not* constitute LDS qualification.

One of the very important aspects outlined in this section is team training. Employees should be trained to work together effectively as a team.

3.1 Guidance

Sections that pertain to leak detection in related API RPs and documents, including:

API RP 1130, "Computational Pipeline Monitoring for Liquids." Generally, the principles in this RP apply mostly to gas pipelines as well.
API RP 1113, "Developing a Pipeline Supervisory Control Center."
API RP 1160, "Managing System Integrity for Hazardous Liquid Pipelines."
API RP 1161, "Recommended Practice for Pipeline Operator Qualification (OQ)."
API RP 1162, "Public Awareness Programs for Pipeline Operators." Also recommended by INGAA. This is particularly relevant since many rupture incidents are in fact reported by the public.

API RP 1167, "Pipeline SCADA Alarm Management."
API RP 1168, "Pipeline Control Room Management."
API/AOPL White Paper, "Liquid Pipeline Rupture Recognition and Response."

3.2 Training Program Contents

Training program contents are covered in API RP 1175 in Section 10.2, as well as several other sources. The major items to consider can be summarized as follows:

3.2.1 Roles and Functions

All personnel related to the LDS in the roles identified in the Leak Detection Management Program should receive training. Pipeline operators do not have the same organizational structure, so pipeline operator should define the roles needed, based on the size and complexity of its systems and LDS. Based upon this, a cross-reference relating Role to their Content of Training (c.f. API RP 1175 Table 5) should be developed.

3.2.2 Level of Training

Similarly, a cross-reference relating Role to their Level / Amount of Training (c.f. API RP 1175 Table 6) should be developed.

Each level of training should consist of a set of modules, appropriate to the role of the individual. For example, Control Center Staff need a basic understanding of internally-based LD technique architecture but do not need the same depth of training on that subject as do the Leak Detection Staff.

3.2.3 Content

Recommended training content considerations are as follows:

- LDS Operational Training is primarily for Pipeline Controllers and Control Center staff who directly responds to LDS alarms or indicators. However, analysts from the leak detection staff also need to understand the operational response to alarms or leak indicators. Content considerations are given in API RP 1130: *Computational Pipeline Monitoring for Liquids* Section 6.5, Pipeline Controller Training and Retraining.

- LDS Technical Training is primarily for Analysts from the leak detection staff who analyze alarms and maintain internally-based LD platforms. Control Center staff should be exposed to this training as well to assist them with initial analysis of alarms. Sections of this training are also applicable to Engineering, IT and SCADA support staff.

- SCADA Deviation Alarm Training is for both Control Center and other staff who analyze deviation alarms to understand their significance and the algorithms behind them.

- Externally-based LDS method training is for the Control Center and analysts who analyze alarms and for engineering support staff and field operations staff tasked with maintaining these systems on the pipeline systems.

- LDS Awareness Training is for Support Staff who do not need LDS technical training but do need an awareness of the various leak indications that are transmitted to the Control Center. The Control Center staff should also receive this training so that they know what level of knowledge is expected from field operations staff with whom they interact.

- LDS basics training is primarily for field operations staff and public entities who may observe a leak. The Control Center should also receive this training so that they know what level of knowledge is expected from field operations staff and public entities with whom they interact.

- LDS management training is specifically for the Control Center, analysts and management as the primary personnel responsible for leadership and successful implementation of the pipeline operator's LDS.

3.3 Training Methods

The methods used to deliver training should be appropriate to the role of the individual in the pipeline operator's leak detection strategy and the depth of training required. The most intense levels of training are for the Control Center Staff and the greatest number and variety of methods should be used with these individuals. A cross-reference relating Role to their Method of Training (c.f. API RP 1175 Table 7) should be developed.

The training methods might include:

- Formal, instructor-led, structured classes with verification testing. Training may include externally-based available courses offered by third parties. Testing should be used as a metric to determine effectiveness. This method should be used as a part of initial and refresher training on internally-based LDS methods and architecture, externally-based LDS methods, over/short analysis and SCADA deviation alarms.

- Individual self-study: informal, interactive computer based learning or a short course of reading material, with verification testing. May be instructor-assisted, but does not have the formal syllabus of classroom training. Testing should be used as a metric to determine effectiveness. This method should be used as a part of refresher training for Control Center and LD staff and may be effective as part of awareness-level training.

- One-on-one procedure review with stakeholders, inclusive of testing and verification of understanding of procedures and policies related to each individual's role.

- Interactive, computer-based simulations, if available. Validate that the simulator is accurate for leaks. The more sophisticated a simulator is, and the more available it is to the Pipeline Controller, the better. Simulate a sampling of "representative" lines.

- SCADA playback to show past alarms and behavior during a leak event or non-leak alarm. Showing the alarms that happened in what sequence with the actual leak or non- leak alarm may help the Pipeline Controllers learn what to look for. It is recommended that the pipeline operator's CPM LDP techniques be pre-configured to capture the data that would be needed to be in alignment with its protocols for conducting a root cause analysis of a real leak.

- Live simulations: for SCADA point analysis this is primarily accomplished through SCADA data manipulation. Modifies pressures, flows or other values used by the alarming logic by manually overriding them in production to induce an alarm. These simulations may be announced or unannounced to the Pipeline Controller. Announced drills typically focus on the alarm systems and response. Unannounced drills include leak recognition by the Pipeline Controller as well.

- Incident Review: group or individual review of a previous leak event from the pipeline operator's history or from investigative documentation from another event in the pipeline industry. This should focus on lessons learned, similarities and differences between the event and current operations. In addition, this method should include a review of any emergency response procedures that were used in a real event. This review should focus on how closely the procedures were followed and determining their effectiveness.

- On the Job Training (OJT). Shadowing of a more experienced individual in the performance of routine and abnormal tasks. This method is appropriate for all roles within the pipeline operator's organization.

Other training opportunities include: Public Awareness Campaigns and Site Visits for orientation, for example.

3.4 Team Training

The emphasis during team training is on effective communications amongst all stakeholders who would be involved in incident investigation.

Training as an integrated team in an exercise which includes all pertinent levels of authority as may be defined in a response procedure is important. The team is presented a scenario and is to respond through the use of associated documentation and/or procedures.

The parties involved should include: Control Center staff, all support staff, field staff, management and external emergency support response. Coordination with government agencies, regulators and the public for simulated reporting and interaction should be considered.

A table-top format may be used, with all players in a single room, or a combination of table-top and field exercise may be appropriate. Team training should focus on the functioning of staff as teams, not as a collection of technically competent individuals. The intent is to train, evaluate and improve response as an integrated team in as realistic an environment as possible.

The importance of clear and unambiguous communication should be stressed in all training activities involving all roles on the team. This training should test and emphasize the abnormal and emergency roles and functions of all of the personnel involved in the exercise. The scenario should test the effectiveness of procedures for elevating the Pipeline Controller's need for support beyond the Control Center, within the time constraints of those procedures. A formal script and separate evaluators are recommended. One of the best techniques for reinforcing effective human factors practices is careful debriefing of the exercise and highlighting the processes that were followed. Additionally, it is essential that each team member be able to recognize good and bad communications, and effective and ineffective team behavior.

3.5 Frequency

Retraining and refresher training intervals and depths should be established for all individuals who interact with the pipeline operator's leak detection strategy.

Retraining is the completion of all parts of the LD training program for each role and should be considered for an individual who has been out of a role for period defined by the pipeline operator. Specifically, for Pipeline Controllers, that period should match the period that the pipeline operator established under its OQ program. Considerations for retraining frequency should include:

- Level of decision making and shutdown authority
- Event driven, such as incident or drill
- As a formal part of the pipeline operator's MOC process for a proposed change affecting its LDS
- Outcome of previous training

Refresher training is an abbreviated form of the initial training and is independent of retraining. The primary audiences for refresher operational and technical training should be Control Center Staff and leak detection staff. Additionally, each pipeline operator should establish refresher training frequency for roles receiving leak detection basics and awareness levels of training. Considerations for refresher training should include:

- Size and complexity of the pipeline operator's systems and LDP
- Event driven, such as incident or drill
- Outcome of previous training
- A fixed frequency for Control Center and LD staff, particularly for alarm attribution skills
- Team training exercises should be scheduled at regular intervals, based on the size and complexity of the pipeline operator's systems and LDP.

3.6 Training Metrics

Training is a soft, pro-active barrier to undesired events involving a pipeline operator's LDP such as degradation, misdiagnosed non-leak and real leak alarms and non or improper response to a real leak. A pipeline operator should establish KPIs that measure both the quantity and effectiveness of the training.

Consideration should be given to measuring these items, similarly to API RP 1175, Section 12.

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4 Maintenance / Calibration

API RP 1175 Section 11 as well as SAE Standard JA1011 describe the Reliability Centered Maintenance (RCM) process. This is a general recommended framework for the maintenance, including calibration, of equipment – including LDS.

The calibration of the LDS as a whole generally relates to Threshold Setting and Tuning. Generally, threshold setting involves obtaining a practically acceptable balance between sensitivity and rate of false alarms for the system as it is. Tuning is a slow process in which a few tuning factors are adjusted and the system is left to run until the impact of the changes can be evaluated reliably. In other words, it is an optimization of the LDS itself. Although these are not "calibration" activities in the technical sense, they are critical to the overall performance of an installed system.

Threshold Setting and Tuning apply, of course, only to LD technologies that incorporate thresholds and/or free parameters that can be tuned.

4.1 Threshold Setting

Ideally threshold setting will involve decreasing the threshold level so the LDS becomes more sensitive. However, threshold setting may also involve increasing thresholds or desensitization.

Threshold setting differs from tuning. It considers the threshold expectations from the selection process, performance monitoring results (particular test results) and input from the Control Center and its staff to set usable, practical detection thresholds (for systems which have adjustable thresholds). The threshold setting considers the LD requirements, ensuring that the thresholds that are used align with the pipeline operator's needs.

A good example is rupture detection by pressure monitoring. The "threshold" is the pressure drop, or rate of pressure drop, at which an alarm is declared in the Control Room. It is set as a balance between detecting a significant, perhaps leak-related, pressure abnormality and declaring numerous alarms due to normal pressure fluctuations.

There is an inherent tension between reliability and sensitivity. As sensitivity is improved (solely by lowering thresholds) reliability may be decreased (increasing false alarms). The adjustment of leak detection thresholds to reduce the sensitivity and increase reliability of the internally-based leak detection method may perhaps be done in conjunction with the addition of complementary or alternative LDS to compensate for this reduced sensitivity. A higher alarm rate may be acceptable if good diagnostic tools are provided or if additional information can be provided that can be used to verify or disqualify alarms.

Threshold setting may use either:

- Reliability-focused philosophy: define a tolerable alarm limit (i.e. a targeted number of alarms), and adjust thresholds until you hit the alarm limit. May result in poor sensitivity
- Sensitivity-focused philosophy: define sensitivity targets and set thresholds to meet those targets. May result in poor reliability
- Balanced philosophy: Set both alarm limits and sensitivity targets. If both cannot be met through threshold tuning other methods may be required to reach targets, such as new instrumentation, hydraulic model tuning, or operational changes. This is probably the right place to start, from a philosophy perspective

Leak indication thresholds may either need to be permanently changed or adjusted on a temporary basis. It is important that the required or desired performance metrics be carefully considered when thresholds are changed, changes are documented, and the MOC process is followed.

Alarm suppression by threshold adjustment should be discouraged. If it is necessary to use this approach, there should be some process that automatically returns the threshold to normal or has a frequent reminder to the Pipeline Controller that alarms are suppressed.

Dynamic thresholds, a type of threshold adjustment, can be considered provided there is an understanding of the risk involved in this approach. The current threshold should be displayed to the Pipeline Controller.

Short-term threshold adjustment performed by a Pipeline Controller or leak detection analyst should be discouraged. However, if necessary, maximum limits for adjustment should be established and there should be threshold notification alarms on a fixed time basis to alert the Pipeline Controller that a temporary adjustment is active. The Pipeline Controller should advise the supervisor that the threshold will be adjusted and the reasons why and the time the adjusted threshold was in effect should be logged.

Ideally the supervisor's approval should be required. There should be a means to validate the function of the LDS after a temporary threshold adjustment.

Before threshold changes are contemplated the pipeline operator should first consider changes that do not involve the thresholds. To reduce false alarms or improve functionality possible changes could include:

- Equipment preventative maintenance or replacement (e.g. failed pressure or temperature probes)
- Modification of operation (minimize vacuum conditions, for example by maintaining a packed line on shutdown) pack pipeline before beginning operations)
- Implementing a complementary leak detection method
- Providing more analysis tools to the Pipeline Controller
- Institute dynamic alarming techniques within the leak detection alarming schema. Note that dynamic alarms do adjust thresholds but only on a temporary basis, the primary or steady state threshold is not changed

There should be a well-considered and conducted review process which may include:

- Determining if thresholds are too tight vs. too loose – feedback from Pipeline Controllers and/or Shift Leads; goal is to gain Pipeline Controller confidence
- Operational changes to reduce impact on leak detection - consider changing an operation which causes alarms
- Determining if the alarms are due to some normally recurring conditions. Are the alarms so numerous to affect system credibility?
- Short term vs. long term review input
- Feedback to Control Center
- Finding changes that will not affect the leak detection technique
- Determining if a complementary method can solve the uncertainty

If it has been determined that thresholds should be adjusted, the pipeline operator should:

- Know if this a system upon which there shall not be any threshold change
- Make the changes off-line and test before implementing
- Make a change to only one of the systems and leave others at same thresholds
- Ensure that the change is in line with strategy
- Make minimum changes

- Attempt tuning instead of threshold changes
- Perform calculations (e.g. using modeling /simulations) to determine the minimum change, and how to make minimum change
- Compare to threshold expectations from the selection process

The pipeline operator should use management of change procedures for any threshold change and of particular importance is informing the Pipeline Controller and Control Center of any changes.

Rupture alarm thresholds are a special case. Rupture thresholds are always set to alarm with high reliability. The API/AOPL White Paper, "Liquid Pipeline Rupture Recognition and Response" contains discussion on this topic.

4.2 Tuning

To lower thresholds without increasing false alarms, tuning may be an option. Tuning is a slow process in which one or a limited number of tuning factors are changed and the system is left to run until it is certain the changes can be evaluated. Tuning may be performed by the pipeline operator or by the vendor of the system. If the pipeline operator undertakes the tuning, the methods suggested by the vendor should be used as a guide. It is critical that as-existing tuning factors and as-changed tuning factors are recorded. The evaluation after changes should be formal and the results should be documented. Tuning generally involves repeated iterations until an optimum performance level is achieved.

Tuning may involve alarm prevention changes to software at the SCADA or PLC level or by making changes to system hydraulics (e.g. installing a backpressure control valve to eliminate unpacking). Implementing data filters to prevent some alarms may be a form of tuning.

Tuning is not exactly calibration but it does achieve improved performance. Most often tuning is applicable to CPM systems, but it can be applied to externally-based LDSs as well. Often CPM systems have a large number of tunable factors and the tuning involves changing the weight of one factor in relation to the others. Tuning is usually pipeline-specific, so even if the same LDS is used on various pipelines, the tuning factors may be different. Ideally, LDS tuning is performed off-line with a data set large enough to encompass all expected seasonal and flow regime variations.

There may be many opportunities for tuning: when software or hardware is updated or patched, when improved instruments are installed, when additional instruments are installed, and when there are more data inputs to the LDS.

4.3 RCM for Leak Detection Equipment

Pipeline operators should establish written policies and procedures to ensure that the leak detection methods or techniques *and their components* are designed for reliability and maintained appropriately. The maintenance should cover both externally-based and internally-based leak detection. Industry best practices should be employed. Reliability centered maintenance is particularly important for continuous monitoring leak detection techniques. Maintenance should cover *all* components associated with all leak detection techniques in use by the pipeline operator. These components include field measurement and instrumentation (e.g. pressure, flow, temperature, density sensors, valve and pump instrumentation, cables, etc.), communication systems (e.g. network hardware, communication media, etc.), processing units (e.g. SCADA/DCS hardware and software, flow computer/PLC, hardware and software, and leak detection software) and back-up systems.

The process for maintenance should include regular scheduled maintenance that is a part of a pipeline operator's policy and existing Reliability Centered Maintenance program. Also, there should be a process for immediate maintenance and repair of LDP components that have failed or are providing inaccurate or "bad" readings.

The term "reliability" is often generally used to reference availability and maintainability. Reliability, for instrumentation, is more correctly defined as the probability of a failure occurring over a specific time interval, whereas availability is a measure of something being in a state of readiness for its intended task (i.e. availability for mission). Maintainability is the parameter concerned with how the system can be restored to normal use after a failure, while considering concepts like preventative maintenance and diagnostics (built-in tests), required maintainer skill sets, and support equipment.

4.3.1 RCM Process

The questions that may be asked in consideration of the maintenance program and process are:

- What is the function of the particular item or component and what is its associated performance standard?
- In what ways can it fail?

- What are the events that cause each failure of that component?
- What happens when each failure occurs?
- In what way does each failure matter to leak detection?
- What system procedure can be set up proactively to prevent consequence of failure? (an active prevention approach)
- What can be done if a prudent or suitable preventive task cannot be found?

These questions outline a RCM process and align with a Failure Mode and Effects Analysis (FMEA) approach. A useful reference is SAE Standard JA1011 *Evaluation Criteria for Reliability-Centered Maintenance (RCM) Processes*. FMEA is covered by SAE Recommended Practice ARP4761.

The reliability assessment should include:

- Understanding all failure mechanisms and the probabilities of each failure listed in the FMEA and the confidence of each failure as a function of time.
- Physics of failure models that align the probability of failure to root causes.
- Overall reliability model. This can be one of several forms:
    - Bow tie diagram
    - FMEA or event tree or fault tree
    - Reliability model of components to system (mixed series and parallel)

Each system component may require specific calibration hardware, training and skills to successfully maintain them. Policies and procedures should be written and followed to ensure that each component is properly maintained and contributing positively to the robust and reliable system performance of each leak detection method or technique. The written policies may be a combined document or separate documents for each component as necessary. In either case, the objective is that clear concise information be included to identify qualifications of the maintenance personnel, roles and responsibilities, as well as design and maintenance criteria for all components of an LDP. Where applicable, documentation may make reference to pipeline operator maintenance manuals. Some topics such as instrument calibration are likely already taken care of in a pipeline operator's maintenance manuals.

4.3.2 LD Measurement and Instrument Identification

All field measurement devices and instruments integral to the reliability of an LDS should be identified and documented. These field measurement devices and instruments should be physically tagged and/or their corresponding SCADA/DCS database tags flagged to signify that they are components of the LDS. Consideration should be given for a common database naming practice for all leak detection database components.

4.3.3 Design

Design for Reliability and Maintainability (DFM) is a closed loop process using the following basic principles:

- Design, analyze, test, and improve/optimize the system. Based on the results of analysis and test (a prototype of portions of the product or even the entire system may be built), the design evolves. Maintenance concepts are reviewed and revised. Flexibility decreases and design change costs rise.

- Engineering finalizes the design and implements the system. At this point, flexibility to modify the product maintenance features is low and the change costs are high.

- Collect field maintenance data and develop information. Collect product field data in the form of customer feedback, warranty information, surveys, and service work. The information derived from this data can be used to evaluate the performance of the product in the field and in designing/implementing new systems.

- Make field improvements as required by safety, economics, and other factors. Initial field performance may be lower than anticipated and additional changes to the design, procedures, or maintenance concept should be considered. At this point, modifying the product is very difficult and expensive. Only those changes dictated by customer acceptance or safety, or that are economically attractive should be made.

- DFM process repeats with next generation product. Based on information generated from the field data, the design for the maintainability process is repeated for the next generation product. Design rules may be revised, new tools developed, and design approaches validated or revised

Consideration should be given to provide redundancy for component failure and or maintenance. This could be hardware redundancy for individual components, backup systems, communication channels or alternative operating procedures. For example, redundant sensors can be made active while the primary is off-line for calibration, maintenance or replacement. The pipeline operator should consider the process by which a redundant system or component becomes active. An automatic "cut-over" to the back-up/redundant system or component is the best approach.

Field instrumentation should be appropriate for the task and design specs should provide for the required accuracy. Program policies should specify design requirements of instrumentation. As an example, measurement accuracy and repeatability should be specified to meet appropriate targets for leak detection.

For field measurement and instruments, the maintenance program should include testing and calibration of individual sensors and instruments. Manufacturer's and/or pipeline operator's recommendations for calibration interval and procedures for maintenance and calibration should be followed. API RP 1130 has a section that outlines calibration and maintenance of leak detection instrumentation and conditions and measurement equipment which should be followed.

Other field instrumentation, such as pressure sensors and valves, are specified by a regulatory (DOT) requirement for calibration and these recommendations should be followed through integration of these devices within an LDS may require more frequent calibration if analysis dictates. Calibration procedures for externally-based leak detection sensors may at a minimum follow API RP 1130 guidance.

Primary maintenance instruments such as calibration equipment need to be carefully selected.

4.3.4 Maintenance Tracking and Scheduling

Consideration should be given to integrate the leak detection components into a pipeline operator's Maintenance Management System (MMS) or Computerized Maintenance Management System (CMMS) system or similar system to provide for automation of maintenance activity and failure tracking. CMMS may include a MOC process. Where a MOC process is not included in the maintenance system, then some MOC process should be applied. Additionally, a CMMS may include the ability to capture real world reliability metrics such as Mean-Time-Between-Failure (MTBF). These reliability metrics should then be evaluated to determine if additional action is needed to prevent future system component failures that would adversely affect leak detection performance. Reliability metrics may be tracked for both communications and processing unit components. (e.g. communication losses to field instruments, or net server up time).

The CMMS should track time or repairs and the condition before calibration or repair and what repairs are made. The CMMS may include details such as the end of life estimate for replacement.

Consideration should be given for scheduled (i.e. routine calibration) and allowance for unscheduled (i.e. break-fix) activity and the device criticality ranking. The schedule may be time based or based upon some other criteria for example, proving may be performed for each batch. Some components of an LDS are more critical than others. Each pipeline operator should consider creating a ranking system (i.e. through RCM) for each component and specify the impact of a component failure and provide clear policies for actions to take when device is compromised. Criticality is determined by the effect the loss of the device (or the associated loss due to for example inaccuracy) has upon the leak detection technique. For example, complete loss of a flow meter in a volume balance system could cause a total loss of function of the leak detection technique while loss of accuracy of a flow meter could reduce the sensitivity or accuracy of the technique but may not make it inoperative.

By tracking reliability metrics for field instruments, communications, and processing units, and having an associated criticality ranking system, a strategic plan can be implemented to address issues and drive for a more reliable LDS.

Additional maintenance and reliability considerations may include software maintenance (e.g. patches, revision, updates, code fixes, etc.). Clear policies and procedures should be in place to ensure that the required maintenance is properly communicated to appropriate stakeholders as to duration and impact, and effectiveness. Potential risks should be identified and communicated.

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Appendix E - Retrofit

LIST OF FIGURES

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1 Framework

Retrofit refers to the implementation of a 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.

Also, note that this report focuses on when issues are substantially different – not necessarily serious or unimportant – when the situation is a retrofit. Many issues like, for example total quality assurance, are critical to any LDS deployment, but are not substantially different on a new or on an existing pipeline.

2 Widely-Used LDS Technologies

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

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

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 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.

2.1 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.

2.2 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 has 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 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[19] and does not always require a pipeline shutdown (although flow meter installation might). 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.

2.3 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 generally fail safe, so any interruption in their power supply will result in a closure and shutdown of the pipeline.

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

3 External LDS Technologies

The installation and other retrofit issues related to External LDS depend primarily on the implementation or packaging of the technique than the physical principles used. Referring back to the Task 2 study, these deployments take the form of:

- Atmospheric sensors
- Point sensors, attached to the outside of the pipe
- Point sensors, penetrating within the pipe
- Cables laid out along the pipeline route, in close proximity with the pipe

The sensors might use thermal, acoustic, chemical or other physical principles, but the retrofit issues are mostly similar for each.

3.1 Atmospheric Sensors

Sensors installed permanently at surface near the pipeline are, in principle, similar to a continual visual inspection. Therefore, most of the discussion in Section 4.1 applies. It is worth remembering that sensors at the surface often need to be installed at frequent intervals and so they can be quite expensive and laborious to deploy especially for long sections. ROW agreements may preclude adding above grade equipment. Sensors imply communications, which necessitate equipment, power and access for maintenance. Note that these issues often apply equally to greenfield construction as to retrofit.

3.2 Point Sensors

Installing point sensors is, in principle, similar to installing pressure and temperature probes. Therefore, most of the discussion in Section 4.2 applies. Most of the limitations and other discussion for sensors in general in Section 5.1 also apply.

It is worth remembering that sensors often need to be installed at frequent intervals and so they can be quite expensive and laborious to deploy especially for long sections. If the pipe is buried, then these frequent excavations can be especially troublesome in a retrofit situation. Extensive excavation can also present an element of safety risk, particularly with older lines.

3.3 Cables

The ideal location for leak detection cables for gas lines, is shown in the following diagram (Figure E-):

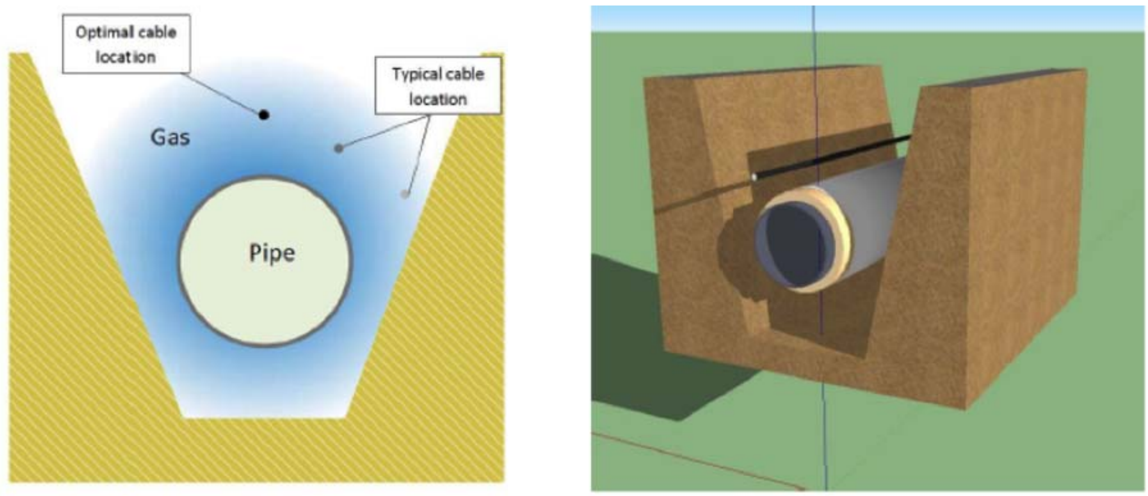

Figure E-1 - Cable Installation, Gas Line

It is recommended to install the cable as close to the pipeline as possible.

In a retrofit, a trench will have to be dug to lay the cable. This in itself might be expensive, time-consuming and perhaps risky with older lines and if the pipeline section is long. Furthermore, the optimal cable location might simply not be possible.

Off-center installations above the pipe are possible, and are marked "Typical cable location" in the diagram. They can even be quite close to the surface, and far from the pipe. However, the effectiveness of this non-optimal retrofit location might degrade the sensitivity of the sensor. As remarked in Task 3, the impact of the location of the cable on performance is extremely hard to predict. It may even make the cable sensitivity effectively useless.

4 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 liquids service to natural gas, 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.

4.1 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 corrosion or condition of pipeline
- Cathodic protection 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.

4.2 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.

4.3 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 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.

4.4 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 to 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.

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Appendix F - Acronyms

Ac	Accuracy
AGA	American Gas Association
AOPL	Association of Oil Pipelines
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
CIP	Continual Improvement
CO2	Carbon dioxide
CPM	Computational Pipeline Monitoring
CRM	Control Room Management
DOT	Department of Transportation (U.S)
EFRD	Emergency Flow Restriction Device
ETA	Event-tree Analysis
FTA	Fault-tree Analysis
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
INGAA	Interstate Natural Gas Association of America
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
MTBF	Mean time between failure
NETL	National Energy Technology Laboratory (U.S. Department of Energy)
OAT	Operational acceptance
PC	Project Charter
PM	Project Manager
PMI	Project Management Institute
PPP	Pre-project planning
RAM	Reliability, Availability, and Maintainability
RCA	Root Cause Analysis
RCM	Reliability Centered Maintenance
ROI	Return on investment
ROW	Right-of-way
Rp	Reliability
RTTM	Real-time Transient Modeling
Ro	Robustness
RP	Recommended Practice (API)
SAT	Site acceptance testing
SCADA	Supervisory Control and Data Acquisition
Se	Sensitivity
SME	Subject Matter Expert
SMYS	Specified Minimum Yield Strength
TOR	Terms of Reference
TQM	Total Quality Management

Appendix G - 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

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