INTEGRITY MANAGEMENT AND CONDITION MONITORING OF PIPELINES AND UNDERWATER SYSTEMS IN OPERATION

Subsea Integrity Management – Maintaining and improving the risk level

Petroleumstilsynet

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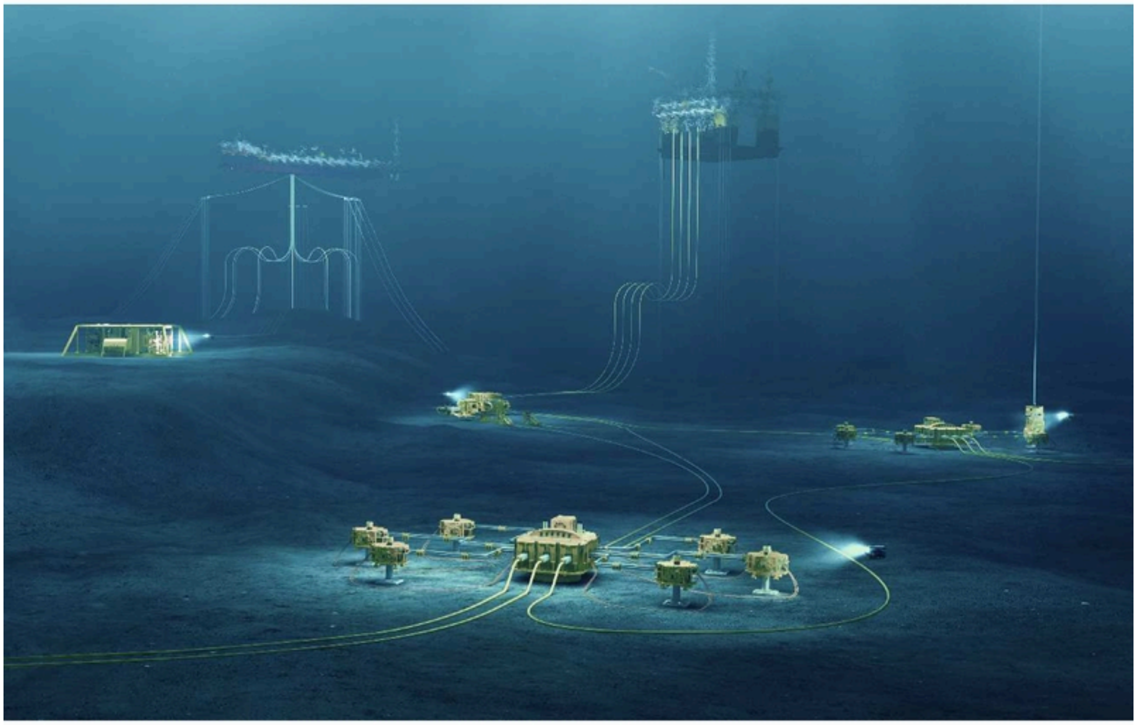

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Report title: ***Subsea Integrity Management – Maintaining and improving the risk level***

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1 EXECUTIVE SUMMARY

Understanding and ensuring control of the technical condition and the integrity of pipelines and subsea facilities in operation through the systems entire lifespan is a key prerequisite for avoiding hydrocarbon leaks, reducing the risk in operation, and maintaining a high level of safety in the petroleum industry. This is particularly important considering the high focus on a transition toward clean energy and decarbonization of the energy mix in the oil and gas industry. The preparations are ongoing with regard to re-qualifying and potentially modifying parts of existing subsea pipeline networks for future CO_2- and hydrogen transport. Challenges beyond normal operation in connection with continuation of the existing natural gas systems exceeding original design life and the development of subsea installations tied-back to existing infrastructure are other examples of changes which need to be identified and managed. This includes awareness regarding how changes in threat picture and implementation of new technology are handled and at the same time satisfies the requirement in regulations for barrier management, risk reduction, continuous improvement and learning. Further, change of ownership of subsea installations from one operator to another, from large, experienced operators to smaller more unexperienced operators, has in many cases caused challenges related to lack of detailed documentation of the system and loss of data and functionality in the transition process.

The main principle of the Petroleum Safety Authority's (PSA) requirements is that the operators shall know the condition of their equipment both individually and collectively and work continuously to reduce risk. The trends presented in the Petroleum Safety Authority's (PSA) annual 'Trends in risk level project' ('Risikonivået i Norsk Petroleumsindustri' (RNNP)) reports indicate a positive development with regards to the reduction of unwanted incidents. This indicates that the industry is willing and able to learn. However, these trends represent our history, and it is essential that the industry can maintain and improve the positive trend as required by the PSA's management regulations §4 'Risk reduction' and §23 'Continuous improvement', also in the future.

The main objective of the study set forth by the PSA has been to look at how to maintain sound management of the technical integrity of pipelines and subsea facilities through the operation phase also accounting for the changes that the industry envisages to come in the years ahead. The main focus has been on 'Management of change' and 'Learning' as means to maintain or improve the existing risk level at the Norwegian Continental Shelf (NCS). 'Understanding the uncertainties' as part of understanding risk has also been looked into in this report.

The current risk level at NCS, and the interpretation of it, is described in Section 4 and 5. Development of understanding and implementation of learning are discussed in Section 6. Section 7 discusses how we as an industry may become better at managing the risk associated with changes. This is followed by a management of change (MOC) example developed by an Operator on the NCS related to a tie-in of a new drill centre to an FPSO through existing in-field infrastructure. Check lists that can be utilised covering aspects to be consider when describing the risk impact related to a change can be found in Appendix C (generic) and D (example). Reflections around challenges and opportunities to maintaining and improve the risk level are presented in Section 8.

The identified key opportunities are briefly summarised below. The full list of opportunities and improvement areas can be found in Section 8.

Learning:

Key activities which may contribute to support and improve effective learning:

- More active use of Learning-activities in subsea integrity management processes, e.g. regular Lessons Learned sessions in the subsea operations organization, with identification of knowledge and understanding obtained, and how to share and implement the understanding to ensure that the learning is not lost. This could be in form of update to specifications and procedures, sharing in relevant fora or to peers, partners and vendors, input to standardization / best practice processes etc. It should be considered to include more formal learning activities as part of the learning process in subsea operating organizations, and it should be recognized that learning activities takes time, hence, a responsible person to drive the learning processes in the organization should be appointed.

- More interactive processes and dynamic approach to standardization and development of best practice in the industry. The industry is requesting new ways of interacting to ensure faster, more open and more effective processes. How to organize and enable such effective processes should be further explored by the facilitating organization in a close dialogue with the industry.
- Information about the technical condition of retrieved subsea equipment should be actively collected and compiled in a format which can be shared to relevant stakeholders in the industry, to support improved design, integrity management and lifetime extension of equivalent subsea facilities (ref. Activity regulations § 50).

Management of Change:

The following main opportunities are highlighted:

- More active use of formal Management of Change processes during the operational phase to ensure traceability and communication around significant changes, and that changes are reflected in the risk assessment and the integrity management program.
- Systematic process to identify changes and assessing their significance. This includes to extract significant changes from all the minor changes. Examples of means to identify significant changes may be monitoring of critical input data to the risk assessment or regular discussions about changes which may impact on the risk. Such assessments should include relevant data and competence within relevant areas, such as drilling and well, topside integrity, process chemistry and flow assurance.
- Use of check list to ensure complementary understanding of risk considering activity, strategy and technology, including its uncertainties; knowledge/evidence/confidence and manageability. Reference is made to the check list included in Appendix C as an example.

2 INTRODUCTION

2.1 Background

The Petroleum Safety Authority (PSA) has commissioned DNV to perform a study on how to improve management of the technical integrity of pipelines and subsea facilities in the operation phase and how to ensure that experience and knowledge obtained through the operational life of the asset are used to reduce risk.

Understanding the condition of all elements of a subsea system and at the same time ensuring control of the integrity in the operation phase through the systems entire lifespan is a key prerequisite for;

- avoiding loss of containment,
- reducing the risk of adverse events in the operation phase
- maintaining a high level of safety in the petroleum industry
- ensure production and up-time.

Having in mind that the life span for many subsea installations can exceed 50 years, the above is particularly important considering challenges that can arise beyond normal operation both in connection with e.g;

- continuation of the existing systems exceeding their original design life,
- the development of subsea installations tied-back to existing structures,
- re-using the existing systems for other purposes as part of the new energy mix such as transporting hydrogen or CO_2, potentially introducing new and previously unknown threats to the system,

What these new challenges can pose to the subsea system needs to be understood and controlled. This also includes awareness regarding how e.g. management of change, prospective changes in threat picture and implementation of new technology are handled and at the same time satisfies the requirement in regulations for barrier management, risk reduction, continuous improvement and learning and experience sharing.

Figure 2-1 illustrates the relationship between safe and robust solutions and the place of barriers in risk management. The work described in this report mainly focuses on the left-hand side of the figure. Further, the Petroleum Safety Authority’s requirements to risk reduction measures and implementation of barriers are stated in the Management Regulations §4 ‘Risk reduction’ and § 5 ‘Barriers’ (ref. Section.3).

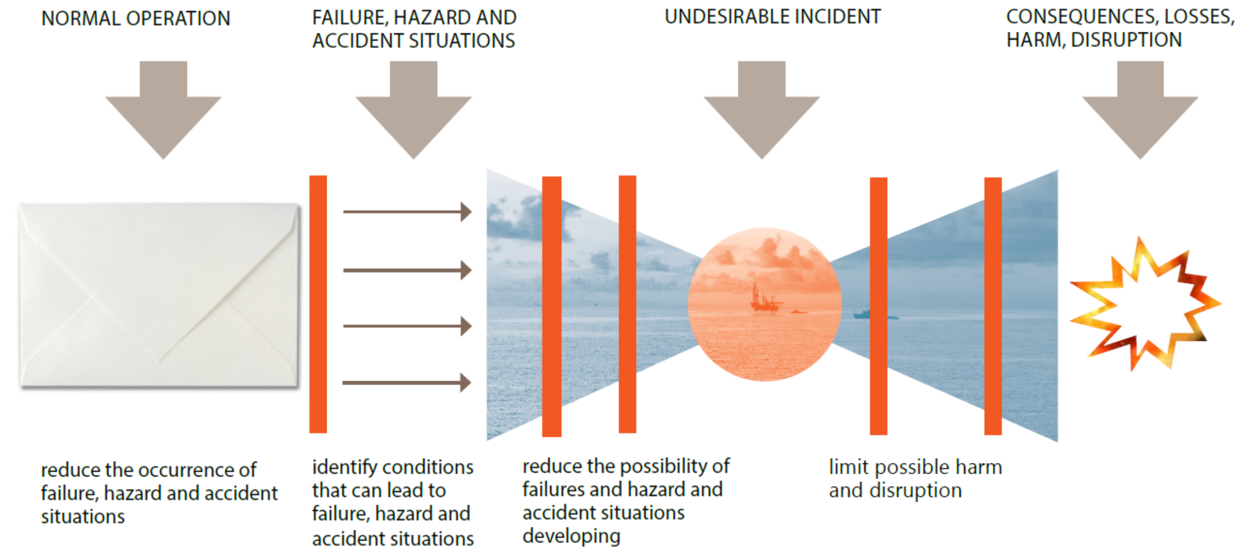


Figure 2-1 Model to illustrate the relationship between safe and robust solution and the place of barriers in risk management /1/

2.2 Objective, scope and battery limits

2.2.1 Objective

Regardless of what design standards have been used and what assumptions form the basis for operations, changes in operations need to be understood and managed, and at the same time, the Operator needs to satisfy requirements in regulations for barrier management, risk reduction, continuous improvement and learning and experience sharing. New knowledge, methods and technologies contributing to improved integrity management of pipelines and subsea facilities need to be handled by the operator’s organization over the lifetime of the facilities. The objective of the study in this report is to;

- highlight how to ensure better management of the technical integrity of pipelines and subsea facilities through the operation phase and how to ensure that experience and knowledge are used to reduce risk.
- look at factors that affect the technical integrity and the risk associated with incidents and leaks for pipelines and underwater systems in operation considering that subsea infrastructures have different designs, ages, lifetimes and conditions, and where changes occur over the operating life.

2.2.2 Scope

The study work addresses the below mentioned topics with reference to the integrity of the systems in the operation phase, however, the main focus has been paid to those topics perceived to add most value to the objective of the work.

- Risk management
- Control of barriers
- Goals, strategies and acceptance criteria for major accident- and environmental-risk

- Operation of facilities including technical solutions, organization and expertise
- Maintenance and inspection
- Changes and modifications
- Technologies and solutions that can contribute to risk reduction and continuous improvement
- Initiative to improve and share experiences

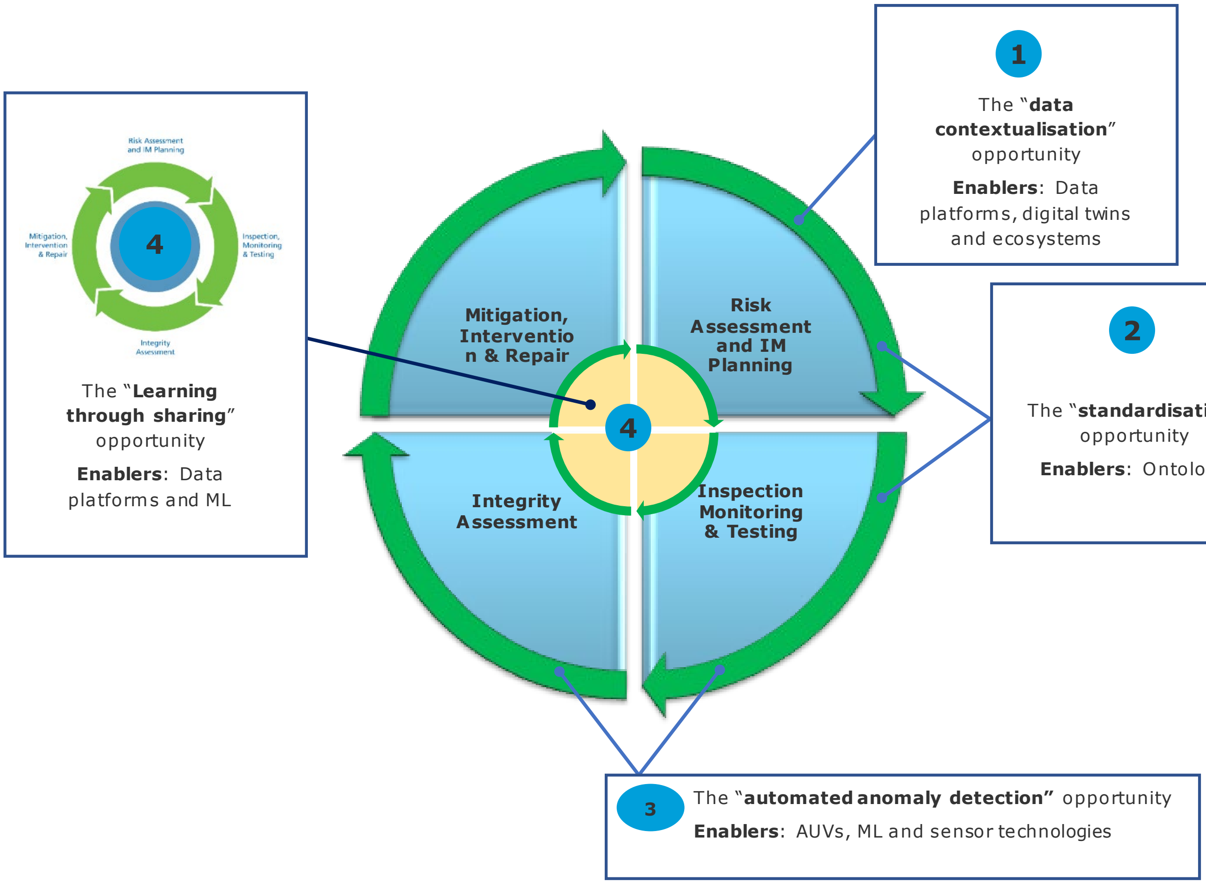
The study work builds on the key take-aways (challenges and opportunities) from the two PSA studies performed by;

- Wood 'Guidelines to Subsea Integrity Management – Wellhead to Topside ESDV', December 2020 (Wood) /11/ and
- DNV 'How digital tools and solutions can improve Subsea IM', December 2020 (DNV) /12/

that are considered relevant for the study performed and described in this report. Both studies focused on the importance of monitoring, recording and understanding data such that operational trends become apparent, and threats are understood, as the subsea systems ages. Further, transfer of ownership or modifications to the subsea configuration over time represent a threat to data availability and quality in this regard.

A key challenge is that sharing of knowledge and lessons learned across subsea system design owners, installations, operators, regulators may be limited due to commercial impact, contract requirements, intellectual properties and patents, company reputation and competitiveness /11/.

Further, subsea integrity management is characterized by vast amount of data collected and available for use. There is a big value in all these data sources if made freely available, accessible and searchable for all players. Work processes and systems to facilitate sharing of data and knowledge may be an enabler for learning and improved integrity management; in own organisation, in the supply chains and across the industry. Systematic collection, analysis and sharing of data and information about degradation, damage and failure, as well as information of what robust integrity looks like, may support improvement to technology, equipment, systems, operation and integrity management of subsea systems. The learning through sharing opportunity as illustrated in the DNV study from 2020 is shown in Figure 2-2.



The "**Learning through sharing**" opportunity

Enablers: Data platforms and ML

The "**data contextualisation**" opportunity

Enablers: Data platforms, digital twins and ecosystems

The "**standardisation**" opportunity

Enablers: Ontology

The "**automated anomaly detection**" opportunity

Enablers: AUVs, ML and sensor technologies

Figure 2-2 The four key opportunities enable by emerging technologies and how they may contribute to improved integrity management /12/

2.2.3 Battery Limits

The battery limits for the work are the hydrocarbon chain from (but not including) the wellhead to (but not including) topside/shore (ref. Figure 2-3). The work has focus on the Norwegian continental shelf (NCS) under the Norwegian petroleum regulations and is further limited to the subsea systems containment function.

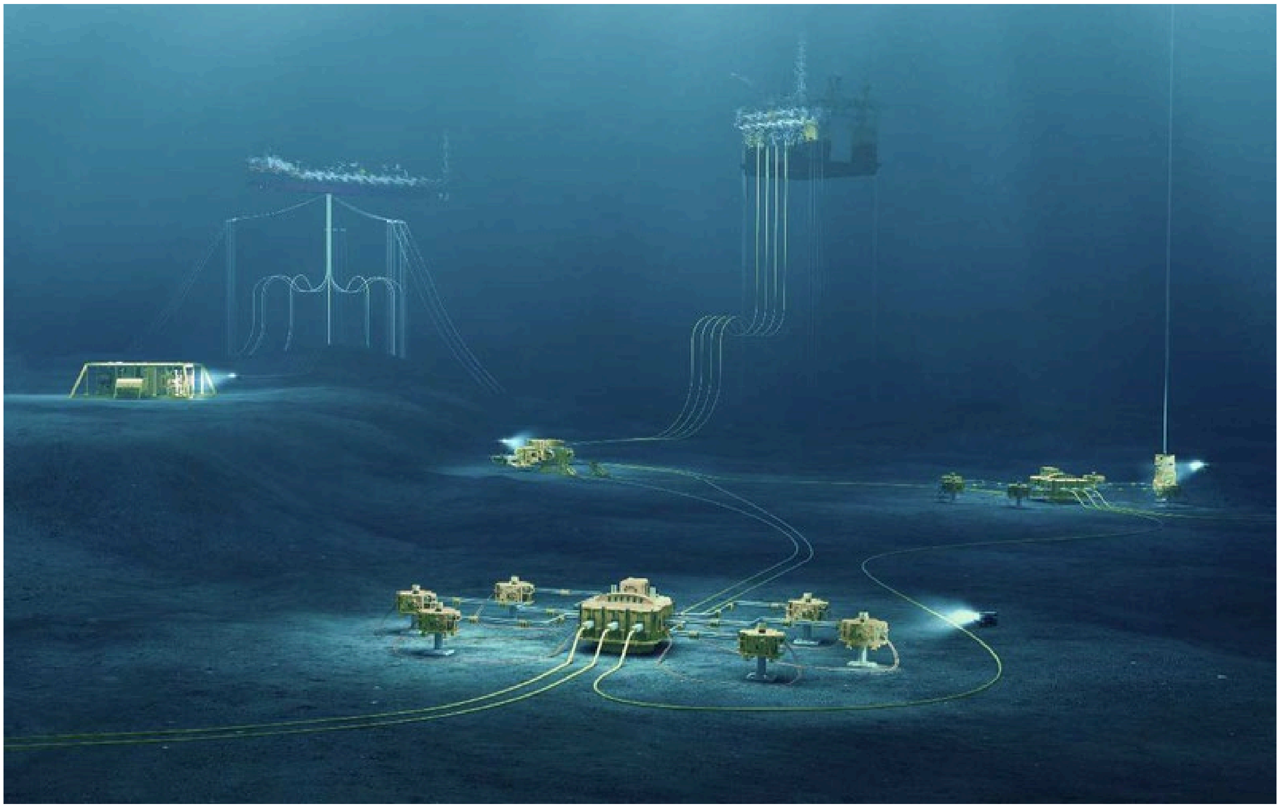


Figure 2-3 Illustration of typical subsea facilities, pipelines and risers.

2.3 Definitions and abbreviations

Abbreviations

Abbreviations	Descriptions
CODAM	CorrosionDamage
DFI	Design, Fabrication, Installation
DSHA	Defined Situations of Hazards and Accidents
FIV	Flow Induced Vibrations
HSE	Health and Safety Executive
MOC	Management of Change
NAV	The Norwegian Labour and Welfare Administration
NCS	Norwegian Continental Shelf
PTIL / PSA	Petroleumstilsynet / Petroleum Safety Authority (‘Trends in Risk Level’)
RNNP	Risikonivået i Norsk Petroleumsindustri
UKCS	United Kingdom Continental Shelf
VIV	Vortex Induced Vibrations

Definitions

Term	Descriptions
Failure	An event affecting a component or system and causing one or both of the following effects: - loss of component or system function; or - deterioration of functional capacity to such an extent that the safety of the installation, personnel or environment is significantly reduced. (DNV-RP-F116)
Integrity	The ability of a system to operate safely and to withstand the loads imposed during the system life (DNV-RP-F116)
Learning	Permanent change in behavior as a result of experience.
Major Accident	A major accident means an acute incident such as a major spill, fire or explosion which immediately or subsequently entails multiple serious personal injuries and/or loss of human lives, serious harm to the environment and/or loss of major financial assets (PSA The Management Regulations § 9)
Operator	The party ultimately responsible for operation, and the integrity, of an asset or a field.
Risk	Risk is the consequences of the activity, with associated uncertainty. Source: Guidelines to the Framework regulations § 11 (new definition introduced in 2015).
Risk level	A characterization of the severity of a given risk picture. Note: In practice, the risk level is typically described in terms of a set of qualitative and quantitative risk metrics that allows risks to be ranked or compared.
Safety	Freedom from unacceptable risk. Source: IEC 61508-4:2010. Note: Safety is here used in a broad sense to cover all types of risk, including risk related to life, property, environment, production, reputation etc.
Subsea Production System	The complete subsea production system comprises several subsystems necessary to produce hydrocarbons from one or more subsea wells and transfer them to a given processing facility located offshore (fixed, floating or subsea) or onshore, or to inject water/gas through subsea wells. (ISO 13628-1)

3 PETROLEUM SAFETY AUTHORITY (PSA) REGULATIONS

Through the authorities (PSA) Management Regulations, requirements are set forth to the responsible (i.e the Operator) in all phases of the petroleum activities to have control over the barriers, set goals and strategies and establish acceptance criteria for both major accident risk and environmental risk. These are examples of aspects that must be followed up to ensure that requirements for risk reduction and continuous improvement are met.

The main principle of PSA's requirements is that the companies involved shall know the condition of their equipment both individually and collectively and work continuously to reduce risk. There is further a requirement that conditions that are important for a sound and safety-wise execution of the activities are monitored and kept under control at any time (ref. the management regulations § 10). In addition, one must work continuously to identify the processes, activities, etc. where improvements are needed and implement necessary improvement measures. Personnel shall be aware of what barriers have been established and which function they are intended to fulfil (ref. also Figure 2-1).

The following sub-sections highlight some of the requirements presented in relevant parts of the Management Regulations and the Activity Regulations. For accurate wording and more details, the full set of PSA's regulations can be visited at PSA - Home (ptil.no).

The Management Regulations:

§ 4 'Risk reduction'

In reducing risk, the responsible party shall select technical, operational and organizational solutions that reduce the likelihood that harm, errors and hazard and accident situations occur. Furthermore, barriers shall be established. The solutions and barriers that have the greatest risk-reducing effect shall be chosen based on an individual as well as an overall evaluation. Collective protective measures shall be preferred over-protective measures aimed at individuals.

§ 5 'Barriers'

Barriers shall be established that at all times can;

- identify conditions that can lead to failures, hazard and accident situations,
- reduce the possibility of failures, hazard and accident situations occurring and developing,
- limit possible harm and inconveniences.

Further, PSA set forth the requirements to have established acceptance criteria both for major accident risk and for environmental risk.

§ 9 'Acceptance criteria for major accident risk and environmental risk'

The operator and the party responsible for operating a mobile facility, shall set acceptance criteria for major accident risk and for environmental risk associated with acute pollution. The acceptance criteria shall be used when assessing results from risk analyses.

§ 10 and § 23 focus on monitoring changes and trends and continuous improvement and learning from experience both within own organisation and from the industry in general, while §14 focus on requirements to manning and competence.

§ 10 'Measurement parameters and indicators'

The responsible party shall establish measurement parameters to monitor factors of significance to health, safety and the environment, including the degree of achievement. The operator or the party responsible for operation of an offshore or onshore facility shall establish indicators to monitor changes and trends in the major accident risk and environmental risk.

§ 14 Manning and competence

The responsible party shall ensure that the personnel at all times have the competence necessary to carry out the activities in accordance with the health, safety and environment legislation. Competence includes both individual competence and group competence, including professional competence, systemic knowledge, and health, safety and environment competence.

§ 23 ‘Continuous improvement’

The responsible party shall continuously improve health, safety and the environment by identifying the processes, activities and products in need of improvement, and implementing necessary improvement measures. The measures shall be followed up and the effects evaluated. The individual employee shall be encouraged to actively identify weaknesses and suggest solutions. Applying experience from own and others' activities shall be facilitated in the improvement work.

§ 25 Consent requirements for certain activities

The §25 states that *(c) The Operator shall obtain Consent […] before significant changes in activities as result of new requirements or permits from authorities, and (d) before use of offshore and onshore facilities beyond the lifetime and assumptions that form the basis for approval of the PDO, PIO or main application. When it is decided to initiate a process for possible lifetime extension of a facility, the Petroleum Safety Authority Norway shall be informed. Such application for consent shall be submitted one year before the planned lifetime expires.*

The guideline to the management regulations states: *The requirement for a new consent in connection with significant changes in requirements or permits as mentioned in the third subsection, litera c, means that, if the operator is required to implement technical or operational changes that have an impact on safety and working environment in the activities, the operator shall obtain consent before such changes can be implemented. (…) In order to fulfil requirements in Section 25 third subsection litera d last sentence, relevant parts of the Norwegian Oil and Gas’ Guideline 122* /18/*, can be used.*

It should be noted that Norsok U-009, Lifetime extension for subsea systems /20/, and Norsok Y-002, Life extension for transportation systems /21/ are relevant references in this regard. It should also be stressed that it is the Operator’s responsibility to identify the *significant changes* which may trigger a need for obtaining *Consent*.

Reporting

With regards requirements to reporting of hazardous situations and damages, this is covered by §29 ‘Notification and reporting of hazard and accident situations to the supervisory authorities’ and §36 ‘Reporting damage to load-bearing structures and pipeline systems (CODAM).

Activities Regulations:

Furthermore, the activity regulations § 20 ‘Start-up and operation of facilities’, §21 ‘Competence’ and § 50 ‘Special requirements for technical condition monitoring of structures, maritime systems and pipeline systems’ give requirements for operation of facilities with regard to technical solutions, organization and competence that shall contribute to safe operation and secure learning and sharing of experiences. § 50 also states that ‘When facilities are disposed of, the operator shall carry out studies of the structure's condition. The results shall be used to assess the safety of similar facilities’.

4 RISK LEVEL AT THE NORWEGIAN CONTINENTAL SHELF (NCS)

The operators at the NCS are, as mentioned in § 4 'Risk reduction' in the management regulations obliged to continuously work to reduce the risk related to their activities and recommended to carry out evaluations that illustrate that the risk is reduced as much as reasonably practicable (ALARP) /6/. Today, an acceptable level of risk is achieved through compliance with the PSA regulations and related public available standards and guidelines. It is considered that this regulatory regime contains the industry's best knowledge on how to design and operate with an acceptable level of risk. The following sub-sections discuss the historical development of unwanted incidents as presented in the Petroleum Safety Authority's (PSA) annual 'Trends in risk level project' ('Risikonivået i Norsk Petroleumsindustri' (RNNP)) reports /, and the importance of maintaining or improving the risk level in the years to come. The trends in risk level project consists of four yearly reports. The RNNP 2020 'Summary' report as referred to below and the Acute spills report (RNNP AU for the period 2005-2020) are published in English, while the main and land reports are only available in Norwegian. More information can be found at https://www.ptil.no/en/technical-competence/rnnp/ /5/.

4.1 Trends in risk level in the petroleum activity (RNNP 2020)

The PSA report 'RNNP 2020: Summary Report 2020 The Norwegian Continental Shelf - Trends in risk level in the petroleum activity' /14/ is by the industry considered to be an important tool for helping to establish a common picture of developments of selected conditions which affect risk and in addition, illustrates safety trends in the petroleum activity.

The following is concluded in the report related to pipelines, risers and subsea facilities:

'N*o serious leaks were reported in 2020 from risers or from pipelines within the safety zones for surface facilities. One leak/spill of methanol was reported from a manned facility where the cause was related to a failure of blind pipes. Two other reported leaks came from a pipeline transporting water and from pressure-testing of a riser with water. Two small oil leaks were reported in 2020 from subsea production facilities, one of which related to a subsea loading system and the other to a well intervention operation. Figure 5.10 presents leaks from risers and pipelines in the safety zone, 2005-20.*

Two cases of serious damage to flexible risers and associated auxiliary equipment were reported in 2020. Flexible risers have been and remain an important contributor to risk. The PSA has followed up this subject over a number of years and conducted a number of supervisory activities directed at these risers in 2020. Based on this follow-up, the seriousness of two flexible-riser incidents in 2019 has been upgraded in the statistics. This raised the number of serious incidents in this year to five. Figure 5.11 presents serious damage to risers and pipelines in 2005-20.'

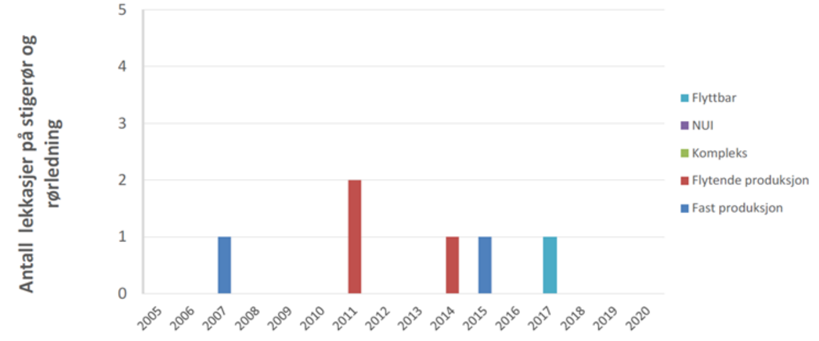


Figure 5.10 Leaks from risers and pipelines in the safety zone, 2005-20

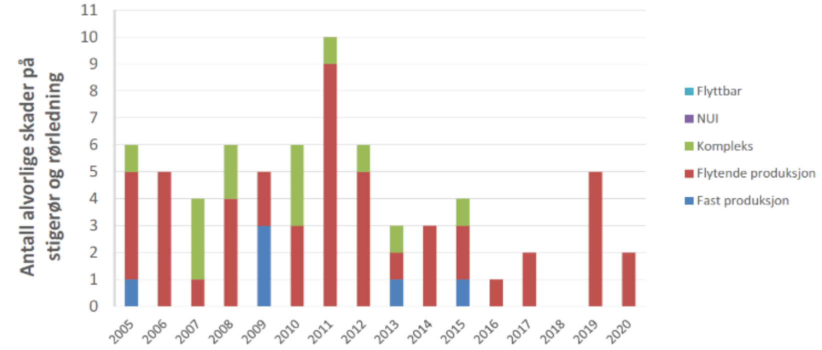


Figure 5.11 Major damage to risers and pipelines in the safety zone, 2005-20

Furthermore, the report's Figure 5.1 that is shown below, presenting the trend for reported Defined Situations of Hazards and Accidents (DSHA) in 2005-2020), illustrates the contribution from pipelines, risers and subsea facilities to the total context.

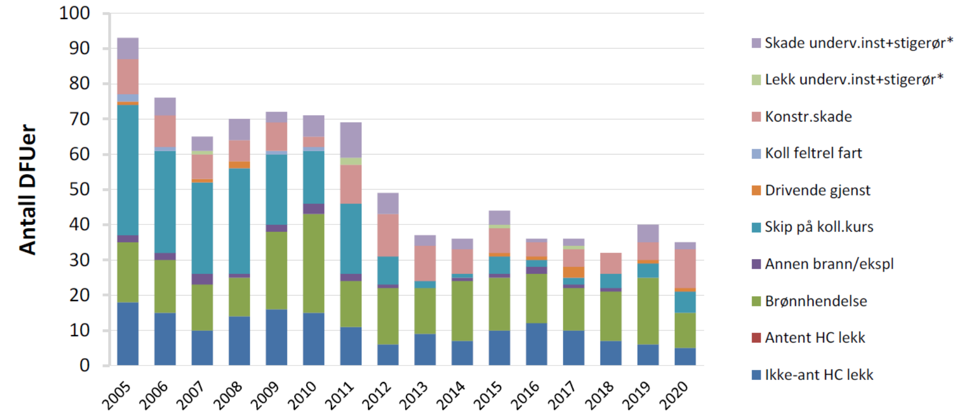


Figure 5.1 Reported DSHAs (1-10) by categories
****Within the safety zone***

The report does not provide any specific recommendations to improving the risk level associated with pipelines, risers and subsea facilities, however, four (general) improvement areas were identified:

- strengthening the reporting culture internally and between companies,
- better reporting of personal injuries and use of the Norwegian Labour and Welfare Administration (NAV) forms,
- preparing a common basis for classifying incidents, and
- improved practice for notifying/reporting hazards and accident situations.

The trend picture in the RNNP report complies with the main findings from the PSA supervision reports in the period from 2018 to 2020 as summarised in /12 / and Appendix A. The PSA reported non-conformances and improvement points in the time period from January 2018 to date, are generally in line with focus areas in the industry as presented in presented in the DNV report 2020/1022: How digital tools and solutions can improve Subsea Integrity Management /12/. The RNNP 2019 report summarises that there were three incidents related to flexible risers in 2019, while there are two reported in the 2020 report. None of these resulted in hydrocarbon leak, but the failure modes indicate that equivalent failures may occur on hydrocarbon flexible risers if the failure development is not detected and may potentially lead to loss of containment. Hence, data collection to detect similar failure development should be given high focus, as further discussed in Section 5.5.3 of /12/.

4.2 Continue the trends

The trends presented in the previous RNNP reports illustrate that there has been a reduction in the number of incidents and accidents over the last couple of years. It might indicate that the industry is willing and able to learn. However, these trends represent our history and do as such not necessarily represent the future. It is no guarantee that such trends will continue, and there are several aspects of the future that might threaten the continuation or improvement of these positive trends. However, as discussed above, improvement areas can still be extracted from the RNNP data. The above-mentioned improvement areas are identified as important for the ability to learn and to continue with a low number of near misses and major accidents.

Maintaining a high safety level at the NCS is essential, not only to avoid damage to the environment, assets or to avoid fatalities or human injuries, but also to the industry’s reputation. As safety can be defined as ‘freedom from unacceptable risk’ (IEC 61508), a high safety level is related to a low level of risk. Consequently, risk management is central to achieve a high safety level. When discussing the integrity of subsea facilities, risk management is linked to integrity management, where the focus is on avoiding loss of containment or loss of critical functionality. Said differently, the focus is limited to the undesirable incidents ‘loss of integrity’ and/or ‘loss of containment’, which are then considered as the center of the bow-tie presented in Figure 2-1. Integrity management does then, mainly, focus on the left side of the bow-tie, working to avoid these undesirable events. As a result, a proper subsea integrity management system is essential to maintain a positive trend and an acceptable risk level, and a set of key improvement or focus areas are presented in the following of this report.

When focusing on avoiding future unwanted incidents and accidents it is necessary to acknowledge that the future might be different than our past. These differences or changes are important, as they, if not managed have the potential to introduce near misses or accidents. This will be further discussed in Section 7. It should also be acknowledged that the future depends on what the industry does in the present, as illustrated in Figure 4-1. For example, today’s inspection activities and results will potentially provide useful information related to the system integrity in the future, making it easier to know, e.g. how fast corrosion or erosion is developing. Further, the past represents the industries experience that we can harvest from at present and prepare for the future given that new threats and challenges are known.

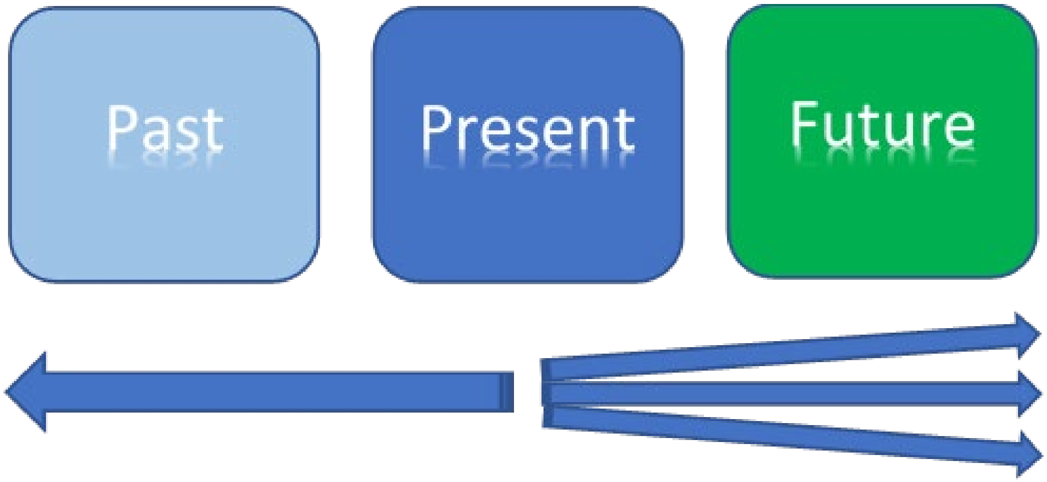


Figure 4-1 Illustration of past, present, future. 'Past' tells what happened at previous time or describes a pattern of behaviour in the past. 'Present' tells what actions that are currently happening or ongoing and 'Future' describes things that have yet to happen including the associated uncertainties.

5 UNDERSTANDING INTEGRITY IN A LIFE CYCLE PERSPECTIVE

5.1 General

Integrity is defined as the ability of the system to operate safely and to withstand the loads imposed during the system life cycle, ref./11//12//13/.

Integrity is established in the concept, design and construction phases, and it is maintained in the operational phase.

In the operational phase, the asset is:

- Operated – Production is managed to deliver according to company objectives and market needs while staying within allowable operational and design limits.
- Maintained – Even though subsea systems are generally engineered and constructed to be robust, maintenance is still necessary. Integrity needs to be maintained.
- Modified – Modifications to the asset are sometimes necessary because of changes in needs, or better solutions becoming available. Modifications, even seemingly minor ones, can have significant impact on production and integrity and must be managed accordingly.

Even though production and modification shall take place without compromising current and future integrity, it is primarily the maintenance (integrity management) function which is responsible for managing integrity.

Simply explained, integrity management is the combined (core) process of threat identification, integrity/condition assessment, risk assessment, planning, monitoring, inspection, testing, maintenance, and repair to ensure continued acceptable subsea integrity.

This core integrity management process is part of an overall integrity management system with many other elements necessary for both short-term and long-term success – see Figure 5-1. These include company policy, organization and personnel, reporting and communication, operational procedures, management of change processes, contingency plans, assurance activities and information management. All such elements govern and support the integrity management process, and ultimately impact integrity as well.

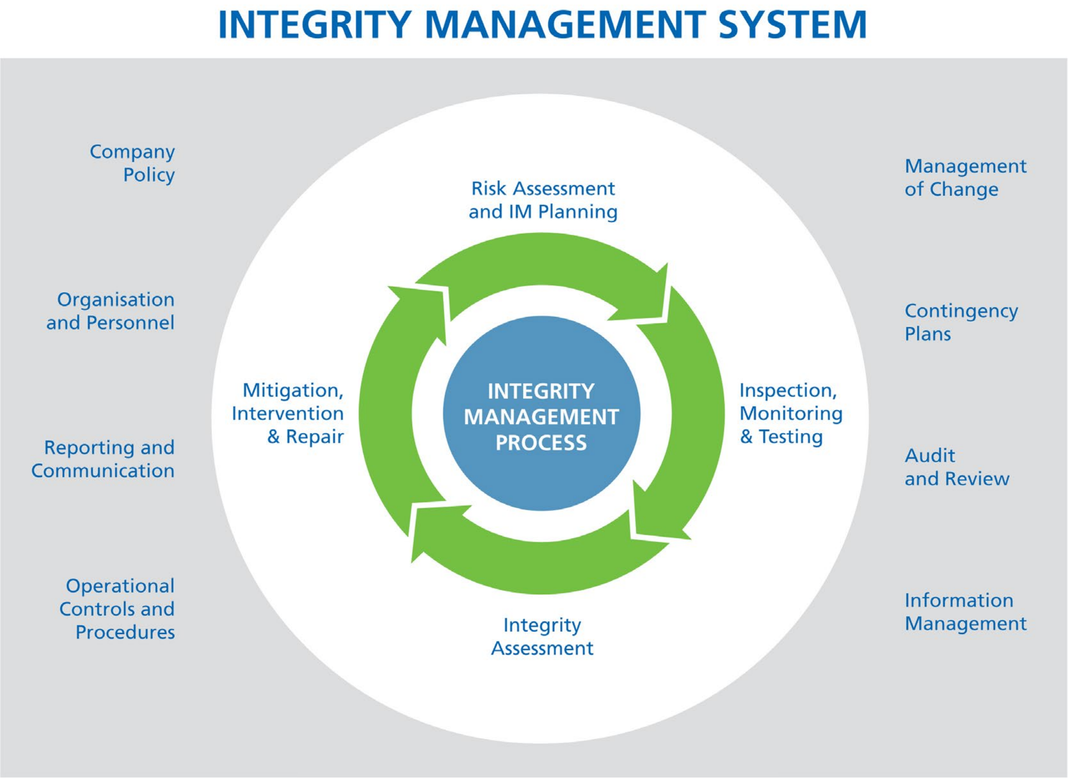


Figure 5-1 Illustration of an integrity management system, Ref. /13//15/

The operator shall establish, implement, and continually improve such a management system that ensures the integrity of the system during its service life.

Planning of integrity management activities in the operational phase starts prior to start-up as shown in Figure 5-2.

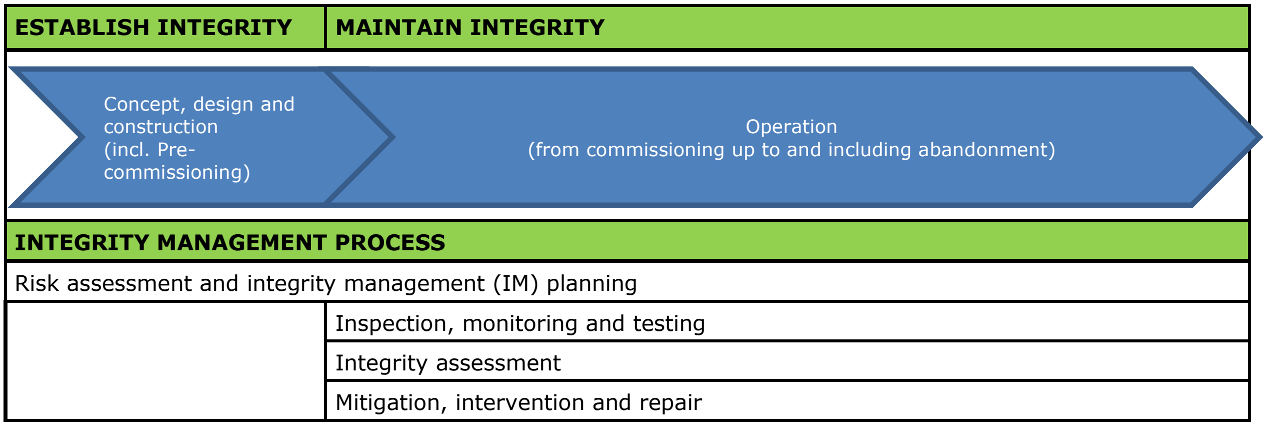


Figure 5-2 Integrity management process in a life cycle perspective

Ensuring integrity is in other words a continuous process of knowledge and experience applied throughout the asset lifecycle to manage risk from design, construction, installation, operation, maintenance and finally abandonment phases of the subsea system to maximize the benefit to the owner whilst at the same time safeguarding people, asset, and environment.

The activity of operating, maintaining, and modifying subsea systems requires proper management systems, technical solutions, and competent organizations to avoid major accidents and maintain an adequate safety level in the industry. Authority requirements have clear focus on these topics (see Section 3) and the different actors on the Norwegian continental shelf (NCS) have been generally working according to these requirements. The track record for operation at the NCS has been good regarding avoiding major accidents (ref. Section 4), and this indicates that life cycle activities have historically been adequate.

This report focuses on key factors affecting technical integrity in the operational phase. Awareness about these factors helps to maintain today's safety level or improve it. This is particularly important keeping in mind that the industry will most likely experience changes due to accelerated energy transition initiatives during the next decade. Also, this is important due to prolonged operation (life extension) requirements of subsea systems as well as the normal processes of continually trying to safely minimize cost and maximize profit.

5.2 From initial causes to final consequences

Excellence within integrity management of subsea assets requires a good understanding of the chain of events from initial causes to final consequences as shown in Figure 2-1 and further illustrated in Figure 5-3. In Figure 5-3, loss of integrity describes an undesirable event which will compromise the system's integrity although not necessarily imply imminent ultimate structural failure. Failure criteria in design codes are of this form. These are typically formulated as violation of a theoretical limit state (e.g. exceedance of calculated structural capacity) implying loss of structural integrity (loss of containment or collapse). For example, due to some initial cause a pipeline may be exposed to a load that results in loss of integrity, such as significant deformations of the cross section. The criteria used in design codes interpret this event as a failure, although the pipeline may still be fit for further operation under certain conditions defined through integrity assessments (see core integrity management process in Figure 5-1).

The lower part of Figure 5-3 (which is based on the barrier concept) also shows the development of a threat into a loss of containment, and the measures implemented to reduce the likelihood and/or consequence of such development. These all have weaknesses, but together they normally stop the development all the way through to the final consequences. Integrity Management has its main focus on preventing loss of containment. The main defenses against loss of containment in the lower part of the figure are:

- Pressure containment and primary protection – This comprises the containment system itself and its primary protective system. Conceptually, a well-developed (or modified), quality assured, robust and well protected system is considered the first line of defense positioned at the far left of the bow tie diagram.
- Operational/process control – Conceptually, this is the second line of defense. It should ensure that the system is being operated as intended and that the predefined operational envelopes are maintained and not violated.
- Pipeline/Subsea integrity control (3 o'clock and 6 o'clock in the core integrity management process in Figure 5-1) – The third line of defense consists of processes and systems to detect and assess anomalies.
- Pipeline/Subsea integrity improvement (9 o'clock in the core integrity management process in Figure 5-1) – The last line of defense (conceptually positioned right to the left of the top event) consists of processes and systems that will improve the integrity where anomalies have reduced the system to an unacceptable condition (loss of integrity).

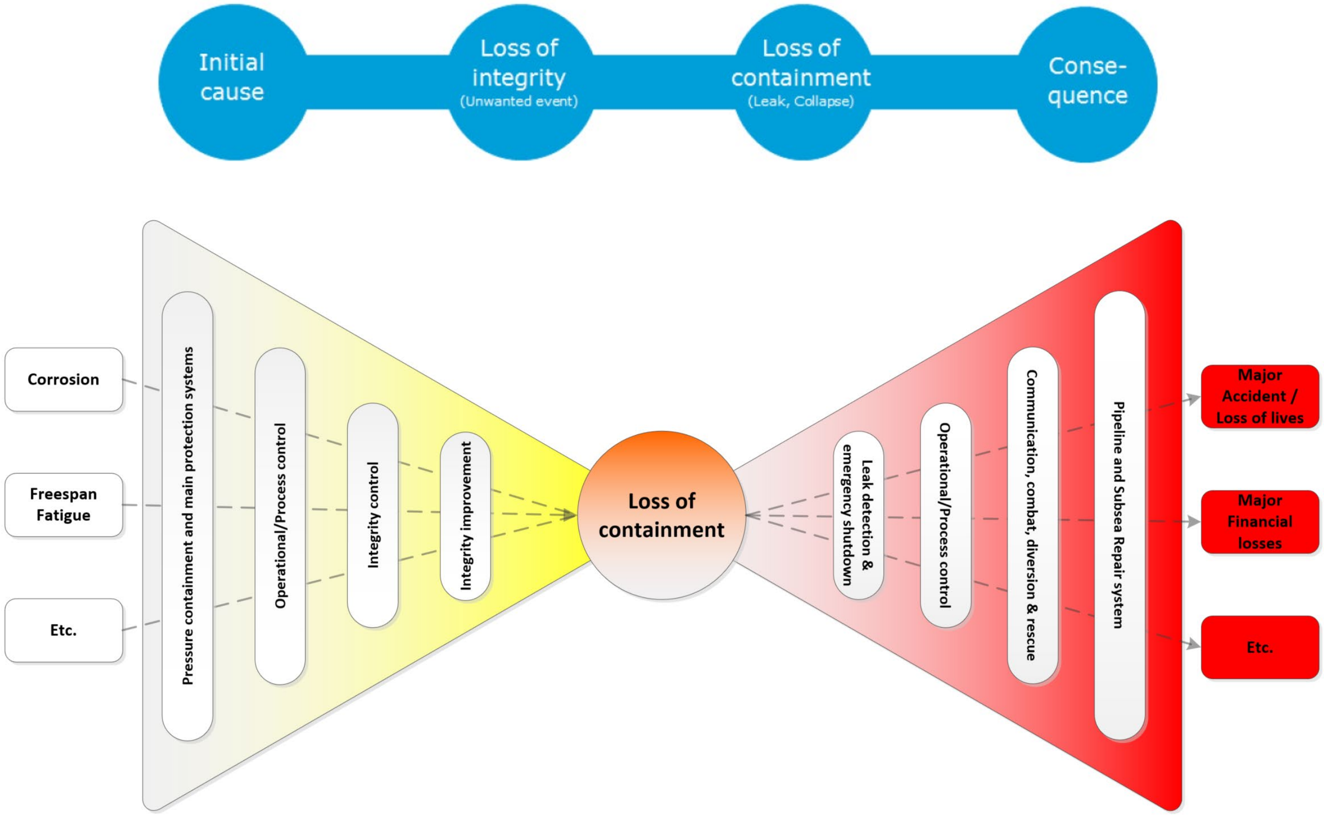


Figure 5-3 Chain of events from initial cause to consequence.

It is in other words important to understand:

- the ***integrity threats*** and how they may lead to loss of containment (contribution from relevant parameters that influence on the degradation rate or likelihood of failure and the trigger levels which make the threat active),
- the current ***technical condition*** and how the assets are likely to degrade over time,
- the ***risk***, i.e. the probability and the consequence of loss of containment,
- how to reduce the ***probability*** with regards to loss of containment through various measures;
    - design ("robustness") including fabrication and installation aspects; typical measures are QA/QC activities including third party verification, inclusion of protective systems such as internal corrosion and external corrosion protection systems, pressure protection systems, mattresses and structures for stability and for protection against third party activities, etc.
    - operational / process controls ("integrity window"); this includes e.g. hardware, software, plans and procedures ensuring that the subsea systems are operated as intended.
    - integrity control ("actual condition"); this includes inspection, monitoring and testing activities to reveal damages/anomalies and their historical development. Also, integrity assessments coupled with prediction models are important for evaluating identified damages/anomalies and their potential development.

  - integrity improvement ("intervention"); this includes both preventive actions (changing the MAOP, rock dumping, etc.) to stop further development into failure and if necessary, corrective actions (cut and replace, etc.)

- how to reduce the ***consequence*** if a loss of containment occurs through;

  - detection: this includes measures such as leak detection systems and inspection.

  - prevention of escalation: this includes measures such as emergency shutdown systems, communication systems, combat systems, diversion systems etc.

  - remediation: this includes measures such as emergency repair systems

- the **knowledge/uncertainties** associated with the system.

5.3 Understanding the track record

In the following, pipeline failure is used as an example, however, this should help for the understanding in a general subsea context.

When designing pipelines, very low annual failure (loss of integrity) probabilities are required (10^{-4} is very common, but they may be as low as 10^{-8}). This is a good starting point and loss of containment statistics from the operational phase show a good track record as already mentioned in 4.1. However, it is expected and confirmed that the failure frequency in operation is at least one order of magnitude above the probability of failure required during design (from for example 10^{-4} up to 10^{-3} or 10^{-2}), Ref. /24//27/. Assuming that the basis for both these numbers are of acceptable quality and comparable, what are the reasons behind the differences.

Looking back at the fundamentals, a structural failure occurs when the effect of the applied load (L) is greater than the resistance (R) of the component or material, i.e., a structural failure occurs when $L > R$. The resistance R is primarily related to the materials, the design, and the in-service condition of the structure. The applied load L can be any type of load; functional, environmental or accidental. The identified reasons why $L>R$ occurs are many and diverse, ranging from e.g. poor design specification, design errors, and material defects, through to e.g. fabrication errors, degradation in operation, and even “incredible” events.

The basic causes resulting in the probability of pipeline failure (P_{total}) can be categorized as follows (adapted from Ref. /28/ and /29/):

- Natural uncertainties in design loads and load bearing capacities ($P_{\text{technical}}$)
- Accidental events ($P_{\text{accidental}}$)
- Gross errors during design, fabrication, installation, and operation ($P_{\text{gross error}}$)
- Unknown phenomena ($P_{\text{incredible}}$)

P_{total} is a function of $P_{\text{technical}}$, $P_{\text{accidental}}$, $P_{\text{gross error}}$ and $P_{\text{incredible}}$. **Table 5-1** provides further descriptions.

Basically, when designing pipelines, it is primarily $P_{\text{technical}}$ and also $P_{\text{accidental}}$, which are considered – see **Table 5-2** where further descriptions are given regarding probability of failure and risk management in a lifecycle activity perspective.

Design assumes that proper measures are implemented during design, fabrication, installation and operation to minimize the contribution from $P_{\text{gross error}}$. This assumption is key. Adequate QA/QC during design, fabrication and installation (including review, verification, inspection and witnessing of key documents, activities, assets, changes and repairs) is very important. Equivalently, similar types of measures are also necessary to continue performing in the operational phase. The assumption of such adequate measures has perhaps been optimistic, and this perhaps explains much of the difference between the required failure probabilities during design and the statistics from the operational phase.

Development projects on the NCS follow standardized engineering management processes with rigorous QA/QC measures involving internal verification and often also third-party verification in addition. Many standards, recommended practices, procedures and tools have been established and are continually improved to support development projects. In the day-to-day operation, the budgets are not the same as for development projects, and the set of resources available for managing assets in the operational phase is not the same. It is therefore tempting to think that gross errors in the operational phase are the main reasons for the operational statistics being at least one order of magnitude above the probability of failure required during design. Other suspected sources of gross errors are early errors related to the basis of design, and errors related to transfer between the different phases (from concept to design, from design to fabrication, from fabrication to installation, and finally when the asset is transferred to operation).

Table 5-1 Basic pipeline failure causes contributing to pipeline failure probability

$P_{technical}$	**Normal statistical variations** $P_{technical}$ addresses uncertainties in loads and resistance due to fundamental, natural random variability, e.g. material strength, and uncertainties due to lack of information, e.g. modelling uncertainties. In addition to natural random variability, human actions and systems which influence design, fabrication and operations of structures normally follow defined procedures and processes. The resulting overall uncertainties in resistance and loads follow certain patterns. Uncertainties can be predicted mathematically including a certain normal level of variability in e.g. welders performance, environmental conditions. Where the human factor departs significantly from “normal” acceptable practice then this is termed a gross error. Note: $P_{technical}$ is referred to as $P_{nominal}$, the nominal failure probability, in structural reliability methods.
$P_{accidental}$	**Accidental events** In addition to the functional and environmental loads, there will be “accidental” events that can affect the pipeline, e.g. geotechnical instability, third party interference. These accidental load events are predictable in a probabilistic form based on historical data. The probabilistic basis for the accidental event is taken from observed, historical or local data.
$P_{gross\ error}$	**Gross error** Gross errors are understood to be human mistakes. Management systems addressing e.g. training, documentation, communication, project specifications and procedures, quality surveillance etc. are all put in place to avoid human error. Gross errors occur where these systems are inadequate or are not functioning. Examples of gross-errors through the pipeline life-cycle include: lack of understanding, lack of / not used information, calculation errors, lack of self-check, insufficient verification, lack of follow-up during fabrication, lack of communication or misunderstanding in communication, lack of training, errors in electronic management systems. It is difficult to predict the probability of a gross error in a project. However, history shows that gross errors are not so rare. Avoiding gross error leading to failure should therefore be a focus of developing, applying and following up the management system in addition to third party checks.
$P_{incredible}$	**Unknown phenomena** Truly unimaginable events are very rare, hard to predict and should therefore be a low contribution to failure. There is little value therefore in attempting to estimate $P_{incredible}$. However, it is important that those designing pipelines understand the level of confidence, i.e. state-of-the-art of their knowledge for the project. Poor technology qualification or design basis is not an excuse for an event to be “unthinkable”. Examples of such events can be a sword fish stabbing a flexible pipeline, unanticipated military activities, unanticipated environmental loads due to changes in weather patterns. It is worth noting that even though incredible events have low probability, they can have very high consequences thus increasing the “risk”. However, public are in general more likely to accept consequences of truly incredible events when they have occurred.

Table 5-2 Lifecycle integrity risk management – reflecting historical / current practices

	Design	Fabrication, installation, commissioning	Operation
P_{total}	QRA applying the generic P_{total} to ensure that risks are within acceptance criteria	Verify that key QRA assumptions and requirements relating to acceptable risk are met as appropriate for these phases.	With respect to risk based on generic P_{total}, verify that key QRA assumptions and requirements are maintained throughout operation[1]
$P_{technical}$	Selection and fulfilment of design code with an appropriate calibrated level of structural integrity.	Fulfilment of code and project requirements established in design phase. HAZID, HAZOP and Qualitative Assessments of where deviations, accidents, or errors affecting integrity could occur during activities.	Integrity management plan as required by the code and risk based to ensure that critical design performance standards established through design and installation are maintained in operation. Identification of trends and unexpected events in integrity performance.
$P_{accidental}$	Risk assessment of accidental loads to provide specific design requirements within acceptance criteria.	Fulfilment of code and project requirements established in design phase. HAZID, HAZOP and Qualitative Assessments of where deviations, accidents, or errors affecting integrity could occur during activities.	Integrity management plan to ensure that critical design performance standards established from the risk assessment of accidental loads are maintained in operation. Identification of trends and unexpected events in integrity performance.
$P_{gross\ error}$[2]	Verification of inputs, critical assumptions, and design work. This can be risk-based. Management system.	Quality surveillance to meet requirements of codes and project design expectations and requirements. Management system. HAZID, HAZOP and Qualitative Assessments of where deviations, accidents, or errors affecting integrity could occur during activities.	Periodic verification of integrity management system performance. Feedback of near misses and events. Management system. Identification of trends and unexpected events in integrity performance.
All aspects	**Communication and Documentation**		
	Feedback, Evaluation and Recording of deviations from design expectations		
	Management of Change with potential to affect integrity		

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[1] This is good practice but may not be done by all operators unless required to do so by law

[2] Risk of gross error is not normally estimated but is aimed to be controlled by quality management and surveillance

5.4 Key focus areas for further improvement in the operational phase

The key factors affecting integrity in the operational phase are linked to how well the main/major activities in the operational phase are managed. As mentioned in Section 5.1, in the operational phase, the asset is basically (1) operated, (2) maintained, and (3) modified. Production is the ‘reason of being’, but it needs to take place without breaching allowable operational and design limits. Integrity needs to be maintained and for various reasons the assets are modified. Even though production and modification shall take place without compromising current and future integrity, it is primarily the maintenance function (integrity management function) which is responsible for managing integrity. An integrity management system needs to be in place with activities starting already prior to start-up, and achieving excellence requires a good understanding of the chain of events from initial cause to final consequence and how to control it. More information about integrity management can be found in previous studies recently issued on the PSA web site, ref. /11//12/. In these studies, there are also various references which provide both additional information and requirements.

Based on the above, there are clearly many factors which affect integrity and risk in the operational phase. Based on engineering judgement and previous experience, some suggested key factors / areas to focus on to further improve integrity management in the subsea industry are listed below:

- **Interfaces between underwater integrity management and both operation/production management and maintenance/integrity management of other parts of the asset**

  As a part of the monitoring activity, pipeline and subsea Integrity Management teams should be more active in regularly gathering and trending relevant data from operation/production and other Integrity Management teams (e.g. topside assets). This is considered a major opportunity which can contribute to keeping or improving the risk trend. It is also considered low hanging fruit, both for the operators to implement and for the authorities to follow up.

- **Integrity status and trending – bottom-up and top-down**

  Integrity management is all about ‘Knowing & Understanding’ your system. More systematic reporting/documentation of integrity status and trending is a key mechanism to build this knowledge and understanding. Furthermore, sharing this from the bottom and up with the rest of the organisation and the industry in a more systematic way can help the industry become even better. From the top and down, authorities can improve the way they gather data on integrity status and trending. This should be harmonized through standardization. It is considered a major opportunity but is most likely a significant challenge to implement in a consistent common/standardized format from the bottom and all the way up, and back down.

- **Modification / re-qualification**

  This has always been an important aspect of the operational phase and much experience has been gathered throughout decades of operation at the NCS and internationally. Learning from the experiences by creating company and industry guidelines and/or standards covering the particulars of such projects can contribute to further improve the safety level. Particular attention should be given to the interface between such projects and existing Integrity Management System, especially with respect to ensuring adequate involvement from existing integrity management team and timely updating of existing risk-based integrity management plans. This is a moderate to major opportunity given the potential changes expected in the near future due to the energy transition to cleaner energy systems. The challenge is considered minor to moderate.

- **More efficient industry standardization**

  Better use of all the progresses made in the digital space can significantly improve the standardization processes. This is most likely a major opportunity but is considered to be a moderate to major challenge. This is also discussed in /11/.

- **Reporting of key indicators to authorities and presentation of findings back to the industry**

  The areas of improvement presented in this report are based only on engineering judgment given the scope and framework for this report. It is recommended to perform more in-depth evaluations based on more detailed facts from the industry. One potential mechanism is the RNNP initiative, ref. Section 4.1. It has improvement potential regarding the risers, pipelines and subsea assets and could possibly include presentation of direct and root causes, sharing of new knowledge and understanding and suggestion of areas where learning is required. Improvements could also include presentation of key indicators in the same manner as currently done for barriers in Chapter 6 of the RNNP summary report for 2020 /14/. Examples of potential key indicators (in addition to leaks/losses of containment and major damages) which will give value to the subsea industry and that should be considered included could be:

  Preventive barrier KPIs (ref. Section 5.2):

  - Inspection related KPIs
    - Kilometres of inspection carried out (or % of length)
    - Number of external and internal inspections carried out
    - Percentage of successful inspections
    - Back log of inspections
  - Monitoring related KPIs
    - Number of formal reviews of monitoring data carried out by Integrity Management team/responsible
    - Back log of monitoring data reviews
    - Number of operational envelop breaches (relevant to IM, e.g. temperature, pressure, water dew point)
  - Intervention and repair related KPIs
    - Number of interventions and corrective repair carried out
    - Backlog of interventions and repairs
  - Modification related KPIs
    - Number and status of on-going modification projects (concept, design, fabrication, installation, operation)
    - Number of non-conformances and status

  Reactive barrier KPIs (ref. Section 5.2);

  - Emergency Repair System
    - in place or not
    - number of inspections and tests carried out
    - number of maintenance hours
    - number of training and drill hours
  - Leak detection system

    - in place or not
    - number of testing and calibration hours
    - number of successful detections
    - number of false alarms
  - Systems to reduce environmental consequences (e.g. oil spill response plans, procedures and resources)
    - in place or not
    - number of training and drill hours
  - Systems to reduce public exposure (e.g. air and maritime traffic diversion plans, procedures and resources)
    - in place or not
    - number of training and drill hours

  In the long run, and considering that historical performance might not necessarily be representative for the expected changed landscapes of the future, this can be a major opportunity and minor challenge given the excellent basis established by the RNNP initiative

- **Pipeline and subsea system barriers**

  Barrier management is more mature when it comes to above water facilities and this is perhaps linked to the fact that there is a more direct personnel exposure to the hazards. Barrier management for pipeline and subsea systems has potential for further development. On its own, this is considered to be a moderate opportunity and moderate challenge. In the context of knowing and understanding a pipeline and subsea system from an integrity and risk perspective, the opportunity can be considered more significant (also if the RNNP initiative should be re-vamped for the risers, pipelines and subsea assets).

- **Understanding the uncertainties**

  The risk definition focuses on understanding and managing uncertainties. The current risk assessments for subsea facilities typically systematically assesses threats, probabilities, consequences and mitigations, but the uncertainties and the critical assumptions are not always well documented, see also discussions in /8/ /9/. It is considered a significant opportunity to systematically assess and document the uncertainties in the risk assessment and the integrity management activities. A number of assumptions are often made as part of the risk assessment, without all assumptions being validated throughout the lifetime of the assets. Loss of containment, loss of structural integrity, and failure in form of unacceptable condition is typically associated with insufficient knowledge (e.g. threat not identified, threat incorrectly assessed, barrier effectiveness incorrectly assessed).

  Mitigating activities are sometimes implemented without a conscious consideration of their effectiveness in preventing threats from leading to events. By nature, and by design, some threats can be effectively managed through the operational phase, while others may not be effectively managed. This is not always reflected in a risk assessment. Some threats are mainly mitigated by design (rely on a robust design, and cannot effectively be monitored or inspected for), while others can rely on effective condition monitoring and inspections to confirm their condition, as well as effective operational controls and procedures. As an example, an inspection is often considered a preventive mitigation, while for a number of threats, inspection is primarily a detection method.

Key focus areas which may contribute to reduce the uncertainty in risk assessments for subsea facilities are highlighted here:

- Critical assumptions and inputs to risk assessments (assumptions, that if changed, could alter the results of the risk assessment) should be identified and the strength of knowledge/evidence/confidence which support the assumptions/inputs, should be documented in the risk assessment. The critical assumptions should be monitored throughout the operational life of the assets to validate that the risk assessment is valid, alternatively, to trigger reassessment when assumptions and input data are no longer valid.
- The effectiveness of each risk mitigation, such as design robustness, monitoring and inspection, operational controls and procedures, should be assessed for each individual threat to understand the manageability of each threat. Manageability as term is here meant to include the means to identify a degraded condition and the means to prevent (further) degradation to occur (alternatively to replace or modify).

In addition to the above, there are two areas considered to be especially important and which have been covered more in detail. These are **'learning and knowledge sharing'** and **'management of change'**, ref. Sections 6 and 7. It should be noted that bullet one above is closely related to many of the points taken up in later in Section 7 (Management of Change) especially in connection with the changes which can go undetected. Also, bullet two is closely linked to the topic of 'Learning' covered by Section 6 as it forms a basic foundational block to building knowledge from the bottom and up. The same applies to bullet five as it would facilitate bringing back overall industry experience in a unique top-down manner.

6 LEARNING AND KNOWLEDGE SHARING IN THE INDUSTRY

6.1 Introduction

Learning is one of the suggested key factors and potential areas of improvement related to subsea integrity management. This section discusses learning as a mean to ensure continuous improvement and contribute to prevent major incidents in the subsea industry.

Learning could be defined in several ways, but a frequently used and established definition refers to learning as a "*permanent change in behavior as a result of experience*" as illustrated in Figure 6-1. Learning develops at different levels including at the personal level, the organizational level and the inter-organizational / industry level. This section will focus on learning on an organizational level and at the industry level.

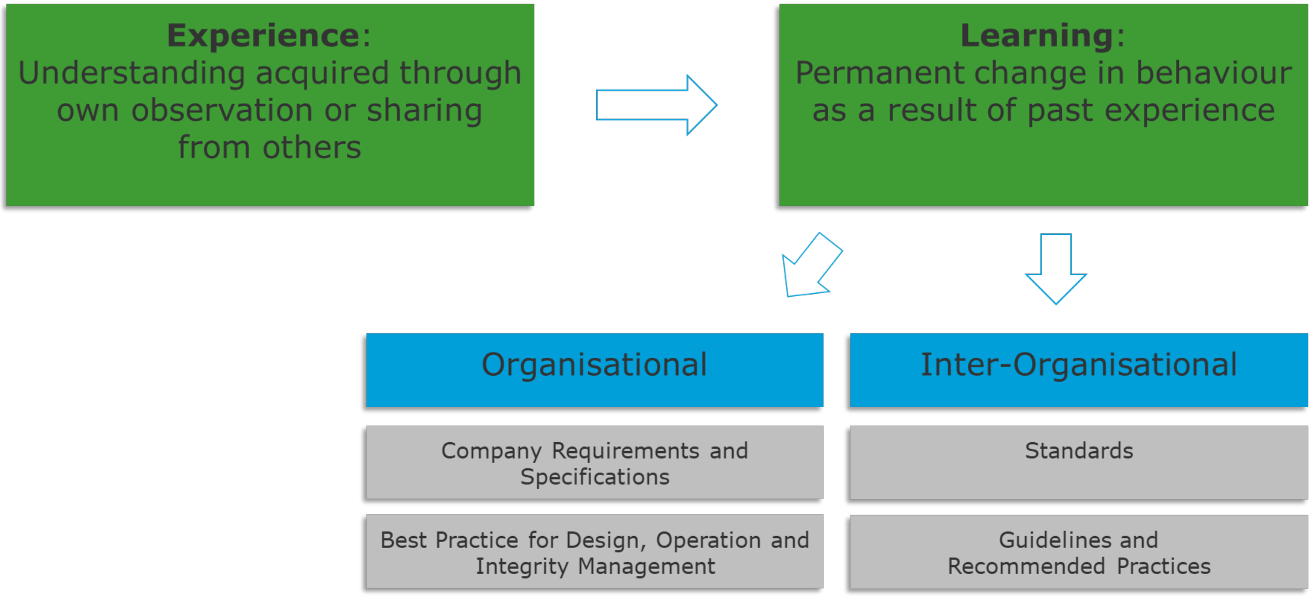

Figure 6-1 Learning in the organization and in the industry.

Learning takes time and is achieved through collection and systemization of data, analysis of data to obtain information, development of knowledge and understanding, and lastly implementation to achieve learning, see Figure 6-2. The process to derive to improved understanding may be both formal and informal. One example of a formal and systematic process to obtain thorough understanding in the industry may be in the form of Joint Industry Projects (JIP). In order to obtain learning, ensuring permanent change in behavior in the subsea industry to support the continuous improvement and prevent major incidents, formal processes are required. Examples of formal implementation of learning on an industry level are Standards, Guidelines and Recommended Practices. Examples at an organizational level are Company Requirements and Specifications, as well as Best Practices, see Figure 6-1.

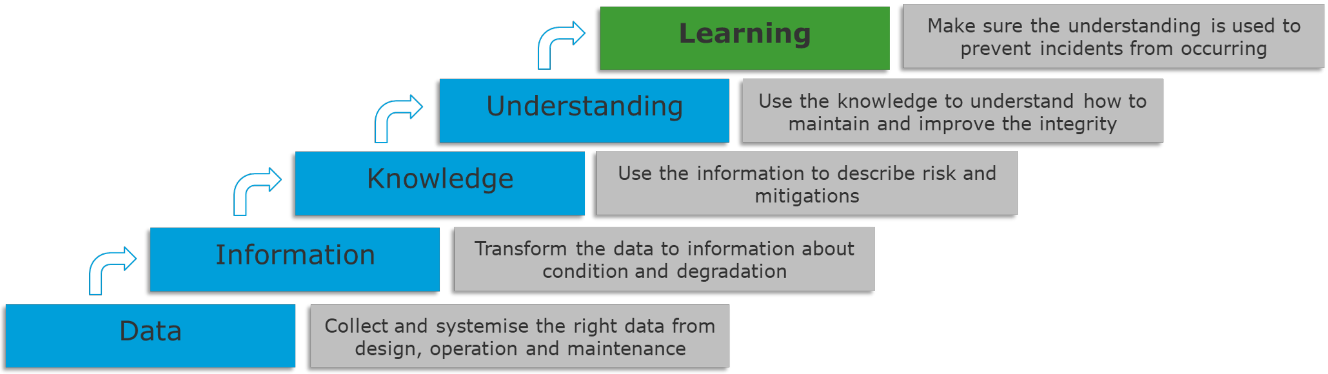

Figure 6-2 From data to understanding – and learning, see also /3//25/.

The DNV report, "How digital tools and solutions can improve Subsea Integrity Management" /12/, discusses how improved data management and use of data, facilitated by digital tools and solutions, can bring benefits to day-to-day operations, such as increased production efficiency, cost reduction and improved safety. This report will, hence, not go into details of how to go from data to knowledge and understanding but will mainly focus on some of the main challenges in going from knowledge and understanding to learning. Figure 6-3 is included to illustrate some of the data which may benefit the understanding of technical condition and the risk associated with subsea operations.

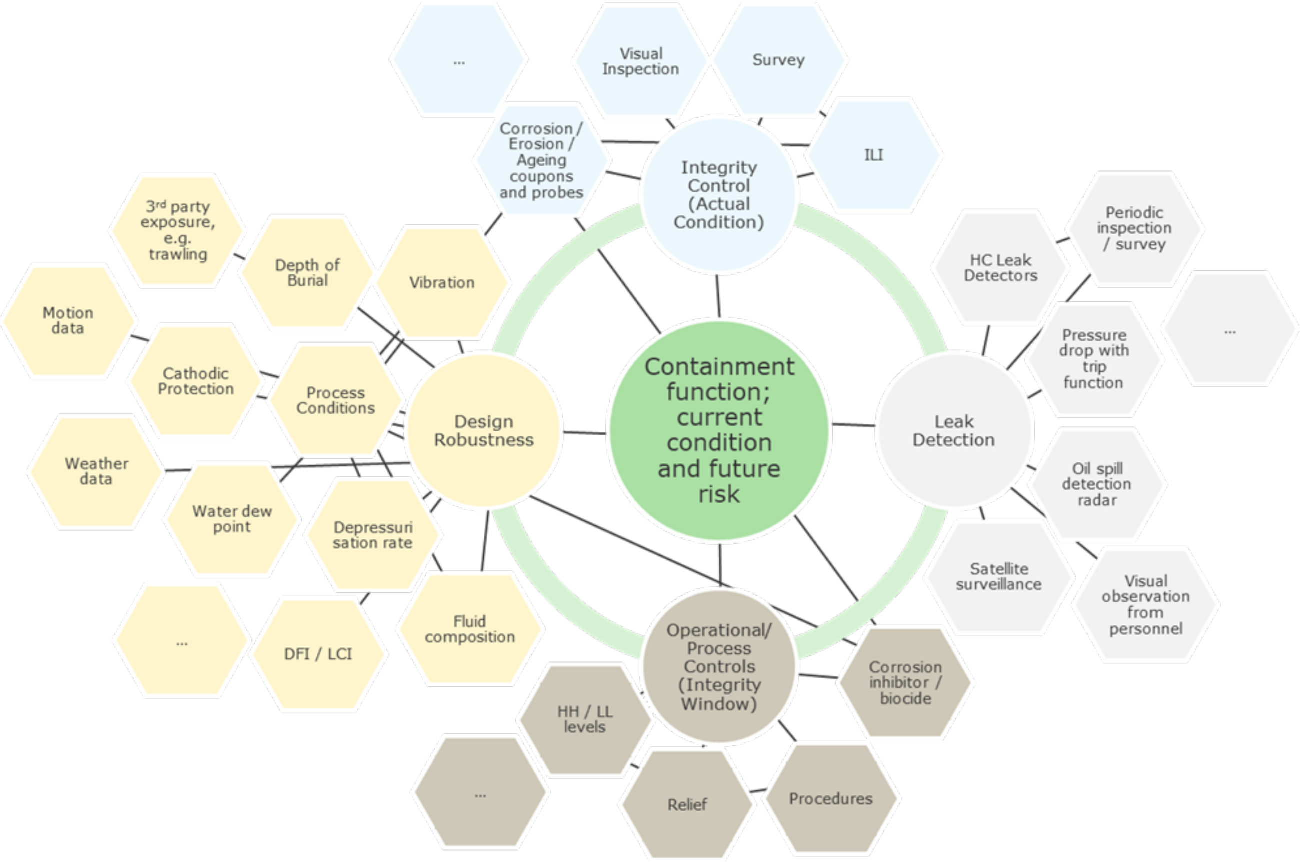

Figure 6-3 An illustration of some of the data that forms basis for assessing the technical condition and the risk.

Work processes and systems to facilitate sharing of data and knowledge may be an enabler for learning and improved integrity management; in own organisation, in the supply chains and across the industry. Operational experience of what has added value and where improvements are needed may be more systematically fed back to designers and Original Equipment Manufacturer (OEM) as well as within the operator organisation. Systematic collection, analysis and sharing of data and information about degradation, damage and failure, as well as information of what success look like, may support improvement to technology, equipment, systems, operation and integrity management of subsea systems.

ISO14224 /26/ offers a view on continuous improvement in the context of operation, maintenance and failure data, see Figure 6-4. It illustrates how improvements can be obtained through learning from e.g. failure and maintenance event.

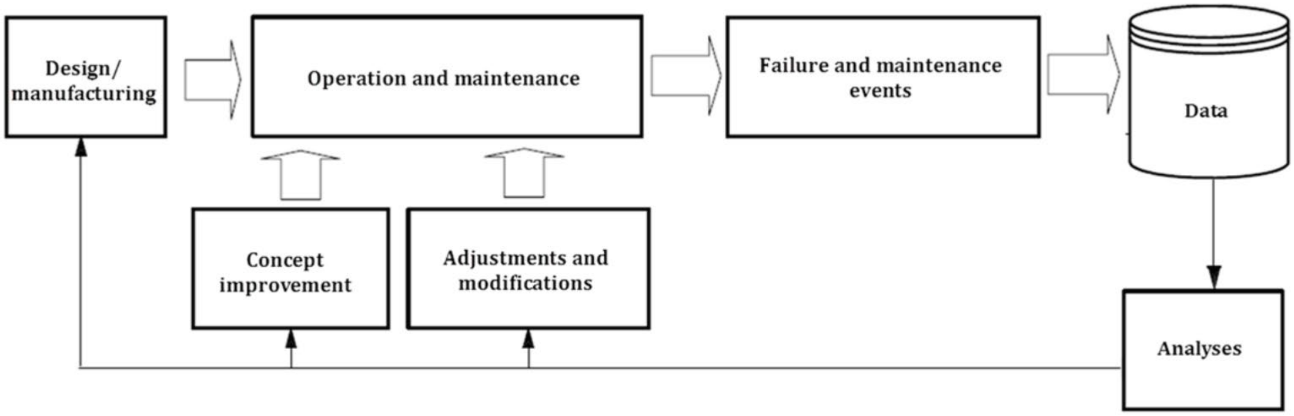

Figure 6-4 Improvement process as illustrated in ISO 14224 /26/

Although learning is considered an important mean in reducing risk and preventing major incidents, it is acknowledged that learning is complex and sometimes difficult. The following subsections will describe some of the aspects important to obtain effective learning and discuss some of the challenges to learn effectively.

- Presentation of information in a format that enables knowledge and understanding.
- Sharing of experience.
- Activities to support effective learning.

6.2 Presentation of information in a format that enables good understanding

Historically, information from operation and maintenance, including failures, have been collected in databases. Some examples of relevant databases are presented in Table 6-1. For incidents with a certain potential, root cause analyses are being performed. These are either available within the operator organization, in the field / license partnership or made available via the PSA Norway web site, https://www.ptil.no/en/supervision/investigation-reports/. Statistics for incidents and near-misses at the Norwegian Continental Shelf (NCS) are presented in the yearly RNNP reports, as discussed in Section 4.1 of this report.

Table 6-1 Overview of some of the most common databases (both publicly available and restricted) for subsea equipment and what they cover.

Data Source	Application	Coverage
WOAD (Worldwide Offshore Accident Database)	Offshore	Mainly offshore accidents in US GoM and North Sea from 1970-2014
PARLOC	Offshore risers and pipelines	Operators in UK, Norway, The Netherlands, and Denmark in the period before 2001. Operators in only the UK in the period 2001-2012.
PHSMA	Onshore and offshore gas pipelines	Natural gas pipeline system in the US https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-flagged-files
BOEM, report no 2018-032, 2018. (Bureau of Ocean Energy Management)	Offshore oil pipelines	In GOM and PAC OCS (US OCS) BOEM 2018-032
HCR, UK HSE incident database	Offshore hydrocarbon pipelines and subsea equipment	Hydrocarbon releases database system by Health and Safety Executive (HSE) within UKCS in the period 1992 to 2019. HSE Offshore: Statistics
Concawe report no 4/21, May 2021	Onshore oil pipelines	European cross-country oil pipelines in the period 1971-2019. https://www.concawe.eu/wp-content/uploads/Rpt_21-4.pdf
EGIG 11th report, December 2020	Onshore gas pipelines	European gas transmission network. Incidents recorded during the period 1970 – 2019.
UKOPA, report no UKOPA/RP/19/002, January 2020	Onshore pipelines	UK
IOGP (International Association of Oil & Gas Producers)	Subsea assets	Access to the restricted areas of this website is for IOGP Member Companies only (www.iogp)
OREDA	Subsea assets. Does not cover pipelines	Main focus is offshore subsea and topside equipment, but onshore equipment is alsoincluded. The information contained in this database is not public information
PSA database of reported incidents and damages/degradations	Offshore pipelines	CODAM (COrrosion and DAMage). The database is administered by the PSA and contains damage and incidents to structures and pipeline systems from the mid-1970s. Data are used, among other things, in the work with Risk Level Norwegian Shelf (RNNS) and a summary of reported injuries and incidents are published in the PSA's annual report. Data from CODAM is available on the PSA's website (PSA - Home (ptil.no) and by contacting the Petroleum Safety Authority Norway.
SureFlex	Flexible pipes	The Sureflex JIP has focused on improving industry knowledge and understanding relating to flexible pipe integrity management. The JIP has compiled global damage and failure statistics for flexible pipes across the industry and, in parallel, gathered comprehensive population statistics. The JIP also presents an extensive review and assessment of flexible pipe inspection and monitoring technologies. Furthermore, the work has reported integrity management good practice and guidance, summarised areas of current technology development focus, and shared operator case studies relating to flexible pipe integrity management. Access to the data is for members only.

The relevant authorities in selected countries, such as BSEE (US), HSE (UK), NOPSEMA (Australia) and TSB (Canada), release annual reports with statistics and data from each year. PSA Norway issues the RNNP report /5/ presenting trends in risk level in the petroleum activity, but the report covers subsea systems with very limited information. In addition, PSA publishing an overview of every pipeline incident reported.

The annual reports for each country differ in content and how complementary they are. For instance, TSB's report is rather comprehensive with statistic of pipeline occurrences, including causes, and comparisons to earlier years. NOPSEMA's report consists only of some key performance data, and do not include any causes and details about what kind of accidents/incidents that have occurred. The HSE collects all offshore hydrocarbon releases, and the annual reports only include total numbers of releases. Thus, it does not consist of any data specific to pipeline or other subsea equipment.

However, with the amount of data collected and analyzed, and with the number of subsea databases and root cause analysis reports available; why is it still potentially challenging to come to a better understanding? It is an observation that failure statistics and direct causes are relatively easy to retrieve from available data. It is also an observation that detailed information about the root causes is more difficult to retrieve and analyze. One reason may be that there is no standard format of reporting a root cause analysis in the industry. In addition, the terminologies applied in databases, failure investigation reports and root cause analysis reports are not consistent. It should be noted that ISO14224 /26/ defines taxonomy, terminology and definitions which may be used in this context. It is believed that analysis of root causes represents significant potential for further developing understanding and potentially learning in the industry.

It should be noted that with current search capabilities, it should be considered if traditional databases are the best way forward for collection of data as basis for developing knowledge and understanding or not. Ontologies for retrieving relevant data and information from data bases, failure investigation reports and root cause analysis may be developed to fit the context of the search.

Even with sound data and information at hand, it should be acknowledged that it takes expertise to develop knowledge and understanding. Hence, data analytics must be combined with subject matter experts when trying to climb the steps towards understanding and learning, see Figure 6-5. We want to better to understand why loss of containment occurs, how loss of containment can be prevented from occurring in the future and how to ensure that this understanding is shared and implementing in the design, operation and integrity management of subsea assets going forward. Section 6.3 discusses sharing in the industry, and why effective sharing may be challenging. Section 6.4 discusses activities which may support effective implementation processes.

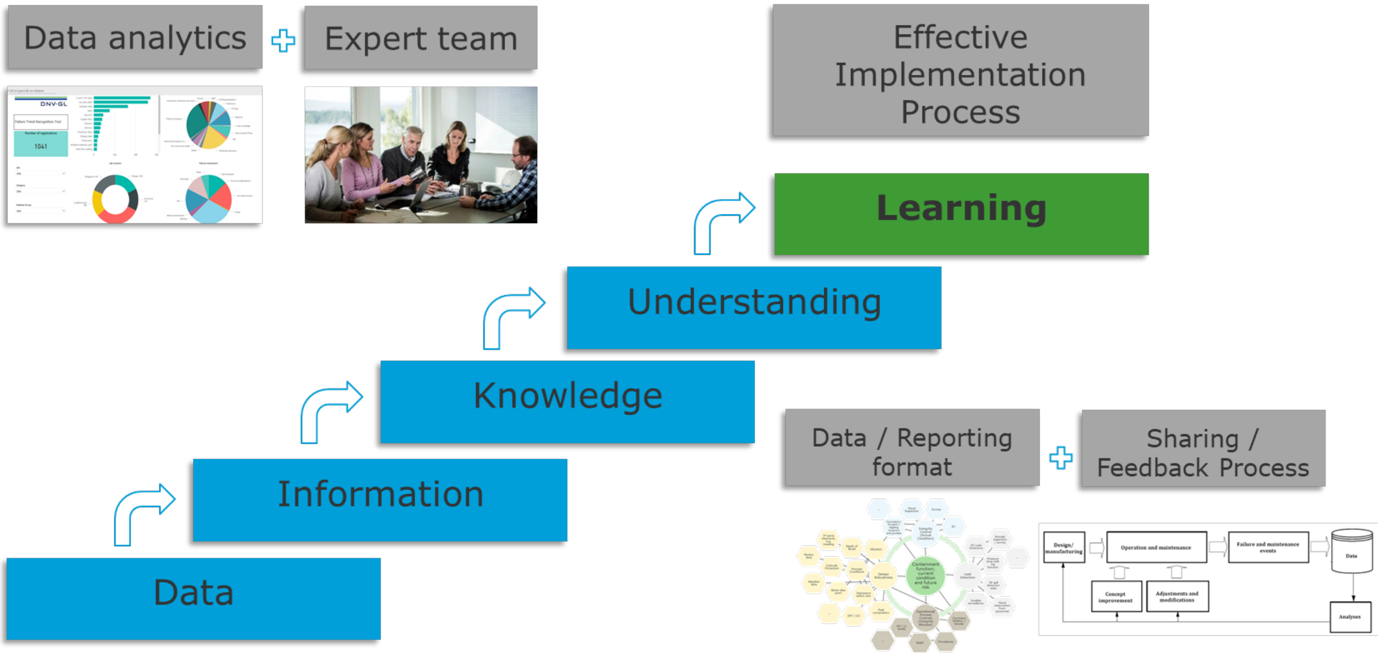

Figure 6-5 Illustration of important aspects in order for Learning to happen.

6.3 Sharing of data and information

Traditionally the Norwegian industry can be characterized by collaboration and open dialogue when it comes to developing a safe industry. Subsea integrity management, as a means to reduce risk and prevent incidents, is considered a topic where the industry should work together. Operators are typically interested in sharing their experience from incidents; loss of integrity or loss of containment. For practical purposes, however, it is sometimes a challenge to ensure effective sharing.

Information about incidents is often sensitive and can be restricted to those who need to know, or within the license partnership. Vendors of subsea equipment state that experience from operation, maintenance, integrity management, including failures and events, to a very limited extent is fed back to them. This may prevent understanding and learning. Experience sharing between operators may also be limited and on a need-to-know basis. This may also prevent improved understanding across the operator organizations.

Further, learning is a time-consuming activity and might therefor both be costly and prevent effective understanding and learning in the industry. Data analytics need to be combined with subject matter expertise to aggregate information to improve knowledge and derive better understanding. The knowledge and understanding then have to be shared within own organization and in the industry in a format where sensitive data and information is not included.

The PSA Norway stresses that it is the industry's responsibility to ensure that experience is being shared as part of the continuous improvement work. Various actors in the oil and gas industry would like to challenge the PSA Norway to take a more active role in sharing data and presenting experience as basis for improving understanding in the industry. This report does not conclude on how to improve sharing in the industry but include some considerations on effective sharing in the following sections.

- Databases are effective for collecting data, structuring data and storing data. It is however considered difficult to obtain improved understanding from databases. Some of the reasons for this are discussed in Section 6.2. It is believed that in the future, traditional databases will be combined with other data sources available through search engines. Ontology to support retrieval of knowledge based on available data and information needs to be developed to obtain this.

- Information sharing forums such as webinars, committees, conferences, and lessons learned sessions are considered effective for sharing and for developing better understanding. Such forums may consist of data analytics and subject matter expertise, as well as dialogue between peers, to derive common understanding. Some forums are however closed, or open by payment or membership only. This may prevent relevant people to from having access.

6.4 Activities to support effective learning

This section presents activities which may contribute to improved learning in an organization or in the industry. The list of activities is not complete but highlights some selected opportunities which may be explored further.

- **Learning in the subsea integrity management organization**

  Lessons Learned is typically a mandatory activity in a project. Past experiences relevant to the project is presented with the purpose of implementing learning in design, FMECA, HAZOP etc. It is an observation that Lessons Learned as activity is typically less formalized in an operating organization such as a subsea integrity management organization. It should be considered to include more formal learning activities as part of the learning process in operating organizations. New or improved understanding should be actively communicated and implemented in relevant Company governing documents, integrity management programs, inspection task lists etc. Understanding with potential to improve industry practice should be shared in relevant fora, and where relevant, be proposed as improvement to standards and recommended practices. It should be noted that learning activities takes time, hence, someone need to be responsible to drive the learning processes in the organization.

- **Development of understanding across stakeholder organizations**

  Joint Industry Projects (JIP) are typically collaboration projects of mutual interest to a number of stakeholders each contributing to fund the work. The goal of a JIP is to gain knowledge and understanding based on a concerted effort by various industrial stakeholders and/or research parties. Projects typically addressed in JIPs are either too complex or costly to be solved by one party alone or require specialized personnel or equipment, which is not readily available for individual parties. A JIP is a valuable ‘tool’ that can be used to develop understanding as basis for new standards and recommended practices or give input to update of existing ones.

- **More effective and interactive processes for standardization and development of recommended practice*s***

  National and international Industry standards, guidelines and recommended practices covering all phases of a subsea system from design through manufacturing, fabrication, installation, operation and decommissioning or abandonment as e.g. ASME, ISO, DNV, NORSOK. These standards and guidelines build on industry experience and are often developed from joint industry projects. They are considered the basis for a sound and robust design and reflects best industry practice. It is an observation that standards and best practices are not always kept up to date to reflect current understanding. Standardization and updates to standards takes a lot of time. The industry is requesting new ways of interacting to ensure faster, more open and more effective processes.

- **Learning from subsea equipment being retrieved**

  Considering the significant amount of equipment being retrieved as part of decommissioning operations, it would be beneficial to obtain more information about the condition of the equipment by performing inspections and sharing information to benefit the OEMs, the operators and the subsea industry. This supports the intention of the PSA’s Activity Regulations §50 requiring that when facilities are disposed of, the operator shall carry out studies of the structure's condition. The results shall be used to assess the risk associated with equivalent facilities.

Learning activities and processes are costly and require involvement from the already very busy subject matter experts. It should however be considered an important investment to reduce risk and a significant contribution to prevent future failures and leaks, see Figure 6-6. Hence, learning activities should be highlighted as important activities, and should be given priority.

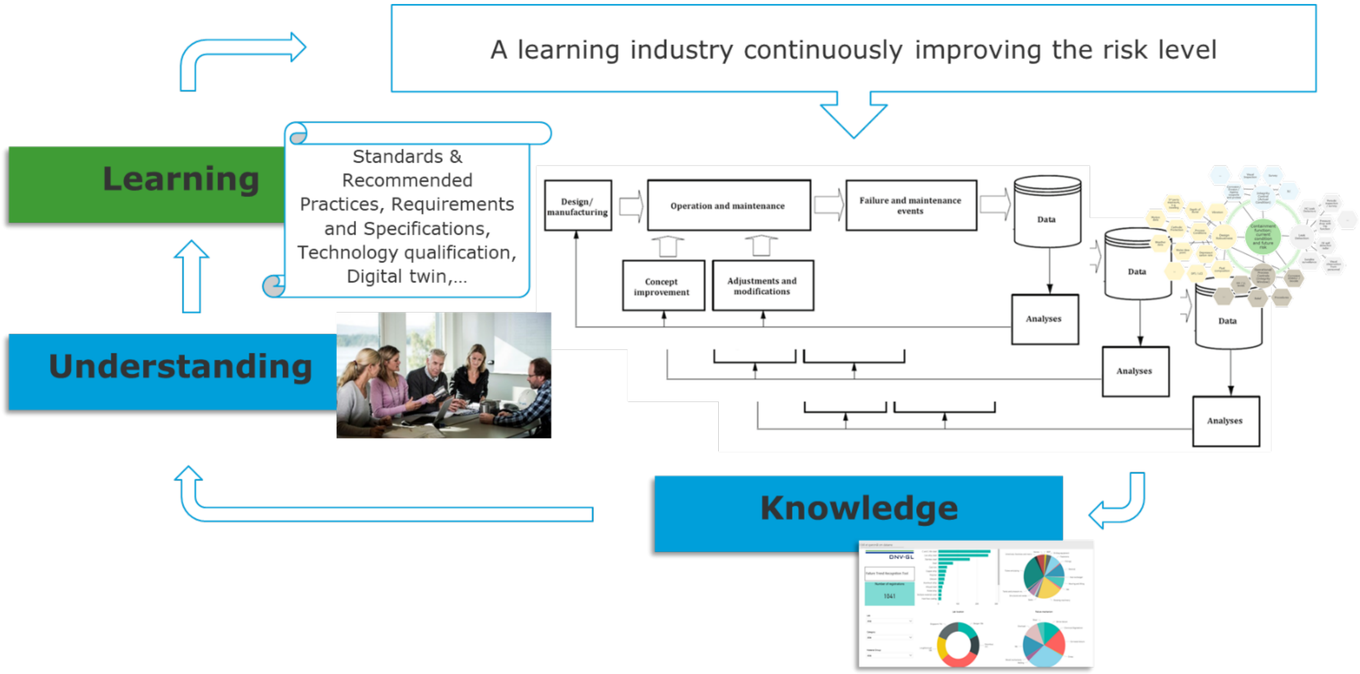

Figure 6-6 Illustration of a learning industry.

It is noted that Learning is not explicitly presented as a key element in the integrity management system illustrated in Figure 5-1, as it is considered an integrated element in the integrity management process. It is covered via the “Organisation and Personnel” and the “Audit and Review” elements, but also the core integrity management process as it is stated that all its activities involve planning, execution, **evaluation** and documentation. However, considering the importance of learning activities and learning processes, it should be considered to more clearly and explicitly present Learning as a key element in the integrity management system and the integrity management process, see Figure 6-7.

Figure 6-7 Learning a key element in the integrity management system and the integrity management process.

This report discusses learning activities and learning processes and does not include an assessment of specific topics which should be given specific focus going forward. It is an observation, however, that the following topics are currently given significant focus in the industry when it comes to development of understanding and implementation of learning:

- Subsea leak detection and particularly risk associated with minor leaks.
- Degradation and incidents related to flexible risers and jumpers.
- Electrification and particularly subsea safety functions.
- Transport of CO_2, hydrogen and ammonia.

7 MANAGEMENT OF CHANGE (MOC)

7.1 Introduction

A new subsea system is handed over from project to operation with a basis of design and DFI/design documentation describing for which operating conditions and within which limitations the subsea system is fit for purpose. Safe operating limits or integrity envelopes are typically developed to ensure operation within these design limitations. Operation outside the defined limitations may trigger integrity assessments by the integrity engineer or operator response in the control room (alerts and alarms, e.g. High and High High levels). The subsea asset operation is supported by an Operator organization with defined roles and responsibilities, and processes to ensure safe, reliable and cost-effective operation.

When loss of containment is observed, it is sometimes found that assumptions and assessments related to the technical integrity were not valid because changes were not detected, not understood or not properly managed.

This section gives some examples of changes that may increase the risk associated with loss of containment, presents formal requirements related to the management of changes (MOC) process and discusses how we as an industry may become better at managing the risk associated with these changes.

7.2 What is a change?

During the operational life of an asset, there will be a number of changes occurring at either distinct point in time or gradually over time. The changes can be either technical, operational, or organizational. In addition, changes may be associated with the project execution phase, see Figure 7-1. Some changes will not significantly impact the technical integrity and the risk level. Other changes may significantly degrade the containment function or reduce the organization’s ability to correctly assess the technical integrity and the risk level, and if necessary, perform mitigating actions. An important task for a subsea operation organization is to distinguish changes of significance from the high number of insignificant changes. Experience shows that this may be a challenge. It requires competence, work processes and tools to identify, assess and manage changes effectively.

Organisational Changes (People)

Organisational changes may affect the capability and effectiveness of the organisation to operate safely, maintain the integrity of the facilities and respond effectively to emergency situations.

Organisational MoC may be required for:

- Safety critical role change
- Onshore and offshore supervisory and leadership positions including operations, engineering, HSSE disciplines
- Technical Authorities roles or equivalent roles
- Changes that affects shift schedules, as well as key personnel leaving the organisation

Technical Changes (Facility)

Technical changes are significant if they may alter the integrity, operation or function of the facility or equipment. Examples could range from minor plant changes, such as components and instruments, to significant modifications or additions to a facility, such as a new tie-in

A planned technical change would normally be initiated through an Engineering Query or similar.

An unplanned technical change may be triggered by a deviation and / or improvement, or an unintended operation outside design boundaries or safe operating window.

Operational Changes (Process and Tools)

Operational changes may impact safe, compliant and reliable operation.

Operational MoC may be required for:

- Work processes and tools used to facilitate operation and integrity management
- The Maintenance Management system
- Contracts, suppliers and contractors
- Changes to process safety information, facility operating procedures and response plans

Project Changes

Changes are significant if they may represent significant risk in projects, such as:

- Change to project mandate, project execution plan, design basis, functional requirements, plan for development and operation etc.
- Changes with schedule or cost impact
- Changes with HSSE impact
- Changes affecting more than one delivery line or other projects

Figure 7-1 Changes, categorised into organisational, operational, technical and project changes.

Some examples of changes which may occur during the operating life of a subsea asset are presented below. The objective is not to present a complete list, but to present some examples in order to raise awareness of changes which may degrade the technical condition, increase the risk level or reduce the organization’s understanding of the risk:

- **As-installed condition.**

  It is important that the actual technical condition at point of production start-up is used as the baseline for the risk assessment and the integrity management program. Aspects related to manufacturing, fabrication, installation and commissioning may change the design robustness and the conservatism compared to the design intent. Examples may be non-conformities and deviations during manufacturing and fabrication (e.g. forging quality issues, weld misalignments, coating defects and local coating repairs), installation (e.g. lay curvature, installation tolerances, insulation material defects, unintended drain points from the sacrificial anodes cathodic protection system, potential trawl snag points and inadequate depth of burial) and commissioning (e.g. inadequate preservation or prolonged water filling time due to delayed start-up).

- **Operation within design boundaries**

  Over the operating life of a subsea asset, it is expected that operating conditions will change. E.g. operating pressures and temperatures, water content and acidity, flowrates and sand, and weather conditions and environmental loads will vary over the years. Hence, design shall be performed to allow operating conditions to vary within a certain operational envelope. Although operation is maintained within design boundaries, sudden or gradual changes may significantly impact on threats to the containment function. Some examples are: Increased water content may lead to formation of a separate water phase or water accumulation in low points. Reduced flow rates may lead to deposition of particles. Increased flow rates and potentially change in fluid composition may initiate slugging or flow induced vibrations. Hence, although operation varies within the design boundaries, the rate of degradation may vary significantly over time. Degradation rates experienced in the first phase of operation may not necessarily be used to predict future degradation rates.

- **Operation outside design boundaries**

  Some design assumptions may not be valid over the lifetime of the assets. Some examples: Scouring may lead to too low depth of burial or too long free spans for a pipeline. Scouring may also lead to exposure of potential snag points on a subsea protection structure. Increased trawl gear weight may lead to non-conservative trawl pull-over and trawl impact design, ref. /17/. Higher water cut in the late life of a reservoir may lead to temperature increase beyond the original design temperature of a flexible riser. Insufficient dehumidification may lead to water drop out in systems intended to operate with dry gas. Assets designed for “sand free” production may experience sand production due to failure of sand screen. Defective or degraded supports and guides may lead to non-conservative fatigue life estimates for a rigid riser.

- **Chemical injection**

  Chemicals are typically injected to benefit the production and the technical integrity, e.g. corrosion inhibitor, MEG, H_2S scavenger, O_2 scavenger, scale inhibitor, biocides. Chemicals (e.g. acids) may also be used for stimulation of the reservoir and clean-up in the well, and these chemicals are sometimes produced back through subsea production systems, flowlines and risers. Seawater may also be used for well clean-up purposes. It is important that all chemicals injected or transported through the subsea system are assessed and confirmed compatible with the respective subsea systems prior to use. Changes in chemicals, e.g. due to new suppliers and more environmental friendly substances, should be given sufficient focus to document that changes do not negatively impact the integrity. In a CO_2 corrosion assessment, the corrosion inhibitor is typically assumed to have a certain effectiveness and a defined availability. A reduction in the availability of the corrosion inhibitor, e.g. due to unreliable injection pumps topsides, may be a concern for the corrosion protection of the subsea systems.

- **Operational patterns**

  Examples of changes in operational patterns may be that some wells may be choked back to allow more production from other wells, start-up of new wells or tie-in of new manifolds. Increased gas production may be prioritized during periods of time with high gas prices. Gas lift may be used in wells where this has been enabled, when the reservoir pressure falls below a certain level. Cleaning pigs are sometimes used to keep lines free from scale and debris or to remove a liquid phase. A change in the pigging frequency may alter the condition internally in a line. Changes in a topside process system may significantly impact the corrosiveness in the downstream systems (e.g. gas dehydration system less effective may lead to higher water dew point in hydrocarbon gas, oxygen ingress topside e.g. into lift gas or injection water may lead to initiation of aggressive corrosion subsea).

- **Instrumentation and functionality**

  Over the lifetime of subsea assets, it is sometimes experienced that some instruments lose their function and stop providing data. Some of these data may not be critical to the production but may provide important information when assessing the asset technical condition. The operator may also experience that valve operations become degraded, e.g. restriction in choke operation or stuck valves.

- **Temporary operations**

  Threats associated with “normal operation” is typically well analyzed, while threats and risks associated with temporary operations may be less well analyzed or understood. Examples may include risk contribution from surface vessels operating in the vicinity (e.g. IMR or interventions), pigging operations, inspections performed from the outside.

- **Temporary modified use**

  Some lines and systems may for shorter or longer periods be used for other purpose than originally designed for. Examples may be gas lift or water injection line temporarily used for production.

- **New technologies and new methods**

  Over the operating life of a subsea asset, new and better technologies are likely to be introduced, such as inspection and monitoring technologies. New extensions and tie-ins may e.g. introduce pipe-in-pipe and heated pipe, electrically actuated valves, as well as new materials for subsea applications, like thermoplastic pipes and elastomeric seals. New methods may also be introduced such as analyses methodology, simulations, as well as diagnostic and predictive tools. Digital twins are currently being explored, developed and implemented for both new and existing subsea assets.

- **Modifications and tie-in of new assets to existing infrastructures**

  To enable cost effective subsea developments these typically utilize existing infrastructure when developing new production facilities. This may include to connect new facilities to existing drill center manifolds and transportation lines. It may include to connect a brand new system with the latest technologies to a degraded existing system, potentially with a different inherent safety philosophy.

- **Life-time extension and other changes in the basis of design**

  The design life is one of several parameters defining the basis of design. Any changes in the basis of design should be properly managed. Examples, other than change in design life, may be changes to maximum operating temperature and pressure, change of medium, change of flow direction, going from sweet to sour service as well as environmental loads.

- **Change in the availability and quality of data and information**

  It was previously mentioned that loss of instruments may lead to loss of data. Monitoring data may also drift over time, and if not detected, may not correctly present a parameter or a condition. It should be mentioned that increased access to data is another change that needs to be managed. Data and information overflow may represent a threat if not properly managed. There are numerous examples that information about the physical assets including as installed condition and operational history is lost because documentation is lost. Documentation can be lost because ownership of the asset may change over the years, data and documents may be archived in different systems and that sufficient effort is not put into structuring, maintaining and making these data and documents available as basis for retrieving information about the system.

- **Organization and competence**

  Over the operating life of a subsea asset the subsea operations organization is likely to change, new people will come in and possibly bring new competence and experience to the organization. Asset specific knowledge, however, is likely to be lost with key personnel leaving the organization. Changes in how the integrity management is organized and changes in personnel and competence must be managed to ensure that the subsea operations organization at all times has the right competence and the right understanding of assets, their condition, credible threats and the effectiveness of the present mitigations.

- **Regulations, standards, best practices and company requirements**

  As requirements and best practice are likely to change over the operating life of the subsea assets, these changes need to be considered. Critical gaps between current requirements and as-installed assets should risk assessed, and mitigations may have to be considered.

7.3 Change Processes

The requirements to the change process should be a function of what extent the change impacts the risk level. Some changes require a formal consent from the authorities, some changes require a documented management of change process in the Operator’s Business Management System, and other changes may only trigger assessments in relevant parts of the organization. The formal requirements to the change process may be different. The change and how it impacts the risk level should however be documented and be available to the operating organization throughout the facility operating life.

The management regulations §25 presents the requirement to obtain Consent when significant changes are being planned, see Section 3. It should be stressed that it is the Operator’s responsibility to identify the *significant changes* which may trigger a need for obtaining Consent.

Operators of subsea assets will, in their Business Management System, typically have requirements defined for Management of Changes (MoC). Figure 5-1 shows Management of Change as one of the processes with an interface towards the integrity management core process. The MoC process should ensures that:

- Consequences of a change are properly assessed prior to approval decision.
- Decisions are made in a timely fashion and protect the business, operations, project scope and economy.
- Risks associated with changes are identified, assessed, managed and communicated.
- Changes are planned and executed safely, transparently, traceably, timely and efficiently.
- All relevant parties and stakeholders are involved either via the risk assessment, as reviewers, or are informed about changes.
- The approval process and authorization requirements for changes are adhered to.
- The results of the change will be fully documented to enable safe, conformant and efficient projects, operations and other supporting functions.

Typical criteria for initiating a formal MOC process are presented in Figure 7-1.

As can be interpreted from the requirements and objectives described above, the MOC process it typically defined to handle planned changes. Significant planned changes are typically associated with a systematic approach which may include design review (alternatively organizational review, system review etc. depending on type of change), HAZID / HAZOP, and where required, a qualification or re-qualification process. The DNV-RP-A203:2019, Technology Qualification /23/, may be a relevant reference in this regard.

Planned change processes may be triggered through an engineering query, updates to work processes, new software systems, reorganization etc. MOC process for unplanned changes may be triggered through deviations, non-conformities, operation outside design boundaries or safe operating limits etc.

An example of a change description, based on an MOC developed by an Operator on the NCS, is included in Appendix B, and briefly discussed in Section 7.4.

7.4 Management of Change (MOC) - Example

An example of a MOC description has been included in Appendix B. The description is based on a real MOC developed by an Operator on the Norwegian Continental Shelf (NCS) related to a tie-in of a new drill centre to an FPSO through existing in-field infrastructure. Due to the new tie-in, the maximum operating pressure had to be increased. The MOC text has been modified to fit the purpose of this example and to only have general references to "Operator" and "Facility". Changes required to the operation of subsea equipment; flexible risers, flowline, manifold jumpers and manifolds, due to the tie-in of the new drill centre are outlined in the text. A generic schematic of a tie-back of subsea well to FPSO is included in Figure 7-2, illustrating the example.

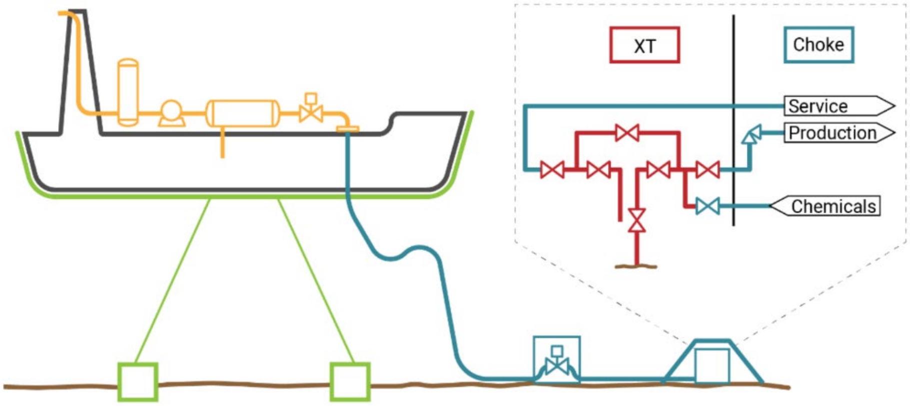

Figure 7-2 Generic schematic illustration of tie-back of subsea well to FPSO

Some of the observations and reflections from the MOC example description in Appendix B are highlighted below:

The example summarizes the work performed to justify an increase of the maximum operating pressure of a subsea system. The new operating pressure was well within the design pressure of the subsea system. The work included a systematic re-assessment of the threats to the subsea equipment as well as the operational procedures and control system alarm settings:

- Flexible risers:
  - Re-assessment of fatigue considering actual fluid parameters, annulus condition (i.e. water filling), as well as weather data. A refined fatigue assessment methodology was used to obtain a more accurate prediction of service life (hence, reduce conservatism compared to the initial design fatigue assessment).

- Re-assessment of creep of the non-metallic layers.
    - Re-assessment of depressurization effects with regards to carcass collapse and blistering of the pressure sheath by using numerical modelling and actual fluid parameters.
- Flexible jumpers:
    - Re-assessment of compatibility and corrosion of non-metallic layers and armour layers respectively, based on actual fluid parameters.
    - Re-assessment of tie-in stresses.
    - Re-assessment of depressurization effects with regards to carcass collapse and blistering of the pressure sheath by using numerical modelling and actual fluid parameters.
- Rigid flowline:
    - Re-assessment of buckling risk and free spans.
    - Re-assessment of trawl pull-over robustness.
    - Re-assessment of low cycle fatigue and vortex induced vibrations (VIV).
- Manifold:
    - All required assessments were covered by original design.
    - It was identified that an increase in flow velocity may trigger need for further flow induced vibrations (FIV) assessment.
- Operating procedures, alarm settings and integrity management program:
    - High pressure alarm settings in the control system changed (three-day average operating pressure).
    - Maximum depressurization rate, alternatively step-wise depressurization procedure, confirmed. Depressurization controller implemented.
    - Enforced monitoring of trawl activity and associated trawl gear sizes.
    - Monitoring of flow velocity in manifold.

The MOC describes that "(…) S*ome of the 10" production risers have historically been operated above the 90 bar operating limit. This to maintain production levels and simultaneously manage flow induced vibration risks at the associated production manifolds. There is therefore a need to formalize increase of the limit from 90 to 115 bar*". Hence, changes on operating limits had previously been implemented without formal and documented assessment. It is a general observation that assessments to justify changes to a larger extent should be documented, and that it would benefit the operator organizations to more frequently trigger a formal MOC process.

The MOC illustrates that an apparently minor change, which was well within the design limitations of the subsea system, may have significant effects and may trigger significant detailed assessments in order to understand risk and mitigations.

Refined and more sophisticated assessment methodology using more optimized input parameters were used to confirm fitness-for-service. It is a general observation that more advanced assessment methodologies are applied when margins in original design are challenged. A good understanding of the uncertainties in both input parameters and in the assessment methods is important when implementing more optimized analyses. It should always be ensured that optimized analyses are still conservative to the extent they are aligned with the inherent safety philosophy in the design standards.

The systematic and formal MOC approach ensures that all relevant roles in the organization are involved and informed, that a complete set of documentation to support the change is traceable and available, that the change is reflected in relevant risk assessment, and that relevant procedures, control system settings and integrity management programs are updated to reflect the change.

7.5 How can we become better at detecting and managing changes?

The study performed as basis for this report has not included a systematic evaluation of MOC systems and processes in relevant organizations, and it has not investigated to what extent processes and requirements related to changes are being complied with. The following observations have however been made, and are further discussed in the sub-sections below:

1. More frequent use of a formal change process may support improved risk assessments and subsea integrity management.
2. Significant changes occurring over the facility lifetime are sometimes not formally identified as changes, hence, are not being managed as changes.
3. It may benefit the change process to have a “check list” covering complementary aspects to support a complete understanding of risk associated with the change.

7.5.1 More frequent use of formal change process

A systematic and formal approach to Management of Change has a number of benefits. The MOC process may be considered time consuming, but it serves its purpose, as exemplified in previous sections. In projects, including new developments and modifications to existing assets, there will normally be formal processes in place to identify changes which require a formal MOC process. During the operational phase of an asset, the activities to identify changes which may require – or may benefit from – a formal MOC process, are typically less formalized.

When working with Subsea Integrity Management it is all about managing all the different changes that happens or develops from day to day and from year to year during the lifetime of the assets. The changes are typically assessed by the responsible / Subsea Engineer, and when required, escalated to e.g. Technical Authority. Assessments are typically either informally documented e.g. in e-mails, or more formally in e.g. technical notes. It should be considered an opportunity to ensure that the subsea integrity management processes include consideration of changes which may benefit from a formal MOC process.

7.5.2 Identification of changes through the operational phase

Section 7.2 presents examples of changes which may lead to increased risk to the facility, but which may not always trigger formal MOC processes in the operating organization. Planned changes should be assessed with regard to the need for or potential benefit from a formal MOC process. Unplanned changes, however, are sometimes not detected. How can a subsea integrity management organization become better at identifying changes which benefit from a formal MOC process? Some reflections on possible approaches to this question are offered below:

- Identification of changes which may benefit from a formal MOC process should be part of the integrity management processes. On a regular basis it should be consider if any observed or planned changes would benefit from formal MOC processing. This should include changes made or experienced in other parts of the facility and the organization, such as drilling & well (e.g. use of chemicals or sea water in reservoir stimulation or clean up) or topside process systems (e.g. sand in separators, unreliable corrosion inhibitor injection pumps, high oxygen content in injection water).

- Identification of unplanned changes which may impact the risk level. Triggers for detection and initiation of engineering assessments (alternatively other assessments) should be established, and one should move away from using “assumptions”, and rather base assessments on validated data. Integrity analyses and risk assessments are often found to be based on some important assumptions, e.g. that the as-installed condition is within the design criteria, that corrosion inhibitor is being injected continuously (or minimum e.g. 95% of the time), that the sand screen is functional, that the pipeline is robust towards trawl pull-over or impact, that the safety factor towards fatigue is robust. Experience shows that assumptions are not always valid, or that they at some point in time may become invalid. It is therefore important that key inputs to the integrity assessments are not based on assumptions, but that they are being confirmed through the lifetime by verifying they are valid.

7.5.3 Check list to ensure complementary understanding of risk

When describing how the risk level might be impacted by a change, three complementary perspectives may be used (note that these can be applied for projects and new solutions, but are here presented in the context of managing changes). These perspectives are developed in the research project Safety 4.0 Demonstrating Safety for Novel Subsea Technology /10/, these perspectives include:

- Activity perspective: From this perspective, the focus is on what the solution is used for (i.e. activities and objectives) and the application context (including the physical environment, the regulatory environment, and the business environment). Risk is described in terms of scenarios that can lead to losses, with associated severity and uncertainty.

- Strategy perspective: From this perspective, the focus is on how the solution achieves the objectives. This includes the barrier strategies employed to reduce risk to a tolerable level, the design- and operating principles used for barrier elements, and the performance of barrier elements and barrier functions.

- Technology perspective: From this perspective, the focus is on how the activities and strategies are implemented concretely in terms of technical, organizational and human elements. The risk description from this perspective focuses on technologies’ functionality, performance, failure modes etc., and the effects on the wider risk picture.

When managing a change, it may be helpful to have a checklist of questions to make sure key aspects associated with activities, strategies and technologies have been considered. A suggested check list, based on work developed in the Safety 4.0 project /10/, is included in Appendix C. The check list can be used as a guidance to ensure that the MOC has addressed and described how the change impacts the risk level, and as such secures that the operation is still safe. The suggested ‘check list’ could alternatively be used as part of a simplified MOC process. Some aspects which might have been relevant to consider when assessing the risk associated with the change described in Section 7.4 are presented in Appendix D. It shall be noted that the considerations made in Appendix D have not been performed by the Operator (hence, does not represent how the Operator would consider these aspects to be covered during their work), but has been established by DNV as an example of how the check list can be used related to the example MOC.

8 MAINTAINING AND IMPROVING THE RISK LEVEL

Section 4 presented the positive trends regarding the safety level for the Norwegian oil and gas industry over the last two decades. The trends presented by the RNNP represent our history and illustrates the success of the existing asset's life-cycle activities. Identification of one or a few central aspects that can be given credit for the positive RNNP trend is difficult, but it can, however, be argued that it is a result of a balanced combination of robust design, rigorous quality assurance throughout design, fabrication and installation, and sound integrity management in the operational phase. Having stated that, the RNNP data does as mentioned, represent our history, and it is essential that the industry can maintain or improve the positive trend in a potentially rapidly changing landscape. It is expected that the subsea systems, in the relatively near future, will be subject to various significant challenges and changes due to the anticipated transition to cleaner energy combined with the fact that they are ageing. With fewer and fewer new installations being developed, the contribution from robust design and quality assured construction to future trends will be much less, whereas integrity management will become significantly more important.

When focusing on avoiding future incidents and accidents it is necessary to acknowledge that the future might be different than our past. These differences or changes are important, as they, if not managed have the potential to introduce near misses or accidents. It should also be acknowledged that the future depends on what the industry does in the present. For example, today's inspection activities and results will potentially provide useful information related to the system integrity in the future, making it easier to know, e.g., how fast corrosion or erosion is developing. Further, the past represents the industries experience that we can harvest from at present and prepare for the future given that new threats and challenges are known.

This report discusses some of the key contributors to maintaining and improving the risk level going forward. Some of the key opportunities are presented below and the full overview of improvement areas and opportunities as identified and described throughout the report is given in Table 8-1.

Learning:

Key activities which may contribute to support and improve effective learning in an organization or in the industry are highlighted below.

- More active use of Learning activities in subsea integrity management processes, e.g. regular Lessons Learned sessions in the subsea operations organization, with identification of knowledge and understanding obtained, and how to share and implement the understanding to ensure that the learning is not lost (e.g. update to specifications and procedures, sharing in relevant fora or to peers, partners and vendors, input to standardization / best practice processes). It should be considered to include more formal learning activities as part of the learning process in subsea operating organizations and it should be recognized that learning activities takes time, hence, someone need to be responsible to drive the learning processes in the organization.
- More interactive processes and dynamic approach to standardization and development of best practice in the industry. The industry is requesting new ways of interacting to ensure faster, more open and more effective processes. How to organize and enable such effective processes should be further explored by the facilitating organization in a close dialogue with the industry.
- Information about the technical condition of retrieved subsea equipment should be actively collected and compiled in a format which can be shared to relevant stakeholders in the industry, to support improved design, integrity management and lifetime extension of equivalent subsea facilities.

Management of Change:

Integrity management of subsea assets is a lot about managing all the changes that happen day to day for a subsea facility. This report discusses the importance of detecting and managing the significant changes (planned and unplanned changes) which may impact the risk significantly. The following opportunities are highlighted here:

- More active use of formal Management of Change processes during the operational phase to ensure traceability and communication around significant changes, and that changes are reflected in the risk assessment and the integrity management program.
- Systematic process to identify changes and assessing their significance. This includes to extract significant changes from all the minor changes. Examples of means to identify significant changes may be monitoring of critical input data to the risk assessment or regular discussions about changes which may impact on the risk. Such assessments should include relevant data and competence within relevant areas, such as drilling and well, topside integrity, process chemistry and flow assurance.
- Use of check list to ensure complementary understanding of risk considering activity, strategy and technology, including its uncertainties; knowledge/evidence/confidence and manageability. Reference is made to check list included in Appendix C as an example.

Table 8-1 Overview of Key improvement areas and opportunities

Topic	Key improvement areas and opportunities	Section
IM	**Interfaces between underwater integrity management and both operation/production management and maintenance/integrity management of other parts of the asset.** As a part of the monitoring activity, pipeline and subsea Integrity Management teams should be more active in regularly gathering and trending relevant data from operation/production and other Integrity Management teams (e.g. topside assets).	5.4
IM	**Integrity status and trending – bottom-up and top-down.** More systematic reporting/documentation of integrity status and trending is a key mechanism to build this knowledge and understanding. Furthermore, sharing this from the bottom and up with the rest of the organization and the industry in a more systematic way can help the industry become even better. From the top and down, authorities can improve the way they gather data on integrity status and trending. This should be harmonized through standardization.	5.4
Learning	**Modification / re-qualification** Learning from the industry's extensive past experiences by creating company and industry guidelines and/or standards covering the particulars of such projects can contribute to further improve the safety level.	5.4
Learning	**Reporting of key indicators to authorities and presentation of findings back to the industry** The RNNP report /14/ has improvement potential regarding the risers, pipelines and subsea assets and could possibly include presentation of direct and root causes, sharing of new knowledge and understanding and suggestion of areas where learning is required.	5.4
IM	**Pipeline and subsea system barriers**	5.4

	Barrier management is more mature when it comes to above water facilities and this is perhaps linked to the fact that there is a more direct population exposure to the hazards. Barrier management for pipeline and subsea systems has potential for further development.	
IM	**Understanding the uncertainties** The industry is generally good at performing risk assessments associated with subsea operations, but the uncertainties and the critical assumptions are not always well documented. It is considered a significant opportunity to systematically assess and document the uncertainties in the risk assessment and the integrity management activities.	5.4
Learning	**Learning in the subsea integrity management organization** Lessons Learned is typically a mandatory activity in a project. It is an observation that Lessons Learned as activity is typically less formalized in an operating organization such as a subsea integrity management organization. It should be considered to include more formal learning activities as part of the learning process in operating organisations.	6.4
Learning	**Development of understanding across stakeholder organizations** Joint Industry Projects (JIP) are typically collaboration projects of mutual interest to a number of stakeholders each contributing to fund the work. A JIP is a valuable ‘tool’ that can be used to develop understanding as basis for new standards and recommended practices or give input to update of existing ones.	6.4
Learning	**More effective and interactive processes for standardization and development of recommended practices** Standards and guidelines are considered the basis for a sound and robust design and reflects best industry practice. It is an observation that standards and best practices are not always kept up to date to reflect current understanding. Standardization and updates to standards takes a lot of time. The industry is requesting new ways of interacting to ensure faster, more open and more effective processes.	5.4 & 6.4
Learning	**Learning from subsea equipment being retrieved** Information about the technical condition of retrieved subsea equipment should be actively collected and compiled in a format which can be shared to relevant stakeholders in the industry, to support improved design, integrity management and lifetime extension of equivalent subsea facilities (ref. Activity regulations **§** 50).	6.4
MOC	**More frequent use of formal change process** More active use of formal Management of Change processes during the operational phase to ensure traceability and communication around significant changes, and that changes are reflected in the risk assessment and the integrity management program	7.5
MOC	**Identification of changes through the operational phase** Systematic process to identify changes and assessing their significance. This includes to extract significant changes from all the minor changes.	7.5
MOC	**Check list to ensure complementary understanding of risk** Use of check list to ensure complementary understanding of risk considering activity, strategy and technology, including its uncertainties; knowledge/evidence/confidence and manageability.	7.5 & App. C & D

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APPENDIX A

Main findings from the PSA supervision reports (2018-2020)

Topic	Non-conformities:	Improvements
Leak detection	• Acceptance criteria and performance requirements for leak detection: Inadequate monitoring / indicators and acceptance criteria for external leak (2020).	• System for leak detection not having been sufficiently operationalized in order to detect and quantify leaks. The operator had not sufficiently described how to collect, interpret and use the data (2020). • The combined information from leak detection system and subsea visual inspection. The inspection interval had been extended from one to four years while the leak detection systems were reported to have challenges (2019). • Inadequate specification of performance requirements for leak detection (2018).
Integrity management	None	• Performance standard for the containment function and lack of holistic strategy for verifying containment as barrier function. This included aspects related to different responsible parties operating different connected and dependent assets (2020). • Considering instrumentation to inform about ageing effects (2020). • Limited use of data to identify degradation or defects (2019). • How to use data for the purpose of subsea integrity management (inadequate strategy) (2018). • Having a holistic approach to integrity management and barrier management for the containment barrier across the different systems and interfaces (2018).
Flexible risers & jumpers	• Operation of flexible risers. Unclear operating limits related to pressure and depressurization rates, and how to ensure compliance with these limits (2020). • Maintenance management of system for annulus monitoring. Unclear maintenance requirements and routines to ensure reliable annulus monitoring (2020). • Operating parameters for flexible risers and jumpers. Operating parameters and limitations in procedures and in control room not in accordance with parameters used for integrity management (2018).	Flexible jumpers: The maintenance program was insufficient to detect degradation or defects under development in order to timely intervene (activities included visual inspection, review of operational data, operational limits) (2018).

	• Integrity management of flexible risers and jumpers; different aspects including NDT, monitoring and testing (2018).	
Pipelines	None	• Uncertainty in corrosion model for internal corrosion in pipeline which has not been internally inspected. It was pointed out that leak has previously occurred in water injection line due to corrosion, and the corrosion model was considered non-conservative (2020). • Verification of dry gas in gas transport pipelines through follow up of measurement and equipment for water dew point (2019).

APPENDIX B

Example MOC description

MOC EXAMPLE - CHANGES TO EXISTING SUBSEA EQUIPMENT TO SUPPORT TIE-IN OF A NEW DRILL CENTRE

1 INTRODUCTION

This example is based on a real MOC as documented for a tie-in of a new drill centre to an FPSO through existing in-field infrastructure. Due to the new tie-in, the maximum operating pressure had to be increased. The MOC text has been modified to fit the purpose of this example and to only have general references to "Operator" and "Facility".

Changes required to the operation of subsea equipment; flexible risers, flowline, manifold jumpers and manifolds, due to the tie-in of the new drill centre is outlined in the following subsections. A generic schematic of a tie-back of subsea well to FPSO is included in Figure 2-1.

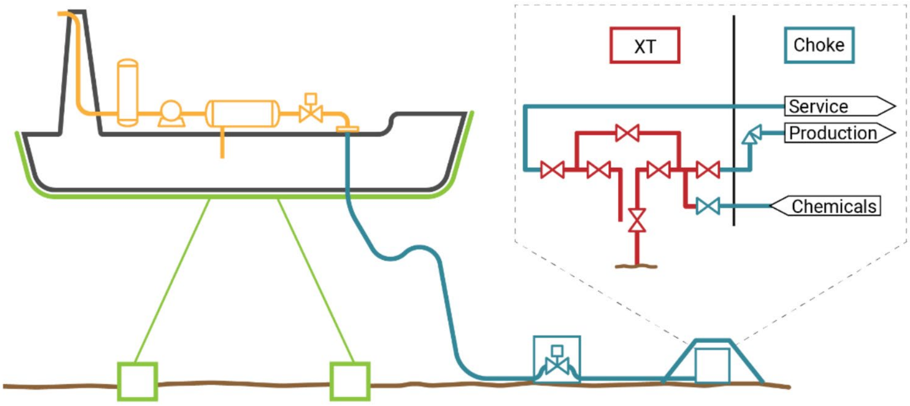

Figure 2-1 Generic schematic illustration of tie-back of subsea well to FPSO

2 RISERS - INCREASE OPERATING PRESSURE FROM 90 BAR TO 115 BAR

2.1 Situation prior to change

The facility includes five 10" production risers which are structurally identical and currently have a maximum operating pressure limit at 90 bar. This limit was set to allow the risers to operate to the end of its service life of 25 years. The fatigue assessment was based on the assumptions regarding Facility operations at time of original design, and the at the time best practice regarding design and fatigue analysis.

2.2 Proposed solution

Increase the fatigue pressure limit for the 10" production risers from 90 bar to 115 bar in the operating manual, and that the associated 3-day average pressure High alarm in the control system is increased from 100 to 120 bar. The original fatigue reports performed a number of sensitivities, of which some were found to not have sufficient fatigue life to last the 25-year service life. However, operational data indicated that conservatisms in the original fatigue assessments were excessively conservative and that the risers would most likely have sufficient fatigue life for the entire service life. Fatigue re-assessment performed at later point in time did not include sensitivities and removed some of the conservatism originally built into the work. The fatigue re-assessment was concluded to document acceptable fatigue life for 25 years in service. The risk associated with the new fatigue results was documented through a separate risk assessment. A comparison of the conservatisms and sensitivities between the original fatigue analysis and the later fatigue re-assessments is visualised in Figure 2-1.

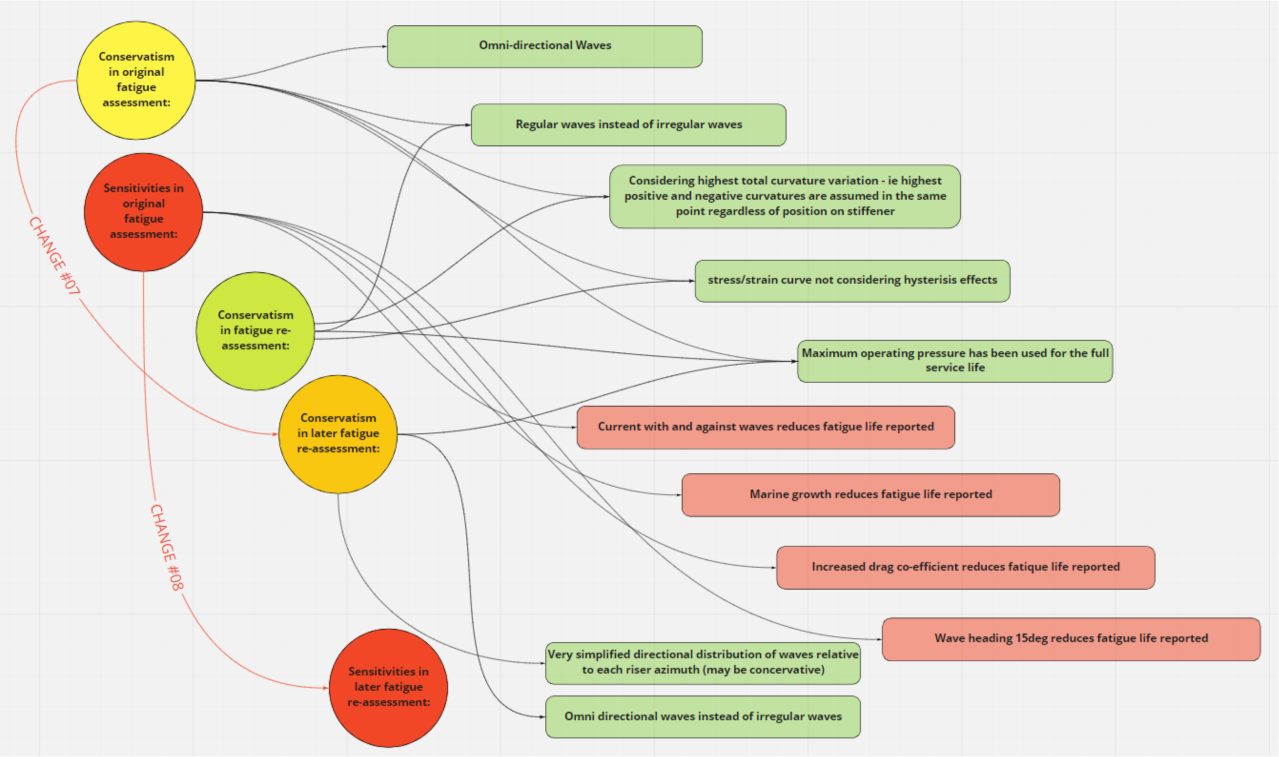

Figure 2-1 Riser service life analyses – illustration of comparison between original assessment and later re-assessments.

Some years before tie-in it was discovered that several of the 10” production risers were operated regularly and continuously above the 90 bar fatigue pressure operating limit. To check if this was ok, the flexible risers Original Equipment Manufacturer (OEM) was requested to perform an evaluation of increased operating pressure from 90 bar to 115 bar. The fatigue re-assessment report included a sensitivity on gas diffusion to select updated SN-curves for both dry and wet riser annulus as well as a local fatigue recalculation. The report concluded that the fatigue life is greater than 25 years at 115 bar given dry annulus at the Bend Stiffener. For a wet annulus case however, considering condensed liquids and seawater ingress, the fatigue life is substantially reduced to 4.5 and 6.3 years respectively for the 115 bar operating pressure (assumes annulus wet from day one, and riser operated at 115 bar at all times). The analysis and assessment were based on the existing global analysis from the facility design phase, and only local fatigue at the hot spot in the bend stiffener was considered. Because this report built on previous global analysis, conservatism from the previous analysis remained, and it was recommended to do some further work to reduce conservatism and increase accuracy of the fatigue assessment.

The OEM therefore performed a follow up assessment using a slightly refined fatigue methodology to obtain a more accurate prediction of service life when the risers were operated at 115 bar. The following improvements were made:

1. Global dynamic analysis model with hysteretic bend stiffness in the bend stiffener region.
2. Irregular wave dynamic analysis.
3. Riser model including structural damping.
4. Rain-flow counting based on time series of stresses.
5. Pipe in pipe model for bend stiffener.

In addition, a review of expectation of annulus filling rate was performed, with estimates from 9 to 11 years for the various risers. It was therefore agreed that accumulated fatigue assessment should be based on 10 years with the riser in the dry condition and then a flooded annulus for the remaining 15 years. This assumption was considered valid as estimation of actual annulus filling rate based on testing of annulus free volume on the riser with the greatest reduction in free volume would become fully wet 10 years after installation. It should be mentioned that operating experience on rate of annulus filling shows that the rate of filling reduces over time, and that the risers are unlikely to get 100% filled with condensed fluid. Annulus vacuum testing results have also shown that there is no known damage to the outer sheet to date resulting in annulus flooded with seawater.

Using this refined methodology, the report concluded that fatigue life, when operating at 115 bars, was 24.9 and 17.4 years for the condensed water case and seawater case respectively. Results were based on the assumption that the riser was operated at 115 bar for its entire service life.

Operating experience shows that the various risers have been operated differently with regards to pressure. Some drill centers using pressure support through gas injection have operated at pressures of around 115 bar for the longest duration, and pressure is likely to remain high until gas injection stops and blow down phase starts. The other risers facilitating production from drill centers with natural pressure depletion over time have already seen significant reduction in pressure, and wells have been converted to low pressure production. This has led to reduced riser operating pressure with pressures generally being in the region of 65-25 bar. However, with the introduction of the new tie-in the risers will experience an increase in pressure to around 105 bara. This will still be within the proposed new limit of 115 bar.

Investigation of experienced wave heights and directions at the facility, based on NORA-10 hindcast data shows that the directional distribution between near, far and transverse directions (relative to riser plane) assumed for all previous fatigue analyses contribute to conservatism in the results. The results show that some service life is gained by using actual wave distribution compared with assumed distribution. Gains are ranging from around 1.3 % to around 5.3 % depending on the riser. Similar gains are experienced for the dry and the flooded annulus case.

Over time there has been a change in the S/N curve used for the fatigue assessments. The original fatigue assessments from the original project used the FC44 S/N curve. This was used due to a requirement to consider 50 ppmv H_2S content for the analysis. Operating experience has shown that this was very conservative. The subsequent fatigue studies have therefore used 5 ppm H_2S in combination with an updated methodology for calculating gas diffusion and annulus environment. As a result of this the FC44 curve was replaced with the less onerous FC1 S/N curve. The FC1 fatigue curve is considered applicable in the bend stiffener area of the 10" production risers provided H_2S content in the bore fluid is at 5 ppmv. Should the fatigue assessment be performed at a location other than the bend stiffener the FC1 S/N curve may no longer be applicable. The same is the case if an increase in H_2S is to occur. However, this is considered unlikely as no sea water is injected into the reservoir. Reservoir souring is therefore not expected.

The OEM also assessed whether the changes in operating pressure and temperature caused by the new tie-in will negatively impact creep. Creep was confirmed successfully checked for the design and FAT conditions. No change is therefore expected for the production risers with regards to creep due to the introduction of the new tie-in.

In recent years, an alarm has been implemented in the control system to allow the control room onboard the FPSO to be able to take action when the 10" risers are operated at pressures above the 90 bar fatigue operating limit for 3 days. This to prevent prolonged operations above the 90 bar fatigue limit. Information about the fatigue risk has also been added to the relevant Operating Manual. For some risers the alarm limit was set at 100 bar. Whereas, for other risers the alarm limit was set at 120, operating limit set at 115 bar, despite not having any approved MOC in place for increasing the operating limit for these risers from 90 to 115 bar. As a result of this MOC all alarm limits will be increased to 120 bar.

2.3 Justification for change

1. Some of the 10” production risers have historically been operated above the 90 bar operating limit. This to maintain production levels and simultaneously manage flow induced vibration risks at the associated production manifolds. There is therefore a need to formalize increase of the limit from 90 to 115 bar.

2. A new drill center will be tied-in to the Facility. To allow safe operation the associated riser will need to be operated at approximately 105 bara. Therefor there is a need to increase the maximum operating limit from 90 bar to 115 bar to allow operation from the new drill center.

3 RISERS – RE-ASSESSMENT OF DEPRESSURIZATION RATE

3.1 Situation prior to change

The 10” flexible production risers have operating limits on allowable depressurization rate to prevent carcass collapse and blistering of the pressure sheath. Maximum allowable depressurization rate is set to 100 bar/hr. In operations there has been challenges related to staying below the 100 bar/hr depressurization rate, and as a result of this an alternative depressurization method was developed. The alternative depressurization methodology involved dividing the depressurization into steps where there is no limit on the depressurization rate, but the depressurization is stopped and paused at set pressure levels to allow pressure stabilization of the various layers in the riser. The operating procedures for riser depressurization therefore describe stepwise rules. For the 10” production riser the following stepwise rules applies:

- Pressure > 179 bar: Depressurise to 179 bar and the hold for 1.5 hrs.
- 119 bar < Pressure <179 bar: Depressurise to 119 bar and hold for 2 hrs.
- 59 bar < Pressure <119 bar: Depressurise to 59 bar and the hold for 2 hrs.
- Pressure < 59 bar: No limits on rate and no given hold period.

3.2 Proposed solution

No change will be made to the allowable depressurization rate of the riser as part of this MOC. Summary of work performed with regards to riser depressurization is summarized below. It has been concluded not to be acceptable to increase the maximum depressurization rate above the 100 bar/hr. As the tie-in project implements a riser depressurization rate controller a change is not required.

The flexible riser OEM has assessed the technical limit of the flexible pipe with regards to updated knowledge and calculation methods on depressurization limits. The two aspects considered are:

- *Blistering*: During operation the fluids permeate through the pressure sheath with the rate being a function of the temperature, pressure and fluid composition. During depressurization the fluids try to escape from the polymer sheath. If the depressurization rate and the pressure drop is high, gas voids may initiate and grow in the polymer sheath, leading to blisters. Blistering tests are part of the qualification process accordance to API17J. The qualification tests were performed at 70 bar/min.
- *Carcass collapse*: During operation, the fluid which is transported in the bore of the pipe, can penetrate in the annular space between the sacrificial sheath/carcass and the pressure sheath. The pressure in the annular space builds-up up to reach the bore pressure. During a depressurization, the pressure of the fluid trapped between the sacrificial sheath and the pressure sheath does not decrease as fast as in the bore of the pipe (due to small flow path, fluid viscosity, etc.). Depressurization of the bore should thus be performed at a limited and controlled rate to avoid an excessive differential pressure between the pipe bore and the annulus that could potentially cause collapse of the carcass.

The flexible riser OEM has developed a numerical model to calculate the maximum differential pressure between the bore and the annuli. The calculated maximum differential pressure must then be compared to the collapse resistance of the structure.

In the first load cases studied, a fluid was selected from the original Statement of Requirement containing 4 mol% CO_2 and 5 ppmv of H_2S. In the last load case, the gas fluid composition from the new wells was used. The fluid composition used for the first load cases was very conservative due to high liquid content, which was only the case for early phase oil production. All drill centers today produce mostly gas.

The results of the calculations taking both blistering and carcass collapse risk into account are presented below.

Only the fluid for the new drill center was considered relevant, allowing for a depressurization rate limit of 220 bar/h between 310 bar and 10 bar (considering start and end pressures at 10 and -20 ºC respectively). As the 220 bar/hr did not include any safety factor it was concluded that maximum depressurization rate for the production risers should remain at 100 bar/hr. The new tie-in implements a depressurization controller for the production risers, which allows for a very controlled depressurization of the riser, and shall prevent depressurization at rates higher than 100 bar/hr.

If a more viscous fluid has flown in the flexible pipe for some time (i.e. from other drill centers), then the depressurization allowance studied in the first load cases should be used as standalone limitations or combined. This will need to be assessed based on the known start pressure and planned end pressure, as well as the required depressurization time in order to ensure carcass collapse and blistering does not occur.

3.3 Justification for change

The FPSO will get a new tie-back. The new wells and subsea system are operated at a much higher pressure than the current subsea system. This means that in the event of certain trips and shutdown cases, the settle out pressure in the riser and flowline will be much higher than today (around 200 bar, exact value will depend on sequence and timing of valve closures). This will lead to an increase in the number of depressurizations the associated 10” production risers will experience, as the flowline/riser pressure must be reduced to 100 bar prior to start-up. In addition, the new wells will operate at a lower temperature compared with the existing Facility wells. For this reason, the system will enter the hydrate formation zone quicker (reduced cooldown time/no touch time). To get out of the hydrate formation zone, depressurization to ambient is an effective tool, and will be necessary if flowline heating is not available. The stepwise rules currently used for this in existing operating procedures will be too time consuming due to long hold periods. Thus, there is a need for utilizing a linear depressurization rate. To control the depressurization rate an automatic depressurization controller has been developed. This gives the control room good control over the riser depressurization and controls the rate to keep it is below 100 bar/hr at all times.

4 FLOWLINE

4.1 Situation prior to change

New in-place analyses for Flowline Operating Conditions (250 barg, 80 ºC and 180 kg/m^3 density) has been performed. The analyses show that the new Operating Conditions give negligible changes in buckling pattern and free span configuration.

Trawl Pull-Over: Minimum radius in trawl pull-over is 12.8 m which is still above the minimum radius defined in the detailed design (11.6 m). Note that the sensitivity analysis was performed for the potential higher trawl gear equipment of 10 tonnes (flowline was originally designed for 6.5 tonnes trawl load), this leads to unacceptable radius during pull-over, however, this is the case for most of the Facility flowlines. But due to no known bottom trawling activity in the area to date, the risk is considered low and acceptable.

Low Cycle Fatigue: Low cycle fatigue analysis gives a maximum stress range of 195 MPa which is below the one defined in the detail design (278 MPa).

Fatigue due to VIV: The VIV analysis shows that there are more load cycles and the maximum stress range is slightly higher, however, when comparing the fatigue results the changes are negligible.

It is concluded that the Operational Loads for flowline is acceptable (according to DNV-OS-F101: 2013) and updating detailed design (Engineering Criticality Assessment) is not required.

4.2 Proposed solution

No new proposed solution is required at the moment.

Monitoring of trawl activity in the Facility Area to continue to ensure no bottom trawling occurs. Attention should also be on increases in trawl gear sizes as they are likely to be greater than the design loads.

4.3 Justification for change

The flowline has been assessed for the changes in operation due to the new wells, and it has been identified that no changes are required.

5 MANIFOLD JUMPER - INCREASE OPERATING PRESSURE FROM 115 TO 220 BAR

5.1 Situation prior to change

The 10” manifold production jumpers are structurally identical and have an operating pressure of 115 bar. Limit was increased from 90 bar following fatigue assessments performed on the 10” production risers which are structurally identical to the 10” manifold production jumpers. The results were considered applicable to the 10” manifold jumpers. The manifold jumpers are static, and therefore see less fatigue damage than the flexible risers.

5.2 Proposed solution

Operating pressure for the 10” manifold jumpers is increased from 115 bar to 170 bar. For the manifold jumpers producing fluids from the new drill center an additional increase to 220 bar is implemented.

A review of the jumper design has been performed to identify the areas where the increase in pressure might impact the flexible jumper design. The aspects of the flexible design that were identified then underwent more detailed analysis:

- Bore fluid characterization and gas diffusion analysis to establish bore and annulus environment.
- Suitability of the riser materials was checked against bore and annulus environment.
- Stress analysis of load bearing metallic layers accounting for uniform corrosion.
- Thermal and pressure expansion analysis.
- Tie-in analysis.

From the bore environment definition, it was concluded that the metallic and polymeric layers of the bore are suitable for the application according to the OEM’s material qualification.

From the gas diffusion analysis and the annulus environment definition, it was concluded that the polymer layers of the annulus are suitable for the application according to the OEM’s material qualification.

The utilization factors considering the reduction in nominal cross section area due to CO_2 and H_2S corrosion over the design life are in accordance with API 17J allowable utilization factors.

The maximum elongation due to the combined effect of the internal pressure and temperature is 0.21%.

The most onerous load case is the one with zero internal pressure (i.e. empty pipe) and hydrostatic external pressure applied to the flexible pipe, for which the allowable compression is 856 kN according to API 17J criteria. Interface loading at connector at Manifold and Pipeline End Termination (PLET) were not checked by the OEM. But the loads have been compared with the connector capacities and are found to be within the connector's max capacity.

The tie-in analysis revealed that the API 17J Maximum Bend Radius criterion is respected at both tie-in locations (PLET and manifold).

The material compatibility assessment of the annulus metallic layers shows that the bore operating conditions are within an untested Stress Corrosion Cracking (SCC) domain and, therefore, the flexible pipes can be exposed to SCC risk. The results of the SCC sensitivity analyses show that:

- To operate at 110 ºC with a fluid composition containing 4 mol% of CO_2, the operating pressure should not exceed 176 bars.
- To operate at 220 bars and 110 ºC, the CO_2 content in the fluid composition should be less than 3.2 mol%.

The new wells have CO_2 contents substantially lower than the 4 mol% used in design. Actual CO_2 content is 0.48 mol%, which is substantially less than the maximum allowable CO_2 content to allow operation at 220 bars. For the manifold jumpers associated with the new drill center, it is therefore acceptable to increase the allowable operating pressure to 200 bar. For other drill centers the CO_2 content has historically been below the 3.2% mol CO_2. However, as they do not need to operate at pressures as high as 220 bar, the limit is increased from 115 to 170 bar for these jumpers to give greater flexibility for Flow Induced Vibration (FIV) management.

5.3 Justification for change

The Facility manifold jumpers have historically been operated above the original 90 bar fatigue pressure operating limit. In order to manage vibration risks at the manifold the operating pressure was increased to 115 bar a few years back. To allow safe operation of the new drill center, the manifold jumpers will need to be operated at approximately 150 bara and 220 bara respectively. Therefore, there is a need to increase the operating limit on these manifold jumpers from 115 bar to 220 bar to allow operation of the new drill center.

Additionally, increased operational pressure for the existing manifold jumpers will be beneficial for managing the Flow Induced Vibration (FIV) Risk experienced by well slots on the Facility manifolds, while also maintaining higher production levels.

6 MANIFOLD JUMPERS – RE-ASSESSMENT OF DEPRESSURISATION RATE

6.1 Situation prior to change

The Facility flexible manifold jumpers have operating limits on allowable depressurization rate to prevent carcass collapse and blistering of the flexible jumpers. Allowable depressurization rate is set to 100 bar/hr. In operations there have been challenges related to staying below the 100 bar/hr depressurization rate, and an alternative depressurization method was developed for the risers, which can also be applied to the jumpers. The alternative depressurization methodology involves dividing the depressurization into steps where there is no limit on the depressurization rate, but the depressurization must be stopped and paused at set pressure levels to allow pressure stabilization of the various layers in the riser. See further details in Section 2.3.1.

6.2 Proposed solution

Allowable depressurization rate for the 10” manifold jumpers is increased from 100 bar/hr to 200 bar/hr.

The jumper OEM has performed a study to assess the technical limit of the flexible jumper with regards to updated knowledge and calculation methods on depressurization limits.

The two aspects being looked at are blistering risk of the pressure sheath and carcass collapse (see further description in Section 2.3.2).

The Flexible Jumper OEM has developed a numerical model that enables to calculate the maximum differential pressure between the bore and the annulus. The calculated maximum differential pressure must then be compared to the collapse resistance of the structure.

The lowest allowable depressurization rate is found for the new tie-in composition at 15 bar/min or 900 bar/hr, no safety factors are included in the results. To allow for some safety factor in the allowable depressurization rate, it has been agreed to increase the allowable manifold jumper depressurization rate to 200 bar/hr.

6.3 Justification for change

The new wells and subsea system are operated at a much higher pressure compared to the Facility today. This means that in the event of certain trips and shutdown cases, the settle out pressure in the flowline and manifold jumpers will be much higher than today (around 220 bar, exact value will depend on sequence and timing of valve closures). This will lead to an increase in the number of depressurizations for the flexible jumpers associated with the new drill center, as the flowline/riser/jumper pressure must be reduced to 100-110 bar prior to start-up.

In addition, the new wells operate at a lower temperature than the current wells. The system will therefore enter the hydrate formation zone quicker (reduced cooldown time/no touch time). To get out of the hydrate formation zone, depressurization to ambient is an effective tool, and will be necessary if flowline heating is not available. But the stepwise rules used for this in existing operating procedures will be too time consuming due to long hold periods. Thus, there is a need for utilizing a linear depressurization rate. To control the depressurization rate, an automatic depressurization controller has been developed. This gives the control room good control over the riser depressurization, and controls the rate so it is below 100 bar/hr. However, it has been agreed that the work performed in preparation for the new tie-in is to be used to extend the allowable depressurization rate for the jumpers to give more operational flexibility and document that the jumpers may no longer be the “bottle neck” when depressurizing.

7 MANIFOLD

7.1 Situation prior to change

The manifolds associated with the new tie-in currently only see production from existing well slots on the template and are operated within the existing Facility design basis.

7.2 Proposed solution

No changes are required for the Manifolds with regards to changes in operating pressure and temperature, as this is covered by the existing design. A review has been performed on the work done by the tie-in project to manage the FIV risk in order to understand the potential impact on the manifolds. The conclusion is that the maximum velocity through the manifolds is estimated to be 17 m/s and this is evaluated not to represent a significant FIV threat.

However, after startup of the new tie-in the actual velocities are to be checked when data becomes available. If velocity is below 17 m/s no issues are expected. Should the velocity be significantly above 17 m/s then the dynamic pressure could represent a threat in terms of FIV, and further assessments should be performed. This has been included as a post-implementation action.

8 CHANGE PROCESS

The change was managed through the Operator’s tool for change management and in accordance with the Business Management System requirements for a change process. The following roles were involved in processing the MOC:

- OEM
- Subsea Operations Engineer
- Asset Engineering Manager
- Subsea Technical Authority
- Offshore Installation Manager

This case description, as it has been generalised, does not include reference to data sources and documentation. The following data and documents should be referred, and activities are confirmed to be in place:

- Reference to updated Design Basis, Design Reports, As-installed documentation, Engineering Assessments, Inspection, Monitoring and Test Data (to ensure traceability and completeness).
- Changes incorporated in Risk Assessment.
- Changes reflected in Operation Procedures and Settings and Alarms in the Control System.
- Changes reflected in the Integrity Management System by incorporating updated Integrity Operating Envelope and trigger levels/thresholds for Integrity assessments.

APPENDIX C

Aspects to consider when describing risk impact from a change

Table C-9-1: Aspects to consider when describing risk impact from a change /10/.

Perspective	Risk aspects	Comment
Activity	Describe wanted/expected/possible gains from the activity.	E.g. income, employment, technology development, market position/advantage.
	Describe effects/loss categories of concern, with associated acceptance criteria.	E.g. loss of life, resources of value, property, money, production, reputation. These categories tend to be generic, but the weighting can vary from project to project.
	Describe physical consequences of concern.	E.g. pollution, explosion, damage to asset. It is useful to distinguish physical consequences from losses, because the same physical consequence may lead to very different losses depending on the solution and environment it occurs in.
	Describe hazardous events of concern.	To be able to compare risk for different solutions it is smart to define generic hazardous events such as “hydrocarbon release” and “loss of communication.” The more “fine-grained” the hazard list is, the less likely each hazard is, which may give an impression that the overall risk is low. Aggregation into a smaller set of more generic hazards can provide a better impression of the overall risk level.
	Describe particular risk sources at the location.	E.g. subsurface conditions, geology, seabed, ocean and climate conditions, third party activity.
	Describe risk acceptance criteria and risk reduction needs.	Comparison to risk acceptance criteria and evaluation of compliance should take into account the strength of the background knowledge. Meeting a quantitative risk acceptance criteria by a narrow margin is not adequate unless the knowledge supporting such a conclusion is strong.
	Provide quantitative, qualitative or semi-quantitative assertions about risk related to accident scenarios.	Multiple risk metrics will generally be needed to give a comprehensive risk picture. Use of quantitative risk metrics for comparison is only sensible if the knowledge strength is sufficient to support it. Qualitative and semi-quantitative risk metrics may be more robust to assumptions and weak knowledge, and are often sufficient to differentiate decision options.
	Describe critical assumptions that could jeopardize the answers above.	E.g. assumptions introduced when defining the scope of the risk assessment, selecting model and methods, and choosing which risk metrics to present/use. The criticality depends on the sensitivity of results to the assumption, the belief that it may deviate or be wrong, and the strength of the knowledge used to assign and evaluate the assumption. Critical assumptions may be related to aspects addressed from a strategy of technology perspective (below).
Strategy	For each relevant hazardous event:	
	Describe the risk reducing measures in place to treat risk related to the specific hazardous event.	I.e. functions put in place to prevent various hazardous events from occurring or mitigate the consequences and effects if they do occur. Incl. technical, operational and organizational elements.
	Describe how the intent of regulations is adhered to.	This includes basic principles such as double barriers, independent safety and control systems, fail-safe mechanisms. This also includes assumptions that need to be valid for the regulations to be met.

Perspective	Risk aspects	Comment
	Describe the needed performance from risk reducing measures.	Performance should include all relevant aspect, e.g. functionality, integrity and survivability.
	Describe the total risk reduction provided by the strategy (compared against risk reduction requirements).	I.e. an assessment of the overall ability of the strategy to reduce risk, given the barrier functions, barrier elements and their associated performance along various dimensions. This includes both preventive and mitigative barriers. Assumptions made must be evaluated.
	Describe the independence (or possible dependencies and common cause failures) among risk reducing measures.	Including dependencies on a functional level and between the physical risk reducing measures (e.g. barrier elements). Dependencies could be either mechanical, via software, through power supply and power management systems etc.
	Describe the robustness of the strategy.	E.g. the extent to which failure in one component, system or a single mistake can result in unacceptable consequences, such as loss of protection. This includes addressing the criticality of assumptions that the strategy is based on.
	Describe of the resilience of the strategy.	E.g. the ability to adapt/change the strategy if necessary. This includes the flexibility of the organization and operations, in addition to the configurability and adaptability of the technical barrier elements.
Technology	For each technology:	
	Describe of the performance and operational limits of the technology.	Description of the technology's capabilities/functionality and performance versus possible demand situations and operational circumstances, and requirements with respect to risk reduction.
	Describe failure modes, and evaluate their likelihood (of occurrence or presence), effects and criticality	This includes hardware, software, organisational and human elements. The term likelihood reflects a qualitative or quantitative expression of uncertainty, which may stem from both the randomness in the nature of hardware failures and human errors, and the lack of knowledge about latent weaknesses in software, hardware or organizations.
	Describe possible interactions or conflicts among system elements which could lead to hazards.	E.g. dependencies in authority or dependability among technology elements. Interactions may be intended or unintended.
	Describe common cause failure modes.	E.g. related to shared resources, software or mutual dependability.
	Describe the ability to monitor the technology and detect critical conditions before hazardous events arise.	E.g. condition monitoring, diagnostics, ability to perform tests and inspections. This includes assumptions that need to be valid for critical conditions to be detected.
	Describe the risk-reducing effects of the technology with respect to specific hazards.	E.g. hazards or losses that are removed or favourably modified. This includes description of critical assumptions affecting the hazards.
	Describe the risk-increasing effects of the technology with respect to specific hazards.	I.e. hazards or losses that are introduced or adversely modified by the technology. This includes description of critical assumptions affecting the hazards.

Perspective	Risk aspects	Comment
	Describe the degree of dependence on the technology and the possibility to intervene in the event of unexpected/unintended/faulty behaviour (e.g. wrong output from a safety critical function).	E.g. the existence of independent backup solutions and alternative/manual control options. This includes identifying and addressing critical assumptions.
	Describe the expected useful lifetime of the technology compared to the system life cycle.	I.e. both related to physical integrity, the possibility of technology becoming outdated and the possibility of future upgrading.
	Describe the impact of the technology on system/facility design complexity.	E.g. side effects on system level from using the technology, like removal or introduction of supporting infrastructure.
	Describe the impact of the technology on the complexity of system/facility operation.	E.g. side effects related to how the system can be operated.
	Describe the impact of the technology on the complexity of system/facility maintenance.	E.g. side effects related to how the system can be maintained, incl. maintenance/update of software.
	Describe the impact of the technology on the complexity of commissioning and decommissioning.	E.g. side effects related to how the system can be installed and removed after end of useful life.

APPENDIX D

Aspects to consider when describing risk impact of change – Example

The table lists aspects to consider when describing risk impact of change as presented in Section **Error! Reference source not found.** and is based on the process presented in /10/. Note that the table is developed by DNV as an example and does not necessarily represent the Operators view.

Table D-9-2: Aspects to consider when describing risk impact from a change- Example.

Perspective	Risk aspects	Example, ref. MOC case in Section 7.4
Activity	Describe wanted/expected/possible gains from the activity.	Enable effective production from a new tie-in while ensuring 25-year service life for the subsea infrastructure. Covered by MOC.
	Describe effects/loss categories of concern, with associated acceptance criteria.	Loss of containment may impact all consequence categories (safety, environment, reputation, finance), while reduced service life will mainly impact reputation and finance. Acceptance criteria as per Operator risk matrix. Covered by Risk Assessment.
	Describe physical consequences of concern.	Increased operating pressure may lead to reduced service life. If a loss of containment occurs, the leak rates and volumes, and the potential consequences, may increase. Covered by Risk Assessment.
	Describe hazardous events of concern.	The main events assessed are loss of containment; full bore leak and small bore leak. Covered by Risk Assessment
	Describe particular risk sources (threats) at the location.	Threats particularly considered as part of the change include: fatigue, corrosion, rapid depressurisation (carcass collapse, blistering), material compatibility, excessive mechanical loads, buckling, free spans, trawl pull-over, VIV and FIV. Covered by Risk Assessment.
	Describe risk acceptance criteria and risk reduction needs.	For risk acceptance criteria; ref. the Operator risk assessment.
	Provide quantitative, qualitative or semi-quantitative assertions about risk related to accident scenarios.	Reference is given to the Operator risk assessment for the tie-in and subsea facilities. Covered by Risk Assessments.
	Describe critical assumptions that could jeopardize the answers above.	The MOC includes all equipment from new drill center to riser hang-off. The scope of work excludes utility lines as the pressures are well within design boundaries. Important assumptions / input data to the MOC include: - Water filling of annulus in flexible pipes, selection of S/N curve for fatigue assessment. - Weather data and actual operating data, selection of load spectrum and diffusion rates. - Current technical condition including degradation, defects, configuration and loads. All of these input data are validated. Covered by the MOC.
Strategy	For each relevant hazardous event:	
	Describe brisk reducing measures in place to treat risk related to the specific hazardous event.	Risk reducing measures implemented: - Analyses performed to confirm 25-years service life. - Alarm levels for operating pressure updated in control system. - Operating procedure updated to reflect depressurisation limits. - Depressurisation controller implemented. - Monitoring of flow velocity in manifold implemented with trigger level for further analysis of FIV. - Monitoring of trawl activity and trawl gear loads enforced. Covered in the Risk Assessment and in the MOC.
	Describe how the intent of regulations is adhered to.	Change does not impact this aspect. Operation is within design boundaries. Fitness-for-service for the service life is confirmed.
	Describe the needed performance from risk reducing measures.	Not covered in the MOC text. Implemented in relevant performance standard.

Perspective	Risk aspects	Example, ref. MOC case in Section 7.4
	Describe the total risk reduction provided by the strategy (compared against risk reduction requirements).	With implemented mitigations in place, the risk has been considered not to increase due to the change. Activities performed as part of the change management process has contributed to obtaining a better understanding of the design robustness, the threats and the service life for the subsea facilities. Covered by MOC and Risk Assessment.
	Describe the independence (or possible dependencies and common cause failures) among risk reducing measures.	N/A. Relevant aspects covered by Risk Assessment.
	Describe the robustness of the strategy.	Strategy considered to be strengthened. . Activities performed as part of the change management process has contributed to obtaining a better understanding of the design robustness, the threats and the service life for the subsea facilities. Covered by MOC and Risk Assessment.
	Describe of the resilience of the strategy.	Not made a significant topic in the MOC. Topic covered in Risk Assessment.
Technology	For each technology:	*Note that physical modifications to the subsea equipment was not part of this change.*
	Describe the performance and operational limits of the technology.	Operational limits better understood through performed assessments. Covered by MOC
	Describe failure modes, and evaluate their likelihood (of occurrence or presence), effects and criticality	Failure modes considered include Loss of Containment (full bore or small bore) and reduced service life. Threats particularly considered as part of the change include: fatigue, corrosion, rapid depressurisation (carcass collapse, blistering), material compatibility, excessive mechanical loads, buckling, free spans, trawl pull-over, VIV and FIV. Covered by MOC and Risk Assessment.
	Describe possible interactions or conflicts among system elements which could lead to hazards.	Not identified.
	Describe common cause failure modes.	Not identified.
	Describe the ability to monitor the technology and detect critical conditions before hazardous events arise.	Monitoring of parameters significantly contributing to the relevant threats has been implemented. Relevant inspection and survey activities to verify actual condition are included in inspection plans. Inspection to confirm condition of respective layers in the flexible risers is considered not feasible with current design and available inspection technologies, and condition evaluation is performed mainly through engineering assessments (considering actual operating parameters and monitoring data) with involvement from OEM. Covered in MOC and Risk Assessment.
	Describe the risk-reducing effects of the technology with respect to specific hazards.	Not impacted by the change.
	Describe the risk-increasing effects of the technology with respect to specific hazards.	Not impacted by the change.
	Describe the degree of dependence on the technology and the possibility to intervene in the event of unexpected/unintended/faulty behaviour (e.g. wrong output from a safety critical function).	Not impacted by the change.

Perspective	Risk aspects	Example, ref. MOC case in Section 7.4
	Describe the expected useful lifetime of the technology compared to the system life cycle.	25-year service life confirmed. Covered in MOC.
	Describe the impact of the technology on system/facility design complexity.	Not impacted by the change.
	Describe the impact of the technology on the complexity of system/facility operation.	Updates have been implanted in control system and operating procedures, and by integration of depressurisation controller. Complexity not considered to significantly increase. Covered in MOC.
	Describe the impact of the technology on the complexity of system/facility maintenance.	Evaluations has ensured that relevant monitoring is being performed to verify operation within integrity envelope. No change in inspection scope. Covered in MOC and Risk Assessment.
	Describe the impact of the technology on the complexity of commissioning and decommissioning.	Not impacted by the change.

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