Achieving successful in-line inspection

Recommended Practice

POF 300

June 2026

PIPELINE
OPERATORS FORUM

Foreword

This recommended practice on achieving successful In-Line Inspection (ILI) can be used by operators and contractors and is written to facilitate ILI run success.

The objective of ILI is to obtain data on the pipeline condition as part of the baseline and/or revalidation process. It is highlighted that this recommended practice is written to improve first run success rate of ILI works and is not designed to provide an introduction or fundamentals for completing in-line inspections or appropriate tool selection.

For details of the ILI questionnaire, recommended check lists and best practices referred to in this document, please visit the "Documents" page on the POF website (www.pipelineoperators.org).

This document has been reviewed and approved by the Pipeline Operators Forum (POF) and is based on knowledge and experience available from POF members and others at the date of issue. It is stated however, that neither POF nor its member companies (or their representatives) can be held responsible for the fitness for purpose, completeness, accuracy and/or application of this document.

Comments on this specification and proposals for updates may be submitted to the Administrator at specifications@pipelineoperators.org with the form which is available on the POF website (www.pipelineoperators.org).

Changes June 2026

The following areas have been updated and/or added compared to the previous (2018) version of this document:

- Data quality information has been moved from the Introduction to a separate section (7.7)
- A new chapter (3) on guidance to first time ILI
- Updated causes of failed ILI runs (4.2)
- New section on Accessories (6.3)
- New section on CO_2 pipeline environment (6.6).
- New section of H_2 pipeline environment (6.7)
- Revised tool tracking to also include signalling and locating (7.5)
- New section on ILI run acceptance (7.7)
- Improved distinction between pipeline features and anomalies
- Various small edits and updates throughout the entire document.

Acknowledgement

Photographs used in this recommended practice have been provided by and are used with permission from several sources including ILI suppliers.

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1. Introduction

The objective of In-Line Inspection (ILI) is to obtain data on pipeline condition as part of the integrity management process. Getting ILI right is important to minimise inspection cost and verify pipeline integrity. A failed run usually results in a re-run which generates extra cost such as increased production loss, additional mobilisation or tool adjustment. Health, safety and environment aspects can also be affected as well as reputation. For offshore operations where support vessels are involved, the cost induced by a re-run can be considerable.

Achieving ILI run success requires close collaboration between the operator and contractor teams, where adequate planning and preparation are important factors. Pipeline data and definition of expected anomalies should be up to date. Operating conditions passed on to the contractor should apply for the inspection run, as the selection and set-up of the ILI tool is based on this information.

The ultimate goal for a successful ILI is that good data has been collected over the full pipeline length and circumference; i.e. both in terms of data quantity and data quality there is a 100% score. This is difficult to achieve in practice and POF 100 [1] recommends criteria and conditions for a successful ILI run. This document aims to help achieve a 100% score on ILI data quality and quantity and it provides more detailed information about run acceptance.

Checklists to support achievement of ILI run success are provided in POF 302 [2].

2. Definitions and abbreviations

2.1 Definitions

For the purposes of this document, the definitions in POF 100 apply.

2.2 Abbreviations

For the purposes of this document, the following abbreviations apply:

AGM	Above Ground Marker
ART	Acoustic Resonance Technology
ATEX	ATmosphères EXplosibles
CFD	Computational Fluid Dynamics
DGPS	Differential Global Positioning System
EMAT	Electromagnetic Acoustic Transducer
ERF	Estimated Repair Factor
HSSE	Health, Safety, Security and Environment
ILI	In-Line Inspection
IMU	Inertia Measurement Unit
MEG	Mono-Ethylene Glycol
MFL	Magnetic Flux Leakage
NDE	Non-Destructive Evaluation
NORM	Naturally Occurring Radioactive Material
QA/QC	Quality Assurance / Quality Control
ROV	Remotely Operated Vehicle
TRL	Technology Readiness Level
UT	Ultrasonic Testing
UTCD	UT Crack Detection
UTWM	UT Wall Measurement

3. Guidance for first time ILI

The pipeline industry has experienced an increase in the number of pipelines being constructed in the last fifteen years, but a recent trend of short-term pipeline failure has been observed.

A number of these failures have occurred within ten years of startup, which is sooner than expected for modern pipelines [10, 11]. These incidents are mainly due to lack of understanding of the following threats: Internal Corrosion, External Corrosion, Outside Force and Design, Manufacture, and Construction.

This chapter aims to establish guidance for the first time ILI on a newly constructed pipeline or a pipeline with significant partial replacements.

3.1 Baseline ILI

A common industry best practice for new pipelines (for all services) is to include an ILI to confirm the quality of the newly constructed pipeline (which means an absent of dents, ovalities, etc). This typically involves running a geometry tool often fitted with an Inertial Measurement Unit (IMU) to determine the as-built centreline.

If an ILI tool using technology intended to detect future in-service degradation is run before any degradation has occurred, this is considered as a "baseline" ILI. Certain specific risks to the pipeline could require a baseline ILI, for instance:

- When the need for a highly accurate corrosion growth rate is important.
- If the pipeline is constructed in a section where axial strain could be suspected.
- When pipeline is being repurposed as a hydrogen transportation pipeline and certain manufacturing anomalies should be excluded.
- When a pipeline is being expose to conditions that could lead to accelerated degradation of manufacturing and construction anomalies (see also 3.3).

3.2 First time ILI (during in-service)

There is limited guidance for pipeline operators to establish the timing and technologies to define the first-time ILI. Often, these concerns are driven by the future integrity and adjustments of corrosion rates inputs for Risk Based Inspections (RBI) or Fitness for Service (FFS) assessment.

The following sections prioritise scenarios where the first-time ILI will be key to ensure the reliability and future integrity of the pipeline.

Based on the scenario, the pipeline operator should:

- Use a Risk Based Inspection (RBI) approach that leverage a credible corrosion rate to define the timing when the first-time ILI should be scheduled.
- Understand the threats to consider additional technologies for first-time ILI.

For all scenarios where a metal loss inspection is required for first-time ILI, MFL technology will likely provide sufficient information to conduct an RBI. In some cases, UTWM may be required to address specific threats or improve accuracy.

3.2.1 Scenario 1: Severe sour service

Pipelines operating in severe sour service (i.e. region 3 as per ISO 15156 / NACE MR0175) warrant a comprehensive ILI plan before any corrosion has occurred, i.e. a baseline inspection should be considered.

It is recommended to consider a metal loss and crack technology to understand the condition of manufacturing and construction anomalies.

UTWM technology would be useful to identify laminations that may interact with corrosion in the future (cracking and/or blistering) and Hi-Lo (girth weld mismatch

UTCD technology may be required in seam welded line pipe (SAWL, ERW) to understand the condition of seam weld anomalies leaving the mill, including complex anomalies interacting with the seam introduced during construction.

3.2.2 Scenario 2: External corrosion caused by CP interference

Interference to the Cathodic Protection (CP) may cause external corrosion that drives the first-time ILI. Alternating Current (AC) corrosion caused by nearby powerlines is one of the most aggressive forms of CP interference.

Although the construction surveys support the selection of the most optimum route, in many cases the pipeline will be near, or follow, a powerline corridor.

External corrosion due to AC Corrosion starts right after mechanical completion, and it is expected that the Cathodic Protection design has already mitigated AC interference.

Data integration and Cathodic Protection surveys will indicate if AC corrosion may be credible.

1. Is the pipeline route in a powerline corridor?
2. If in a powerline corridor, is there unmitigated AC interference?

Not having an AC interference survey should be treated as having unmitigated AC interference, up to 1.5mm/yr (60 mpy).

It is recommended that metal loss ILI technology is considered and corrosion rates based on Cathodic Protection Performance to establish first-time ILI.

3.2.3 Scenario 3: Internal corrosion

Any internal corrosion mechanism would start with the introduction of product in the pipeline, so the timeline begins at start-up.

Depending on the product, some internal corrosion mechanisms could be aggressive and therefore, a baseline ILI may help to identify metal loss from manufacturing origin and to determine more realistic corrosion rates.

Table 1 provides the basics for likelihood of internal corrosion for downstream and midstream pipelines. Internal corrosion is likely in almost all upstream pipelines and flowlines.

Products	Internal Corrosion likely	Internal corrosion unlikely
Refined or partially refined	Naphtha, or other partially refined product with H2S or BS&W.	Gasoline (MOGAS), Diesel (ADO), Jet Fuel, Aviation Gas, or refined products without H2S or BS&W
Highly Volatile Liquids (HVLs)	Refinery grade propylene crude butadiene, or other non-purity HVLs	Ethylene, chemical grade propylene, or other purity HVLs
Crude oil	Condensate, “Drip Gas”, etc	-
Gas	Dense phase gas, gas with H2S, or off-spec gas with water cut	Dry natural gas or purity gaseous ethylene (CFR192/B31.8 regulated)

Table 1: Summary of internal corrosion likelihood base on service.

Pipeline Industry data for loss of containment (LOC) due to internal corrosion indicates a wide range of corrosion rates. Therefore, it is not prudent to provide general guidance for internal corrosion rates but rather use pipeline specific data.

It is recommended to consider a metal loss technology for first-time ILI.

The timing of the first-time ILI can be estimated using unmitigated and mitigated corrosion rates resulting from laboratory testing or simulations that account for: water analysis, bacteria analysis, asphaltenes and wax deposition, scaling, debris, reliability of inhibitors, oxygen scavengers, etc.

3.2.4 Scenario 4: External corrosion

If none of the previous conditions apply, external corrosion may be the factor that drives the first ILI.

The external corrosion mechanism would start when the pipeline is mechanically complete, i.e., it begins before start-up.

NACE SP 0502 (ECDA) provides guidance on generic corrosion rates that may be used to establish the first-time ILI, e.g., 0.4mm/yr (16 mpy).

3.2.5 Scenario 5: Repurposing to hydrogen or CO_2 (with diluted hydrogen)

When pipelines are repurposed for hydrogen a new damage mechanism can occur in carbon steel pipelines, hydrogen enhanced fatigue crack growth. Defects, with special attention to planar defects occurring at weld joints in pipelines, represent a significant material risk and should be investigated through a (crack-growth) fatigue analysis and a fracture-mechanics analysis. The defect dimensions that should be considered will depend on the welding processes used, the non-destructive testing technique(s), and the associated acceptance criteria. Prior to repurposing the pipeline to hydrogen, a baseline inspection of the pipeline can confirm the absence of planar defects in both axial and circumferential direct with sizes above the tool detection threshold.

3.3 Drivers for additional ILI technology or accelerated Timing

In the following cases it may be desirable to include additional ILI technology as part of the baseline inspection or accelerate the first-time ILI:

1. Known construction anomalies that were accepted.
2. QA/QC indicates one instance of something from quarantine/reject was installed inadvertently in the pipeline and want to determine if the issue is systemic.
3. Movement indicated on the pipeline due to geohazard events (frost heave, seismic, settlement, erosion, etc.).
4. CP test leads not installed in a timely manner or installed with reversed polarization.

4. ILI preparation

4.1 General

ILI projects require a significant level of preparation including:

- Definition of objectives
- ILI technology and tool selection
- Tool qualification, if required, e.g., for emerging inspection technologies
- Pipeline information gathering
- Site visit & stakeholder engagement
- Risk assessment.

Through the preparation process the operator, working with the contractor, should confirm that the selected ILI tool will be able to meet the initial objectives and requirements. Final confirmation of ILI tool selection should take place after the information gathering, site visit, stakeholder engagement, and risk assessment have been completed.

Prior to an in-line inspection the following should be in place:

- The Client to communicate the objectives of the ILI to the contractor
- Technology and tool selection to be proposed by contractor and discussed and agreed between operator and contractor
- Contractor to confirm that tool selection is appropriate given the goals and objectives of the ILI.

4.2 Causes of failed ILI runs

ILI runs typically have high success rates, this section is providing more details on the causes of the small percentage of ILI runs that are not successful, Experiences from operators and ILI companies have been collected by a survey among POF members and ILI companies. Any tool type and technology, exceeding TRL 7 and data using generalized predefined categories were considered. Figure 1 illustrates the survey results as of 2025. The root cause of a total number of 237 failed runs has been considered. Although this number of runs might be recognized as representative, the distribution amongst categories is indicative.

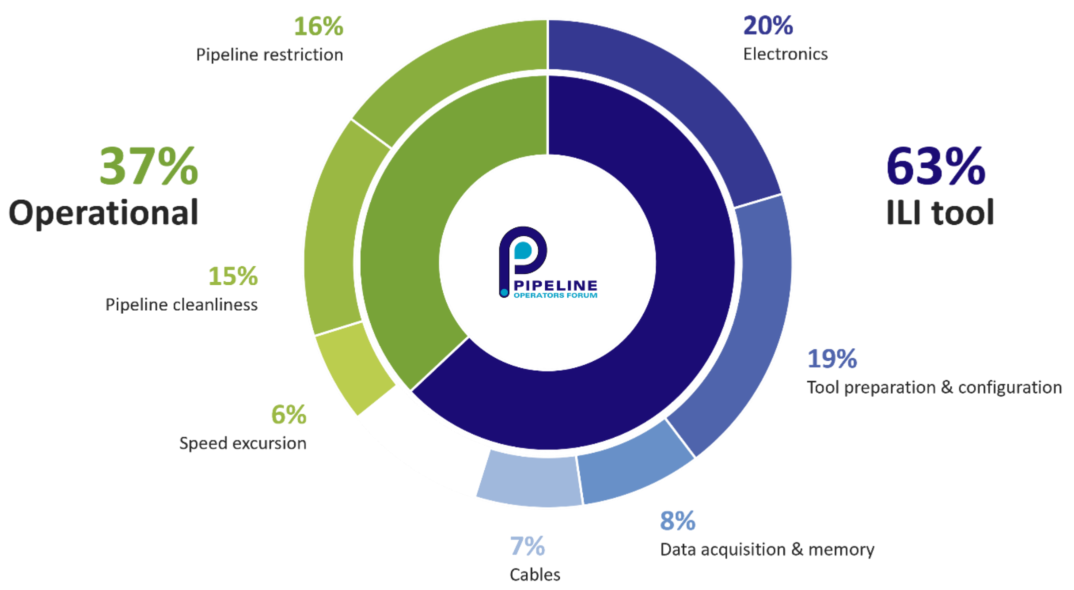


Figure 1 - Causes of ILI tool failure

About 63% of all failed ILI runs considered can be attributed to failures of ILI tool components and tool preparation procedures, where 37% are caused by operational issues outside the ILI contractor's control. One should keep in mind, that nowadays the majority ILI tool runs are repeated runs of pipelines already inspected before. The occurrence of operational root causes, such as unknown bore restrictions, might therefore be affected when compared to historic statistics.

Most root causes for failed ILI runs originate from failure of ILI tool hardware components, resulting in an incomplete inspection coverage of the pipeline wall and might be intermittent through the pipeline length. Non-conforming or incorrect tool preparation is a less frequent cause. However, this frequency of this cause might be controllable by either improved communication of requirements or in-house procedures. The same holds for operational issues, where accurate pipeline and operational data might help to reduce the number of failed runs due to the most frequent operational root causes.

4.3 Inspection objectives, ILI technology and tool selection

The inspection process adds value when the inspection objectives are clearly set and aligned with the threat assessment with a clear understanding of the critical anomalies that may potentially be present in the pipeline.

The operator should clearly define the objectives of an ILI before technology selection can take place. A key aspect in this process is a proper identification of pipeline threats and anticipated degradation mechanisms. The expected type, size, location and orientation of anomalies are important inputs to technology selection. In many cases this selection requires a deeper understanding and details of specific technology and tools which can best be obtained in a discussion between operator and contractor. Once the technology is selected, tool selection is often straightforward although in some cases various different tools exist for a given technology and pipeline diameter. Factors that may influence tool performance, such as level of cleanliness and pipeline operating conditions should be considered as well.

Some of the variables to consider include:

- Pipeline operating history
- Pipeline threats and objective of the inspection run, i.e., what are the pipeline deterioration mechanisms to be potentially observed and defect types resulting from these processes?
- Critical flaw detection, sizing and the level of certainty
- Pipeline operating conditions: product composition, flow conditions, pressure, temperature
- Ability to clean the pipeline to the required level for good inspection performance
- Physical properties of the pipeline: wall thickness, range of internal diameters, bend restrictions, length of pig traps, diameter, presence of pipeline features that could affect piggability, such as wyes, divertor valves, non-return valves, flexible pipe sections, etc.
- Presence of internal flow coating
- Experiences from previous pigging and in-line inspections
- Contractor performance: HSSE performance, inspection solutions offered, tool availability and performance, reporting times, run success rates.

Inspection tools can often be optimised to the inspection requirements by using special modification kits. In advance of an inspection campaign, it is often worthwhile asking different ILI companies for the best suited solution, which might save costs while performing the inspection or when following up on the inspection results at a later stage.

In cases where NDE field verifications are impractical due to safety, cost or environmental constraints, a baseline inspection could be beneficial. Performing a baseline inspection before putting the pipeline into service could help discriminating corrosion anomalies (internal or external) from manufacturing and construction anomalies in the future and limit the probability of false identifications.

If a baseline inspection and subsequent ILI are performed with the same technology, a run comparison could be made to assess corrosion rates more accurately for remaining life calculations.

Much of the preparatory information is collated in the ILI pipeline questionnaire available in POF 301 [3] and POF 302 [2].

Some form of tool testing may be required as part of the tool selection process, e.g. to confirm or establish a performance specification, or to demonstrate passage of specific pipeline features, see POF 330 [4] for more guidance on this topic.

4.4 Pipeline information gathering

ILI preparation requires a multitude of information gathering activities. Operators should adopt a cross-discipline attitude to define the inspection “environment”.

Information required for successful project execution will include at a minimum: pipeline design data, pipeline operating parameters and product composition. Physical line constraints to be considered include both bore restrictions and pig trap lengths which are more critical where either combination tools or higher-level accuracy tools are required. A detailed feature list or bore map should be created for the pipeline and provided to the contractor. Appendix A contains an example feature list.

Input from key discipline functions will be necessary so that an accurate picture of the risks to operations/production is built prior to engagement with ILI contractor. Based on the pipeline questionnaire, an early technical review starts the process of matching the inspection objectives and requirements with the tool attributes and inspection capabilities for a range of technologies that could be deployed.

The discussion should address the physical limitations of the ILI tool types and their inspection performance for the anticipated operating conditions. Understanding the technical limitations for inspection and the key parameters that drive both probability of detection and sizing accuracy are important aspects that should be considered at an early stage.

It may be possible that the operating conditions in the pipeline can be optimised to maximise tool performance through adjustments to the flow rates or frequency of sampling.

For heavy wall pipelines, when using MFL principles, understanding the relationship between achieved magnetization and the tool velocity is critical. Checks should be made to ensure that the tool selected can inspect the targeted wall thickness for a given tool velocity.

For other technologies, similar restrictions may exist depending on what accuracy is required. UT and EMAT tools may require cleaning runs and ART tools also requires a minimum operating pressure.

For pipelines that have not been subject to ILI before or for known challenging pipelines, a detailed piggability review is recommended to identify problem areas and actions to be taken to minimise risks related to damaged, stalled or stuck ILI tools.

Key information gathering subjects include:

Information required to be provided by the ILI contractor

1. ILI tool specifications (including trap dimensions and access required around the trap)
2. Defect detection capabilities
3. Sizing accuracy
4. Tool class history
5. Bore, bend and in-line feature passing capabilities
6. Tool length and weight
7. Speed thresholds
8. Maximum and minimum wall thickness
9. Technology availability
10. ILI tool schedule availability.

Information required to be provided by the operator

1. Objective of inspection, e.g., target anomaly, etc.
2. Technology requirements
3. Pipeline design conditions, e.g., diameter(s), known restrictions, type of valves, internal diameter of tees, existing stopples, etc.
4. Operating conditions during inspection
5. Product composition during inspection
6. Pipeline condition (cleanliness)
7. Trap dimensions, access and specifics (intermediate girth welds, type of reducer (excentric/concentric or reduction cone) or any other item that may cause an issue during the loading or receiving of the ILI tool)
8. Facilities and procedures to load and recover the tool (including safe operations of ILI equipment under explosive conditions)
9. Proposed cleaning, bore proving and ILI schedule
10. Logistic issues associated with controlled items e.g. isotopes, inertial navigation systems
11. Additional legal requirements (e.g. EU methane regulations, [5]).

Other requirements

1. Above Ground Marker (AGM) information established
2. Alignment sheets / as-built drawings
3. Past ILI reports as applicable
4. Other historical data
5. Roles & responsibilities (key personnel)
6. Site restrictions (hazardous areas etc.)
7. ATEX requirements (or equivalent outside of Europe)
8. Hazardous substances (e.g. Naturally Occurring Radioactive Material (NORM), Mercury, Polychlorinated Biphenyls (PCBs), pyrophoric dust, black powder, etc.) and arrangements for waste disposal.

Other criteria may also be considered, but for the purpose of this document the above referenced items are key components of communication between operator and contractor.

Some ILI may require special tool modifications or changes to operating practices and procedures. Early discussion with the contractor and information transfer is recommended to ensure that these can be accommodated within the inspection programme.

4.5 Site visits and stakeholder engagement

Project site visits and early stakeholder engagement are critical components of pipeline information gathering and provide an opportunity to identify operating limitations, potential risks to consider during the planning phase, or if minor modifications are required to accommodate the selected ILI technology. Stakeholders are defined as all parties involved in the ILI project including those providing third party services, e.g., tracking, lifting, cleaning, DGPS surveyor subsequent field measurement, and those impacted by the inspection activities, e.g., downstream facilities.

The site visit and stakeholder engagement promote buy-in from all personnel involved in planning and conducting the ILI project. Identifying all prospective stakeholders allows for a more thorough assessment of risk management actions required due to schedule, resource, or commercial concerns.

Properly documenting the site visit and stakeholder engagement can assist with identification of risks and the planning of a more comprehensive project scope. The site visit and stakeholder engagement checklists (see POF 302) are a resource that can be utilised for this purpose. A simple stakeholder mapping exercise can help identify the key stakeholders and will assist teams in establishing the appropriate interfaces, see Figure 2 for an example.

Interest →	KEEP INFORMED • Leverage interest via involvement • Consult on key interest area	MANAGE CLOSELY • Requires focused effort • Involve in governance & decision making • Ongoing engagement and consultation
	MONITOR • Minimum effort • Inform using broad communication, e.g., website, emails	KEEP SATISFIED • Engage and consult on interest area • Increase interest if positive attitude
	Power/Influence →	

Figure 2: Example stakeholder map

The following items should be addressed during site visits and stakeholder engagement:

1. Confirmation of information to assess the effort to perform the inspection
2. Collection of information to establish the detailed inspection and maintenance procedures and action plans
3. Collection of information to assess required (3rd party) support, e.g., lifting, pumping facilities, rigging, dealing returns from pig receiver, compressor units, filters, cleaning area, etc.
4. Confirmation that site facilities are suitable for execution of the works using the selected ILI tool. This includes a readiness check of pig traps, position indications of in-line and isolation valves and associated facilities such as cranes, filters, cleaning area, etc.
5. Identification of key personnel and establishment of communications
6. HSSE audits and contingency / mitigation plans for relevant credible scenarios
7. Identification of local communication lines, logistics and crew accommodation
8. Specific final inspection reporting requirements.

4.6 Risk assessment

Successful ILI requires effective management of risks identified at an early stage in the ILI process.

By conducting risk assessments, the key factors can be evaluated for their impact and probability of occurrence (or likelihood). The risk factors are generally assessed against the impact to safety, the environment and the operations including lost production.

Risk assessments associated with personal safety are well established. Further risk assessments on wider process safety issues require increased attention addressing the impact the ILI tool run can have on operation of the pipeline, including process upset conditions due to the transfer of pipeline debris; changes in flow conditions and pressure changes due to ILI operations (with the potential of increasing line pressures) and the implications of a stalled or stuck ILI tool.

Environmental considerations generally include the effects of cleaning operations, disposal of materials, flaring, venting or gas booster, and decontamination of tools and equipment.

Business considerations include the impact on production of a stalled or stuck tool. Failure to recover a complete ILI tool with all the parts may also have implications in pipelines which are regularly pigged to control liquid inventories.

Note that there are subtle but important differences between a stalled and a stuck pig. In the first case the pipeline has insufficient flow, or the pig has excessive bypass that prevents the pig from moving while the pipeline is still flowing. In the second case the pipeline has stopped flowing as the pig, potentially with associated debris, has stopping moving and is blocking the pipeline.

The information gathering and site visit phases of the ILI preparation facilitate the identification of risk factors which should be considered during project planning, including risks based on pipeline construction, operating conditions and location, e.g., a pipeline located onshore may incorporate less risk than that of a pipeline offshore. The information obtained during the information gathering steps should be measured against the project scope to effectively anticipate potential risks that could threaten the success of the project.

A risk assessment checklist (see POF 302) is a good way to document and evaluate the findings. It is recommended to evaluate the risk assessment checklists on a regular basis and adopt the assessment to latest developments. When assessing potential risks associated with ILI projects, the operator should incorporate the following contributing factors into their business risk assessment strategy:

1. Potential risk criteria for consideration: Available historical data (data related to the pipeline design & construction process, information received from any previous cleaning runs and historic pipeline inspections, history of known pipeline defects etc.)
2. Existing pipeline conditions indicated by gauge plate information including pipeline valves and fittings, potential for presence of solids from past pigging operations, modelling, assessment or debris mapping technologies
3. Valve operability and leakage rates
4. Pipeline geographic location
5. Pipeline access at launch/receipt and along pipeline length for marking and tracking
6. Pipeline operating conditions and product composition, including effect of launching medium on downstream systems
7. Subsea operations e.g. diver/ROV access
8. Recovery options and sequencing in case of a stalled or stuck pig
9. Weather (wind, wave & current) conditions for subsea and offshore operations
10. Visibility (day vs night) during expected time of launch and receive of the tool
11. Seasonal complications (human factors, access and environmental issues).

The risk assessment should take into consideration the following common cause of failed ILI runs:

1. Speed, pressure, and temperature related issues (too high and too low)
2. Product related issues (incorrect product, gas phase formation, incomplete gas removal)
3. Pipeline related damage
4. Bend configurations (bend radius and back-to-back bends)
5. Wall thickness changes
6. Line debris/paraffin/pyrophoric dust
7. Pipeline bore restrictions or openings (i.e. valves)
8. Availability of product (e.g. tank volume to maintain flow)
9. Tool component failure
10. Separation of multi-module ILI tools
11. Wrong inspection technology selection
12. Operational failures
13. Pipeline valve operations & isolation difficulties
14. Launch or receive cassette sealing difficulties
15. Loose components in the pipeline (e.g. previous ILI tool parts, bolts, welding rods, tee bars)
16. Incorrect pig launching/receiving procedures or not following procedures.
17. Inadequate or insufficient ILI tool battery lifetime

"Pigging on paper" exercises with key stakeholders and go/no go pre-requisites have proven useful for more complex ILI activities.

5. Pipeline cleaning and verification

5.1 Introduction

The quality of inspection results is not only dependent on the quality of the inspection methodology used, but also on the operational conditions of the pipeline during the inspection.

A critical parameter to the success of an inspection is the cleanliness of the internal surface of the pipeline. Ineffective cleaning can also have consequences for the normal operation of the pipeline, including reduced flowrates and reduced efficiency of corrosion inhibitors with accelerated degradation of the pipeline condition. Presence of dust, black powder, solids, debris or liquid slugs in gas lines can cause tool damage, poor data quality or may result in process upsets that adversely impact production and pigging operations.

The consequences of ineffective cleaning are even higher, when the cleaning regime is not specially geared in preparation of inspecting the pipeline using ILI tools, see an example of a damaged tool in Figure 3. In such cases it can lead to:

- Incomplete and/or low-quality inspection data
- Damage to the inspection tool
- Worst case, a stuck inspection tool.

Figure 3: Damaged tool due to excessive debris

The ability to clean the pipeline adequately should be taken account of as part of ILI technology selection. For difficult to clean applications, an ILI technology that is less susceptible to cleaning issues should be considered, e.g., MFL over UTWM.

In certain cases, and for specific products, e.g. O_2, the pigging tools, connections and pig traps should also comply with a cleaning procedure to avoid the risk of contamination that could have an impact on operational safety. The pipeline operator should decide on cleaning responsibilities: it can be performed by the operator, the ILI contractor or a specialist third party cleaning contractor. The selected ILI contractor should be consulted for advice in this matter. In some cases, extensive cleaning is required and in other cases only limited, final cleaning/gauging is sufficient:

- The best case: the pipeline operator has a well-established cleaning strategy in place and cleaning runs have been performed regularly or operation conditions are such that there are no solids drop out or deposition mechanism in the pipeline. In these cases, only final cleaning/gauging runs by the contractor is necessary prior to ILI.
- The worst case: there is no cleaning strategy, or it is not efficient and an intensive cleaning phase is necessary prior to ILI. A dedicated, jointly agreed cleaning program needs to be

established where some parts can be executed by the operator and other parts by the contractor, depending on experience of the operator and practicalities of the execution.

Planning of cleaning should include handling of waste products such as sand, scale and wax, with specific attention to the handling of hazardous waste, e.g., NORM, mercury, benzenes and pyrophoric dust, and the effect that debris can have on downstream facilities and operations.

It is recommended that early proving of the pipeline bore is carried out during the pipe cleaning phase. The cleaning tool should contain multiple gauge plates and mimic the profile of the proposed ILI to:

1. Enable an early assessment of the suitability of the ILI tool to pass through the pipeline.
2. Allow time to mobilise a calliper tool if a more detailed assessment is required.

Completing this early in the process will help to minimise cost, should either ILI tool or pipeline modification be required.

More recently, debris mapping and calliper survey technologies can be utilised in flexible pig designs such as foam pigs and so can be considered for cases where there are uncertainties on piggability and cleanliness. Debris mapping can also be useful in the early, mid and final stages of pre-inspection pigging to assist with assessing pipeline cleanliness throughout cleaning campaign and input to decision making on next pig type and number of cleaning runs.

It should be noted that the use of gauge plates will not detect overbore sections of pipe. These have caused ILI tools to get stalled or damaged. Use of a dedicated calliper tool is recommended for pipelines where there is uncertainty of the pipe bore or the gauge/profile tool indicates a bore restriction.

5.2 Preparation of cleaning campaign before inspection

Time should be taken to conduct a kick-off meeting or site visit together with the inspection contractor. The meeting should be scheduled shortly after the contract has been awarded and well in advance of the inspection campaign. If the pipeline operator does not have a well-established cleaning strategy, the preparations for cleaning should start well in advance of the planned inspection date. In this way there will be sufficient time to:

1. Gather all historical cleaning and operational information
2. Define a progressive cleaning program if required. In cases of significant uncertainty on volumes, type and location of solids, debris mapping technologies could be considered
3. Execute the program
4. Monitor the effectiveness of the cleaning and adjust if necessary
5. Analyse the cleanliness of the pipeline
6. Perform compositional and chemical analysis of received debris
7. Review previous ILI campaign lessons learned.

Between the initial cleaning programme and inspection runs the pipeline should be maintained with regular pigging.

The effort for cleaning may depend on:

- The type of product transported within the pipeline
- The frequency and type of cleaning runs previously completed
- The inspection technology to be used and the proposed setup of the ILI tool.

Different types and quantity of debris is usually observed in pipelines depending on their service. The following table gives a rough indication for the pipelines commonly used in the oil & gas industry.

Table 1: Typical pipeline debris

Service	Type of debris	Expected quantity of debris
Refined products	Corrosion product.	Little.
Crude oil	Hard and soft paraffin (wax), asphaltenes, sand, hard scale, corrosion product.	Potentially large depending on product composition, temperature and crude velocity.
Multiphase	Hard scale, sand, wax, corrosion product.	Potentially large depending on product composition.
Injection water	Hard scale, sand, corrosion product.	Potentially large depending on product composition.
Dry gas	Corrosion product, compressor oil, black powder.	Usually little if pipeline is regularly cleaned and not affected by black powder.

In pipelines that have never been inspected before, construction related debris such as bricks, poles, tools, toolboxes, safety shoes, welding rods and ferric debris may also be expected.

Routine pigging, as part of the pipeline operations and management, can generate useful information on the condition of the pipeline and its contents that can be used when planning an ILI programme. Information about the frequency, type of cleaning tools and analysis of material in pig traps should be used as input when setting up the cleaning program (also refer to section 5.3).

To reduce the risk of a failed run, the cleaning programme objective should be to remove as much as practical all debris from the internal pipe wall, independent from the inspection technology to be used. However, due to operational reasons the pipeline may contain some residual deposits which can limit the number of suitable inspection techniques. This is particularly the case with waxy crude pipelines where due to the wax appearance temperatures, the line will normally have deposits. In these cases, a combination of chemicals and mechanical cleaning may be required.

For large diameter, import/export crude pipeline where cleaning pigging is difficult, some form of cleaning may be possible by operating the pipeline temporarily with higher flow and/or with a lighter crude.

5.3 Cleaning procedures

The cleaning procedure determines the sequence and type of cleaning tools before the ILI.

A relatively simple brush tool is shown in Figure 4.

Usually "progressive cleaning techniques" are used for pipeline cleaning, which implies that the aggressiveness of the cleaning tools gradually increases as the cleaning activities are progressing. For certain applications, it is useful to start with chemicals, e.g., introducing a wax dissolver in a gel pill followed by flushing has proven to be useful in waxy pipelines. Thereafter, the safest way to continue a progressive cleaning program is by running gel or foam pigs.

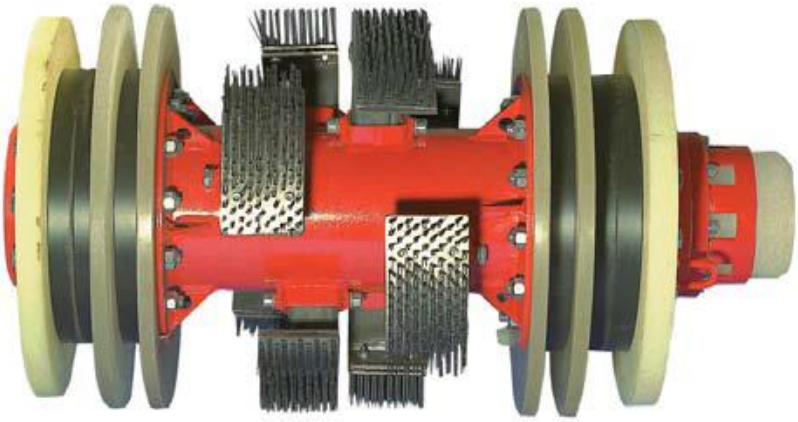


Figure 4: Typical bi-directional brush cleaning tool

The success of a cleaning program depends on the operator's experience and knowledge of the pipeline operating conditions.

Each cleaning program is uniquely defined for its objective, the pipeline and the given operating conditions. Therefore, a variety of cleaning procedures and cleaning tools exist. Combining mechanical cleaning with the use of chemicals can significantly reduce the time and number of runs required.

5.4 Assessment of cleaning results

During a cleaning program the cleanliness of the pipeline should be assessed continuously to identify the moment in which the objective has been achieved.

Various assessment types can be distinguished:

- **Visual assessment** of all cleaning pigs and retrieved deposits immediately after the run. If possible, the debris should be recovered shortly after the cleaning tool reaches the receiving trap and flushing of the trap should be minimized.
- **Monitoring** of relevant pipeline operating conditions such as pressure, flow, etc.
- **Pipeline Data Logger (PDL)** units can be used to identify trends, such as the movement of any soft wax deposits in the pipeline. These can be identified by measuring the differential pressure of the tool, while it is travelling through the pipeline. A logger can be installed on standard cleaning pigs and does not require any additional runs just for monitoring.
- **Debris mapping tools** which are basically a more advanced version of a cleaning pig with data logger. These tools are typically offered by companies that specialise in pipeline cleaning in preparation for an ILI run. They have sensors to measure debris thickness and may even include some inspection capability to confirm the ability to capture data.
- **Non-intrusive methods** such as acoustic pulsing, radio-isotope diagnostics, or even digital radiography (CT scans) for subsea pipelines can be used to assess/measure level of debris in a pipeline.

All above assessment results should be assessed jointly by the operator and contractor during the cleaning process.

Regardless of contract requirements, the final decision on whether the pipeline is ready for the ILI inspection run should be made jointly by the operator and ILI contractor.

Figure 5: Debris build up within trap after cleaning.

6. ILI tool preparation

6.1 Introduction

ILI tool preparation is a key component to a successful run. A notable portion of ILI failures have been caused by inappropriate tool preparation and set up. These can be avoided using simple check lists as discussed in Chapter 4. These usually manifest themselves through loss of data quantity, for example through loose connections although more significant failures have occurred where component parts had to be replaced.

6.2 Use of new tools and components

The introduction of new tools will remain a feature of the ILI industry. Driven by competition between contractors and requests from operators to inspect ever more challenging pipelines, their marketing poses a dilemma, as this introduces a level of uncertainty, particularly as contractors report a higher level of incidence associated with new tools with new components (e.g. sensors).

Contractors who extensively test tools before their introduction generally have lower failure rates. How rigorous the testing programme may be? There will inevitably be times where new components are introduced and used. This should never be done without consultation between the contractor and operator, and the risks should be discussed and included in the risk assessment.

6.3 Accessories

Sometimes, to avoid pig trap modifications by the operator, the contractor may use a specific device to load the tool inside the launcher, such as a half-pipe or loading tube, to launch the tool, such as a launching tube, and/or to receive the tool, such as a cassette or tray. The cassette or tray should be designed to avoid any damage to the pig traps (door, barrel, girth weld, etc.).

The device used to load the tool has to be removed from the pig trap before closing the door to avoid an additional opening after launching the tool. This action is beneficial for the environment as it avoids additional venting. This action avoids launching the device in the line with the risk of loss or jamming it in the line and/or in a valve.

The tray used by the contractor should be designed and used in a way to avoid any damage to the installations or the tool, especially the trap enclosure and its gasket while loading or removing tools. It should be adapted to the height of the pig trap and to the size of the tool.

An electrical grounding and mechanical abutment of the tray should be considered.

6.4 Tool set up

It is expected that the ILI contractor has an effective Management of Change (MoC) process. This should ensure that whenever new tools are introduced, their design considers field operatives and consistency of operation with earlier models. Failures have occurred simply due to the change of orientation of an on/off switch.

Training and knowledge of field technicians is crucial if these failures are to be avoided. This should not only include the use of check lists but also a good understanding of tool operation. Failures reported in this category include lack of knowledge of battery histories.

6.5 Pipeline environment

Even when tools have been tested and their design proven over time, new applications will be found to challenge and test the tool. Therefore, it is important that each contractor maintains records of the pipelines inspected. Failures may occur either due to an environment at the limit of operational experience, such as operations in dry environments and higher pressures or they may be the result of fatigue. Each failure should be recorded and used to build the envelope of suitable operating conditions.

As with new tools or components, wherever the use of the tool is proposed in an environment that is at the edge or beyond of current proven operating conditions, this should be recognised and discussed between the contractor and operator and the risks included in the risk assessment. The operator needs to consider the normal operating conditions and any credible abnormal transient conditions.

There is much experience in the industry running ILI tools in pipelines containing hydrocarbons. However, as part of the energy transitions, other pipeline media such as carbon dioxide (CO_2) and hydrogen (H_2) will also become relevant. If pigging in these media is not practical/feasible, taking the line out of service and filling it with nitrogen or water could be considered.

6.6 Carbon dioxide pipelines

Pipelines for transporting carbon dioxide (CO_2) in either gaseous or dense phase state, pose additional challenges to ILI when compared to running in hydrocarbons at similar operating conditions. Some aspects to consider are described below.

Rapid gas decompression. Rapid gas decompression (RGD), also known as explosive decompression can affect polymeric materials in ILI tools. Dense phase CO_2 is a strong solvent and it will absorb into polymeric material at high pressure. When the pressure is reduced again (e.g. in the receiver), the absorbed CO_2 might not diffuse quickly enough into the environment, and may lead to bubble expansion, swelling and blistering, or even explosive decompression, of polymeric material. Components such as polyurethane cups and discs, (sensor) cables and seals will be affected by this phenomenon. To a certain extent it can be mitigated by proper material selection and controlled decompression, but another approach is to consider certain ILI parts as consumables that need replacement after the run. A slow, controlled decompression rate of approximately2-3 bar/min is recommended to mitigate some of the RGD effects. As RGD typically occurs after the run, the inspection data will not be compromised. However, the costs to replace damaged equipment (mostly cables) will make the ILI run more expensive.

High wear and abrasion. Products which can act as a solvent are categorized as “dry” by pigging contractors. Not just CO_2 but also other gases like ethylene are very dry and can cause high wear to the cups of an ILI tool. Many ILI contractors have built up experience running ILI tools in dry environments and longer distances. Measures to limit cup wear include: selection of proper grade polyurethane (PU), using other cup materials like Ethylene Propylene Diene Monomer (EPDM) rubber, reinforced cups (e.g. with tungsten studs) and use of support wheels. High cup wear could lead to excessive tool bypass and loss of driving force to an extent that the tool stalls in the pipeline.

Temperature control. During depressurization of dense phase (or high pressure) CO_2, its temperature will drop considerably due to the Joule-Thompson-effect. Without control, ambient temperature dense phase CO_2 might cool down to -60°C when pressure is reduced to atmospheric. Therefore, pressurization of the launch trap and depressurization of receive trap should be carefully managed to limit temperature drop to avoid damage of the tool. For example, cups may lose flexibility and get damaged, or electronics components may fail at low temperatures.

6.7 Hydrogen pipelines

Hydrogen gas (H_2) has quite different properties when compared to natural gas for which the ILI industry has built up extensive experience and expertise. More information on in-line tool readiness for hydrogen pipelines is contained in POF 520 [6]. The main aspects to consider are summarized below.

Effect on other materials. In addition to the well-known effect of hydrogen on carbon steel, it may also affect the properties of other materials being used for ILI tools. This implies that a hydrogen compatible ILI tool requires careful material selection of its various components including, but not limited to, sealants, high strength steel, rubber, cable jackets, magnets, ceramics, spacers, cups, sensors, etc.

Speed excursions. The low density of hydrogen can result in excessive speed excursions for high drag tools for ILI technologies such as MFL and EMAT. In areas with high tool speed, data degradation or even loss of data can occur.

Safety considerations. Hydrogen has a lower density, wider explosion limits and smaller ignition energy in air when compared to natural gas. This affects the health and safety risk to people when launching, running and receiving ILI tools in hydrogen lines. In addition, there is also the risk of excessive tool speed excursions that may damage the pipeline with potential consequences to people working nearby. One of the ways to mitigate the health and safety risk of launching and receiving tools in pipelines containing a flammable and potential explosive environment, is to require the ILI tool to be certified against a safety standard. The ATEX and IECEx schemes are commonly accepted. ATEX certifications are valid for a group of gasses and a tool that is certified for use in hydrogen should fulfil more stringent requirements than a tool certified for natural gas.

One way to prevent these issues is by replacing the hydrogen with nitrogen when ILI is required. This is a common practice for hydrogen product lines which are typically smaller diameter and not very long. It may also be possible to run the ILI tool in a batch of nitrogen if complete replacement is not practical. However, these options may not be practical for larger diameter, long length hydrogen transportation pipelines which are required for the energy transition.

7. Field operations

7.1 Introduction

The operational objectives are to ensure that the ILI tool is configured and run within defined limits to acquire usable data without incident. To achieve this, effective coordination and communication is needed between operator and contractor. The knowledge of operations about the flow, off-takes, debris, wall thickness, bends, etc. is essential information for the contractor.

7.2 Onsite preparation

The onsite preparation phase generally covers the period from ILI tool mobilisation to site, final and preparatory checks prior to launch. During this phase general issues and documentation should be reviewed to confirm that all procedures are in place; the pipeline is ready and that the tool has been appropriately prepared and is set up to meet the inspection requirements.

Typical documents reviewed during this phase include:

- Pre-mobilisation documentation (Pipeline questionnaire, feature list, site visit and stakeholder meetings and risk assessments)
- Method statement with pigging program, operating procedures, risk assessment, drawings, principal pipeline characteristics, roles and responsibilities, contingencies
- Communication procedures: clearly identifying who is responsible and who should be aware or notified
- Site safety meetings: specific to each location where work will be carried out including compliance with ATEX requirements.

To ensure that the pipeline has been prepared and the ILI tool has been set up appropriately, the contractor will use and will make reference to a number of check lists. Significant failures have occurred where recognised steps have not been followed. Although the check lists may differ slightly with each contractor and for each ILI tool, the basic contents are similar:

- Pre-job meetings to confirm objectives, scope of work, operating procedures, safety and environment, risk assessments
- Setup and calibration checklist to confirm that the tool is properly configured
- Mobilization checklist to make sure that all required support equipment is onsite
- Pipeline operations checklist to ensure medium pressure and flow are adequate to ensure stable run conditions and ability to launch and receive the tool safely
- Site safety meeting onsite with operator and contractors to reconfirm the work, operating procedures, safety, risk assessments and communications
- Location of Above Ground Markers to support the accuracy of geographic surveys
- Operational training if applicable
- Provision for pre-mobilisation quality check/tool inspection onsite in case of critical runs.

Location accuracy of pipeline features is essential for the field verification success, especially in dense urban areas. It is directly linked to Above Ground Markers (AGMs) location and spacing.

The location and spacing of AGMs should be thought through and is generally established with contractor as part of the preparation of ILI operation. AGM spacing depends on:

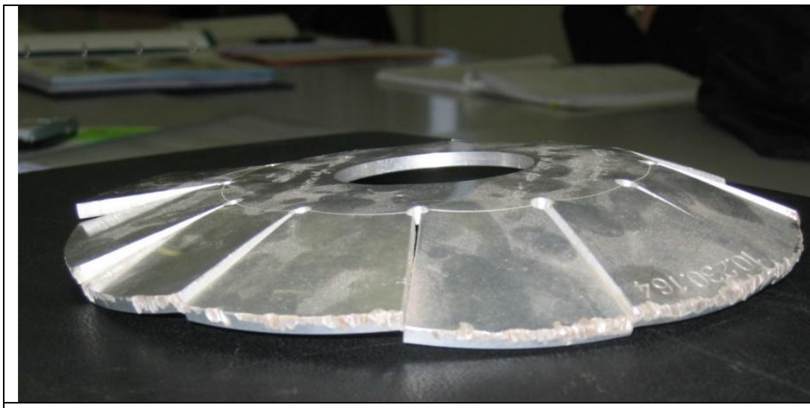
- Technology used: basic geometry versus high resolution IMU mapping require different AGM spacing to reach the claimed location accuracy of pipeline features
- Pipeline profile: for instance, AGM spacing is shorter in areas where the pipeline profile is disturbed

- Pipeline environment: in order to accurately locate anomalies for field verification in critical areas, it is a good practise to increase the number of AGM.

7.3 Final cleaning, profile or gauge plate run.

Whilst early proving of the pipeline bore is recommended as an early activity in the process, the final step should be verification that the line is clean and ready for this ILI tool. This should normally be completed in the presence of the contractor.

A key step in all inspection runs is the final profile or gauge plate run. This should be completed no more than one week prior to running the ILI tool. The gauge or profile tool is used to verify that the line does not have any obstructions that could cause the ILI tool to get stuck. (e.g. a changed valve position or corrosion monitoring point). As such the profile or gauge tool should be sized to mimic the ILI tool. Examples of features identified by running gauge plate tools are depicted in Figure 6. Figure 7 is a photo of a damaged UT sensor carrier.



Deformed gauge plate

Gauge plate damage caused by weld penetrations

Gauge plate damaged by gate valve

Figure 6: Damaged gauge plates

All operational changes between running the profile and gauging tool should be discussed by operator and contractor and any risks should be recognised and acted on accordingly.

The contractor should have a clear set of procedures for setting up the gauge/profile tool consistent with the ILI tool being run. The procedures should include clear guidance on interpreting damage to the plates. If any doubts arise during the cleaning and proving process, a calliper tool should be run to establish if more than a single incidence has caused damage to the gauging plate, speed effects or pipeline geometry. If a profile/gauge tool is damaged, a calliper tool or impact logger will be required to locate the restriction.

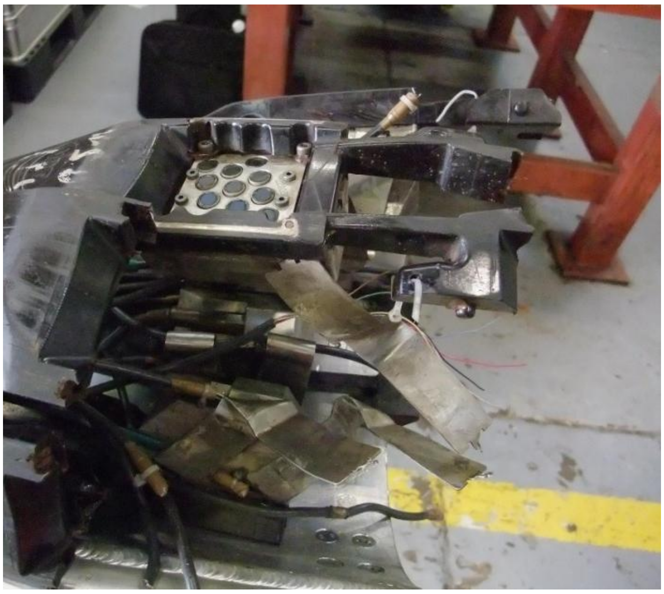


Figure 7: Damaged UT tool sensor carrier due to bore restriction

If pipeline gauging is not carried out, the reasons to justify this (including risk assessment) should be clearly documented. If pipeline gauging is carried out, the details of the gauging tool, analysis of the tool on receipt and confirmation that the inspection run can proceed, should be documented. This documentation should be approved by both operator and contractor.

7.4 Launch, ILI run and receipt

After the pre-job meeting, responsibilities and duties for all personnel involved should be clear. At this point, the main responsibility for the interactive process of operating the pipeline belongs to the operator. The contractor's ILI technicians should remain available to assist as appropriate and as requested.

In general responsibilities are shared as follows, notwithstanding any contractual or project specific agreements made in between operator and contractor:

- The contractor is responsible for ensuring the tool is fit for purpose prior to launch, handling of the ILI tool into and out of the pig traps.
- The operator is responsible for safety on the site and all operating conditions in the pipeline; pressurising the pig traps and running the ILI tool; de-pressurising pig traps on receipt and providing assistance with cleaning the ILI tools. Where the tool is contaminated due to the pipeline contents (e.g. NORMs) the operator is responsible for providing specialist cleaning services. A pre-NORM measurement of the tool and the environment is advised before loading the tool in the launcher.

NORM measurement of the tool and in the environment after the run is recommended to compare with the measures before the run (Tool and environment). National and international allowable NORM activity thresholds to transport, import or export equipment might exist. It is recommended to clarify the acceptable limits and required level of cleaning with the contractor upfront to ILI.

Figure 8: Preparing for ILI launch

ILI tool tracking and monitoring can be with both parties and needs to be mutually agreed. Failure of tracking devices can lead to failed inspection runs. Nevertheless, the contractor should provide the required training prior to start of the tracking.

The condition of the ILI tool should be recorded on receipt and following cleaning to verify that the tool is undamaged and that all components of the ILI tool have been received. If there is any doubt at the receiver site on the part of either the operator or the contractor communication should be initiated with supervisors or other stakeholders as appropriate.

After the ILI tool is received, safely extracted from the receiver and cleaned, the contractor is responsible for downloading the data and getting that data where it needs to be to begin the analysis process. This may take minutes or hours according to the length and diameter of the pipeline and the complexity or volume of the data. Specific checks include whether the ILI tool speed has remained within inspection limits and the completeness of data recovery. Some data loss may be acceptable if this is not in a critical section of the pipeline where any data loss would defeat the inspection objectives.

Although the contractor's ILI supervisor may be capable of deeming the run successful, some ILI companies require that the data be reviewed by a senior analyst. This may seem an extra step but remember that the entire purpose of the pig run is to provide suitable data for suitable answers. The time involved in this step can be minimized with good planning. For instance, data upload may prove to be slow if carried out from an offshore platform or support vessel.

Documents that help to ensure that this part of the project is successful include:

- Field data check
- ILI run acceptance form
- Short field run report

It is generally advisable that the data is reviewed and approved according to the agreed criteria. If data irregularities are discovered, clear communication between operator and contractor is required to determine next steps prior to releasing the ILI crew. Allowance of a little extra time can be very beneficial as after the tool and crew have been released, the complexity and cost of a rerun can increase dramatically.

7.5 Pig and ILI tool signalling, tracking and locating

Pig signalling (signallers), tracking and locating whilst related are in fact separate activities and can be described as follows:

- Pig signalling is monitoring if and when a pig has moved past a fixed location in a pipeline.
- Pig tracking is monitoring the position of a pig that is moving through a pipeline.
- Pig locating is finding the position of pig after it has stopped in a pipeline.

Typically signalling is used alongside tracking with locating being utilised if a pig does not traverse the pipeline within an expected timeframe.

There are intrusive and non-intrusive pig signallers on the market. Intrusive require correct set up and maintenance for reliable operation. Some have captive magnetic components in a fully welded housing others work through static seals. Some will not work with foam pigs; some are bi-directional others are uni-directional.

Non-intrusive pig signallers can be strapped onto the pipeline. The magnetic type of pig signallers typically require rare earth magnets to be fitted on the pig. Pig velocity is important: too high or too low results in unreliable detection. Slugs of ferrous material in the pipeline can cause a false call, as can metal objects (such as spanners) moving in vicinity of the detector externally. Thick wall pipe or small metal bodies on pigs can reduce detection capability. Pipe vibration e.g., during a pig launch can also give a false call.

Radioisotopes have reliable, accurate, long signal life but can be sensitive to pig velocity being too high. They can be used for pipe-in-pipe/concrete coated lines, liquid, or gas. They are normally expensive due to requiring additional controls and requirement for source handling personnel.

Acoustic pingers require a liquid couplant required internally/externally in which case long range detection possible and high accuracy using triangulation locally. Usually require a vessel offshore. Pinger emits signal constantly hence have relatively short battery life, transponders have to be signalled and then reply so reaching them in a noisy marine environment can be problematic. Not suitable for gas lines and onshore lines.

Electro Magnetic Pingers can be difficult to use (operator skill a prime requisite to tune instrument and recognise pinger signal). Battery life can also be limiting factor.

Pressure monitoring recorders are useful for obtaining a signature of pig passage through a liquid pipeline. Records pressure fluctuations utilising a sensitive pressure transducer connected to pig receiver. Limitations - suitable only for relatively short liquid lines. Minimum pigging velocity required to obtain recordable pressure fluctuations (>0.8 m/s). Volumetric meter readings are another method to track the approximate location of a pig.

For the AGM, a good practice is to lay all AGMs before launching the tool to avoid using the “leapfrog” technique to lay the AGMs. It is better for the safety of technicians who are in charge of deployment.

AGMs should not be removed before receiving the tool or if the technician does not have proof that the tool passed the AGM position.

Contractor technician should perform a demonstration of AGM utilization for all personnel involved in ILI tool tracking operations. ILI tool tracking personnel should confirm that all AGMs are operational and in good mechanical condition.

7.6 Subsea launch/receipt

For subsea pig launch and receipt operations the same principles apply as for onshore or offshore topsides operations, but the added complexity of ROV and /or diver intervention creates interfaces which are required to be managed proactively to reduce the risk of operational delays. Vessel day rates introduce costs which are significantly higher than onshore pipeline intervention costs and because of this and delays to the inspection schedule often becomes a key cost driver. The subsea interface also introduces other risks and additional Stakeholders which may have an impact on successful execution of the inspection.

Since an ILI can lead to subsea interventions, a baseline inspection could be beneficial to reduce the possibility of a false identification of the defect.

The risk of hydrates and potential for environmental incidents through lack of control during pig launch/receipt is increased subsea and requires special focus. As such, the focus for subsea ILI is more on subsea equipment handling, pig trap connection flushing, leak testing and valve operations than the pig launch/receipt or running the tool itself. Subsea launch and receipt usually require hydrocarbon fluids to be displaced from the pipeline prior to or during the first pigging operation for diver and environmental safety reasons and to avoid risk of hydrates. Subsea launching typically requires a different pigging medium compared to the medium in the pipeline, e.g. pushing the ILI tool into the pipeline using MEG, N_2 or other medium. The ILI tool should be launched using a detailed and purposeful valve operation sequence which includes options for leaving the worksite in a safe state in adverse weather or equipment breakdown scenarios.

It is therefore highly recommended that for subsea pigging operations, project controls such as used for capital projects are used, with regular project risk management reviews, involvement of specialists where appropriate and monthly reporting to management. Planning for subsea-to-subsea pigging operations should ideally start around 2 years prior to the offshore operation with issue of a project execution strategy document and a high-level execution plan endorsed by all stakeholders.

The main responsibility for the interactive process of operating the pipeline and controlling flows during pig launch and receipt lies with the operator. Detailed step-by-step procedures will have been developed in close cooperation with the offshore intervention and pumping contractors as well as equipment suppliers. It may be worth conducting an onshore pumping test to verify that pig launch is feasible using the approved procedures, especially for a first inspection of a pipeline. This will enable pumping equipment to be fully tested before use offshore, temporary hardware (spools etc.) to be verified to be compatible with proposed pig design and the pressure profile/envelope to be established prior to introducing mechanical tools into the pipeline for the first time. Focus during subsea pig launch and receipt needs to be on rigorous compliance with agreed procedures and controlled management of change processes where procedures need to be changed.

In general responsibilities are shared as follows, notwithstanding any contractual or project specific agreements made in between operator and contractor:

- Typically, subsea intervention on systems requiring cleaning/inspection will require regulatory permits & approvals especially if chemical discharge to sea is required. These should be submitted by the pipeline operator in a timely manner. Experience in this area has proved that the usual formal approval process can be longer than anticipated. The authority applications should provide clarity on the main areas of risk through a step-by-step review of planned activities, their associated risks and proposed mitigations to reduce these risks to acceptable levels.

- The contractor is responsible to ensure that the ILI tool is fit for purpose prior to mobilisation and that it has been properly mounted in the subsea launcher prior to vessel mobilisation. The reliability of ILI tools can be reduced in the presence of sea water and this can increase the probability of run failure when using for inspection in a subsea environment. The operator should make clear all operational constraints when defining the scope of work to be performed by the contractor to enable a full appraisal of tool requirements and recommendations for a fit for purpose inspection vehicle.

- The ILI tool bypass rate should be stated by the contractor based on the operational conditions to be used. Launching/receiving conditions and pipeline conditions should be considered separately.

- The operator is responsible for safety on the site and all operating conditions in the pipeline; flushing and pressurising the pig traps to acceptable levels using glycol, nitrogen or the pigging medium, running the ILI tool by controlling pressures and flow rates, controlling subsea release of gas where necessary and de-pressurising pig traps after receipt. Where the ILI tool is contaminated due to the pipeline contents (e.g. NORM) the operator is responsible for providing specialist cleaning services on the vessel and onshore site prior to transportation to the contractor's workshop.

Pig signalling can be done using non-intrusive pig signallers on the pig trap and in some cases selective available locations on the subsea pipeline. In addition to signalling, pig locating can be performed using external detectors fitted to ROV or operated by divers. Failure of tracking devices can lead to failed inspection runs and very high costs related to locating the pig to verify that it has been launched and not stuck in a main line valve. The use of pig tracking should be part of the overall risk evaluation.

Subsea pig receipt is a complex operation. When release of hydrocarbon gas is necessary, it should be modelled using plume and dispersion modelling CFD tools such that the support vessel is always up-wind and up-current of the location where a gas plume is expected to surface. It is highly recommended to partially open the subsea choke valve on the pig receiver around 1 minute before the ILI tool arrives at the bypass line, so that the pig does not stop at the tee and continues to move at a controlled and pre-determined speed into the receiver. A stalled pig in a tee or the main receiver isolation valve can create problems. It is therefore useful to use two pig signallers around 100m upstream of the pig trap, thus allowing time for the subsea choke to be opened prior to ILI tool arrival at the bypass line tee.

The condition of the ILI tool should be recorded on receipt and following cleaning to verify that the tool is undamaged and that all components of the ILI tool have been received. If there is any doubt at the receiver site on the part of either the operator, the offshore intervention contactor or the ILI contractor that the pig has completely entered the receiver, this should be communicated to the operator onshore support team.

Guidance for design and operation of subsea pig trap systems should be obtained from a reputable pipeline/subsea facilities contractor who has experience with design and/or operation of subsea pigging systems. Additionally, the Pipeline Research Council International (PRCI) has published guidelines for subsea pig trap design and operations based on input from PRCI membership companies. These guidelines can be purchased via PRCI's website, www.prci.org.

7.7 ILI run acceptance

A run can be accepted if ILI data is of sufficient quantity and quality for both the ILI contractor and pipeline operator. This means that the ILI contractor is able to perform a reliable analysis of the inspection data that meet the agreed performance specifications and that the pipeline operator receives sufficient information about the condition of the pipeline to enable a reliable assessment of pipeline integrity over its entire length and circumference.

POF 100 [1] defines criteria and conditions for a successful ILI using the term loss of data. Data loss is often erroneously interpreted as loss of data quantity but should consider data quality as well. Some reasons for loss of data quantity or data quality are given below.

Loss of data quantity is often caused by tool hardware failures or limitations, for example:

- Damage to sensors, sensor carriers or wiring leading to loss of data from affected sensors.
- Failure of data acquisition module leading to loss of data from all or large number of sensors.
- Empty battery or battery failure leading to complete stop of data acquisition.
- The tool speed was too high leading to an increase of axial sampling distance such that reliable data analysis is not possible anymore. The tool operates out of specification although the sensors may still function correctly.

Loss of data quality is often caused by operational reasons that prevent the sensors from working reliably and depends on the ILI technology applied, for example:

- Wall thickness outside the tool operating range. For instance, with MFL this can lead to insufficient or excessive pipe wall magnetisation and with EMAT certain wave modes cannot be excited.
- Sensor lift-off outside operating range. This typically applies to electromagnetic technologies such as MFL, EMAT and Eddy Current. Excessive lift-off is often caused by debris in the line that was not removed by proper cleaning. It can also be caused by intrusions.
- No or weak echoes received by ultrasonic transducers. This can be caused by lack of coupling medium when even the interface echo is not received. It can also be caused by debris, scale or wax that prevents or reduces coupling of the sound waves into the pipe wall leading to a loss of backwall echo.
- A very rough internal pipe surface may create problems for reliable ILI measurements. Sensor lift-off variations will affect technologies such as EMAT and MFL. UT technologies may suffer from the uneven interface between liquid and steel leading to weak or no echoes received by the transducers.
- Tool velocity out of specification for the technology. For example, with MFL and depending on the design, higher tool speed can result in non-uniform pipe wall magnetisation affecting detection and sizing capabilities. Also EMAT has strict tool velocity ranges for reliable measurements. When tool velocity is out of specification for the technology, the sensors do not function correctly anymore even if sampling distance is still within specification.
- Too large a tie-point distance for accurate measurement of pipeline centreline by the IMU module. This could be caused by insufficient AGMs or when some AGMs are not detected.

Issues about data quantity and data quality should be reported by the ILI contractor and discussed with the operator even if the loss of data is within acceptable limits as defined in POF 100. The operations report contents (as specified in chapter 7 of POF 100) will provide a good starting point for this discussion.

Loss of data quantity can often be quickly determined by ILI field operations staff and therefore easily addressed in the field operations report. Loss of data quality can be more difficult to determine although some quality indicators such as tool speed and pipe wall magnetisation (MFL) can be calculated quickly.

In many cases, especially for ultrasonic technologies, only a first indication of data quality can be given in the field operations report. In these cases, a final confirmation about data quality should be given in the preliminary report or otherwise as specified by the pipeline operator. For instance, it can be agreed that a dedicated data quality report will be issued shortly after the operations report but before the preliminary report.

If in certain areas the data quality is insufficient to meet the agreed performance specification, it does not mean it is useless. In many cases the ILI contractor can quantify the effect and estimate a reduced performance specification. The operator should review and discuss the updated performance specification to see if it can be accepted or not, see Figure 9.

In cases where it is decided to re-run the tool, it is recommended to see if the causes of the failed run can be mitigated or removed. For instance, by adapting the launching procedure, by hardware changes or repairs to the tool, changing pipeline operating conditions (medium pressure and velocity), additional cleaning runs, etc. When an ILI contractor recommends rerunning the ILI tool, the final decision rests with the pipeline operator.

When there are concerns about data quality at certain locations, the operator should consider the pipeline degradation threats at these locations and how it compares to the locations where good quality data has been acquired. For instance, if locations where data quality is affected coincide with locations where the highest pipeline degradation is expected, it will result in a less reliable pipeline integrity assessment when data quality is accepted.

If loss of data quantity and quality is accepted, this should be clearly stated and explained in the final report. In addition, the pipe tally and anomaly list should indicate where the start and end is of sections where the specified performance specification is not achieved and what the reduced specification is in each section. This will help the operator in the final assessment of pipeline integrity.

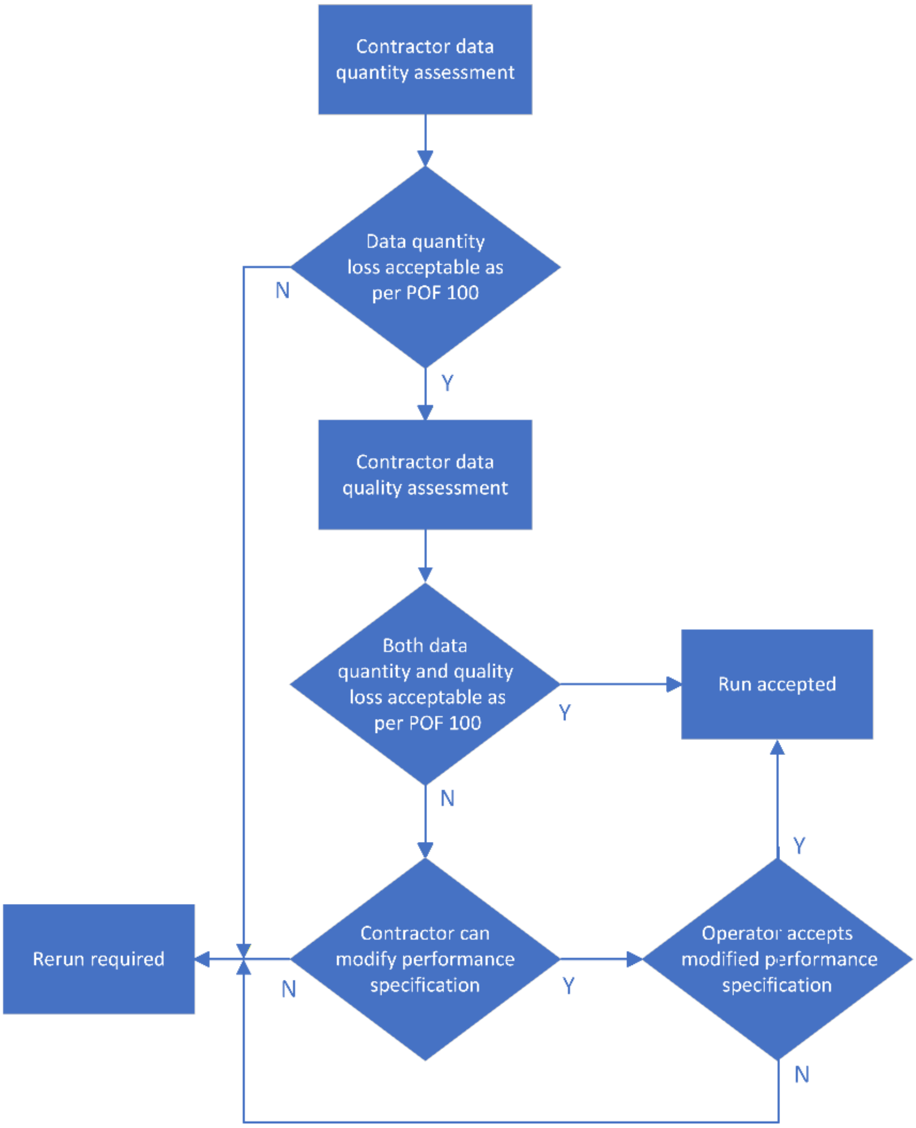


Figure 9 Run acceptance flow chart

8. Field verification

8.1 Introduction

Pipeline operators often perform additional measurements of several indications identified by an ILI tool. The process which is followed in the field to achieve this is important as inappropriate inspection techniques in the field can invalidate an otherwise valid report.

Field verification of reported anomalies has two important aspects as this helps confirm:

- The reported anomalies confirming the condition of the line to operator and generating data for a more detailed defect assessment to support any actions that may be taken.
- The specified tool performance for acceptance/rejection of ILI run or for use on other lines where dig verification is not possible.

Detailed guidance is provided in POF 310 [6]. Hence, this chapter is not meant to give exhaustive details on field verification but to give some highlights of the main parameters making field verification successful.

The main steps for field verifications are:

- Anomaly selection
- Procedures preparation
- Operation:
    - Anomaly location and excavation
    - Anomaly identification and sizing
- Data comparison: ILI measurements vs. field verification measurements.

It is important to involve the ILI contractor in this process as feedback on anomaly identification and size will help improve their performance.

8.2 Anomaly selection

Anomaly selection is an important parameter. A first, natural reflex would be to focus only on the most critical anomalies. This is necessary but it is not sufficient to achieve field verification objectives. A good practice for anomaly selection should be, as minimum but not limited to:

- The most critical anomalies in depth, length, width and/or ERF (or failure pressure)
- Anomalies close to the minimum detection threshold of the ILI tool
- Anomalies located in the most representative areas of the pipeline. For example, if there is evidence of a corrosion mechanism on the pipeline in a specific area, even as non-critical, some anomalies in this area should be verified.
- Selecting anomalies across the full range of reported depths helps validating the ILI sizing.

8.3 Procedures preparation

As for all inspection operations, the preparation phase is key factor.

It is important to have a consistent and reliable data set in which to work. In order to achieve consistency, it is necessary to set standards and protocols that must be followed, and to train and certify field personnel to gather the data with the required accuracy and competency so that the results can be relied upon. In this stage it could be beneficial to contact the ILI contractor and have an agreement about the procedures, the techniques and the equipment used during field verification. The techniques and equipment used should be tested and certified in calibration. The calibration and device tolerances should be taken into account when evaluating the results.

Procedures, technical or organisational, should be developed in the early project stage.

Contractors should be contacted prior to dig verifications either to have the possibilities to attend or to recheck the proposed location and give additional advice e.g. other corrosion that could exist in the same joint.

8.4 Operation

Field personnel assigned to dig verification should be certified competent with the equipment being used to measure the required defects reported.

Significant problems to an integrity program can occur where reported anomaly sizes are incorrectly measured in the field. This has an impact not only on the verification of the reported anomalies but also on determining the tool performance, and subsequent use of the ILI data in other pipeline integrity decision making.

Contractors will usually support field verification work as this helps support verification of tool performance. It is important to check that qualifications of field technicians comply with acceptable and recognised standards.

Results should be recorded as per the POF 311 ILI field verification form [8]. In case of large discrepancies between ILI and field verification data, it is recommended to make available to the ILI contractor, the full field report, including details on the inspection techniques, equipment, setup, as well as detailed anomaly characteristics, photos and screenshots.

8.5 Data comparison and validation

A unity plot can clearly and graphically display the performance of any inspection results against actual field measurements, and should be produced for every pipeline inspection, which has a field verification program.

9. Lessons learnt

Performing an ILI run on a pipeline can be a straightforward exercise when the operating conditions and pipeline design are just right for the tool that is being used. That is in the ideal world. For this reason it is imperative to have the most detailed information about the line design, including bends, barred tees, valves and wall thickness, as well as the operating conditions of the pipeline, including the cleanliness of the line, composition of the propelling liquid and the conditions under which the tool is being run (e.g. temperature, pressure, pressure differential, fluid velocity). It may also be useful to review the speed from previous runs to identify any locations where tools persistently tend to stop and may accelerate afterwards.

Unfortunately, not all of this information is always available from the operator. In many cases data has either not been recorded or has been lost. It is therefore recommended that the run experience report supplied by the contractor is registered in the pipeline integrity management system for each pipeline such that it can be easily retrieved when the next inspection is being planned.

In order to maximize the run success rate and ease of execution of the inspection run it is important to be able to capture pertinent information and develop a methodology of record keeping of the data on the line and subsequently reevaluate and update the process (e.g. risk assessment, verification or maintenance procedures, etc.). The steps followed to execute the project and any lessons learned can make subsequent projects run smoother. Information on a particular line may also be of value for other pipelines operating with similar conditions. Records should, where possible, include photographs.

Typical pipeline and operating data that should be retained follows the steps required for run success:

Project preparation

- Pipeline operating history
- Pipeline questionnaire and any updates
- Previous inspection data including calliper runs
- Type of defects observed in previous digs to help select the right inspection tool

Pipeline cleaning and preparation

- Records of the cleaning programme; quantities and debris analysis
- Cleaning tool details (disc type, cup type etc.) and specifications
- Subsequent cleaning and pigging runs
- Results of gauge plate inspections
- AGM placement.

Pipeline inspection

- Procedures and special operating requirements
- Operating records including pressure traces
- Line conditions and valve conditions and arrangements
- Comments on the effectiveness of the cleaning programme.

Dig Verifications

- ILI inspection reports
- Feature verifications
- Actions taken.

Most of the information should be held by the operator but data will also be held by the contractor. Where inspection was not successful, records should be retained of the failure investigation and any steps taken to rectify the problems.

A feedback form that can be used for an ILI contract is available in POF 303 [9].

Each failed ILI run should be thoroughly investigated as the root cause initially reported from the field may not be the critical factor. Investigations should look at common causes across a number of runs as recurring factors and/or wear factors (e.g. component fatigue) should be considered.

Mechanical failures associated with tool hardware are generally more significant as they can lead to a tool becoming stuck or severely damaged. Equally important for disclosure and discussion between the operator and the contractor are the changes that may be made to data processing algorithms particularly where improvements have occurred since a previous inspection if a comparison of results will occur.

In all cases it is important that the results of contractor failure investigations are clearly understood and communicated to the operator.

10. Summary

While ILI run success rates are high, understanding the impact and causes of failed ILI runs are key steps in the process of improving run successes. In some cases, particularly where there are high operating costs associated with the inspection runs, as may be found with subsea operations, a discussion on the anticipated run success rates may result in changes to the inspection programme support requirements and the need for a standby inspection tool.

This recommended practice has drawn together some of the key points developed from best practices used across the industry. Run success, however, can only really be declared when field data verifies the inspection report. It is one of several performance metrics that can be used to help improve the performance of ILI operations.

Successful ILI requires good communication between all parties from the initiation of an ILI project and selection of the tool to field execution, analysis and field verification.

Whilst check lists, competency and experience clearly play a significant part, the common factor in many failed runs is a break down in the communication process between operator and contractor.

Building on the operational data gathered from earlier inspection runs, the pipeline questionnaire, and the use of best practices in this document should help improve run success rates. It cannot be used however, as a substitute for open discussion in the preparation for each inspection project.

Improvements in ILI run success will be driven through improved feedback and investigation of failed runs. This requires changes to reporting processes which will improve over time. Without feedback and a willingness to improve processes, it is not possible to fully realise the potential value anticipated with improved run success rates.

Continued dialogue and use of best practices will continue to help improve the ILI run success rate and will help reduce operational risks for operators. Regular review of the metrics and root causes is recommended.

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Appendix A – Example of a Pipeline Feature List

ROUTEMAP NR. N-569-12-KR-	Length Routemap (m)	Accumulated Length Routemaps (m)	AGM	TYPE OF FEATURE or REFERENCE	Stationing Feat./ Ref. (From start routemap) (m)	Accumulated Stationing Start Pipeline (m)	Clock Pos. hrs:min	Distance between Tee's (m)	REMARKS/SPECIALS Detail drawings of crossings and constructions
	13.0			**MOBILE LAUNCHER**					S-114 Hoogvliet
				Temporary installation					A-690-S-114
				Flange					A-517-LM-079-1
				API 18" WT = 11,13					
				Weldolet DN50			09:00		
				Pig Switch			00:00		
				10D Bend 30°					
				Tee 18"x6"x 18"					
				Weldolet 2"					
				Pig Switch			00:00		
				3D Bend 15°					
				3D Bend 15°					
				WTC 7,72 x 6,43					
		13.0							
001	310.6			API 18" WT = 11,13					A-537-XW-001-1 (VE)
				Steel Casing (Begin 11,9m)	3,5	16.5			A-537-XW-001-2
				Steel Casing (end)	15,9	28.9			
				10D Bend 80°	18,5	31.5			
				40D Bend 9,5°					
				40D Bend 9,5°					
				Steel Casing (Begin 25,24m)	39,5	52.5			
				Steel Casing (end)	64,7	77.7			
				10D Bend 15°	66,9	79.9			
				10D Bend 15°	72,3	85.3			
				10D Bend 11°					
		323.6							
002	282.3			API 18" WT = 11,13					

				WTC 14,,27 x 11,13					
				API 18" WT = 14,27	258,3	581.9			
		605.9							
003	285.2			API 18" WT = 14,27					
				WTC 19,05 x 14,27					A-537-LP-003-1
				API 18" WT = 19,05	61.0	666.9			A-537-XD-003-1 (VE)
				15D Bend 45°	74.8	680.7			
				15D Bend 45°	95.1	701.0			
				Sheet Pilling	98.2	704.1			
				Sheet Pilling	99.2	705.1			
				WTC 19,05 x 14,27					
				API 18" WT = 14,27	109,7	715.6			
				40D Bend 5°	143.0	748.9			
				40D Bend 5°	176.3	782.2			
				WTC 14,27 x 11,13	285.2	891.1			
		891.1							