

PD 8010-5:2013



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Pipeline systems –

Part 5: Subsea pipelines – Guide to operational practice

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Summary of pages

This document comprises a front cover, an inside front cover, pages i to iv, pages 1 to 70, an inside back cover and a back cover.

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 30 September 2013. 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 8010-5 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*;
- Part 5: *Subsea pipelines – Guide to operational practice*.

This part of PD 8010 is intended to be read in conjunction with PD 8010-2 and PD 8010-4:2012.

Information about this document

This part of PD 8010 was initially drafted using Pipeline Users Group documents as a basis, with their kind permission.

As an industry develops, the practices and procedures it adopts improve so that the way business is conducted within that industry improves with that development. In the oil and gas offshore industry, some subsea assets have been in operation in the North Sea for several decades, during which time lessons have been learned and operational practice improved. This part of PD 8010 presents a number of operational practices that have been established as a result of these developments.

It is anticipated that operational pipeline engineers will use this part of PD 8010 on a regular basis; pipeline design engineers will take cognisance of it in the design of pipeline systems; and third-party providers of equipment and services will be able to align the products and services they provide with the guidance and recommendations given.

Use of this document

As a guide, this part of PD 8010 takes the form of guidance and recommendations. It should not be quoted as if it were a specification or a code of practice and claims of compliance cannot be made to it.

It has been assumed in the preparation of this part of PD 8010 that the execution of its guidance will be entrusted to appropriately qualified and experienced people, for whose use it has been produced.

BSI permits the reproduction of Figure B.1, Figure D.1, Figure G.1, Figure H.1 and Table E.1. This reproduction is permitted only where it is necessary for the user to use the sample pro-formas given in the figures and table during each application of the standard.

Presentational conventions

The guidance in this part of PD 8010 is presented in roman (i.e. upright) type. Any 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.

1 Scope

This part of PD 8010 gives guidance on the following aspects of offshore subsea system operational practice:

- determining the requirement for a subsea isolation valve (SSIV);
- selection and use of high pressure in-line isolation plugs;
- pipeline integrity data exchange;
- caisson and J-tube integrity management;
- emergency shutdown valve (ESDV) testing;
- operational testing of pig launchers and receivers.

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

PD 8010-4:2012, *Pipeline systems – Part 4: Steel pipelines on land and subsea pipelines – Code of practice for integrity management*

3 Terms, definitions, symbols and abbreviations

3.1 Terms and definitions

For the purposes of this part of PD 8010, the terms and definitions given in PD 8010-2, PD 8010-4:2012 and the following apply.

3.1.1 annulus

void between a caisson/J-tube inner wall and the outer wall of components (e.g. one or more flexible or rigid risers, J-tubes, umbilicals) installed within the caisson/J-tube

3.1.2 bellmouth

short conical extension piece at the end of a J-tube, the purpose of which is to aid insertion of risers and umbilicals into the J-tube and minimize the risk of damage during installation, and to provide a similar mechanical protection during operation by maintaining a filleted contact and supporting surface at the entry point

3.1.3 caisson

prefabricated tubular assembly, containing one or more smaller diameter tubular components (usually rigid risers and J-tubes) which pass through the top and bottom sealing bulkheads

NOTE A caisson can be in multiple components, e.g. upper and lower caisson sections.

3.1.4 closed-in tubing head pressure

pressure at the bottom of a well, caused by formation fluids at the bottom of the well, when the surface valves on the top of the well are completely closed

NOTE This is also referred to as shut-in bottomhole pressure.

3.1.5 failure

event, state or condition of not meeting a desirable or intended objective

3.1.6 flowline

pipeline between two subsea facilities (e.g. wellhead and manifold) or between a subsea facility and an offshore installation

3.1.7 installation duty holder

person appointed by the licensee to manage and control, directly or by any other person, the execution of the main functions of a production installation

3.1.8 integrity strategy

document typically supported by a relevant risk assessment, describing appropriate mitigation measures that are put in place to ensure that deterioration processes are controlled and/or monitored

NOTE It is common that a separate integrity strategy is prepared for different disciplines or areas (e.g. external integrity, internal integrity, functional integrity).

3.1.9 threat

act, condition or event that could result in degradation of equipment or otherwise detrimental effect on integrity and ultimately to failure

NOTE This is also known as a hazard.

3.1.10 tidal zone

area inside an annulus affected by tidal water movement

NOTE There are subtle differences between the environment in the annulus tidal zone and the external splash zone, but the primary risk remains corrosion resulting from the changing wet and dry environment, aggravated by the very limited accessibility and inspectability.

3.2 Symbols

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

B	benefit of an SSIV
C	cost of an SSIV
D_i	pipeline internal diameter
F_D	frequency of demand
f_{GD}	factor of gross disproportionality
f_i	frequency of incident type i
i	incident type
L	pipeline length
n_i	number of fatalities due to incident type i
P	pipeline pressure
P_1	pressure behind ESDV at start of test, in bar ¹⁾
P_2	pressure behind ESDV at end of test, in bar
P^*	maximum acceptable probability of failure (Poisson distribution)
P_{Fa}	maximum acceptable probability of failure
P_{Fm}	probability of failure occurrence for given failure mode m
PLL_i	initial PLL with no SSIV installed
PLL_f	final PLL with an SSIV installed

¹⁾ 1 bar = 10^5 N/m² = 100 kPa.

P_T	pressure in main pipeline during test, in bar
T	design life of an installation
T_{rem}	remaining life of an existing installation
t	time for pressure to rise from P_1 to P_2
V	volume of piping behind ESDV, in metres cubed (m^3)
Z	test interval
λ_m	failure rate for given failure mode m

3.3 Abbreviations

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

ALARP	as low as reasonably practicable
CITHP	closed-in tubing head pressure
CP	cathodic protection
ESCI	equivalent social cost index
ESDV	emergency shutdown valve
FA	number of failures averted
FPSO	floating production, storage and offloading (vessel)
HAZID	hazard identification
HAZOP	hazardous operations
ICAF	implied cost of averting a statistical fatality
ID	internal diameter
NDT	non-destructive testing
NOP	normal operating pressure
OD	outer diameter
PLL	potential loss of life
PMR	planned maintenance routine
QRA	quantitative risk assessment
ROV	remotely operated vehicle
SSIV	subsea isolation valve
VIV	vortex-induced vibration
VSL	value of a statistical life
WT	wall thickness

4 Determining the requirement for a subsea isolation valve (SSIV)

COMMENTARY ON CLAUSE 4

This clause reflects operational practice regarding the North Sea hydrocarbon infrastructure. It is assumed that it would be largely applicable in any offshore hydrocarbon domain.

The clause offers guidance to pipeline engineers on how the decision regarding the requirement for an SSIV is made and, in the same light, regarding whether, later in field life, it might no longer be required. A key element in the decision is quantitative risk assessment (QRA), and this clause explains how the results of a QRA are used (but not how one is carried out).

It is important to recognize that the question as to whether an SSIV is required cannot be resolved by a simple rule-based approach, as is illustrated in Annex A.

4.1 Reasons for installing an SSIV

4.1.1 General

A disproportionate number of incidents to pipelines occur close to installations. A subsea isolation valve (SSIV) is used to isolate a platform or other installation from the full inventory of a pipeline in the event of a rupture of that pipeline close to that installation, i.e. it prevents the inventory of hydrocarbons from feeding, and thus escalating, a hydrocarbon release incident that has the potential to adversely impact the safety of the installation. An SSIV is assumed to be a safety device, i.e. it is installed to protect life. It cannot prevent the initial release from an incident, but it stifles the bulk flow from the pipeline, preventing escalation.

Where a hydrocarbon-carrying pipeline with a connection to an offshore installation is involved, the installation of an SSIV is beneficial. However, the benefits and disadvantages need to be weighed against each other as part of the decision-making process (see 4.2).

4.1.2 Causes of hydrocarbon releases

On a typical subsea pipeline, the length of pipeline close to an installation (typically 500 m on the seabed plus the length of the riser) constitutes a very small percentage of its total length. Across the North Sea, more incidents tend to occur near the installation than mid-length.

Statistics given in PARLOC 2001 [1] suggest that incidents within 500 m of an installation might be slightly more likely to involve loss of containment. Taking into account the high level causes of failure, it is possible to see why the majority of incidents occur close to installations:

- **Internal corrosion.** Flow at the arrival end is at its coolest, so water drop-out or condensation might be more likely than at the entry end. Reduction of hydrostatic head in the riser can lead to gases coming out of solution. Slugging might occur in the riser. Internal corrosion might be more likely in the platform zone.
- **External corrosion.** The splash zone, which includes the tidal range and the area above it that is wetted by waves and wind-driven spray, is the most vulnerable part of any pipeline system to external corrosion. Tidal zones within J-tube annuli are also at risk from corrosion, and difficult to inspect.
- **Impact damage.** Damage can arise from failed lifts (dropped objects), structural failures (e.g. water-winning caissons falling off), or lateral impacts. The first two are specifically associated with platforms (few lifts are carried out in the vicinity of the mid-lengths of pipelines). Lateral impacts include

vessel impacts (see below) and impacts on the seabed. Concentrated vessel activity means greater likelihood of anchor damage, although there is a general expectation that fishing will not be permitted within 500 m of an installation.

- **Vessel impacts.** These are a special case of lateral impact because, occurring close to sea level, which is also the most vulnerable zone for external corrosion, they can have catastrophic consequences for both the platform and the impacting vessel.
- **Structural modes.** Expansion spools can become buried, either by drilling mud or by deposition caused by the platform hydrodynamics. Alternatively, scour can lead to long spans in riser base tie-in spools. Both mechanisms are known to have led to failure. Excessive riser clamp/guide spacing can lead to failures due to wave loading or vortex-induced vibration (VIV)-induced fatigue.
- **Failures at fittings.** Most fittings (flanges, valves, etc.) are found within 500 m of an installation.

An installation can be a fixed platform (steel jacket or concrete caisson type) or a floating production system. In the latter case, the risers are flexible, except in deep water where steel catenary risers may be used. Flexible risers may also be installed on fixed platforms. Flexible risers exhibit a number of unique failure modes, but a major cause of failure is corrosion of armour wires following external sheath damage that allows seawater ingress.

NOTE For more information on failure modes of flexible risers, refer to State of the Art Flexible Riser Integrity Issues, Study Report (2001); prepared by MCS International for UKOOA, Doc No 2-1-4-181/SR01, Rev 04 [2].

4.1.3 The nature of hydrocarbon releases

COMMENTARY ON 4.1.3

If an incident leads to loss of containment outboard of the riser emergency shutdown valve (ESDV), then the full inventory of the pipeline could escape, at least until the internal (pipeline) and external (hydrostatic) pressures become balanced. This subclause examines how this could occur.

4.1.3.1 Sub-surface releases

In the case of a gas pipeline, or a line carrying a volatile product, the gas exits the pipeline and rises to the surface in a plume, entraining water and spreading as it ascends. Erosion is likely to enlarge a pinhole leak rapidly in such a scenario, so that large volumes of gas will quickly reach the surface. An initial effect of this might be a reduction in the buoyancy of any vessels in the zone, which could be over 100 m in diameter, depending upon the flow rate and pressure of the gas, and the water depth. A smaller vessel might sink.

On attaining the surface, the gas forms a cloud, which might be toxic as well as flammable. This might ignite if a suitable heat source is in the vicinity, or it might move downwind. If this takes it towards an installation, exposed crew could suffer asphyxiation or toxic effects, or the gas could ignite.

Meanwhile, lighter liquid fractions are carried to the surface where they form pools. If the gas ignites, these pools are likely to be ignited also. Whether or not they are ignited, they pose a hazard to any crew who might abandon a vessel that loses buoyancy. If extensive, they could impede access to the installation to fight fires or evacuate personnel.

In the case of an oil pipeline, all but the heaviest product rises to the surface and forms a slick. This might not threaten human life, but it harms animal life and causes environmental damage.

4.1.3.2 Above-surface releases

In the case of a failure in a gas riser above the sea surface, the gas could ignite, in which case the release momentum will lead to a jet fire. A jet fire can play on other parts of the structure and either cause subsequent fires, or significantly weaken structural members. If the gas does not ignite, the threat of asphyxiation or, in some cases, toxicity remains.

Liquid riser releases can collect on lower decks but are more likely to fall to the sea surface. If ignited, they can form pool fires; if not, they cause environmental damage, and obstruct access to the installation (for fire-fighting or evacuation).

4.1.3.3 Prevention of escalation

An SSIV does not prevent the initial loss of hydrocarbons, so gas clouds or jet fires are likely to occur. By minimizing the feed-in from the main pipeline, however, an SSIV is expected to prevent any escalation of the incident: a jet fire is unlikely to be sustained for long enough to start secondary fires or weaken the structure. If a gas cloud ignites, it will be short-lived.

4.1.4 Location of an SSIV

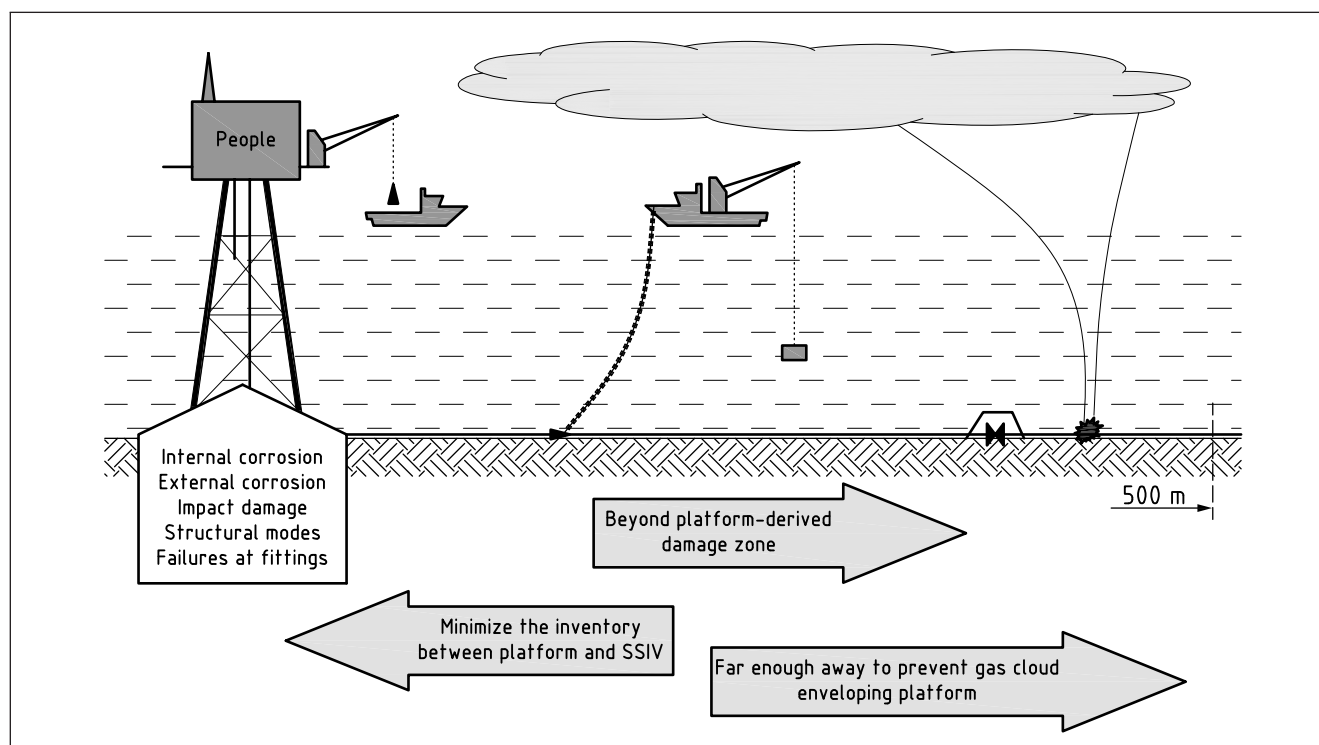
The location of an SSIV is of great importance. Poorly positioned SSIVs might have negligible benefit to the safety of an installation. There are four main factors.

- A primary aim is to minimize the inventory that can feed a loss of hydrocarbons incident outboard of the riser ESDV: this implies that it should be installed close to the riser base.
- Conversely, it has been shown that a significant proportion of loss of containment incidents occur in close proximity to installations: this implies that it should be installed at some distance from the installation, at least beyond the range of the greatest vessel activity.
- Another consideration is the potential gas cloud: ideally, if loss of containment arises following an incident just outboard of the SSIV itself (i.e. fed by the full inventory of the pipeline), the location of the SSIV should be far enough away to maximize the chance of dissipation of the gas cloud before it reaches the installation.
- The SSIV gains some measure of protection itself if it is within 500 m of an installation, from which fishing and merchant vessels are excluded under the Petroleum Act 1987 [3].

These points are illustrated in Figure 1.

The consequence analysis and QRA described in 4.2 should be used in determining the optimum position for the SSIV.

Figure 1 Influences on the location of an SSIV



4.2 Decision-making process

COMMENTARY ON 4.2

The basis of the decision-making process is to determine the difference between the potential loss of life (PLL) with an SSIV and the PLL without an SSIV. If the PLL without an SSIV is unacceptable and there is a beneficial reduction in PLL with an SSIV, then the decision is clear. Where the reduction in PLL with an SSIV is marginal then a cost-benefit analysis can contribute to the decision-making process.

4.2.1 Quantitative risk assessment

COMMENTARY ON 4.2.1

A key element in determining the requirement for an SSIV is to carry out a quantitative risk assessment (QRA), and this is especially true where an SSIV is in place and there is a need to assess whether it is still required. The QRA for an installation takes account of all possible hazards, not just hydrocarbon releases, which are identified by a hazard identification (HAZID) exercise as applying in any part of the installation. This subclause looks only at those aspects of the QRA that are pertinent to the SSIV decision.

HAZID is a process of identifying and recording hazards and as such is a common technique supporting qualitative risk assessments. HAZIDs are normally carried out by a team of competent persons from a mixture of disciplines (e.g. subsea, process, corrosion, structural, safety) and are led by a person who is experienced in the HAZID technique. It is a common practice to break down the subject (i.e. the pipeline) into segments and consider individual segments against a pre-prepared checklist of hazards. Where it is agreed that a hazard exists in a particular segment, the risk presented by the hazard is considered, and all possible means of either eliminating the hazard or controlling the risk and/or the necessity for further study are noted on a HAZID worksheet. Actions are assigned to either discipline groups or individuals to ensure the mitigating control, or further study is completed.

The first step in a QRA is to carry out a detailed fire risk analysis for the installation, which involves modelling hydrocarbon releases from all areas. All isolatable segments should be identified (from the HAZID), the inventory included in each segment should be calculated, and assumptions should be made concerning the likely size of breach in each area (a range of sizes should be investigated – typically small, medium and large). The isolatable segments are the riser, tie-in spools and pipeline, constrained or not by an SSIV. Consequence modelling should also include failure of the riser-top ESDV to close, which will extend the isolatable segment to the next barrier within the topsides pipework.

NOTE 1 The probabilities of hydrocarbon release, size of hole and ignition, and of safety systems (e.g. deluge systems) containing different types of fire, can all be derived from published data: for instance, PARLOC 2001 [1] is a source of data on hydrocarbon releases from pipelines and risers.

For jet fires, the modelling should typically define:

- a) initial flame length;
- b) flame length after certain specified periods;
- c) distance from the flame centre to specified heat flux levels;
- d) duration of the fire.

For pool fires, diameters and thermal radiation contours should be modelled. These have probabilities associated with them, of a given pool fire of a given radius possessing a given thermal radiation contour.

These consequence models, for a range of hole sizes, should then be used to determine the likelihood of escalation, e.g. other critical elements of the installation (such as key structural components) failing, or other parts of the plant failing, resulting in further emissions which could then ignite. With regard to SSIVs, items b) to d) above can be defined both without and with an SSIV, as can the diameter of a pool fire. Thus the benefit of the SSIV in terms of preventing escalation can be ascertained.

The second step in a QRA is to convert the fire modelling data into numbers of potential fatalities and injuries resulting from fires modelled both with and without an SSIV. Some of these will be due to the initial release and direct contact, others will result from escalation over time. Various studies of installations provide the probability of varying numbers of people being in various locations at different times, although any SSIV study should ideally be conducted using installation-specific information.

By combining the probability of a given fire event with the probability of people being in its location, the probability of fatalities and injuries can be calculated. Investigations of escalation should look at the probability of impairment of the temporary refuge, and combine this with the probable numbers in the temporary refuge to calculate fatalities and injuries there. The inclusion of an SSIV minimizes the escalation, so the benefit can be defined as the prevention of fatalities and injuries.

One possible output from a QRA is the calculation of a potential loss of life (PLL) value:

$$PLL = \sum_{i=1}^n f_i n_i \quad (1)$$

where:

- f_i is the frequency of incident type i ;
- n_i is the number of fatalities due to incident type i .

The value of n_i can be determined by summing, for incident type i , the predicted numbers of fatalities for each of the different categories of people on an installation, e.g. those who work only in the temporary refuge, those whose duties take them outside the temporary refuge occasionally, and those who work mostly outside the temporary refuge.

The PLL values, with and without an SSIV in place, can be used, as described in 4.2.2, to determine whether the installation of an SSIV is justified. The same approach can be used to determine whether an existing SSIV might be locked open.

NOTE 2 An enhancement of the PLL concept is the equivalent social cost index (ESCI) which is almost the same as the PLL except that the n_i term is factored by an aversion index, p , as a means of including the aversion of the public, or a relevant subset of the public, to a particular type of multi-fatality incident (e.g. people generally appear to have a greater aversion to fatalities due to air crashes than they do to fatalities due to car crashes). Thus, as explained in greater detail in the research report Application of QRA in operational safety issues [4], a PLL is an ESCI with an aversion index of unity.

4.2.2 Cost-benefit analysis

The detailed fire risk analysis and the QRA can be used to determine, for every relevant type of incident, the PLL value with and without an SSIV installed. The SSIV cannot prevent the initial release and so has no impact on the incident frequencies, but is assumed to prevent escalation and limit the duration of the incident. Thus, it is possible to define the number of fatalities averted (FA) over the lifetime of the installation:

$$FA = (PLL_i - PLL_f)T \quad (2)$$

where:

PLL_i is the initial PLL with no SSIV installed;

PLL_f is the final PLL with an SSIV installed;

T is the design life of the installation.

This is the fundamental measure of the benefit of installing an SSIV but, for practical purposes, it has to be converted into cost terms.

One term that can be calculated is the implied cost of avoiding a statistical fatality (ICAF):

$$ICAF = \frac{C - B}{FA} \quad (3)$$

where:

B is the benefit of an SSIV;

C is the cost of an SSIV.

In this case, the cost is that of installing, operating, maintaining and decommissioning (i.e. the full life cost of) the risk reduction measure, in this case an SSIV. Benefit refers to other, non-safety, value that is obtained by the installation (e.g. improved production) but, in the case of an SSIV, there are unlikely to be any such parallel benefits.

Rearranging and substituting results in:

$$C - B = (PLL_i - PLL_f)T \times ICAF \quad (4)$$

This ensures that, if there is a benchmark for the cost of avoiding a fatality, it is possible to determine a justifiable cost for an SSIV.

NOTE The ICAF refers to a statistical fatality. Various government and industry bodies in various countries have determined the value of a statistical life (VSL). There are various ways of approaching this (e.g. relating peoples' views on earnings in comparison to the risk associated with different jobs, or simply questioning large numbers of people) and results are somewhat variable. Most major oil and gas operators have their own values for VSL.

Equation (4) could be used for the SSIV decision provided that some factor of gross disproportionality is included:

$$C - B = (PLL_i - PLL_r)T \times f_{GD} \times VSL \quad (5)$$

where:

f_{GD} is a factor of gross disproportionality.

The right-hand side of equation (5) can be thought of as the justifiable cost. The purpose of the factor of gross disproportionality (f_{GD}) is to make clear a cost above which an SSIV is not justified. It is suggested here that the value should lie in the range $5 \leq f_{GD} \leq 10$.

Using equation (5) with these inputs, it is possible to set a simple rule:

$$IF : C \leq (PLL_i - PLL_r)T \times f_{GD} \times VSL \quad THEN : \text{install SSIV}$$

where the cost includes procurement, installation, maintenance, and decommissioning.

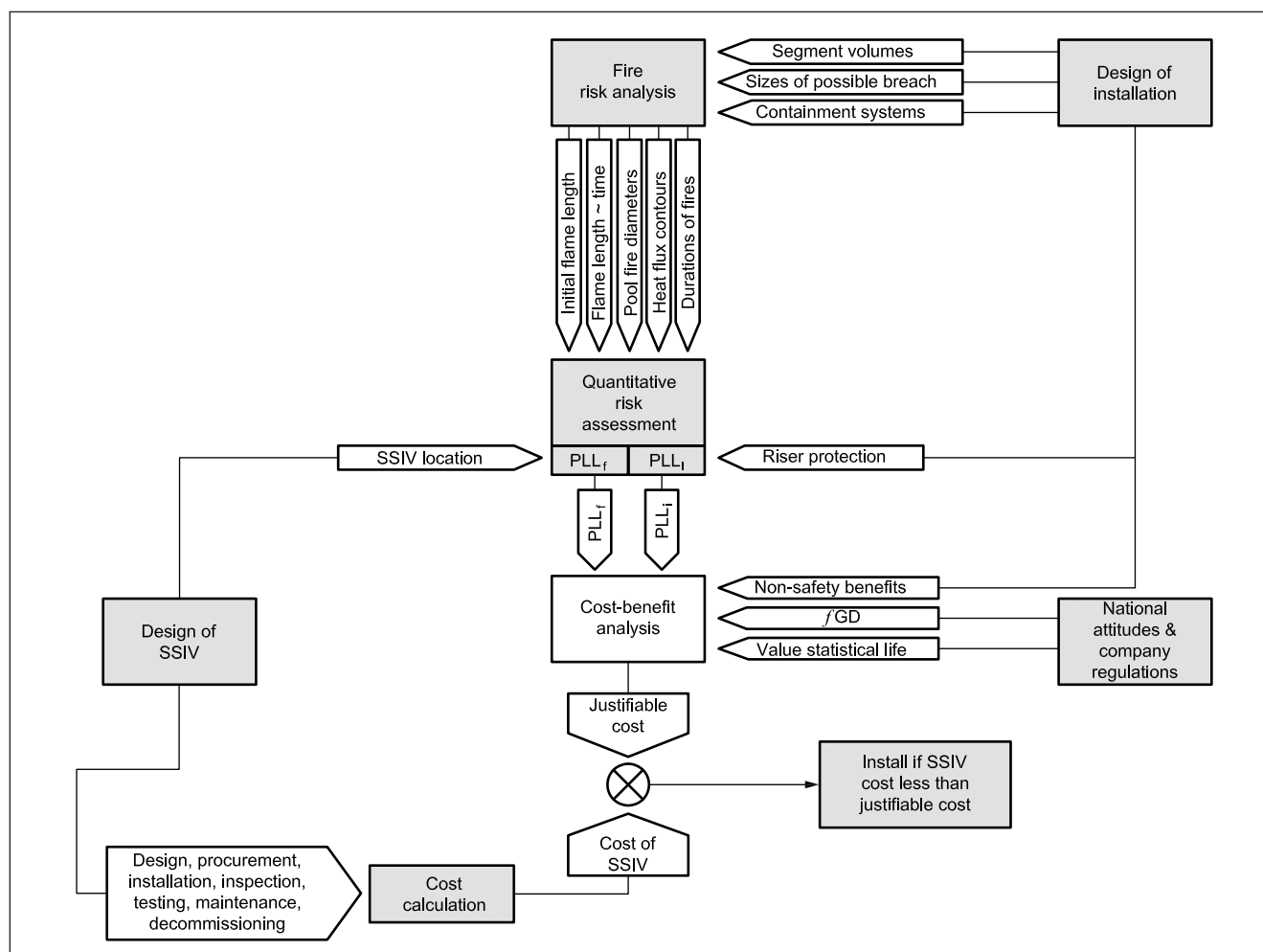
The respective values of PLL are critical in the decision. In the UK, demonstrating risks to be ALARP also requires consideration of industry standards and good practice, and these form part of any SSIV requirement decision, with the starting point being presumption that an SSIV would be good practice. The information flow process involved in the analysis that might justify a decision not to install one is depicted in Figure 2.

4.2.3 Factors influencing the decision

The high level causes of pipeline failures that occur close to installations are listed in 4.1.2. If these causes can be controlled so that the probability of failure is minimized, then the value of PLL_i will be reduced. As a result, the term $(PLL_i - PLL_r)$ will also be reduced and an SSIV might not be required (as is the case at many installations). In general, these controls should be implemented during pipeline design and fabrication so that they are built in and not subject to human error during operation. Examples of controls that may be implemented to reduce the probability of a pipeline incident are given below.

- a) **Internal corrosion.** The probability can be reduced during the design and procurement phases by selecting corrosion-resistant materials; avoiding piping designs that encourage water which has separated to be trapped; and, where applicable, installing adequate and reliable dehydration facilities. Pipelines should be designed to be pigged (both for water sweeping, etc., and for inspection). Attention to detail in the design of the chemical injection system can maximize the ability to control corrosion in operation through chemical inhibition. The annulus vents of flexible risers should be properly plumbed in, with provision for monitoring the flow rate and constituents of the gas.
- b) **External corrosion.** The probability can be reduced by attention to coating selection and application. Field joint coatings can be a weakness. Where risers move through guides, precautions should be taken to ensure that coatings cannot be damaged. Installation cathodic protection (CP) should be suitable. If riser caissons are installed, provision should be made for monitoring the pressure, and for sampling the environment at intervals. If risers are installed in J-tubes, provision should be made for sampling the water in the annuli and for replenishing the corrosion inhibitor, as required,

Figure 2 Information flow – The decision whether an SSIV is required



both at the surface (the tidal zone) and at the bottom (close to the J-tube seal) (see *Guideline on caisson and J-tube Integrity management* [5]). Topsides, attention should be paid to minimizing corrosion under passive fire protection coatings, which should be installed wherever practicable.

- c) **Impact damage.** Risers should be installed where they are protected from vessel impacts (well within the jacket structure of fixed platforms, ideally behind legs), and where dropped objects are unlikely.

Flowline tie-ins should be located clear of platform cranes and other likely sources of dropped objects. Flowlines and tie-in spools close to installations should be protected by concrete structures or mattresses.

It should be possible at all times to determine the relative location of the flexible risers to the deck cranes in the case of weather-vaning FPSOs.

- d) **Structural modes.** Riser clamp spacings should ensure that environmental loading or VIV cannot lead to failure. Spoilers could be used for VIV protection (taking into account the need for access for inspection). Tie-in expansion spools should not be located near drilling mud discharges, etc. Scour protection should be taken into account. For FPSOs, prevention of failures is part of the detailed design of the flexible riser system (including mid-water arches, tether systems, etc., as applicable) and the mooring system.
- e) **Failures at fittings.** The probability can be reduced by attention to the specification of fittings, and to the quality of welding or other connections. Topsides, pipework routes should be selected to minimize escalation.

The list above is not comprehensive, but suggests ways in which PLL_i can be reduced by attention at the design stage. Many of these issues are not, however, within the domain of the pipeline engineer. A number of these causes can be controlled by lifecycle management, but this can be subject to human errors of omission and commission and, as such, might not reduce PLL_i to such an extent.

Many of the controls suggested above would incur additional cost to a project. The cost of procurement and installation of an SSIV might appear cost-effective in comparison. Project teams frequently minimize their costs at the expense of lifecycle costs, although the latter might be far greater and should be used for the comparison. The net present value of the lifecycle costs of the various options might have to be used.

If an SSIV is deemed to be required, then it should be included in the safety case for the installation, and it should be subject to regular testing (see 4.3).

4.2.4 Existing SSIVs

The guidance in 4.2.3 covers the decision whether to fit an SSIV, but a number of SSIVs are already in service, incurring inspection and maintenance costs, and might no longer be justified. In such cases, QRA becomes the recommended approach to examining this issue and the current requirement for an SSIV may be challenged on one of three grounds:

- the original decision to install an SSIV was not based upon a QRA ²⁾;
- some of the assumptions in the original QRA are found in service to be clearly incorrect;
- operating conditions have changed since the original QRA was carried out.

In these cases, the challenge should make use of the QRA and cost-benefit equation (5):

$$IF : C > (PLL_i - PLL_r)T_{rem} \times f_{GD} \times VSL \quad THEN : \text{consider locking SSIV open}$$

where the cost includes maintaining for the remaining life (T_{rem}) and decommissioning.

Industry practice should also be taken into account in demonstrating that risks are ALARP.

Later in field life:

- it might be possible to show that $(PLL_i - PLL_r)$ has reduced;
- the remaining life (T_{rem}) might be small; and
- it might be argued that the late life value for f_{GD} should be lower;

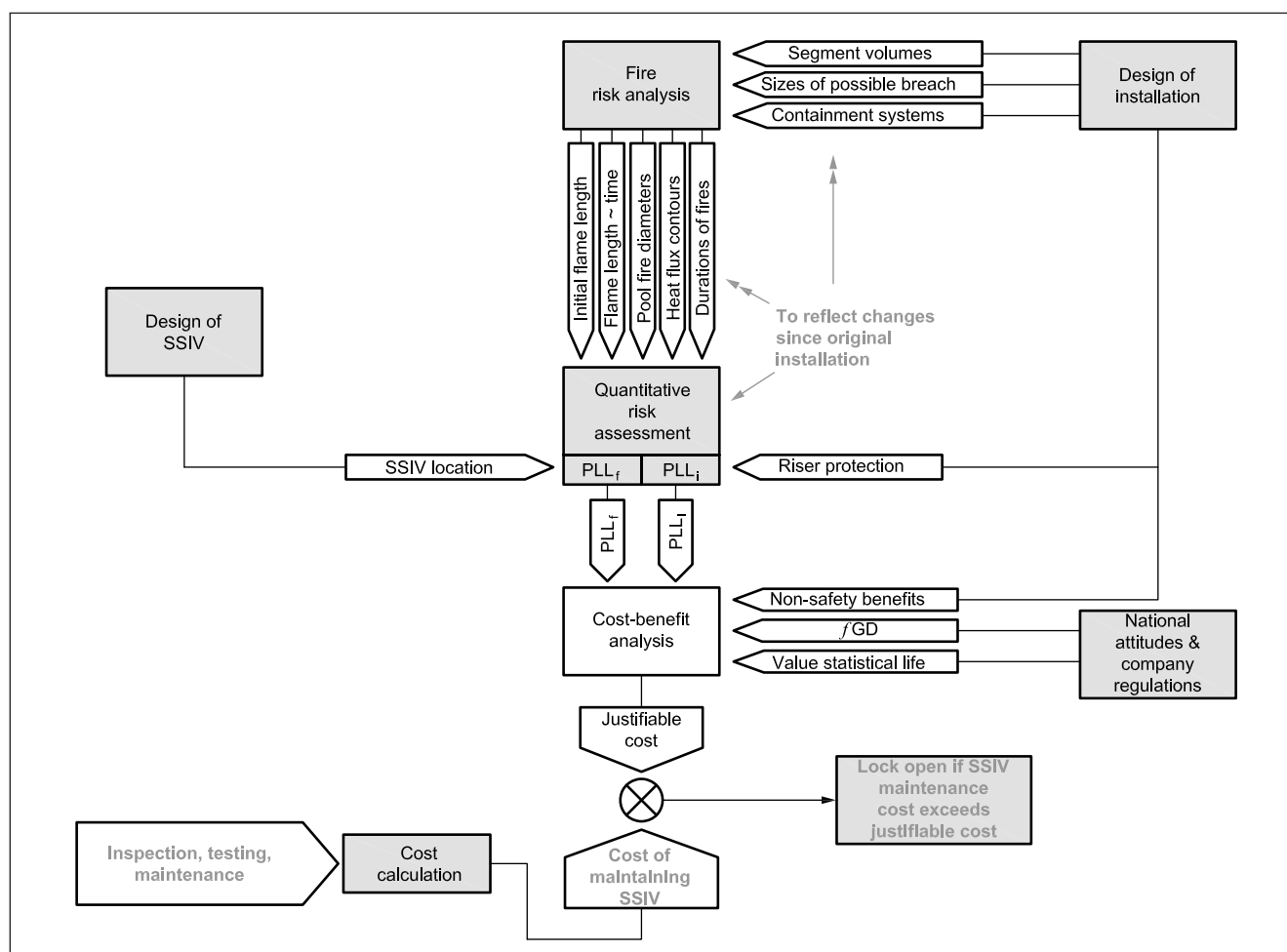
but the residual lifecycle cost of the SSIV (inspection, maintenance and decommissioning) might also be relatively small, so that the cost of the SSIV is still justified.

On the other hand, if the remaining lifecycle cost exceeds the justifiable cost, then an argument can be made to lock the SSIV open and to cease testing. If the argument is accepted, this should be recorded in the safety case for the installation. The information flow for this scenario (taken from Figure 2, with alterations in bold grey type) is shown in Figure 3.

²⁾ Following the Piper Alpha disaster, and while the report of the Cullen Enquiry was being prepared, it is believed that some operators, anticipating that SSIVs were to be made mandatory, decided to avoid the potential log jam of orders by procuring and installing SSIVs without waiting for the new rules (which never were introduced). It is not clear whether QRAs were used at all in these decisions.

Platform-based personnel might be reassured by the presence of an SSIV. Consultation should be carried out before any final decision is made, and personnel views taken into account. Conversely, ongoing inspection and maintenance does increase the risk to divers.

Figure 3 Information flow – The decision whether to retain an SSIV



4.3 Testing

4.3.1 General principles

The test is intended to demonstrate that bulk flow has stopped, although an acceptable leak rate may exist. If SSIV closure is initiated while the ESDV remains open, the pressure at the top of the riser should fall rapidly. Once stabilized, the allowable flow rate should be quantified. If it is too small to measure, this will be acceptable. In general, an acceptable flow rate should be defined by the design team (and handed over to the operations team), together with a method for measuring it that is practicable and achievable.

4.3.2 Establishing the pass/fail criteria

The purpose of an SSIV is to minimize the volume and duration of the types of hydrocarbon release described in 4.1, so as to prevent escalation of any related incident. It is accepted that an SSIV cannot prevent an initial release. An SSIV should, therefore, restrict the inventory so that:

- in the case of a subsea release, conflagration from an ignited gas cloud cannot be sustained; or
- in the case of an above-surface release, a jet fire, if one arises, is not sustained for long enough to cause escalation.

On this basis, a small leak past the SSIV is acceptable, “small” being defined as having no escalation potential, i.e.:

- the flame is neither hot enough nor sustained enough to start new fires; and
- the flow is inadequate to support a major conflagration.

The performance standard for an SSIV might therefore include the provisions that:

- the primary requirement of the SSIV is to close fully and stifle the bulk flow from the pipeline;
- a small residual leakage past the SSIV is acceptable provided it falls well below that required to sustain a fire, or to initiate new fires.

4.3.3 Calculating the test interval

The maximum test interval is obtained by plotting the probability of failure and the maximum acceptable probability of failure against a range of test intervals (Z): the maximum test interval is given by the intersection of the two curves (see Figure 4).

The maximum acceptable probability of failure, P_{Fa} , is given by:

$$P_{Fa} < \frac{1}{F_D \times Z} \quad (6)$$

where:

F_D is the frequency of demand;
 Z is the test interval.

This can be assessed using a Poisson distribution, which reflects that, in practice, failures will still occur, and it can be shown that, to satisfy equation (6) – no failures acceptable – the maximum acceptable probability of failure, P^* , is given by:

$$P^* = e^{-P_{Fa}} \quad (7)$$

The probability of a failure occurrence for a given failure mode is given by:

$$P_{Fm} = \frac{\lambda_m \times Z}{2} \quad (8)$$

where:

Z is the test interval;
 λ_m is the failure rate for the given failure mode.

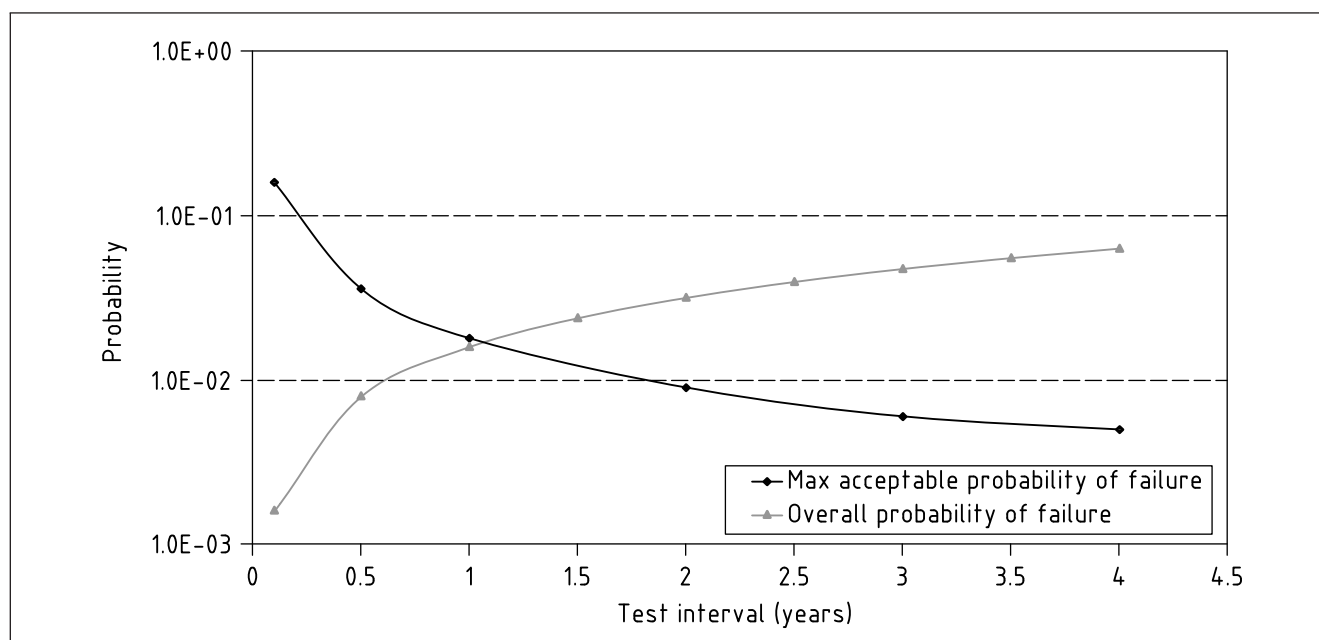
NOTE The value of λ_m can be obtained from published data (e.g. OREDA [6]) or from in-company data.

In the example given (Figure 4), the intersection (maximum inspection interval) is just over 1 year, so the inspection interval would be defined as annual.

In addition, the frequency of testing may be linked to the value of $(PLL_i - PLL_f)$ from the QRA, i.e. the higher the differential, the more frequent should be the testing. For example, if the intersection is at 1.5 years, with $(PLL_i - PLL_f)$ being relatively large, the inspection interval might still be set at annual.

The probability of failure is derived from published, pan-industry data. The maximum acceptable probability of failure is based on the historical shut-down demand frequency on the installation in question, and relates to test frequency. Therefore, calculating the test interval in this way takes account of operational experience, and is preferable to selecting an interval simply on the basis of typical practice.

Figure 4 Example – Determination of test interval



5 Selection and use of high pressure in-line isolation plugs

COMMENTARY ON CLAUSE 5

This clause provides guidance on the issues that need to be taken into account prior to running an isolation plug into a pipeline as part of an intervention task. It addresses high pressure isolation plugs, i.e. equipment that has to be pigged into place within pipelines and locked in place hydraulically under remote or tethered control, and that is generally required to hold a significant pressure differential. The locking action can subsequently be reinforced by the pressure differential. The clause does not give details of such isolation plugs, or give guidance on plug selection, although the information given can assist in the selection process.

Guidance on the safe isolation of plant and equipment is given in HSG253 [7].

5.1 General

Isolation plugs are used under upset conditions. A situation can exist where either the designed-in isolation provision is not suited to the current requirement (e.g. a length of subsea pipeline requires local isolation for repair purposes), or the designed-in isolation provision itself has failed and requires repair (e.g. an ESDV has failed). In such circumstances, a plug has to be introduced into the pipeline in the manner of a pig, i.e. driven to a location by either the production fluid or a different fluid (e.g. water, diesel or gas) introduced for the purpose. (In some circumstances, multiple plugs might be required.) The plug has to be pigged in, set, tested and, eventually, pigged out, and all these activities can suffer failures that are likely to impact the overall operation and the ongoing availability of the pipeline system. In some cases (e.g. intervention on an ESDV), the plug might have to be moved in only a few metres, in which case it can be located and actuated by a rigid push bar.

Some plugging operations have experienced failures in the past, where the plug has not sealed effectively or has been difficult to unseat and/or remove. When this happens, not only can production be interrupted for a lengthy period, leading to significant loss of income, but several years of time-consuming litigation might follow. For this reason, it is recommended that all possible alternatives are assessed prior to embarking on an isolation plug solution. If this remains the only viable, or the preferred, option then application of the guidance presented in this clause is expected to help to minimize the likelihood of such failures.

5.2 Supply of information

Once it has been determined that a pressure isolation barrier is necessary and that this is to be an inline isolation plug, the supplier should be provided with the information required to select the appropriate plug.

NOTE Annex B gives a pro-forma containing all of the information that a supplier is likely to need to enable correct selection to be made.

Preparations by the executive operator, including dialogue with the contractor, are addressed in 5.3. The questions in Annex B also form a basis for that guidance.

A copy of the overall job specification should be provided to the contractor, so that they can see their responsibility in the context of the overall project, and make comments as appropriate.

The job specification should be prepared in accordance with standard industry guidance. HSE publication HSG253 [7] has an appendix specific to pipelines.

5.3 Preparations to be made by the executive operator and site operator

5.3.1 General

Before an isolation task is carried out, the executive and site operators should identify as many as possible of the parameters discussed in this subclause, with the information provided in 5.2 being used as a basis.

Following some guidance on planning (see 5.3.2), the key issues that should be addressed in a pre-project risk assessment are set out in 5.3.3: unknowns should be identified, and answers found, ahead of the formal risk assessment.

NOTE A sample failure mode listing, as a basis for the risk assessment, is provided in Annex C. It includes a broader range of functions than just the key issues. More general issues that need to be considered by the executive and site operators are discussed in 5.3.4.

5.3.2 Planning

Sufficient time should be allowed for planning in order that a number of HAZIDs, HAZOPs and other risk assessments can be convened. The detail, and hence the number of people involved, is likely to increase as the planning progresses; however, the following stakeholders might need to be involved:

- team undertaking the intervention (both executive operator staff and contractor staff);
- operations staff from the facility (or facilities) involved;
- third parties;
- dive support vessel (or similar) representatives, where applicable;
- plug vendor;

- pigging contractors (if different to plug vendor);
- pump suppliers (if temporary pumps required).

Some of these stakeholders might benefit from an early site visit (where appropriate), and time and resources should be allowed for this.

Where two platforms and/or a dive support vessel or similar vessel are involved, a communications protocol should be agreed. This may involve pre-formatted and agreed templates to be communicated at different stages. Bridging documents between safety management systems should cover all reasonably foreseeable eventualities.

If third-party verification of the project is required, the planning schedule should allow for this.

Time should also be allowed for the management of change process where applicable (see PD 8010-4:2012).

5.3.3 Pre-project risk assessment

5.3.3.1 Setting the plug

Control of the plug may be via a tether or may be effected remotely. In the latter case, the initiation may be by a signal, or by a pressure pulse/differential on a receptor on the plug.

Local conditions have been known to make it difficult to achieve the necessary reverse pressure differential to set a plug. This could have implications for the particular task.

The following factors should be taken into account:

- how the slips are set;
- how the slips are subsequently retracted and whether there is a chance they might not retract fully and cleanly;
- how the seals are set;
- the extent to which the seals are exposed to the product after they have been set.

A pipeline stress analysis should be carried out if appropriate.

5.3.3.2 Pressure monitoring

The primary purpose of the plug is to retain fluids at pressure so that a limited section of a pipeline can be reduced to atmospheric pressure (or possibly hydrostatic pressure) in such a way that it is safe for human intervention to be carried out. To this end, it is necessary to monitor pressure continuously to ensure that the pressure retention is fully effective, and in such a way that the intervention can be reinstated before safety is compromised in the event that the retention starts to fail. The usual method for monitoring is double block and bleed, where two isolations are put in place and the cavity between them monitored for pressure increase, with any build-up of fluid vented. With an in-line plug, the cavity cannot be properly vented, since the only place to vent it is into the depressurized section. Therefore, the cavity is monitored for pressure build-up (double block and monitor).

This is critical to the safety of the operation, and the whole process of sealing and monitoring should be examined in detail to ensure that the system will be fully effective. If the pressure monitoring is not fully reliable, either the task will have to be curtailed, or pressure retention could be lost with disastrous consequences.

5.3.3.3 Seals and packers

The pressure is held by the seal and packer arrangement and, therefore, it is critical that this will work satisfactorily for the duration of the intervention. The materials should be fully suited to the fluids to which they will be exposed, since degradation over time could necessitate abandoning the task. Therefore, it is important to establish the original specification for the materials, and whether this is suitable, and also what tests have been carried out, and under what conditions, to establish suitability if there is any doubt.

5.3.3.4 Power

Power is required both for communications and for actuation (setting and release). It is important to ensure that, subject to the longest reasonable foreseeable delay, it will still be possible to initiate the un-setting process, to confirm that this has been successful, and to track the plug to recovery. There should be adequate power, under all conditions, for two attempts at setting the plug without compromising all other power requirements. Account should be taken of the tolerance of the plug to conditions and delays, and of the location of the battery on the plug.

As a contingency, there should be a back-up method for un-setting the plug if all power is lost.

5.3.3.5 Plug equipment

A full review of the plug and its control system is recommended, which should include:

- reliability of electronics and small bore hydraulics;
- redundancy;
- robustness of moving parts, long-term, e.g. slips.

5.3.3.6 Position location and management

For tether-less operations, the ability to communicate with the plug is critical, since all setting, monitoring and un-setting has to be initiated remotely. A full review of the communications system should be undertaken. The location of non-tethered plugs may be by acoustic, magnetic or radioactive methods. The following factors should be determined and taken into account:

- accuracy of stopping;
- method of tracking;
- range, reliability of through-wall communications (if applicable);
- back-up for loss of communications;
- plans for release and pigging out.

If the plug is on a tether, some of these factors are not relevant, but the existence of a tether can be a limitation in itself, i.e. it can interfere with the intervention task.

There should be an independent contingency plan for release for both tethered and non-tethered operations.

In some cases (e.g. intervention on an ESDV), the plug might have to be moved in only a few metres, in which case it can be located and actuated by a rigid push bar.