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Pipeline systems

Part 4: Steel pipelines on land and subsea pipelines – Code of practice for integrity management

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Foreword

Publishing information

This part of PD 8010 is published by BSI Standards Limited, under licence from The British Standards Institution, and came into effect on 31 July 2012. It was prepared by Subcommittee PSE/17/2, *Pipeline transportation systems*, under the authority of Technical Committee PSE/17, *Materials and equipment for petroleum*. A list of organizations represented on these committees can be obtained on request to their secretary.

Relationship with other publications

PD 8010-4 is a new part of the PD 8010 series. The series comprises:

- Part 1: *Steel pipelines on land*;
- Part 2: *Subsea pipelines*;
- Part 3: *Steel pipelines on land – Guide to the application of pipeline risk assessment to proposed developments in the vicinity of major accident hazard pipelines containing flammables – Supplement to PD 8010-1:2004*;
- Part 4: *Steel pipelines on land and subsea pipelines – Code of practice for integrity management*.

This part of PD 8010 should be read in conjunction with PD 8010-1 and PD 8010-2.

Information about this document

This part of PD 8010 was initially drafted using the Energy Institute document *Guidelines for the management of integrity of subsea facilities* [1] as a basis, with their kind permission. The EI document has been substantially changed to cover steel pipelines on land and subsea pipelines and to align with PD 8010-1 and PD 8010-2. The new PD 8010-4 is organized as follows:

- an extended introduction intended for senior executives;
- recommendations intended for use by integrity management practitioners;
- annexes giving additional information and guidance.

Use of this document

Integrity management is a complete process for a pipeline system, covering its life from design to abandonment. This part of PD 8010 gives guidance on integrity management through the design, construction, testing and operation phases of a pipeline system, as described in PD 8010-1 and PD 8010-2. It is intended to be used by integrity engineers, but it also provides guidance for design engineers, installation engineers, and people working in the supply chain. Managers at all levels within organizations are encouraged to read the Introduction, which explains the importance of integrity management of pipeline systems.

As a code of practice, this part of PD 8010 takes the form of guidance and recommendations. It should not be quoted as if it were a specification and particular care should be taken to ensure that claims of compliance are not misleading.

Any user claiming compliance with this part of PD 8010 is expected to be able to justify any course of action that deviates from its recommendations.

It has been assumed in the preparation of this Published Document that the execution of its provisions will be entrusted to appropriately qualified and experienced people, for whose use it has been produced.

Presentational conventions

The provisions in this publication are presented in roman (i.e. upright) type. Its recommendations are expressed in sentences in which the principal auxiliary verb is "should".

Commentary, explanation and general informative material is presented in smaller italic type, and does not constitute a normative element.

Contractual and legal considerations

This publication does not purport to include all the necessary provisions of a contract. Users are responsible for its correct application.

Compliance with a Published Document cannot confer immunity from legal obligations.

0 Introduction

0.1 General

This part of PD 8010 provides all those with an involvement in pipeline systems – designers, equipment manufacturers, fabricators, constructors, installers, executive operators, site operators, control room operators, integrity and maintenance engineers, safety and associated pipeline personnel – with guidance on how to ensure that any pipeline system retains its integrity: i.e. that it continues to function as originally intended for the duration of the required operating life, which might be significantly longer than the original design life.

Subclauses **0.2** to **0.8** present the high level management policy and principles, and the framework under which a successful integrity management process can be achieved. These subclauses are recommended reading for all senior managers whose responsibilities are associated with the design, construction, testing or operation of pipeline systems.

Cross-references are given to the subclauses in the main text which deal with each issue in greater detail.

In any pipeline system, it is not sufficient solely to ensure that there are no leaks of hydrocarbons or other chemicals to the environment; the system needs to be able to transport fluids throughout its operating life without blockages, unacceptable reductions in flow rate, or de-rating required due to excessive corrosion or erosion. The management of reliability and maintainability in operations is closely related to integrity management.

Clauses **4** to **12** provide recommendations for executive operators, site operators, control room operators and contractors regarding:

- how to manage system integrity and reliability throughout the life of a pipeline system;
- the features that will encourage integrity and reliability, and support maintainability, throughout the pipeline system's operating life, from the design stage, including shut-down periods and into the decommissioning phase.

The recommendations can be applied to any pipeline system at any stage in its life (e.g. new facilities, or existing pipeline systems when the executive operator, site operator and control room operator will not have been involved at the design phase).

The aim of a pipeline integrity management system is to achieve safe operation and 100% availability and capacity at all times, except for planned shut-downs. Intervention due to a potential or actual integrity issue can result in significant repairs, or even full or partial shut-down. Subsea repairs can be particularly difficult as compared to pipelines on land.

It is much better to avoid the requirement for intervention, or to optimize such interventions that might be required, by paying attention to good design, high quality manufacture and careful installation, than to carry out unplanned interventions during the operating life. Good operation, inspection and maintenance are equally important in avoiding unplanned interventions.

0.2 Management policy

An integrity management policy is required for pipeline systems (see **4.1**).

0.3 Key principles

It is important that certain key principles are established, including:

- authorization at the highest level;
- adequate resources;
- definition of key roles and processes, including lines of communication with all third parties;
- regular review and auditing of processes;
- definition of necessary reports;
- interface management;
- definition of "failure";
- investigation of incidents, including failures;
- consideration to through-life integrity management.

Further guidance is given in **4.2**.

0.4 Outline of the integrity management process

The integrity management of a pipeline system includes the following activities:

- contributing to the design of the pipeline system;
- defining the pipeline system;
- subdividing the pipeline system into segments;
- defining the threats to the pipeline system;
- identifying the failure modes following from the threats;
- gathering failure likelihood data;
- identifying the consequences of each failure mode;
- carrying out a risk assessment;
- planning for mitigation;
- carrying out process and condition monitoring;
- carrying out inspection;
- carrying out repairs and modifications;
- managing information.

Further guidance is given in **4.3**.

0.5 Management processes

The following specific processes are an important part of the overall integrity management process:

- operational procedures;
- spares philosophy;
- preparedness;
- review and audit;
- management of change;
- emergency response;

- incident investigation and learning;
- competence assurance.

Further guidance is given in **4.4**.

0.6 Documentation

Every pipeline system will require documentation to be in place which will, as a minimum, address:

- risk mitigation;
- design, fabrication and installation;
- operations.

Further guidance is given in **5.2**.

0.7 Key roles and responsibilities

It is important that the roles and responsibilities of all persons involved in pipeline integrity management are defined and, as a minimum, include the following roles:

- asset owner (**3.1.2**);
- responsible person (**3.1.11**);
- technical authorities (**3.1.14**);
- control room operator (**3.1.8.1**).
- executive operator (**3.1.8.2**);
- site operator (**3.1.8.3**).

Further guidance is given in **5.3**.

0.8 Reporting

It is important to define the requirements for reporting, including but not limited to:

- reports to legislative authority;
- reports to senior management and third parties;
- reports of tests and inspections carried out;
- reports of non-conformities.

Further guidance is given in **5.4**.

1 Scope

This part of PD 8010 gives recommendations and guidance on integrity management of steel pipelines on land and subsea pipelines, as defined in PD 8010-1 and PD 8010-2 respectively.

2 Normative references

The following documents, in whole or in part, are normatively referenced in this document and are indispensable for its application. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

PD 8010-1, *Code of practice for pipelines – Part 1: Steel pipelines on land*

PD 8010-2, *Code of practice for pipelines – Part 2: Subsea pipelines*

3 Terms, definitions and abbreviations

3.1 Terms and definitions

For the purposes of this part of PD 8010, the terms and definitions given in PD 8010-1, PD 8010-2 and the following apply.

3.1.1 anomaly limit

value of a parameter of a potential failure mode above or below which the component is no longer considered fit for purpose

3.1.2 asset owner

individual who is responsible to the senior management for the performance of an asset

3.1.3 failure mode

manner in which a component or system might fail

NOTE Typical failure modes for pipelines include leak and rupture.

3.1.4 header

<of manifold> principal component of pipework that is normally used for gathering production

3.1.5 inline inspection tool

device or vehicle that uses a non-destructive testing technique to inspect a pipeline from the inside

NOTE Most inline inspection tools use either MFL or UT measurements to measure wall thickness, coating defects and identify other inline pipeline defects.

3.1.6 integrity management

set of processes that ensures incident-free transportation of fluids through a pipeline system

3.1.7 J-tube

rigid tube on a platform through which a riser (rigid or flexible) is pulled

3.1.8 operators

3.1.8.1 control room operator

individual who manages and controls a pipeline system

3.1.8.2 executive operator
company or organization responsible for the operation of pipeline systems

NOTE In the industry, this is usually referred to as an "Operator", with an upper case "O".

3.1.8.3 site operator
company or organization responsible for carrying out the instructions of the executive operator

NOTE In the industry, this is usually referred to as an "operator", with a lower case "o".

3.1.9 produced water
water native to a reservoir and produced with hydrocarbons

3.1.10 quill
component of chemical injection that ensures proper dispersal of the chemical into the flow

3.1.11 responsible person
person who is knowledgeable about the operation of the pipeline system and who takes responsibility for its integrity

3.1.12 risk assessment
process of identifying threats to the integrity of a pipeline, estimating the likelihood and consequence of failure to determine risk, and evaluating the calculated risks to determine their significance

3.1.13 safe operating limit
value of an operating parameter beyond which the system should not be operated

3.1.14 tree
system for isolating and controlling the flow to and from a well

3.1.15 umbilical core
tube or tubes for the conveyance of hydraulic fluid or chemical

3.1.16 water cut
percentage of produced water (**3.1.9**) in the production stream

3.1.17 water injection
process of injecting water into a reservoir to maintain reservoir pressure and/or sweep out oil

3.1.18 wax
long chain paraffins (alkanes), generally with 20 or more carbon atoms

NOTE Pure waxes are white odourless solids with melting points between 45 °C and 65 °C.

3.2 Abbreviations

For the purposes of this part of PD 8010, the following abbreviations apply.

CDT	current drain test
CIPS	close interval potential survey
CIS	chemical injection system
ESD	emergency shut-down
ESDV	emergency shut-down valve

HAZID	hazard identification study
HAZOP	hazard and operability study
HPU	hydraulic power unit
IPPS	instrumented pressure protection system
IRCD	injection rate control device
LRU	long range ultrasonics
MEG	monoethylene glycol
MFL	magnetic flux leakage
MIC	microbially-induced corrosion
MoC	management of change
NDT	non-destructive testing
ROV	remotely operated vehicle
SCADA	supervisory control and data acquisition system
SIT	silicon intensifier target
SMART	specific, measurable, achievable, relevant, time-based
SRB	sulphate reducing bacteria
SSIV	subsea isolation valve
SSS	side-scan sonar
TEG	triethylene glycol
UT	ultrasonic testing (inspection and measurement)
UTM	umbilical termination module

4 General recommendations

*COMMENTARY ON CLAUSE **4***

The term "integrity management" encompasses all the activities required to ensure that a pipeline system delivers the design requirements throughout the required operating life. It also includes all activities required prior to commissioning (e.g. design, procurement, fabrication, installation) to ensure that the system is optimized for achieving integrity throughout its life, and all activities required to make decommissioning or out-of-service planning as straightforward as possible.

4.1 Management policy

The integrity management policy should define the basis upon which the integrity management process for a pipeline system is established.

NOTE A set of typical policy requirements is given in Annex A.

4.2 Key principles

The key principles for a successful and effective integrity management process are listed below.

a) The policy should be authorized at the highest level in the organization and should be promulgated to every person who has an involvement with pipeline operations, in every asset, as a fundamental aim of the organization.

b) The organization should provide adequate resources, in terms of both equipment (including software) and suitably qualified, trained and experienced personnel, for the achievement of the policy.

c) The organization should define key integrity management roles, lines of communication and responsibilities.

d) The organization should require the definition of the integrity management process by the designated responsible individual(s). The process should be clearly defined, including performance indicators, and should be audited regularly. Some performance indicators should measure the performance of senior management.

e) The organization should ensure that the processes are reviewed and audited regularly (e.g. annually), and updated as required.

f) The reports required by senior management, and by the relevant legislative authority, should be clearly defined.

g) Particular attention should be paid to managing interfaces in the system, e.g. between technical groups, between the organization and third parties, and between project phase and operations.

h) The term "failure" should be clearly defined in the context of the organization. Some might view failure as limited to loss of containment of hazardous fluids to the environment, possibly with safety implications, whereas others might view any condition that constrains maximum production as a failure.

i) All incidents (including failures) should be fully investigated and the outcomes promulgated to ensure that lessons are learned and good practice updated.

j) It should be emphasized that integrity management commences during the design phase (with definition of maintainability and integrity management-friendly design), and continues throughout the life cycle into the decommissioning phase.

4.3 Outline of the integrity management process

*COMMENTARY ON **4.3***

*The integrity management of a pipeline system involves the activities outlined in **4.3.1** to **4.3.13**. It is important to recognize that the outputs of the early activities (e.g. defining the pipeline system, system subdivision, defining the threats, etc.) are not fixed: rather, they are all part of a live system that will need to be adjusted in the light of operating experience and changes.*

4.3.1 Contribute to the design of the pipeline system

Personnel who are knowledgeable in the operation of pipeline systems should contribute to the design and procurement process, in order to achieve the policy objectives. Executive operators, site operators, control room operators and third party operators should understand, and agree with, the assumptions made, and should define potential mitigations if any of these assumptions prove in service to be incorrect.

4.3.2 Define the pipeline system

The limits of the pipeline system for which the integrity management activities apply should be clearly defined and documented.

4.3.3 Subdivide the pipeline system into segments

The risks are not uniform throughout a pipeline system, partly due to geography and geometry, partly because of changes in internal conditions (e.g. fluids hotter nearer the production well or after a pump/compressor station), and partly because unrelated, threatening activities might be localized. The pipeline system should therefore be divided into segments, selected to seek uniformity of risks, or risk management. Components of the system (e.g. SCADA, leak detection or CIS) may also constitute segments. Care should be exercised not to overly segment the pipeline, as each segment requires the completion of the risk assessment process.

NOTE See Annex B for further guidance on CIS.

4.3.4 Define the threats to the pipeline system

The threats constitute the generic causes that can lead to failure of components within different segments of different pipeline systems, based upon world-wide operating experience. The possible threats should be addressed for each defined segment of the pipeline in question, taking full account of their specific characteristics. A threat list should be created (see **7.2**).

4.3.5 Identify the failure modes following from the threats

The threat list (see **4.3.4**) should be used as the basis for defining the failure modes that apply to each component of each segment.

The initial identification of failure modes should be carried out during the design phase, at the same time as the initial risk assessment (see **4.3.8**).

4.3.6 Gather failure likelihood data

Data should be obtained on the probabilities of different threats and failure modes in different locations and conditions. Information on the effectiveness of mitigation should also be obtained as it becomes available.

4.3.7 Identify consequence of failure modes

The consequence of failure associated with each failure mode should be assessed for each segment (see **7.2.6**).

4.3.8 Carry out a risk assessment

A risk assessment should be carried out (see **7.2**), working though each component in each segment, listing every applicable failure mode, and assigning probability and consequence values.

NOTE Risk is the product of probability and consequence. Probability can be assigned quantitatively or qualitatively to the failure mode in question. Consequence includes safety, environmental damage, need for containment and repair, deferral of production, and impact on reputation.

The risk assessment should be carried out for the base case, without mitigation, and then for the mitigated case. The reason for this is that the mitigation activities (i.e. activities to be carried out by, or on behalf of, the integrity management personnel during operations) effectively define the integrity management process and, if these are not carried out, the risk reverts to the unmitigated value.

It is important that senior management recognize the implications of not carrying out the mitigation activities (i.e. heightened risk of failure), and provide adequate resources and support to the integrity management process.

4.3.9 Introduce mitigation

The mitigation activities should be identified during the risk assessment, which should also facilitate prioritization of tasks, including:

a) inspection;

b) surveillance;

c) monitoring;

d) sampling;

e) testing;

f) maintenance.

NOTE Further guidance is given in Annex C.

4.3.10 Carry out process and condition monitoring

Monitoring, sampling and testing should be carried out in accordance with the mitigation measures (see **4.3.9**). The condition of equipment should be ascertained, and the need for maintenance should be assessed.

Much of the data will be obtained through process monitoring. Data acquisition is therefore not risk-based, but the schedule for review of relevant data by the integrity management team should be.

4.3.11 Carry out inspection and surveillance

Inspections should be carried out to validate that the pipeline segment is operating within the required parameters, and that the mitigation measures (see **4.3.9**) are effective. This may be achieved by the use of internal inspections using inline inspection tools, and external inspections incorporating visual, sonar and above-ground survey techniques.

NOTE Subsea inspection can be carried out by divers, but they are limited by water depth and local metoceanographical conditions.

4.3.12 Carry out repairs and modifications

Repairs and/or modifications should be carried out as required to address any anomalies identified during inspection.

4.3.13 Manage information

The acquisition and management of data is an essential part of the integrity management process.

Data trending should be used to reveal degradation and to allow the assessment of the point at which a component will cease to be fit for purpose (e.g. wall thickness reaches an unacceptable limit).

Data, including calculations, analyses, reports, etc., should be stored centrally, and be accessible (with the necessary security) to a variety of users. Where possible, data should be integrated with respect to length/position/chainage along the pipeline, in order to identify location-specific issues.

4.4 Management processes

4.4.1 Operational procedures

NOTE See also ***5.2.4****.*

Operational procedures should be clearly established and laid out for integrity to be successfully managed. Day-to-day operations are always subject to unexpected occurrences, and the risk of these should be assessed and plans for the required rectification put in place.

4.4.2 Spares philosophy

NOTE See also ***11.2****.*

The risk assessment leads to the priority list of failure modes. If the most likely failures can be prevented or repaired by replacement of components, then the system can be brought on line most quickly if spares are stocked. However, some spares can lose calibration, or degrade, while in storage. The spares philosophy should take account of both the positive and negative aspects of stocking spares.

Where spares are held, maintaining the integrity of those spares, and the management of obsolescence, should be part of the integrity management process.

4.4.3 Preparedness

NOTE 1 See also ***11.3****.*

The risk assessment should include the creation of a priority list of threats and failure modes. The response required for some failures might involve major shut-downs and complex interventions (e.g. serious internal corrosion of a pipeline). Contingency plans should be developed for the threats and failure modes higher on the priority list that fall into this category. Contingency planning should include:

- how to blow down the system;
- how to calibrate or measure the defect;
- understanding examination and testing protocols (e.g. inline inspection);
- suppliers of intervention equipment (e.g. hot tap spreads, welding habitats);
- primary intervention contractors;
- preparing procedures for the activities that will be required.

NOTE 2 The integrity management process defines what failures might occur.

4.4.4 Review and audit

NOTE See also Clause ***12****.*

Senior management should expect the responsible person for the pipeline system to regularly review the integrity management process. They should also require that the process is audited by an independent body at intervals.

Senior management have responsibilities in relation to integrity management, and should anticipate that some performance indicators will relate to their own performance (e.g. provision of adequate resources).

4.4.5 Management of change

The organization should have a documented management of change (MoC) procedure to assess potential impacts on the safe operation of the existing system, and to control and approve changes. Any changes proposed within the integrity management process should be subject to the MoC procedure.

The MoC process should be used to identify possible failure modes resulting from any proposed change (e.g. to hardware; to a process; of a vendor or supplier; to the organization; to resourcing), after which a risk assessment should be carried out, and mitigations put in place where necessary. Production operations, and integrity, reliability and pipeline engineers should all participate in the process.

The changes, the reasons for the change(s), the risks and the mitigations should all be recorded in the information management system (see Clause **10**), so that all personnel who assume responsibility for aspects of the system later in the life cycle can find out what deviations from the original design intent have been adopted, and why.

MoC procedures should be adopted during the design process once the initial basis of design has been agreed, and at any time thereafter throughout the whole life cycle until decommissioning.

4.4.6 Emergency response

Certain failures within a system can be so critical as to require an immediate response to protect safety or the environment. This immediate response is referred to as emergency response, and procedures, with action check lists, should be available to the control room operators and the organization's central emergency response team prior to the pipeline being brought on stream for the first time.

The priority listing from the risk assessment should be used to identify all possible emergency scenarios that could affect the system, and emergency response procedures should be drawn up for each.

4.4.7 Incident investigation and learning

Organizations should develop procedures for incident investigation to ensure that a structured approach is adopted and all aspects reviewed. It is important that an incident investigation should aim to determine the root cause of an incident.

The incident investigation should start with a clear definition of the event, which can be obtained from records, physical evidence and interviews. This should lead to the identification of root causes, which might relate to the environment, the hardware, the organizational structure and character, or the people, including their training and competence. The investigation should seek to understand what went wrong, why it went wrong, how the response might be improved, and how the problem might be avoided in future.

NOTE 1 A check list might include:

- *facilities – not inspected according to current plan;*
- *facilities – not addressed, or incorrectly addressed, in risk assessment;*
- *equipment, materials, tools – defective, inadequate or wrong type for function or task;*
- *facilities or equipment – lack of maintenance, inspection or housekeeping;*
- *correct safety protection or equipment not provided;*
- *failure to use safety protection or equipment provided;*

- *Hazard and Operability study (HAZOP) – not carried out, or actions not completed ahead of task;*
- *inadequate procedure;*
- *lack of training;*
- *use of unqualified or non-competent personnel;*
- *lack of suitable supervision;*
- *poor communications;*
- *poor interface management.*

On completion, the investigation report should be submitted to the relevant managers, who should act upon the findings. The outcome of the investigation should be promulgated widely within the organization to minimize the likelihood of repetition or to improve the mode of response. So far as is compatible with confidentiality, the outcomes should also be shared throughout the industry.

Personnel should not await the submission of the incident report to start putting into action obvious lessons from the incident.

NOTE 2 Damage assessment can be seen as a subset of an incident investigation. It is necessary to determine the extent of damage, but also to understand the underlying causes, before specifying the repairs required. The necessary repairs can be achieved most expeditiously if contingency plans have been put in place (see ***11.3****).*

4.4.8 Competence assurance

Management should establish clear competence requirements for all the roles defined within the pipeline integrity management organization, from senior levels to technicians and operations staff. A process should be put in place to ensure that only competent personnel are assigned to posts unless they are training under supervision. Management should ensure that their staff are fully equipped to carry out their responsibilities.

5 Integrity management processes

5.1 Overall process

Integrity management is a sequence of activities that often takes the form "define – plan – implement – feedback". It is important to appreciate the continuity of the risk assessment throughout the life cycle.

The design process should:

- define what is required to ensure that integrity can be managed;
- plan how to fit this into the design;
- implement the design;
- review and make sure the requirements are satisfied (and feed back accordingly).

The issues related to integrity management that should be addressed during the design process are described in Clause **6**.

Those who will be required to operate the pipeline system should contribute to the design and procurement. Operations staff should understand the assumptions made, and define potential mitigations in the event that any of the assumptions are incorrect.

It is recognized that in some circumstances, e.g. acquisitions or old/aged/existing pipeline systems, the executive operator will not be involved at the design phase.

Because new information tends to be acquired and the degree of detail increases during the design process, the design process needs to be flexible and take account of these changes. The integrity management process is the same. The solution is honed through the design process. If the effectiveness of the design is based upon actions to be carried out by the site operators, control room operators and third party operators, a formal system should be in place to ensure that the operators are fully informed both of what those actions are, and of how and why they are to be carried out.

The review process continues to apply once the pipeline is in operation and throughout its operating life.

A fundamental aim should be to develop a system that incorporates experience and learning. Another aim should be to streamline the system and discard superfluous activity wherever possible. In other words, only necessary activity should be repeated.

The integrity management process should take into account the experience gained from previous projects, and each process should take into account any feedback received on the previous processes. In the event that an asset is acquired by a new executive operator, the integrity management organization should ensure that it takes into account the history and experience from the previous owner.

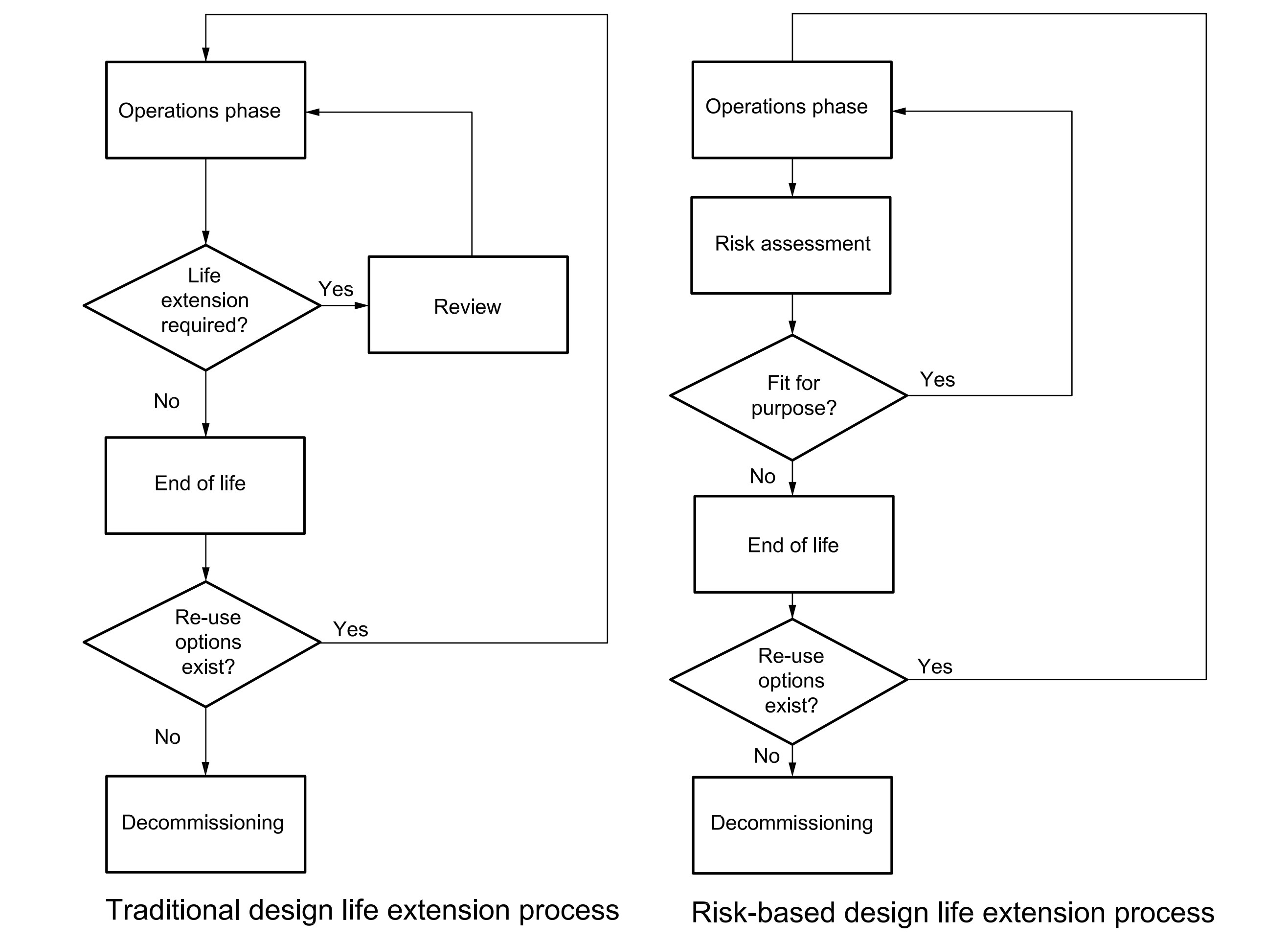
At the outset, a design life will have been established. The design life will have been employed to determine such factors as the appropriate environmental and fatigue loads, the likely rates of internal and external corrosion, the extent of coating breakdown, the cathodic protection requirements, material degradation, etc. Prior to operating the pipeline beyond its nominated design life, the executive operator of the pipeline should assess the current condition of the pipeline and its operating history, in order to determine the future fitness for purpose of the pipeline and hence establish an extended design life. Using a risk-based integrity management strategy, the predicted remaining operating life of the pipeline should be regularly assessed and compared against the original design life, thus negating the need for a formal restatement of the design life.

The decommissioning and abandonment processes (see PD 8010-1 and PD 8010-2) will determine whether there is a need to continue integrity management thereafter.

Any opportunity during or at the end of the life of a pipeline system should be taken to carry out inspection and testing of recovered components, to investigate their condition. Lessons learned should be used to improve the integrity of existing and new systems.

The design life extension process, traditional and risk-based, is shown in Figure 1.

Figure 1 **End of operating life**



5.2 Documentation

5.2.1 General

As a minimum, organizations should require the documentation described in **5.2.2** to **5.2.4** to be in place for every pipeline system.

NOTE Attention is drawn to the Pipeline Safety Regulations 1996 [2] regarding additional documentation for major accident hazard pipelines.

5.2.2 Risk mitigation documentation

At the end of the design cycle, documentation should be produced that includes:

a) all the assumptions made during the design, and the implications if the assumptions are incorrect;

b) all the risks identified for the system, and how they have been mitigated by design, or how they are to be mitigated by actions, imposed on the site operators, control room operators and third party operators, to be undertaken during the operations phase;

c) the safe operating limits of the system; and

d) the performance standards required of any critical equipment.

The risk assessment included in this documentation should become the basis of the risk assessment used in the operations phase.

NOTE In addition to the above, some pipelines will have legal requirements that include emergency response plans and major accident hazard pipeline plans.

5.2.3 Design, fabrication and installation documentation

Documentation should be produced prior to commissioning that includes:

a) a summary of the design basis and parameters;

b) a record of the adjustments, events and non-conformances of the fabrication and installation phases;

c) a statement of the safe operating limits of the system.

This should be readily accessible on a day-to-day basis, and should be maintained and kept up to date throughout the life of the pipeline until final abandonment, e.g. details of modifications and repairs, or changes in transported fluid chemistry.

This documentation should provide the site operators, control room operators and third party operators with all the information they require to operate the system safely and effectively.

NOTE Attention is drawn to the Pipeline Safety Regulations 1996 [2] in respect of the requirement to declare safe operating limits.

5.2.4 Operations documentation

Documentation should be produced, which should include the following as a minimum.

- **Pipeline operations and control philosophy**. This should describe how the pipeline system is to be operated and controlled, e.g. continuous or batched, pigged or not, continuous production or peak shaving, flow or pressure control. The operations philosophy will influence the design of the pipeline system and the integrity management arrangements.
- **Pipeline inspection and maintenance philosophy**. This should describe the basis for undertaking the inspection and maintenance of the pipeline system, e.g. risk-based or deterministic, preventative or breakdown. It should identify the maintainable items, their criticality to the integrity of the system, their reliability and the strategy for ensuring their availability.
- **Pipeline integrity management system**. This should include:
  - an overall statement as to how integrity is to be managed. This should define the executive operator’s aims in terms of integrity management, the limits of the system to be managed (including definition of responsibilities shared with third parties), the key processes, the key roles and responsibilities (see **5.3**), and the relevant guidance documents; and
  - detailed guidance on the integrity management process. This should define the system in detail, including segmentation of each system (see **7.2.2**), and the activities required to be carried out to fulfil the aims of the integrity management strategy. It should define those documents lower in the hierarchy that detail these activities. This document should also define the performance indicators, which determine how the effectiveness of the scheme will be measured (see **5.5**).
- **Integrity management manuals**. These should define the various processes and activities, e.g. risk assessment, corrosion management and inspection procedures. The specific list is likely to vary with the type of asset.

- **Operations procedures**. These should include detailed instructions on how the pipeline system will be operated under all anticipated circumstances, including both normal operations (e.g. swabbing pigging or batching) and abnormal operations (e.g. inline inspection or shut-down).

5.3 Key roles and responsibilities

Individual organizations will have their own management structures and systems, so specific guidance cannot be given.

As a minimum, the following roles should be defined and the personnel who undertake them identified:

- asset owner;
- responsible person;
- technical authorities;
- operator.

Organizations should establish clear competence requirements for all the roles listed, as well as for other engineers and technicians involved in operations and integrity management, and should ensure that their staff are fully equipped to carry out their responsibilities.

Some pipeline systems will commence or terminate at, or cross, sites operated by other executive operators. In such circumstances, the roles and responsibilities of the third party should be formally defined and documented, including lines of communication and reporting procedures.

5.4 Reporting

Reporting, mainly related to the operations phase, occurs on three levels:

- outside the company, e.g. to legislative authorities, possibly to satisfy legislative requirements;
- upwards within the company, e.g. from responsible person to asset owner, or from asset owner to senior management, on the status of the asset/system;
- laterally, e.g. between disciplines and departments, both within the company and in third parties (including inspection authorities), associated with the daily integrity management processes.

The requirements for reporting on all these levels should be clearly defined within the integrity management scheme, in terms of both what should be reported, and by whom. The requirements will generally be at the discretion of individual organizations. The following are examples of reports that may be used.

- Periodic integrity report to legislative authority – this may be a written submission, or a verbal presentation, depending upon local requirements, and should confirm fitness for purpose for the medium term and/or flag up any significant maintenance or upgrades planned.
- Periodic integrity report to senior management – this should confirm the fitness for purpose of the pipeline, both currently and the predictions for the required operating life, or, alternatively, should highlight potential problems that might impact on production or budgets in the medium term (short-term issues should have been reported via more immediate processes).
- Periodic integrity reporting to third parties – in some cases, a pipeline operated by one organization crosses a facility (e.g. platform, terminal)

operated by another organization, and these reports should be passed in both directions so that both parties are aware of the total integrity status of the system.

- Reports of tests carried out – for instance, this may include the regular testing of emergency shut-down valve closure and leak testing, or the regular gas analysis of transported fluids for levels of CO_2, H_2S, etc.
- Reports of inspections carried out – for instance, this may include inline inspection or external inspections.
- Reports of non-conformities – for instance, this may include leaks, valves failing to close or seal, or pig trap doors failing leak tests.

Where there are interfaces in the system, such that one group of personnel might not be aware of the relevant actions that another group has carried out, a formal reporting requirement can be beneficial.

Interfaces occur between life cycle phases (e.g. between design and manufacture, or between project and operations), between zones (e.g. between topside, subsea and onshore), between groups (e.g. between operations and integrity, or between well engineering and pipeline operations) and between organizations (e.g. between third parties). One of the main root causes of incidents and failures is that responsibilities, or information, failed to cross one or more interfaces. Identifying and managing interfaces is therefore critical to pipeline operations, including integrity management.

5.5 Performance indicators

NOTE 1 Performance indicators show where performance is good, average or deficient. Where it is deficient, remedial measures are required immediately; where it is average, there is scope for improvement.

A system should be put in place to measure the extent to which the integrity management scheme is being followed. A common method is the use of performance indicators, and a comprehensive system should use both leading and lagging indicators as follows.

- Leading indicators are used to confirm that integrity tasks are undertaken as intended as a means to show that the mitigations in place are active.
- Lagging indicators measure the degree to which the system has not, in fact, worked as intended, by identifying failures, real or potential.

The indicators should be selected by those involved in the process (i.e. not externally imposed), and should be SMART (see **3.2**).

They should also be meaningful: for instance, "pigging runs achieved in accordance with the plan" is both SMART and meaningful, while "kilometres of pipeline inspected per year" is SMART but not meaningful, since there is no requirement to maximize or minimize this – the scope is a function of the risk-based plan. Performance indicators can be negative: for instance, "the number of anomalies not closed out by a certain date" is both measurable and meaningful, since outstanding anomalies represent known threats to integrity.

NOTE 2 Examples of leading indicators are:

- *percentage of aerial surveys achieved against the annual plan;*
- *percentage of inline inspection runs achieved against the annual plan;*
- *chemical injection system availability against design requirement;*
- *percentage of anomalies not closed out by the due date.*

NOTE 3 Examples of lagging indicators are:

- *number of third party infringements;*

- *number of inline inspection runs that reveal corrosion rates in excess of the design assumption (or that rate modified in the light of subsequent trending);*
- *number of valves failing to meet performance standard;*
- *number of leaks of hydrocarbons to the environment from the pipeline system.*

Organizations should establish leading performance indicators at senior manager level as well, to ensure that they recognize their responsibility for supporting the integrity management function.

6 Design for integrity

6.1 General

Integrity management of the pipeline system should be first addressed at the design stage.

The pipeline integrity management system should be developed with the aim of achieving 100% availability and capacity at all times, except for planned shut-downs.

6.2 Procurement quality assurance

The procurement quality assurance process should be in accordance with PD 8010-1 for steel pipelines on land and PD 8010-2 for subsea pipelines.

Deviations and concessions against specified requirements that are established as part of the quality assurance system during or subsequent to procurement should be taken into account in the integrity management system and detailed in the design, fabrication and installation documentation referred to in **5.2.3**.

6.3 Installation, testing and commissioning

Installation, testing and commissioning comprise a short period of the total life cycle, but can have a significant influence on the integrity of the pipeline system throughout its operating life.

Damage that can occur during or subsequent to installation and testing, e.g. weld defects, coating damage and dents, should be taken into account in subsequent integrity management, including the maximum surviving defect size established by the hydrostatic test pressure.

Information during commissioning, relating to the operation of the system, should be collected and used in condition monitoring and integrity management, e.g. valve hydraulic profiles and fluid usage.

6.4 Piggable systems

Pipeline systems should be designed to use inline inspection tools. In many cases this is the most effective way of confirming that the integrity management strategy has been effective.

6.5 Reliability, maintainability and data accessibility

In order to achieve a design of pipeline that can be well managed, it is important to maximize:

- reliability (i.e. to use well-established processes to minimize failures);
- maintainability (i.e. to make it as easy as possible to conduct maintenance); and
- data accessibility (i.e. the ability to identify degradation and to conduct diagnostics).

7 Risk management

7.1 General

The risk management process should consist of three main steps:

- risk assessment;
- risk mitigation;
- review.

Risk assessment should be carried out at the design stage to determine mitigation measures that are required before the pipeline is constructed and commissioned.

Review and update of the risk assessment should be carried out on a regular basis throughout the pipeline life, including during design, operation and decommissioning.

7.2 Risk assessment

7.2.1 Overall approach

Risk assessment should be carried out using a semi-quantitative method that includes the following activities:

a) segmentation of the pipeline system;

b) identification of threats;

c) estimation of failure likelihood (probability);

d) identification of failure mode;

e) estimation of failure consequence;

f) evaluation of the risk.

The outcome of the assessment should be presented on a risk matrix in terms of likelihood and consequence, the categories for which should be defined in quantitative terms where possible. An example of a risk matrix is shown in Figure 2.

NOTE Figure 2 shows a 5 × 5 matrix, but any dimension can be used. It includes a possible set of likelihood and consequence level key word definitions.

It is important to have definitions that are unambiguous, consistent, and that minimize the degree of subjectivity. Therefore, the key word definitions inserted in the matrix should be expanded elsewhere so that those carrying out the risk assessment are clear on the boundaries of each level.

Risk assessments should be carried out by a group that includes competent and experienced representatives of those responsible for operating, maintaining and managing the integrity of the pipeline system. Between them, they should have adequate knowledge of the system to be able to assign accurate likelihood and consequence values, and to be able to define practicable mitigation measures. Possibly assisted by a facilitator, they should work through all the threats for each of the identified segments of the system. It is important to involve those who will be responsible for the various disciplines during operations, or 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.

Figure 2 **Example risk matrix**

			Risk				
Likelihood	VH	Almost certain	M	H	H	VH	VH
	H	Likely	L	M	H	H	VH
	M	Possible	L	M	M	H	H
	L	Unlikely	VL	L	M	M	H
	VL	Improbable	VL	VL	L	L	M
Risk category		Safety	First aid	Lost time injuries	Few major injuries	Few fatalities	Many fatalities
		Environment	Low-level	Moderate	Large	Major	Disaster
		Cost	Cost levels to be determined				
			VL	L	M	H	VH
			Consequence				

7.2.2 Segmentation

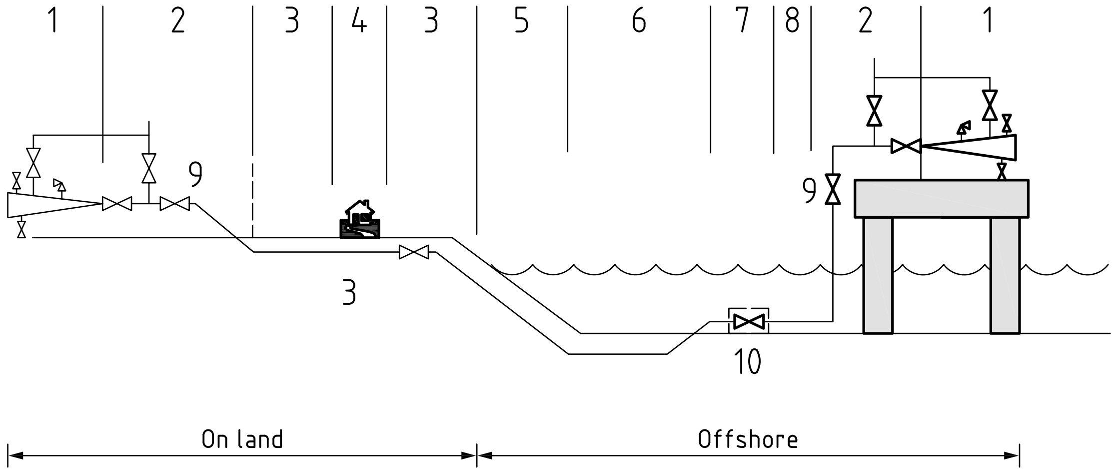
The pipeline system should be divided into segments based on pipeline characteristics and the characteristics of the area through which the pipeline passes. The choice of segments should be such that failure likelihood and consequence can be considered uniform within each segment.

An example of segmentation for a typical pipeline system is shown in Figure 3.

NOTE In addition to the items shown in Figure 3, a typical system might include:

- *above-ground installations such as compressor or pump stations, block valve stations;*
- *cathodic protection systems including anodes, transformer rectifiers, ground beds;*
- *corrosion and hydrate inhibitions systems;*
- *SCADA system including sensors, telemetry, processors, displays;*
- *control systems including buttons, telemetry, cables, actuators;*
- *over-pressure protection systems;*
- *leak detection systems including inputs, processors, outputs;*
- *ESD system including inputs, processors, outputs.*

Figure 3 **Typical pipeline system segmentation**



Key

1 Pigtrap
2 Pipework
3 Landline
4 High consequence area
5 Landfall
6 Seabed pipeline
7 500 m zone
8 Riser
9 Emergency shut-down valve
10 Subsea isolation valve

7.2.3 Threat identification

Threats to the integrity of the pipeline should be identified for each segment. Threats should be determined based on experience of operation of similar pipeline systems, but as a minimum the threats listed in Table 1 should be taken into account for each segment.

Threats considered to be non-credible for a particular segment should be documented.

Processes such as hazard identification study (HAZID) and hazard and operability study (HAZOP) may be used as an input to the threat identification.

7.2.4 Likelihood of failure

The likelihood of failure should be estimated for all credible threats identified for each segment. Likelihood of failure may be estimated using industry or local failure statistics, or by probabilistic analysis.

NOTE 1 Failure frequencies for pipelines are presented in a number of databases including those generated by CONCAWE (Conservation of Clean Air and Water in Europe), EGIG (European Gas pipeline Incident data Group), UKOPA (UK Onshore Pipeline Operators Association) and PARLOC (Pipeline And Riser Loss Of Containment).

NOTE 2 PD 8010-3 provides data on failure frequencies for pipelines on land in the United Kingdom.

The effect of existing mitigation measures should be taken into account in the estimation of failure likelihood.

Table 1 **Threats and mitigations**

Threat category	Threat	Typical mitigation measures	
		Design	**Operation**
Internal corrosion	CO_2 corrosion O_2 corrosion H_2S corrosion MIC Erosion	Material selection, e.g. corrosion-resistant alloy Corrosion allowance	Corrosion inhibition Inlet specification control
External corrosion	Galvanic corrosion Crevice corrosion Soil corrosion A.C. corrosion D.C. stray current corrosion Atmospheric corrosion Corrosion under insulation MIC	Coating Cathodic protection	Stray current mitigation
Environmentally assisted cracking	Hydrogen-induced cracking Stress corrosion cracking	Material selection	
Mechanical damage	Third party impact, e.g. excavator, trawl gear, anchor, vehicle impact Dropped objects Sabotage Unauthorized hot taps	Burial	Surveillance Right-of-way marking Public awareness, e.g. one-call Impact protection, e.g. concrete coating/ rockdump/concrete slabs
Natural hazards	Earthquake Landslide River crossing scour	Routing Backfill selection	River bank civil works
Operational issues	Blockage/freezing Incorrect operation		Operator competence assessment/training
Design and materials	Pipe body defects Seam weld defects	Mill quality assurance/ quality control	Pre-commissioning hydrotest
Construction	Girth weld defects Construction damage e.g. dents, gouges	Construction quality assurance/ quality control	Pre-commissioning hydrotest
Equipment failure	Valve Flange Pig launcher/receiver		
Fatigue	Pressure cycling Thermal cycling Cyclic external loading Vortex-induced vibration	Construction quality assurance/ quality control Anti-VIV strakes	Pre-commissioning hydrotest Monitoring of pressure cycles

7.2.5 Failure mode

In conjunction with the threat identification, the possible failure modes should be determined. As a minimum, the two failure modes of leak and rupture should be taken into account. The leak failure mode may be further divided according to the size of leak, and failure modes that involve no loss of containment may also be taken into account.

If more than one failure mode is credible for a given threat, likelihood should be estimated for each failure mode.

7.2.6 Consequence of failure

Consequence of failure should be expressed in terms of three categories:

- safety;
- environmental impact;
- business impact (deferred production, impact on operations, repair, etc).

Business impact may also include reputation and societal effects.

The consequence assessment for each category should be carried out by a specialist in that area.

NOTE PD 8010-3 provides guidance on the calculation of safety consequence for pipelines on land in the United Kingdom.

The consequence of failure should be determined for each failure mode for each segment.

7.2.7 Risk evaluation

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 Figure 2.

The probability and consequence should 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.

7.3 Risk mitigation

The results of the risk assessment should be used to determine where additional mitigation measures are required to reduce risk. Mitigation measures may be applied to reduce either the likelihood of failure or the consequence of the failure.

Mitigation measures may include a combination of physical design changes (e.g. wall thickness), processes, and ongoing inspection, maintenance and repair programmes. Some common mitigation measures for different threats are shown in Table 1.

NOTE PD 8010-3 provides guidance on mitigation measures for pipelines on land.

7.4 Review

Where mitigation is in place, data should be gathered to determine whether it is effective (see lagging performance indicators, **5.5**).

Review of the risk assessment and effectiveness of the mitigation measures used should be performed on a regular basis and, additionally, in response to:

- changes in design or operation of the system;

- acquisition of new information about the system (e.g. the results of an inline inspection run);
- incidents that occur on the pipeline system or systems of similar nature.

8 Process and condition monitoring

Adequate management of pipeline integrity requires acquisition of current data obtained through monitoring of relevant information recorded by the SCADA, CIS and cathodic protection systems, sampling of product to check quality, and testing of the function of critical equipment. Processes and systems should be established to ensure such data acquisition and updating within the pipeline integrity management system.

The integrity engineer should be involved at the design stage in determining what data will be obtained, from where and how, to ensure that integrity can be effectively controlled in operations.

NOTE Further guidance on monitoring, sampling and testing is given in Annex D.

The integrity engineer should also aim to obtain threat-specific information such as:

- the level of construction or maintenance activity (influencing the probability of external impact);
- the level of third party activity in the vicinity of the pipeline (influencing the probability of third party damage).

9 In-service inspection

9.1 General

In-service inspection should be carried out to provide information on the internal and external condition of the full range of a pipeline system.

NOTE 1 Inspection can provide information on the internal condition of the pipelines, but is limited with regard to manifolds, and cannot generally be applied upstream of a manifold (i.e. trees and the associated tie-in jumpers).

Inspection should be used to confirm that mothballed systems, and any components of decommissioned systems that remain in situ, exceed the specified minimum condition and pose no threat to other stakeholders.

NOTE 2 The "specified minimum" condition might refer to, for instance, the amount of degradation a mothballed system can be allowed to sustain.

NOTE 3 Further guidance on external and internal inspection is given in Annex E, and UKOPA recommendations for pipeline inspection and maintenance are given in UKOPA/12/0027 [3], available from the UKOPA website.

9.2 Surveillance of land pipelines

Regular aerial and/or ground surveillance of the pipeline route should be undertaken in accordance with PD 8010-1, at intervals typically not exceeding 2 weeks, or otherwise set using a risk-based assessment. The purpose of surveillance is to monitor third party activity in the vicinity of onshore pipelines, and to identify any changes along the route which might pose a threat to the pipeline integrity, including encroachments, ground movement, soil erosion and flooding. Remedial or mitigation measures required to ensure that pipeline integrity is not affected should be put in place as appropriate.

The type and frequency of surveillance should be determined for each pipeline section, taking into consideration a range of factors such as location and developments in the area, the extent of third party activity, pipeline design (wall thickness and operating stress) and environmental conditions.

NOTE The frequency of inspection can be significantly reduced if the pipeline segment is fitted with an automatic detection system for third party contacts.

In addition to route surveillance, works notification systems should be established to obtain information on planned activities and identify their potential impact on the pipeline. Where appropriate, arrangements for monitoring and supervision of the site work should be put in place to ensure that pipeline integrity is not affected by the work.

9.3 Interpretation of inspection results

Features observed during the pipeline inspection should be assessed to determine their impact on pipeline integrity and the subsequent need for any remedial work. Assessments should be performed using recognized design codes or guidelines, taking into account all potential failure mechanisms and the relative accuracy of the measurement technique used.

NOTE 1 A list of typical features and associated assessment methodologies is given in Table 2.

NOTE 2 In order to increase the efficiency of the assessment process, anomaly limits may be derived. Anomaly limits define a conservative threshold of acceptability for common features such as spans and exposures, which can be used for preliminary screening purposes. Any features violating the anomaly limits will require further assessment.

10 Information management

An information management process should be developed in order to:

- facilitate the management of the pipeline itself, from the commencement of design onwards; and
- ensure that, at any time through the life cycle, including planning for upgrades or decommissioning (and possible re-use of components), it is possible to fully appraise the condition of the pipeline, and to understand the implications of change (see **4.4.5**).

The information to be managed should include:

- background documents, e.g. those defined in **5.2** and facility drawings;
- feedback data, e.g. data from monitoring systems (although some might be held in a production operations logging system, in which case duplication is not recommended), wall thickness measurements, and inspection records (including photographs and video records);
- results, e.g. from the manipulation and trending of live data, and from risk assessments;
- reports, e.g. of the analysis of anomalies, of inline inspection runs, of corrosivity studies;
- performance indicators (see **5.5**).

Information should be managed against the location along the pipeline.

NOTE Further guidance on information management is given in Annex F.

Table 2 **Inspection results: typical features and associated assessment methodologies**

Feature	Applicable code or guideline
Anode loss or depletion	BS EN 12954 BS EN 13509 DNV-RP-F103 [4] ISO 15589-1 ISO 15589-2 NORSOK M-503 prEN 12496 (in preparation)
Coating damage/loss	BS EN 13509 DNV-RP-F102 [5]
Corrosion/metal loss	API 579-1/ASME FFS-1 ASME B31G BS 7910 DNV-RP-F101 [6]
Crack	API 579-1/ASME FFS-1 BS 7910 DNV-OS-F101 [7] DNV-RP-F113 [8]
Dent	API 579-1/ASME FFS-1 ASME B31.4 ASME B31.8 ASME B31.8S API 1160 [9] BS 7608 DNV-OS-F101 [7] DNV-RP-C203 [10] DNV-RP-F111 [11] DNV-RP-F113 [8] UKOPA /10/0051 [12]
Exposure	DNV-RP-F107 [13] DNV-RP-F109 [14] DNV-RP-F110 [15]
Free span	DNV-RP-F105 [16]
Global buckle	DNV-RP-F110 [15] *Germanischer Lloyd Rules for classification and construction – III Offshore technology – Part 4 – Subsea pipelines and risers* [17]
Gouge	API 579-1/ASME FFS-1 ASME B31.4 ASME B31.8 ASME B31.8S API 1160
Local buckle	DNV-OS-F101 [7] PD 8010-1/PD 8010-2

11 Maintainability, spares and preparedness

11.1 Maintainability

COMMENTARY ON ***11.1***

There are two ways to ensure that failures have minimum adverse impact:

- *incorporate redundancy; or*
- *optimize maintainability.*

The method of incorporating redundancy, in the event of this option being selected, falls within the remit of reliability engineering and control systems engineering. Maintainability, on the other hand, is common ground for reliability, integrity and pipeline engineering.

The priority lists generated by the risk assessment process (see ***7.2****) identify those components that are more likely to fail, and whose failure is most critical. The potential for failure of some of these components is minimized by mitigation. In other cases, such as subsea control modules (SCMs), chemical injection valves or temperature and pressure sensors, there might be little that can be done to prevent failure, but failure can inhibit performance and, therefore, it is necessary to make replacement as easy as possible – in other words to optimize maintainability.*

No system can be designed with perfect reliability (i.e. a guarantee that nothing will fail), and therefore failures should be anticipated.

Maintainability should be addressed during design (see **6.5**). If the design does not facilitate easy maintenance, little can be done subsequently to improve this. Subsea, and especially in deep water, the degree of difficulty in replacing components can be high. Therefore, it is important that criticality of components and the need for maintainability is incorporated in the design.

Wherever possible, subsea maintenance tasks should be designed to be carried out without divers, either by ROV, or by dedicated tools.

11.2 Spares philosophy

NOTE 1 See also ***4.4.2****.*

Where replacement has been identified as the maintenance strategy for any component, it follows that spare components should be available for replacement. Spares might not be stocked for all components, however. The spares philosophy (i.e. what spares to keep in stock and which to procure as required) should be driven by the priority lists generated by the risk assessment process. It should also be driven by the reliability of the various components (both as specified at design, and as experienced in practice), which should be advised by the reliability engineer, and the lead times for manufacturing of spares.

NOTE 2 Over significant periods, the spares themselves can degrade, such that they are no longer fit for purpose; or they might become obsolete, superseded by a new or upgraded version, possibly because a generic fault has been discovered. It is important that the integrity of spares is managed along with that of active components.

NOTE 3 One approach that lies midway between stock-holding and procurement as required is to participate in spares sharing clubs, whereby several executive operators or site operators agree to hold spares in common. In some cases, the spares may be partially-manufactured so that the final specification can be adjusted when the demand arises.

11.3 Preparedness

*NOTE 1 See also **4.4.3**.*

Preparedness implies contingency planning. This goes beyond the holding of spares, and applies where the holding of spares is impractical. For example, the amount of downtime for repairs can be reduced if planning has been carried out and procedures developed for isolation, blow-down, flushing, pigging, etc., and if potential suppliers of spares and services have been identified.

The priority listing from the risk assessment should be used to identify the most likely failure scenarios affecting the system as a whole (i.e. not simply component failure, unless such a failure would result in pipeline shut-down), and response plans should be drawn up for each such scenario.

NOTE 2 Attention is drawn to UKOPA guidance on emergency planning (UKOPA/11/0034) [18].

11.4 Emergency materials and repair

In order to respond to major accidental damage or failure, emergency repair materials should be readily available. Such materials should include line pipe, leak clamps and repair sleeves, and required consumables, e.g. coating materials. In addition, procedures for the safe management of damaged pipelines and defect assessment should be in place, and arrangements should be made for immediate access to appropriate plant, materials and expertise needed to undertake essential remedial actions.

12 Review and audit

*NOTE See also **4.4.4**.*

12.1 Review

The feedback included in the "define – plan – implement – feedback" cycle (see **5.1**) can include review of individual tasks, but should also include performance of the overall integrity management process as a whole. The responsible person should undertake a regular review of the process (e.g. at three-monthly intervals), using the performance indicators (see **5.5**), to ensure that personnel are achieving what they are supposed to, and also to confirm that the process is really serving the integrity of the system.

An important part of this review is to attempt to determine what might not have been considered during the design process. One approach to this is to work through a schematic of the system, analysing what is known, with the aim of identifying what is not known.

The review should also include confirmation that:

- the size of the integrity management team is adequate;
- each team member is suitably qualified and competent;
- interfaces with departments and technical authorities are active and well-managed; and
- senior management are aware, and supportive, of the process.

This process enables the responsible person to prepare for audit.

12.2 Audit

At a suitable interval (e.g. annually), the responsible person should organize an audit by an external body (possibly an independent audit group within the parent organization). The audit should draw upon the performance indicators, and also integrity strategy, the integrity management scheme, etc. (see **5.2.4**). The result of the audit should be reported to senior management.

Annex A (informative) Typical policy requirements

Figure A.1 is an illustration of a typical integrity management policy. The actual policy and the way in which it is worded will vary between different organizations.

Figure A.1 **Typical policy requirements**

Integrity management policy

- Pipeline integrity management is defined as: "the management of a pipeline system or asset to ensure that it delivers the design requirements with an adequate safety margin, and does not harm life, health or the environment, throughout the required operating life".
- The assets of the organization will conform to the applicable legislative and statutory requirements, which might pertain to the country of origin of the organization, or to the geographical area in which it is operating, or both.
- All components of every asset will be designed in full accordance with the relevant codes and standards applicable. Similarly, integrity management practice will adhere to the relevant codes and standards and recognized good practice.
- The risks to safety, the environment and commercial aspects that arise due to the operation of any asset will be identified and quantified numerically or subjectively (i.e. quantitatively or qualitatively), and the asset will be managed to reduce or mitigate these risks.
- Any asset will be designed, installed and commissioned, and subsequently operated, to be reliable, maintainable and cost-effective, and to retain its integrity, throughout the operating life.
- The condition of any asset will be established at regular intervals, and data will be updated, so that the life expectancy can be established for a number of management scenarios.
- The integrity management process will be subject to regular review (to make sure the strategy and processes remain fully applicable) and audit (to make sure the processes are being followed).
- The performance of assets will be continually improved by sharing lessons learned around the organization, and through recognized industry forums such as user groups and conferences.

Annex B (informative) The chemical injection system (CIS)

For some pipeline systems, particularly in production environments, it is not possible to control the composition of the product entering the pipeline, and therefore chemical injection is used to control threats to integrity such as corrosion, hydrate formation, scale, etc.

Although the surface area liable to corrosion is far greater in a pipeline than it is in manifold pipework, the latter has many more corrosion-enhancing features (tee connections, elbows, dead legs, etc.) and is generally much harder to inspect, so that design of a CIS to protect the manifold pipework is an important, and frequently overlooked, aspect of the design cycle. In many cases, corrosion-resistant alloy is used for the manifold pipework, but the chemical injection system for the protection of the pipelines is no less critical.

Chemicals can be injected for reasons other than corrosion. Methanol (MeOH), monoethylene glycol (MEG) or triethylene glycol (TEG) can be injected as hydrate inhibitors to prevent blockages associated with, in particular, shut-downs and start-ups. Wax inhibitors can also be injected to prevent pipeline blockage. Scale inhibitors can be injected at the trees, or at a manifold, to prevent scale deposition: scale can lead to valves failing to seat properly, or to blockages, and corrosion can occur beneath layers of scale. Scavengers, such as H_2S scavenger, can also be injected at a manifold.

The CIS consists of the following:

- chemical holding tanks and handling system;
- injection pumps;
- metering valves and/or injection rate control devices (IRCD);
- pipework;
- umbilical;
- manifold:
  - umbilical termination module (UTM);
  - small bore pipework;
  - injection ports and quills;
  - metering.

During design the following need to be considered:

- types of corrosion that are anticipated in different parts of the system and what chemicals might best combat them;
- elimination of potential corrosion or erosion "hot spots";
- general system requirements – e.g. number of umbilical cores with what capacity and at what pressure rating; number of chemical injection pumps; capacity of holding tanks; components of the chemical injection control system, including metering.

It is important to define the chemicals as early as possible, both so that adequate time is available for the design of the CIS, and so that chemicals can be tested for compatibility, interaction, etc. Issues that have caused problems in the past include phase inversion (i.e. when the water cut exceeds a certain level, the chemical is no longer effective) and lack of shear strength, such that the chemical is stripped from pipe walls and is therefore ineffective.

Annex C (informative) Inspection, monitoring and maintenance plans

C.1 Inspection plans

The primary aim of inspection is to confirm the anticipated condition and to detect defects and degradation.

At the end of the design stage, a good understanding needs to have been achieved of the failure modes associated with the system developed.

Once in operation, the objective of inspection is to confirm this understanding by looking for evidence of any of the recognized, possible failure modes and causes, although in practice some unanticipated degradation might be revealed.

In addition, degradation can occur at a higher rate than anticipated, and needs to be identified before the integrity of the system is impaired. Inspections of pipeline facilities that are subsea or below ground/buried are difficult and, therefore, are carried out at discrete intervals, the frequency of inspection being selected to optimize identification prior to failure in light of the risk-based priority listing.

For example, under normal operating conditions anode depletion on a subsea pipeline is a gradual process that is taken into consideration in the cathodic protection design. The design will include allowances for some anode failures and there is a redundancy element in the number of anodes installed. Even if cathodic protection is not 100% efficient, it will still significantly reduce the corrosion rate of exposed steel. Therefore, in the light of both risk and degradation rate, the inspection frequency can be long. If buckling of a high pressure/high temperature pipeline is the failure mode, the inspection frequency might be relatively short.

The aim of inspection planning is to take the risk-based priority lists, the data gathering requirements and the mitigation activity lists to determine inspection frequencies and, hence, to determine when and how inspections will need to be carried out. From these, annual plans can be prepared.

C.2 Monitoring, sampling and testing plans

Monitoring, sampling and testing are different approaches to the acquisition of data remotely, by telemetry rather than inspection. These methods of data acquisition have a number of purposes, as discussed in Clause **8** and Annex D, but one of them, as with inspection, is confirmation that equipment is performing as anticipated at the design stage, as well as identification of any anomalies.

Unlike inspection, monitoring is effectively a continuous process, but it is still necessary to define a data acquisition rate. For example, for integrity purposes, temperature and pressure values do not have to be obtained every second, and hourly readings might suffice, whereas operational monitoring by the control room might demand a higher frequency.

Online corrosion monitoring by corrosion probes does not require hourly readings; monthly readings will probably suffice. Sampling and testing are also discrete processes, but they are initiated, and the data are collected, remotely. Therefore, the activities might be carried out at a much higher frequency than is practical for inspection of a pipeline.

Cathodic protection systems can also be monitored on a continuous basis.

The aim of monitoring, sampling and testing planning is to take the risk-based priority lists, the data gathering requirements and the mitigation activity lists so as to specify data acquisition frequencies.

It is important that remotely monitored data is validated periodically (e.g. annually).

C.3 Maintenance plans

Inspection and monitoring are likely to reveal that some equipment (possibly including the monitoring equipment itself) is in an unacceptable condition (sometimes referred to as an anomaly). In this case, maintenance will be required. Once again, the risk-based priority lists, the data gathering requirements and the mitigation activity lists have to be consulted. If a piece of equipment that is needed to mitigate a high risk failure mode has failed, or is degrading at an unacceptable rate, the requirement to repair or replace it will be urgent. It might even be that an unscheduled intervention has to be made, although the selection of inspection or monitoring interval is expected to preclude this. If the component and its failure mode is classified as low risk, the requirement to repair or replace it will be less urgent. The maintenance plan will reflect this logic.

Depending upon the approach adopted by individual organizations, some equipment might be replaced on a scheduled basis as part of a planned maintenance regime. If this is the case, these interventions also need to be included in the maintenance plan. In practice, these requirements would probably define the maintenance plan and the unanticipated interventions will have to be added to it.

C.4 Inspection, surveillance and monitoring intervals

An inspection, surveillance or monitoring interval can be calculated for any degradation-type failure mode (see Note). At present, however, there is no method for calculating an inspection or monitoring interval for an "instantaneous" failure mode, such as impact damage. Inspection or monitoring will reveal nothing until the event has occurred.

It is possible to monitor levels of third party activity, etc., to determine changing levels of probability and, hence, risk (possibly on a day-by-day or week-by-week basis), but this does not directly translate to an inspection, surveillance or monitoring interval.

The common approach is to use engineering judgement to decide the longest period that could possibly be acceptable (i.e. associated with the lowest possible risk), and then to determine inspection intervals on a linear scale of risk. For example, if the longest possible interval is chosen as 10 years, then on the basis of Figure 2, the inspection intervals might be as shown in Table C.1.

Table C.1 **Possible inspection intervals based on a maximum ten-year interval**

Risk level	Inspection interval
X	(unacceptable level of risk)
H	1 year (i.e. annual)
M	2 years (i.e. biennial)
L	5 years
N	10 years

Annex D (informative) Guidance on process and condition monitoring

D.1 Monitoring

Monitoring refers to any continuous or quasi-continuous data stream obtained from any part of the system via the SCADA system.

NOTE "Quasi-continuous" refers to data that are logged locally and then downloaded in batches, e.g. sand or corrosion probes.

Such data may include:

- temperatures;
- pressures;
- flow rates.

Other monitoring may include:

- CO_2 content;
- H_2S content;
- water and hydrocarbon dewpoints for gas;
- water cut for liquid hydrocarbons;
- density of product;
- viscosity of product;
- hydraulic fluid returns;
- chemical injection rates (for corrosion and wax inhibitors, oxygen scavengers, biocides etc.);
- feedback from probes (e.g. sand production, corrosion);
- feedback from any instrumented system (e.g. strain gauge);
- insulation resistance in umbilical signal and power lines;
- pressure in riser caissons;
- pressure and temperature cycles;
- cathodic protection monitoring;
- chromatograph analysis;
- iron counts;
- corrosion coupon data.

While temperature and pressure can be measured at sensors located with the pipeline physical limits, flow rate and other data is normally measured outside the physical limits of the pipeline. Nonetheless, data from the upstream facilities such as a well, a process plant, a manifold, a pumping or compressor station or a pressure control station can be utilized to estimate conditions within, or affecting, the pipeline. Data can similarly be gathered from facilities down stream of the pipeline.

If the measurement point is remote from the pipeline then care needs to be taken to ensure that the data is representative of conditions within, or affecting, the pipeline. For example, corrosion probes mounted within pipework upstream of the pipeline can experience significantly different conditions, e.g. a hotter, higher and more turbulent flow regime, than the pipeline.

These data provide the operators with a real-time picture of the system performance, but can also give the integrity engineer an insight into:

- system availability;
- prediction of future maintenance requirements;
- flow assurance threats;
- system integrity.

For instance, an increasing pressure differential between the pipeline inlet and outlet could indicate wax build-up, severe wall roughening (internal corrosion), or a partial blockage (possibly a hydrate). Increasing gas production in a multi-phase system could indicate encroaching slugging conditions. Fluctuating pressures could indicate slugging, development of two-phase flow conditions or sand production in bursts.

The data stream into the control room, collected for production purposes, is effectively continuous: the acquisition frequency is generally not risk-based. The integrity engineer should, however, carry out reviews of the data at a frequency related to the level of risk.

Data from components of the SCADA and CIS can take a finite time to reach the control room, and not all data arrive sequentially, so that it can prove difficult to fully understand system performance. For this reason, the SCADA needs to be configured to "time stamp" all data so that they can be ordered sequentially when diagnostics are being carried out.

Data such as these are also of use to the integrity engineer to ensure that the system continues to be operated within its safe operating limits and, with the supporting corrosion engineer, for determining potential corrosion rates in different parts of the system. The integrity engineer might not require the data with such a high frequency as production operations, and not necessarily online, but needs to be able to download data readily for integrity monitoring purposes.

D.2 Sampling

Sampling refers to obtaining samples of product, lift gas, injection water, hydraulic control fluid, injection chemical, etc., and carrying out tests to obtain data. Examples include:

- product – water cut, bulk solids, chlorides, iron count, wax, asphaltene, gases;
- lift gas – H_2S level, dewpoint;
- injection water – O_2 levels, residual O_2 scavenger (e.g. bisulphite), sulphate-reducing bacteria (SRB) counts;
- hydraulic control fluid – cleanliness [in both the supply containers and the hydraulic power unit (HPU) reservoir];
- injection chemical – cleanliness, concentration;
- separator residues – after cleaning – corrosive species, sand, wax, asphaltene;
- pig debris ("pig trash") – corrosive species, sand, wax, asphaltene, hydrates;
- flexible riser annulus – corrosive species, measure permeation of gas.

NOTE Some parameters, such as dewpoint and CO_2 level, can be monitored online in real time but, in some older systems, might also have to be obtained by sampling.

Sampling is generally carried out by production technicians to a defined schedule (i.e. might not be risk-based). Data derived from sampling are frequently passed on to the production chemist to analyse further. The analysis output is passed to the integrity engineer, who reviews the data with a frequency based upon the level of risk.

Well testing (i.e. measurement of some of the above parameters on a well-by-well basis, via a test header or manifold and pipeline) is a form of sampling, but this becomes increasingly difficult as step-out distances increase, because it is difficult to know where the production from different wells starts and stops, given the degree of mixing that occurs.

D.3 Testing

Testing refers to activating a process for the sole purpose of confirming that initiation and function match the performance standard. Tests are prescribed to be conducted at specified intervals. In general, the testing intervals are risk-based, although until such time as sufficient, suitable data is available, it might be necessary to rely on suppliers' manuals. Examples of equipment that might require testing include:

- emergency shut-down valve (ESDV);
- subsea isolation valve (SSIV);
- instrumented pressure protection system (IPPS) valves;
- slam shut valves.

These tests confirm that:

- initiating a demand leads to a signal being sent to the actuator;
- the actuator moves the gate or ball (partial closure test);
- the gate or ball closes to the stop (full closure test).

A full closure test also permits a leak-off test to be carried out.

A leak-off test comprises closing off the zone behind the valve being tested, and monitoring for an increase in pressure. If the pressure increases, then the rate of increase and the volume of the zone allows the leak rate to be calculated. This can be compared to the maximum allowable rate of passing defined in the performance standard for the valve. It is good practice to monitor the pressure in the next zone downstream as well, to ensure that any pressurization is not occurring from downstream rather than upstream.

It is also possible to obtain a valve "footprint" – the hydraulic profile of the closure (or opening) – and to measure the usage of hydraulic fluid, provided that positive displacement flow meters are provided (which is strongly recommended). The footprint and usage can be trended from test to test. Ideally, a baseline test will have been carried out at commissioning so that "in service" footprints, etc. can be compared to the "as installed" footprint.

Not all valve actuators incorporate remote positional feedback, the only direct position indication being local (e.g. can be observed by ROV). In some cases, valve movement is inferred by pressure sensing or even, in some cases, by a "success" report from the control system. In the latter case, in the event of a fault, the valve position might not actually change – indeed, the actuator might not even get charged – but success will be inferred. This can result in erroneous assumptions. Due consideration is needed at the design stage to ensure that valves can be satisfactorily tested when required.

Testing is not limited to valves. Many components of the control system can be tested as part of ongoing reliability confirmation. Chemical injection metering and rate control components can be tested. Vacuum or nitrogen testing of flexible riser annuli can demonstrate whether there is a breach of the outer sheath, with the potential for corrosion.

Feedback from the pipeline system can also help the integrity engineer to understand the performance of the system. For example, if a routeing valve is operated, this means that the corrosivity in various parts of the system might change. Feedback can also identify whether the chemical injection is likely to be protecting the system as anticipated.

Annex E (informative) In-service inspection

E.1 External inspection

E.1.1 Pipelines on land

A range of methods are used for external inspection of pipelines on land, including:

- coating surveys, e.g. direct current voltage gradient;
- cathodic protection surveys, e.g. CIPS and a.c./d.c. interference surveys;
- current attenuation survey in locations subject to a.c./d.c. interference, and current drain test (CDT) at locations where the pipe has been installed using trenchless techniques;
- electromagnetic current attenuation surveys at locations where a full CIPS survey is not possible;
- right-of-way surveillance by air or ground patrol;
- crossing surveys at major river/water crossings (and other geohazards), including visual inspection of exposed pipework and the condition of supports;
- long range ultrasonics (LRU), or other similar examination methods, where access to pipework or pipeline sections is difficult;
- general visual inspection and non-destructive testing (NDT) of above-ground facilities.

Particular consideration needs be given to external inspection of pipeline and pipework sections which cannot be internally inspected.

E.1.2 Subsea pipelines

There are two principal methods of subsea external inspection:

- general visual inspection – of structures, pipelines, umbilicals, etc.;
- side-scan sonar (SSS) – for pipelines and umbilicals.

General visual inspection is usually carried out by ROV. For inspecting manifolds, trees, and other subsea facilities (see Annex B), small observation ROVs are used, generally equipped with a colour camera, a black and white [silicon intensifier target (SIT)] camera, lights, a manipulator capable of deploying a cathodic protection stab or similarly light-weight tools, and a sonar. These ROVs are small enough to gain access to the more spacious structures, but generally move slowly along the top and then each face in turn.

External inspection of structures can also be carried out by divers, but this is becoming increasingly uncommon. In the case of some older subsea facilities [e.g. manifolds, subsea isolation valve (SSIV) skids, tee and wye connection enclosures], however, diving is the only available method for inspecting equipment within protection covers. Diving is limited to water depths of approximately 200 m, and many nations actively discourage the use of divers even within these water depths.

For general visual inspection of pipelines, umbilicals, etc., specialized pipeline inspection ROVs are generally used. These are, typically, fitted with:

- three closed-circuit TV cameras (with video recording), one of which takes the pilot's view while the other two are on booms (or outriggers) to each side of the ROV to look at the sides of the pipeline (the pilot's view might be duplicated with a SIT camera);
- a transverse profiler system, rotating head or multibeam, to record the seabed profile transverse to the pipeline (looking at scour, embedment, etc.);
- a pipetracker, to enable the pilot to follow the pipeline or umbilical when buried, and to measure depth of burial;
- remote cathodic protection measurement;
- a cathodic protection stab (for measuring the potential at individual sacrificial anodes).

This suite of tools can provide a wealth of data, provided the ROV transits relatively slowly.

An SSS can be fitted into a towed fish (i.e. a streamlined body, towed by a ship, the control of attitude being limited to the speed and manner of towing), or into a remotely operated towed vehicle, which is a less streamlined body, also towed by a ship, that is equipped with control surfaces to give a pilot good control of attitude. In either of these arrangements, inspection is a relatively fast process. Since it is towed, SSS can only be used to inspect pipelines, umbilicals, etc., and cannot inspect those parts close to platforms or other installations (since the ship needs to keep a safe distance off). SSS can also be fitted to an ROV, but the inspection cannot be conducted with equivalent speed. It can, however, inspect relatively close to installations.

General visual inspection is well suited to identifying features such as coating damage, anode depletion, spans, unanticipated exposure or burial and upheaval buckles along pipelines. Displacements, either global displacements or lateral buckles, might not be apparent to the survey team from the visual evidence. SSS is well suited to identifying features such as spanning, embedment, unanticipated exposure or burial, lateral and upheaval buckles, and gross displacement (e.g. due to instability or anchor hooking), and can also identify features in the vicinity of pipelines, such as trawl scars, that might indicate local damage, although SSS is unlikely to be able to detect such damage.

SSS can also identify gross damage, e.g. mattresses displaced, pipeline or umbilical jumpers displaced, fishing gear stuck on structures, fishing scars indicating interactions (even if nothing else detectable), and SSS pipeline surveys can be extended across subsea facilities for this purpose.

For pipelines and umbilicals, SSS and general visual inspection can complement each other, and it is common practice to run a (general and rapid) SSS survey and then follow that up with general visual inspection of areas that, from the SSS survey, might have suffered local damage, or where greater detail is required (e.g. spans or buckles).

External inspection of non-piggable pipelines, jumpers, manifold pipework, etc. can be conducted externally using ultrasonic or eddy current techniques. In this case, it is important that:

- an adequate length of pipe is inspected at every relevant location to ensure that pitting, erosion, etc. is identified;
- the inspection locations are clearly marked so that all measurements are taken at exactly the same place every time.

It might be necessary to install removable insulation at these locations, noting that this can increase the likelihood of external corrosion under the insulation. Once again, it is most important that the integrity engineers are involved in the design to ensure that good inspection provision is made.

E.1.3 Flexible risers

Flexible risers can be inspected externally with small inspection ROVs (as used for structures). Gross problems, such as bend stiffeners becoming disconnected and dropping from the tie-in, or buoyancy modules slipping, will be clearly evident. Sheath damage might be evident, but marine growth, or the small dimensions of the damage itself, might make it difficult to find.

The existence of sheath damage can be checked by either a vacuum test or a nitrogen test, each of which is designed to check the volume of the annulus. Since seawater is incompressible, if there is water ingress to the annulus, the volume will shrink (a baseline test at commissioning is strongly recommended to support this assessment).

If the annulus appears to be flooded, then corrosion inhibitor can be introduced via the relief ports in the upper end fitting. This will be beneficial in itself, but if a dye is mixed with the inhibitor, this can help with location of the damage: for example, fluorescent dye shows up clearly (based upon just a few parts per million) under ultraviolet light and, if an ROV carries such a “black” light while carrying out an inspection, damage can be more easily found.

E.1.4 Riser caisson and J-tube sampling

Pipeline risers are sometimes installed on fixed platforms in either caissons (sealed jacket structures) or J-tubes, either to enhance protection or to facilitate installation. In the case of a caisson, the annulus is generally designed to be dry (possibly with a nitrogen environment) and provision needs to be made to confirm that it is dry. A pressure sensor, with an alarm, can be fitted to give early warning of the failure of a riser within the caisson.

In the case of a J-tube, the bottom is generally closed by a seal (clamped around the riser, which can be rigid or flexible), but this might leak, especially as the pipeline ages. The annulus will contain seawater that needs to be treated to prevent both oxygen corrosion (concentrated at the tidal zone) and corrosion by anaerobic bacteria such as sulphate reducing bacteria (SRB), the latter being concentrated at the bottom near the seal and requiring biocide for control. The annulus can be sampled regularly to ensure that corrosion is adequately inhibited, and chemicals can be replenished as required.

Umbilicals are generally brought on to platforms via J-tubes that are not sealed, as the plastic sheath of the umbilical is expected to prevent corrosion. In this case the annulus cannot be treated. Sometimes, J-tubes are incorporated within riser caissons, in which case corrosion of the J-tube bore could threaten the integrity of the caisson annulus.

E.2 Internal inspection

E.2.1 General

The internal inspection of pipelines can be carried out by a range of pigs, including:

- metal loss;
- crack detection;
- geometry;
- mapping.

Other tools such as video cameras and laser imaging are also available.

It is recommended that all pipelines be piggable. Where pipelines were not originally designed to be piggable, modifications can be made to facilitate conventional pigging or the use of specialist inspection tools.

E.2.2 Pigging considerations for onshore pipeline systems

Pig launch and receive stations are generally provided at intervals along the pipeline in order to enable cleaning and inspection. Such facilities may comprise permanent or temporary launch, receive or universal pig traps. The use of temporary pig traps is required at locations where planning permission for above-ground pig trap installation cannot be obtained.

In some cases, inline inspection of pipeline sections might not be possible (due to design/geometric restrictions) or might be subject to flow restrictions. Where pipelines are not piggable, particular consideration needs to be given to the application and reliability of external inspection techniques covered in **E.1.1**, or to the application of alternative pigging technology (e.g. tethered or robotic inspection tools).

E.2.3 Pigging considerations for subsea production systems

Most pigs are driven by flow and require pig launchers/receivers at each end of the line. Subsea pig launchers/receivers can be installed, but loading requires either a dive support vessel or ROV support vessel, and is difficult in the case of inline inspection tools because of their size and weight. It is good practice to incorporate a pigging loop, either of twin production pipelines or of production and water injection pipelines, through the manifold, so that pigs can be both launched and received on a platform (and some manifold pipework can be inspected). Experience shows that pigging is more likely to be carried out in this case.

The disadvantage of twinning water injection and production pipelines is that solids from the water injection pipeline (the common result of poor water quality control) are deposited into the production pipeline, and ultimately end up in the first stage separator.

Pigging loops can be fitted at the rear of the manifold, so that a pig will transit the headers, subject to the nominal pipe size. To facilitate pigging, the headers have to be the same diameter as the pipelines, and larger diameters become unwieldy. In the case of large diameter pipelines, the pigging loop tends to be fitted at the front of the manifold, with smaller diameter headers connected into it with tee connections.

Pigging loops introduce other threats. For instance, it is more difficult to protect manifold pipework than it is pipelines by chemical injection, so that there is a greater possibility that a pigging loop could suffer deposition of scale or wax: this could lead to a pig becoming stuck, and it is difficult to recover a stuck pig from manifold pipework. It is important to check the compatibility of fluids that might be commingled at a pigging loop to ensure that this will not encourage solids deposition, for example. The risks need to be understood, and mitigation measures put in place.

NOTE Short runs of pipeline can be inspected by tethered crawler pigs. In this case, only a single pig trap is required. Some contra-flow pigs are in prototype at the time of publication of this part of PD 8010, but not in common use: these would also require only a single pig trap, and could, theoretically, inspect the full length of the pipeline.

Contra-flow pigs progress against the flow, deriving their propulsion energy from the flow. On reaching the far end or a blockage, they revert to passive pig mode and return with the flow.

Umbilicals cannot generally be inspected internally. Failures of individual cores might only be apparent from monitoring to compare what is injected on the platform with what is injected subsea. More general damage can be identified by loss of control functions.

MFL and UT inline inspection toolscan traverse flexible risers, but these technologies are not suitable for internal inspection of them. Electromagnetic methods have been developed for localized internal inspection, but they have yet to be incorporated into any effective general inspection pigs.

E.3 Flexible risers

Radiographic methods can be used, but they are not yet suitable as common underwater inspection tools.

Annex F (informative) Information management

F.1 General

Facilitation of integrity management is achieved by having the background documents and reports readily to hand. Indeed, it can be enhanced by having all key data, such as principal dimensions, safe operating limits and anomaly limits in a readily-accessible database. Having the performance indicators readily accessible provides an instant measurement of how well the pipeline is being managed. The responsible personnel are likely to change several times over the life of an asset, and good information management also ensures continuity of knowledge and experience.

The more information is available, the easier it is to assess the likely condition, and the likely impact of change. For example, regular integrity reviews and risk assessment reappraisals will be more reliable if the full integrity history can easily be reviewed. This will result in more efficient inspection planning. If a field upgrade is to be considered, the impact can be more readily assessed if the integrity status is clearly documented. Decommissioning planning will be more efficient: for example, if a case has to be made for decommissioning a pipeline in situ, the likelihood of unburial can readily be assessed.

Management of change (see **4.4.5**) requires that the likely effects of change can be forecast, and this is much easier if all life cycle data are readily available.

F.2 Data stream allocation

Particular sets of data can benefit more than one group of personnel. For example, pressure and temperature data give production operations an insight into well flow characteristics and confirm that it is safe to continue to operate the asset. They allow the integrity engineers to confirm that the system is operating within its safe operating limits, and to assess corrosivity. They provide information on sensor performance to the reliability engineers, and on pipeline status to the pipeline engineers.

The feedback from the operation of an isolation/routeing valve in a manifold informs production operations that the required task is successful. It advises the integrity engineer that the corrosivity in the headers and pipelines will have altered. It provides condition monitoring data to the reliability engineers via the operating footprint; and it advises the pipeline engineers of the valve status.

Further examples of a single set of data informing different groups are given in Table F.1. The information management process can be used to direct data towards the relevant groups, configured to their particular applications.

Table F.1 **Examples of data stream allocation**

Data type	Operators	Integrity engineers	Reliability engineers	Discipline engineers
Temperature, pressure, flow, etc.	Assessment of well performance Confirm safe to continue operating	Input to calculations of corrosivity and chemical injection rate Confirm operation within safe operating limits	Sensor performance data	Sensors OK **or** Maintenance task to plan
Isolation valve operated	Task complete	Requirement to calculate new corrosivity in each leg	Valve condition monitoring data (footprint)	Valve status
Dewpoint, gas sampling (CO_2, H_2S, etc.)	Confirm safe to continue operating	Assessment of corrosivity	Sensor performance data	—
Chemical injection performance	Requirements achieved	Achieving protection (anticipate corrosivity)	Achieving availability (system condition monitoring)	Pumps, IRCDs, umbilical cores OK **or** Maintenance task to plan
Corrosion/ erosion probe output	—	Confirm corrosion under control, or calculate remaining life	Achieving availability (system condition monitoring)	Probes OK **or** Maintenance task to plan

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