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Petroleum and natural gas industry — Pipeline transportation systems — Pipeline integrity management specification —

Part 2: **Full-life cycle integrity management for offshore pipeline**

Industries du pétrole et du gaz naturel — Systèmes de transport par conduites — Spécification de gestion de l'intégrité des conduites —

Partie 2: Gestion de l'intégrité des conduites en mer pendant leur cycle de vie complet

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Foreword

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The procedures used to develop this document and those intended for its further maintenance are described in the ISO/IEC Directives, Part 1. In particular, the different approval criteria needed for the different types of ISO documents should be noted. This document was drafted in accordance with the editorial rules of the ISO/IEC Directives, Part 2 (see www.iso.org/directives).

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For an explanation of the voluntary nature of standards, the meaning of ISO specific terms and expressions related to conformity assessment, as well as information about ISO's adherence to the World Trade Organization (WTO) principles in the Technical Barriers to Trade (TBT) see www.iso.org/iso/foreword.html.

This document was prepared by Technical Committee ISO/TC 67, *Materials, equipment and offshore structures for petroleum, petrochemical and natural gas industries*, Subcommittee SC 2, *Pipeline transportation systems*.

A list of all parts in the ISO 19345 series can be found on the ISO website.

Any feedback or questions on this document should be directed to the user's national standards body. A complete listing of these bodies can be found at www.iso.org/members.html.

Introduction

This document addresses the integrity of petroleum and natural gas pipelines through their entire life-cycle, from design to eventual abandonment. For this reason, considerations relating to design, construction and abandonment have been included. This approach supports the development and implementation of a holistic and integrated pipeline integrity management program that bridges between life-cycle elements and thereby avoids compartmentalizing of the pipeline life-cycle into essentially independent data and functional silos, which has traditionally been the case. The integrated approach was developed on the basis of extensive research and examination of best practices and results from pipeline integrity audits world-wide.

This document is intended to be used by companies that have not yet developed an official program or are developing a program for new pipelines. This document can also be used to guide continual improvement of existing programs by both operating companies and regulators to evaluate integrity management program effectiveness.

Petroleum and natural gas industry — Pipeline transportation systems — Pipeline integrity management specification —

Part 2: Full-life cycle integrity management for offshore pipeline

1 Scope

This document specifies requirements and gives recommendations on the management of integrity of a pipeline system throughout its life cycle, which includes design, construction, commissioning, operation, maintenance and abandonment.

This document is applicable to offshore pipelines for transporting petroleum and natural gas. It is applicable to rigid steel pipelines. It is not applicable to flexible pipelines, dynamic risers or those constructed from other materials, such as glass-reinforced plastics.

NOTE 1 An offshore pipeline system extends to:

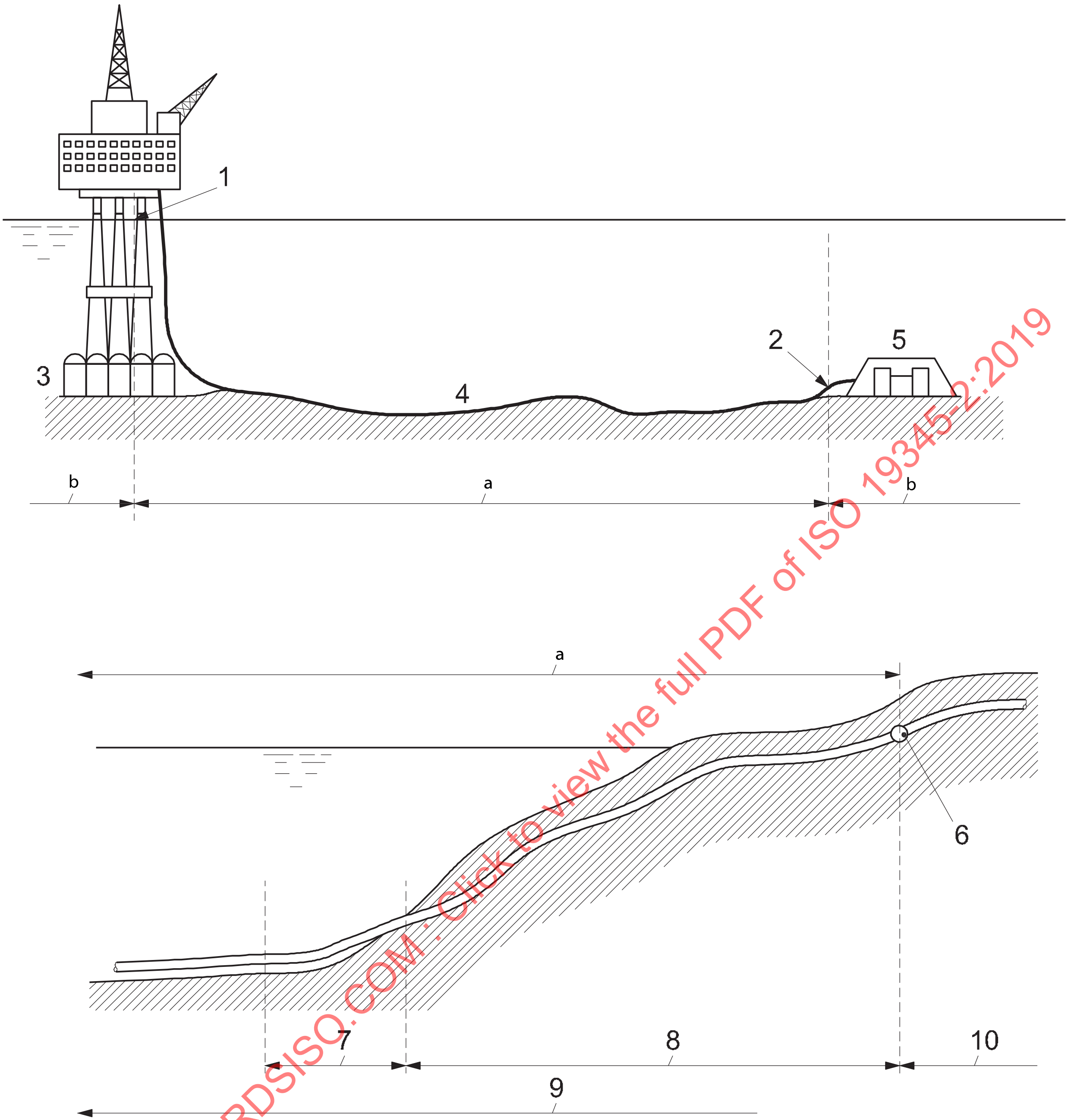
— the first valve, flange or connection above water on platform or subsea mechanical connector with subsea structure (i.e. manifold or dynamic riser);

— the connection point to the offshore installation (i.e. piping manifolds are not included);

— the first valve, flange, connection or isolation joint at a landfall, unless otherwise specified by the onshore legislation.

NOTE 2 The components mentioned above (valve, flange, connection, isolation joint) include also any pup pieces, i.e. the offshore pipeline system extends to the weld beyond the pup piece, see Figure 1.

This document is used for integrity management, which is initiated at the design and construction stage of the pipeline. Where requirements of a design and construction standard (e.g. ISO 13623) are different, the provisions of this document will enhance the design and construction from an integrity perspective.



Key

1 first valve, flange, connection or isolation joint
2 connector point to subsea piping
3 topside
4 pipeline system
5 pipeline subsea structure
6 first valve, flange, connection or isolation joint
7 nearshore section
8 shore approach
9 offshore section
10 onshore section
a covered by this document
b not covered by this document

Figure 1 — Extent of pipeline systems covered by this document

2 Normative references

The following documents are referred to in the text in such a way that some or all of their content constitutes requirements of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

ISO 13623, *Petroleum and natural gas industries — Pipeline transporting system*

ISO 15589-2, *Petroleum, petrochemical and natural gas industries — Cathodic protection of pipeline transportation systems — Part 2: Offshore pipelines*

ISO 31000, *Risk management — Guidelines*

IEC 31010, *Risk assessment techniques*

3 Terms, definitions and abbreviated terms

3.1 Terms and definitions

For the purposes of this document, the following terms and definitions apply.

ISO and IEC maintain terminological databases for use in standardization at the following addresses:

— ISO Online browsing platform: available at https://www.iso.org/obp

— IEC Electropedia: available at http://www.electropedia.org/

3.1.1
abandonment
activities associated with taking a pipeline permanently out of operation

Note 1 to entry: An abandoned pipeline cannot be returned to operation.

Note 2 to entry: Depending on the legislation abandonment can require cover or removal.

3.1.2
anomaly
possible deviation from pipe material or weld soundness

Note 1 to entry: The identification of an indication of an anomaly can be generated by non-destructive inspection, such as in-line inspection.

3.1.3
baseline assessment
first integrity assessment prior to or after operation

3.1.4
cathodic protection
corrosion control technique to prevent or reduce the external corrosion of metal pipelines by transferring an electrical current onto the pipe to achieve increased negative electrical potentials

3.1.5
corrosion
deterioration of a material, usually a metal that results from an electrochemical reaction with its environment

3.1.6
crack
planar flaw, or linear discontinuity, with a sharp tip radius

3.1.7
critical consequence area
location where a pipeline release might have a significant adverse effect on public safety, property and the environment

Note 1 to entry: The pipeline segments in CCAs are of particular interest in risk assessment and integrity assessment evaluations and prioritizations.

3.1.8
deactivation
removal of a pipeline from service, though the pipeline might be returned to service after a proper assessment

Note 1 to entry: Also defined as decommissioning or suspension.

3.1.9
deformation
change in shape of the pipe or component, such as a bend, buckle, *dent* (3.1.11), ovality, ripple, wrinkle, or any other change that affects the roundness of the pipe or original cross-section or straightness of the pipe or component

3.1.10
defect
imperfection of a type or magnitude exceeding acceptable criteria

3.1.11
dent
depression which produces a disturbance in the curvature of the pipe wall, caused by contact with a foreign body resulting in plastic deformation of the pipe wall

3.1.12
design life
period for which the design basis is planned to remain valid

[SOURCE: ISO 13623:2017, 3.1.2]

3.1.13
failure
event in which a component or system does not perform according to its operational requirements

3.1.14
fitness for purpose
quantitative engineering evaluation that is performed to demonstrate the structural integrity of an in-service component that can contain an imperfection, *defect* (3.1.10) or damage

3.1.15
gouge
surface damage to a pipeline caused by contact with a foreign object that has scraped (gouged) material out of the pipe, resulting in a metal loss defect or imperfection

3.1.16
incident
unintentional release of gas or liquid due to the *failure* (3.1.13) of a pipeline

Note 1 to entry: Some regulatory authorities define "incident" as an event occurring on a pipeline for which the operator is required to make a report to the concerned regulatory authority.

3.1.17
in-line inspection
inspection of a pipe wall from the interior of the pipe using specialized tools

3.1.18
integrity assessment
process that includes the inspection and testing of a pipeline in order to determine physical characteristics and assess its integrity condition by combination of an analysis of data, use of reliability assessment methodologies of the structure and an evaluation of the safety state of the pipeline

3.1.19
integrity management program
documented program that specifies the practices used by the operating company to proactively manage the safe, environmentally responsible, and reliable service of a pipeline system throughout its lifecycle and which incorporates a continuous improvement process

3.1.20
life extension
additional period of time beyond the original design or *service life* (3.1.36) (but within the assessed remnant life) for which permission to continue operating a pipeline system is granted by the regulatory bodies

Note 1 to entry: Life extension is considered as a modification to the design basis.

[SOURCE: ISO/TS 12747:2011, 3.7]

3.1.21
magnetic flux leakage
type of in-line inspection technology in which a magnetic field is induced in the pipe wall between two poles of a magnet

Note 1 to entry: Anomalies affect the distribution of the magnetic flux in the wall. The magnetic flux leakage pattern is used to detect and characterize anomalies.

3.1.22
management of change
process that systematically recognizes and communicates to the necessary parties changes of a technical, physical, procedural or organizational nature that can impact system integrity

3.1.23
manufacturing defect
defect (3.1.10) in the pipe body or coating created during the pipe or component manufacturing or coating processes

3.1.24
maximum allowable operating pressure
maximum internal pressure at which a pipeline system, or parts thereof, is allowed to be operated

Note 1 to entry: The MAOP is established by the maximum pressure achieved during testing (see ISO 13623).

3.1.25
metal loss
pipe anomaly in which metal has been removed

Note 1 to entry: Metal loss is usually the result of corrosion, but gouging, manufacturing defects erosion, or mechanical damage can also result in metal loss.

3.1.26
non-destructive testing
wide group of analysis techniques used to evaluate the properties of a material, component or system without causing damage

Note 1 to entry: "Non-destructive inspection" (NDI) and "non-destructive evaluation" (NDE) are also commonly used to describe this technology.

3.1.27
offshore pipeline
part of a pipeline system that, except for pipeline risers, is laid on the seabed or below it inside a trench

Note 1 to entry: The pipeline might be resting wholly or intermittently on, or buried below, the seabed.

3.1.28
operator
person or organization who owns or operates a pipeline system or facilities who is ultimately responsible for the operation and integrity of the pipeline system

3.1.29
pipeline integrity management
set of processes and procedures that proactively assures incident-free safe and environmentally responsible transportation of fluids through a pipeline system

3.1.30
pipeline integrity management program
continuous improvement closed-loop system using information technology to realize functions such as data acquisition and integration, integrity and *risk assessment* (3.1.33), mitigation and repair activity and maintenance decisions, with comprehensive management of change and continual review and improvement processes

3.1.31
pressure test
means of assessing the integrity of a new or existing pipeline that involves filling the pipeline with water and pressurizing to a level in excess of the MAOP of the pipeline to demonstrate that the pipeline is fit for service at the MAOP for a given time frame dependent on the identified integrity hazards

Note 1 to entry: See ISO 13623:2017, 6.7.

3.1.32
risk
measure of loss, either qualitative or quantifiable, in terms of both the likelihood of incident occurrence and the magnitude of the consequences of the incident occurrence

3.1.33
risk assessment
systematic, analytical process in which potential hazards from the pipeline system are proactively identified, and the likelihood and consequences of potential adverse events are determined

3.1.34
risk management
coordinated activities to direct and control an organization with regard to *risk* (3.1.32)

[SOURCE: ISO Guide 73:2009, 2.1]

3.1.35
safe operating pressure
pressure, calculated using the appropriate analysis and mathematical formulas for the specific type of *defect* (3.1.10) identified

EXAMPLE For corrosion defects using recognized remaining strength of corroded pipeline formulas, where all corroded regions will withstand a calculated safe operating pressure.

3.1.36
service life
length of time over which the pipeline system is intended to operate

[SOURCE: ISO/TS 12747:2011, 3.21]

Note 1 to entry: Service life is considered the actual operational life to date, but can include any planned future use of the line. Service life can be less or longer than design life.

3.1.37
sizing accuracy
accuracy with which an anomaly dimension or characteristic is reported

Note 1 to entry: Typically, accuracy is expressed by tolerance and certainty.

EXAMPLE Depth sizing accuracy for metal loss using NDT methods, such as an ILI tool, is commonly expressed as +/−10 % of the wall thickness (the tolerance) and 80 % of the time (the certainty).

3.1.38
third-party damage
damage done to the pipeline as a result of activities by personnel not associated with the pipeline

3.1.39
threat
activity or condition than can adversely affect the pipeline system if not adequately controlled

[SOURCE: ISO/TS 12747:2011, 3.23]

3.2 Abbreviated terms

AC	alternating current
CP	cathodic protection
CCA	critical consequence area
CoF	consequence of failure
DA	direct assessment
ECDA	external corrosion direct assessment
FFP	fitness for purpose
GIS	geographic information system
HIC	hydrogen-induced cracking
ICDA	internal corrosion direct assessment
ILI	in-line inspection
IMP	integrity management program
MAOP	maximum allowable operating pressure
MFL	magnetic flux leakage
NDT	non-destructive testing
PIM	pipeline integrity management

PoF	probability of failure
SCC	stress corrosion cracking
SCCDA	stress corrosion cracking direct assessment
SMYS	specified minimum yield strength
SSC	sulphide-stress cracking

4 General

4.1 Key principles

The operator uses integrity management programs (IMPs) to enable it to manage its pipeline systems in a safe, environmentally responsible and reliable manner. An effective IMP anticipates and mitigates or eliminates integrity issues before they lead to incidents or failures.

Key principles for an effective IMP are listed below:

a) Pipeline system integrity shall be viewed as a lifecycle approach from initial planning, design, construction, operation and maintenance up to and including abandonment.

b) The operator shall provide adequate resources in terms of funds, equipment and competent personnel to implement the IMP.

c) Clearly defined roles and responsibilities with clear communication processes are necessary.

d) Document and records control and retention and data gathering are key mandatory elements that enable informed decisions.

e) Performance measures of the IMP's effectiveness should include both leading and lagging indicators to identify trends and areas for continuous improvement.

f) An effective IMP uses risk-based decisions to prioritize integrity-related actives.

4.2 Integrity management program

4.2.1 General

The operator shall establish, implement, maintain and document an IMP or equivalent, and continually review its adequacy and implementation and improve its effectiveness.

The pipeline IMP shall be part of a comprehensive management system which includes, as a minimum, integration with safety and environment programs.

To facilitate the development and implementation of the initial IMP for a pipeline system, the operator shall develop an integrity management plan, which includes a plan for initial data acquisition, threat and hazard consequence identification and risk assessment, and improve it with integrity elements introduced in 4.2.2. If applicable, the operator can also choose to incorporate mature IMP elements from other pipeline systems, and customise them to their pipeline system or segment.

4.2.2 Introduction to IMP elements

The pipeline IMP shall address operators' approach to the following elements, as illustrated in Figure 2.

a) Life cycle phases for integrity management:

Integrity shall be applied through the entire life cycle of pipeline, including:

1) feasibility;
2) design;
3) procurement;
4) installation;
5) transportation and storage;
6) construction;
7) pre-commissioning and commissioning;
8) handover;
9) operation and maintenance;
10) modification;
11) suspension/abandonment.

b) Pipeline integrity management process:

As part of the continuous improvement process, the inputs into these elements shall be routinely updated, as required, to reflect the dynamic nature of pipeline systems:

1) data acquisition, review and integration;
2) risk assessment (threat, consequence, probability, CCAs);
3) inspection and monitoring;
4) integrity assessment;
5) mitigation activity;
6) performance measurement and improvement.

NOTE 1 Understanding the pipeline's integrity and threats in the context of the surrounding environment is key to making informed integrity management decisions.

NOTE 2 Performance measurement can verify that the goals, targets and objectives of the integrity program are being met and can be used during management reviews to identify improvement opportunities.

The following elements shall be developed for the operational phase to ensure that adequate management practices are in place to assess failures and manage and respond to emergencies:

— failure assessment plan;
— emergency response plan;
— remaining life assessment plan.

NOTE 3 The failure assessment plan considers failure causes and contributing factors and provides critical information to the IMP. The goal is to prevent recurrence of similar failures.

NOTE 4 The emergency response plan is designed to ensure that the operator is prepared to deal with accidents and incidents in a timely manner to aid in the reduction of consequences. These accidents or incidents can occur because the IMP did not foresee or was unable to effectively mitigate the threat. Emergency response plans also include contingency repair plans and procedures.

NOTE 5 The remaining life assessment provides input into the economic viability assessment of the pipeline. As the pipeline ages, the operational risks and mitigation costs increase until continuing the operation is no longer viable.

c) Management elements:

The following elements shall form part of an IMP and might be written to encompass more than one pipeline or system. These elements usually interact with other management systems within an organization:

1) policy and commitment;

2) scope of the IMP;

3) organizational structure including key roles and responsibilities.

The following mandatory elements predominately deal with information flow, providing the core of the data system providing information for assessment and review. They are usually presented as plans with procedures:

— communication;

— records and documents control;

— management of change;

— management review and audit;

— training and skills.

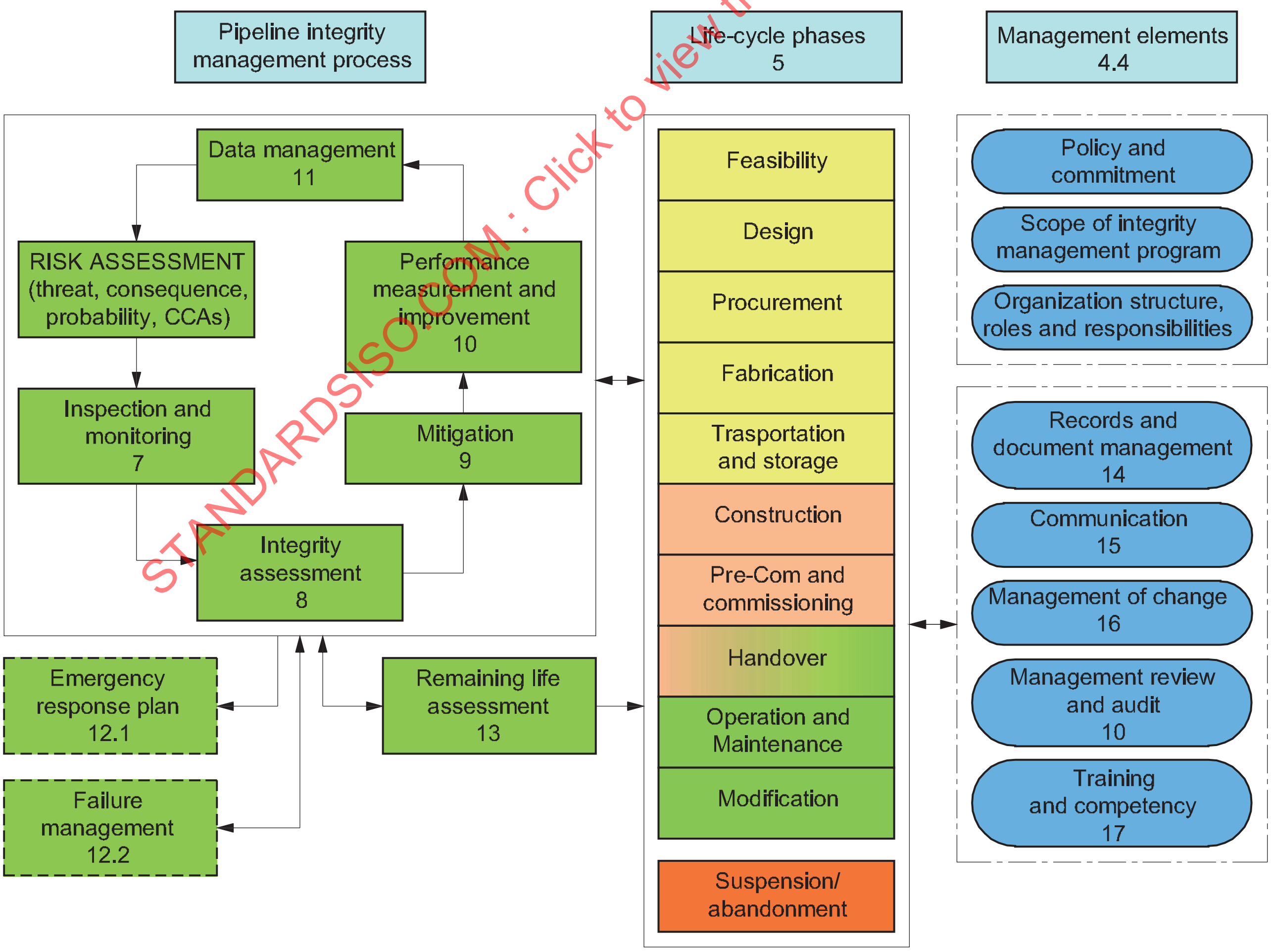


Figure 2 — Pipeline integrity management program structure

4.3 Integrity management process elements

4.3.1 Data acquisition, review and integration

The first step in evaluating the potential threats for a pipeline system or segment is to define and gather the necessary data and information that characterize the segments and the potential threats to that segment. A plan for collection of historical data shall be established and maintained for the pipeline system lifecycle. The operator shall perform the initial collection, review and integration of relevant data and information from pipeline design, construction, operation, maintenance, monitoring, inspection and failure investigation data. Data acquisition is needed to understand the condition of the pipeline, identify the location-specific threats to its integrity; and understand the public, environmental, and operational consequences of an incident.

4.3.2 Risk assessment

Risk analysis is an analytical process through which the operator considers the likelihood of the threats occurring and the nature and severity of the resulting consequences.

Risk assessment shall be performed for all scenarios including low consequence—high likelihood and critical consequence—low likelihood events. Every plausible failure mode shall be listed and assigned risk evaluation. Where multiple consequences occur from a single failure mode, multiple assessments are required.

The operator shall consider all the threats and any interactive threats that can be applicable to its system. It can be appropriate to consider risks in pipeline segments where the consequence of failure is particularly high and where explicit integrity management measures have to be implemented.

Completed risk assessment shall be reviewed at regular intervals and when substantial changes occur to the pipeline. The assumptions and variables used in the risk assessment shall be validated and updated, where applicable as part of the review.

4.3.3 Inspection and monitoring

The operator shall select and conduct appropriate inspection and monitoring based on the risk assessment made in the previous step, typically including in-line inspection, pressure testing, direct assessment, or other inspection and monitoring methods based upon the threats that have been identified. More than one inspection or monitoring method can be required to address all the threats to a pipeline segment.

4.3.4 Integrity assessment

Integrity assessment will implement the following hierarchy of controls:

— physical controls;

— procedural controls;

— elimination.

Where risks cannot be sufficiently controlled, mitigation activities shall be implemented until the risk is considered satisfactory.

The process of establishing and implementing effective preventive and mitigation measures requires suitable data collection, data integration, and informational analysis within the IMP. Data integration and the analysis can identify aspects of the operator's operations and maintenance that allow the operator to address the threats. Most importantly, local knowledge of the operational environment around the pipeline and the incident history associated with certain components or circumstances should be considered.

4.3.5 Mitigation activity

Where a threat cannot be controlled, the operator shall develop appropriate actions to mitigate the threat to an acceptable level of risk.

The results of mitigation assessments shall be used to determine what additional prevention or mitigation measures are required to reduce unacceptable risks identified in the assessment. Prevention and mitigation activities should be applied to reduce the likelihood of failure and/or the consequence of the failure to an acceptable level. Preventative measures typically involve activities to reduce the likelihood of an event.

The operator shall perform mitigation activities to ensure the pipeline system remains safe for its intended service. Where applicable, these mitigation activities shall provide a factor of safety that is notionally similar to the design factor of safety. This notional equivalent design factor of safety shall be maintained, throughout the life of the pipeline. The mitigation activities can include activities such as increased internal and external inspections and survey and pressure reductions.

4.3.6 Performance measurement and improvement

The operator shall develop procedures to regularly measure and evaluate the adequacy of implementation and effectiveness of IMP and its conformity to relevant standards.

The operator shall also evaluate the effectiveness of its other related management programs and processes in supporting integrity management decisions.

A combination of performance measures and system audits can be necessary to evaluate the overall effectiveness of a pipeline integrity system.

Performance measurement results shall be used to continuously identify areas for improvement of the IMP. In addition, advances in technology and industry best practices shall be considered.

4.3.7 Emergency response plan

Plans and response procedures for emergency situations shall be established and maintained based on a systematic evaluation of possible scenarios that can affect the safe and reliable operation of the pipeline system. Plans and procedures for contingency repair of the pipeline shall be established depending on the criticality of the pipeline system, based on factors such as safety, environmental, legislative or commercial considerations.

4.3.8 Failure management plan

The operator shall develop procedures for pipeline failure investigation to ensure that a structured approach is adopted and all aspects of a failure are reviewed. The failure investigation shall aim to determine the root cause and contributing factor of a pipeline failure and recommend corrective actions to prevent similar failures. This can include a targeted risk management program for causes that are not isolated. The operator shall setup a database to record relevant pipeline failure information to support failure management.

4.3.9 Remaining life assessment

The operator shall develop a remaining life assessment for all pipeline segments and systems and apply updates as new integrity information is gathered e.g. ILI, or when the operational parameters change (e.g. pressure or temperature). The remaining life assessment shall be reviewed at regular intervals, such as at the end of the design life and after pipeline failures, or when changes in key operating design parameters occur.

The remaining life assessment will be used to enable lifecycle management processes to balance the risks of ongoing operation with safety and protection of the environment and associated costs of operations and management.

4.4 Management elements

4.4.1 Policy and commitment

The operator shall have a policy that expresses management commitment for developing, implementing, reviewing and continuous improvement of a pipeline IMP. The operator shall instruct personnel to meet its requirements.

4.4.2 Scope of integrity management program

The operator shall determine the scope of the IMP, including identifying the applicable pipeline systems and the goal and objectives of the IMP for the identified pipeline system.

The operator shall maintain a documented IMP that addresses the management of the pipeline integrity and specific treatment for all unacceptable risk.

4.4.3 Organization structure, roles and responsibilities

The operator shall have a clearly defined organizational structure to implement the IMP. Pipeline integrity management shall be carried out by personnel with clearly defined roles, responsibilities, authority and accountability in implementing and reviewing the IMP.

Where applicable, the organizational structure shall identify the linkages to other related management system programs, such as the safety and environmental programs.

The organizational structure should also take into account both upstream and downstream system inputs/outputs to ensure no changes in one system can have a negative effect on an adjacent system not within the control of the operator.

4.4.4 Records and document control plan

The IMP shall be documented and effectively updated. Program items to be documented shall include the following:

— documents and records needed by the operator to ensure the effective operation and control of its processes;

— statements of integrity management policy and objectives;

— procedures required by the implementation of integrity management.

A records and documents control plan shall be developed to facilitate the storing and retrieving of records and documents in a timely manner. The plan shall include means to confirm accuracy and quality of inputs.

4.4.5 Communication plan

A plan for reporting and communication to all stakeholders, including but not limited to employees, management, authorities, customers, public, local officials and responders, shall be established and maintained.

4.4.6 Management of change plan

A systematic process shall be used to ensure that, prior to implementation, changes to the pipeline system product being shipped, design, operation or maintenance are documented and evaluated for their potential risk impacts, and to ensure that changes are documented and evaluated.

4.4.7 Management review and audit plan

Management review and audit of the pipeline IMP shall be conducted at regular intervals to determine the adequacy, implementation and effectiveness of the integrity program. The focus of management reviews and audits shall be on evaluating the following:

— effectiveness and adequacy of the IMP to meet its stated goals and targets;

— implementation of the IMP;

— conformity to regulatory and operator's requirements;

— identification of corrective actions for continual improvement.

4.4.8 Training and skill plan

The IMP shall establish clear skill requirements for all roles involved in pipeline integrity management, including operators, contractors, engineers, and other persons using this document.

Training needs shall be identified and training shall be provided for relevant personnel in relation to management of pipeline integrity.

5 Integrity management for the pipeline lifecycle phases

5.1 General

5.1.1 Objectives

Pipeline system design (including material procurement and selection) and installation (including installation testing and commissioning) along with operations and maintenance activities have an impact on pipeline integrity.

Although these activities follow recognized standards, it is important to realize that conformity to a minimum standard might not identify potential long-term integrity issues. Therefore, it is important to review pipeline risks at handover from each pipeline phase and throughout the integrity lifecycle.

Designers, procurers, constructors, operators and maintenance personnel and integrity management practitioners shall be aware of 5.3, that highlight the interrelation between the pipeline lifecycle phases (which entails includes components such as design, procurement, installation, commissioning, operation and maintenance) and integrity. 5.3 identifies areas where changes in each of the pipeline lifecycle phases could be needed to aid in long-term integrity management.

5.1.2 Principles

The following high-level principles shall be considered during each of the pipeline lifecycle phases:

a) Risk-based approaches to integrity management shall be applied. Clause 6 provides guidance on risk assessment methodologies.

b) Functional requirements for integrity management shall be incorporated into each lifecycle phase.

c) The concepts and requirements of IMP shall be regarded as the basis for long-term asset management.

d) Any deviations shall be reviewed to evaluate impacts on integrity.

e) Pipeline segments shall be designed according to ISO 13623, or a similar standard, to accommodate in-line inspection (ILI) tools. Where ILI accommodation is not practical, e.g. short service life, short connections or off-takes, the operator shall identify an appropriate alternative integrity assessment method.

f) Data is regarded as the foundation of a pipeline integrity management and the operator shall have a comprehensive plan for collecting, managing, retrieving and analysing all data sets.

5.2 Key lifecycle integrity processes

Integrity assessment is an ongoing process that utilizes data from the various pipeline lifecycle phases to enable the operator to determine the integrity or soundness of the pipeline for its continued operation or design purpose.

The integrity assessment process for new pipelines utilizes construction inspection data and for operating pipelines utilizes data from pipeline condition monitoring activities, such as seabed movement monitoring, ILI, and pressure test to identify threats. The potential consequence and likelihood of identified threats are further evaluated using the appropriate method to determine fitness for purpose that includes a notional factor of safety. The operator shall determine the appropriate integrity assessment methods based on the threat and the capabilities and limitations of the integrity assessment method.

An integrity assessment can be conducted to evaluate the risk, and the interval for the next integrity assessment shall be determined based on the findings.

For pipelines already in operation, an integrity assessment shall be completed within 3 years if no previous integrity assessment has been performed.

5.3 Lifecycle phases for integrity management

5.3.1 General

Integrity management occurs throughout the whole lifecycle of an asset from the initial feasibility studies through to abandonment and heavily influences the design considerations and the ongoing maintenance/management techniques.

All threats to the integrity of the asset shall be identified and controlled throughout the lifecycle; therefore, the elimination of the threats by improvements in design can provide a significant advantage to the on-going safe and reliable operations of the pipeline.

Each of the lifecycle phases has opportunities to mitigate or control integrity threats and each life cycle phase shall be adequately designed and controlled to optimise the integrity oversight.

The personnel responsible for each lifecycle phase should be familiar with basic pipeline integrity issues and concepts. In addition, a process shall be developed where the pipeline integrity subject matter experts will review each lifecycle phase to determine if there are potential pipeline integrity issues that need resolution.

5.3.2 Feasibility

5.3.2.1 Objectives

At the feasibility phase of the integrity management lifecycle, the key integrity risks are associated with the physical attributes of the route. Proactive avoidance of threats is a critical design objective, and action at this phase in the lifecycle can provide significant benefits during construction. This could reduce the level of future mitigation being applied throughout the pipeline lifecycle leading to improved reliability and reduced operating cost.

5.3.2.2 Principles

At this phase in pipeline development, the basic route selection is often a straight line between supply and delivery points. Modifying the route would typically increase the overall pipeline length, but reduced operation and maintenance costs can warrant the increased installation cost.

Optimized routing can take into account many of the key potential threats by avoiding obvious difficulties during installation. Improved routing at landfalls shall determine: seabed geology and topography specific to landfall and costal environment, environmental conditions caused by adjacent coastal features. Other considerations at this phase include access to the pipeline for pressure test activities and pipeline drying. In addition, areas of critical consequences associated with safety of the public or damage to the environment would be avoided.

Realistic route selection at this phase will improve the cost estimates for the proposal enabling more realistic evaluation of the project costs.

5.3.3 Design

5.3.3.1 Objectives

At the design phase, all of the integrity threats that the pipeline system will be exposed to during its lifetime are anticipated. The operator shall also anticipate future sea area/landfall use activities and encroachment that can lead to elevated consequences and a change in the original risk profile or have a direct impact on pipeline integrity, due to third party damage. In addition, the pipeline designer should consider designing the pipeline to enable condition monitoring of the pipe wall, using applicable inspection technologies, such as ILI.

5.3.3.2 Principles

At the design phase, CCAs analysis shall be implemented. Routing selection shall be optimized to avoid CCAs where practical. To confirm that suitable physical and procedural protective methods have been implemented, pipeline segments, especially CCAs, shall be validated including consideration of future changes to the environment, e.g. future projects or possible field congestion.

Where special construction methods or processes are utilized, they shall be assessed to determine any impact on future integrity and necessary mitigation that might be required.

5.3.4 Procurement

5.3.4.1 Objectives

At the procurement phase of the integrity management lifecycle, the key integrity risks are associated with meeting the quality and functionality of the materials detailed by the designer. Proactive avoidance of inappropriate or defective material at this phase in the lifecycle can reduce the risks associated with failure during testing and operation.

In the operating phase poor procurement decisions can lead to substandard equipment reducing functionality or safety and can be significant to the economic performance of the assets.

5.3.4.2 Principles

At this phase in the lifecycle, the quality of the final asset can be directly related to the material supplied. During design, specific materials will have been selected for the required operation envelope and might have been specified to deal with the risk from identified threats. Failure to obtain the desired material quality during procurement could lead to substandard materials being installed which could introduce integrity threats to the pipeline.

Data management during procurement is essential to facilitate verification of the material received and its source and specification to ensure they meet design specifications. These records shall be maintained throughout the life of the asset.

5.3.5 Fabrication

5.3.5.1 Objectives

At the fabrication phase of the integrity management lifecycle, the key integrity risks are associated with poor quality in the fabrication processes and not meeting design specifications.

5.3.5.2 Principles

At this phase in the lifecycle, the quality of the final asset can directly relate to the fabricated items and its dimensional tolerances. Where fabricated items are incorrectly built, this could lead to long-term operational and integrity threats.

5.3.6 Transportation and storage

5.3.6.1 Objectives

At the transportation and storage phase of the integrity management lifecycle, the key integrity risks are associated with pipeline components suffering damage and no longer being suitable for construction or fit for purpose.

5.3.6.2 Principles

At this phase in the lifecycle, the quality of the final asset can be directly impacted by the transportation and storage of each of the pipeline system components such as pipe, coating and fittings. Care is required during handling and storage techniques shall be suitable for the items being handled to ensure that they do not sustain impact and are correctly stored to protect against environmental damage. Appropriate handling techniques shall be designed specified and used with correctly designed storage facilities. Any delays that can impact pipeline integrity during transportation and storage shall be reviewed and their potential impact on the pipeline materials assessed and mitigated.

5.3.7 Integrity during installation

5.3.7.1 Objectives

At the installation phase of the integrity management lifecycle, the key integrity risks are associated with failing to build the asset to the specification laid down by the designer.

5.3.7.2 Principles

At this phase in the lifecycle, the quality control of the installation works and records management are the key aspects for management activities. Failing to build the asset to the design specifications and standards for valid reasons shall be managed and assessed on a case-by-case basis. Installation re-works and even the repair of major defects developed during installation can significantly increase both the time line and costs for installation.

In all cases management of change will be required to confirm the suitability of any design changes and can require adjustment to the arrangements for ongoing integrity and reliability Risk assessments shall be carried out to identify any necessary mitigation adjustments to the integrity management planning.

As-built documentation shall reflect the exact details of the final build to ensure that integrity issues in future years can be investigated without requiring inspection. In the event of any change in the route during the installation phase, CCAs shall be re-identified and re-assessed for the design optimization. Relevant information shall be updated from time to time in the event of any change to pipeline segmentation identified during the installation phase.

5.3.8 Pre-commissioning and commissioning

5.3.8.1 Objectives

At the pre-commissioning and commissioning phases of the integrity management lifecycle, the key integrity risks are associated with failing to design and implement appropriate procedures during the pressure test which might lead to insufficient testing or in an extreme case damage to the pipeline and/or its coating from excessive strain. Additional integrity issues might arise due to incomplete cleaning, drying, purging, or preservation prior to start-up.

5.3.8.2 Principles

The pre-commissioning and commissioning phases require an appropriate checking and proving procedure. Significant damage can be caused to the asset from incorrect testing and the personnel shall be aware and conform to the detailed requirements.

Pressure testing has the potential to impact safety and the environment, therefore a pressure testing plan shall be developed and a risk assessment shall be completed. The risk assessment shall examine the potential consequences associated with a pressure test such as worker safety and failures. In addition, contingency plans shall be put into place in the event of a pipeline failure during the pressure testing.

Gauging is an important check to verify the geometric condition of the pipeline. It can be used to detect dents and other deformations in pipeline.

Data records and retention of the records of the pressure testing are critical requirements that demonstrate initial safety of the pipeline and provides a degree of ongoing proof of ongoing safety, particularly where future changes to operating pressure are being considered and pipeline defects are being assessed.

Following pressure test the pipeline shall be protected from all threats regardless of whether it has been fully pressurised.

5.3.9 Handover — Preparation for operation

5.3.9.1 Objectives

At the handover phase of the integrity management lifecycle, the pipeline systems are implemented to ensure that key integrity threat mitigation is adequate and records are retained.

5.3.9.2 Principles

Operation personnel and integrity management practitioners shall be informed of any mitigation aspects built into the design of the pipeline including the interrelation between any particular integrity aspects built into the operational activities and the resultant integrity control.

The following principles shall be considered:

— All data collected from the design, fabrication, installation, and commissioning phases shall be gathered, maintained and updated throughout the lifecycle of the pipeline. The constructor shall provide full design, installation and "as-built" documentation in a format to suit the operator.

— Installation design requirements to ensure pipeline integrity shall be incorporated into the pipeline operating procedures and shall be maintained.

— At this phase operators shall review all records for completeness and data quality and shall ensure the necessary records are preserved for the life of the asset. Storage methods shall utilise electronic systems where possible, while taking into consideration the impact of future changes to computer operating systems and programs.

— Designed threat mitigation shall be reviewed to ensure that the pipeline risks have been adequately considered and all necessary threat mitigation implemented. Assumptions regarding pipeline segments within the critical consequence areas shall be validated and confirmed prior to the commissioning. If changes or variances are identified, the risk assessment and treatment of the CCA shall be updated and this might include commissioning plans that consider CCAs and safety during the commissioning phase.

— The operator shall review/determine the planned maintenance requirements for new pipeline assets and schedule the maintenance into a documented maintenance system.

— Where geology information system is being used, the data shall be uploaded within a suitable timeframe to enable integrity management practices to commence.

5.3.10 Operation and maintenance

5.3.10.1 Objectives

Pipeline system operation and maintenance activities can directly impact pipeline integrity. Thus, all activities executed on or in the vicinity of a pipeline, either by third-party companies or the operator itself, shall be adequately designed and controlled throughout operation to ensure that integrity is not compromised.

Integrity management during operation shall primarily be pro-active to prevent damage and failure incidents. The operator shall put in place an adequate organization to gather all relevant changes from the original data used for the first integrity assessment. Potential issues shall be identified to enable consideration of any necessary mitigation activities for every risk and threat during the operational period.

5.3.10.2 Principles

The following principles shall be considered for pipeline operation and maintenance.

— The operator shall be adequately resourced to monitor operational conditions to detect and assess any relevant changes impacting integrity on an ongoing process.

— Relevant changes in operation (pressure cycles, etc.) shall be assessed to identify any specific integrity threats.

— The impact of any deviation from operating procedures shall be recorded and assessed to identify any immediate or long-term implications to pipeline integrity.

— The operator shall collect sufficient data to perform threat analysis, consequence analysis and risk assessments. Implementation of the IMP will drive the collection and prioritization of additional data elements required to more fully understand and prevent/mitigate pipeline threats.

— Any threats to integrity and issues identified during operation shall be recorded and used to consider whether additional mitigation activities are required.

— Any change to the operating environment of the pipeline including sea area/landfall use shall be assessed and mitigated as necessary.

— Any incident during the operational period shall be recorded and mitigation against further instances shall be considered and implemented as necessary.

— The performance/efficiency of the IMP shall be reviewed periodically using key performance indicators (KPI).

5.3.11 Modifications during operations

5.3.11.1 Objectives

During operations, pipelines might be modified for various reasons. These modifications might employ different processes design specification and standards from the original design. For example, the modifications can use different material grades and thickness, installation and joining techniques and, coating. Modifications also include changes to the original design basis or production or operating parameters such as production fluid, flow rate, pressure, or temperature. These modifications shall be evaluated and shall be managed, relevant to integrity, in accordance with procedures applied to a new construction.

5.3.11.2 Principles

Modified pipelines shall be designed appropriately utilizing similar processes to a new pipeline to ensure that any adverse change to threat levels are eliminated or avoided where possible. New or changed threats and/or consequences shall be documented and mitigated.

Pipeline as-built drawings and abandonment details shall be stored and maintained in association with the original records and all existing drawings and drawing systems updated as necessary.

5.3.12 Abandonment

5.3.12.1 Objectives

When a pipeline is abandoned in place and not removed, the abandoned sections shall be appropriately decommissioned, such that, they are left in a condition that is safe for the public and the environment.

5.3.12.2 Principles

When pipeline is abandoned in place and not removed, the following shall be considered:

— internal cleaning;

— local ambient regulation;

— maintaining signage.

6 Risk assessment

6.1 Definition of objectives and requirements

6.1.1 General

Risk assessment shall be applied throughout the entire pipeline lifecycle to identify and quantify risk to enable identification and prioritization of mitigation activities. There are several approaches to pipeline risk assessment that range from a qualitative to a quantitative risk approach. The operator can choose any model that supports its objectives and meets regulatory requirements, while still meeting a minimum level of technical justification. The approach should be selected according to data sufficiency and objectives of the assessment. Annex A shows an example of a semi-quantitative approach.

The outcome of a risk assessment should be presented in terms of likelihood and consequence, the categories for which shall be defined in quantitative terms where possible. An example of likelihood and consequence is shown in in Annex B.

If the pipeline system information is insufficient or very limited, conservative assumptions on the system conditions shall be taken into account.

6.1.2 Objectives

The objectives of a risk assessment for an IMP should include:

a) identification of the threats to pipeline integrity;

b) determination of the probability (likelihood) of failure (PoF) for each plausible threat;

c) determination of the consequence of failure (CoF) for each plausible threat;

d) determination of the risk represented by PoF and CoF;

e) prioritization of segments of a pipeline system in the order of risk level (risk register);

f) risk reduction through mitigation (see Clause 9);

A typical risk assessment process follows the flowchart in Figure 3.

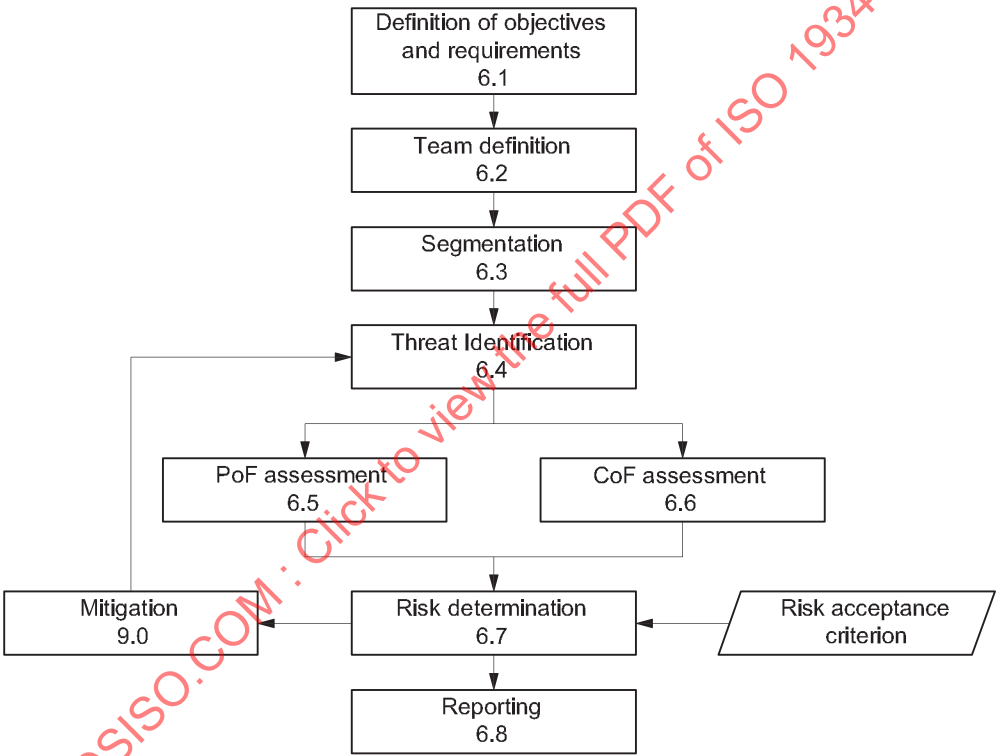


Figure 3 — Risk assessment process

6.1.3 Requirements

The risk assessment approach shall conform to ISO 31000 and IEC 31010 and should consider the following parameters.

a) Assessment parameters - The risk assessment defines ‘failure’ and produces verifiable estimates of failure potential. The probability of failure is the likelihood of the full failure potential occurring, not just that of an event occurring. Therefore, the risk assessment produces related measures of probability of failure and potential consequence.

b) Integrate pipeline knowledge - All plausible failure modes and mechanisms are to be included in the assessment of the probability of failure. The risk assessment integrates all available risk knowledge from each of the lifecycle phases, but especially lessons learned from operation and maintenance and any issues discussed and/or resolved under management of change.

c) Quantify data uncertainty - It is important to know the level of uncertainty of all input parameters. It is acceptable to use data with high uncertainty; however the risk assessment methodology should mitigate this uncertainty and show its effect on the final risk results. Black-box models should be avoided where possible to ensure a good understanding of the mechanism behind the results.

d) Fully characterize consequences of failure - The risk assessment identifies and acknowledges the full range of plausible failure scenarios. The consequences of all scenarios, no matter how unlikely, should be quantified. Any interaction or overlap of threats should be taken into account.

e) Produce risk profiles - The risk assessment should produce a continuous profile of risk levels along the pipeline. The risk assessment shall incorporate sufficient granularity by dividing the pipeline into segments where risks are unchanged (e.g. all risk levels are essentially the same within each segment).

f) Control the bias - The risk assessment shall generate transparent results. The assessment shall be free of inappropriate bias that might lead to incorrect conclusions.

g) Appropriate aggregation - Summaries of the risks presented by multiple segments is desirable. Guidance of segmentation can be found in 6.3. Aggregation of risk shall be utilized to avoid simple statistics that can mask the real risks presented by the segments.

6.2 Team definition

Risk assessments shall be carried out by a group that includes competent and experienced representatives of those responsible for operating, maintaining and managing the pipeline system. They shall have adequate knowledge of the system to be able to determine accurate PoF and CoF and to be able to define practicable mitigation measures. It is important to involve those who will be responsible for the various disciplines during operations, (or alternatively the relevant technical authorities), in the design risk assessment cycle, to ensure that they agree with the assessment of risk, and the practicality and effectiveness of proposed operational mitigations.

6.3 Segmentation

The segmentation of a pipeline allows for a clear understanding of the presence of threats in order to identify the likely damage processes and to establish the most likely consequence scenarios.

The pipeline system shall be divided into segments based on pipeline characteristics and the characteristics of the sea area through which the pipeline passes. The choice of segments shall be such that PoF and CoF can be considered to be uniform within each segment.

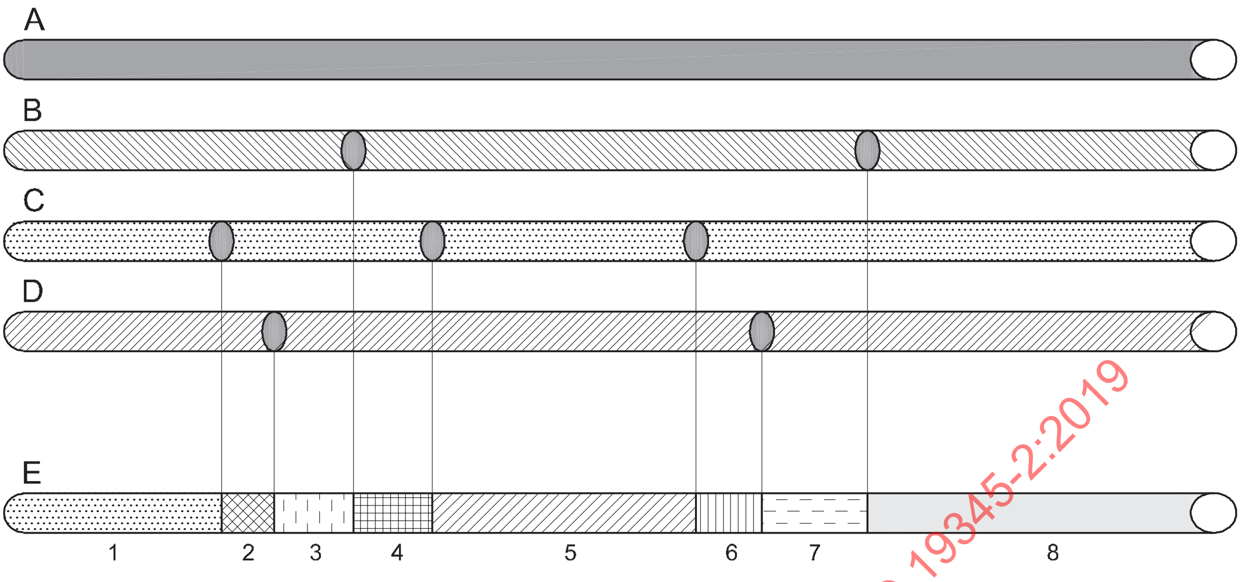
Along the length of each segment, the following items shall be uniform, e.g.:

a) pipeline properties, e.g. diameter, wall thickness, coating type;

b) third-party threats;

c) most likely consequence scenario.

An example of segmentation for a pipeline system is shown in Figure 4.



Key

A	diameter	D	third-party thread
B	wall thickness	E	pipeline segment
C	coating type	1 to 8	pipeline segment No.

Figure 4 — Example of pipeline segmentation

6.4 Threat identification

Threats to the integrity of the pipeline shall be regularly identified throughout the service life of the pipeline. In addition, threats shall be determined based on an analysis performed at each lifecycle phase. Identification of potential or known threats for each lifecycle phase can be based on data obtained through a pipeline lifecycle quality assurance process that utilizes quality control data such as design and data reviews and inspections conducted throughout the lifecycle. In addition, potential or known threats can be identified based on an analysis of industry-wide pipeline failure history and operation of similar pipeline systems. Processes such as hazard identification (HAZID) study and failure tree analysis (FTA) can also be used as an input to the threat identification.

The following list illustrates typical pipeline lifecycle phases:

a) feasibility;

b) design;

c) procurement;

d) construction;

e) transportation and storage;

f) installation;

g) pre-commissioning and commissioning;

h) handover;

i) operation and maintenance;

j) modifications;

k) decommissioning/suspension/abandonment.

Table C.1 in Annex C provides an example of threat categorization and associated causes of occurrence during each phase of the pipeline lifecycle.

6.5 Probability of failure assessment

The probability of failure (PoF) shall be estimated for all plausible threats identified for each segment. If more than one failure mode is plausible for a given threat, the PoF shall be estimated for each failure mode.

The PoF can be estimated using industry-wide or company failure statistics, or by using a probabilistic analysis. The effects of existing mitigation measures shall be taken into account in the estimation of the PoF.

Where historical data are used for frequency analysis or for validation of frequency analysis conducted by other methods, the suitability of the data and its compatibility with the characteristics of the pipeline system being analyzed, shall be considered.

In assessing the threat, the mechanism of the threat shall be considered. For example, the threat of "corrosion" can result from localized pitting or from uniform metal loss over a large area. Both will lead to different failure modes.

Interaction of threats and of the associated damage mechanisms shall be considered and taken into account in the PoF assessment.

The PoF can be expressed qualitatively or quantitatively. It can be expressed quantitatively on a collective basis (e.g. failures per year) or on a linear basis (e.g. failures per kilometre-year).

6.6 Consequence of failure assessment

6.6.1 Consequence assessment

The consequence of failure can be expressed in categories such as:

— offshore platform proximity, activity levels;

— impact on the environment (environmentally sensitive area, etc.);

— impact on business (deferred production, reputation, societal effects, operations, repair, etc.).

The consequence assessment for each category shall be carried out by a competent specialist in that area. The consequence of failure shall be determined for each failure mode for each segment.

Estimation of the impact of the loss of containment shall take into account the following:

a) nature of containment, e.g. gas or liquid, ignition, flammability, toxicity, reactivity, dispersion mode;

b) pipeline properties, such as pipeline diameter, wall thickness, type of coating, pressure, etc.;

c) geological and geotechnical features (seabed canyons, landslide);

d) human activity environmentally sensitive areas, such as coral areas, etc.;

e) failure mode, such as leak or rupture;

f) presence of mitigating measures to restrict loss of containment, such as leak detection, use of remote operated isolation valves and emergency response plan;

g) possible consequences following a loss of containment, which can include, for interface with topside installations:

   1) pressure waves following fluid release;

2) combustion/explosion following ignition;

3) toxic effects or asphyxiations.

4) contamination of environment and assets.

Knowledge of the release mechanism and the subsequent behaviour of the released material enable qualitative or quantitative estimates to be made of the effects of the release at any distance from the source for the duration of exposure.

Appropriate methods of consequence analysis vary widely in extent and degree of detail, depending on the type of threat to be analyzed and the objectives of the assessment.

6.6.2 Critical consequence areas analysis

Critical consequence areas for pipeline can be categorized as follows:

— Location class 1: The area where no frequent human activity is anticipated along the pipeline route.

— Location class 2: The part of the pipeline in the near platform (manned) area or in areas with frequent human activity. The extent of location class 2 should be based on appropriate risk analyses. If no such analyses are performed, a minimum distance of 500 m should be adopted.

6.7 Risk determination

For risk assessment, the methodologies listed in IEC 31010 can be used. The probability and consequence shall be matched to the same failure mode. For example, if the consequence level is assigned on the basis of a leak, then the probability should be that of a leak, not merely the probability of the threat (e.g. corrosion) occurring. For quantitative methods, risk can be described by Formulae (1) and (2) for independent failure modes. For dependent failure modes, recourse should be made to more sophisticated models.

a) For a single failure mode:

$$Risk_i = p_i \times C_i \tag{1}$$

b) For multiple failure modes 1 to n:

$$Risk = \sum_{1}^{n} p_i \times C_i \tag{2}$$

where

C is the CoF;

p is the PoF;

1 to n is threat category.

For a semi-quantitative method, the likelihood and consequence for each threat should be plotted on the risk matrix to determine their significance. The matrix should be divided into bands representing increasing levels of overall risk as illustrated in Annex B.

Quantitative risk assessments can be carried out using deterministic and probabilistic approaches.

6.8 Reporting

The risk assessment process shall be documented in a risk assessment report.

The report shall clearly portray the pipeline risk profile at a specified time, or as a function of time. In such reports, estimated risk should be expressed in terms appropriate for the stated objectives and audience, the strength and limitation of different risk measures used should be explained, and the uncertainties surrounding estimated risk should be set out in straightforward language.

The extent of the risk assessment report depends upon the objectives and scope of the assessment; however, the documentation shall include as a minimum the following:

a) objectives and scope;

b) pipeline system description;

c) risk assessment methodology;

d) limitations and assumptions;

e) threat identification results;

f) impact of identified risk

g) PoF analysis results, including assumptions;

h) CoF analysis results, including assumptions;

i) risk evaluation results;

j) sensitivity and uncertainty analysis;

k) discussion of results (including a discussion of analysis problems);

l) conclusions and recommendations;

m) references, including all sources necessary to support any models or analytical techniques applied; and

n) names and qualifications of personnel who participated in the analysis.

6.9 Reassessment

The risk reassessment shall be carried out a regular basis or at specific dates set by the risk assessment group.

Additionally, a risk reassessment shall be carried out in response to:

a) changes in design or operation of the system;

b) changes to the pipeline environment;

c) unexpected results of mitigation measures;

d) acquisition of new information about the system (e.g. the results of an inline inspection run).

NOTE A risk reassessment might be carried out in response to incidents that occur on the pipeline system or relevant incidents or on systems of similar nature.

7 Inspection and monitoring

NOTE This clause is based on DNVGL-RP-F116[23].

7.1 Inspection

7.1.1 General

Inspection and monitoring are condition monitoring activities carried out to collect operational data and other type of information indicating the condition of a component. Operational data can be physical data, such as pressure, fluid, temperature, injection volume of chemicals, or number of operating cycles.

Generally, an inspection physically monitors the state of a component directly (e.g. wall thickness, damage to the pipeline, coating defect, pipeline displacement), whilst monitoring is the collection of relevant process parameters which indirectly can give information regarding the condition of a component.

Inspection planning, tool selection, capabilities and qualification of personnel might be dependent on regulatory requirements. If no regulatory requirement is available, the following standards can be used as references:

— API Std 1163;

— ASNT ILI-PQ;

— NACE SP0102;

— NACE 35100.

The inspection plan should be updated on a regular basis and be based on preceding plans and the results achieved from the integrity control activities.

Unexpected events can initiate the need for unplanned control activities. To what extent, how and when to carry out this control activity, should be handled through the risk assessment and IM planning activity. This is to ensure coordination with other prospective control activities and to evaluate the need for modification of the original strategies.

Any (clearly) unacceptable situation, mechanical damage or other abnormalities detected (discovered) during the planned control activities, should immediately be reported and subjected for review and the appropriate actions defined and initiated. The purpose for an inspection shall be clearly defined prior to inspection.

The main activities associated with the inspection are:

a) detailed planning, for internal or external inspection, including the following:

 1) detailed description of the scope of work;

 2) specification of reporting criteria;

 3) development of work packages;

 4) preparation of work instructions and procedures;

 5) establishment of responsibilities and communication lines between inspection contractor and operator;

 6) procurement of equipment;

 7) establishment of plans for the mobilisation of equipment and personnel;

 8) carrying out risk management activities for the inspection activity.

b) execution of the inspection, including the following:

 1) mobilisation of personnel and equipment and transportation to the site;

2) carrying out safety activities;

3) de-mobilisation;

4) preliminary reporting towards the specified reporting criteria.

c) documentation and final reporting of the inspection, including:

1) quality control of the inspection results;

2) issue of final inspection report.

d) assessment of the data collected during inspection.

7.1.2 Preparation for inspection

The detailed work description should be prepared prior to inspection and should include the following:

a) description of the pipeline system, including any special information important for the inspection/survey;

b) purpose of the inspection including description of relevant threats and types of damage as well as criteria;

c) specification of required equipment;

d) detailed description of the equipment and inspection tools;

e) requirements for calibration of the equipment;

f) qualification of personnel;

g) detailed instructions for the inspection including operation procedures;

h) requirements for documentation of inspection results and/or findings;

i) preparation of an outline of the inspection report.

7.1.3 Requirements of equipment

The long-term inspection program specifies the purpose of the inspection, the type of inspection to be carried out and where to be carried out. It can, for example, specify intelligent pigging using MFL or external remote operated vehicle. Further specification of the required equipment shall be addressed when planning a specific inspection in detail. This should be done as part of the detail planning. The accuracy of the selected methodology should be considered.

The following information will typically be required when preparing for an in-line inspection:

a) what to inspect for (wall thickness loss, cracks, dents);

b) internal or external corrosion attacks;

c) inner diameter for the entire system;

d) pipeline length, pipeline wall thickness;

e) pipeline material, internal cladding or lining, if applicable;

f) elevation profile;

g) data (as location, dimensions) on bends, tees, wyes, valves, etc.;

h) pipeline content, pressure, temperature, fluid velocity.

The following information will typically be required when preparing for an external survey:

— what to inspect for:

1) the CP system - looking for abnormal anode consumption and/or passive anodes;

2) indication of inadequate coverage or potential from the CP system leading to excessive corrosion;

3) damages or cracks in coating or concrete, general damage to structures and pipelines from impact (dropped object, equipment handling, anchor impact or dragging, fishing, etc.);

4) burial depth, free spans;

5) flanges and hubs - looking for leaks;

6) pipelines - looking for upheaval buckling, lateral buckling, expansion, displacements, structure movements (displacements and rotations);

7) abnormal/unexpected pipeline system behaviour as oscillation/vibration (including jumpers and spools);

8) settling or manifolds resulting in an increased stress level for the pipeline;

9) pipeline support and crossings - ensuring that rock-dumps are intact and that the pipeline remains positioned within the intended support area, gap between crossed pipelines.

— pipeline configuration;

— water depth;

— pipeline components.

7.1.4 Reporting requirements

7.1.4.1 General

Operator and inspection vendor shall reach an agreement on the requirements and specifications of the inspection report in advance. If a number of technologies (e.g. magnetic flux leakage and ultrasonic testing tools) are adopted for the inspection project or multiple functions are integrated in an inspection tool (e.g. integrated technology tools of magnetic flux leakage, calliper and mapping), the pipeline information obtained by inspection tools of different types should be integrated in the same report which includes the different anomalies (defects).

The following requirements and recommendations apply:

a) Reporting of inspection results should aim at being in a standardised format to ease the assessment work and to better allow for trending of inspection data as free span measurements, corrosion rate, cover heights, etc.

b) The report format, including all reporting titles, list of characteristics and data specification, shall be specified. All characteristics and weld numbers specified in the contract and integrated reports shall conform to the agreed format.

c) For anomalies in girth welds and spiral welds, the pipe wall thickness shall be provided.

d) The inspection data software version shall be provided and clearly defined. Any updated software version shall be compatible with previous data formats. The final inspection report, pipeline list and data interpretation software report shall conform to the agreed format.

7.1.4.2 Delivery requirements

7.1.4.2.1 Field report

After completion of the field inspection, within agreed time frame, the inspection service provider shall provide an initial report notifying the operator if the inspection was successful. The field report shall include, but is not limited to:

a) data sampling frequency or interval;

b) inspection threshold;

c) report threshold; if report threshold is unspecified features of POD = 90 % shall be adopted;

d) speed curve, pressure curve and temperature curve of inspection tool operation;

e) count of damaged sensors;

f) statistics of return loss if an ultrasonic testing tool is run;

7.1.4.2.2 Preliminary report

After completion of field inspection, the inspection service provider shall submit a preliminary report within the agreed to timeframe. The initial report shall cover all items agreed to in the contract. For example features of metal loss with peak depth exceeding 70 % of pipe thickness; features of metal loss for the five most serious places, or if estimated pipeline parameter data relating to a pressure assessment of features of metal loss was available in preparation of the preliminary assessment report, features of metal loss of exceed a predetermined estimated repair factor (ERF) shall be provided.

7.1.4.2.3 Final report

After completion of the field inspection the inspection service provider shall submit a final report within the agreed timeframe.

The final report typically includes the following:

a) overview of inspection project, including pipeline defects;

b) performance index of inspection technology;

c) inspection time;

d) operating data of inspection tools;

e) pipeline list;

f) list of anomalies;

g) defect statistics and summaries;

h) defect assessment method;

7.1.4.2.4 Supplement report for other type of anomalies

If there are additional requirements which were agreed to in the contract, such as immediate reporting of evidence of leakage, or severe damage, the inspection service provider shall additional supplement analysis reports on other features, (such as evidence of leakage or severe damage, spiral welds anomalies and girth weld anomalies), these shall be submitted within the agreed time frame.

7.1.4.2.5 Software

Software capabilities shall include but not be limited to the following functions:

a) signal data review;

b) presenting absolute and relative distance of characteristics;

c) presenting clock orientation of characteristics;

d) measuring axial and girth distance between any two points in a pipeline;

e) generating clock orientation of interaction between spiral welds/longitudinal welds and girth welds;

f) generating a repair list.

7.1.5 Review of inspection results

Acceptance of inspection data shall be based on two primary principles: data completeness and data quality; which describe the nature and quality of the collected data, as expected for using in integrity management processes.

In addition to the report from the inspection contractors, which might include an assessment of the results, the operator should carry out and document a high level evaluation of the inspection and the results. This evaluation should address:

— if the inspection has been done according to the plan, which describes what, how and when to inspect;

— the quality of the inspection (e.g. confidence in results);

— a high level evaluation of the inspection results with respect to the integrity (e.g. classified as insignificant, moderate, significant, severe findings);

— recommendations for further assessment of the findings (e.g. remaining life calculations).

7.2 Monitoring

7.2.1 Main monitoring activities

Monitoring is the measurement and collection of data that indirectly can give information on the condition of a component or a system.

The monitoring data are typically either online measurements or offline measurements (scheduled). Monitoring plans and schedules should be founded on risk assessments based on current flow and expected fluctuations under different production scenarios.

Monitoring should include the following main activities:

a) description of the purpose of the monitoring;

b) data acquisition and storage;

c) retrieval and analysis of data;

d) documentation and reporting, including comparison against acceptance criteria.

7.2.2 Identification and follow-up of available technology

The operator should determine and follow-up the available and relevant monitoring technology.

The techniques for condition monitoring can be either on-line or offline. Online monitoring represents continuous and/or real-time measurements of parameters of interest. Offline monitoring would typically be scheduled sampling with subsequent analysis at, for instance, a laboratory.

Monitoring can be performed by (locally) direct and indirect techniques. With regard to corrosion, direct techniques typically measure the corrosion attack or metal loss at a certain location in the pipeline system utilising corrosion probes, whilst indirect techniques measure parameters that affect the corrosion (e.g. O_2 content).

Monitoring is further classified as intrusive or non-intrusive. An intrusive method will require access through the pipe wall for measurements to be made, whilst a non-intrusive technique is performed externally (will not require access through the wall thickness) or analysis of sample data taken from the process stream.

Monitoring techniques are related to the monitoring of following:

— chemical composition (e.g. CO_2, H_2S, water);

— process parameters (e.g. pressure, temperature, flow velocity);

— external or internal corrosion;

— internal erosion (e.g. sand);

— currents;

— waves;

— vibrations;

— oscillations (due to, e.g. slugging);

— strains;

— pipe displacements;

— ship traffic and fishing activity;

— seabed movement;

— leak detection.

7.2.3 Current and vibration monitoring

Seawater currents near the seabed can be monitored to control the likelihood of scouring or pipeline movement, while vibration monitoring systems can be installed in connection with free spans to monitor vortex induced vibrations (VIV) or vibrations caused by currents.

Vibration monitoring systems are typically clamp sensor packages that are attached to the pipeline at regular intervals to record vibrations in three axial dimensions.

7.2.4 Monitoring of ship traffic and fishing activities

The tracking data of the locations and movements of ships and fishing vessels should be requested for vulnerable parts of the pipeline (e.g. not designed for over trawl ability, high risk areas) confirmation.

7.2.5 Leak detection

Leak detection in the form of flow monitoring or external leak detection systems is essential in order to detect any leaks at an early stage. Industry practice shows that mass/flow monitoring and pressure drop-monitoring are the most commonly used methods for detecting leaks (or rupture) from a pipeline while external devices as point sensors are more commonly used for subsea equipment such as templates and manifolds to measure leaks from, for example, valves.

7.2.6 Review of monitoring data

The results from monitoring activities should be evaluated at least on annual basis. More frequent review can be appropriate in the early operational phase. The review should at least consider:

a) that all planned monitoring activities have been done and in accordance with specifications;

b) that the monitoring data are within the design envelope, and if not, ensure that deviations have been handled according to relevant procedures;

c) a high level evaluation of the monitoring results with possible impact on the integrity assessment recommendations for further assessment as required.

8 Integrity assessment

8.1 General

Integrity assessment methods include fitness for purpose assessments to assess the suitability of the pipeline for service. Assessment can be carried out on anomaly data obtained through inspections, e.g. ILI data, pressure testing, external survey or from the direct measurement of a defects dimensions during direct examination.

The process evaluates whether:

a) there is sufficient structural integrity to withstand all forces to which it can be subjected to during current and future service;

b) the pipeline is able to operate within prescribed safety margins.

8.2 Fitness for purpose

8.2.1 Assessment data collection

Collected data required for integrity assessment shall include but not be limited to: pipeline properties, defect parameters, mechanical performance, load parameters, installation data, and operating data, historical data.

8.2.2 Defect data statistics and causation analysis

Analysis shall be conducted on defect data from various inspections to identify the probable cause of any defects including the defect type, location on the pipe, distribution along the length of the pipe, coating type and external influences, such as topography, soil type and other relevant attributes identified from the inspection or similar evaluation results. Such analysis should include but is not limited to:

a) statistical analysis on overall defect populations;

b) statistical analysis on specific defects;

c) distribution statistics and causation analysis; and

d) statistical analysis of changes between two or more time periods.

The output from the analysis should be considered in the risk assessment.

8.2.3 Assessment method selection

The defect assessment methods shall be selected taking into consideration the following variables: defect type and characteristics, load type, service fluid type, pipe material properties, limitations and confidence level of the methodology.

Commonly used assessment methods for the various types of defects are given in Table 1. There can be other proprietary methods not listed in Table 1 and it is not the intent of this document to prevent the use of other methods. However, before using other methods the operator shall verify the suitability and accuracy of the chosen method for each specific defect type assessment.

Table 1 — Assessment standards for defect types

Types of defects	Recommended criteria
Corrosion (internal, external)	ASME B31G API RP 579-1 BS 7910 DNVGL-RP-F101
Gouges	API RP 579-1 BS 7910
Manufacturing defects	API RP 579-1 BS 7910
Dents	API 1156 API RP 1160 API RP 579-1 ASME B31.4 ASME B31.8 AS 2885.3 CSA Z662
Girth weld defects	API RP 579-1 BS 7910
Seam welding defects	API RP 579-1 BS 7910
Spiral weld defects	API RP 579-1 BS 7910
Cracks	API RP 579-1 BS 7910
Environmental cracking: stress corrosion cracking (SCC); hydrogen-induced cracking (HIC).	API RP 579-1 BS 7910
Global buckling	DNVGL RP 110
Free span VIV	DNVGL RP-F105

8.2.4 Residual strength and remaining life assessment

8.2.4.1 General

The ability to accurately determine the residual strength and any impact upon remaining life is dependent on the availability and accuracy of data relating to the defect. Where data is limited, the operator shall use conservative assumptions and shall update the assessments once accurate data become available.

Safety factors shall be determined by the operator and applied to all calculations of pipeline strength use for remaining life considerations.

The remaining life of defects shall be predicted based upon the defect growth, failure mode and an applicable safety coefficient. Where the defect strength does not satisfy the proposed service life at MAOP, it shall be scheduled for repair or removed or the MAOP adjusted.

Defect residual strength and predicted remaining life calculations shall consider all of the relevant uncertainty and probability of exceedance associated with variables such as defect sizing, assumed growth rates and operation loads as part of the evaluation.

When conducting remaining life calculations, the defect repair time shall be the time from the initial identification of the defect until the time the defect will be repaired. ILI results will be re-validated with ongoing verification results and if applicable modifications to the defect sizing and predicted growth rate shall be undertaken.

NOTE API Std 1163 provides guidance on ILI verification.

When a defect is found that exceeds the acceptability criteria then immediate mitigation actions, such as reducing the pressure, defect removal or repair, shall be undertaken. The operator shall be able to demonstrate that the mitigation action taken has rendered the defect safe for continued pipeline operation.

8.2.4.2 Acceptance criteria

Acceptance criteria for the different types of defects referenced shall be as stated in 8.2.4.3 to 8.2.4.7, unless otherwise determined by the operator or prescribed by regulations.

8.2.4.3 Acceptability criterion for corrosion

Immediate mitigation is required for corrosion anomalies with calculated failure pressure less than the design safety factor multiplied by MAOP or with depth greater than 80 % of nominal wall thickness.

Scheduled mitigation is required for anomalies to be operated safely at MAOP. Growth calculations will identify anomalies that will become unacceptable at a future time period. Mitigation shall be scheduled according to growth calculation results.

8.2.4.4 Acceptability criterion for manufacturing defects

Manufacturing defects will normally have passed a pressure test and therefore should remain capable of operating throughout the service life at MAOP. Where manufacturing defects are developing in severity they shall be assessed and mitigated as if they were corrosion.

8.2.4.5 Acceptability criterion for cracks

Immediate mitigation is required for cracks with calculated failure pressures less than a design safety factor multiplied by MAOP.

Scheduled mitigation is required for situations where the main crack development mechanism has been identified and assessed to be safe to remain in service. Remaining life assessments shall consider ongoing fatigue and/or growth mechanisms. Mitigation shall be undertaken prior to any future time periods where the defect is assessed to have a calculated failure pressure being less than the design safety factor multiplied by MAOP.

8.2.4.6 Acceptability criterion for dents

Dents can be assessed using standards listed in Table 1 or other acceptable standards. Cracking associated with the dent shall be identified and ground out and the pipe reinforced as necessary. Where repair is not possible, the dent shall be removed.

8.2.4.7 Acceptability criteria for weld defects

Welding defects shall be assessed for their suitability for ongoing service. Where repairs are necessary, suitable temporary mitigation shall be applied until repairs can be completed.

Welding defects that are unsatisfactory and cannot be repaired safely shall be removed from service.

Assessment of planar defects should be considered as cracks, see Table 1.

8.2.4.8 Reporting requirements

A report shall be prepared that specifies the defect type, cause, actual dimensions, pipe and coating conditions and any relevant soil and topography information and the repair actions taken.

8.3 Pressure test

8.3.1 General

A pressure test, also known as hydrostatic testing, is a pipeline integrity assessment method recognized by the oil and gas transportation industry that evaluates a pipeline's capability to safely operate at a determined pressure (such as MAOP); see, e.g. ISO 13623:2017, 6.7. Pressure tests are also used to determine if there are leaks. The pressure test can include spike testing such as described in API RP 1110.

Pressure testing as described in this 8.3 is only for the integrity assessment of in-service pipelines.

Before conducting a pressure test, the operator shall consider performing a risk assessment for both the applicability of assessment methods and procedures and the activities of the pressure test itself. Any remedial actions identified in the risk assessment shall be completed before proceeding with the pressure testing.

The operator shall consider results of risk assessments and severity of known defects to confirm the frequency and scheduling of any pressure test.

If the target pipeline operating pressure is higher than the initial design, then it is a matter of uprating, see 13.5.

Pressure testing shall use water as the testing medium for all pipelines unless the operator can demonstrate that the use of water is not feasible. The use of non-combustible gas for pressure testing can substitute water as long as the associated risks are mitigated, and it conforms to applicable regulations.

8.3.2 Preconditions for use of pressure-testing on an in-service pipeline

Selection of a pressure test to determine the integrity of an in-service pipeline shall include at least one of the following conditions:

a) Pipelines that are required to have pressure-test assessments according to risk and/or integrity assessment.

b) The pipeline has been in operation at a pressure lower than the designed MAOP, and is being considered to be operated at a higher pressure or MAOP.

c) Frequent incidents continue to occur even after a number of other integrity assessment methods for pipelines are performed, including ILI and direct assessment.

d) The medium or process conditions are altered from the design parameters.

e) Pipelines that have been inactive for over a year are returned to service.

f) Pressure testing shall be conducted on any replaced pipe segments.

8.3.3 Features to be considered for pressure test

The test pressure shall be based upon ISO 13623, related risk assessments and operator practices, and shall ensure to follow local regulations.

The followings shall be reviewed when performing a pressure test:

a) The pipeline operating conditions and influences of geography and the impact of pressure testing with water. Such conditions can include impact of the pipeline shutdown, accessibility for repairs and replacements, water disposal, topological geography of the pipeline routing.

b) The planned targeted operating pressure. The test pressure shall be obtained at the high point of the minimum strength test section and shall not be higher than the pressure required producing a hoop stress equal to SMYS as determined by testing. An extensive safety assessment shall be conducted to ensure the pressure testing does not pose a threat to safety.

c) The strength and capability of exposed and unsupported pipelines. These shall be calculated and included in the risk assessment plan (to prevent unplanned permanent deformation).

d) Original design standard and safety factors applied.

8.3.4 Pressure test risks

Pressure testing is an activity with a temporarily increased risk level and particular attention should be paid to the safety of personnel and the public. Risk identification shall be implemented prior to pressure testing by competent personnel. Risks shall be identified and mitigated. Examples of risks associated with pressure testing include:

a) variances in material properties as process parameters can vary;

b) risks of water injection and drainage on future pipeline corrosion;

c) risks of pipeline failure incurred by considerable pipeline leak points;

d) risks of disturbance to entire system during pressure testing;

e) risk of unplanned permanent damage to pipe materials and strain.

8.3.5 Management measures

Risk management of pressure testing is a dynamic process and the operator shall monitor and regularly update the risk assessment and its recommended activities prior to and during the testing.

The operator shall ensure that safety and management controls are in place through the process. These controls shall include preparation of checklists to ensure completion of all works, collection and summary of post-test experiences.

The operator shall formulate a detailed pressure test plan that includes the identified risks. The operator shall also conduct a material property analysis to ensure the pressure test does not impact the materials. Where material properties are unknown, the operator shall conduct tests of the materials to determine their properties. The evaluation shall include calculation of the strength of materials used according to relevant standards and codes and shall be included in the formal documentation of the pressure test.

The operator shall conduct an assessment regarding changes in pipeline stresses caused by the medium replacement and temperature variations; methods such as finite element analysis (FEA) can be used to identify stress changes requiring controlling.

The operator shall prepare emergency response plans in relation to pressure testing to mitigate any safety or environmental consequences associated with pressure testing.

The operator shall ensure personnel are adequately trained and qualified prior to pressure testing. Records of training shall be kept as part of the pressure test activities.

The operator shall ensure that the pressure test plans include reviews of field conditions; accessibility and logistics for temporary facilities as needed for performing pressure tests including capabilities to capture and dispose of testing product.

8.3.6 Monitoring of pressure test procedures

The operator shall ensure that personnel are available to comprehensively monitor for pressure changes caused by pipeline failures, and resulting forensic analysis in cases of pipes rupture during pressure testing. The operator shall ensure surveillance over pressurizing and depressurizing activities at both ends of pipe segments tested.

8.3.7 Review of pressure test results

Relevant personnel of the operator shall review and analyze process data during the pressure test to identify leak points in order to directly acquire and collect integrity data as part of the integrity plan and pressure test records.

The pressure test shall be monitored and recorded over time and form part of formal test documentation.

In the case of any leak points detected, the operator shall perform prompt repair measures including pipe replacement, or weld repair as determined by relevant personnel.

For any pipeline segments that failed, the operator shall perform a failure analysis (see Clause 12) and mitigation shall be conducted to prevent reoccurrence.

8.3.8 Pressure test report

The pressure test assessment report shall include:

a) project information;

b) pressure test plan;

c) records of the pressure;

d) defects and anomalies detected;

e) repair-related information;

f) reassessment period;

g) conclusions.

8.4 Direct assessment

8.4.1 General

Direct assessment is an integrity assessment method utilizing a structured process through which the operator is able to integrate knowledge of the physical characteristics and operating history of a pipeline system or segment with the results of inspection, examination and evaluation, in order to determine the integrity.

Direct assessment is applicable for three types of time-dependent defects: external and internal corrosion, stress corrosion crack (excluding fatigue related threats such as corrosion-fatigue).

In general, direct assessment is applicable for the following conditions:

a) pipelines where ILI or pressure test is not possible;

b) pipelines that require costly renovation as evaluated by other methods; and

c) direct assessment is confirmed to be more effective than ILI or pressure test.

8.4.2 Direct assessment process

Direct assessment usually has a four-element approach:

a) Pre-assessment: It is used for determining feasibility of direct assessment by data collection and analysis, identifying assessment sections and choosing indirect inspection tools.

b) Indirect inspection.

c) Direct examination: Based on analysis of indirect inspection results, choose location and number of examination locations and conduct a direct inspection of the pipeline surface. Such works require inspectors to have sufficient professional knowledge.

d) Post-assessment.

8.4.3 Direct assessment methods

Direct assessment method mainly includes internal corrosion direct assessment (ICDA) for offshore pipelines, etc. Relevant standards are provided for reference in Table 2.

Table 2 — Main types and references of direct assessment

Direct assessment method	Reference
ICDA	NACE SP0206 (dry gas)
	NACE SP0110 (wet gas)
	NACE SP0208 (liquid petroleum)

8.4.4 Limitations of direct assessment

Each direct assessment method is tailored for implementing integrity assessment on one main risk for specific fluid and requires users to follow the applicable standards in their entirely. Direct assessment shall only be conducted by competent personnel knowledgeable in the method. Results of in-line inspection can also be considered when doing direct assessment.

8.5 Other assessment

The operator might consider alternative integrity assessment methods, providing the alternative integrity assessment follows an industry-recognized methodology and is approved and published by an industry standards organization.

IMP techniques other than those published by standards organizations can be utilized. However, when utilizing a new technology, the operator should plan to ensure that it has demonstrated its ability to perform an adequate assessment and provide an equivalent understanding of the pipeline that is comparable to ILI, direct assessment (DA) or pressure testing.

9 Mitigation

NOTE This clause is based on DNVGL-RP-F116[23].

9.1 General

The results of assessments shall be used to determine whether the current prevention or mitigation measures are adequate and if necessary, to specify what additional measures are required to mitigate any unacceptable risks identified by the assessment, including previously unidentified threats.

Prevention and mitigation activities are designed to reduce the risk to an acceptable level by reducing the likelihood and/or the consequence of a failure.

The process of establishing and implementing effective preventive and mitigation measures requires suitable data collection, data integration and informational analysis within the IMP. Data integration and the subsequent analysis can identify additional threats requiring attention. Most importantly, local knowledge of the operational environment and the incident history around the pipeline components is necessary.

Mitigation measures can include a combination of physical design changes (e.g. wall thickness), processes and ongoing inspection, maintenance and repair programmes for pipeline and critical equipment.

In addition to routine maintenance, (e.g. inspection, maintenance and testing of mainline valves) common mitigation measures for different threats are shown in Table 3.

Table 3 — Mitigation measures for different threats

A	B	C1	C2	C3	C4
Feared event (failure mode)	**Root causes (potential): pipe body/ welds/ components**	**Physical phenomenon/ environment**	**List of features**	**How to monitor**	**How to mitigate**
Immediate: flow restriction/ leak/rupture Future: flow restriction/leak/ rupture	Material Process Fluids Environmental factors Third party	Mechanical/ structural damage	Gouges Dents Ovality Spans	ROV/visually ILI NDT Pressure monitoring	Pipe protection (1,3,4,6) Repair techniques (3,4,6) Quality control (3,4,6) Identification (1,4,6,7) Communication (1,4,6,7) Depth of cover (1, 4,6)
		HP/HT phenomena	Buckling Walking	ROV/visually ILI	Reduction in operation parameters (1, ,6) Rectify seabed (1,6) Rock dumping (1,6)
					Possible retrofit of skid and sleepers
		External corrosion related	Coating damage Anode damage	Visually Direct pit gauge measurement ILI Direct assessment CP survey	Anode Material and coating selection Coating application Repair techniques Coating repair Pressure test

Table 3 *(continued)*

A	B	C1	C2	C3	C4
Feared event (failure mode)	**Root causes (potential): pipe body/ welds/ components**	**Physical phenomenon/ environment**	**List of features**	**How to monitor**	**How to mitigate**
		Internal corrosion related	Internal corrosion Erosion	ILI NDT Corrosion product sampling Direct assessment Corrosion monitoring by probes and coupons Sand monitoring Erosion monitoring	Product quality Inhibitors Material and coating selection Coating application Repair techniques Pressure test Operational cleaning/pigging Biocide
		Incorrect operation	Buckling Wrinkle	ROV/visually ILI	Quality control Repair techniques Pressure derating Maintenance program
		Weld/pipe body flaws	Grinding Hydrogen embrittlement Hardspot	ILI NDT Visually	Quality control Repair techniques Pressure test Pressure derating
			Planar		
			Volumetric imperfections		
		Cracks	HIC SCC	Visually ILI	Pipe protection during transportation
			Fatigue cracks SSC Corrosion fatigue Hook crack	NDT	Pressure regulation (cycles frequencies and amplitude) Coating repair Temperature regulation Repair techniques Quality control Pressure test
		Weather related	External corrosion Anode Coating	Visually ILI NDT	Pipe protection

Table 3 *(continued)*

A	B	C1	C2	C3	C4
Feared event (failure mode)	**Root causes (potential): pipe body/ welds/ components**	**Physical phenomenon/ environment**	**List of features**	**How to monitor**	**How to mitigate**
		Geologic hazard	Dents Ovality Strain	Visually ILI NDT	Pipe protection Repair techniques Pressure test

9.2 Internal mitigation methods

The operator should select methods of mitigation that reduce risk through the reduction in the likelihood of failure. Typical methods of mitigation include, but are not limited to the following:

— restrictions in operational parameters, such as MAOP, inlet temperature, flow rate, and number of given amplitudes of these (e.g. shut-downs). Such restrictions can have an impact on the set-point value for the pressure protection system or the pressure regulating system;

— use of chemicals in order to mitigate corrosion rate, flow improvement, reduction of scaling, avoid hydrate formation;

— maintenance pigging with the objective of removing scale, deposits, liquid accumulated in sag bends;

— temporary increased flow rates to flush out local accumulated liquid or particles;

9.3 External mitigation methods

The operator should establish processes and procedures within the integrity management plans regarding the use of intervention methods.

Pipeline external mitigation is typically used to:

— control thermal axial expansion causing lateral or upheaval buckling;

— ensure bottom stability;

— provide protection against third-party damage;

— provide thermal insulation;

— reduce free span length and gaps.

Typical means of intervention are:

a) rock dumping;

b) pipeline protection layers against third-party damage (mattresses, grout bags, protection structures, gravel cover);

c) trenching.

Risk reducing measures for external hazards are provided in Table 4.

Table 4 — Risk reducing measures for external hazards

Measure	Reduce	Comments
Limit lifting to certain zones, sectors, areas	Frequency	A limitation on lifting and handling near the pipeline reduces/ eliminates the frequency of occurrence effectively.
Limit the type of objects lifted in certain zones	Frequency	For example, only the cranes furthest away from the vulnerable area can lift heavy objects.
		not allow to lay barge loading pipe onboard within platform safety zone.
		Reduces the frequency of the most critical objects, however does not eliminate the risk totally.
Introduce safety distance	Frequency	The activity is performed at a predetermined safe distance away from the pipeline (e.g. anchor handling).
		Reduces/eliminates the risk efficiently.
Introduce safe areas	Frequency	Activity of a certain kind is not allowed within a specified area (e.g. trawling nearby platforms).
		Reduces/eliminates the risk efficiently.
Change the field lay-out	Frequency	By careful routing, this has the same effect as for safety distance and can be set for parts of the pipeline.
Introduce extra chaser tug or anchor chain buoys	Frequency	To ensure that no interference between the anchor chain and the installation take place.
Tie-in corridor in-line with rig heading above installation	Frequency	The tie-in corridor should be in-line with the rig heading, thus the rig cranes are oriented in favourable positions.
Weather restrictions for operations.	Frequency	If a prevailing current direction have been included in a safe distance, the activity should not be performed if the current direction is other than that considered, or the frequency have shown to increase with increasingly worse weather, the activity should be postponed until the weather normalizes.
Increase the physical protection	Consequence	Increased protection will reduce the damage to the pipeline. Increased protection can be obtained by a variety of solutions. Some solutions (e.g. massive tunnel structures) might introduce a very high risk to the pipeline during installation, and in addition can introduce scouring problems during the lifetime.
Stop/reduce pressure or production in pipeline	Consequence	This effectively reduces the consequence of release; however, this solution can be very expensive. Further, it does not reduce the economic consequence of damage.

9.4 Corrosion control systems

9.4.1 External corrosion

All new pipelines and their field joints shall be protected from external corrosion by using a suitable external protective coating system in accordance with ISO 21809 (all parts). An adequate cathodic protection system shall also be used, ISO 15589-2 shall be referred as minimum criteria for the application.

At areas where potentials fall outside the required potential level, the operator shall investigate the cause of the potential anomaly and mitigate it. Mitigation shall consist of bringing the CP levels into conformance either by making sufficient repairs to the coating, electrical cable connections and/or by increasing the current outputs of existing anodes/adjustment of the rectifier.

9.4.2 Internal corrosion and erosion

If the fluid being transported in a pipeline has the potential to corrode or erode the internal surface of the pipeline, the operator shall determine the nature of the corrosion and erosion that could occur within the pipeline and shall take adequate steps to mitigate it.

Mitigation steps can include, but are not limited to the following:

a) the injection of a suitable inhibitor or biocide;

b) frequent cleaning with cleaning tools to remove sediment, wax and water;

c) maintaining a minimum flow velocity to minimize water and sediment dropout;

d) flushing dead-leg segments and valve bodies where fluid can be static and not influenced by general pipeline fluid flow.

e) temporary increased flow rates to flush out local accumulated liquid or particles;

f) erosion might be mitigated by filtering and/or reducing flow velocity.

9.5 Management of unintended releases

An integrity management plan shall contain protocols for detecting leaks and for limiting the consequences in the event of an unintended release. Elements of the plan shall describe the means and procedures for:

a) minimizing the time required for detection of a release;

b) minimizing the time required to confirm and locate a release;

c) minimizing the volume that is released;

d) minimizing emergency response time;

e) protecting the first responders;

f) protecting the public and limiting adverse effects on the environment.

The operator shall consider whether a leak detection system is necessary for the transported fluid and the environment through which the pipeline passes. The role of leak detection is to minimize the time required to detect leaks from a pipeline system. The type of system used shall be carefully reviewed to ensure that it meets the needs of the operator. API RP1175 provides information for Leak detection program management.

The operator shall select, install and maintain a system or systems appropriate for the length and size of the pipeline, the type of products within the pipeline and the leak/spill scenarios for critical locations.

9.6 MAOP reduction

A reduction in operating pressure can be used to reduce the risks associated with threats to pipeline integrity, that are dependent on hoop stress, such as metal loss, SCC, mechanical damage, or the growth of an anomaly through pressure-cycle-induced fatigue. A pressure reduction can be either permanent or temporary. The safe operating pressure for the defect shall be determined by an engineering assessment and documented and advised to the pipeline controllers.

If the operator is unable to meet repair or reassessment schedules, the implementation of temporary pressure shall be considered. For time-dependent threats, such as corrosion, other risk control measures shall be applied in parallel with a pressure reduction. The operator shall ensure that the determined MAOP provides a suitable factor of safety.

The MAOP shall not be increased without a documented engineering assessment that demonstrates the pipeline is safe to be operated at the revised pressure.

9.7 Emergency response

To limit the consequences of a release, the operator shall provide a rapid and effective response applicable to the circumstance. For a liquid pipeline, physical barriers might be appropriate to limit the spread of released product and to recover as much of the product as possible.

The operator shall update the emergency data, which are listed in 12.1.3, periodically. Emergency exercises covering several scenarios shall be carried out periodically to train response personnel, to test response equipment, to improve procedures and verify response capability. The operator shall evaluate its response after any exercise or emergency to identify opportunities for improvement.

Agencies, such as law-enforcement and fire-fighting agencies, should be informed of and considered for participation, in any emergency response exercises.

The requirements and description of emergency response and failure management are specified in Clause 12.

9.8 Repair methods

9.8.1 Repair methods selection

The operator shall select the most suitable method for pipeline repair according to established practices and process that shall address and consider the extent and mechanism of the damage, pipe material, pipe dimension, location of the damage, load condition, pressure and temperature.

The purpose of a repair is to restore the pipeline safety level and reduce identified integrity risk by reinforcing the damaged section or to replace the damaged section.

A repair can be temporary or permanent, depending upon the extent of the damage. A temporary repair might be acceptable until the permanent repair can be carried out. In case of a temporary repair, it shall be documented that the pipeline integrity and safety level is maintained either by the temporary repair itself and/or in combination with other precautions (e.g. reduced pressure or flow rate).

The following repair methods can be used:

a) Replacement where the damaged portion of the pipeline is cut out and a new pipeline spool is installed either by welding or by a mechanical connector.

b) Local repair by installation of repair clamps externally on the pipeline. The type and functional requirement of the repair clamp depends on the damage mechanism to be repaired. Structural clamps shall be qualified to accommodate specified pipeline wall axial and radial loads, whereas leak clamps shall provide sealing in a leak initially inside the clamp.

Leaking flanges and couplings can be sealed by:

— installing a seal clamp covering the leaking flange;

— installing a new coupling;

— increasing the bolt pre-load;

— replacing gaskets and seals.

Prior to increasing the pre-load in bolts, it shall be documented by engineering calculation that no over-stressing occurs in the bolts, flange or gasket and seals. In case the pre-load in the bolts is removed, e.g. due to changing of a gasket, new bolts shall be used for the flange connection.

All repair clamps, sleeves, pipe spools and mechanical connectors shall be qualified to the governing design premises and codes for the respective operating pressure prior to installation and leak tested after installation.

For guidance upon pipeline subsea repair, reference is made to DNV RP F113, which provides description of different pipeline repair equipment and tools, their application, qualification principles to be used, pipeline interaction forces to be designed for, design principles and guidelines, requirements related to mechanical sealing, hyperbaric welding, test philosophy relevant for the different phases of repair equipment qualification and documentation requirements. Design and qualification guidelines for hot tap fittings and plug applications are also given in DNV RP F113.

9.8.2 Detailed procedures

The operator shall establish detailed procedures regarding the execution of mitigation activities, intervention and repair operations. The typical sequence of activities involved in a pipeline section replacement repair operation can include:

a) emptying or isolating the location with isolation plugs;

b) seabed intervention (e.g. excavation, gravel filling), for access and to provide stable support condition for pipeline support and alignment tools;

c) cutting and removal of weight and corrosion coating;

d) cleaning, close visual inspection and NDT of damage, as required;

e) restraining and supporting the pipeline prior to cutting (e.g. by H-frames);

f) cutting and removing the damaged section;

g) onshore detailed inspection of the damaged section;

h) preparation and inspection of pipeline ends at seabed, to conform to the repair tool specification;

i) installation of new pipeline section and connecting the ends after required alignment by use of the repair tool;

j) marine operation procedures as required, e.g. buoyancy elements, jacking from the seabed or lifting assistance from support vessel, tie-in and alignment tools, mounting frame and welding habitats;

k) retrieval of installation tools and equipment.;

l) commissioning of repair operation (e.g. NDT, leak test);

m) protection over repaired section (e.g. cover, gravel bags or mattresses) against third-party interference;

n) pressure testing.

For any detailed procedures that are prepared, the procedures should include at a minimum:

— project procedures defining repair project organization, the roles, responsibilities and communication lines between all parties involved;

— procedures for emptying and cleaning the pipeline prior to cutting of pipe section;

— emergency preparedness plans for the operation;

— procedures for seabed interventions;

— procedure for required marine operation, including restrictions related to weather window;

— pipeline repair procedures;

— NDT and leak test procedures;

— procedures for protection of the repair location against third-party loads.

10 Performance measurement and improvement

10.1 General

The integrity program shall be periodically reviewed, at least annually, to evaluate the adequacy of the IMP's processes, the extent of implementation and the effectiveness in achieving the intended results. The operator shall identify goals and objectives for its IMP, and as part of a continual improvement process these goals and objectives shall be adjusted accordingly. To facilitate the integrity program evaluation, the operator shall use performance metrics and audits. The results of the performance metrics and audits shall be regularly reviewed by both the IMP personnel and by management to evaluate the IMP's adequacy, implementation and effectiveness. This review will provide feedback for continual improvement of the IMP, which can include recommendations for corrective and preventative actions if deficiencies are identified.

10.2 Performance measurement

10.2.1 The operator shall develop performance measures to enable the evaluation of IMP results. The performance measures shall evaluate the representative sections of the IMP.

NOTE ASME B31.8S and API RP 1160 provide examples of performance measures. Example for performance measurement is also shown in Annex D.

10.2.2 The operator shall evaluate the performance measure results at least annually and the analysis shall identify any trends and areas for improvement. The operator shall compare the performance measure results between different segments in the same pipeline system or different pipeline systems in different areas. The information obtained shall be used to evaluate the effectiveness of preventive and mitigation actions or overall IMP and to analyze and identify the improvements. The operator shall also compare its results with industry benchmark trends to identify areas for improvement.

10.2.3 A formal performance measurement report shall be prepared including the results, recommendations and requirements for improving performance. Results of performance measurement and the benefit of the integrity management programme shall be communicated to relevant stakeholders.

10.3 Management review

The operator shall develop a process to conduct annual management reviews of the performance results when reporting operator's goals and targets. The management review will identify areas for continual improvement of the IMP.

10.4 System audit

10.4.1 An audit of the IMP shall be conducted on a minimum 5-year basis to enable the operator to identify any non-conformances with the adequacy, implementation and effectiveness of the IMP. The audit shall be conducted by an independent third party or by the operator using persons independent of the development and implementation of the IMP.

10.4.2 Any findings of non-conformance shall be documented and corrective actions shall be proposed, implemented and monitored.

11 Data management

11.1 Data acquisition

11.1.1 Data acquisition content

Pipeline integrity management shall cover the entire lifecycle of a pipeline. Data sources for pipeline integrity management include information relating to design, materials, installation, commissioning activities as well as for operating, maintenance, repair and abandonment data. Data sources also include survey records, environment data, social resource data, failure analysis, emergency response plans, etc.

Annex E provides data categories and suggested data acquisition processes for pipeline integrity management. Not all pipelines will need all the data categories as in Annex E.

The operator shall gather and maintain the necessary data for adjacent areas for consideration of integrity management, particularly items that impact pipeline integrity threats and failure consequence assessment.

11.1.2 Data acquisition method

11.1.2.1 Routing survey

The pipeline baseline is defined as the routing survey (or as-built) which is developed after pipeline installation. The surveyed pipeline coordinate points shall include, but not be limited to the depth of cover, bend corner points and intersections with other infrastructure.

During operation and maintenance activities, the operators shall maintain and update survey data as appropriate.

Where a pipeline is re-aligned, the new baseline shall be established and pipeline records shall be updated accordingly to form a new baseline.

11.1.2.2 Data acquisition for pipeline facilities

Information of the pipeline facilities and bathymetric/map shall be obtained during the pipeline installation phases as part of the survey and digital pipeline data collected. During the pipeline installation phase, the operator shall consider gathering information of seabed geology and topography.

Data acquisition should include digitization activities such as the transfer of paper records formed during installation and operating periods into the pipeline integrity management system. Such records can include: sourcing and quality records, operating records, repair records, examination and construction source records and maps or remote sensing images.

11.1.3 Data alignment

Pipeline data shall be aligned according to surveyed results which can include joints, girth weld number, or other unique reference in geospatial reference coordinates. The description of the pipeline properties should align to girth weld number. Data shall be aligned with installation data and operational integrity data. The basis for alignment will vary according to the accuracy and type of data.

The baseline alignment of installation and operational integrity data shall confirm to the following requirements:

a) A baseline alignment shall be completed that defines the centreline reference. This baseline alignment shall be from original installation surveys or from aligned mapping data from routing survey.

b) If internal inspection is carried out, alignment shall be referenced to internal inspection circumferential weld number.

11.2 Data transfer

Pipeline data shall be transferred to operator prior to hand over from the installation phase. The operator shall establish a system and transfer procedure to ensure accurate data is available for initial operations. The operator shall resolve discrepancies in data through the use of ILI, external inspection, etc.

Pipeline facility data shall be submitted in either digital or hard-copy format. Among them, centreline data shall be submitted in standard format, and the examples of these tables are given in Annex F.

11.3 Data integration

11.3.1 General

The data management system shall enable data integration and inquiry. Data integration generally refers to the process of utilizing two or more data sets to identify conditions of interest on the pipeline. In more advanced applications, data integration processes can include computer applications that spatially align and correlate the available data along the pipeline with predetermined criteria and rules.

11.3.2 Data integration requirements

Various data elements used to assess the consequence of a threat and its likelihood might change with time. The need for these changes can be caused by various factors including modifications to operating practices, changes in pipeline properties, reroutes and new lines, as well as changes in pipeline surroundings changes due to encroachment. The operator shall have management practices that ensure that data used for risk assessment is accurate and current.

The operator shall provide ways to update data content and means to validate and check updated data. Any automated calculations and/or management discussions shall use updated and validated datasets.

Data integration requirements should include the following specified elements:

a) Storage checking: Stored data should be routinely validated to ensure consistency and its integrity.

b) Update of data content: All changed asset information, e.g. coating or replaced pipeline sections, shall be collected and stored including information relating to the local environment and other assets in the vicinity. The integrity management system should be updated as necessary and will utilize the data.

c) Update checking: Periodic checks should be made to ensure that the data is current. Where human activities have or will occur checking should be more frequent.

d) Version management: All updates shall identify version details and these data comparison of historical data with current data shall enable changes to be assessed in the asset and the surroundings.

e) Data modification rule: Modifications of the pipeline system data shall be subject to a management of change procedure that shall address the continuing safe operation of the pipeline system. Documentation of changes and communication to those who need to be informed is essential.

The modification of pipeline centreline requires a procedure for examination and approval. Updates should be managed to make sure data's safety and efficiency. Base data prior to updating should be retained for information.

12 Pipeline integrity management within emergency response planning and failure management

12.1 Emergency response planning

12.1.1 General

Pipeline integrity management is designed to control the risks of failure by managing the pipeline and its environment throughout its life. No method can be considered 100 % successful and third parties and severe natural causes can defeat the control mechanisms leading to damage and potential leak paths. Emergency planning is therefore necessary to prepare for and minimise the consequence of a failure.

The IMP process provides valuable information that shall be used when emergency response plans are developed. Integrity management personnel shall be included in the emergency response organization to provide known information of the threats, consequences and conditions of the pipeline assets.

12.1.2 Emergency plan preparation

Emergency planning is focussed on logistical and command activities; however the planning is supported by proactive assessment of the pipeline risks and environments. All pipeline events are catered for in the planning, however additional attention is necessary where the consequence of failure is significant.

The operator shall prepare emergency plans for the entire pipeline. The operator shall identify potential failure types, their consequence and the environment involved to enable specific response preparedness measures to be implemented for those. These measures can involve operational pipeline shut down procedures, 24/7 duty call and emergency controller operators, specialist materials, equipment and manning requirements and consider locational challenges and local regulatory requirements.

12.1.3 Preparation for emergency data

The operator shall organize documentation required for emergency rescue and deliver them to emergency command centre, repair and recovery centre or other relevant units or individuals to make sure that they will have required documents in hand. Such documents can include but are not limited to:

a) drawings of pipeline routing, pipeline-surrounded seabed topography;

b) basic pipeline information: material quality, pipeline diameter, wall thickness, welding technique, and pipeline depth (for buried pipe section);

c) operating parameters: transportation medium and property, temperature, pressure and flow, etc.;

d) the most recent integrity management reports, such as in-line and external inspection reports, risk assessment reports, defect-repair program status, and any plans relating to risk prevention and mitigation measures in place or required for that segment.

12.1.4 Emergency response

In case of an emergency, the emergency controller operator should obtain the detailed information on the pipeline segment. As a first step, shutting down the pipeline system by shutdown valves shall be considered.

Defect information from GIS and inspection records can be used to identify possible leakage points, to assist with equipment preparation for the response crews. Relevant personnel should, based on field location information and features of pipelines (bend, repair sleeve, etc., if applicable), match pipelines with ILI results and other known information regarding the type and dimension of defects known, to identify potential failure causes and modes.

The information regarding type, dimension of defects and other neighbouring of defects can impact the emergency recovery strategy, which can be tailored and adopted with such information.

12.2 Failure management

12.2.1 General

Where a pipeline has failed, the failure segments shall be either removed from service or mitigated via an approved engineering approach. Where the cause is not obvious, the segment shall be forensically analyzed as per 12.2.2. The failure analysis report shall be made available to the incident investigation team and integrated into the IMP review.

The operator shall analyze the causes of all pipeline integrity events that cause or can cause loss of containment. These events can include: auxiliary equipment failure incidents due to leakage, status of pipelines failing to meet expected operational functions as a result of pipeline defects (fatigue or erosion, etc.), status of design requirements or loads that are beyond expectations as a result of any third-party construction, natural and geologic disasters, or other external factors. Several methods currently exist both on the market and internally within operator's organization. Examples are bow-tie assessments, fault tree analysis, etc.

Failure management shall analyze both the root causes and contributing causes, including management system changes that can have contributed to the incident. This analysis can involve: root causes of incidents, analysis of emergency response and reviews of any identified weaknesses in the current integrity program or procedures and of the related implementations of the program and/or procedures etc.

12.2.2 Failure analysis

The operator shall develop a failure analysis plan specifying the failure analysis, required test and investigation methodology to be used for typical failures according to best known practices and expertise available. An overall and systematic root cause analysis shall be conducted to determine failure mode, causes of failures based on field survey and background documents and with combination of forensic test results.

Background information to be included in the analysis shall be identified. Such information shall include, but is not limited to the following:

a) condition of pipeline segments;

b) operating record of the pipeline or station equipment, including pressure measurements, temperature measurements and properties of the product medium;

c) maintenance and failure records of pipeline segment or equipment;

d) material selection, manufacturing methods and thermal treatment history of pipeline segments (as well as acceptance/commissioning test results); and

e) prior risk assessment.

12.2.3 Incident investigation report

The incident investigation report shall be prepared by qualified and assigned personnel within operators' organization, including at least one individual with approval authority of procedures. Personnel for the incident investigation and analysis shall possess professional competence required for investigating incidents (i.e. incident investigation training) and be capable of understanding the technical process of how the equipment functions. In cases of complex investigation or where experience is not present within the operator's organization, third-party experts should be considered to assist as necessary. The extent of the incident investigation and analysis shall be determined from the complexity of the incident and its severity. The senior management staff of the operator shall play an active role in the management of investigations into major failure incidents.

The incident investigation report should include, but is not limited to the following:

a) background and information of the incident(s);

b) incident investigation results;

c) conclusions and recommendations.

The operator shall fully implement improvement measures as raised in the incident investigation report to avoid future incident of a similar nature. The operator shall also further re-establish the performance level of the IMP through analysis using the incident data and other data of known incidents.

12.2.4 Remedial and preventative measures

The operator shall prepare and implement remedial or preventative measures to remove the threat of a repeat incident, including any specific lessons learned relating to the failure recovery phase. Such measures should include, but are not limited to a risk assessment on measures taken including procedures for corrective and preventative measures as well as implementation of a tracking and monitoring system on the remedial and preventative measures put in place to ensure root causes of the incident are mitigated.

The implementation plan of corrective and preventative measures shall meet the following requirements:

a) specific timeline for implementation;

b) implementation of processes to drive and monitor the close out of recommendations;

c) review conformity of corrective and preventative measures taken to ensure that they meet requirements of relevant procedures.

12.2.5 Failure recovery prior to restart

The operator shall carry out an engineering assessment of the failed pipeline section to confirm that all other defects which are identified as having the potential to induce further failures have been addressed and that the risks and/or consequences have been mitigated in accordance with the integrity management plan, before a restart of the pipelines. The decision to restart the pipeline and the analysis shall be documented and take into account the requirements of the local regulatory body.

The operator shall collect all the documents relating to emergency measures taken, including all records of changes to pipelines due to the emergency response as according to 12.1 and all analyses of the trends of failure as per failure statistics of 12.2.6.

12.2.6 Trend analysis of pipeline incidents and causes

The operator shall perform statistical analysis and track trends of incidents either by itself or by participation in relevant organizations, to provide basic data to support to the effectiveness of pipeline integrity management.

Incident data trend analyses shall include: incident classification types, causes classification types, classifications and common calculations of the magnitude or scale of the incident effects. The incident data collection shall be made to comprehensively meet relevant requirements to ensure data validity and accuracy. Incident data shall be recorded in a consistent manner to aid in future comparison analysis. Qualified personnel shall perform the statistical analysis including a review and documentation of the quality of data, such as to minimize the use of suspect data in the analyses.

The designated qualified personnel or group that performs the statistical analysis shall make periodic analyses (every year or every five years) on any trends of pipeline incidents using broader data sets as available. Trend analyses can be divided into overall trend analysis and trend analysis for any certain type of incident.

13 Pipeline remaining life assessment and abandonment processes

13.1 General

At a point in the pipeline's lifecycle, the pipeline might enter a stage where the increase of risk factors exceed the practicality and ability to mitigate those risks such as a high operational risks from a large number or density of growing corrosion defects that cannot be repaired in a timely manner. Should such a situation occur, a pipeline life assessment should be carried out.

A pipeline life assessment is required to verify that the ongoing risk of running the pipeline with respect to public and environment safety is still lower than the acceptable risk, while still meeting any economic targets of the operator.

A pipeline life assessment shall also be performed if the pipeline operational life exceeds, or would exceed the original design life, or if the economics of the pipeline operations becomes unfavourable following upstream or downstream changes in pipeline operation.

An effective pipeline life assessment should include, but not is limited to, the following aspects:

a) pipeline integrity assessment;

b) risk assessment;

c) economic viability assessment;

d) physical life assessment;

e) mitigation or re-inspection suggestions for risks related to use of life extension, e.g. suggestions about safe operating pressure (optional);

f) review of the applicability of operation and the maintenance procedures, the emergency response, safety and environmental program (optional);

g) assessment on nonconforming items against current law, regulation or standard;

h) analysis of any changes to the specifications for design, pipe manufacture and installation.

Repair measures required to mitigate any future hazards shall be developed as necessary.

Pipelines that have been idle can be re-used or re-designed for other purposes (see 13.4).

If a pipeline life assessment cannot demonstrate that a pipeline can run safely and economically, the operator shall consider decommissioning, abandoning or down rating the pipeline pressure. Conversely if a pipeline life assessment is used to demonstrate that the pipeline is able to run safely and economically at a higher operating pressure, it can be uprated.

13.2 Pipeline remaining life assessment process

13.2.1 General

The process for a pipeline remaining life assessment is illustrated in Figure 5.

Early in the pipeline lifecycle, an integrity assessment shall be performed. The requirements for data collection, risk assessment and pipeline integrity assessment methodology shall be followed. The integrity assessment, economic life assessment and risk assessment shall be compiled to provide an initial baseline pipeline remaining life assessment.

During the pipeline lifecycle should an integrity assessment indicate increased risk factors, the pipeline physical life determination, the economic viability and an updated risk assessment shall be developed by the operator to determine whether the pipeline should continue to operate, be down rated or be abandoned.

In the case of a pipeline having specific physical issues, those results shall be considered as the dominant factors for decision making. Otherwise, the minimum values of physical and economic life should be used to determine the remaining life of the pipeline. The pipeline risk assessment might provide the operator with strong technical support for remaining life considerations, whilst the ongoing costs of integrity requirements might impact the economic life considerations.

If the pipeline remaining life assessment indicates that the pipeline is still viable for ongoing operation, any necessary pipeline repair and maintenance activities shall be scheduled and performed in a timely manner. A further pipeline remaining life reassessment shall also be scheduled, at an interval based upon the key factors of the pipeline remaining life review, to support continuous safe pipeline operation.

If the pipeline remaining life assessment results indicate that the remaining life of a pipeline is zero, then the pipeline shall be abandoned.

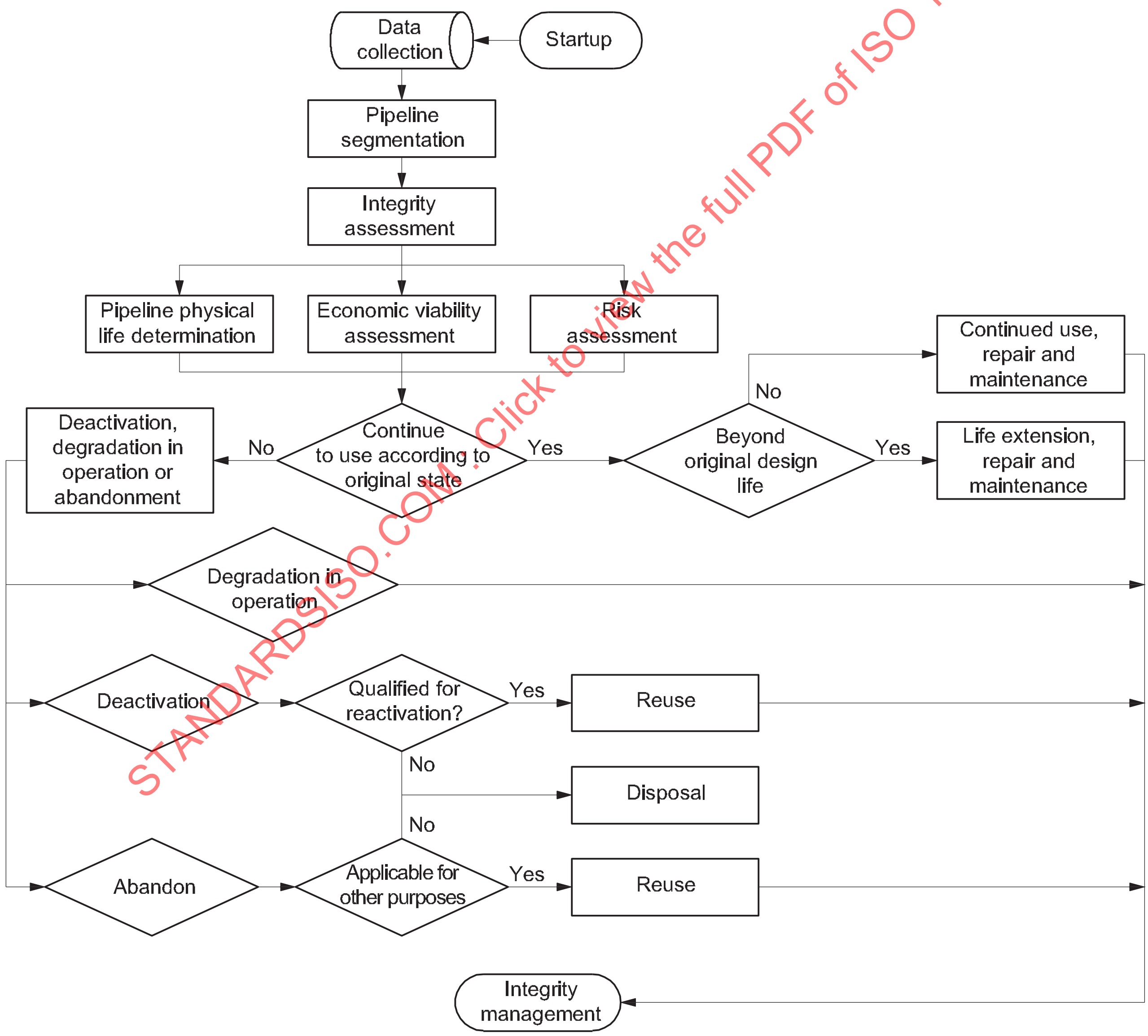


Figure 5 — Process for pipeline life assessment

13.2.2 Data collection

The following data is required for a pipeline life assessment:

a) Design: Grade and type of steel pipes, performance index, wall thickness, pipe diameter, design pressure, CP system information and coating information; initial design standard and specification, including version number and date of publishing.

b) Product properties: Physical and chemical properties, including density, viscosity, solidifying point, wax content, components, impurities, water-cut, etc.

c) Manufacture and installation: Industrial welding methods and processes, mode of pipeline laying, field welding methods and processes, buried depth, field non-destructive test.

d) Commissioning: Commissioning and bulge testing records.

e) Operating data: Historical records of pressure, flow and temperature; historical records of corrosion detection, leak detection, safety forewarning system, corrosion monitoring and record of use of chemicals.

f) Environment load: Wave, current, fishing trawling, etc.

g) Inspection results: In-line, direct assessment and CP surveys: including details of inspection method, inspection frequency, inspection results such as size and distribution of corrosion, welding defect, crack or coating defect, etc.

h) Integrity assessment results: Historical records of pressure bearing capacity of all types of defects, number of unacceptable defects, repair and maintenance suggestions, suggestions for re-inspection intervals.

i) Failure statistics and analysis: Mode, causes, likelihood or consequence of failure, hydro-blasting experimental results, analytical results of the true failure of steel pipes.

j) Historical records of repair: Overhaul records of coating, repair method and time for all types of defects.

k) General inspection results: Records of settlement, crossing inspection and other third-party events.

l) CCAs identification: Current changes and future.

m) Risk assessment results: CCAs segment information.

n) Historical finance data: Transportation revenue, transportation cost, the original value of the fixed asset and the increasing value for the pipeline system, the original value of the pipeline, the newly increased value of the pipeline (fixed assets counted in route section due to overhaul, updating or renovation), pipeline maintenance cost (route maintenance cost, wax clearing fee and pipeline cleaning fee, patrolling fee, flood protection fee, barrier removal fee and safety protection fee).

o) Future expenditure data: Costs of abandonment/decommissioning efforts.

NOTE The above data is not an all-inclusive list; other data sets can be required as determined by the operator's integrity management practices and the pipeline's circumstances.

The most recent verified data should be used to ensure the accuracy of the resultant analysis data used for reporting and data sharing.

13.2.3 Pipeline segmentation

Individual pipeline segments can have a distinct difference on the likelihood of failure and consequence in the risk evaluation, due to the differences in fabrication, installation and surrounding environmental factors. The operator shall therefore segment and assess the pipeline segment according to logical factors. Pipeline segmentation shall utilise data including: variation to operating condition, failure history, unacceptable defect density, material performance and operation pressure, pipeline running time and risk assessment results.

13.2.4 Integrity assessment

Any integrity assessment shall follow the practices as stated in Clause 8. An ILI-based integrity assessment method is preferred however direct assessment and pressure testing can be used as an alternative. Additional assessment methods can also be considered including:

a) review of the historical operation records;

b) detailed assessment of the integrity of the pipeline system;

c) failure mode and cause analysis;

d) analysis and testing of steel pipe and weld quality;

e) change of pipeline process;

f) recommendations for safe operation and management.

13.2.5 Physical life determination

After the assessment of the pipeline integrity conditions, a key index method should be adopted to determine pipeline physical life, where other appropriate assessment methods can also be used and where technical conditions and data availability permits.

The key index method, which is based on inspection and assessment data, uses key factors that affect the life of a pipeline through subject matter expert review and assessment. This method details the pipeline integrity and is used to determine the likely pipeline availability and in-service risks.

Specifying a key technical index is a requirement in assessing pipeline physical life and investigates the following:

a) whether pipeline materials and performance of welds (parent metals and strength, plasticity or ductility of welds) meet relevant standards;

b) whether pipelines have time-related defects that cannot be maintained or repaired and are found to introduce an increasing likelihood of failure;

c) pipelines that are unsuitable for conventional inspection (e.g. serious wax deposit or insufficient flow) that cannot be maintained or repaired and are found to have a greater likelihood of failure;

d) assessment results for changes in pipeline operational process conditions (transportation temperature and medium, etc.) indicate that the pipeline cannot satisfy safe operation requirements and there is greater likelihood of failure;

e) ineffective corrosion resistance from coating failure e.g., failure of aging coatings, disbonded sleeves, ineffective CP;

f) likelihood of failure of all segments within the pipeline, where in the case that the likelihood of failure exceeds the acceptable risk level and recent likelihood of failure increases abruptly, the situation shall be considered unacceptable;

g) conformity of the operation and integrity of transportation pipelines to relevant pipeline laws, regulations and standards;

h) whether demands of transportation of liquid and gas resources match the pipeline's practical transportation capacity.

If one or more of above technical indexes cannot satisfy the requirements for safe pipeline operation, the operator should consider abandonment of the pipeline. If the operator can demonstrate pipeline integrity with sufficient evidence, the pipeline operations can continue.

With a corrosion growth rate model, crack growth propagation model and other related methods, defect growth and its impact on pipeline integrity for future years can be predicted. By the analysis and application of such data, the conformity of a pipeline to specified technical indexes in coming years can also be preliminarily confirmed, in order to facilitate decisions and actions regarding pipeline abandonment.

This document suggests the use of calculations of likelihood for the failure that are based upon reliability of inspection data where technical conditions and data permit. Such calculations will help determine the likelihood of pipeline failure at specific times in the future for comparison to the maximum allowable likelihood, in order to define the physical life of the pipeline. After pipeline re-inspection, a physical life assessment should be performed again. This physical life assessment should account for uncertainty in the inspection (e.g. ILI defect sizing or probability of detection) data as well as uncertainty in service condition.

All records of integrity assessment, physical life assessment, economic assessment and decisions on pipeline operation shall be captured as data within the data management of the pipeline integrity management system.

13.2.6 Economic viability assessment

13.2.6.1 Economic comparison

This document describes the economic comparison of schemes, including the minimum annual average cost method and cost-benefit analysis method for assessing a pipeline's economic viability. Other appropriate assessment methods can also be applied wherever technical conditions and data permit. If pipelines do not have such data, or have insufficient future liquid or gas supply and cannot meet the minimum requirements for pipeline transportation, then that result should be considered at the end of the original design life or earlier, particularly if transportation costs of operating the pipeline are higher than those of alternative methods, such as railway and ocean transportation.

Economic comparison includes:

a) comparison between life extension of existing pipelines and new replacement;

b) comparison of different transportation modes for low transportation quantity.

Compared to existing, and particularly older pipelines, newly-constructed pipelines will be more technologically-advanced and scientifically-designed to run more safely and efficiently. Replacement of a pipeline will reduce operating risks and maintenance costs, however, it will require a significant amount of capital investment. In terms of the optimal time to replace a pipeline, consideration should be given to the likelihood that an abandoned pipeline will produce substantial resource waste.

In the economic evaluation of the viability of an existing pipeline, the cost comparison should be based upon the total costs for the existing pipeline against the minimum annual average cost of a newly-built replacement pipeline. The decision to continue or replace the pipeline shall be accordance with the principle of minimising overall annual cost.

In the case of a higher operating loads, the unit transportation cost for pipelines is typically economical relative to other transportation modes (road, railway, and ocean). For low carrying capacity, the economical efficiency should be compared to alternative transportation modes to identify the one with the minimum unit transportation cost.

13.2.6.2 Minimum annual average cost method

Regardless of revenues derived from the operating pipeline, the minimum annual average method judges the pipeline economic viability merely from the operating costs. This method is applicable for circumstances that have guaranteed upstream resources and demand, thus a stable throughput for the pipeline. It therefore sets safe, reliable operation as the top priority.

The time period set for an annual average total cost for pipeline operation is the economic viability. The annual average total cost, inclusive of annual average asset recovery cost and annual average operating cost, should also consider the time value of capital.

After obtaining the actual cost data in operation, historical trends in costs during pipeline operation should be analyzed to predict operating costs in years to come. Economic viability of a pipeline is determined by observing any variation of average total cost. Consecutive years during which average total cost fluctuates below 5 % before and after the end of a pipeline's economic viability is called the economic viability region.

13.2.6.3 Cost-benefit method

Relative to pipeline income, costs arise from pipeline operation and are applicable for circumstances under which the upstream resources for the throughput of the pipeline are not stable and business objectives include a criteria for profit maximization.

Based on the bearing capacity and operator preferences, this method outlines the economic viability for pipelines.

13.2.7 Risk assessment

Risks related to pipeline operations are key indices (see Clause 6 for detailed methods) in the decisions regarding pipeline service life. Risks considered shall include consequence factors for safety and business disruption for current and future operations. It therefore constitute an important part of the life assessment.

The operators should establish specific standards for allowable risks that meet its operating requirements. ISO 16708 provides guidelines in risk acceptability and target likelihood of failure.

13.2.8 Remaining life assessment

According to the assessment results in the previous sub-clauses, decisions can be made regarding continued pipeline use, degradation in operation, deactivation and abandonment. If the pipeline is still required for operation integrity, management shall be applied otherwise it shall be appropriately abandoned.

13.3 Deactivation and abandonment process

13.3.1 Guideline for the abandonment of a transportation pipeline

If it has been determined, by remaining life assessment, or according to local legislation that a pipeline should be abandoned, the operator shall undergo the steps for decommissioning and then abandonment.

Before abandonment, activities including field assessments, risk assessments and targeted risk mitigation measures should be performed to ensure that any risks from the pipeline abandonment are known and manageable. The use of a comparative assessment process in order to assess the relative benefits versus the potential drawbacks of the decommissioning options should be considered.

The abandonment of pipeline facilities shall include safe disconnection from any operating pipeline system, purging of combustibles and hazardous materials, and the sealing of any abandoned facilities to minimize safety and environmental hazards.

Once a pipeline is abandoned, it should be physically isolated from the liquid or gas transportation system network.

Cleaning activities should be performed immediately after the pipeline is deactivated. Safety and environmental risks for the abandoned pipeline should be thoroughly eliminated or reduced to a predetermined acceptable level. For the abandonment in place, the operator should consider filling the abandoned pipeline with a permanent inert substance (e.g. filling seawater and inhibitor) and such pipelines should be capped, plugged, or otherwise effectively sealed.

13.3.2 Preparation before pipeline abandonment

Before undertaking pipeline abandonment, the operator shall organize qualified personnel to prepare the pipeline abandonment plan and entrust environmental evaluation and safety evaluation considerations personnel. The abandonment plan is required to analyze safety and environmental risks in each disposal segment and to determine the relevant control measures, ensuring that entire pipeline abandonment and disposal processes are under control and that environmental protection conforms to local requirements. If there is no transported liquid medium disposed on site during abandonment, assessment of its impact on environment and safety assessment will be unnecessary.

13.3.3 Pipeline cleaning

Cleaning shall be conducted if necessary before abandonment. All pipeline cleaning activities shall be conducted in accordance with the specified environmental protection methods, including the recovery, recycling, separation, measuring, transportation and storage of removed liquid and gas.

13.3.4 Deactivation of pipeline

To reuse a pipeline or pipeline segments in the future, deactivation should be carried out. The deactivation of pipelines involves depressurization, cleaning and isolation of the segment from the main transportation pipeline network. The operator shall isolate the pipe using blind flanges, weld caps, or blinding plates and where required, provide a pressure-relief system.

The operator shall fill the pipe segment with a suitable medium; having regard for the intended duration of the deactivation, the effects of the medium on the integrity of the pipeline, and the potential consequences of a failure. For instance, water carrying a corrosion inhibitor, low-pressure nitrogen or any other proper inert gas can be used for filling.

Upon completion of pipeline sealing, further in-service pipeline management measures should be carried out to eliminate any further risk. Such measures shall include, but are not limited to the following:

a) maintain external and internal corrosion control;

b) maintain records; and

c) where considered appropriate, perform other maintenance activities.

For pipelines that have been deactivated, the operator shall annually confirm the suitability of the deactivation methods used, the corrosion control and other maintenance activities to ensure ongoing the integrity of the pipeline in its expected deactivated state.

13.3.5 Records

13.3.5.1 Records shall be maintained for all pipelines that have been abandoned in place. Such records shall include the locations and lengths for each pipe diameter and, where practical, the burial depth. The operator should maintain all pertinent records related to the abandoned piping.

13.3.5.2 Upon the completion of the abandonment process for the pipeline, the operator shall supply all relevant documentation of the abandoned and disposed pipelines including the location, length, burial depth, disposal measures and environmental control measures, to relevant stakeholder groups (e.g.

local government agencies) and archival departments within operator's organization including related communications to local government agencies.

13.3.5.3 Management of change processes (see Clause 16) should be performed for the pipeline abandonment and deactivation.

13.4 Life extension and recycle of pipeline

13.4.1 Life extension

Where it is intended to operate a pipeline beyond its original design life, a life extension assessment shall be completed that describes the steps required to continue operation of the pipeline such that it will not produce any unacceptable risks after life extension. A life extension assessment shall include risk and integrity assessments of current and future states of the pipeline and any remedial activities required.

If the life extension of a pipeline is concluded to be unreasonable or impractical (such as in comparison to a new pipeline as a cost-optimal solution), the pipeline should be planned to be operated and then decommissioned upon the end of its design life.

The operator shall document and record the life extension assessment.

Life extension processes include the integrity assessment of the current pipeline and assessment of life extension applicability. Such an assessment shall consider circumstances that have been documented in routine operation, but were not considered in the original design of the pipeline.

The allowable life extension period shall be determined within the life extension assessment including results from the related integrity assessment of the pipeline. If operator's planned life for the pipeline system exceeds the remaining life identified in the integrity assessment, further remedial measures shall be determined to extend the remaining life of pipeline system.

Such remedial measures include:

a) replacement of pipe fittings;

b) reassessment of limit values of anomalies and correction of anomalies;

c) reassessment of pipeline degradation while still in operation.

Assessment can be referred to ISO/TS 12747 for pipeline life extension and to 13.2 for detailed methods of life extension.

13.4.2 Reactivation of pipeline

The operator can reuse a pipeline which has been previously deactivated. Prior to reactivating the pipeline, the operator shall conduct an engineering assessment to determine whether the pipeline would be suitable for its intended service. Where the engineering assessment indicates that the pipeline would not be suitable for its intended service, the operator shall implement measures necessary to make it suitable before reactivating the pipeline.

13.5 Uprating

13.5.1 General requirements

The evaluation of a pipeline for service can also include an assessment for operation of the pipeline at a higher capacity than current operations. This would be typically facilitated by investment into significant modifications to the pipeline to meet the changes in service.

The operator shall conduct an engineering assessment to determine suitability of the pipeline for service at the proposed higher pressure.

If the operator intending to uprate its pipelines shall establish a written plan that includes all associated works and complete management of change for the pipeline uprating. All records of the plan and its execution shall be maintained by the operator.

13.5.2 Limitation on increase in maximum allowable operating pressure

The proposed MAOP shall not exceed the maximum allowed under ISO 13623 for a new segment of pipeline constructed of the same materials in the same location.

NOTE Local laws and regulations can also apply.

13.5.3 Uprating method

Before increasing the operating pressure of the pipeline above the previously established MAOP, the operator shall apply the following steps as a minimum.

a) Review the design, operating and maintenance history and previous testing of the segment of pipeline to determine whether the proposed increase is safe and consistent with the new operating condition.

b) Make any repairs, replacements, or alterations necessary to be compatible (safe) with the new operating level.

c) Adequately reinforce or anchor any offsets, bends and dead ends in coupled pipe to prevent movement of the pipe.

d) Review the class location change in pipeline right-of-way and determine that the proposed increase is safe and consistent with new requirements of regulations and laws.

e) Repair any failure detected before a further pressure increase is made.

f) If the pipeline materials can be identified through a material test and the design calculations for the pipeline would be the same as those for a new pipeline in the same area, a hydrostatic test can be completed to establish a new MAOP.

g) If a hydrostatic test is identified in the written plan as the method for uprating the pipeline, the test of the pipeline segment should be performed in accordance with 8.3.

h) If the new MAOP will be established by sequentially increasing the pressure in the pipeline, then the following shall be considered:

   1) Any increases in pressure shall be made in increments, where the pressure shall be increased gradually, at a rate that can be controlled. At the end of each incremental increase, the pressure shall be held constant while the entire segment of pipeline that is affected is checked for leaks.

   2) The new MAOP does not exceed 70 % of that allowed for a new line in the same location and the same design.

The operator shall verify that the new MAOP is consistent with the conditions of the segment of pipeline and the design requirement.

The incremental increases in pressure shall be made equal to:

— 10 % of the pressure before the uprating; or

— 25 % of the total pressure increase,

whichever produces the fewer number of increments.

13.6 Reporting

The operator shall prepare and maintain a detailed report which summarizes the works related to life assessment and life extension assessment. This report shall include the following as a minimum:

a) general description of the pipeline and pipeline life assessment procedure;

b) main results of the pipeline integrity assessment;

c) main conclusions to the risk assessment;

d) nonconforming items identified relating to current applicable laws, regulations and standards;

e) conformity of previous design, fabrication, installation and other specifications to current relevant specifications;

f) main conclusions of the economic life assessment.;

g) main conclusions of the physical life assessment;

h) statement and basis of the remaining life estimated from the above assessments (both as safe and economical operating viability).

14 Records and documents management

14.1 The operator shall establish plans for the classification, identification, collection, storage and disposal of records and documents pertinent to:

a) historical information required for the safe operation and maintenance of the pipeline over the pipeline's life;

b) objective evidence of pipeline management system effectiveness and conformity;

c) records and documents of decision-making and approvals.

Procedures shall cover electronic and paper-based records and documents. Classification included documents considered confidential or non-confidential.

14.2 The operators shall prepare and manage records and documents related to pipeline design, construction, commissioning, operation, maintenance and abandonment that are needed for performing the activities included in the pipeline IMP. The following items shall be included as a minimum:

a) Design, construction and commissioning details, including but not limited to:

   1) design basis, including design calculations;

   2) material specifications and certification;

   3) inspection and test certification and reports;

   4) documents relating to authorizations and permits to operate;

   5) surveys and route documentation;

   6) pressure testing summary;

   7) any adjustments, events and non-conformances during each phase.

b) Operation and maintenance details, including but not limited to:

   1) historical pipeline management system plans and procedures;

2) any change to operating conditions;

3) any modifications to the maps, charts, plans, drawings and procedures, required to allow the procedures to be properly administered;

4) details of any corrosion, dents or other anomalies;

5) details of the CP system;

6) failure records, analysis and subsequent preventative actions;

7) details of inspections and inspections and testing carried out when cutting a pipeline or making hot taps;

8) repairs and modifications;

9) pipeline surveillance reports;

10) emergency response and exercises records;

11) personnel training and qualification records;

12) reports on third-parties.

c) Abandonment details:

The operator shall document the archiving or disposal of records associated with an abandoned pipeline. A record shall be kept of all abandoned pipelines that remain *in situ*, to prevent possible mistakes in identifying an abandoned pipeline as an operational pipeline. Where CP is applied, to prevent the corrosion of the pipeline, the responsibility for maintenance of the system shall remain with the operator and appropriate records shall be kept.

15 Communication

15.1 General

The operator shall develop and implement a communications plan in order to keep appropriate personnel, jurisdictional authorities and the public informed about its integrity management efforts and the results of its integrity management activities, for pipelines near shore. Information can be communicated routinely or upon request. Use of industry, jurisdictional and company websites can be an effective way to conduct these communication efforts.

15.2 Communications

The operator manager and other appropriate operator personnel shall understand and support the IMP. This shall be accomplished through the development and implementation of a communication plan. Performance measures reviewed on a periodic basis and resulting adjustments to the IMP shall be part of the communication plan.

The following items shall be considered as a minimum for communication to the various related departments:

a) key components of the integrity management framework, and any subsequent modifications.

b) adequate reporting, its effectiveness and the outcomes.

c) relevant information derived from the application of integrity management available at appropriate levels and times.

16 Management of change

Formal management of change procedures shall be developed in order to identify and consider the impact of changes to pipeline systems and their integrity. Management of change shall address operational, technical, physical, procedural and organizational changes to the system, whether permanent or temporary.

A management of change process shall include at a minimum the following:

a) reason for change;

b) authority for approving changes;

c) effective date for change to occur;

d) analysis of implications of the change;

e) documentation, drawings and records updating communication of change to affected parties.

Impact and risk of changes should be adequately identified and communicated internally and externally.

Changes shall be managed through the full life of the pipeline, including design, construction, operation, maintenance and abandonment. Any new results derived from the integrity management efforts and the subsequent amendments should be effectively updated in the system and managed as changes.

Re-evaluation of critical consequence areas, risk and modification of the IMP shall be applied wherever there is a process change, modification to the pipeline or a pipeline repair.

17 Training and skills

17.1 General

It is recognized that different jurisdictions require a minimum qualification, such as an engineering degree to perform any pipeline engineering work. This clause establishes the complementary skill requirements for personnel who perform pipeline integrity management. It also specifies guidance for the required training of pipeline integrity management staff.

The operator should identify training and skill requirements for integrity management personnel.

The training and skill of pipeline integrity management is a stratified system. When qualified individuals achieve a higher level previous levels remain valid. Individuals at each level of skill are allowed to perform corresponding works as stated in 17.2.

When new regulations, equipment, techniques and procedures, or new management concepts are adopted into a pipeline operating company and relate to pipeline integrity management, the relevant personnel shall be re-trained as necessary.

17.2 Levels of skill

The training and skill can be divided into three levels:

a) level 1 (preliminary level);

b) level 2 (intermediary level);

c) level 3 (senior level).

Based on the intended scope of work, individuals shall have sufficient qualification in pipeline integrity management to the level required for the works that they are intended to perform. Otherwise the designated individuals should undertake the appropriate training required to achieve the necessary skill level. Annex G shows the training and skills approach.

Only individuals who obtain a skill level above level 1 can carry out data acquisition tasks. Individuals who achieve level 2 skill level can carry out threat identification and risk assessment. Individuals who achieve level 3 skill level can carry out integrity assessment, comprehensive risk assessment and performance measurement.

The operator should arrange to provide training for its employees or engage third parties for the work.

Annex A
(informative)

Example approach of semi-quantitative risk assessment

An example of semi-quantitative risk assessment is provided in Table A.1. The failure likelihood is the sum value of third-party damage, internal corrosion, external corrosion, manufacturing defect, construction defect, and geologic hazard. The failure likelihood is multiplied by the failure consequence to obtain the risk. The operator should decide the weighting value of each category

Table A.1 — Example of semi-quantitative risk assessment

Category	Factors	Value
Third-party damage	Cover	0 to 100
	Public education	
	Dropping objects/ trawling	
	Activity level	
	Locating and response	
	Government's attitude	
Internal corrosion and erosion	Product corrosivity	0 to 50
	Internal protection	
	Sand production	
External corrosion	Soil and water corrosivity	0 to 50
	Cathodic protection effectiveness	
	Cathodic protection test	
	Coating condition	
	External inspection and repair	
	In-line inspection and repair	
Manufacture defect and construction defect	Internal inspection	0 to 100
	Specified minimum yield strength	
	Safety factors	
	Fatigue	
	Surge potential	
	Pressure test	
	Seam weld type	
	Pressure	
Geologic hazard	Topography	0 to 100
	Geotech	
	Hydrotech	
	Pipeline design	
	Mitigative structures	

Table A.1 *(continued)*

Category	Factors	Value
Incorrect operations	Threat identity	0 to 100
	Safety system	
	Procedures	
	Training	
	Documentation	
	Lack of timely data collection	
Failure consequence	Product threat	0 to 10
	Leak volume	
	Emergency response	
	Population density	
	Environment	
	Cost	

Annex B
(informative)

Risk matrix

The risk matrix is defined including failure probability rank, failure consequence rank and risk categories. The failure probability can be preferably defined as per Table B.1. Assessment of failure consequences could take the safety, cost, environment, service interruption and reputation into consideration, as shown in Table B.2. An example of a risk matrix is shown in Table B.3, and the risk categories are defined in Table B.4. The operator can modify or determine its own category criteria and applicable values.

Table B.1 — Failure probability rank

Probability description		Rank
Probability	**Description**	
Very high	Failure has occurred in location; or Failure is expected in 1 year	5
High	Failure has occurred several times a year in operating company; or Failure is expected in 1 to 3 years	4
Medium	Failure has occurred in operating company; or Failure is expected in 3 to 5 years	3
Low	Failure has occurred in the industry; or Failure is expected in 5 to 10 years	2
Very low	Failure has not occurred in industry: or Failure is expected >10 years	1

Table B.2 — Failure consequence rank

Consequence categories	Increasing consequence				
	A	**B**	**C**	**D**	**E**
Safety	None or superficial injuries	Major injury, long-term absence	1 to 2 fatalities	3 to 9 fatalities	>10 fatalities
Cost (e.g. $M)	<0,01	0,01 - 0,1	0,1 - 1	1 - 10	>10
Environment	Insignificant	Slight/Minor effect	Local effect	Major effect	Massive effect
Service interruption	Insignificant	Major impact to service	Major impact to upstream/downstream company	Major national impact	Major international impact
Reputation	Insignificant	Local impact	Major regional impact	Major national impact	Major international impact

Table B.3 — Risk matrix

Consequence	Likelihood				
	1	**2**	**3**	**4**	**5**
E	III	III	IV	IV	IV
D	II	II	III	III	IV
C	II	II	II	III	III
B	I	I	I	II	III
A	I	I	I	II	III

Table B.4 — Risk category

Category	Description
I	Low
II	Moderate
III	High
IV	Very high

Annex C
(informative)

Example of the threat identification in lifecycle phases

Table C.1 provides an example of threat categorization, and associated causes of occurrence during each phase of the pipeline lifecycle. The structure of the table is such that it lists all lifecycle phases and the potential threats for each lifecycle phase. These potential threats are categorized according to the nature of the threat, such as mechanical (intrinsic factors), environmental (extrinsic factors) and then further sub categorized to state the damage mechanism(s) and the initiating source of the threats. This process of categorization will aid in the management or mitigation of the threat either by taking specific actions to prevent the threat from materializing at the specific lifecycle phase or by acknowledging the potential for the threat occurring and anticipating, managing and mitigating, or eliminating the threat during the service life of the pipeline. If the threats are not fully mitigated from occurring at a given lifecycle phase, then these threats need be anticipated and regular condition monitoring need to be conducted to verify the absence or existence of the threat throughout the service life of the pipeline.

Table C.1 — Categorization of threats

Threats	1. Design	2. Manufacture/construction	3. Transportation and storage	4. Installation	5. Pre-comissioning/commissioning	6. Operations	7. Abandonment
Mechanical/structural damage	Material selection Mechanical protection Use appropriate safety factors Free span Stability Vibration by gas flow Landfalls	QC	Damage to pipe or concrete coating when stacking	QC Installation design Local buckling Concrete coating damage Post trench damage		Trawling interference damage Anchoring Vessel impact Dropped objects Anchor snagging Other mechanical impact Free span Stability Vibration by gas flow	
HP/HT phenomena	Buckling Walking				Control start-up procedures	Buckling Walking	
External corrosion related	Material and coating selection Poor anode design	QC	Coating damage/degradation Atmospheric corrosion		ROV survey before start-up to identify coating damage	Anode degradation Coating degradation	

Table C.1 *(continued)*

Threats	1. Design	2. Manufacture/ construction	3. Transportation and storage	4. Installation	5. Pre-comissioning/ commissioning	6. Operations	7. Abandonment
Internal corrosion related	Material selection Chemical selection Design to avoid upset conditions Use appropriate corrosion modelling Landfall cathodic protection	QC Caps (to avoid water)	Caps (to avoid water) Atmospheric corrosion	Environment Dewatering Purging	Compatibility of fluids Pre-commissioning and system testing to leave treated water environment Dewatering Purging	Erosion MIC Products Different composition Wrong chemical frequency and concentration	
Incorrect operation	Overpressure Poor understanding of actual service Miscommunications of requirement Avoid upset conditions			Incorrect procedure Procedure not implemented		Wrong start-up shut down Procedures Wrong chemical frequency and concentration	
Weld/pipe body flaws	Material selection/ testing Poor welding procedures	Deviation in welding process QC		Welding process (circular) QC Poor welding Bevel damage	System pressure test		
Cracks in pipe body	Material selection	QC			System pressure test	Over charging the CP system	
	Typically no cracks accepted in design specification					Pressure cycles	
Weather related	Current/ soliton conditions and directions Extreme wave/wind conditions Route/landfall selection		Protect from environment	Incorrect weather window		Extreme current/ wave/wind conditions	

Table C.1 *(continued)*

Threats	1. Design	2. Manufacture/construction	3. Transportation and storage	4. Installation	5. Pre-comissioning/commissioning	6. Operations	7. Abandonment
Geologic hazard	Route/landfall selection Seismic design Sand wave/cliffs/landslide design Liquefaction			QA of DP systems (abbr) Pre- and post- installation survey		Soil stability Earthquakes Sand slope and wave Landslides Liquefaction Landfall geology	