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ABSTRACT

Well integrity is defined as*:" the application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids, throughout the life cycle of a well"* ***(1)***.

An uncontrolled release of hydrocarbons to the surroundings may have devastating consequences involving loss of lives, environmental damage and huge economic impact. Therefore it is extremely important that the integrity is assured at all times. A two barrier criterion is required for all the wells on the Norwegian Continental Shelf in contact with an over pressured reservoir. The dual barrier envelopes shall reduce the risk of a hydrocarbon leak to the surroundings.

The highest risk for a major accident is experienced and considered to be during drilling and well operations, and not in the production / injection phase. However, history clearly shows the risk for a blowout / well release from wells that have been in production with the Bravo and Snorre A blowouts as serious examples. With today's extended well lifetime, the integrity in the operational phase needs increased focus as the failure rate in old wells may become more frequent.

To have overview and control of the wells in operation a categorization system for well integrity was developed in Norwegian Oil and Gas Recommended Guidelines 117, chapter 4. This system is based on the condition and number of barriers in a well, thus it is in direct association with the probability of a leak to the surroundings. Operators on the Norwegian Continental Shelf have used this system as a basis when developing their own risk status codes, but there is a common interest for a categorization system that captures the total risk picture in a better way. By only looking into the physical barrier status of the wells, an important part of the overall risk is left out. The leak is not quantified (above the acceptance criteria), if it is serious or insignificant, and the potential consequences of the leak are not taken into consideration. Statoil is one of the operators realizing the need for a risk status code that includes these aspects. They have experienced difficulties when ranking and prioritizing wells outside the dual barrier criterion, and are interested in a system for further differentiation of the most critical wells. In this way the most risky wells can be prioritized first and evaluated in a more detailed risk assessment.

The main scope of this thesis is suggesting a categorization system describing the overall risk in a better way than the existing. This is done by implementing the potential consequences as a second dimension in addition to the barrier status. Risk can be defined as the combination of the probability of an event and the associated consequences, and a status including both these elements will give a better description of the overall risk. As the main task is producing a new classification system for the consequences, this will be the part emphasized in the suggested models. In combination with the existing barrier status codes (based on the color codes in Norwegian Oil and Gas Recommended Guidelines 117 for Well Integrity) this gives a status which represents a more complete risk picture.

This thesis suggests several systems for consequence categorization, and the one most representative is presented as model 3. By testing it on 5 field cases, the results clearly show why the new system gives a better description of the overall risk contra the existing.

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Stavanger, June 2014

Kristine Kostøl

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ABBREVIATIONS

ALARP	As Low As Reasonably Practicable
AMV	Annulus Master Valve
ASV	Annulus Safety Valve
D&W	Drilling and Well
DHSV	Downhole Safety Valve (SCSSV)
DMF	Drilling Managers Forum
EAC	Element Acceptance Criteria
ESD	Emergency Shut Down
FMECA	Failure Modes, Effects and Criticality Analysis
FTA	Fault Tree Analysis
HPHT	High Pressure, High Temperature
HSE	Health Safety and Environment
iWIT	Intetech Well Integrity Toolkit
KPI	Key Performance Indicator
MAASP	Maximum Allowable Annulus Surface Pressure
MD	Measured Depth
NCS	Norwegian Continental Shelf
NOG	Norwegian Oil and Gas
OWC	Oil Water Contact
PBR	Polished Bore Receptacle
PMV	Production Master Valve

PSA	Petroleum Safety Authority
PWV	Production Wing Valve
ROV	Remotely Operated Underwater Vehicle
SCP	Sustained Casing Pressure
SCSSV	Surface Controlled Subsurface Safety Valve
TOC	Top Of Cement
TVD	Total Vertical Depth
WB	Well Barrier
WBE	Well Barrier Element
WBS	Well Barrier Schematic
WDP	Well Design Pressure
WIF	Well Integrity Forum
WIM	Well Integrity Management

1. INTRODUCTION

The importance of well safety has been recognized and accepted for a long time, and improvements concerning design and operating procedures have been made. Despite this, failures still occur and will continue to occur in the future. The gas blowout on the Snorre tension leg platform in 2004 exemplifies the need for continued focus on well safety. According to the Petroleum Safety Authority (PSA) the blowout could have resulted in a major accident with the loss of many lives. Deficient assessment of overall risk and breach of requirements to well barriers were two of the conclusions drawn from the PSA investigation ***(2)***.

A number of serious well failures in recent years, with the Snorre event in 2004 as a major contributor, have led to an increased focus on well integrity. In 2006 PSA performed a pilot well integrity survey on the Norwegian Continental Shelf (NCS). This survey was based on supervisory audits and requested input from seven operating companies - one of them being Statoil ASA. 12 preselected offshore facilities and 406 production and injection wells, with variation of age and development categories, were investigated.

PSA had experienced shortcomings in the industry's handling of well integrity management, and the scope of the survey was to analyze how comprehensive the well integrity problems on the NCS were. Main issues and challenges, especially related to the barrier status of the wells, should be brought to light.

The common report from the pilot survey showed that the findings and improvements identified were the same for all the operators, and some of the key results were ***(3)***:

- 18 % of the investigated production and injection wells were to some degree impaired by well integrity issues, including 7 % full shut in. The impairments clearly represented a generous potential for improvements both to health, safety and environment (HSE) and production.
- Each company generally needed to improve focus on well integrity issues.
- Well integrity and the dual barrier concept needed common attention from the industry in order to comply with the regulations, and thereby reducing the potential for well related accidents.

- Improved attention on verification and monitoring of well barriers was needed.
- There was a need to align with a common way of documenting well integrity within the industry. The methods for describing the well barriers / envelopes varied in the industry and even within the same operating company.

The operating companies were positive to the PSA findings, and there was a common understanding and agreement that well integrity was an arena that required improved attention.

Based on the findings and identified improvements submitted in the pilot survey report from the PSA, the operators initiated an operators cooperation forum called Well Integrity Forum (WIF). WIF has been active since 2007 and is facilitated by Norwegian Oil and Gas Association and reports to Drilling Managers Forum (DMF). Since 2007 WIF has developed Norwegian Oil and Gas (NOG) Recommended Guidelines 117 for Well Integrity.

The NOG Guidelines 117, chapter 4, describes a system for classifying a well based on its integrity status. Operators benefit from this categorization system as a method of ranking well integrity for wells in operation, whereas the PSA use it to summarize well integrity across the entire NCS. A common categorization system also promotes a level of consistency among the various operators when evaluating the integrity of their wells.

The system principle is based on number of well barriers, thus it has a direct association with the probability of a leak to surface / environment. However, it does not quantify the leak (above the acceptance criteria), if it is insignificant or serious or the potential consequences of the leak. In this way it does not give a total risk picture for the different wells. For instance, two wells with only one remaining barrier can pose different levels of risks if one is a high rate gas well on a manned platform whereas the second is a subsea water injector.

Statoil has developed several systems based on the NOG Guidelines 117, included the newly implemented system Intetech Well Integrity Toolkit (iWIT), but none of them seems to capture the total risk picture in a good enough way. Operators, with Statoil in the lead, and the PSA realize the need for an improved system for well categorization reflecting the total risk picture for a well in operation and not only the barrier status.

The scope of this thesis will be to describe and evaluate the existing systems for well integrity well categorization for the operational phase. Improvements for defining risk status codes and how to perform specific risk assessments for the most critical wells will be suggested. Hopefully this will contribute to a better way of ranking and prioritizing the most critical wells with regards to well integrity issues and to an improved understanding of the risks that can cause undesirable events.

2. THEORY

2.1 Well system description

This chapter will give a short description of the main characteristics of an offshore well in the operational phase.

2.1.1 Well operational phase

The operational phase of a well is considered to extend from handover of the well after construction to handover prior to abandonment and is illustrated in figure 1. Handover is the process of transferring responsibility for operating a well from one party to another, including both custody to operate and the data and documents which describe the well construction ***(4)***. The operational phase (production / injection) starts after the well construction organization has handed the well over to the production organization and ends with a handover back to drilling and well (D&W) organization for intervention, workover or abandonment ***(1)***. Figure 1 shows the cycle of handovers in a well's lifetime.

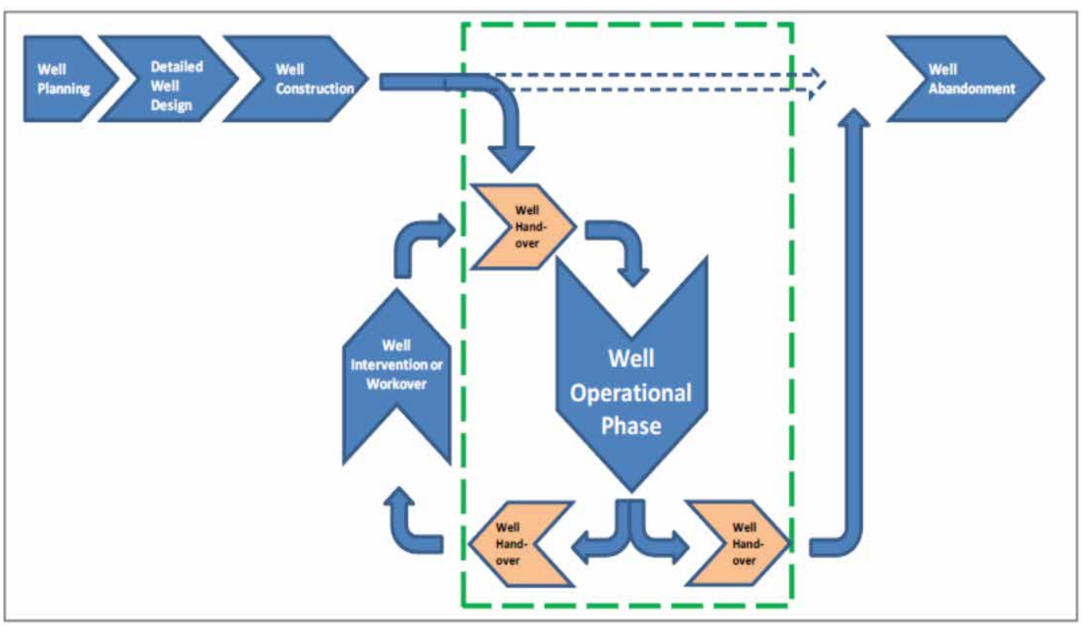


Figure 1: Well operational phase (4).

2.1.2 Well system

The main components of a well are *casing program, well completion, wellhead* and *x - mas tree* ***(5)****:*

- The *casing program* consists of all casings and liner strings, including hangers and cement.
- The *wellhead* is the seabed / surface termination of a wellbore with facilities for installing casing hangers during the well construction phase and for hanging the production tubing and installing the x - mas tree.
- The *x - mas tree* is an assembly of valves, pressure gauges and chokes controlling well flow.
- The *well completion* is the assembly of tubing hanger, tubing, safety valve, production packer, and other equipment placed inside the production casing / liner giving access to the reservoir.

On a surface well the wellhead, x - mas tree and production control system are positioned on the platform. On subsea wells these systems are located at seabed and the produced fluids are transported to the platform through a flowline and riser.

All wells contain valves which are constructed to shut in the well in an emergency situation - emergency shutdown (ESD) valves. These are typically the surface controlled subsurface safety valve (SCSSV), annulus master valve (AMV), production master valve (PMV) and production wing valve (PWV). The well safety valves are fail - safe, meaning they will close when hydraulic pressure or signal is lost. During production / injection they are kept in an open position, and it is critical that they automatically close in situations when power or hydraulic support is lost or if a fire occurs ***(5)***.

Figure 2 illustrates a typical oil producing surface well.

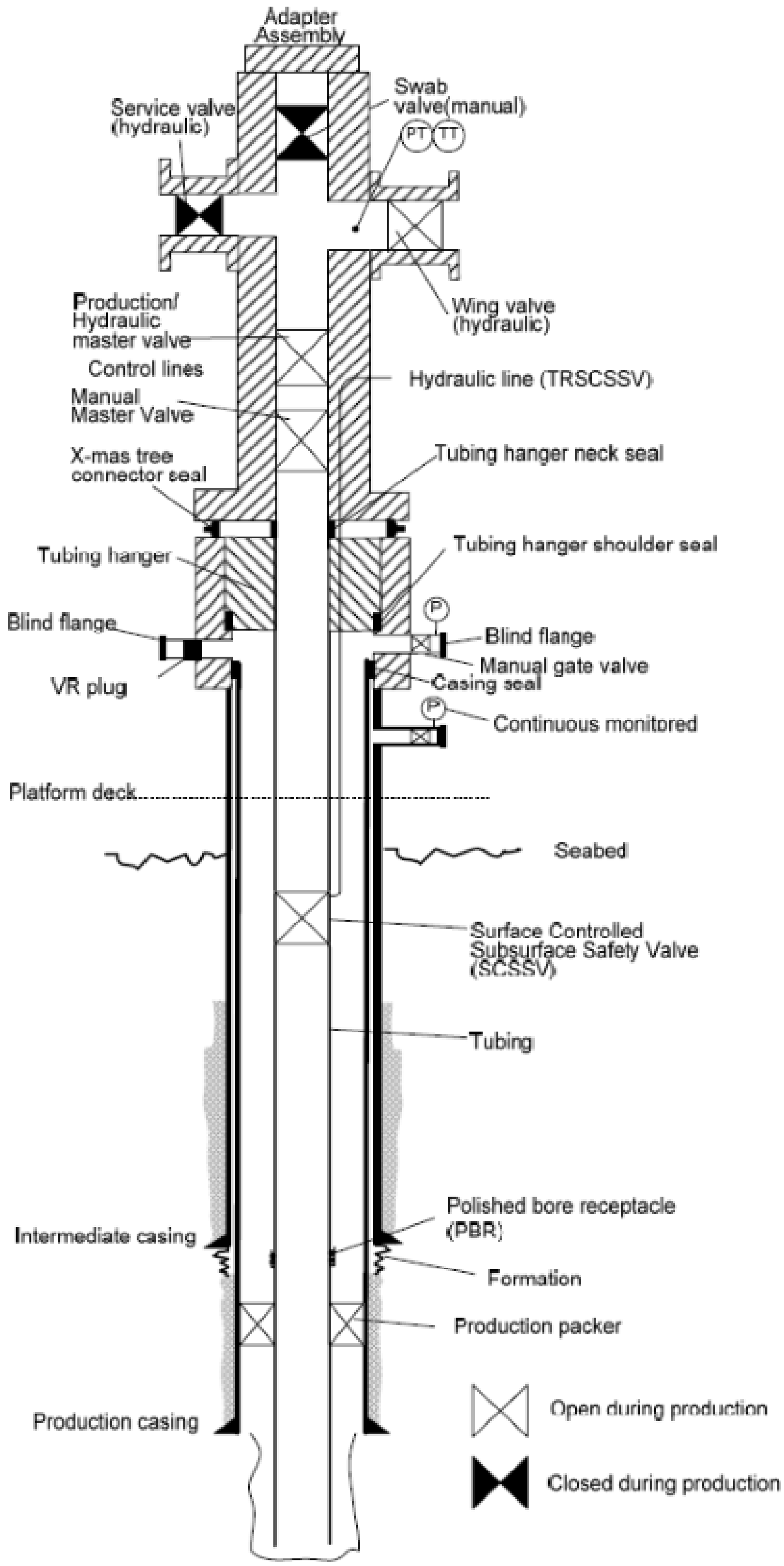


Figure 2: Typical oil producing surface well (5).

2.1.3 Well types

A well in operation may either be a producer or injector. Production wells produce reservoir fluids, while injection wells are used to inject gas or water into the reservoir to maintain / increase the pressure.

The production well transports fluids from the reservoir to the process facilities on the installation. Typical fluids produced are oil, gas, condensate and water. In a naturally flowing production well the reservoir pressure is sufficient to produce hydrocarbons in a commercial rate. However, after a period of time the pressure may decrease and it is required with artificial lift to continue production. Artificial lift is when a system adds energy to the fluid column in a wellbore with the objective to improve production from the well. The most common principles used are gas lift and electrical submersible pumps.

In a gas injection well, separated gas from production wells or imported gas is injected into the upper gas section of the reservoir. Water injection wells use filtered and treated seawater or produced water to inject into the lower water bearing section of the reservoir. The main purpose of the injectors is to maintain / increase reservoir pressure in order to get a higher recovery.

The production and injection wells on the NCS must follow standards, laws and regulations for well integrity in order to be operated in a safe and legal way. These will be described in the following chapters.

2.2 Standards, laws and regulations for well integrity in Norway

A standard is a publication that provides rules, guidelines or characteristics for activities or their results, for common and repeated use ***(6)***.

International (developed by ISO), American (developed by API) and European standards (developed by CEN) form the basis of all activities in the petroleum industry. Experts from a wide range of Norwegian companies participate in the development of these, in order to define safe and economical design and processes. However, Norwegian safety framework and climate conditions may require own standards, or additions and supplements to International, (ISO), American (API) and European Standards (EN) ***(7)***. The NORSOK standards are developed to fulfil these needs.

NORSOK D-010 "Well integrity in drilling and well operations" is developed by the Norwegian petroleum industry to ensure adequate safety, value adding and cost effectiveness for well integrity in Norway. It is a functional standard and sets the minimum requirements for the equipment / solutions to be used in a well, but leaves it up to the operating companies to choose the solutions that meet the requirements. In this way the companies develop their own sets of requirements and work processes that in minimum must follow NORSOK D-010. The preparation and publication of NORSOK D-010 is supported by Norwegian Oil and Gas Association and Federation of Norwegian Industries, and is issued by Standards Norway.

Figure 3 illustrates that above all standards are the Norwegian laws, regulations and guidelines which are the overriding requirements to be followed. Petroleum activity in Norway is based on the "Regulations relating to Health, Environment and Safety in petroleum activities" (Framework Regulations) issued by PSA. PSA serve as regulator for technical and operational safety, emergency preparedness and the working environment in all phases in the petroleum industry. They are subordinate to the Ministry of Labor and Social affairs as figure 3 shows.

Regarding well integrity aspects the Facilities Regulations (relating to design and outfitting of facilities in the petroleum activities) and the Activity Regulations (relating to conducting petroleum activities) are the most important.

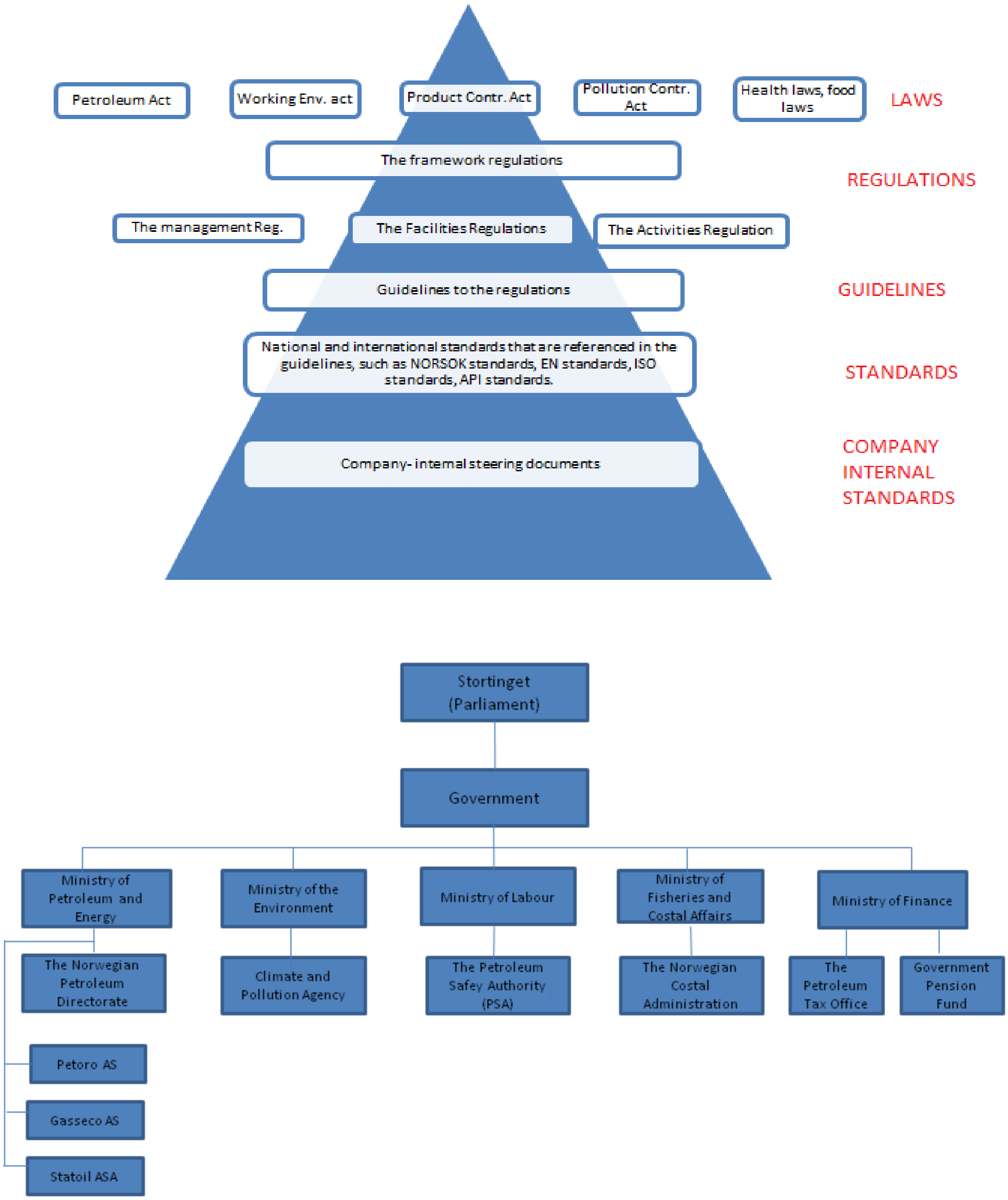


Figure 3: Laws, regulations and guidelines controlling the petroleum industry in Norway and the national organization of the petroleum sector in Norway.

For the operators on the NCS there is a requirement of having a system in place for managing the well integrity for the life cycle of all their wells. The intention with this system is to control and reduce the risk of incidents related to the wells. A well integrity management (WIM) system is a combination of technical, operational and organizational processes to assure a well's integrity ***(8)***. A description of elements required in a WIM system can be found in Norwegian Oil and Gas Recommended Guidelines 117 and is shown in figure 4. Whereas the Norwegian regulations refer to management systems in general, the specifics are left to each operator. The NOG Guidelines 117 provides some minimum criteria for WIM system based on a review of the Norwegian regulations and is intended as a supplementation to these.

Statoil follows the ARIS management system, which contains a complete set of technical requirements, guidelines and description of work processes developed for onshore and offshore facilities engineering, including the well integrity discipline. ARIS describes how well integrity for the entire life cycle of a well shall be managed; however, the focus in this thesis is well integrity in the operational phase of a well.

Figure 4: Elements in a WIM system (8).

2.3 Well Integrity fundamentals

Well integrity is defined in NORSOK D-010 as:" the application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids, throughout the life cycle of a well". The primary purpose of well integrity is to maintain full control of fluids at all times to prevent unintended flow.

2.3.1 Well barrier (WB)

A well barrier (WB) is the corner stone of managing well integrity, and is an envelope of one or several dependent well barrier elements (WBE). These physical elements do not prevent flow alone, but form a closed system in combination with others. This system shall prevent fluids from flowing unintentionally from the formation into the wellbore, another formation or to the external environment. The well barriers shall be defined before an activity or operation by identifying the required well barrier elements to be in place, their specific acceptance criteria and monitoring method ***(1)***. This is also impaired in Norwegian law, in the regulations relating to conducting petroleum activities governed by the PSA. The Activities Regulations § 85 – Well barriers says ***(9)***:

"During drilling and well activities, there shall be tested well barriers with sufficient independence. If a barrier fails, activities shall not be carried out in the well other than those intended to restore the barrier. When handing over wells, the barrier status shall be tested, verified and documented"

Similar is found in The Facilities Regulations § 48 – Well barriers ***(10)***:

"*Well barriers shall be designed such that well integrity is ensured and the barrier functions are safeguarded during the well's lifetime. Well barriers shall be designed such that unintended well influx and outflow to the external environment is prevented, and such that they do not hinder well activities. When a well is temporarily or permanently abandoned, the barriers shall be designed such that they take into account well integrity for the longest period of time the well is expected to be abandoned. When plugging wells, it shall be possible to cut the casings without harming the surroundings. The well barriers shall be designed such that their performance can be verified".*

Primary well barrier is closest to the pressurized reservoir, and is the first envelope that prevents flow from a source. Secondary well barrier is the second envelope that prevents flow from a source if the primary fails. A simple sketch illustrating the barrier principle is shown in figure 5. The main rule states that two independent barrier envelopes against uncontrolled blowout from reservoirs shall at all times be in place if there are hydrocarbon - bearing over pressured formations ***(11)***. Two defined barriers shall to the extent possible be independent of each other without common barrier elements ***(12)***. Wells with no source of inflow / reservoir shall as a minimum have one mechanical well barrier ***(1)***.

The well barriers shall be designed, selected and constructed with capability to ***(1)***:

- Withstand the maximum differential pressure and temperature it may become exposed to (taking into account depletion or injection regimes in adjacent wells).
- Be pressure tested, function tested or verified by other methods.
- Ensure that no single failure of a well barrier or WBE can lead to uncontrolled flow of wellbore fluids or gases to the external environment.
- Re - establish a lost well barrier or establish another alternative well barrier.
- Operate competently and withstand the environment for which it may be exposed to over time.
- Determine the physical position / location and integrity status at all times when such monitoring is possible.
- Be independent of each other and avoid having common WBEs to the extent possible.

An addition to the dual barrier principle seen in figure 5 is the requirement of a double block when the barrier element is in contact with the external environment. Valves in contact with the external (e.g. x - mas tree and annulus access valves) need to be in series of two preventing hydrocarbons from escaping the well.

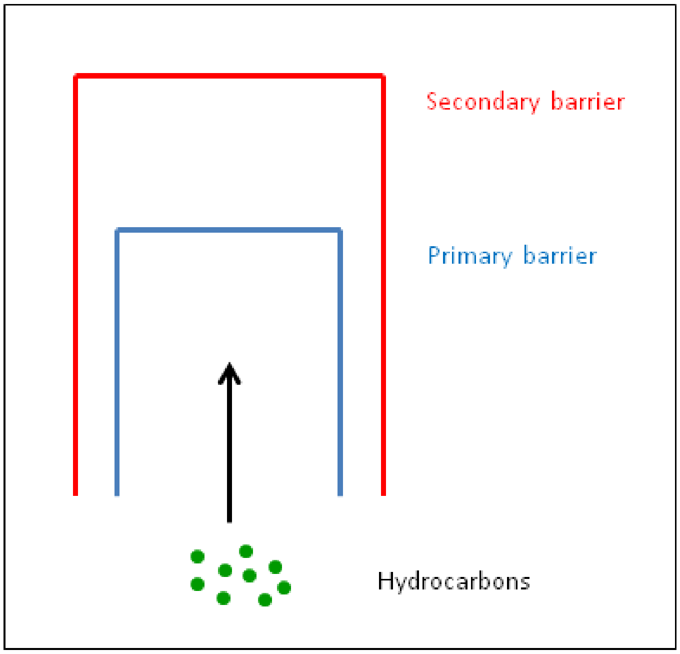


Figure 5: Dual barrier principle.

2.3.2 Well barrier element (WBE)

For a well barrier element to be considered operational, it should be verified and maintained through regular testing and maintenance. The location and integrity status of each well barrier element should be known at all times ***(11)***.

For a well in operation, the primary well barrier envelope typically constitutes the following well barrier elements ***(4)***:

- Cap rock above reservoir.
- Casing cement.
- Casing.
- Production packer.
- Tubing.
- SCSSV.

The secondary well barrier typically constitutes the following well barrier elements ***(4)***:

- Formation above production packer.
- Casing cement.

- Casing with hanger and seal assembly.
- Wellhead with valves.
- Tubing hanger with seals.
- Annulus access valve / line.
- X - mas tree with valves and x - mas tree connection.

The main WBEs for the operational phase are further described (function and failure mode) in appendix A.

2.3.3 Well barrier schematic (WBS)

A well barrier schematic (WBS) is a static illustration of the well and its main barrier elements, where the primary and secondary well barrier elements are marked with different colors. One of the PSA findings from the spring 2006 well integrity audit was the requirement for the creation of WBS for the operational phase of each individual well on the NCS. Each operating company worked to fulfil this requirement, and used the WBS presented in NORSOK D-010 as a basis.

There shall be a well specific WBS for any planned drilling or well operation, for each operational phase and where there is a change to barrier envelope. The WBS shall describe planned position and method of verification for each well barrier element, since the actual position and status of the barrier / barrier element shall be known at all times. Any deviations or changes to the status shall be reflected in an updated schematic ***(12)***.

NORSOK D-010 describes when a new WBS should be made:

- When a new well component is acting as a WBE.
- For illustration of the completed well with x –mas tree.
- For recompletion or workover on wells.
- For final status of permanently abandoned wells.

NORSOK D-010 also describes what information the WBS should contain:

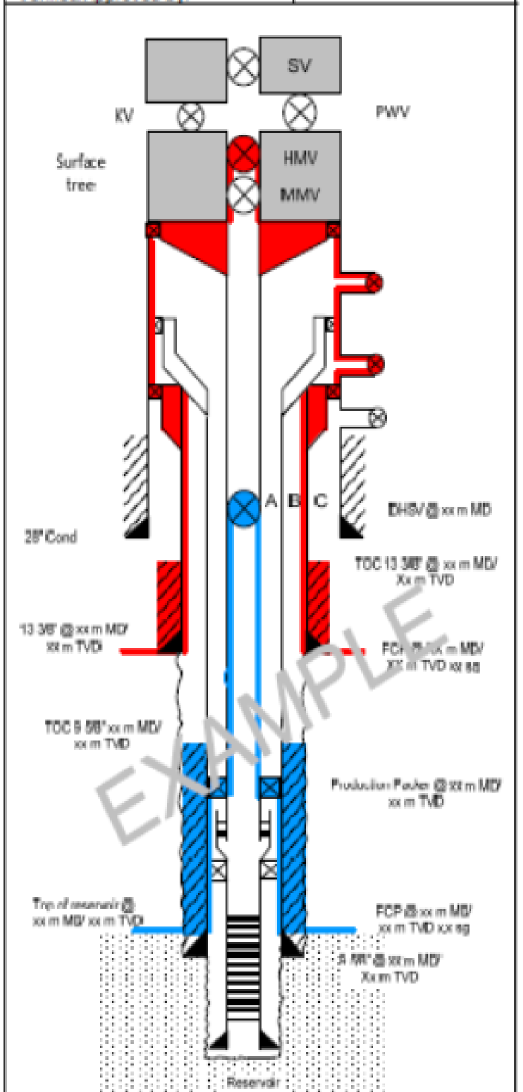
- A drawing illustrating the well barriers, with the primary well barrier shown with blue color and secondary well barrier shown with red color.

- The formation integrity when the formation is part of a well barrier.
- Reservoirs and potential sources of inflow.
- Tabulated listing of WBEs with initial verification and monitoring requirements.
- All casings and cement. Casing and cement (including TOC) defined as WBEs should be labelled with its size and depth (TVD and MD).
- Well information: field / installation, well name, well type, well status, well / section design pressure.
- Revision number and date, “Prepared by”, “Verified / Approved by”.
- Clear labelling of actual well barrier status – planned or as built.
- Any failed or impaired WBE to be clearly stated.
- A note field for important well integrity information (anomalies, exemptions, etc.).

Well barrier schematics shall contain tables showing the WBEs that are found as primary or secondary barriers. A typical production well WBS from NORSOK D-010 with indicated WBEs and envelopes is illustrated in figure 6. The blue line indicates the primary barrier and includes cap rock, casing cement, casing, production packer, completion string and the SSCSV. The red line envelope indicates the secondary barrier and includes the formation at the intermediate casing, casing cement, casing, wellhead, annulus valves, tubing hanger and production tree with connectors and valves.

Through this kind of illustration it is possible to verify the status of the barriers and identify issues. Future operation of the well is greatly dependent on these assessments and control and monitoring may be planned based on the schematics. Therefore it is very important that the WBSs are updated and quality checked at all times, especially during handovers.

Well information (as built)	
Field/Installation:	
Well name:	
Well type:	Producer
Well status:	Shut-in
Well design pressure:	xx bar
Revision number:	Version 1.0
Date prepared/revised:	
Prepared by: Verified/Approved by:	



Note 1: Well shut-in due to tubing leak above DHSV.

Nomenclature:
PT: Pressure test
IT: Inflow test
FCP: fracture closure pressure
XLOT: extended leak off test
AC: acceptance criteria

Well barrier elements	EAC table	Verification / Monitoring
Primary well barrier		
In-situ formation (cap rock)	51	FCP: x.x s.g. Based on field model
		n/a after initial verification
Casing cement (9 5/8")	22	Length: xx mMD Cement bond logs
		Daily pressure monitoring of B-annulus
Casing (9 5/8")	2	PT: xx bar with x s.g. EMW
		n/a after initial verification
Production packer	7	PT: xx bar with x s.g. EMW
		Continuous pressure monitoring of A-annulus
Completion string	25	PT: xx bar with x s.g. EMW
		Continuous pressure monitoring of A-annulus See Note 1.
Completion string component (Chemical injection valve)	29	PT: xx bar with x s.g. EMW
		Periodic leak testing AC DHSV: xx bar/xx min
Downhole safety valve (incl. control line)	8	IT: xx bar (DHSV) PT: xx bar (control line)
		Periodic leak testing AC DHSV: xx bar/xx min
Secondary well barrier		
In-situ formation (13 3/8" shoe)	51	FCP: x.x s.g. Based on XLOT
		n/a after initial verification
Casing cement (13 3/8")	22	Length: xx mMD Method: Volume control
		Daily pressure monitoring of C-annulus
Casing (13 3/8")	2	PT: xx bar with x s.g. EMW
		Daily pressure monitoring of C-annulus
Wellhead (Casing hanger with seal assembly)	5	PT: xx bar
		Daily pressure monitoring of C-annulus/ Periodic leak testing
Wellhead / annulus access valves	12	PT: xx bar
		Periodic leak testing of valve AC: xx bar/xx min.
Tubing hanger (body seals and neck seal)	10	PT: xx bar
		Periodic leak testing
Wellhead (WH/XT Connector)	5	PT: xx bar
		Periodic leak testing
Surface tree	33	PT: xx bar
		Periodic leak testing of valves AC: xx bar/xx min

Figure 6: WBS for a typical production well (1).

2.3.4 Well barrier element acceptance criteria

Well barrier element acceptance criteria are technical and operational requirements and guidelines that need to be fulfilled in order to qualify the WBE for its intended use. These criteria could be leak rates, time to valve closure, fail - safe specification; etc**.** ***(4)***.Well barrier element criteria shall be in place for all WBEs used, and NORSOK D-010 has collated them in an element acceptance criteria - table (EAC - table). This table contains the minimum standards to be fulfilled, and does not replace the technical and functional requirements that the operating company specify for the equipment. Table 1 shows an example of a general EAC - table, and section 15 in NOROSK D-010 describes the criteria for each WBEs used throughout the lifecycle of a well. Appendix B in this thesis contains an excerpt from this, showing the most common WBEs during the operational phase.

Table 1: General EAC – table (1).

Features	Acceptance criteria	See
A. Description	This is a description of the WBE	
B. Function	This describes the main function of the WBE	
C. Design (capacity, rating, and function), construction and selection	For WBEs that are constructed in the field (e.g. drilling fluid, cement), this should describe a) design criteria, such as maximal load conditions that the WBE shall withstand and other functional requirements for the period that the WBE will be used, b) construction requirements for the WBE or its sub-components, and will in most cases consist of references to normative standards. For WBEs that are pre-manufactured (production packer, DHSV), the focus should be on selection parameters for choosing the right equipment and proper field installation	Name of specific references
D. Initial test and verification	This describes the methodology for verifying the WBE being ready for use and being accepted as part of a well barrier	
E. Use	This describes proper use of the WBE in order for it to maintain its function during execution of activities and operations	
F. Monitoring (regular surveillance, testing and verification)	This describes the methods for verifying that the WBE continues to be intact and fulfils the design criteria	
G. Common WBE	This describes additional criteria to the above when this element is a common WBE	

In general the acceptance criteria for leaks through seals that are defined as barrier elements are zero (unless specified otherwise in the EAC) to have a qualified WBE. However, in reality it would be impossible to maintain a zero rate of leakage under all circumstances and as time goes by. Acceptable leak rates shall satisfy at least all the following acceptance criteria ***(4)***:

- Leak across a valve, leak contained within the envelope or flow path: requirements in ISO 10417 need to be fulfilled ***(13)***.
- Leak across a barrier envelope, conduit to conduit: not permitted unless the receiving conduit is able to withstand the potential newly imposed load and fluid composition.
- No leak rate from conduit to conduit exceeding the leak rate specified in ISO 10417 / API RP 14B ***{ (13), (14)}.***
- No unplanned or uncontrolled leak of hydrocarbons to the surface or subsurface environments.

API RP 14B (bullet point 3) states acceptance criteria for leakage rate through a closed subsurface safety valve system ***(14)***:

- 0.4 liters / min for liquid.
- 0.42 m^3 / min for gas.

Statoil uses the API RP 14B criteria for all their WBEs. Leakage rates below these criteria have been assessed to have acceptable and manageable consequences. However, a leak directly to the external environment (seabed, surface) is not acceptable, and there is a zero rate requirement.

From a leakage rate perspective a WBE can be failed, degraded or intact. The term failed is used when the WBE is leaking above the acceptance criteria, degraded when there is a leak below the acceptance criteria and intact when there is no leak through the barrier element.

2.3.5 Well barrier element testing

There are different tests to verify and monitor the WBEs, and these are described in the bullet points in this section ***(4)***:

- **Verification testing** is a check whether a component meets its acceptance criteria, and includes (but is not limited to) function testing and leak testing.
- **Function testing** is a check to whether or not a component or system is operating correctly. For example, the function test of a valve indicates that the valve opens and closes correctly. It does not provide information about possible leaking of the valve.

- **Leak testing** is the application of differential pressure to assure the integrity of the sealing system of the component. This can either be done by pressure or inflow testing.
- **Pressure testing** is the application of a pressure from an external source (non-reservoir pressure) to assure the mechanical and sealing integrity of the component.
- **Inflow testing** uses the tubing or casing pressure to perform leak testing of for example a valve. The valve that is tested is closed, the pressure downstream of the valve is reduced to create a pressure differential across the valve, and the volume downstream is monitored for a pressure increase that indicates a leak.

2.3.6 Verifying well barriers

Initial verification involves verifying the different WBEs being ready for use and accepted as a part of the well barrier.

Initial verification of a well barrier shall be performed directly after it has been constructed or installed, and the function and integrity shall be verified by means of ***(12)***:

- Leak testing by application of differential pressure.
- Function testing of WBEs that require activation.
- Verification by other specified methods.

Re - verification of a well barrier shall be performed when ***(12)***:

- The condition of the barrier could have been changed since the initial / previous testing.
- There is a change in worst case loads / well design pressure (WDP) for the remaining life cycle of the wells.

WDP is the highest pressure expected at surface / wellhead and shall be established based on reservoir pressure minus the hydrostatic pressure of gas plus kill margin, or maximum injection pressure for injection wells ***(1)***.

2.3.7 Monitoring well barriers

Well barrier integrity during the production life of the well is monitored by registration of annulus pressure and frequent leak testing of WBEs.

NORSOK D-010 specifies the following requirements:

- Downhole safety valves, production tree valves and annulus valves shall be regularly leak tested. Leak test acceptance criteria shall be established and available.
- The pressure in all accessible annuli shall be monitored.
- Registered anomalies shall be investigated to determine the source of anomaly and if relevant, quantify any leak rate across the well barrier.
- Upon confirmation of loss of the defined well barrier, the production or injection shall be suspended and shall not re - commence before the well barrier or an alternative well barrier is re - established.

NORSOK D-010 states that pressures in all accessible annuli shall be monitored and maintained within minimum and maximum operational pressure range limits. Well parameters such as temperatures and rates shall also be monitored to give a correct picture of pressure trends and identification of abnormal pressure behavior. Any change of annulus pressure, increase or decrease, can be indicative of an integrity issue. The well operating pressure limits should be based on the specifications of the components that make up the well. Any changes in well configuration, condition, life cycle phase or status requires the well operating limits to be checked and potentially updated.

The maximum allowable annulus surface pressure (MAASP) is the greatest pressure that an annulus is permitted to contain, as measured at the wellhead, without compromising the integrity of any barrier element or exposed formation. MAASP shall be determined for each annulus of the well, and the calculations documented ***(4)***.

There are three types of annular pressure that can occur during the well's life cycle ***(8)***:

- **Imposed annulus pressure:** pressure applied to an annulus by operator as part of the well operating requirements; typically this can be gas lift in the A - annulus.
- **Thermally induced annulus pressure**: pressure created by thermal changes occurring within the well.
- **Sustained annulus pressure (SCP):** pressure in any well annulus that is measurable at the wellhead and rebuilds when bled down, not caused solely by

temperature fluctuations or imposed by the operator. SCP can arise for a variety of causes, including degradation or failure of well barriers.

A bleed - down / build - up test performed on the annulus is one method to confirm the nature of the pressure source, and the well operator should establish a procedure for conducting these tests ***(11)***. When the temperature and flow rates are stable, the annuli pressures should also be stable. Abnormal pressure changes (SCP) may indicate a failure in the barrier envelope, such as a leakage.

2.4 Loss of Well integrity

2.4.1 Major accidents on the NCS

The Bravo oil and natural gas blowout in 1977, West Vanguard shallow gas blowout in 1985 and the Snorre A gas blowout in 2004 seen in figure 7 are some examples on major accidents on the NCS. These are the main drivers for the current focus on well integrity in the industry.

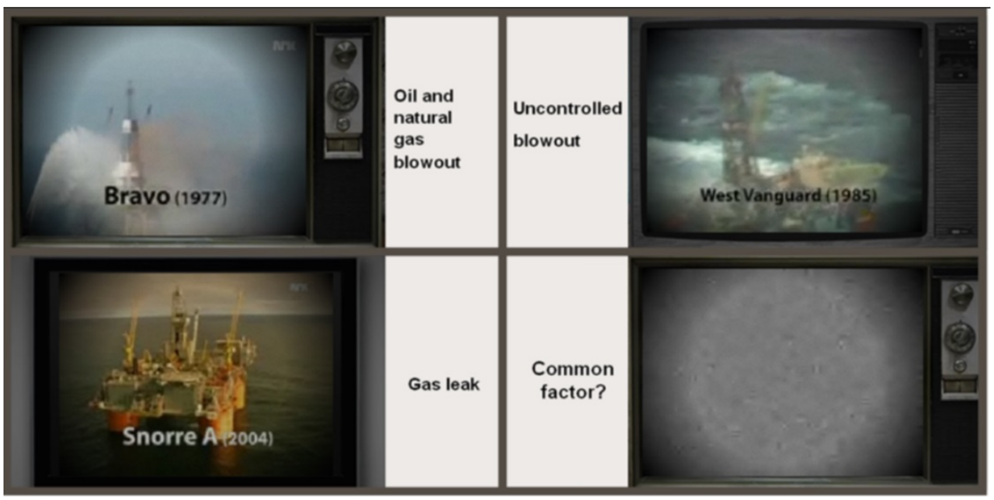


Figure 7: Major accidents on the NCS.

2.4.1.1 Bravo blowout in 1977

On April 22, 1977, well B-14 on the Bravo production platform in the Ekofisk field experienced an oil and natural gas blowout during workover. It resulted in the worst oil spill in Norwegian history, and seven days passed before the well was killed. An amount of 202 380 barrels of oil escaped in an estimated rate of 1170 barrels per hour. Fortunately, none of the 112 crew members were injured ***(15)***.

2.4.1.2 West Vanguard blowout in 1985

A shallow gas blowout occurred on 6 October 1985 while the rig was drilling an exploration well on the Halten Bank in the Norwegian Sea. The gas flowed up the topside and ignited causing an explosion which killed one person and caused great material damage. Afterwards the industry implemented a number of measures to reduce the risk of shallow gas blowouts. One of the main measures was to drill a pilot borehole in order to maintain better control when encountering shallow gas pockets ***(16)***.

2.4.1.3 Snorre A blowout in 2004

On 28 November, 2004, an uncontrolled situation occurred during preparation for drilling a sidetrack in well P-31A on the Snorre A facility. The situation developed into an uncontrolled gas blowout on the seabed, resulting in gas under the facility. The PSA characterized this incident as one of the most serious to occur on the NCS. This is due to the potential of the incident, as well as comprehensive failure of the barriers in planning, implementation and follow - up of the work on well P-31A. Only chance prevented a major accident with the danger of loss of many lives, damage to the environment and loss of material assets. Under slightly different circumstances the incident could have resulted in ignition of the gas as well as buoyancy and stability problems. Surveys on the seabed after the incident revealed several large craters near the well template and near the fastening anchors for the Snorre A platform ***{ (17), (2)}.***

2.4.2 What are the major accident risks during the operational phase of the well?

The common factors from the accidents mentioned above were integrity issues resulting in barrier failure and hence a blowout. However, none of them occurred during the operational (production) phase of the well, but when the D&W organization had the operating responsibility. Some may ask why there needs to be such a focus on blowout risk during production, as blowouts have never occurred during the operational phase of the wells on the NCS.

Although the probability of an uncontrolled blowout during production is very low, the potential consequences of such an event would be catastrophic. Blowouts in the operational phase outside Norway illustrate that it is not an unimaginable event. The wells on Bravo and Snorre A had both been in production before they were handed back to D&W for a well operation, and the barrier status could have been changed before the handover. This would have given a better description of the risks before any work was started in the well, and the situation potentially avoided. The handover between the organizations is therefore a critical part. In case the barrier status has changed, the handover documentation must be updated to reflect the status and associated risk making the new owner aware of the changes.

Because of the possibility of extended profitable production beyond the assumed design life of wells (due to high oil prices, increased recovery and governmental incentives) well integrity in the operational phase is of major importance. Life extension may result in more frequent failures involving leakages to the surroundings which can have huge consequences.

There can be two types of leakages in the well during production, explained by dividing them into “internal” and “external”. Leakages through SCSSV or x- mas tree valves are categorized as “internal” and there is a bleed off possibility via flowline to a closed production system. There are in addition several valves (not considered to be a part of the WBEs) after the PWV which can be used to shut in the well if there is a leak into the flowline system. “External” leakages are leakages outwards in the well through tubing, casing, cement, formation or x- mas tree / wellhead, and are considered the worst. This is due to potential of getting uncontrolled flow of hydrocarbons to seabed or in worst case scenario - all the way up to the platform. Compared to the “internal”, “external” leakages will be much more challenging to repair involving time consuming and costly interventions / workovers. Possible leak paths to the surroundings are shown in figure 8 where four scenarios are illustrated:

1. Internal leakage due to failure of SCSSV and x-mas tree valves. Bleed off possibilities via flowline to closed systems.
2. External leakage into overlying formation – a buffer zone. The leakage is trapped in the formation, and will not cause any further fracturing.
3. External leakage into the overlying formation. The formation cannot take the increased pressure, and the leak will cause fracturing all the way up to seabed.

4. External leakage through x-mas tree / wellhead resulting in hydrocarbons reaching surface (platform wells) or seabed (subsea wells).

The two last scenarios are considered worst as you get a release of hydrocarbons to sea / installation.

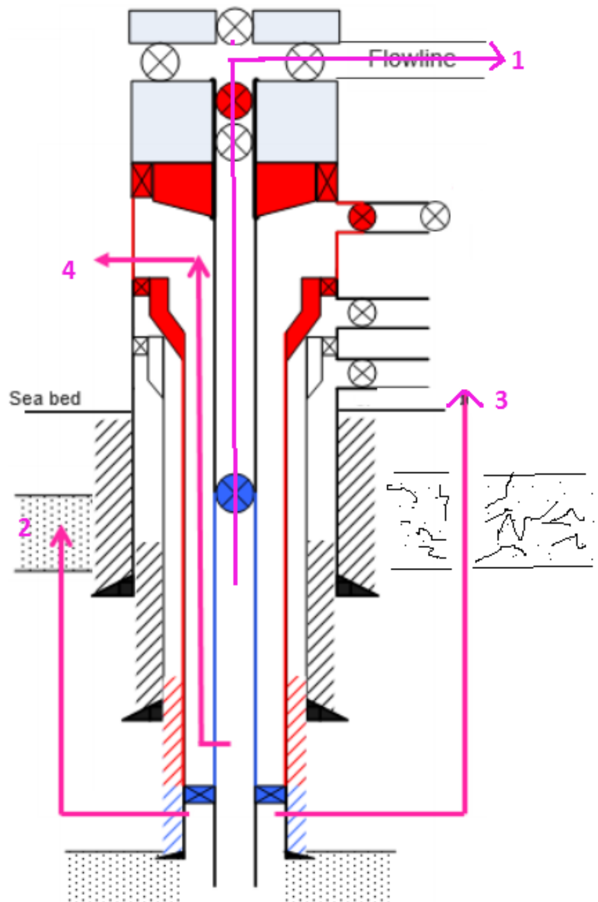


Figure 8: Possible leak paths.

Potential consequences of uncontrolled flow of hydrocarbons to sea or installation are:

- Blowout / well release.
- Fire / explosion.
- Washout of foundation.
- Stability and buoyancy problems.

A blowout is an incident where formation fluid flows uncontrollably out of the well due to the failure of well barriers or the activation of the same has failed. A well release is an incident where oil or gas flows from the well from some point where flow was not intended, and stopped by use of the barrier system that was available in the well at the time the incident started. It is not a continuous flow like a blowout, but the hydrocarbons are released in one portion. During a blowout / well release the formation at seabed can be washed out potentially causing stability problems for the platform or damage on other structures at seabed. There will also be a major risk of a fire / explosion if a certain amount or concentration of gas reaches the installation. A major gas release may also cause stability and buoyancy problems for floating production units.

2.4.3 Well integrity issues

Well integrity can easily be defined as a condition of a well in operation that has full functionality and two qualified well barrier envelopes. Any deviation from this state is a minor or major integrity issue. Common issues are often related to leaks in tubular or valves, but can also be related to reservoir issues as loss of zonal control ***(18)***. Typical failure modes are shown in figure 9. If a well barrier has failed the only action that that can take place in a well is to restore the failed barrier. This is impaired in the Activities Regulations § 85. In some cases the well barrier can be redefined and production continued. If redefinition of the barrier envelope is not possible, the well has to be shut in to avoid further escalation and damage. Shutting in a well means to close one or several valves in the well stopping further production / injection. In some special cases shutting in a well because of an integrity issue can do more harm than continued production / injection. This is due to the high pressure that can build up in the well from the reservoir.

Loss of well integrity is either caused by mechanical, hydraulic or electrical failure related to the well components, or by wrongful application of a device. The corrective actions are often costly and risky, and losses due to production / injection - stop may be very high ***(18)***. Any factor that leads to a functional failure is a loss of well integrity. The challenge is to define all possible scenarios and this is where the crucial part of risk assessment comes into play. For successful delivery of well integrity there needs to be an understanding of the risks that can cause undesirable events. Performing a risk assessment on a well will help determine and rank the potential risks, and increase the understanding of the potential negative consequences that may result from specific problems a well may have or develop. The operators can use this information to reduce risk in the operational phase and minimize potential well integrity issues. This will be the topic in the next chapters.

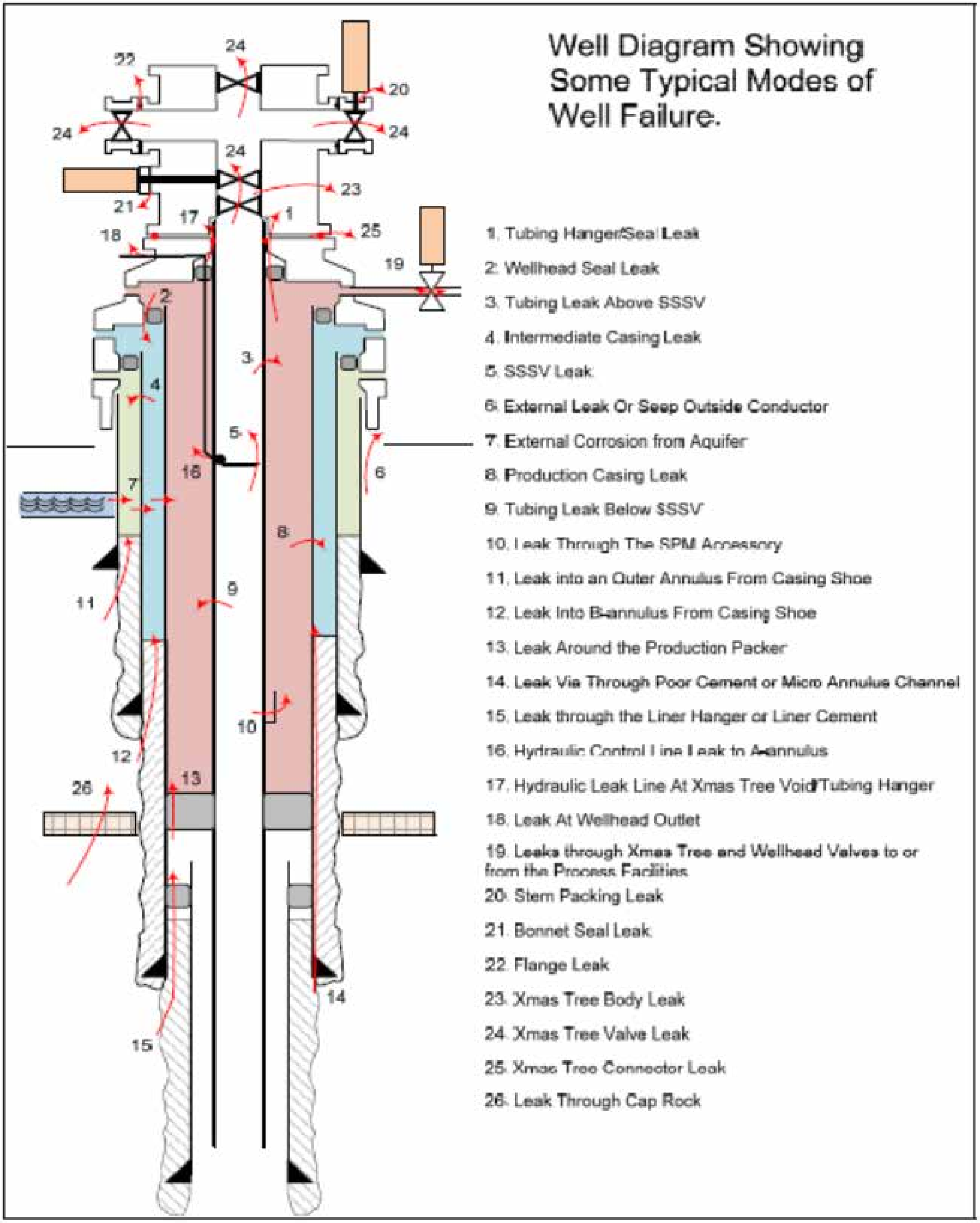


Figure 9: Typical modes of well failure (4).

2.5 Risk fundamentals

The most common way to see risk is as the opposite of safety, and it can be defined as the combination of consequences of an event and the associated likelihood of occurrence of the event. Risk management includes all measures and activities carried out to manage risk, and it deals with balancing the conflicts inherent in exploring opportunities on the one hand, and avoiding losses, accidents and disasters on the other ***(19)***. In the safety field however, it is generally recognized that consequences are only negative and therefore the management of risk is focused on prevention and mitigation of harm. ISO 31000 defines risk as "effect of uncertainty on objectives". This uncertainty is associated with the event (which may or may not happen) and the outcomes of the event ***(20)***. Since risk relates to future happenings there will always be a lack of knowledge ruling. In well integrity, the most serious event potentially caused by well component failures is obviously a leak of hydrocarbons to surface, and the consequences can be huge.

Risk can be related to losses compromising:

- Safety.
- Environmental damage.
- Asset damage.
- Negative public image.

Well barriers are used to prevent leakages to surface and hence reduce the risk of blowouts and well releases. The main objectives of a well barrier are to:

- Prevent any major hydrocarbon leakage from the well to the external environment during normal production / injection.
- Shut in the well on direct command during an emergency shutdown situation and thereby prevent hydrocarbons from flowing from the well.

2.5.1 Risk assessment

NORSOK D-010 states that if a well barrier is degraded, a risk assessment should be performed and the following considered ***(1)***:

- Cause of degradation.
- Potential of escalation.
- Reliability and failure modes of primary WBEs.
- Availability and reliability of secondary WBEs.
- Outline plan to restore or replace degraded well barriers.

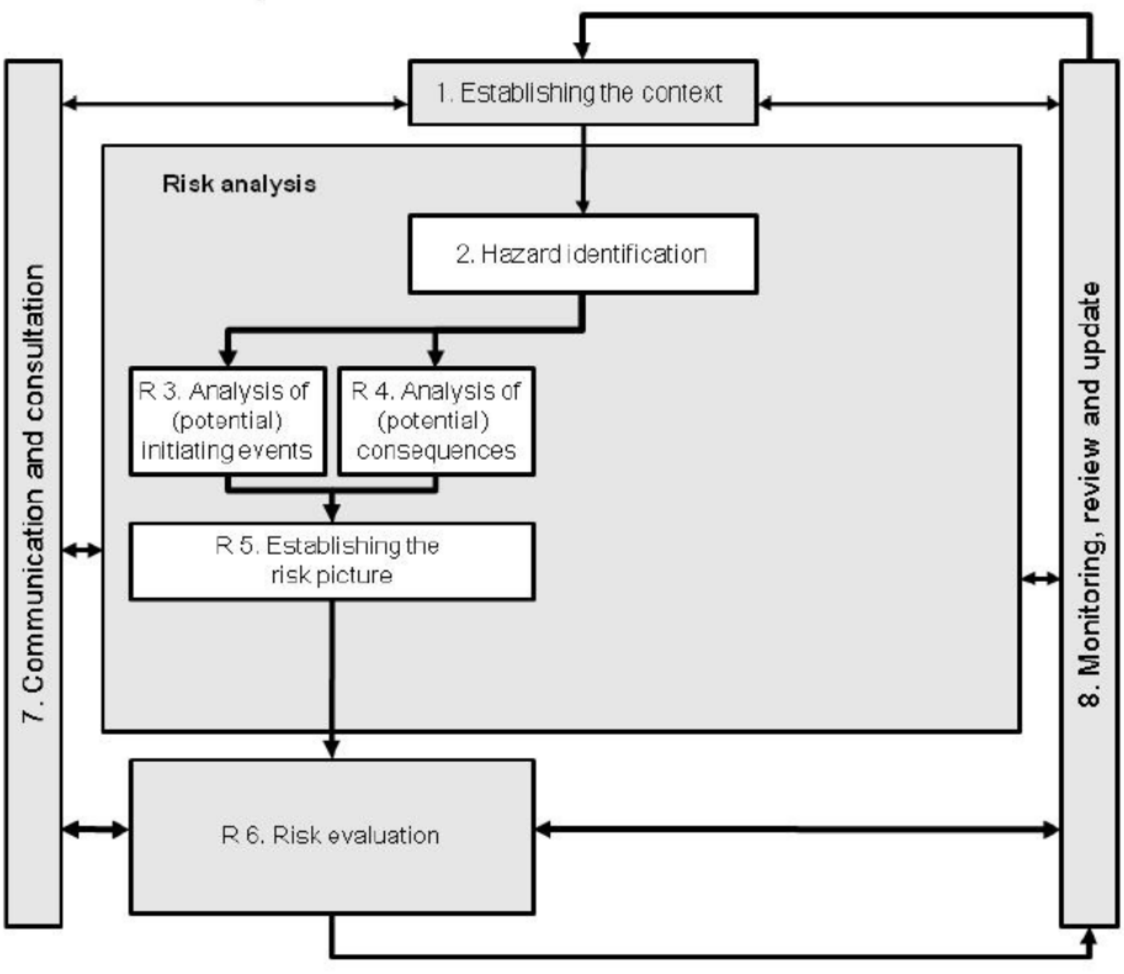


Figure 10: The risk assessment process (21).

Risk assessment provides a basis for decisions about the most appropriate approach to be used when treating risks and prioritize them. It is the overall process of risk analysis and risk evaluation, and is illustrated in figure 10 ***(21)***.

Risk analysis is about developing an understanding of the risks, and shall identify potential hazards and hazardous events. A hazard is a potential source of harm, like for example a well component failure. A hazardous event occurs when the hazard's potential to cause harm is realized, for example a leak of hydrocarbons to surface ***(22)***. The main objective of risk analysis is to identify the hazardous events, and find the causes (hazards) and potential consequences of these events. Based on the outcome from the analysis a risk evaluation about which risks need treatment and the priority for treatment implementation is made. This is the other crucial part of the risk assessment process. NS 5814 defines risk evaluation as: "A comparison of the results of a risk analysis with the acceptance criteria for risk and other decision criteria". Further NS 5814 defines acceptance criteria as: "Criteria based on regulations, standards, experience and knowledge used as a basis for decisions about acceptable risk" ***(23)***. In the operational phase of a well the risk analysis should illustrate the changes in risk resulting from an integrity issue, and the evaluation should conclude whether this change is acceptable or not.

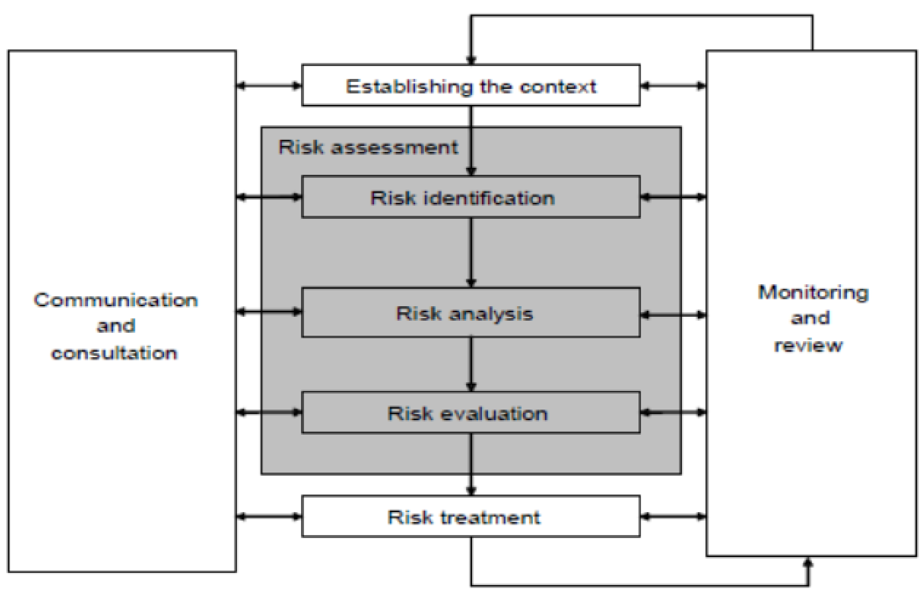


Figure 11: Risk assessment is an input to the decision making process of the organization (24).

As seen from figure 11 the output from the risk assessment is an input to the decision - making process of the organization, and helps the responsible parties on how to treat the risks. Risk treatment involves selecting and agreeing on relevant options for changing the probability of the event, the consequences of the event, or both, and implementing these options. Thus, based on the risk picture, different measures are introduced to change the risk ***(24)***.

Different types of techniques are used to assess the magnitude of a well integrity issue, but in general a standard risk assessment typically involves ***(4)***:

- Identification of hazards.
- Identification of hazardous events.
- Cause analysis of the event.
- Determination of potential consequences.
- Determination of the probability of the event occurring.
- Determination of the magnitude of the risk based on the combined effect of consequences and probability of occurrence.

The assessment of any well failure related event is normally done by constructing a risk assessment matrix. Here the magnitude of the risk can be categorized or ranked based on the combined effects of consequences and likelihood of occurrence.

Failure modes, effects and criticality analysis (FMECA) can also be used to determine well integrity risk. It is particularly useful in establishing the types of component failures that can occur, the effect on the well barrier envelope(s) and the likelihood of such failures occurring. Detailed risk assessment methods and techniques can be found in ISO 17776, ISO 31000 and ISO 31010. The two mentioned above plus a more comprehensive analysis for system reliability will be discussed in more detail in the next section.

2.5.2 Risk assessment techniques for well integrity

For analyzing well integrity issues, a qualitative risk assessment approach is best suited, as it makes the process significantly easier. Operating companies typically do not record or maintain accurate records of the number of and types of actual well component failures that have occurred over time. Also the sharing of such data within the industry is generally lacking, thus makes it hard to produce a numerical value (quantitative value) of risk level. However, using a qualitative approach relies heavily on the experience and knowledge of the participants, and is therefore subjective in nature. To deliver a thorough and consistent qualitative assessment, it is important to have participation from experienced and knowledgeable team members from a variety of disciplines and backgrounds. In this section some examples on qualitative risk assessment techniques for well integrity will be described.

2.5.2.1 Risk matrix

A risk matrix is made by combining the probability and consequence of an event to produce a level of risk in the means of risk rating. In the well integrity aspect a matrix can be used to decide whether the integrity issue poses an acceptable level of risk or not. It is relatively easy to use, and provides a rapid ranking of risks into different significance levels. The format of the matrix and the definitions applied to it depend on the context it is used in, and it is suited to evaluate risks related to single activities, tasks or scenarios. It is commonly used as a screening tool when many risks have been identified, to define which need further and more detailed analysis, treatment first or a higher level of management. It also helps communicate a common understanding for qualitative level of risks across the organization ***(24)***.

The consequence scale should cover the range of different types of consequences to be considered, for example relating safety, financial loss, environment, reputation or other parameters depending on the context. Definitions of probability need to be selected to be as unambiguous as possible, and the scale should be constructed in the way that the lowest probability must be acceptable for the highest defined consequence ***(24)***.

Figure 12 shows an example of a matrix with consequence (impact) on one axis and probability (likelihood) on the other. The risk levels assigned to the cells will depend on the definitions for the probability / consequence scales. The matrix is usually separated into three regions as follows ***(21)***:

- High risk (red): Not acceptable. Risk reduction, high management attention or more detailed assessment is necessary.
- Medium risk (yellow): Risk reduction based on the ALARP principle.
- Low risk (green): Broadly acceptable risk.

ALARP expresses that the risk shall be reduced to a level that is as low as reasonably practicable. The term reasonably practicable implies that the risk reducing measures shall be implemented until the cost (in a wide sense, including time, capital cost or other resources / assets) of further risk reduction is grossly disproportional to the potential risk reducing effect achieved by implementing any additional measures ***{ (21), (19)}.***

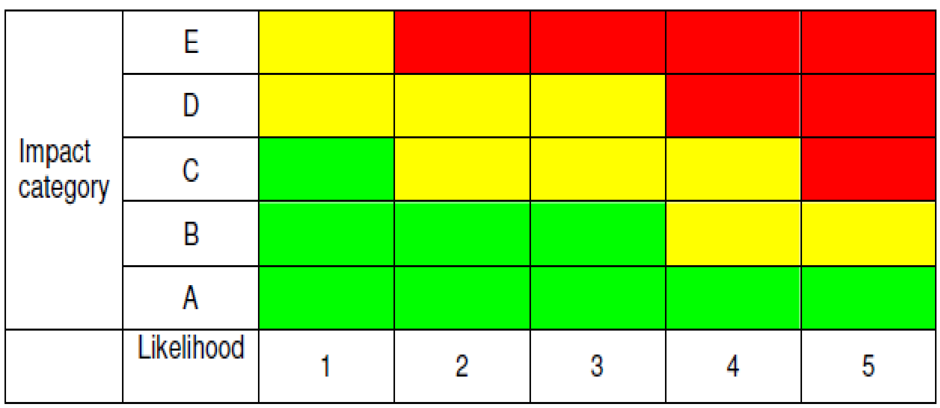


Figure 12: Standard risk matrix (21).

2.5.2.2 Failure modes, effects and criticality analysis (FMECA)

The main method for failure identification is the failure modes, effects and criticality analysis (FMECA). This is a simple method to reveal possible failures and to predict the effects on a system as a whole. Figure 13 shows a system made up of several components / elements. The analysis is carried out by asking questions for each component ***(19)***:

- What is the function?
- Failure modes?
- Effect on the system?

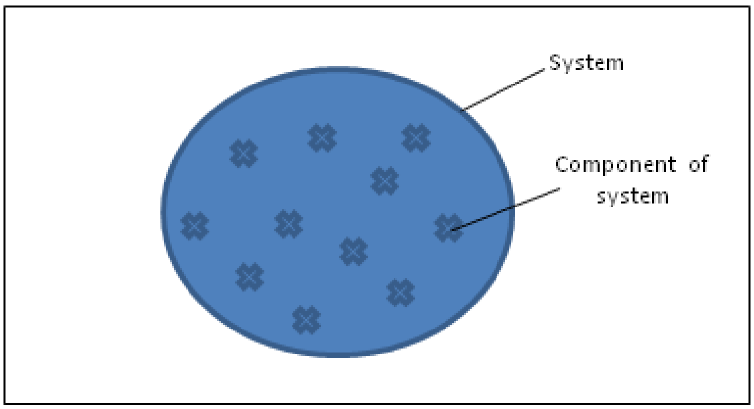


Figure 13: System with several elements.

In a well integrity context, failure modes of the well barrier elements and how these affect the barrier envelopes is described in a FMECA.

The primary output from the analysis is a list of failure modes, the failure mechanisms (cause) and effect on the system as a whole. It should also include a rating of importance based on the likelihood that the system will fail, and the level of risk resulting from the failure mode. Failure modes for a valve as an example may be fail to close, fail to open or leakage in closed position. Failure mechanisms describe the causes and may be physical (e.g. corrosion, erosion, fatigue) or human errors. The effect on the barrier envelope may be classified as safe or dangerous ***(18)***. A FMECA worksheet is shown in table 2.

Table 2: FMECA worksheet (18).

Description of item			Description of failure			Effect of failure					
Ref. no	Function	Operational mode	Failure mode	Failure cause or mechanism	Detection of failure	One the subsystem	On the overall system	Failure rate	Severity ranking	Risk reducing measure	Comments

A weakness of the FMECA is that it may have too much technical focus, whereas human failures are often overlooked. It is also unsuitable for analyzing systems with much redundancy, as it only looks in to single failure modes and not combination of component failure. FMECA gives a systematic overview of failures in the system, and is a good basis for more comprehensive assessment such as a fault tree analysis. It detects the weaknesses of the system as a result of individual component failure ***{ (24), (19)}.***

2.5.2.3 Fault tree analysis (FTA)

A fault tree analysis (FTA) is as mentioned a more comprehensive assessment used to analyze system reliability, and the main purpose is to explain why a system failure can occur. In a well integrity context, the system failure may be "Leakage to environment", and is called the TOP event of the fault tree. The causes of the TOP event are identified and combined by logic gates. Fault tree construction is a deductive approach, as it iteratively asks what type of events (component failures) that may result in the system failure. A fault tree compromises ***(18)***:

- **The TOP event***:* This is a precise description of the system failure, and should describe what the system failure is (for example leakage to surface), where the failure occurs or is observed (for example the wellhead) and when the failure may occur (for example in the operational situation). The TOP event may be described as "Leakage to environment through the wellhead during normal production".
- **OR and AND gates**: A fault tree applies two main types of logical gates, OR and AND gates. When using an OR gate the output event occurs when one or more of

the basic (input) events occur. When using an AND gate the output event occurs when all the basic (input) events occur at the same time.

- **Basic events:** Represent the lowest level of events (component failures, external events) that may initiate the development of a system failure. The events in a fault tree are described in rectangles, and for basic events, a circle is drawn beneath the rectangle. A triangle is used when the event needs further development on a different page / tree.

  The different elements can be seen in figure 14.

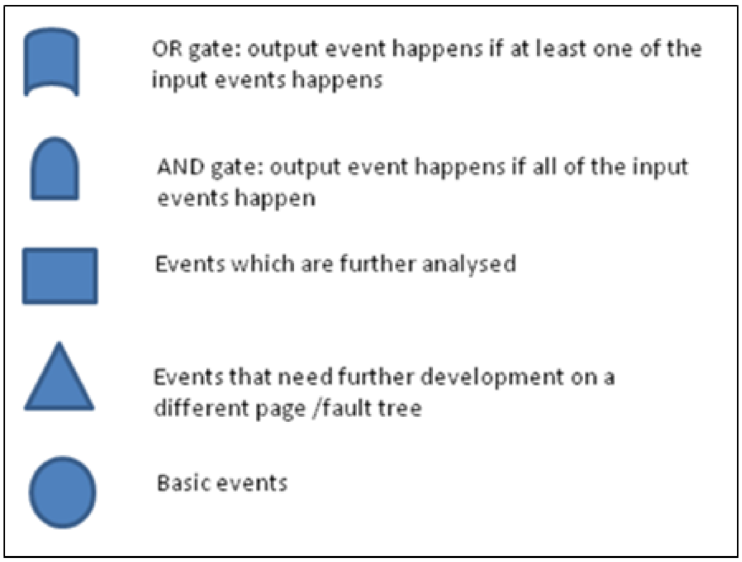


Figure 14: Elements in a FTA.

An example of how to construct a fault tree is described in the compendium "An introduction to well integrity" ***(18)***, and will now be presented:

The FTA always starts with the TOP event, and for well integrity this will as mentioned usually be "Leakage to surroundings". The fault tree is then developed step by step from the TOP event by repeatedly asking "How can this event happen?" This is answered by identifying all possible places the leakage can come out, and then do a further analysis of each and every flow path.

As seen from figure 15, there are ten different arrows (representing flow paths) that can cause a leakage to surroundings. If at least one of the flow paths is leaking, the TOP event will happen. This means that there is an OR relationship. The triangles beneath the rectangles indicate that the fault tree is not completed and that a further evaluation of the event is needed on a separate page.

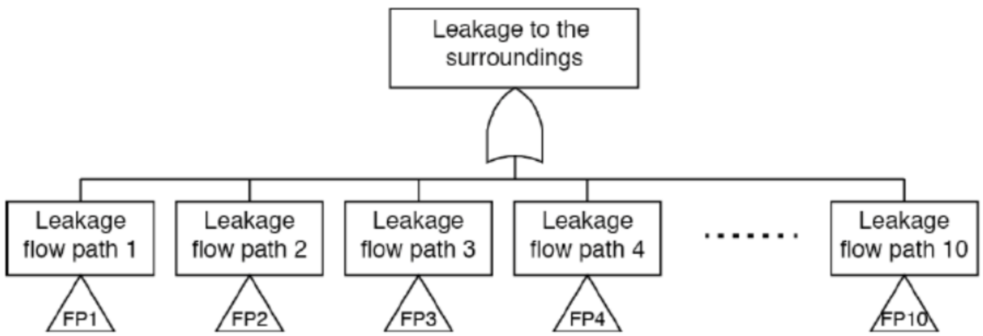


Figure 15: Fault tree representing leakage flow paths (18).

Figure 16 shows the start of a separate fault tree constructed for flow path 6 as an example. To have a leakage through this flow path the wellhead must be leaking and there must be flow to the wellhead. The event "Flow into wellhead" needs further development and is therefore marked with a triangle. The basic event "Leakage from wellhead" is marked with a circle that has a code for abbreviation, hence WHL for "Wellhead leak". The event "Flow into wellhead" is developed further in figure 17. Fault trees for the other nine flow paths can be constructed in the same way, and combining them would give the final result showing all the failure modes.

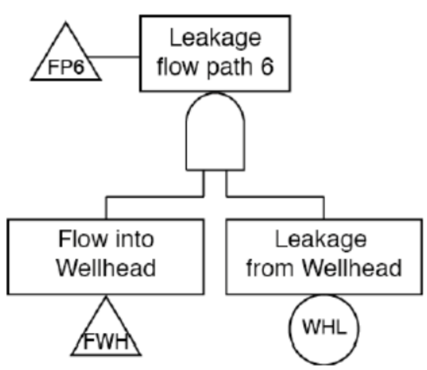


Figure 16: Fault tree for leakage flow path 6 (18).

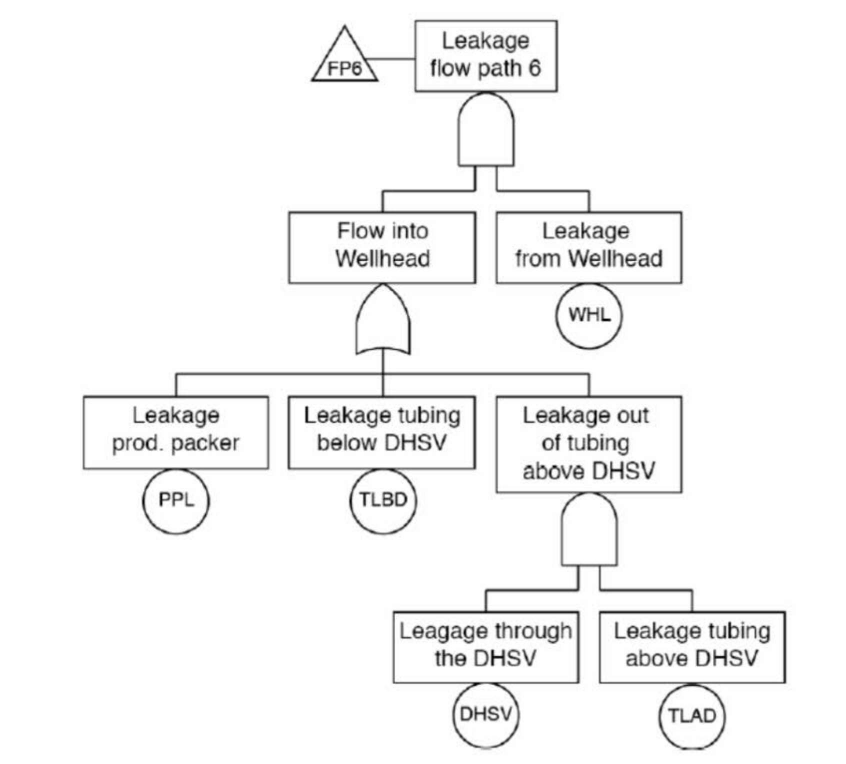


Figure 17: Fault tree showing the event "Flow into wellhead" (18).

A complete fault tree shows all failure combinations or causes that lead to a specified failure or dangerous situation. These combinations are referred to as "cut sets", and is a set of basic events whose (simultaneous) occurrence ensure that the TOP event occurs. If not all the basic events of the minimal cut set occur, the top event fails to happen ***(19)***.

The minimal cut sets related to the event "Leakage flow path 6" in figure 17 are:

- *{WHL,PPL}:* wellhead is leaking AND production packer is leaking
- *{WHL, TLBD}:* wellhead is leaking AND the tubing below DHSV is leaking
- *{WHL, DHSV, TLAD}:* wellhead is leaking AND the DHSV (SCSSV) is leaking AND the tubing above the DHSV is leaking.

The fault tree construction is based on a very simple and logical procedure, and is therefore suitable for brainstorming sessions involving people that have not been trained in fault tree construction. Pictorial representation leads to an easy understanding of the system behavior and the components included, but as the trees are often large the processing of them may require computer systems. As they may become big and consist of many pages, it can be easy to lose oversight, and they are time consuming to create. However, the logical analysis of the trees and the identification of cut sets, are useful in identifying failure pathways in complex systems. Unlike the FMECA, human errors can also be included in the FTA.

2.5.2.4 Statoil's compliance and leadership model

Statoil's compliance and leadership model seen in figure 18 is an easy and understandable method of performing a risk assessment before a work task. The advantage of the model is its comprehensibility to most people who may not be that familiar to the risk assessment discipline and complex analysis methods. It describes how to plan, execute, evaluate and learn from any task, and compromises five steps denoted the "A- standard" ***(25)***.

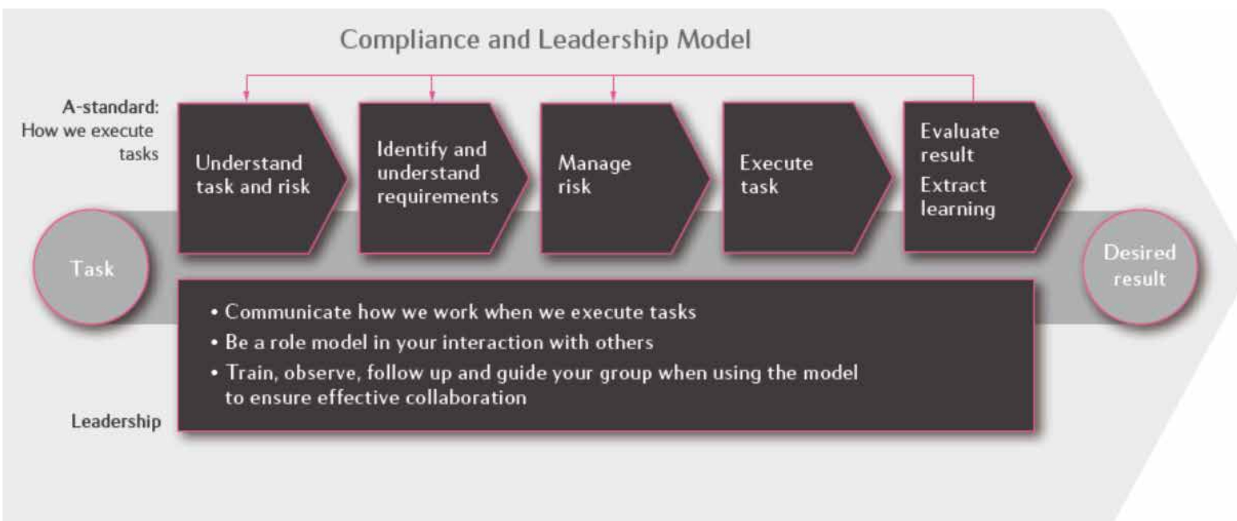


Figure 18: Statoil's compliance and leadership model (25).

The three first steps are related to planning. Identification of risk (step 1) and risk handling (step 2 and 3) are strongly emphasized in the A-standard. A correct and shared understanding of the task is a precondition for identifying and handling risk. Beneath is a general description of each step in the model ***(25)***:

Step 1: Understand the task and risk: Ensure a shared understanding of the delivery, the sub - tasks that must be performed, the purpose of the task, necessary relationships (context) and risk associated with executing the task. Identify knowledge and experience that may contribute to understanding of the task, its risks and effective execution.

Step 2: Identify and understand requirements: Identify and develop a shared understanding of relevant requirements for the task. Most tasks are subject to specific requirements in the ARIS management system.

Step 3: Manage risk: Evaluate whether the identified requirements are adequate for managing the risks involved. Determine how identified risks not addressed by the management system shall be managed.

Steps 1-3 result in a plan for how to execute the task.

Step 4: Execute task: Assess and manage changes in risk and assumptions continually while executing the task.

Step 5 Evaluate result. Extract learning: Assess progress, gaps, experience and learning. Propose improvements and share best practice.

The compliance and leadership model can be used for every work task in Statoil. In a well integrity context the work task will be related to evaluating whether a well with integrity issue is within the requirements for acceptable risk.

After many incidents in relation to well integrity, more focus has been directed towards risk assessment of wells in operation. As mentioned there are several methods and techniques, and the degree of complexity and time effort varies. In response to the industry and regulatory interest a simple system for risk categorizing a well based on its integrity status was developed by WIF in the NOG Recommended Guidelines 117. This system describes the barrier status of the wells, and hence says something about the probability of a leak to the surroundings. The operators on the NCS have used this as a basis for developing their own well categorization systems in order to rank their wells with regards to risk. However, they have not yet managed to find a system which captures the total risk picture in a good enough way. In the next chapters different well categorization systems developed will be described, starting with the basis in the NOG Guidelines 117.

2.6 Well integrity categorization of wells in operation with regards to risk

The PSA's pilot well integrity survey in 2006 revealed that the industry needs to increase focus on barrier philosophy. Control of barrier status is an important HSE factor to avoid major incidents caused by leaks and well control situations. The 2006 survey included the operators on the NCS and PSA selected new and old facilities, platform and subsea wells, injection and production wells from north to south of the NCS. Seven selected operating companies (included Statoil ASA) received an audit notification from PSA and were requested to provide status of well integrity issues for 12 preselected offshore facilities and 406 wells. The scope of the audit was to analyze how comprehensive the well integrity problems on the NCS were, and identify the main issues and challenges ***{ (26), (3)}.***

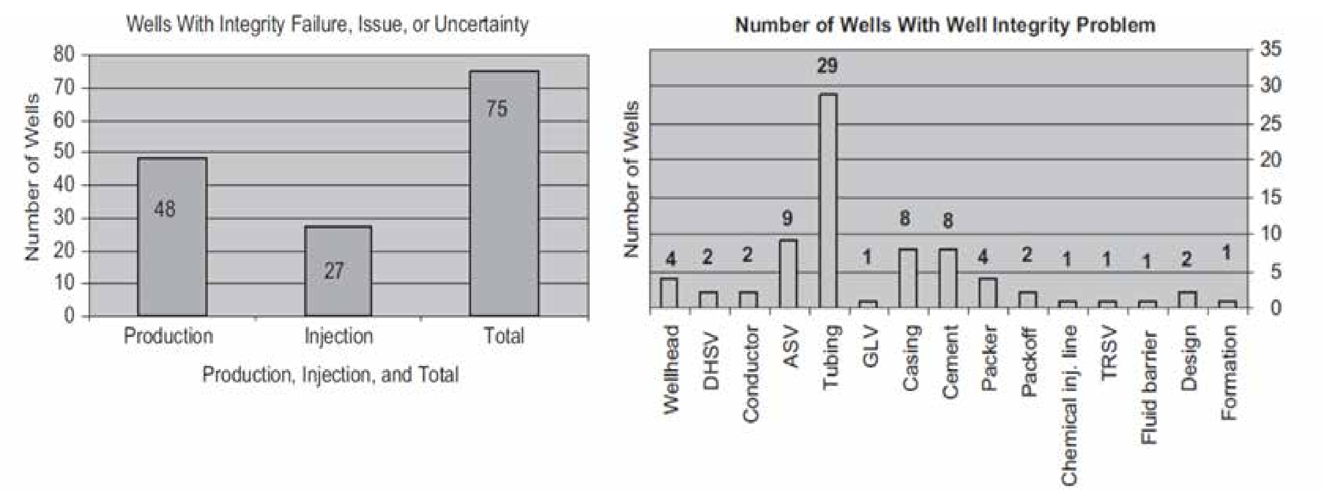


Figure 19: Number of wells with well integrity issues and category of barrier element failure (26).

Based on input from 21 percent of the active wells on the NCS, the survey formed a basis for an evaluation of well integrity status on the NCS. Figure 19 shows the number of wells with well integrity issues, and illustrates the category of barrier element failure. Most of the integrity problems were within barrier elements such as tubing, annulus safety valves (ASV), casing, cement and wellhead. Table 3 shows that 7 percent of the wells were shut - in because of well integrity problems, and that 9 percent of the wells were working under exemptions ***{ (3), (26)}.***

Table 3: Well integrity impact (A, B, C) for production and injection wells (26).

	Total Number of Wells	Well-Integrity Impact (A,B,C): A: Shut In	B: Working Under Conditions	C: Insignificant Deviation for Current Operations
Production	323	18	22	8
Injection	83	10	16	1
Total	406	28 (7%)	38 (9%)	9 (2%)

The survey concluded that the need for having a 100 percent control of barrier status at all times is of utmost importance to eliminate potential risks. A well - known status code enables the companies to rank their wells with regards to well integrity, and take the right actions in a proactive manner before any major losses.

2.6.1 Norwegian Oil and Gas (NOG) Recommended Guidelines 117 for Well integrity

In response to the findings from the 2006 survey WIF developed a system for classifying a well based on its integrity status. The system is described in NOG Recommended Guidelines 117, chapter 4 - Well integrity well categorization ***(8)***. The intention with this well categorization was to help the operators finding a system to rank and prioritize their wells. PSA could also use the results to summarize the well integrity across the entire NCS.

It was decided that WIF should work on a Norwegian oil industry recommendation that would focus on wells in the production phase. Furthermore, it should be kept simple with only 3 - 4 categories. With the feedback from DMF and PSA, WIF was able to propose a 4 category, traffic light system based on the double barrier principle. The Guidelines 117 presents these 4 resultant categories, summarizes the basis of each and one and provides examples in effort to promote a common understanding of each category for the end user. The system is intended for categorization of all well types that are in operation, shut in, suspended or temporarily abandoned.

The well integrity categorization is based on the double barrier philosophy that is outlined in the regulations and NORSOK D-010:

"There shall be two well barriers available during all well activities and operations, including suspended or abandoned wells, where a pressure differential exists that may cause uncontrolled outflow from the borehole / well to the external environment".

2.6.1.1 Overview of the category principles

The four category system utilizes a green / yellow / orange / red traffic light, color coded system to rank the wells in regards to well integrity, and the system principle is based on number of well barriers. Green and yellow are acceptable according to standards and in compliance with the two barrier principle. Orange and red are wells with integrity problems which usually will be further diagnosed, evaluated and risk assessed for appropriate follow up action. Red is used for wells which in addition to failure of one barrier have a considerable degradation or failure of the second barrier. An overview of the category principles can be seen in table 4. In the following sections the categories will be described in more detail as they are in the Guidelines 117.

Table 4: Category principles from Guidelines 117 (8).

Category	Principle
Red	One barrier failure and the other is degraded/not verified, or leak to surface
Orange	One barrier failure and the other is intact, or a single failure may lead to leak to surface
Yellow	One barrier degraded, the other is intact
Green	Healthy well - no or minor issue

2.6.1.2 Green category

The principle for the green category is:

"Healthy well - no or minor integrity issue"

Wells categorized as green should be regarded to have an associated risk which is identical or comparable to the risk associated with an identical new well with a design in compliance with all regulations. It does not necessarily mean that the well has a history without failures or leaks, or that the WBEs fulfil all acceptance criteria described in the latest revision of NORSOK D-010, but the well is in full compliance with the double barrier requirement. Typically a well categorized as green will not require any immediate repairs or mitigating measures. For a well to fall in the green category the condition of typical well barrier elements would usually fulfil the criteria in table 5:

Table 5: Criteria for green category (8).

WBE	Condition
DHSV or deep set plug	Leak rate within acceptance criteria
Christmas tree ESD valves and annulus valves	Leak rate within acceptance criteria
Tubing hanger and internal wellhead seals	Leak tight
Completion and casing string	Leak tight
Production packer	Leak tight

2.6.1.3 Yellow category

The principle for the yellow category is:

"One barrier degraded, the other is intact"

Wells categorized as yellow should be regarded to have an incremental associated risk which is not negligible compared to the risk associated with an identical new well with design in compliance with all regulations. Although a well categorized as yellow has an increased risk, its condition is within regulations. It should also be noted that even if the well has a history without any leaks or failures and the WBEs fulfil all acceptance criteria described in NORSOK D-010 the well may fall within the yellow category if conditions exist which constitutes a threat to both barriers and risk of dual failures is present.

For a well to fall in the yellow category the condition of typical well barrier elements would usually fulfil the criteria in table 6:

Table 6: Criteria for yellow category (8).

WBE	Condition
DHSV or deep set plug	Leak rate within acceptance criteria
Christmas tree ESD valves and annulus valves	Leak rate within acceptance criteria
Tubing hanger and internal wellhead seals	Leak rate within acceptance criteria
Completion and casing string	Leak rate within acceptance criteria
Production packer	Leak rate within acceptance criteria

A well with sustained casing pressure can fall within the yellow category even though there are hydrocarbons present in the annuli (not intentionally placed there) if it fulfils the following criteria: There are no leaks through both established primary and secondary barriers, annuli pressures are maintained below the defined pressure limits in a controlled manner and the leak rate into the annuli is within acceptance criteria. Wells not cemented according to the latest version of NORSOK D-010 can fall within the yellow category if: Sufficient strength or permeability does not exist in the formation which would be exposed to well pressure should a barrier failure occur under the production packer as long as the cement is still qualified as WBE.

2.6.1.4 Orange category

The principle for the orange category is:

"One barrier failure and the other is intact, or a single failure may lead to leak to surface"

Wells categorized as orange should be regarded to have an associated risk which is higher than the risk associated with an identical new well with design in compliance with all regulations. Typically a well categorized as orange will be outside the regulations. Repairs and / or mitigations will be required before the well can be put into normal operation, but the well will still have an intact barrier and there will usually not be an immediate and urgent need for action.

For a well to fall in the orange category the condition of typical well barrier elements would usually fulfil the criteria in table 7:

Table 7: Criteria for orange category (8).

WBE	Condition
DHSV or deep set plug	Leak rate outside acceptance criteria
Christmas tree ESD valves and annulus valves	Leak rate outside acceptance criteria
Tubing hanger and internal wellhead seals	Leak rate outside acceptance criteria
Completion and casing string	Leak rate outside acceptance criteria
Production packer	Leak rate outside acceptance criteria

A well with sustained casing pressure will fall within the orange category if the leak rate into the annuli is outside acceptance criteria. Wells not cemented according to the latest version of NORSOK D-010 can fall within the orange category if: Sufficient strength or impermeability does not exist in the formation which would be exposed to well pressure should a barrier failure occur below production packer, and there is a potential for breaching to surface, as long as the cement is still qualified as WBE.

2.6.1.5 Red category

The principle for the red category is:

"One barrier failure and the other degraded / not verified, or leak to surface"

Wells categorized as red should be regarded to have an associated risk which is considerably higher than the risk associated with an identical new well with design in compliance with all regulations.

Typically a well categorized as red will be outside the regulations. Repairs and / or mitigations will be required before the well can be put into normal operation and there will usually be an immediate and urgent need for action. A well should fall within the red category if at least one WBE in a barrier envelope has failed and at least one WBE in the other barrier envelope has also failed or is regarded as degraded or not verified (for example exposed to pressure outside verified design limit or evidence of corrosion).

For a well to fall within the red category the condition of at least one typical WBE in a barrier envelope will usually be as mentioned in table 7 (Orange), and at the same time at least one typical WBE in the other barrier envelope will usually be as mentioned in table 6 (Yellow) or table 7 (Orange). This could for example be leak outside acceptance criteria in completion string and additional leak within acceptance criteria in casing string. Another example is a leak outside acceptance criteria in SCSSV and additional leak outside acceptance criteria in x - mas tree ESD valve.

A well with sustained casing pressure will fall within the red category if annuli pressures are above the defined pressure limits and the leak rate into the annuli is outside acceptance criteria. Wells not cemented according to the latest version of NORSOK D-010 can fall within the red category if: Sufficient strength or impermeability does not exist in the formation which would be exposed to well pressure should a barrier failure occur below production packer, there is a potential for breaching to surface and the cement is not qualified as WBE.

2.6.2 Statoil's first development of risk status codes from NOG Guidelines 117

Based on the categorization principles and examples generated in WIF, Statoil developed their own set of internal risk status codes to classify wells in operation and temporary abandoned wells. These describe whether the wells are within internal and regulatory requirements and the risk associated with any deviations. They should be used for prioritization of well interventions and workovers in order to re - establish barriers ***(27)***.

The system consists of five different risk status color codes as seen in table 8. The only way this system differs from Guidelines 117, is the introduction of a new color; the light green.

Table 8: Statoil's first development of risk status codes from Guidelines 117 (27).

Red	Principle: One barrier failure and the other is degraded/not verified, or leak to surface.
Orange	Principle: One barrier failure and the other is intact. Or a single failure may lead to leak to surface.
Yellow	Principle: One barrier degraded, the other is intact.
Light green	Principle: Barriers intact. Minor integrity issue
Green	Principle: Healthy Well

To determine risk status in this system each well had to be individually assessed, and the basic principles in table 8 should be used. It was decided that each field should have an overview of the risk status for all their wells at all times. This was done by having a generic KPI spreadsheet compromising a lot of information like well name and type, life cycle status, operational code, integrity code and the resulting risk status code. Table 9 shows a part of the KPI sheet from the Statfjord A field as an example.

In this KPI sheet the risk status will be automatically generated based on different integrity codes. These integrity codes are selected from a predefined pick list, and the pick list is based on examples of well component failures generated in WIF. The integrity codes with their description and assigned risk status code are shown in table 10, and they are grouped into different failure areas. The main rule states that one should always pick the case with the highest risk status if there are several non - conformances.

In 2013 a new software, Intetech Well Integrity Toolkit (iWIT), was developed for Statoil to present the well integrity status for wells in operation. This tool includes an overview of the risk status of the wells, and is based on the principles from the section above in addition to a new aspect – escalation risk factors. iWIT will be further described in the next section.

Table 9: Well integrity KPI's from Statfjord A.

Well integrity KPI's (Do not change)														
#	Field	Well	Subsea / Platform	Year Updated	Month Updated	Lifecycle Status	Operational Code	Welltype	Integrity Codes	Comments	Disp no.	Exemption from int or ext reg's	Disp Valid until	Risk Status code
1	Statfjord A	33/9-A-1	PL	2013	11	T&P - Mon	WSIWI	WAG	CAT 2	BTC threads in both 9 5/8" and 13 3/8" casing. Well shut in with plug in tailpipe and 2 PP&A cement plugs installed in 9 5/8" csg. Small pressure increase in B-annulus.	84654	INT	Lukket	2
2	Statfjord A	33/9-A-2	PL	2012	12	OPERATING	WOPERWI	OILPROD	BARREDC	Unloader valve not V1 qualified. 13 3/8" csg. (shoe & thds.) integrity issue. **GASLIFT NOT ALLOWED. Plan to install IGLS in 2013.**	84915	INT	Permanent	4
3	Statfjord A	33/9-A-3	PL	2013	10	T&P - Mon	WIOK	GINJ	CAT 2	Tubing 76% corroded. BTC threads in both 9 5/8" and 13 3/8" casing. LongTerm shut-in on surface (not plugged). **10k-tre -> HMV closure time not 100% intact. Small pressure increase in B-annulus observed. Well intervention planned for end December to install deepset plug.**	122151	INT	29.04.2015	2
4	Statfjord A	33/9-A-4	PL	2011	11	T&P - Mon	WSIWI	WINJ	TACABVCLOS	BTC threads in both 9 5/8" and 13 3/8" casing. Well shut in with inj valve in tailpipe. Tbg corroded.				4
5	Statfjord A	33/9-A-6	PL	2013	5	OPERATING	WIOK	OILPROD	WEAKDESIGN	Korrodert tubing. Høyt scale potensiale. BTC threads in both 9 5/8" and 13 3/8" casing.	103596	INT	01.05.2013	4
6	Statfjord A	33/9-A-7	PL	2013	5	T&P - Mon	WSIWI	OILPROD	SMALLKCSG	Well plugged in tailpipe. BTC threads in both 9 5/8" and 13 378" casing. Well shut in pr. nov.2010. Tbg. --> A-ann.leakage. Deep & shallow plug installed	116911	INT		4
7	Statfjord A	33/9-A-8	PL	2013	4	T&P - Mon	WSIWI	WAG	TACCOMP	Plugged well. Small leakage from tbg. --> A-annulus above DHSV (DHSV pulled). BTC threads in both 9 5/8" and 13 3/8" casing. **Well shut in.**	92844	INT	Avslått	4
8	Statfjord A	33/9-A-9	PL	2013	2	OPERATING	WIOK	WINJ	BARREDC	BTC threads in both 9 5/8" and 13 378" casing. Well used as a waste injector. **Injisere > 10 000 m3 i brønn uten å inspisere brønnen.**	113471	INT		4
9	Statfjord A	33/9-A-10	PL	2011	11	OPERATING	WIOK	OILPROD	HEALTH	BTC threads in 13 3/8" casing.				5
10	Statfjord A	33/9-A-11	PL	2013	10	OPERATING	WIOK	OILPROD	BARREDC	BTC threads in 13 3/8" casing.				4
11	Statfjord A	33/9-A-12	PL	2011	11	T&P - Mon	WIOK	OILPROD	HEALTH	BTC threads in 13 3/8" casing. Formerly used for cuttings re-injection in the B-annulus. Long term shut in on surface (not plugged)				5
12	Statfjord A	33/9-A-13	PL	2012	2	OPERATING	WOPERWI	OILPROD	WEAKDESIGN	BTC threads in 13 3/8" casing. Small p.build up in cavity (C-section/ XMT), in conn. w/ p.test dec.12				4
13	Statfjord A	33/9-A-14	PL	2013	4	T&P - Mon	WSIWI	WAG	TACABVCLOS	Well shut in with inj valve in tailpipe. Tbg corroded. BTC threads in 13 3/8" casing.	122153	INT	29.04.2015	4

Table 10: Pick list with examples on well component failures generated in WIF (27).

	Description	Risk Status Code
XT/WH or Tubing hanger issues		
SVXTLK	SCSSV and tree valve failure (LMV, PWV, PMV)	1
XTVLS	Dual tree valve failure (LMV, PMV, PWV) and DHSV not leak tight	1
MLTTBGHWH	Multiple hanger/wellhead failures (Tubing hanger and casing seal assembly failure)	1
XTVLV	Tree valve failure – Upper Master Valve, Flowing Wing Valve, Annulus Valve (with no compensating measures in place)	2
TBGHGRLK	Hanger/wellhead leaks above leak criteria (tubing hanger failure which leads to tubing to annulus communication)	2
XTVLCOMP	Leak in tree valve (PMV or PWV) above leak criteria, but compensating measures let other tree valve take over the barrier function	3
Annuli/Tubing/Casing issues		
TCLKCOR	Leak in tubing or casing thru a barrier and start of corrosion in secondary barrier	1
TCLKPSI	Tubing or casing barrier leak into an annuli that is not designed for the pressure	1
TABLK	Tubing and production casing leak (if both are part of the barrier envelope)	1
ANNLKAV	Leak in tubing or casing thru a barrier and tree annulus valve not verified as a barrier.	1
ANNLFM	Leak from formation into annuli and the annuli not qualified	1
LEAKOUTER	Leak into annulus where annulus pressure exceeds pressure limit (next outer casing not designed for the pressure).	2
ATOB	A Annulus to B annulus communication	2
TAC	Tubing to A annulus communication (leak outside acceptance criteria)	2
LEAKANN	Leaking annulus but not into an adjacent annuli or tubing	2
HYDANN	Hydrocarbons in any annuli not intentionally introduced (no leak through both barriers)	3
TACCOMP3	Tubing to annulus leak above SCSSV or down hole injection valve with measures to control potential for degradation of a barrier element	3

	Description	*Risk Status Code*
Annuli/Tubing/Casing issues		
SMALLKCSG	Tubing, casing or other barrier element leaking within leak rate criteria	3
TACCOMP	Tubing to annulus leak above SCSSV or down hole injection valve (a leak within acceptance criteria that is not effecting or leading to degradation of the barrier envelopes)	4
SCPLOW	Sustained casing pressure (no hydrocarbons and not a leak through a barrier)	4
TACABVCLOS	Tubing to annulus leak above SCSSV or down hole injection valve and well is closed in.	4
DHSV/ASV/ Control line issues		
SVFAIL	DHSV failure	2
CNTLKBEL	Control line leak from below the primary barrier element	3
CNTLKABV	Control line leak above the primary barrier element (2 independent barriers intact)	4
ASVFAIL	Well on gas lift and ASV not functioning (e.g. ASCV installed and GLV periodically tested)	4
Cement issues		
CMTPKRFMAB	Cement (or other qualified barrier element) is not above production packer but the cement height is sufficient to act as primary barrier element, and formation strength at next outer casing shoe is too weak to accommodate reservoir pressure (Potential of breaching to surface if a casing leak below production packer occurs)	2
CMTPKRFM	Cement (or other qualified barrier element) is not above production packer but the cement height is sufficient to act as primary barrier element, and formation strength at next outer casing shoe is sufficient to accommodate reservoir pressure (No potential of breaching to surface if a casing leak below production packer occurs)	3
NOCMT	No cement above packer but other barrier elements in place, (e.g. formation strength and next outer casing/cement)	4
POORCMT	Cement above packer but less than requirements or cement above reservoir but less than requirements.	4
NOCMTHIRISK	Cement (or other barrier element) below production packer and with insufficient height to qualify as primary barrier element, and formation strength at next outer casing shoe is too weak to accommodate reservoir pressure. (Potential of leak breaching to surface)	1

	Description	*Risk Status Code*
Generic failure modes		
MULT	Multiple barrier failures. Use when no other code is available.	1
CAT 1	One barrier failure - other is degraded. Use when no other specific code is available. Put specific info in comments field.	1
CAT 2	One barrier failure and other is intact. Or a single failure may lead to leak to surface. Use when no other specific code is available. Put specific info in comments field.	2
LEAKCOMP	Leak through pressure containing element (which is not part of a barrier) with measures to control potential for degradation of a barrier element if not compensated for.	3
RSKDUAL	Risk of dual well barrier failures due to common causes (high scaling, erosion, corrosion on both barriers)	3
BARREDC	Well barrier element reliability reduced (e.g. seal tite in seal assembly, gel plug in A annulus, DHSV failure compensated with injection valve installed)	4
WEAKDESIGN	Equipment design weak -- Can still accommodate load scenarios (still qualified) E.g. leak into a cavity outside barrier envelopes	4
CAT 3	One barrier degraded, the other is intact. Use when no other specific code is available. Put specific info in comments field	3
Leak to surroundings		
CFLOW	Uncontrolled crossflow between formation zones not capable of breaching to surface. (On well integrity basis on not reservoir management basis)	2
EXTLEAK	External leaks through both barriers to environment or uncontrolled crossflow between formation zones with potential of breaching to surface. (On well integrity basis on not reservoir management basis)	1
Healthy well		
HEALTH	Healthy well	5

2.6.3 iWIT

iWIT presents the well integrity status for wells in operation as well as historical well integrity information. The tool supports the work processes for handover of well responsibility and well integrity monitoring ***(28)***. It will by 2014 be used for all Statoil's installations on the NCS, and the process of implementing all the wells in this software is ongoing. In figure 20 the front page when entering iWIT is shown. There are many different status codes like operational, well barrier, annulus, valve, wellhead and lifecycle status of wells. In this thesis, the status of interest is regarding risk, the circle highlighted red in figure 20. The front page illustrates the percentage of wells within the different risk status codes.

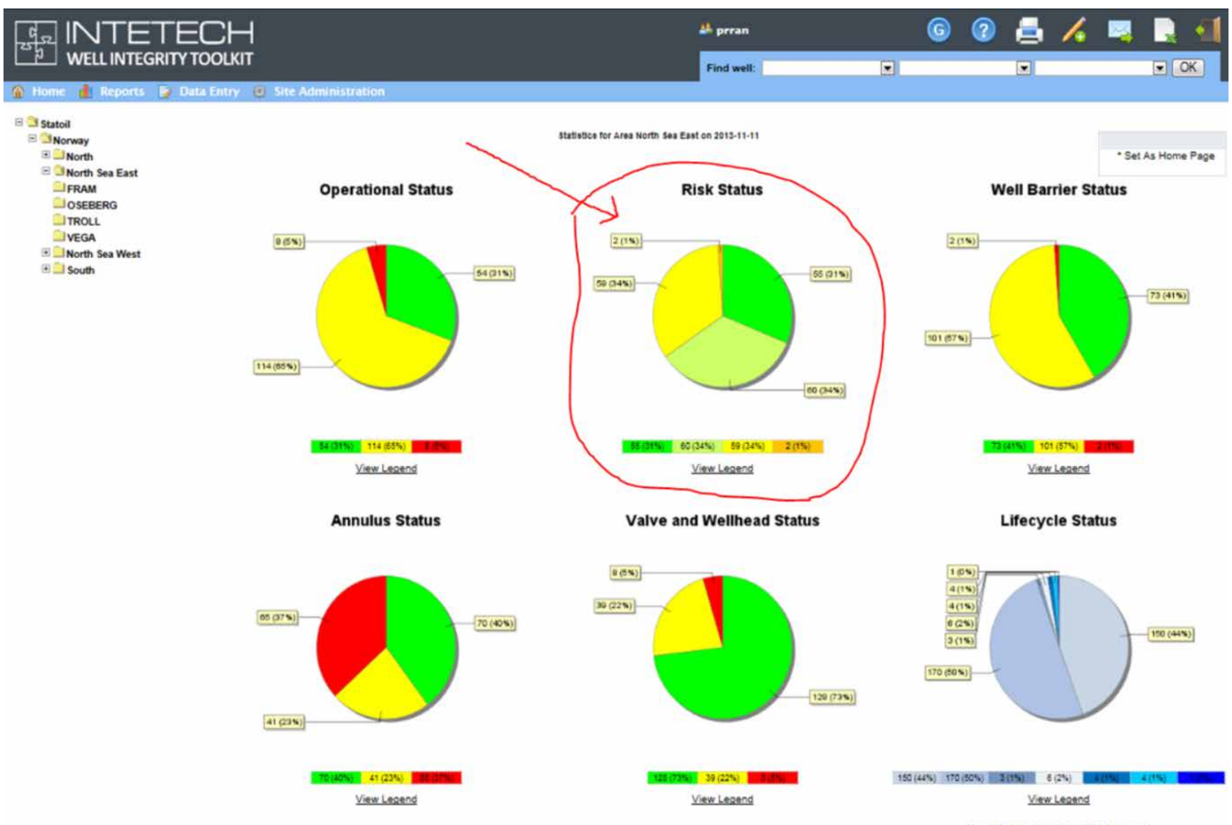


Figure 20: Front page when entering iWIT. The risk status code is highlighted in red.

iWIT is a sophisticated system developed from the KPI sheet, and the risk status codes are based on the same 5 category principle with color codes seen in table 8 from the previous section. In addition it introduces 5 sub codes presented in table 11. These provide a better basis for describing the final risk status as they something about the escalation potential when having a well integrity issue. When the well experiences abnormal changes and / or non - conformances, the following risks shall be evaluated ***(28)***:

- **Well blowout risk / dual barrier**: Is the dual barrier principle in place?
- **Well kill / recoverability**: If the leak escalates or a single failure occurs, will it be possible to kill / isolate the leak or restore barriers?
- **Mechanical / pressure loads**: Will the annulus be able to withstand the increased pressure caused by a potential leak?
- **Well release risk**: Is there a potential of external hydrocarbon leaks through both barriers? Will the leakage result in storage of unacceptable hydrocarbon and toxic volumes in the annulus?
- **Corrosion / erosion**: Are there any ongoing corrosion / erosion in the well that can cause acceleration of degradation of well barriers?

The risk status for the well will be set to the worst of the defined escalation factor sub codes. To be able to assess these in more detail, table 12 could be used as guidance.

Table 11: Escalation risk sub codes (28).

Well blowout risk/dual barrier	
Red	One barrier failure and the other is degraded/not verified, or leak to surface.
Orange	One barrier failure and the other is intact. Or a single failure may lead to leak to surface.
Yellow	One barrier degraded, the other is intact.
Light green	Barriers intact. Minor integrity issue.
Green	Healthy Well

Well kill/recoverability	
Red	Leak not possible to kill or isolate and no qualified barriers
Orange	Not possible to kill well if an additional single failure occur
Yellow	Challenging well kill procedure for handling an additional single failure
Light green	Integrity issue. Well kill according to requirements.
Green	Healthy Well

Mechanical/pressure loads	
Red	Failure of one barrier and secondary is exposed to pressures outside verified design limit.
Orange	Pressure limits exceeded and a single failure may lead to leak to surface.
Yellow	Potential for exceeding the pressure limits.
Light green	Integrity issue. Pressure loads not affected.
Green	Healthy Well

Well release risk	
Red	External HC leak through both well barriers or release of unacceptable HC or toxic volumes
Orange	A single failure may lead to release of unacceptable HC or toxic volumes.
Yellow	HC or toxic volumes may become unacceptable.
Light green	Integrity issue. Acceptable HC and toxic volumes.
Green	Healthy Well

Corrosion/erosion	
Red	Failure of one barrier and ongoing corrosion / erosion on other barrier
Orange	Ongoing corrosion or erosion causing leak through barrier
Yellow	Potential for corrosion/erosion exceeding barrier or structural design tolerances.
Light green	Integrity issue. No potential for corrosion/erosion above design tolerances.
Green	Healthy Well

Table 12: Guidance for defining risk status code in iWIT (28).

Escalation factor		Well risk status code remark / criteria
Barrier evaluation (Blowout prob.)	Red	Failure of one barrier and leak in second barrier into an annulus not qualified as barrier.
		Leak from formation into annuli and the annuli not qualified as barrier.
		Uncontrolled crossflow between formation zones with potential of breaching to surface (on well integrity basis - not reservoir management basis).
		Cement (or other barrier element) below production packer and with insufficient height to qualify as primary barrier element, and formation strength at next outer casing shoe is too weak to accommodate reservoir pressure. (Potential of leak breaching to surface)
	Orange	Cement (or other qualified barrier element) is not above production packer but the cement height is sufficient to act as primary barrier element, and formation strength at next outer casing shoe is too weak to accommodate reservoir pressure (Potential of breaching to surface if a casing leak below production packer occurs)
		Leak (any size) to a volume in the well not enveloped by qualified well barrier elements
		Uncontrolled crossflow between formation zones not capable of breaching to surface (on well integrity basis - not reservoir management basis)
		Leak through primary barrier envelope above the acceptance criteria and not possible to redefine a primary barrier envelope. (The other barrier envelope is intact.)
	Yellow	Cement (or other qualified barrier element) is not above production packer but the cement height is sufficient to act as primary barrier element, and formation strength at next outer casing shoe is sufficient to accommodate reservoir pressure (No potential of breaching to surface if a casing leak below production packer occurs)
		Well barrier leak rate to annulus lower than acceptance criterion (includes e.g. shallow gas leaks)
	Light green	Leak rate to annulus lower than acceptance criterion and not through well barrier element (e.g., leak in tubing above DHSV)
		Failed barrier element has been replaced by a plug or the barrier envelope has been moved. (Two intact barrier envelopes.)
	Dark green	Healthy well according to requirements
Corrosion / Erosion	Red	Failure of one barrier (e.g. tubing or casing) and evidence of corrosion/erosion (degradation) in other (secondary) barrier.
	Orange	Material corrosion or erosion is the (most likely) leak cause through barrier.
	Yellow	There is, or is a potential for, exposure of equipment to H_2S/CO_2/pH/etc. levels that are outside design tolerances.
		There is continuous unintended flow in the well
	Light green	Otherwise
	Dark green	Healthy well according to requirements
Mechanical / Pressure loads	Red	Failure in one barrier and the secondary is exposed to pressures outside verified design limit.
	Orange	Pressure limits exceeded and a single failure may lead to a leak to surface.
	Yellow	A leak to annulus with the maximum potential annulus pressure greater than MOASP (see well data check list updated with well pressures and well leak status)
	Light green	Sustained annulus wellhead pressure (no hydrocarbons / no leak through or into barrier envelope). Annulus designed for pressure (pressure below respective maximum allowable annulus wellhead pressure).
		Otherwise
	Dark green	Healthy well according to requirements
Well release risk - hydrocarbon storage in well annuli*	Red	External leak to surrounding environment (any size) through both barriers
		Release fo unacceptable HC or toxic volumes
	Orange	Hanger/wellhead barrier seal leaks above criteria
		A single failure may lead to release of unacceptable HC or toxic volumes
	Yellow	The hydrocarbon storage mass in the well annuli is, or may become, greater than the acceptance criterion
		Well annuli fluids are highly toxic (platform well)
	Light green	Otherwise
	Dark green	Healthy well according to requirements
Well kill/ recoverability	Red	Leak not possible to kill or isolate and no qualified barriers
	Orange	Not possible to kill well if an additional single failure occur
	Yellow	An additional single well barrier leak situation may affect the ability to efficiently kill the well with mud. Consider kill margin required.
	Light green	Otherwise
	Dark green	Healthy well according to requirements

3. DISCUSSION

3.1 Evaluation of existing risk status categorization systems

In this chapter an evaluation of the risk categorization systems described on the previous pages will be carried out.

Chapter 4 in the NOG Recommended Guidelines 117 is the fundament of the development of well integrity status codes, and describes a system for categorizing wells according to their integrity status. The system principle is based on the condition and number of barriers in a well, thus it has a direct association with the probability of a leak to the surroundings and hence the risk of a well integrity issue. However, as the Guidelines also points out, this risk is not absolute. The system should not replace risk assessments as it does not say anything about the potential escalation of the leak (the severity of the well integrity issue) or the consequences of an external leak to the surroundings. For instance, two wells with only one remaining barrier can pose different levels of risk if one is a high rate gas well on a manned platform whereas the second is a subsea water injector. The Guidelines suggests that the operator should consider a further in depth risk assessment process for wells that are ranked high.

Statoil’s first development of a well integrity categorization system from the NOG Guidelines 117 was based on the same principles with 5 colors (introducing a new light green status) - but they were now named risk status codes. This name can be misleading as the system basically is the same as the one generated by WIF, and only says something about the physical status of the barriers in the well. It would have been better suited to call them barrier / integrity status codes.

Statoil’s new software, iWIT, takes the classification system a step further, as it introduces five sub codes which decide the final risk status (seen in table 11). These sub codes say something about the escalation potential when the well experiences abnormal changes and hence describes the severity of the well integrity issue and a small part of the potential consequences. But the leak is not quantified and the consequence description is lacking. As the final risk status is based on the worst sub code, this system does not differ much from the previous. By studying the well blowout risk / dual barrier sub group, one can see that it is identical to the main principle codes. In this way the status of the barriers will directly decide the resulting risk status of the well if ranked high, and the utilization of the other sub escalation factors is overrun. Escalation risks with regards to well kill, well release, corrosion, erosion and pressure loads are in this way camouflaged in the final status. Proper usage of the 5 category sub groups involves finding a better way to utilize each and one of them in the risk status code.

Risk can be defined as the combination of consequences of an event and the associated likelihood of occurrence of the event. A status code for wells in operation should reflect the risk associated with a leak to the surroundings as the major hazardous event is obviously a blowout or well release. The already developed systems for well integrity categorization are based on the barrier status and escalation potential for the leakage (iWIT), thus say something about the likelihood of a leak to the environment / surface. But the consequences of such a leak are not fully represented and taken into consideration. This is the missing part, and should be included in the status code to get a more complete risk picture.

Figure 21 shows a bow tie diagram illustrating the blowout / well release risk for a well. On the left side are the causes, the well integrity issues, leading to the main event placed in the middle. The barrier envelopes are there to prevent the event from happening, thus they are reducing the probability of a blowout or well release. Imagine the barriers are not in place, and the event actually occurs. What will be the consequences? To get a more complete picture of the risk associated with the different wells, both sides of the bow tie need to be investigated. By focusing on the left side only, an important part is left out from the overall risk. If an accident occurs, the potential consequences could be huge. The consequences depend on a lot of factors regarding installation type, type of well, leakage characteristics, reservoir performance etc.

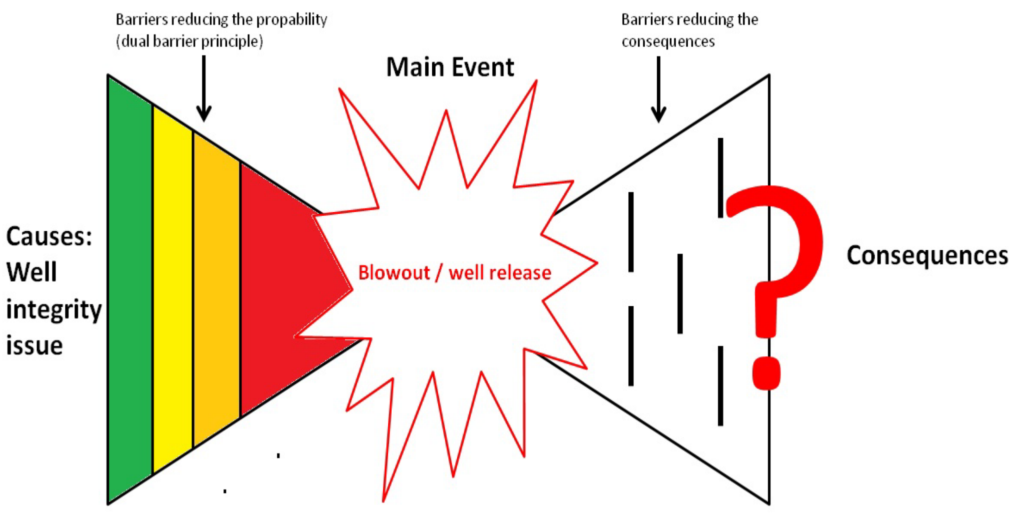


Figure 21: Bow tie diagram illustrating blowout / well release risk for a well.

As it is today, wells within the same risk status code can pose different levels of risk. This can be very misleading, as it may be difficult to rank the wells and find out which needs the highest prioritization. It leads to the question: how red / orange is a red / orange well?

Wells in the operational phase which are ranked as orange or red on barrier status are against the dual barrier authority criterion (ref the Activities Regulations § 85). Scarce resources make it impossible to perform interventions and workovers to re - establish the barrier(s) on all these wells at the same time. A selection of which get the first hand treatment must be made. If the barrier cannot be redefined, the well has to be shut in until the barrier is re - established. Statoil has between 30 - 40 orange wells (a lot less red wells, between 1- 4) at any time and there is a need for further differentiation with regards to risk. In this way the most risky orange / red wells can be identified, handed over to the D&W organization for remediation and prioritized before the ones ranked less critical.

The most critical red and orange wells can be identified by having a system where the escalation risks are implemented in a better way and the potential consequences are included. In the next chapter proposals of such systems will be presented. This thesis suggests three new models for risk categorization. As there are numerous factors controlling the consequences, constructing a model representing all of them is very challenging. Much time was spent on trial and error in the development of the different systems. The final model which is best suited to describe the risk is presented in the end of next chapter.

4. PROPOSAL OF NEW SYSTEMS FOR DEFINING RISK STATUS CODES

In the operational phase a well component failure may result in changes in blowout and well release risk. How to assess this increased risk is focused on in this thesis, and it should be reflected in the final status code. Well barrier elements form an envelope preventing uncontrolled flow to the surroundings. In this way the barrier envelopes minimize the likelihood of a blowout or well release, and the barrier status can therefore be directly linked to the probability part of the risk definition. In the end of this chapter a new procedure for defining risk status codes will be proposed as an improvement to the one used today. It builds on the already existing principles for defining barrier status (shown in table 8), but includes a new feature – the potential consequences if there (in worst case) should be a leak to the environment / surface. The consequences are a function of many factors, in this thesis presented as different consequence factors. The purpose of the new system is to get a better measure of the risks the wells with integrity issues pose, and help differentiate wells within the same red and orange risk status code. This is a challenge today, as wells within the same category may have very different levels of risk depending on the severity of the integrity issue and how big the potential consequences may be. There is need for a system that can help defining which red and orange wells are the most critical with highest priority in the first run.

The wells ranked high in the new categorization system will need additional resources, first in form of a more detailed risk assessment. This assessment shall investigate if these wells actually pose a larger risk compared to the others, and if immediate repair is required.

This thesis will present different suggestions on models for risk categorization including the consequence aspects. Due the number of factors controlling the impact of a leak to the surroundings, it was challenging constructing a model taking all of them in to consideration. As there are several different well configurations and systems, the creation of a model capturing every case is hard. Several attempts on constructing categorization systems were performed before finding the one most representative. The final model, which is best suited to describe the overall risk for most of the wells, is suggested in the end. Its ability to reflect different levels of seriousness is evaluated by testing it on 5 field cases. First a discussion of the most important factors determining the potential consequences will be carried out.

4.1 Consequence factors

The consequences will relate to health, safety and environment (HSE factors). Due to the fact that most of the wells have not yet experienced a leak to the surroundings, the consequences will reflect potential scenarios resulting from a blowout / well release situation. There are a number of factors that will decide the severity of the potential consequences of a well integrity issue. Beneath is a listing of some of them:

Type of x - mas tree

- Dry (Platform wells).
- Wet (Subsea wells).

The position of the x - mas tree will have a huge impact on the consequences if there is a leakage through the wellhead or x - mas tree seal assemblies or valves. On a subsea well the leakage will go to seabed, but on a platform well there is a potential of getting hydrocarbons directly on the platform deck. This will be the worst imaginable scenario. On platform wells there is an annulus bleed off possibility through the annulus access valves when experiencing SCP. The same possibility does not exist for subsea wells where the tree is positioned on seabed and there is only access to the A annulus.

Well type

- Production well.
- Injection well.

It is hard stating which type of well is the most risky. But a water injector with no possibility of hydrocarbon reflux from the reservoir will pose a much lower risk than an oil or gas flowing producer with regards to blowout / well release. A gas injector adding energy to the reservoir will however be more exposed to a dangerous situation as a component failure may lead to a major gas leak.

Artificial lift

- Free flowing producer.
- Producer with artificial lift.

As the pressure decreases in the reservoir, artificial lift may be required for continued production. Energy is then added to the fluid column in the wellbore, and the most common principles used are gas lift and pumps. In a gas lift well, gas is injected via A - annulus through a gas lift valve into the tubing reducing the density of the fluid. Introducing gas in the A- annulus, adds an extra element to the overall risk as a large volume of gas can create a very dangerous situation in a well release situation. Such wells need additional barriers, preventing the gas from leaking out of the annulus. However, it is difficult to determine if there actually is a higher risk associated with gas lift wells contra free flowing production wells as the latter will produce from a reservoir with higher pressure. Assuming that the extra barriers for gas lift are in place and the gas lift pumps will automatically shut down in an emergency situation, these wells shall in theory not be more risky than the free flowing producers, rather contrary.

Installation type

- Fixed platform concepts (used primarily with dry tree wells).
- Floating production units (used in combination with subsea wells).
- Tension leg platforms and deep draft floaters (used primarily in combination with dry tree platform wells but can also have subsea wells).
- Satellite fields with tie - back to installation.

Satellite fields a distance away from the installation will not have the potential of endanger any human lives. But a leakage to seabed may be devastating for the environment, especially if the leaking medium is oil. Fixed installations in combination with platform wells will have higher risk related to injuries / loss of lives in a blowout / well release situation. This is due to the potential of getting hydrocarbons on deck or washouts at seabed which can cause stability problems for the installation. Hydrocarbons reaching the platform deck may lead to fire or explosion which can do extensive harm to personnel and assets. Floating units may experience buoyancy problems if a certain amount of gas leaks directly under the unit, or problems with mooring lines and anchors. This is critical for wells positioned directly under the installation.

Installation activity

- Manned.
- Unmanned.

Obviously an unmanned wellhead platform is less critical than a manned platform with integrated living quarters. A major accident at one of the big platforms with high installation activity can cause loss of many lives.

Well position on seabed relative to the production unit

- Directly under the installation.
- A distance away from the installation.

As discussed previously the well position may have a major impact on the consequences, especially for the floating facilities. Are the wells positioned directly under the floater, a gas leakage may cause buoyancy and stability problems, and in worst case scenario sink the unit. Wells positioned a distance away from the installation will have a lower associated risk, as a leakage will not have the potential of reaching the facility.

Well concentration

- Low concentration.
- High concentration.

The potential of a "domino effect" arises when many wells are situated close to each other in clusters as a blowout / well release from one well can in turn damage other wells or structures at seabed.

Multiple well failures

- Single well failure.
- Multiple well failures.

Multiple well failures in a field will increase the risk for the installation and its personnel. If many wells are outside the dual barrier criterion in a field, they require additional attention.

Water depth

- Deep (> 300m).
- Intermediate (100 – 300m).
- Shallow (< 100m).

In shallow water depths there is an increased risk of gas moving from seabed through water and up to the installation. In deeper water it is more likely the gas never reaches surface. The oil concentration at surface will also be significant lower if the oil needs to overcome a large depth, as it will be more spread.

Formation strength

- Sufficient.
- Insufficient: potential of fracturing.

The strength of the overlying formation around the wellbore exerted to a leakage will determine the possibility of formation fracturing. In worst case the fracture can propagate and the leakage reach seabed. The formation strength will usually depend on the depth at which the formation is exposed to the leakage. If the well has a low TD (total depth), there is an increased risk that the formation does not have sufficient strength if exposed to a high reservoir pressure. The minimum horizontal stress (fracture re – opening pressure) is often used as requirement for formation strength. This is conservative, as it is much lower than the actual pressure needed to create a fracture.

Type of well leakage

- "Internal": leakage to closed system.
- "External": leakage outwards in the well with potential of reaching seabed / surface (through tubing, casing, cement, formation or x - mas tree / wellhead).

The two types of well leakages are discussed previously. An "internal" leakage through SCSSV and x - mas tree valves (in connection with the process facility) has bleed off possibilities through the flowline system. As the leakage goes to a closed system, it is controllable and will never lead to a blowout or well release. However, if the x - mas tree should be damaged due to an external hazard and in worst case scenario, totally removed, it is critical that the SCSSV is in place and working. This is the reason for its required position - minimum 50 meters below the wellhead. For surface wells the main source of external hazard will likely be dropped objects on the platform with a potential for hitting and causing damage on the tree. Other events may be fire or explosions that can do extensive harm. For subsea wells the main source of external hazard will likely be dropped objects from vessels with potential for hitting and causing damage to the tree. Due to the extremely low probability for a total removal of the x - mas tree, this scenario is disregarded in this thesis.

An "external" leakage is more serious than the "internal". Depending on where the leakage exit point is, there will be a possibility of getting a leak of hydrocarbons to the formation, seabed or in worst case; directly on the platform. The last scenario can happen if there is a leakage into an annulus that is in direct contact with the wellhead / x - mas tree seal assemblies or valves (not in connection with the flowline system). If the seals / valves fail and the x - mas tree or wellhead is positioned on the platform, this can be a very dangerous situation. Getting hydrocarbons in a high rate directly on the platform would be catastrophic.

If a leakage results in formation fracturing, a potential buffer sand zone will reduce the risk for the hydrocarbons propagating to seabed. Buffer sand will trap the leakage and due to the size of the zone, there will be no significant pressure build up and further fracturing.

ESD – system

- Valves fail to close (open).
- Leaking above the acceptance criteria.

In an emergency situation it is critical that the ESD valves close in response to loss of signal or hydraulic pressure. A leakage through the valves is regarded less serious as they still maintain their function criteria.

Leakage characteristics

- Accumulation of hydrocarbons (not necessarily in contact with reservoir).
- Continuous flow of hydrocarbons (in contact with reservoir).

A continuous flow of hydrocarbons indicates that the leakage is in contact with the reservoir. An accumulation of hydrocarbons however is not necessarily in contact with a reservoir, and will be less critical with regards to a blowout.

Potential leak rate through barrier envelope

- Low rate: Slightly above the acceptable rate for SCSSV (API RP 14B).
- Medium rate: More than 2x the acceptable rate for SCSSV (API RP 14B).
- High rate / blowout (>> API RP 14B).

The leak rate is an important factor deciding the resulting consequences of a well integrity issue. A high rate will obviously pose a larger risk than a rate slightly above the API RP 14B criteria, which has manageable consequences if released to the surroundings. A high leak rate (blowout) can cause severe environmental pollution, increased risk of fire and explosion and may lead to a major accident which endangers the whole installation and its personnel.

Well leakage fluid

- Water.
- Gas.
- Oil.

Finding out what type of fluid is leaking is of huge importance. Is the fluid water, the risk will reduce significantly. A hydrocarbon leakage with potential of reaching the platform deck is the worst scenario as this may cause fire and explosion. A leak of hydrocarbons to seabed may have huge consequences for the environment, especially if a large volume of oil gets released. Gas leakages are more critical for the installation, due to the potential of the gas propagating through water and up to the facility where it can lead to fire and explosion. If a certain amount of gas gets trapped under a floating unit, this may also cause buoyancy and stability problems.

Ability to access the well

- Monitoring.
- Perform maintenance.
- Perform repairs.

It is harder to access subsea wells contra platform wells, and this makes it more difficult to perform maintenance and repairs. Due to the lack of monitoring of the B and C annuli on wet trees, a leak propagating outside the A-annulus can be hard to track. This makes the severity of the well integrity issue more uncertain. If immediate repair is needed in a critical situation, the subsea wells will pose a challenge due to the potential problems with accessing the well. Hooking up an intervention unit to the subsea x - mas tree may in some situations be impossible due to extreme weather conditions.

Reservoir / injection pressure (relative to hydrostatic)

- ≤ Normal (≤ Hydrostatic).
- Abnormal (> Hydrostatic).
- Abnormal high (>> Hydrostatic – HPHT wells).

The reservoir pressure will be of great importance to the consequences of an integrity issue. A depleted reservoir with no or low source of outflow will never cause a blowout as it will be impossible for the hydrocarbons to overcome the potential energy and travel up the well. A high pressure reservoir however, will have the potential of delivering a huge amount of hydrocarbons due to the amount of energy stored in the reservoir fluid. This makes the high pressure, high temperature (HPHT) wells more critical. As the reservoir pressure is dependent on depth, it will be beneficial relating it to the hydrostatic pressure, as the depth may differ from well to well.

Flow potential from reservoir

- None / some.
- Medium.
- High.

Although a reservoir with high pressure most likely has a high flow rate, there is no guarantee that this is true for all cases. The permeability and type of reservoir fluid will have a say on the flow potential. The reservoir model (size and shape) will also contribute to how much energy potentially flowing to the surroundings.

Energy source

- Reservoir.
- Injection.
- Gas lift

Where the source of energy originates from will have a great influence on possible undesirable scenarios. Is the source injection or gas lift, an automatically shut down system will contribute to reduce the risk contra a manual. An uncontrolled blowout from a reservoir will be the worst imaginable scenario, as it may be difficult killing the well.

Escalation factors

- Corrosion / erosion.
- Well kill / recoverability.
- Mechanical / pressure loads.
- Well release.

These factors are previously discussed in relation to iWIT, and will affect the consequences, especially the well kill / recoverability, pressure loads and well release. A high uncontrollable flow of hydrocarbons to the surroundings not possible to isolate or kill is as mentioned the worst possible scenario. If a leak challenges the mechanical design limits of the well, it can in turn damage other well elements and lead to failure of both barrier envelopes. Ongoing corrosion or erosion causing degradation of well components is critical in the long term perspective, but do usually not require immediate action. The group well release reflects if the leakage can result in storage of unacceptable hydrocarbon and / or toxic volumes in the annulus.

4.2 New models for risk status categorization

There are numerous factors affecting the potential consequences which can result from a well integrity issue, and some of them are listed in the previous section. The task ahead will be linking these factors in a logical system producing different categories illustrating the level of seriousness with regards to the consequences. Due to the number of factors, finding a system capturing all of them will be challenging and probably impossible. A choice as to which are the most important in terms of the overall risk must be made. Including all of them would potentially result in a very complicated and tangled system hard to use in practice. The final risk model will be a combination of the consequence categories and the already existing barrier status codes (shown in table 8), representing both the probability and impact of a blowout / well release.

In the next sections different models for risk categorization will be presented. As the main task is producing a new classification system for the consequences, this is the main part emphasized in the models.

4.2.1 Model 1 – iWIT modification

This model builds on already existing principles, but proposes a modification of the iWIT risk status system. The 5 color codes (red / orange / yellow / light green / green) for defining barrier status (as in the first Statoil KPI sheet) seen in table 8 are now called the principle codes and will be the first step in the process of defining the final risk status. A modification of the sub group system presented in iWIT is proposed as another dimension to describe the severity of the well integrity issue. This will be done as a second step, after the principle code is set, and performed by giving the well a score relating to the sub groups. The two step process is necessary for proper utilization of the escalation factor sub groups. Today's usage of this system only reflects the barrier status for the red and orange wells, as the dual barrier / blowout sub group overruns the others which are hidden in the final risk status. When the principle code is set and the escalation risk is decided after going through the sub groups, the final risk status will be a result of the combination of both. The steps are described below and seen in table 13. The well blowout / dual barrier sub group is intentionally left out, as it is identical to the principle codes.

1. Decide principle code either red, orange, yellow, light green or green.
2. Go through each of the four sub groups relating to escalation risk.
3. Give a score (from 1 to 5 where 5 is the most serious) on escalation risk for each of the sub groups and summarize all of them to a final score in the end.
4. Final risk status will be: principle code + summarized score on escalation risk.

A simple method for separating wells within the same principle code is now available by denoting if they have a low or high associated escalation risk based on the score. The most critical wells have barrier failure(s) in addition to a high score from the sub groups.

The final risk status will qualitatively say something about the likelihood of an external leak and is based on the number / condition of the barriers and potential escalation risks. The escalation factors will to some extent describe the severity of the well integrity issue, and reflect a part of the consequences by involving well kill / recoverability, erosion / corrosion, well release and pressure loads. It is a simple model building on existing principles and will therefore be easy to implement.

Only taking into consideration the escalation factors, the model does not fully describe the consequences of a blowout / well release. It does not include important parameters such as type of well, installation, reservoir performance, leakage characteristics etc. Due to the lack of consequence description model 1 was quickly rejected.

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Table 13: The process of defining risk status codes for model 1.

Red	Principle: One barrier failure and the other is degraded/not verified, or leak to surface.
Orange	Principle: One barrier failure and the other is intact. Or a single failure may lead to leak to surface.
Yellow	Principle: One barrier degraded, the other is intact.
Light green	Principle: Barriers intact. Minor integrity issue
Green	Principle: Healthy Well

Decide principle code

Well kill/recoverability		SCORE
Red	Leak not possible to kill or isolate and no qualified barriers	5
Orange	Not possible to kill well if an additional single failure occur	4
Yellow	Challenging well kill procedure for handling an additional single failure	3
Light green	Integrity issue. Well kill according to requirements.	2
Green	Healthy Well	1

Mechanical/pressure loads		
Red	Failure of one barrier and secondary is exposed to pressures outside verified design limit.	5
Orange	Pressure limits exceeded and a single failure may lead to leak to surface.	4
Yellow	Potential for exceeding the pressure limits.	3
Light green	Integrity issue. Pressure loads not affected.	2
Green	Healthy Well	1

Well release risk		
Red	External HC leak through both well barriers or release of unacceptable HC or toxic volumes	5
Orange	A single failure may lead to release of unacceptable HC or toxic volumes.	4
Yellow	HC or toxic volumes may become unacceptable.	3
Light green	Integrity issue. Acceptable HC and toxic volumes.	2
Green	Healthy Well	1

Corrosion/erosion		
Red	Failure of one barrier and ongoing corrosion / erosion on other barrier	5
Orange	Ongoing corrosion or erosion causing leak through barrier	4
Yellow	Potential for corrosion/erosion exceeding barrier or structural design tolerances.	3
Light green	Integrity issue. No potential for corrosion/erosion above design tolerances.	2
Green	Healthy Well	1

Add the score from each of the four sub groups to a final score

FINAL RISK STATUS:

PRINCIPLE CODE

+

ESCALATION RISK SCORE

4.2.2 Model 2 - Flowchart

A flowchart is a diagram combining the factors in a logical manner by linking them with arrows, and by following different paths (scenarios) the result will be specific consequence categories. The pictorial presentation and logical composition of the factors make the flowchart very easy and intuitive to use and understand. It links the factors in steps or boxes and shows the path to a specific consequence category illustrating different scenarios.

Figure 22 shows an example of a flowchart for consequence categorization with four levels of seriousness illustrated with different color codes; red, orange, yellow and green. The red category represents the most critical wells with high risk for the facility and its personnel if there should be a blowout / well release. These wells have typically an “external” leak, high leak rate and a reservoir with potential of delivering a huge amount of uncontrollable energy. The orange category represents wells with significant risk for personnel, environment and facility, but is one level lower than the red with regards to seriousness. Wells with “internal” leaks, low leak rates and a reservoir with no flow potential will typically fall in the lowest levels – the green and yellow categories. The potential consequences resulting from a well integrity issue will not be as serious for these cases.

As there are numerous factors controlling the consequences, it is hard constructing a flowchart. The one presented in this thesis has selected seven of them (well type, leak type, x – mas tree, well position, leak rate, reservoir pressure and leak fluid) as the most important for the final categories. When constructing the flowchart it quickly grew to a huge and complex diagram when trying to include many factors and produce cases representing different scenarios. As each path required the same questions the chart also got characterized with a lot of repetition. This made the construction very difficult, and it was hard including additional important factors with regards to the consequences. Based on these experiences the flowchart idea was rejected, and no further work was put in to the development of a better diagram than the one presented in figure 22. This is only an example of a very simple flowchart producing different categories based on a few factors. It will not represent the severity of the consequences for different scenarios, as many important factors are not included.

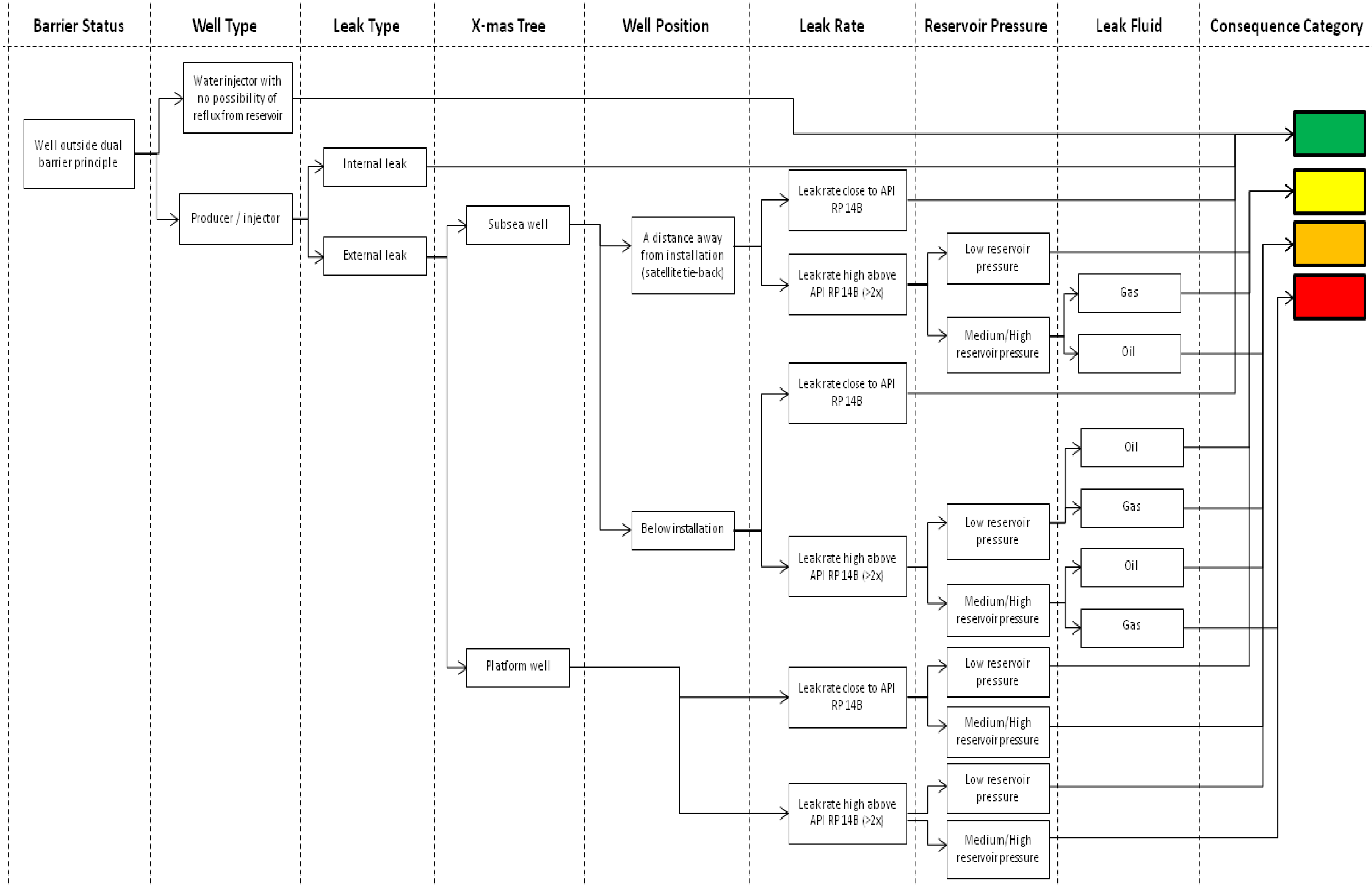


Figure 22: Example of a flowchart for consequence categorization for model 2.

4.2.3 Model 3 – Sum of the weighted consequence factors

This model will give a “consequence score” by summarizing the weighted contribute from the different factors based on their level of significance:

$$CS = \sum w_i * f_i \ ,$$

where CS is the consequence score and w_i is the weight given to the specific consequence factor, f_i.

The experience from constructing the flowchart was how the diagram got very complex and characterized with a lot of repetition when including many factors. These problems can be avoided by using the sum of the weighted consequence factors, as this method can include many parameters without getting too complicated. However, the challenge will be assigning the correct weights to the factors / parameters representing their true level of significance. Assessing which of them contributes most to the risk is a subjective evaluation.

Due to the fact that the wells will get their risk status based on the scenario of factors, some combinations may have larger impact on the consequences than others. This can be a potential problem with this method, and adjustments to the main function may be necessary.

The factors selected for the consequence categorization are parted into three areas:

- **Energy**: energy source, reservoir / injection pressure, leak medium and flow potential.
- **Surroundings**: type of well / installation, installation activity and water depth.
- **Barrier**: leakage path, potential leakage rate and challenges relating to well kill / recoverability, pressure loads, corrosion / erosion and storage of hydrocarbons / toxic volumes in annuli.

Figure 23 represents 3 different well types, a free flowing producer (A), an injector (B) and a producer with gas lift (C). The three main areas (energy, barrier and surroundings) will relate differently dependent on type of well. Free flowing producers have the reservoir as main source of energy. In injection wells the energy goes the opposite way. It flows from the installation, through the well (barrier system) and into the reservoir. Gas lift wells have two sources of energy, the reservoir and the supplied gas which increases the flow rate of the produced fluid.

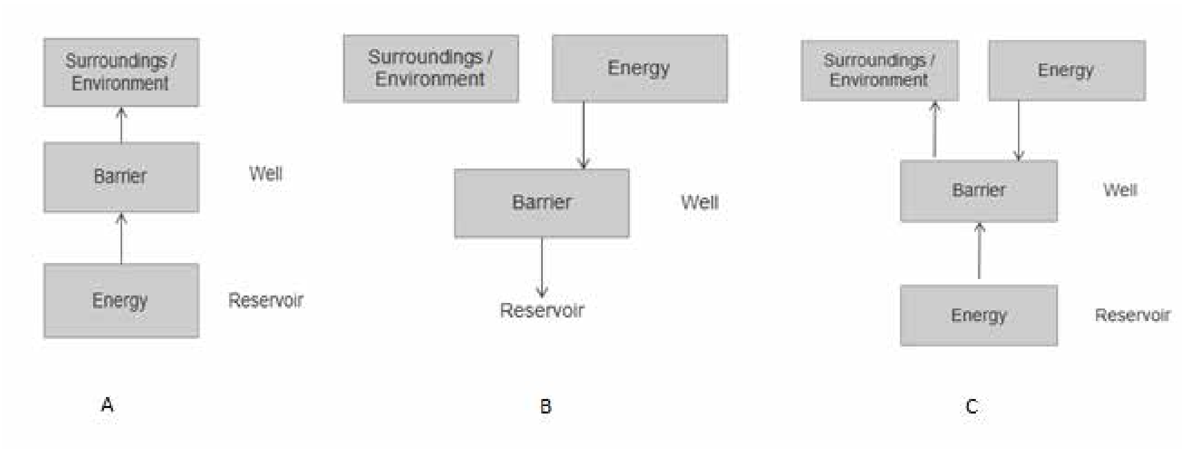


Figure 23: How energy, barrier and surroundings are related for different well types.

Dependent on type of well, the consequences may differ. This makes it challenging constructing a model taking into account every scenario of integrity issues for different types of well systems and configurations. Therefore the model must be general capturing most of the wells, as it will be impossible including the most special cases.

The area energy is the premise to a potential accident. The amount and source of uncontrollable energy, type of leaking medium and flow potential will decide the impact of a well integrity incident. Is the reservoir depleted with low pressure and flow potential, a blowout will quickly die out. A high pressure reservoir however, has the ability to deliver a huge amount of hydrocarbons for a long period of time, creating extensive damage to the environment, installation and personnel.

The area surroundings will affect how severe the consequences will be depending on type of well (platform / subsea), well position, installation activity and water depth. Subsea wells a distance away from the production unit (satellite fields), will never threaten the facility and its personnel. Is the well positioned below the facility, it will have an increased risk as a leak to seabed may propagate through water and up to surface. In deep waters, this risk reduces significantly. Platforms are most critical in regards to safety, as a leak through the wellhead / x – mas tree can lead to hydrocarbons directly on deck. Having an environmental perspective this will differ, as a hydrocarbon leakage to seabed on a subsea well can be devastating causing severe pollution especially if the leaking medium is oil.

The barrier area describes the condition of the dual barrier envelopes, as it includes leak path, potential leak rate and challenges relating to corrosion / erosion, pressure loads, well kill / recoverability and hydrocarbon storage in the well. The barriers are the technical solution preventing the underlying premise, the energy, to realize its potential for a major accident.

Factors relating to barriers, energy and surroundings represent an overall consequence picture, and hence describe the risk in a better way than before. The challenge is linking the factors with their associated weight creating a result which represents a realistic level of risk.

Model 3 summarizes the weighted contribute from each of the factors from the three areas:

$$CS = (\sum w_i * f_i)_{energy} + (\sum w_i * f_i)_{barrier} + (\sum w_i * f_i)_{surroundings}$$

A narrow weighting range (1- 10) does not reflect each factor's impact on the final score. But a wider range (1- 100) makes the weighting process more difficult. A modification to model 3 is necessary when using a narrow range, as the weighting of each parameter will not represent the severity of the most significant consequence factors. Accounting for the most important groups despite having a narrow range, an additional weighting can be performed:

$$CS = (\sum W_j * w_i * f_i)_{energy} + (\sum W_j * w_i * f_i)_{barrier} + (\sum W_j * w_i * f_i)_{surroundings,}$$

where W_j is the additional weighting to the group of consequence factors.

The most influential factors are now accounted for in the consequence score and this will be the final formula used for model 3. Simple calculation methods and layouts in excel are used to create this model, which is illustrated in table 14 (and appendix C). The contribution from each parameter is found by filling in 1 (yes) in the column named f_i (specific consequence factor / parameter) which is multiplied with the associated group weight, W_j, and specific factor weight, w_i. Final consequence score is the combined sum from energy, barrier and surroundings.

Factors contributing most to the score are reservoir / injection pressure, flow potential from the reservoir and leakage fluid, path and potential rate. These parameters will have the greatest influence on the consequences of a well integrity incident, and are given group weight (W_j) 10. The amount, rate and type of hydrocarbons flowing out of the well to the surroundings will directly decide the impact of an accident.

Type of installation, installation activity, escalation factors, water depth and source of energy are considered less important and given group weight (W_j) 5 and 3.They describe how the well / installation can handle a leak, but if the premise to a potential accident is missing, there is no point in a large accounting in the final consequence score.

The escalation factor group differs from the others due to the possibility of several (or none) fill-ins as the well can experience many challenges simultaneously (or none). Group weight (W_j) will than multiply with each factor making a well with several issues more risky.

In the next section the model will be tested on different field cases. These wells have the same barrier status (orange), but will vary in regards to the consequence factors. Final score will hopefully reflect the seriousness of the wells and rank them in a realistic order. The lowest and highest possible scores from model 3 are 111 and 820, and the field cases will fall between these values.

Table 14: Final excel model for consequence categorization.

ENERGY | fill in

	fi (1= yes)	wi	Wj	fi * wi * Wj
Energy source			3	
Injection		6		0
Gas lift		8		0
Reservoir		10		0
Reservoir / injection pressure			10	
≤ Normal		1		0
Abnormal		5		0
Abnormal high		10		0
Flow potential from reservoir			10	
None		1		0
Some		2		0
Medium		5		0
High		10		0
Leakage fluid (mainly)			10	
Water		1		0
Oil		5		0
Condensate		8		0
Gas		10		0
∑ Energy factors			SUM	0

SURROUNDINGS | fill in

	fi(1=yes)	wi	Wj	fi * wi * Wj
Type of installation			5	
Subsea		1		0
Subsea below platform		5		0
Platform		10		0
Installation activity			5	
Unmanned facility / location		1		0
Manned facility / location		10		0
Water depth			3	
Deep (> 300 m)		1		0
Medium (100 - 300 m)		5		0
Shallow (< 100 m)		10		0
∑ Surroundings factors			SUM	0

BARRIER | fill in

	fi(1=yes)	wi	Wj	fi * wi * Wj
Leakage path			10	
Inside well ("internal")		3		0
Inside --> outwards in well (" external")		5		0
Outside well (external surroundings)		10		0
Potential leak rate			10	
Low leak rate (≤ API RP 14B)		2		0
Medium leak rate (≥ 2x API RP 14B)		5		0
High leak rate / blowout		10		0
Escalation factors (can fill in none or several)			5	
Corrosion / erosion in the well		4		0
Mechanical pressure loads > design		8		0
Unacceptable HC storage in the well		10		0
Challenge relating recoverability / well kill		10		0
∑ Barrier factors			SUM	0

FINAL CONSEQUENCE SCORE 0

4.3 Case study

5 cases of wells within the same barrier status (orange: one failed barrier), but with different consequence impact, will now be presented. All have a breach in Statoil's ARIS R – 19678 requirement: *"Two independent barrier envelopes against uncontrolled blowout from reservoirs shall at all times be in place"* and are therefore shut in. They will be run in the new system for consequence categorization to check if the system actually finds the most critical wells and produce a realistic consequence score.

4.3.1 Case 1

WBS for case 1 is shown in figure 25. Additional well information is listed below:

- Water injector.
- Manned platform well.
- Reservoir pressure ≤ normal (≤ Hydrostatic).

- **Well integrity issue:** Failed primary barrier (casing to annulus leak below production packer). When the well is in operation, there is pressure build up in B – annulus as the injected water flows through the failed 9 5/8" casing. When the well is shut in the pressure falls to zero, and there has during three years not been registered pressure build up in tubing or B - annulus. There is a continuous monitoring of the pressures in tubing, A, B and C annuli.

- **Risk evaluation:** The likelihood of hydrocarbons coming from the reservoir is low due to:
  - Perforations are at 2717 m TVD whereas the initial oil water contact (OWC) was at 2702 m TVD.
  - Based on a reservoir simulation (seen in figure 24), the current OWC is at 2635 m TVD ***(29)***.
  - The oil saturation at the upper part of the well (2692 m TVD) is approximately 30%.
  - However, the simulation cannot exclude the existence of small pockets of hydrocarbons not captured in the reservoir model.

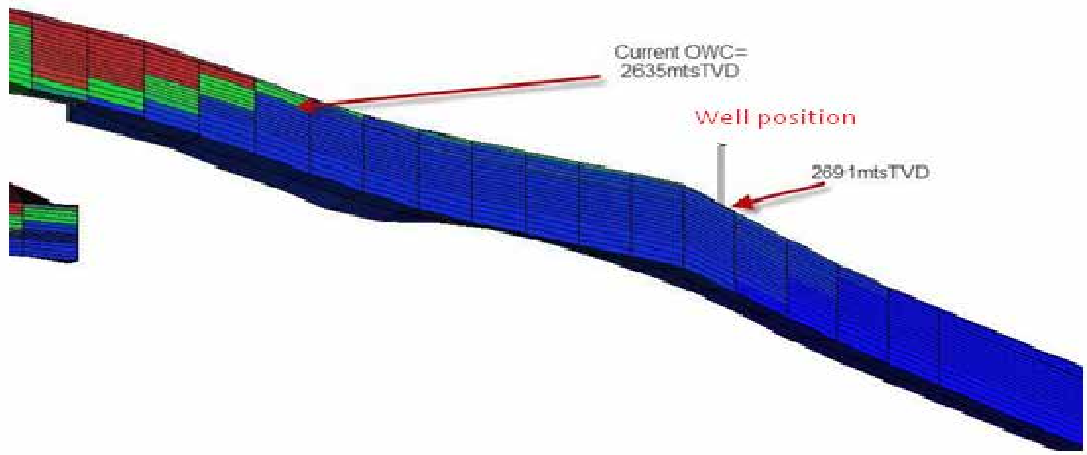


Figure 24: Reservoir simulation showing present OWC and the position of the well in case 1 (29).

Based on the performed reservoir simulation showing the presence of hydrocarbons to be very unlikely and the evaluation concluding the well does not have any inflow potential from the reservoir (continuous pressure monitoring of tubing and annuli shows zero pressure build up for three years), this well poses a low risk. The consequences will be small as the reservoir does not have any potential of creating a major accident.

Table 15 shows the result of the consequence rating for the well. It scores low on every factor, except the surroundings contribution. This is because case 1 is a manned platform well with high installation activity, which always requires additional attention. The final consequence score is 233.

Table 15: Consequence score for Case 1.

CASE 1

ENERGY (fill in)

	fi (1= yes)	wi	Wj	fi * wi * Wj
Energy source			3	
Injection	1	6		18
Gas lift		8		0
Reservoir		10		0
Reservoir / injection pressure			10	
≤ Normal	1	1		10
Abnormal		5		0
Abnormal high		10		0
Flow potential from reservoir			10	
None	1	1		10
Some		2		0
Medium		5		0
High		10		0
Leakage fluid (mainly)			10	
Water	1	1		10
Oil		5		0
Condensate		8		0
Gas		10		0
∑ Energy factors			SUM	48

SURROUNDINGS (fill in)

	fi(1=yes)	wi	Wj	fi * wi * Wj
Type of installation			5	
Subsea		1		0
Subsea below platform		5		0
Platform	1	10		50
Installation activity			5	
Unmanned facility / location		1		0
Manned facility / location	1	10		50
Water depth			3	
Deep (> 300 m)		1		0
Medium (100 - 300 m)	1	5		15
Shallow (< 100 m)		10		0
∑ Surroundings factors			SUM	115

BARRIER (fill in)

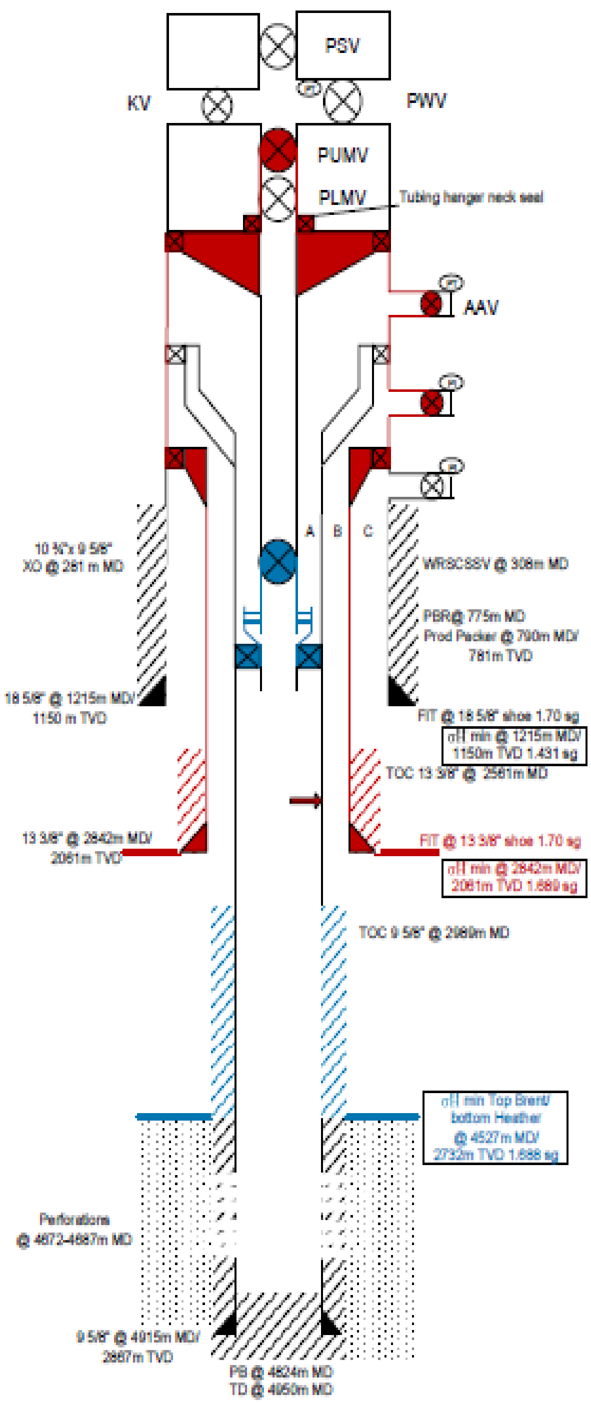
	fi(1=yes)	wi	Wj	fi * wi * Wj
Leakage path			10	
Inside well ("internal")		3		0
Inside --> outwards in well (" external")	1	5		50
Outside well (external surroundings)		10		0
Potential leak rate			10	
Low leak rate (≤ API RP 14B)	1	2		20
Medium leak rate (≥ 2x API RP 14B)		5		0
High leak rate / blowout		10		0
Escalation factors (can fill in none or several)			5	
Corrosion / erosion in the well		4		0
Mechanical pressure loads > design		8		0
Unacceptable HC storage in the well		10		0
Challenge relating recoverability / well kill		10		0
∑ Barrier factors			SUM	70

FINAL CONSEQUENCE SCORE 233

Low impact

WELL BARRIER SCHEMATIC

As built



Well barrier elements	Ref. WBEAC tables	Verification of barrier elements
PRIMARY		
Formation at Cap rock	n/a	σH min 1.688 sg. Method: Ref see Note 3.
9 5/8" Production casing cement	22	Length: 1538m MD > cap rock Method: see Note 1.
10 ¾" x 9 5/8" Production casing (up to packer) Suspected leak, see note 4.	2	PT: 280 bar with 1.50 sg (DBR 18.09.1994)
Production packer	7	PT: 280 bar with 1.10 sg (DBR 22.09.1994)
Production tubing	25	PT: 280 bar with 1.10 sg (DBR 22.09.1994)
Production tubing PBR	25	PT: 280 bar with 1.10 sg (DBR 22.09.1994)
DHSV (WRSCSSV) Control line	8	IT: 30 bar (DBR 22.09.1994) PT: 570 bar (DBR 21.09.1994)
SECONDARY		
Formation at 13 3/8" casing shoe	n/a	σH min 1.689 sg. Method: Ref see Note 3.
13 3/8" Casing cement	22	Length: 281m MD > shoe Method: see Note 2. FIT: 1.70 sg EMW (07.09.1994)
13 3/8" Casing	2	PT: 280 bar with 1.60 sg (DBR 05.09.1994)
13 3/8" Casing hanger with seal assembly	5	PT: 275 bar with 1.60 sg (DBR 06.09.1994)
WH/A-annulus access valve	12	PT: xxx bar (NN xx.09.1994)
WH/B-annulus access valve	12	PT: xxx bar (NN xx.09.1994)
Tubing hanger with seals	10	PT: 200 bar with 1.10 sg (DBR 22.09.1994)
Tubing hanger neck seal	33	PT: 345 bar (OPR 23.09.1994)
X-mas tree connector	33	PT: 345 bar (OPR 23.09.1994)
X-mas tree valve PUMV	33	PT: 280 bar (OPR 23.09.1994)
X-mas tree valves/body	33	PT: 280 bar (OPR 23.09.1994)

Notes:

1. 9 5/8" TOC: Vol control Nov 2010. FWR: 56 m3 pumped, cement job ok, no problems.
2. 13 3/8" TOC: Vol control Nov 2010. FWR: 20 m3 pumped, cement job ok, no problems .
3. Sh calibrated by XLOT, minifrac, mudloss B and vE Mohr (2010).
4. Communication between 9 5/8" csg and B-annulus. Well shut in

Risk Status Code marked (X):

	X			

Disp. no. well integrity issues	Comment
	Manglende brønnbarriere

Figure 25: WBS for case 1 (33) .

4.3.2 Case 2

WBS for case 2 is shown in figure 26. Additional well information is listed below:

- Gas Producer.
- Manned platform well.
- Reservoir pressure is abnormal high (HPHT – well).

- **Well integrity issue:** Deterioration in both primary and secondary barrier (insufficient strength of formation at 9 7/8" casing depth, production packer depth and the 9 7/8" casing cement is of uncertain quality). Breach in Statoil's TR – 3507, as the requirement for minimum horizontal stress at the barrier elements is not met and cement quality not verified. Calculations show minimum horizontal stress < gas gradient, but fracture gradient > gas gradient. Logging of the 7" liner cement revealed no hydraulic seal behind the liner. The log could not proof good cement in the 9 7/8" casing cement either ***(30)***.

- **Risk evaluation:** The worst case scenario in case of barrier failure is a reservoir gas leakage fracturing overburden formation and a subsequent leak to the seabed or to the annulus of the platform wells. A study on the potential leak paths for reservoir gas and the recipient sands in the overburden has been performed. The conclusion was that there is sufficient storage capacity to receive a gas leakage ***(31)***. As the formation integrity requirement is based on the minimum horizontal stress, (the fracture re - opening pressure which is much lower than the actual fracture gradient), it can be discussed if the formation integrity will fail due to a gas leakage. The well has been assessed to be orange, and not red (dual barrier failure), because of the conservative assumptions. However, both the primary and secondary barrier fail to meet minimum requirements, and the 9 7/8" casing cement is of uncertain quality. Although the probability of the leak passing both barriers is regarded low, the consequences would be enormous as it is a HPHT field. A potential blowout would also be hard to kill.

Table 16 shows the consequence score for case 2. The contribution from each factor is high, reflecting the degree of seriousness for the well. As the reservoir has the ability to deliver a huge amount of energy which can propagate to seabed or directly on platform deck (external surroundings), this well poses a very high risk. This is also reflected in the final consequence score which is > three times higher than for case 1, with a value of 735.

Table 16: Consequence score for Case 2.

CASE 2

ENERGY — fill in

	fi (1= yes)	wi	Wj	fi * wi * Wj
Energy source			3	
Injection		6		0
Gas lift		8		0
Reservoir	1	10		30
Reservoir / injection pressure			10	
≤ Normal		1		0
Abnormal		5		0
Abnormal high	1	10		100
Flow potential from reservoir			10	
None		1		0
Some		2		0
Medium		5		0
High	1	10		100
Leakage fluid (mainly)			10	
Water		1		0
Oil		5		0
Condensate		8		0
Gas	1	10		100
∑ Energy factors			SUM	330

SURROUNDINGS — fill in

	fi(1=yes)	wi	Wj	fi * wi * Wj
Type of installation			5	
Subsea		1		0
Subsea below platform		5		0
Platform	1	10		50
Installation activity			5	
Unmanned facility / location		1		0
Manned facility / location	1	10		50
Water depth			3	
Deep (> 300 m)		1		0
Medium (100 - 300 m)	1	5		15
Shallow (< 100 m)		10		0
∑ Surroundings factors			SUM	115

BARRIER — fill in

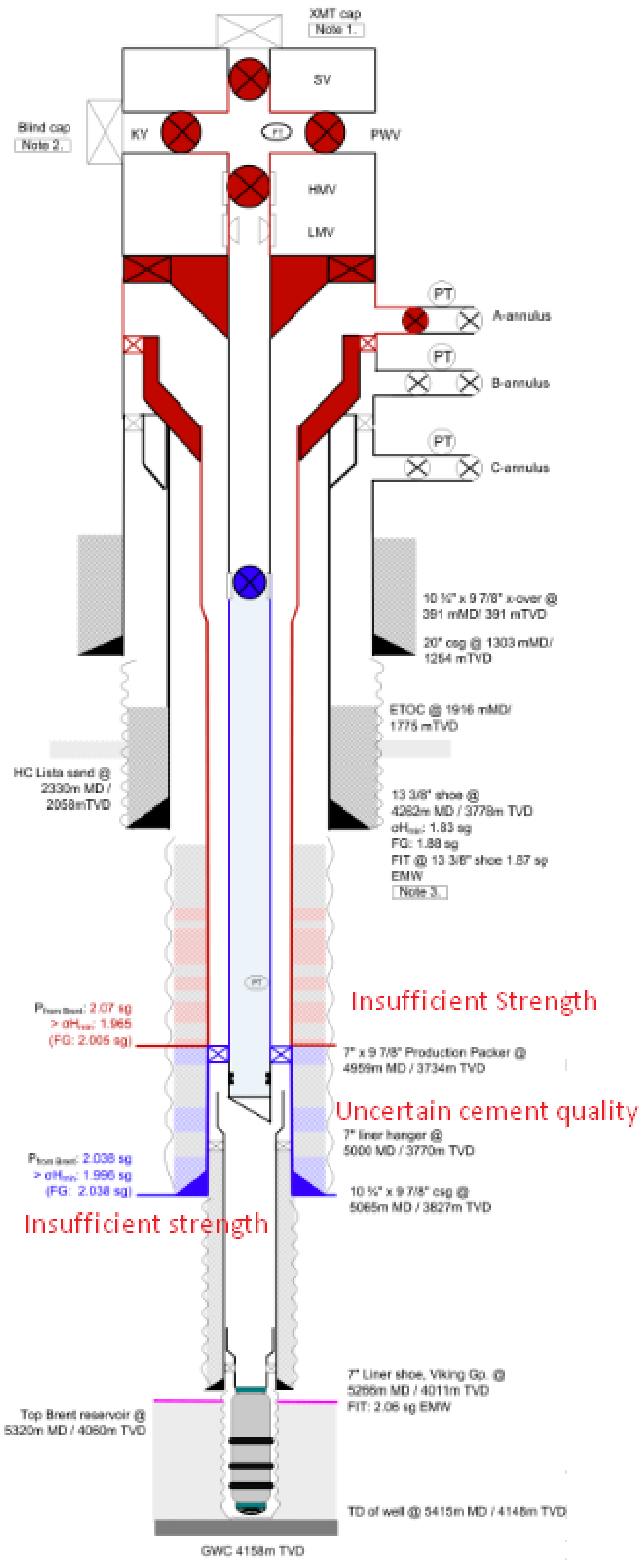
	fi(1=yes)	wi	Wj	fi * wi * Wj
Leakage path			10	
Inside well ("internal")		3		0
Inside --> outwards in well (" external")		5		0
Outside well (external surroundings)	1	10		100
Potential leak rate			10	
Low leak rate (≤ API RP 14B)		2		0
Medium leak rate (≥ 2x API RP 14B)		5		0
High leak rate / blowout	1	10		100
Escalation factors (can fill in none or several)			5	
Corrosion / erosion in the well		4		0
Mechanical pressure loads > design	1	8		40
Unacceptable HC storage in the well		10		0
Challenge relating recoverability / well kill	1	10		50
∑ Barrier factors			SUM	290

FINAL CONSEQUENCE SCORE 735

High impact

WELL BARRIER SCHEMATIC

Verification



Well barrier elements	Ref. WBEAC tables	Verification of barrier elements
PRIMARY		
Formation at 9 7/8" casing shoe (note 5)	n/a	σH_{min}: 1.996 sg (field model)
10 ¾" x 9 7/8" production casing cement (note 7)	22	Method: IBC/CBL/VDL log
10 ¾" x 9 7/8" production casing (below prod. packer)	2	PT: 660 bar with 1.66 sg mud DBR: 29.04.2013
7" x 9 7/8" production packer	7	PT: 660/460 bar differential from above/below with 1.047 sg packer fluid
7" production tubing	25	PT: 660 bar with 1.047 sg packer fluid
TRSCSSV	8	IT low: 70 bar/30 min, IT high: 612 bar/10 min
SECONDARY		
Formation at production packer (note 6)	n/a	σH_{min}: 1.965 (from field model)
10 ¾" x 9 7/8" production casing	2	PT: 660 bar with 1.66 sg mud DBR: 29.04.2013
10 ¾" x 9 7/8" production casing cement (note 7)	22	Method: IBC/CBL/VDL log
10 ¾" production casing hanger w/ seal assembly	5	PT: 690 bar DBR: 17.04.2013
10 ¾" production casing hanger w/ seal assembly	5	PT: 690 bar DBR: 17.04.2013
Tubing hanger with MS-seal assembly	10	PT: 660 bar with 1.047 sg packer fluid (from below when pressuring up annulus)
Tubing hanger neck seal	10	PT: 827 bar (PT with local pump)
WH/XMT Connector	33	PT: 660 bar with 1.047 sg packer fluid
WH/ A-Annulus valve	12	PT: 660 bar with 1.047 sg packer fluid
XMT valves	33	PT: 660 bar with 1.047 sg packer fluid

NOTES: Gas gradient used: 0.0374 bar/m – confirmed by PETEC from samples

1. XMT cap is installed and pressure tested to 660 bar as a double barrier against well.
2. Blind cap on KV is installed and pressure tested to 660 bar as a double barrier against well.
3. B-annulus bullheaded with 1.70 sg $CaCl_2/CaBr_2$ (DBR 18.04.2013)
4. Prognosis: Tarbert/Ness: 760 bar @ 4000 m TVD MSL with uncertainty -35/+14 bar.
5. Required drawdown to get formation integrity at 9 7/8" shoe:
   σH_{min}: 13 bar, FG: -3 bar (the formation integrity with fracture gradient is ok)
6. Required drawdown to get formation integrity at 7" x 9 7/8" production packer:
   σH_{min}: 38 bar, FG: 24 bar
7. Hydraulically sealing cement based on logging in the 9 7/8" production casing:

Interval top [mMD]	Interval bottom [mMD]	Cement bond quality	Hydrualic isolation	Length of isolating interval [m]
4769	4774	Moderate to good	Yes	5
4888	4922	Moderate to good	Yes	34
4926	4935	Good	Yes	11
4938	4946	Good	Yes	8
4952	4961	Good	Yes	9
4979	4983	Moderate to good	Yes	4
5015	5050	Good	Yes	35

Risk status code marked (X):

	X			

Disp. no. well integrity issues	Comment
	Using 9 7/8" shoe fracture gradient as primary well barrier and insufficient formation strength at production packer setting depth.

Figure 26: WBS for case 2 (33) .

4.3.3 Case 3

WBS for case 3 is shown in figure 27. Additional well information is listed below:

- Oil Producer.
- Subsea well distanced away from installation (tie - back well).
- Reservoir pressure is abnormal (> Hydrostatic).

- **Well integrity issue:** Failed primary barrier (oil leakage at approximately 0.8 l/ min through production packer into A and B annuli). During operation an increase in A – annulus pressure (which was impossible to bleed off in the annulus bleed line) was detected and due to holes in tie - back casing the A and B annuli were in communication. The pressure is stabilized at a higher value than the C annulus can withstand if the leakage should propagate out of the 13 3/8" casing.

- **Risk evaluation:** Should the 13 3/8" casing not withstand the pressure in B – annulus the oil will flow under the 20" casing shoe, which has insufficient strength, and into the overlying formation. In worst case scenario the oil could move all the way up to seabed due to formation fracturing. However, as the intermediate casing is a part of the secondary barrier, it is designed and tested to withstand the high pressure. It shall in theory not be exposed for degradation. Due to the fact that this is a subsea well distanced far away from the installation, there is no risk related to safety. But a large leak would be devastating for the environment, as the well has a high potential of delivering huge amounts of oil for a long period of time. There is also an unacceptable amount of hydrocarbons stored in the A and B – annulus, which would cause pollution if released to the environment. As the wellhead area is subsea there are challenges relating to restoring the barrier and to kill the well in a critical situation. This makes the well serious in regards to the consequences if there should be a leak to seabed, as this can result in severe environmental pollution. Due to the lack of monitoring of the B and C annuli on wet trees, a leak propagating outside the A - annulus can be hard to track, and the integrity issue therefore has a larger associated uncertainty.

Table 17 shows the consequence score for case 3, where the well gets a high value, 505, due to the reservoir performance and escalation factors. As mentioned the well can never threaten the safety on an installation, but has the potential to create major environmental damage.

Table 17: Consequence score for Case 3.

CASE 3

ENERGY — fill in

	fi (1= yes)	wi	Wj	fi * wi * Wj
Energy source			3	
Injection		6		0
Gas lift		8		0
Reservoir	1	10		30
Reservoir / injection pressure			10	
≤ Normal		1		0
Abnormal	1	5		50
Abnormal high		10		0
Flow potential from reservoir			10	
None		1		0
Some		2		0
Medium		5		0
High	1	10		100
Leakage fluid (mainly)			10	
Water		1		0
Oil	1	5		50
Condensate		8		0
Gas		10		0
∑ Energy factors			SUM	230

SURROUNDINGS — fill in

	fi(1=yes)	wi	Wj	fi * wi * Wj
Type of installation			5	
Subsea	1	1		5
Subsea below platform		5		0
Platform		10		0
Installation activity			5	
Unmanned facility / location	1	1		5
Manned facility / location		10		0
Water depth			3	
Deep (> 300 m)		1		0
Medium (100 - 300 m)	1	5		15
Shallow (< 100 m)		10		0
∑ Surroundings factors			SUM	25

BARRIER — fill in

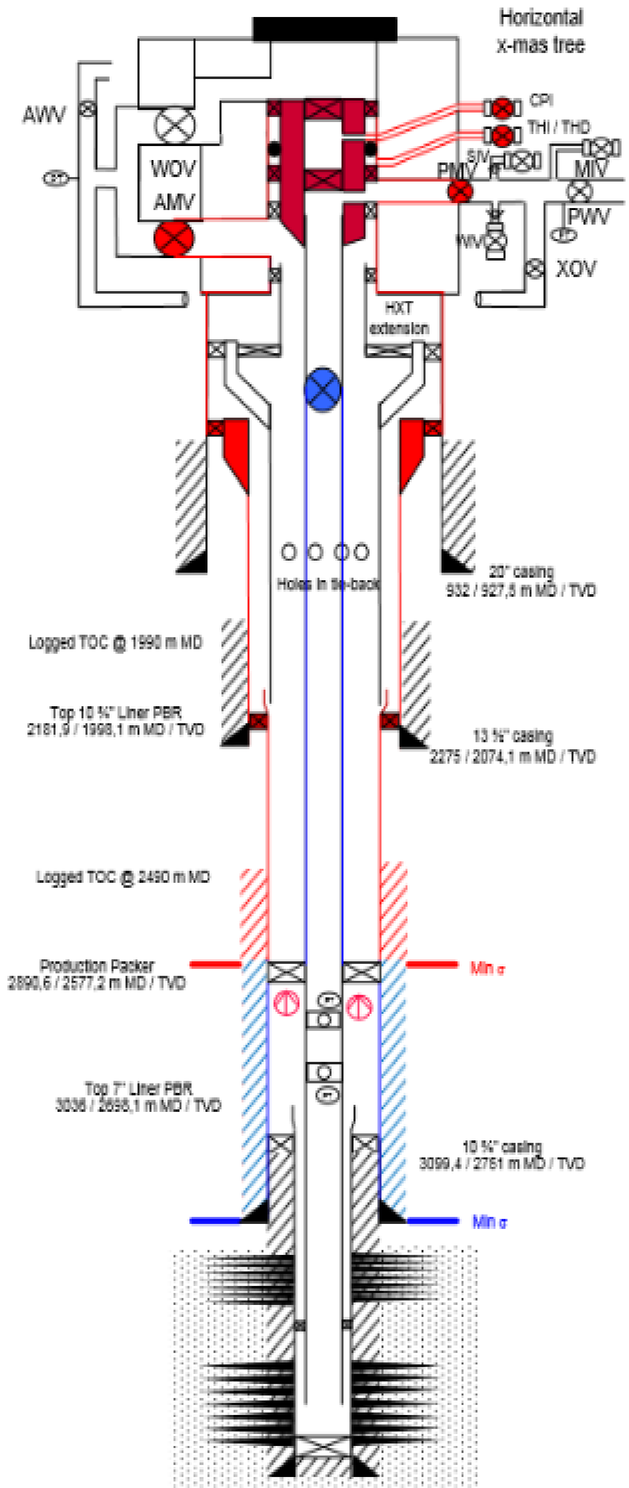
	fi(1=yes)	wi	Wj	fi * wi * Wj
Leakage path			10	
Inside well ("internal")		3		0
Inside --> outwards in well (" external")	1	5		50
Outside well (external surroundings)		10		0
Potential leak rate			10	
Low leak rate (≤ API RP 14B)		2		0
Medium leak rate (≥ 2x API RP 14B)		5		0
High leak rate / blowout	1	10		100
Escalation factors (can fill in none or several)			5	
Corrosion / erosion in the well		4		0
Mechanical pressure loads > design		8		0
Unacceptable HC storage in the well	1	10		50
Challenge relating recoverability / well kill	1	10		50
∑ Barrier factors			SUM	250

FINAL CONSEQUENCE SCORE 505

High impact

WELL BARRIER SCHEMATIC

Monitoring



Well barrier elements	Ref. WBEAC tables	Verification of barrier elements
PRIMARY		
Formation at 10 ¾" Shoe	n/a	σ_h min: 1.80 sg Method: FIT (DBR 26.9.2012)
10 ¾" liner cement	22	TOC 2490 mMD Method: USIT LOG (DBR 22.09.2012)
10 ¾" liner	2	PT: 330 bar with 1.51 sg OBM (DBR 22.09.2012)
Production Packer Failed	7	PT: 420 bar with 1.06 sg brine (DBR 20.12.2012)
Production tubing	25	PT: 420 bar with 1.06 sg brine (DBR 20.12.2012)
DHSV	8	Inflow test to 70 / 410 bar (DBR 20.12.2012)
SECONDARY		
Formation at production packer depth	n/a	σ_h min: 1.81 sg Method: Prognosed
10 ¾" liner cement	22	TOC 2490 mMD Method: USIT LOG (DBR 22.09.2012)
10 ¾" liner	2	PT: 330 bar with 1.51 sg OBM (DBR 22.09.2012)
10 ¾" liner hanger packer	43	PT: 330 bar with 1.51 sg OBM (DBR 22.09.2012)
13 ⅜" casing	2	PT: 420 bar with 1.40 sg WBM (DBR 14.09.2012)
WH/X-mas tree Connector	5	PT: 420 bar with 1.03 sg SW (DBR 26.11.2012)
13 ⅜" casing hanger with seals	5	PT: 420 bar with 1.40 sg WBM (DBR 14.09.2012)
Tubing hanger plugs	11	PT: 420 bar with 1.03 brine (DBR 21.12.2012)
X-mas tree valves	31	PT: 420 bar with 1.03 sg SW (DBR 30.11.2012)

Notes:

1. Leak in production packer outside API criteria. (~0,8l/min)

Risk Status Code – Cat1

	x			

Disp. no. well integrity issues	Comment
	Leak through barrier

4.3.4 Case 4

WBS for case 4 is shown in figure 28. Additional well information is listed below:

- Oil Producer.
- Subsea well distanced away from installation (tie - back well).
- Reservoir pressure is abnormal (> Hydrostatic).
- Special completion with dual wellbores.

- **Well integrity issue:** Failed primary barrier (a fish above SCSSV in bore 1 makes it inoperative and the control line is exposed to reservoir fluid).The control line is isolated with a ROV operated valve in the control module placed on the subsea manifold. The leak potential is very limited, as the control line has a small diameter.

- **Risk evaluation:** If the ROV operated valve fails, there is direct communication between the reservoir and seabed through the SCSSV control line**.** The length of the control line (350 m) and the small diameter (3.5 mm) will however give a high friction, making the potential leak rate to seabed very small (≤ API RP 14 B criteria). Due to the fact that this is a subsea well distanced far away from the installation, there is no risk related to safety. The risk associated with environmental damage is also low. A leak to seabed would have to move more than 350 m to reach surface, and the oil will be significantly spread at shallow depths. This makes the oil concentration reaching surface very small. There are no factors potentially escalating the integrity issue and the remaining barrier condition has been unchanged for many years. The shut in pressure is significantly lower than pressure limit for the control line, there is not a large volume of hydrocarbons present in the well and a leak to seabed is assessed to be easy to kill. The dual wellbore completion also makes the well more robust to integrity issues as there are a several options to solve an integrity issue relating to access and reliability of other WBEs.

Table 18 shows the consequence score for case 4. It scores low on every factor, except the energy contribution. As the reservoir has potential of delivering hydrocarbons, the risk cannot be negligible. The score, 263, reflects the low degree of impact a leak to the surroundings will have both on safety and environment.

Table 18: Consequence score for Case 4.

CASE 4

ENERGY — fill in

	fi (1= yes)	wi	Wj	fi * wi * Wj
Energy source			3	
Injection		6		0
Gas lift		8		0
Reservoir	1	10		30
Reservoir / injection pressure			10	
≤ Normal		1		0
Abnormal	1	5		50
Abnormal high		10		0
Flow potential from reservoir			10	
None		1		0
Some		2		0
Medium	1	5		50
High		10		0
Leakage fluid (mainly)			10	
Water		1		0
Oil	1	5		50
Condensate		8		0
Gas		10		0
∑ Energy factors			SUM	180

SURROUNDINGS — fill in

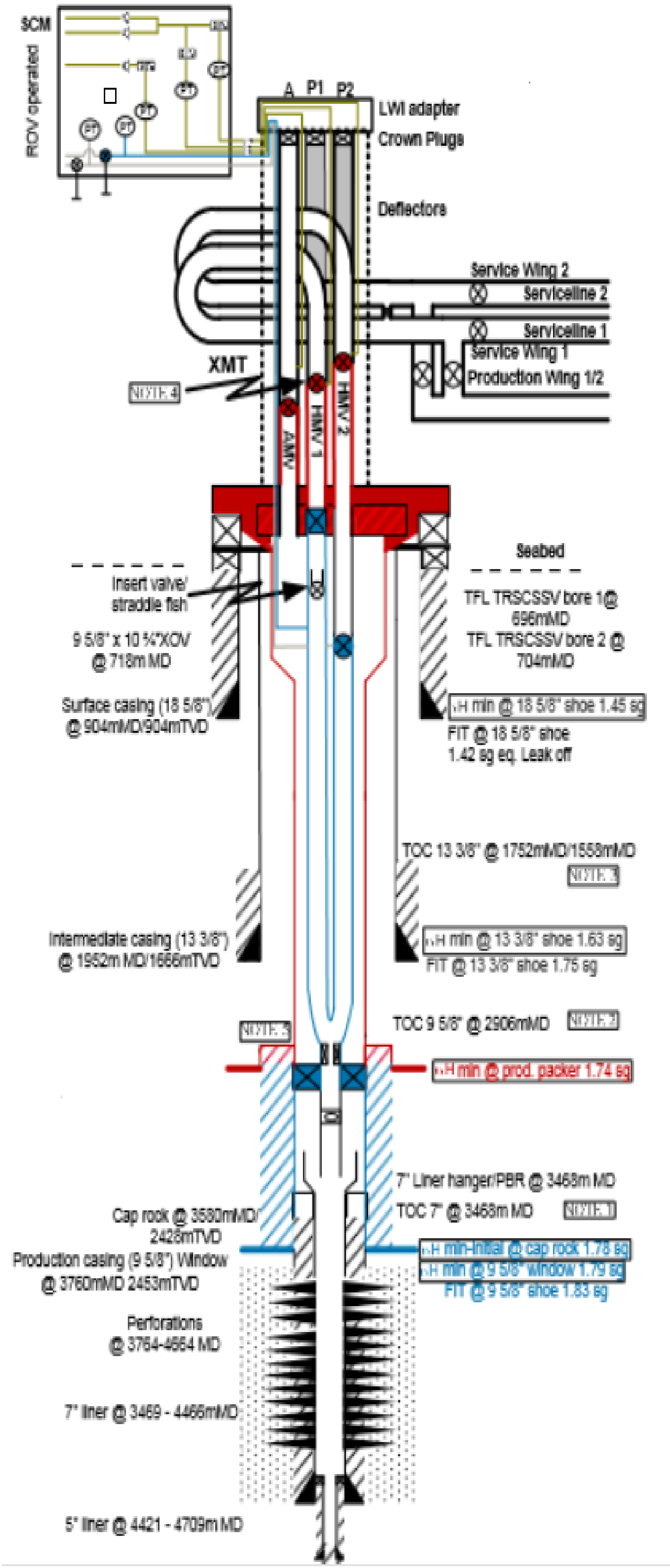
	fi(1=yes)	wi	Wj	fi * wi * Wj
Type of installation			5	
Subsea	1	1		5
Subsea below platform		5		0
Platform		10		0
Installation activity			5	
Unmanned facility / location	1	1		5
Manned facility / location		10		0
Water depth			3	
Deep (> 300 m)	1	1		3
Medium (100 - 300 m)		5		0
Shallow (< 100 m)		10		0
∑ Surroundings factors			SUM	13

BARRIER — fill in

	fi(1=yes)	wi	Wj	fi * wi * Wj
Leakage path			10	
Inside well ("internal")		3		0
Inside --> outwards in well (" external")	1	5		50
Outside well (external surroundings)		10		0
Potential leak rate			10	
Low leak rate (≤ API RP 14B)	1	2		20
Medium leak rate (≥ 2x API RP 14B)		5		0
High leak rate / blowout		10		0
Escalation factors (can fill in none or several)			5	
Corrosion / erosion in the well		4		0
Mechanical pressure loads > design		8		0
Unacceptable HC storage in the well		10		0
Challenge relating recoverability / well kill		10		0
∑ Barrier factors			SUM	70

FINAL CONSEQUENCE SCORE 263

Low impact



Well barrier elements	Ref.WBEAC tables	Verification of barrier elements
PRIMARY		
Formation at cap rock	n/a	sh-min: 1.78 sg, ref P-17 A overburden table
9 5/8" Casing cement (up to production packer)	22	PT: 300 bar with 1.64 sg (25.12.1994) FIT: 1.83 sg (DBR 28.12.1994).
9 5/8" Casing	2	300 bar with 1.64 sg (DBR 25.12.1994)
Production packer	7	345 bar with 1.1 sg (DBR 11.04.1995)
Tubing (bore 2) (prod.packer to TRSCSSV)	25	345 bar with 1.1 sg (DBR 11.04.1995)
Tubing (bore 1) (prod.packer to TH plug)	25	345 bar with 1.1 sg (DBR 11.04.1995)
DHSV #2 with insert Control line	8	IT: 70 bar (DBR 21.04.2008) PT: 520 bar (initial)
DHSV #1 Control line	8	PT: 520 bar (date xx), PT: xx bar (xx)
Tubing hanger plug (in bore 1)	11	Inflow test to 120 bar with MEG (DBR 16.08.2006)
BSV control line bore 1 (closed at ROV isol.valve on SCM)		Communication between production bore and CL
SECONDARY		
Formation at production packer	n/a	sh-min: 1.74 sg, ref P-17 A overburden table
9 5/8" production casing cement	22	345 bar with 1.1 sg (11.04.1995) Method: CBL FIT: 1.83 sg (DBR: 28.12.1994).
9 5/8" production casing	2	300 bar with 1.64 sg (DBR 25.12.1994)
Production casing hanger with seal assembly	5	300 bar with 1.64 sg (25.12.1994)
Subsea WH	5	300 bar with 1.64 sg (DBR 25.12.1994)
Wellhead/ X-mas tree connector	5	300 bar with 1.64 sg (DBR 25.12.1994)
Tubing hanger with seals	10	Initial test 345 bar with 1.64 sg (DBR 10.04.1995)
XMT body	31	Initial test 345 bar with 1.64 sg (DBR 10.04.1995)
WH/X-mas tree connector	31	Initial test 345 bar with 1.64 sg (DBR 10.04.1995)
X-mas tree valve PMV1 & 2	31	Initial test 345 bar with 1.64 sg (DBR 10.04.1995)
X-mas tree valve AMV	31	Initial test 345 bar with 1.64 sg (DBR 10.04.1995)
X-mas tree valves/body	31	345 bar with 1.64 sg (DBR 10.04.1995)

Notes:

Bore 1 is plugged. Fish in bore 1 above SCSSV.
WRSCSSV(insert safety valve) in TRSCSSV in bore 2.

Note 1 to 3: See FWR.

Risk Status Code marked (X):

	X (CAT2)			

Figure 28: WBS for case 4 (33) .

4.3.5 Case 5

WBS for case 5 is shown in figure 29. Additional well information is listed below:

- Alternating water and gas injector.
- Subsea well below manned semi – submersible floater.
- Reservoir pressure is abnormal (> Hydrostatic).

- **Well integrity issue:** Failed primary barrier (tubing to annulus leak above the acceptance criteria below the SCSSV and the 9 5/8" liner cement is of uncertain quality). Corrosion in the tubing has led to a leak into A – annulus of the well below the SCSSV. The tie – back PBR is not qualified as barrier element according to today's regulations, and is regarded as a weak link where the leak can propagate to B - annulus. In addition to the failed primary barrier the 9 5/8" liner cement is also of varied (uncertain) quality according to cement log ***(32)***. The well has been used as water injector for the past months and a reflux of gas from the reservoir is regarded unlikely.

- **Risk evaluation:** Worst possible scenario is a leak of gas from the reservoir which propagates outside 7" and 9 5/8" liner (or through tubing via A – annulus and PBR) reaching the 13 3/8" shoe which cannot withstand today's shut – in pressure with gas gradient all the way up to the shoe (it can withstand the water gradient). Since the well has been used as water injector in the past months, it is regarded unlikely that gas shall flow into the well. However, as former gas injector, there will always be a possibility of reflux from the reservoir (but the gas flow potential is considered small). The probability of the leak reaching 13 3/8" casing shoe is also regarded low. As the well is subsea positioned under a manned facility, a gas leak reaching the floater would be critical. Due to the fact that it is considered to be very unlikely that gas will flow from the reservoir, the wellhead is positioned at deep waters (>350 m) and the possible leak rate of gas would be small and easy to kill, the risk relating to safety is not considerably high. Environmental risk is also small, as a leak of gas to seabed would not cause any significant pollution.

Table 19 shows the consequence score for case 5. It will have a medium impact with score 396 due to conservative assumptions in the risk evaluation, where worst case scenario assumes gas leak with potential of reaching the 13 3/8" casing shoe. As there is a low probability of gas flowing from the reservoir, the flow potential and leak rate is assessed to be small.

Table 19: Consequence score for Case 5.

CASE 5

ENERGY (fill in)

	fi (1= yes)	wi	Wj	fi * wi * Wj
Energy source			3	
Injection	1	6		18
Gas lift		8		0
Reservoir		10		0
Reservoir / injection pressure			10	
≤ Normal		1		0
Abnormal	1	5		50
Abnormal high		10		0
Flow potential from reservoir			10	
None		1		0
Some	1	2		20
Medium		5		0
High		10		0
Leakage fluid (mainly)			10	
Water		1		0
Oil		5		0
Condensate		8		0
Gas	1	10		100
∑ Energy factors			SUM	188

SURROUNDINGS (fill in)

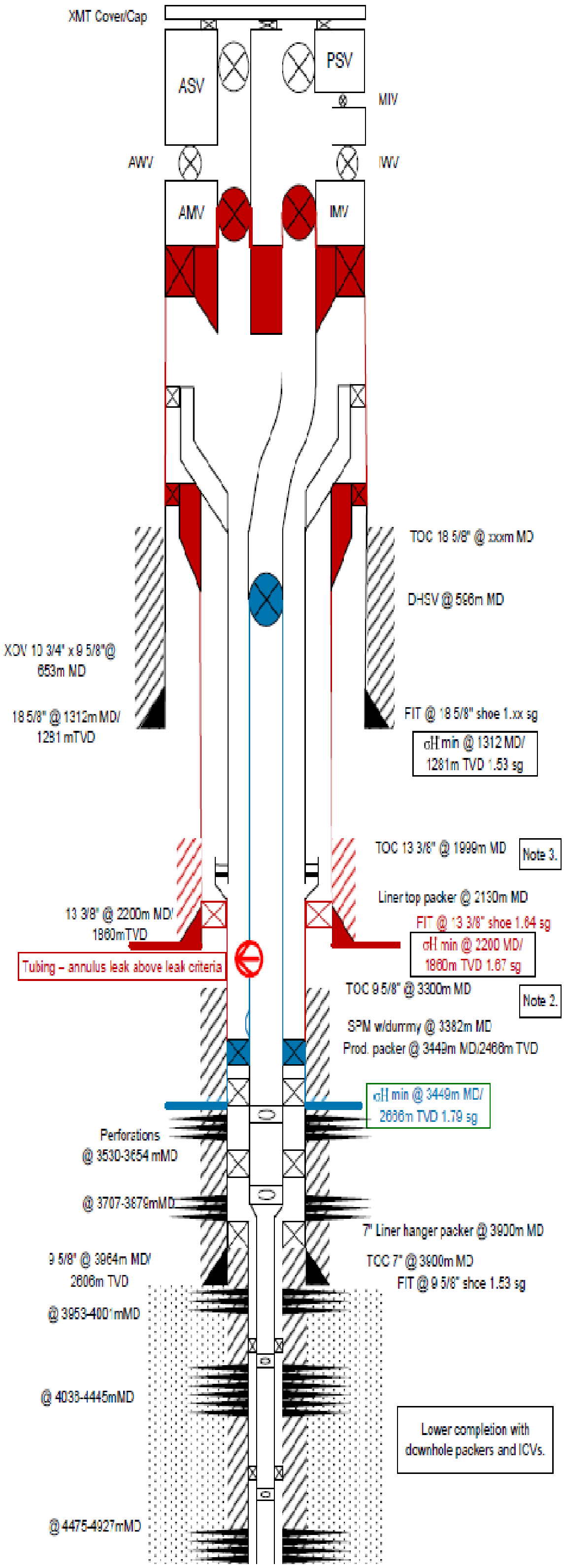
	fi(1=yes)	wi	Wj	fi * wi * Wj
Type of installation			5	
Subsea		1		0
Subsea below platform	1	5		25
Platform		10		0
Installation activity			5	
Unmanned facility / location		1		0
Manned facility / location	1	10		50
Water depth			3	
Deep (> 300 m)	1	1		3
Medium (100 - 300 m)		5		0
Shallow (< 100 m)		10		0
∑ Surroundings factors			SUM	78

BARRIER (fill in)

	fi(1=yes)	wi	Wj	fi * wi * Wj
Leakage path			10	
Inside well ("internal")		3		0
Inside --> outwards in well (" external")	1	5		50
Outside well (external surroundings)		10		0
Potential leak rate			10	
Low leak rate (≤ API RP 14B)	1	2		20
Medium leak rate (≥ 2x API RP 14B)		5		0
High leak rate / blowout		10		0
Escalation factors (can fill in none or several)			5	
Corrosion / erosion in the well	1	4		20
Mechanical pressure loads > design	1	8		40
Unacceptable HC storage in the well		10		0
Challenge relating recoverability / well kill		10		0
∑ Barrier factors			SUM	130

FINAL CONSEQUENCE SCORE 396

Medium impact



Well barrier elements	Ref. WBEAC tables	Verification
PRIMARY		
Formation at 9 5/8" liner shoe	n/a	σH min 1.79 sg. Method: Overburden data from 34/7-P-17 A.
9 5/8" Production liner cement	22	Length: 230m MD > top perforations Method: see Note 2. FIT: 1.53 sg (DBR 20.02.2003)
9 5/8" Production liner (up to prod packer)	2	PT: 385 bar with 1.25 sg (DBR 24.03.2003)
Production packer	7	PT: 385 bar with 1.30 sg (DBR 22.04.2003). σH min 1.79 sg Method: Field model
Production tubing	25	PT: 385 bar with 1.30 sg (DBR 22.04.2003)
DHSV Control line	8	IT: 190 bar (DBR 23.04.2003) PT: 620 bar (DBR 21.04.2003)
SECONDARY		
Formation at 13 3/8" casing shoe	n/a	σH min 1.67 sg. Method: Overburden data from 34/7-P-17 A.
13 3/8" Casing cement	22	Length: 201m MD > shoe Method: see Note 3. FIT: 1.64 sg (DBR 03.02.2003)
13 3/8" Casing	2	PT: 230 bar with 1.49 sg (DBR 31.01.2003)
13 3/8" Casing hanger with seal assembly	5	PT: 345 bar with x.xx sg (DBR 31.01.2003)
Tubing hanger with seals	10	PT: 385 bar with 1.1 sg (DBR 01.05.2003)
WH/X-mas tree connector	31	PT: 385 bar (DBR 15.03.2005)
X-mas tree valve PMV	31	PT: 385 bar (DBR 15.03.2005)
X-mas tree valve AMV	31	PT: 385 bar (DBR 15.03.2005)
X-mas tree valves/body	31	PT: 385 bar (DBR 15.03.2005)

Notes:

1. Corrosion max 29% at 1273m MD. Log evaluation.
2. TOC 9 5/8" 3300m MD theoretical (DBR 11.02.2003). Length of good cement from top of perforations is 5 meter MD. Cement of variable quality (logged).
3. TOC 13 3/8" 1998.9m MD theoretical (DBR 30.01.2003).

Risk Status Code marked (X): TAC

Disp. no. well integrity issues	Comment
	Insufficient cement below and above production packer (flagged in Disp.)
	T/A leak above DHSV leakage criteria, leak area is below DHSV depth.

Figure 29: WBS for case 5 (33) .

4.3.6 Model 3 predictions

An evaluation of the model predictions will now be carried out. Its ability to find the most critical wells is reflected in the different consequence scores.

The 5 field cases are rated equally after the previous categorization system, where the physical barrier status in the wells directly decides the final risk status code. The 5 cases are all orange, as they have a failed barrier or a single failure in the well will result in a leak to the surroundings. However, they will pose different levels of risk depending on the consequences this leak may have both on safety and environment. This difference in risk is shown in the new model for consequence categorization where the wells are ranked in following order (1 = most serious):

1. Case 2 with consequence score 735.
2. Case 3 with consequence score 505.
3. Case 5 with consequence score 396.
4. Case 4 with consequence score 263.
5. Case 1 with consequence score 233.

These results give a good indication of the model's ability to reflect the seriousness for the different wells, as the ranking actually consigns with the risk evaluation for the different cases. There have also been performed well specific risk assessments for the 5 cases internally in Statoil, and these evaluations support the results found from model 3.

4.4 Final model for risk status categorization

The new consequence categorization (model 3) can be combined with the existing barrier status codes (seen in table 8). Constructing a matrix with the barrier status on one axis (accounts for probability) and the consequence scores on the other (accounts for impact), a more complete risk picture will be presented.

Before constructing the final matrix a division of the scores from model 3 is needed to produce different consequence categories (already shown in table 15 - 19). Three groups are reflecting the degree of seriousness relating to the impact:

- Scores < 300: Low impact.
- Scores between 300 – 500: Medium impact.
- Scores > 500: High impact.

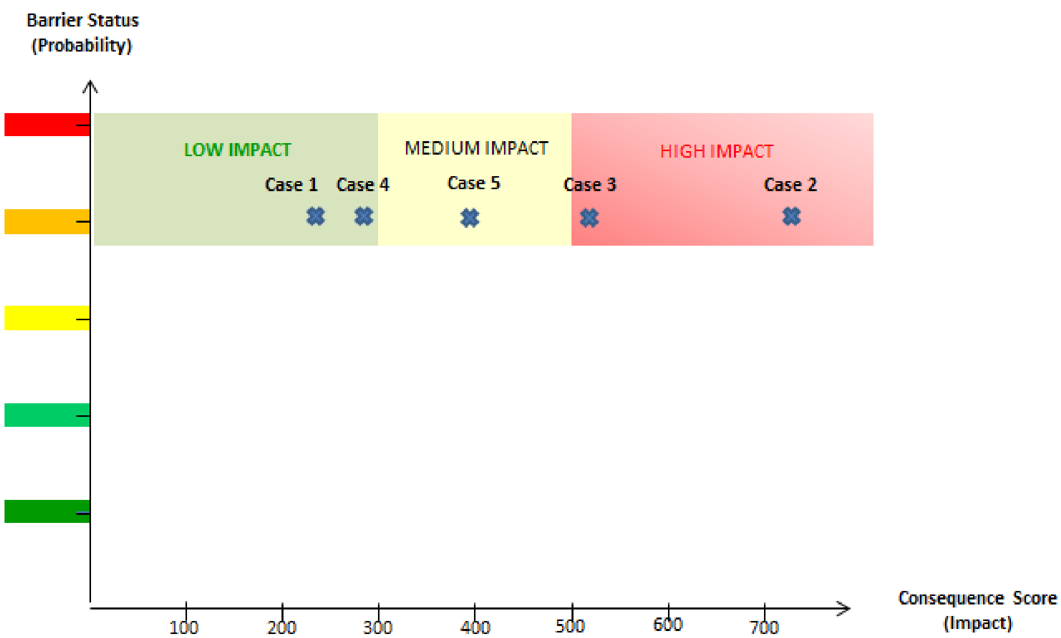


Figure 30: Matrix for final risk status categorization including the 5 field cases.

The final matrix for risk status categorization is presented in figure 30. The wells in the right upper area of the matrix (with scores > 500 and orange / red on barrier status) are considered most critical, needing the first hand prioritization.

4.5 Detailed risk assessment for the wells ranked high

Wells ranked high in the new risk categorization system need high management attention and additional resources. In the first run a detailed risk assessment must be performed finding out if the wells actually pose a higher associated risk than the ones ranked less critical. If the latter is a fact, the wells will be first in line for a workover / intervention returning them to a healthy state. This means re – establishing the lost barrier(s) by either fixing the original issue or by securing the wells with plugs (mechanical or cement).

As previously discussed, there are different risk assessment techniques for well integrity with variation of time effort and complexity. Today Statoil has no fixed standard for a detailed risk assessment procedure for the integrity of wells in operation making it difficult performing this task.

A common and easy method frequently used is a risk register table, where all the risks are listed one by one. Based on the level of impact and probability, the different risks are placed in a matrix showing which are critical and the ones less serious. This method is beneficial in the way that it is very easy to use and present, and has a low level of complexity. However, by only listing the risks, dependencies are not taken into consideration. A major accident is usually a result of the combined effects from many risks occurring simultaneously. Therefore, they need to be assessed in combination, and not isolated, to represent possible undesirable scenarios.

As the dual barrier envelopes can be seen as a system preventing hydrocarbons from flowing out of the well, a system reliability analysis is suited to assess how robust the barriers are when experiencing well element failures. A FMECA is an analysis which investigates how a component failure will affect the barrier envelopes. Nor this method takes into account dependencies, as it only looks into single component failures and isolated effects.

A fault tree analysis is a more detailed method for system reliability accounting for combined effects, as it shows which component failures result in a leak to the surroundings. The fault tree creation is time consuming and will require a lot of resources. Making a diagram representing all the possible component failures leading to a leak out of the well, is a major task. The fault tree may become too complex and hard to create.

Statoil's compliance and leadership model is an easy and understandable method of performing a risk assessment before a work task. The advantage of the model is its comprehensibility to most people who may not be that familiar to the risk assessment discipline and complex analysis methods. A weakness of the model is its generality, as it does not say which techniques to use to identify and evaluate the risks before a work task.

Developing a standard for detailed risk assessment for the most critical wells in operation (wells outside the dual barrier criterion ranked high in the new categorization system) can simplify the process and save lots of time for Statoil. This thesis suggests some techniques, but it is hard finding a perfect tool for assessing the well integrity risk for wells in operation. There needs to be a balance in the degree of details in the analysis as the complexity will increase when the level of details is high. A method too complex and time consuming will never work in practice, but simplifying the analysis can create a wrong representation of the true risks.

5. CONCLUSION

The existing risk status categorization for wells in operation is based on the NOG Recommended Guidelines 117, chapter 4. Although Statoil has developed this system a step further with implementing the escalation risks in iWIT, the creation of a system which represents the total risk picture in a better way is needed. The existing risk status categorization is mainly focused on the physical barrier status in the well hence describes the probability of a leak to the surroundings. It does not evaluate the consequences a blowout / well release would have for the installation, its personnel and the environment. As risk can be described as the combination of consequences of an event and the associated likelihood of occurrence of the event, an important part is left out in the status code.

The scope of this thesis was developing a new system including the consequences in the risk status for the wells. This system can be used for further differentiation of the red / orange wells (that are outside the dual barrier requirement) with regards to which gets the first hand prioritization and resources.

Most of the wells in the operational phase still have one barrier in place preventing the leak from reaching the surroundings. The consequences will therefore be hypothetical relating to a potential event resulting from a well integrity issue. The main hazardous event is a blowout / well release resulting in a flow of hydrocarbons to the surroundings. Depending on a number of factors, the consequences of a blowout / well release will differ from well to well. As they are based on an event that has not yet occurred, there will be a large associated uncertainty. Most likely it will never happen. However, developing a categorization system for the consequences potentially resulting from the well integrity issue will help finding the most critical wells - the wells with the largest potential for a major well integrity accident. These need the first hand prioritization and resources. Returning the most critical wells to a healthy state will reduce the overall risk that affect the whole installation, its personnel and the surrounding environment.

This thesis suggests several systems for consequence categorization, and the one most representative is presented as model 3. It is a simple system building on several factors which are given different weights according their significance. The model function summarizes each factor’s contribute, and produces a final consequence score. This score reflects the seriousness in regards to the impact a potential leak would have to safety and environment. Model 3 was tested on 5 field cases with the same status code (orange – one barrier failure) according to the existing system for risk classification. The model results clearly illustrate how the equal rating of these wells is insufficient, as they actually pose very different levels of risk based on the potential consequences. The scores gave a good indication of the model's ability to reflect the seriousness for the different wells, as the ranking actually consigned with the risk evaluation for the different cases. Well specific risk assessments performed internally in Statoil also support the results from model 3.

The new consequence categorization (model 3) can be combined with the existing barrier status codes (seen in table 8). Constructing a matrix with the barrier status on one axis (accounts for probability) and the consequence scores on the other (accounts for impact), a more complete risk picture will be presented:

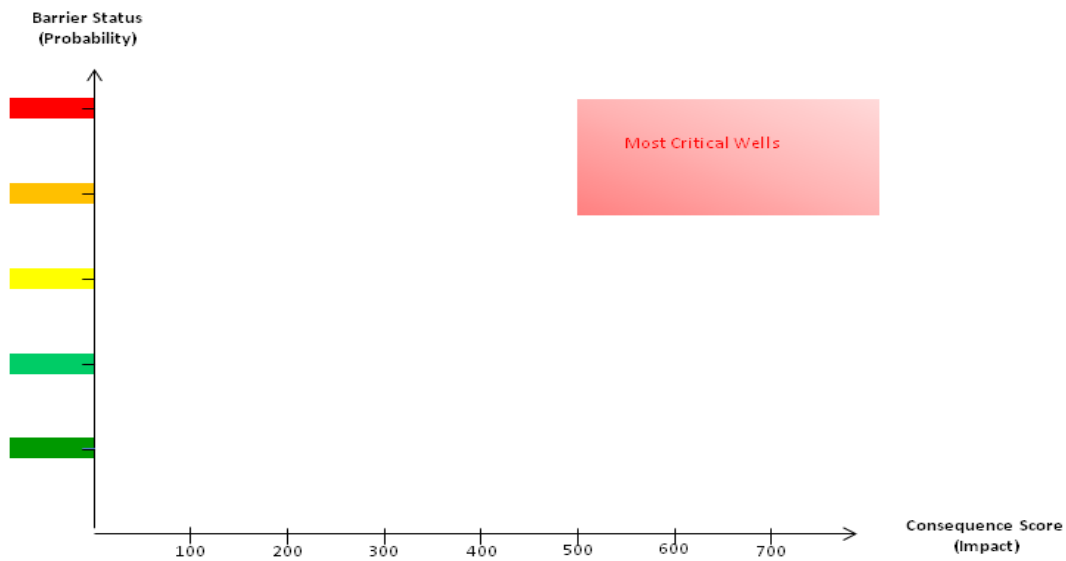
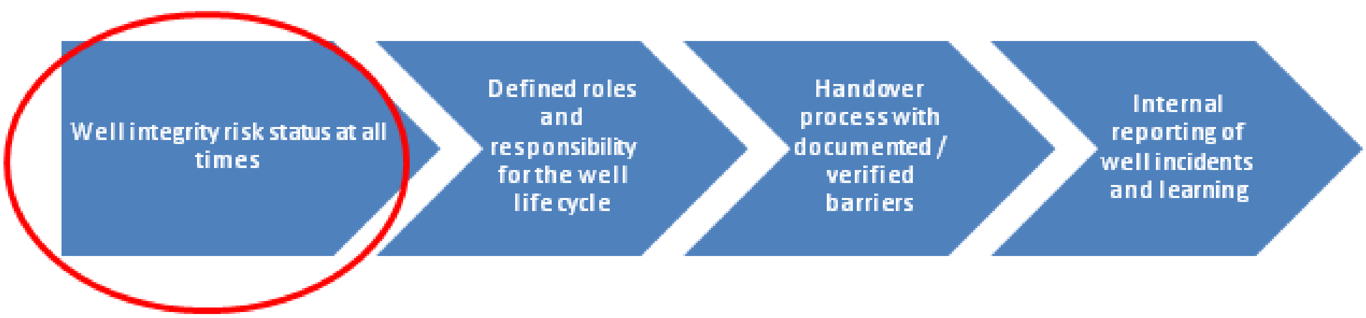


Figure 31: Matrix for final risk status categorization.

It is important to emphasize that the new system shall not undermine the existing regulatory requirement that wells with failed barrier(s) must be shut in until the dual barrier envelopes are regained. Using a low consequence score as argument for continued production / injection could turn into a dangerous trend. This is not the purpose of the new system. It is a tool helping the decision makers to determine which wells get first hand prioritization in a line of wells that need remediation. Scarce resources make it impossible to perform interventions and workovers to re - establish the barrier(s) on all these wells at the same time.

Although a major well integrity accident in the operational phase has a low associated probability, the consequences of such an event would be devastating. Loss of human lives, huge environmental damage and great financial losses (potentially destructing the operating company in charge) are some outcomes that can result from a major accident. Knowing the well integrity risk status at all times is of utmost importance.

There needs to be an understanding of who is responsible and accountable at each stage of the well's lifetime. The well can change organizations multiple times during its life, and the owner needs to be known and accountable at all times. A good process and documentation is essential for smooth and accurate handovers between organizations. Having a status representing the total risk picture for a well is therefore very important in all stages of the wells lifetime allowing the involved parties to understand the risks the wells pose. This can help preventing a major ccident.



6. FURTHER WORK

As there are numerous factors controlling the impact of a potential blowout / well release, it is difficult constructing a model capturing all of them. Model 3 is built on a few factors considered most important, and they are weighted according to which have the greatest influence on the consequences. This weighting is subjective and the values need to be adjusted. To construct a more representative model reflecting a realistic consequence picture it is essential to have participation from experienced and knowledgeable team members from a variety of disciplines and backgrounds. As the factors come from different areas, several engineers (reservoir, mechanical, process, design, risk) must be included in the model development providing a better basis for the assumptions the system is built on.

The model needs to be tested on a high number of field cases to find out which factors are most significant to the consequences. By comparing the results from many wells, it is easier to see trends and adjust the model assumptions.

A standard for detailed risk assessment for the wells that are ranked high in the new risk status categorization system is needed to assess if these are candidates for immediate workover / intervention operations. This can potentially avoid a major accident resulting from an integrity issue.

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APPENDIX A: Well barrier elements, functions and failure modes

The table below lists the types of WBEs, with the description of function and typical failure modes, which are relevant during the operational phase of a well ***(4)***.

ELEMENT TYPE	FUNCTION	FAILURE MODE (Examples)
Fluid column	Exerts a hydrostatic pressure in the well bore that prevents well influx/inflow of formation fluid.	Leak-off into a formation Flow of formation fluids
Formation strength	Provides a mechanical seal in an annulus where the formation is not isolated by cement or tubulars Provides a continuous, permanent and impermeable hydraulic seal above the reservoir Impermeable formation located above the reservoir, sealing either to cement/annular isolation material or directly to casing/liner Provides a continuous, permanent and impermeable hydraulic seal above the reservoir	Leak through the formation Not sufficient formation strength to withstand annulus pressure Not sufficient formation strength to perform hydraulic seal
Casing	Contains fluids within the wellbore such that they do not leak out into other concentric annuli or into exposed formations	Leak at connections Leak caused by corrosion and/or erosion Parted connections
Wellhead	Provides mechanical support for the suspending casing and tubing strings Provides mechanical interface for connection of a riser, BOP or production Christmas tree Prevents flow from the wellbore and annuli to formation or the environment	Leaking seals or valves Mechanical overload
Deep-set tubing plug	Provides a mechanical seal in the tubing to prevent flow in the tubing	Leaks across the seals, internal or external
Production packer	Provides a mechanical seal between the completion tubing and the casing/liner, establishing the A-annulus above and thus preventing communication from the formation into the A-annulus	Leak across the external packing elements Leak across the internal seals

ELEMENT TYPE	FUNCTION	FAILURE MODE (Examples)
Surface-controlled sub-surface safety valve	Safety valve device installed in the production tubing string that is held open, usually by the application of hydraulic pressure in a control line. If there is loss of control line hydraulic pressure, the device is designed to close automatically	Lack of control line communication and functional control Leaking above acceptance criteria Failure to close on demand Failure to close within the acceptable closing time
Liner top packer	Provides a hydraulic seal in the annulus between the casing and the liner, to prevent flow of fluids and resist pressures from above or below	Inability to maintain a pressure seal
Sub-sea production Tree	System of valves and flow conduits attached to the well-head at the sea floor, which provides a method for controlling flow out of the well and into the production system Additionally, it may provide flow paths to other well annuli.	Leaks to the environment Leaks above the acceptance criteria Inability of valves to function Mechanical damage
Annulus surface-controlled sub-surface safety valve	Safety valve device installed in the annulus that prevents flow of fluids from the annulus to the annulus wing valve	Lack of control line communication and functional control Leaking above acceptance criteria Failure to close on demand Failure to close within the acceptable closing time
Tubing hanger	Supports the weight of the tubing and prevents flow from the tubing to the annulus or *vice versa*	Leak past tubing seal Mechanical failure
Tubing hanger plug	Mechanical plug that can be installed within the tubing hanger to allow for isolation of the tubing Often used to facilitate the installation of BOPs or Christmas tree repairs	Failure to hold pressure, either internally or externally
Wellhead/annulus access valve	Provides ability to monitor pressure and flow to/from an annulus	Inability to maintain a pressure seal, or leaking above acceptance criteria Unable to close
Casing/liner cement	Cement provides a continuous, permanent and impermeable hydraulic seal along well bore between formations and a casing/liner or between casing strings. Additionally, the cement mechanically supports the casing/liner and prevents corrosive formation fluids coming into contact with the casing / liner.	Incomplete fill of the annulus being cemented, longitudinally and/or radially Poor bond to the casing/liner or formations Inadequate mechanical strength Allows flow from/to formations behind the casing/liner

ELEMENT TYPE	FUNCTION	FAILURE MODE (Examples)
Cement plug	A continuous column of cement within an open hole or inside casing/liner/tubing to provide a mechanical seal	Poor placement, leading to contamination with other fluids in the well Insufficient mechanical strength Poor bond to the casing or formation
Completion tubing	Provides a conduit for fluid to/from the reservoir to/from surface	Leak to or from the annulus. Wall thinning from corrosion and/or erosion not resistant to the load cases
Mechanical tubing plug	A mechanical device installed in completion tubing to prevent the flow of fluids and resist pressure from above or below, inside tubulars and in the annulus space between concentric positioned tubulars.	Inability to maintain a pressure seal.
Completion string component	Provides support to the functionality of the completion, i.e. gas-lift or side pocket mandrels with valves or dummies, nipple profiles, gauge carriers, control line filter subs, chemical injection mandrels, etc.	Inability to maintain differential pressure Valves leaking above the acceptance criteria
Surface safety valve(s) or emergency shut-down (ESD) valves	Provides shut-down functionality and isolation of well to production process/flow lines based on operating limits of the production system	Leaks to environment Leaks across valves above acceptance criteria Mechanical damage Inability to respond to process shutdown requirement over pressuring process
Surface production Tree	A system of valves and flow conduits attached to the well head that provides a method for controlling the flow out of the well and into the production system	Leaks to the environment Leaks across valves above the acceptance criteria Inability to function valves Mechanical damage

APPENDIX B: Well barrier elements acceptance tables

The tables below are excerpted from NORSOK D-010 section 15, and contain some of the most important WBEs during the operational phase of a well ***(1)***.

15.1 Table 1 – Fluid column

Features	Acceptance criteria	See
A. Description	This is the fluid in the wellbore.	NORSOK D-001
B. Function	The purpose of the fluid column as a well barrier/WBE is to exert a hydrostatic pressure in the wellbore that will prevent well influx/inflow (kick) of formation fluid.	
C. Design construction selection	1. The hydrostatic pressure shall at all times be equal to the estimated or measured pore/reservoir pressure, plus a defined safety margin (e.g. riser margin, trip margin). 2. Critical fluid properties and specifications shall be described prior to any operation. 3. The density shall be stable within specified tolerances under down hole conditions for a specified period of time when no circulation is performed. 4. The hydrostatic pressure should not exceed the formation fracture pressure in the open hole including a safety margin or as defined by the kick margin. 5. Changes in wellbore pressure caused by tripping (surge and swab) and circulation of fluid (ECD) should be estimated and included in the above safety margins.	ISO 10416
D. Initial test and verification	1. Stable fluid level shall be verified. 2. Critical fluid properties, including density shall be within specifications.	
E. Use	1. It shall at all times be possible to maintain the fluid level in the well through circulation or by filling. 2. It shall be possible to adjust critical fluid properties to maintain or modify specifications. 3. Acceptable static and dynamic loss rates of fluid to the formation shall be pre-defined. If there is a risk of lost circulation, lost circulation material should be available. 4. There should be sufficient fluid materials, including contingency materials available on the location to maintain the fluid well barrier with the minimum acceptable density. 5. Simultaneous well displacement and transfer to or from the fluid tanks should only be done with a high degree of caution, not affecting the active fluid system. 6. Parameters required for re-establishing the fluid well barrier shall be systematically recorded and updated in a "killsheet".	
F. Monitoring	1. Fluid level in the well and active pits shall be monitored continuously. 2. Fluid return rate from the well shall be monitored continuously. 3. Flow checks should be performed upon indications of increased return rate, increased volume in surface pits, increased gas content, flow on connections or at specified regular intervals. The flow check should last for 10 min. HTHP: All flow checks should last 30 min. 4. Measurement of fluid density (in/out) during circulation shall be performed regularly. 5. Measurement of critical fluid properties shall be performed every 12 circulating hours and compared with specified properties. 6. Parameters required for killing of the well.	ISO 10414-1 ISO 10414-2
G. Common well barrier	None	

15.2 Table 2 – Casing

Features	Acceptance criteria	See
A. Description	This element consists of casing/liner and/or tubing in case tubing is used for through tubing drilling and completion operations.	
B. Function	The purpose of casing/liner is to provide an isolation that stops uncontrolled flow of formation fluid or injected fluid between the casing bore and the casing annulus.	
C. Design construction selection	1. Casing/liner strings, including connections shall be designed to withstand all loads and stresses expected during the lifetime of the well (including all planned operations and potential well control situations). Any effects of degradations shall be included. 2. Minimum acceptable design factors shall be calculated for each load type. Estimated effects of temperature, corrosion and wear shall be included in the design factors. 3. All load cases shall be defined and documented with regards to burst, collapse and tension/compression. 4. Casing design can be based on deterministic or probabilistic models. 5. Casing exposed to hydrocarbon flow potential shall have gas-tight threads. Exception: Surface casing which is exposed or can be potentially exposed to normal gradient shallow gas.	ISO 11960 ISO 13679 ISO 10405
D. Initial test and verification	1. Casing/liner shall be leak tested to maximum differential pressure. 2. Casing/liner that has been drilled through after initial leak test shall be retested during completion activities. 3. The leak test of casing shall be performed either when cement is wet (immediately after pumping) or after cement has set up. No pressure testing should be performed while the cement is setting up.	
E. Use	Casing/liner should be stored and handled properly to prevent damage to pipe body and connections prior to installation.	
F. Monitoring	1. The A-annulus shall be continuously monitored for pressure anomalies. Other accessible annuli shall be monitored at regular intervals. 2. All casing strings shall be logged for wear after drilling if simulation indicates excessive wear which exceeds allowable wear based on casing design. Metal shavings should be collected by the use of ditch magnets.	
G. Common well barrier	1. During drilling operations with surface BOP, the annulus outside the current casing shall be monitored continuously and alarm levels be defined. 2. Actual status of the casing shall be known and confirmed capable of withstanding maximum expected pressure after expected wear. 3. Pressure test should include safety margin to cover expected wear after testing. 4. Magnet shall be in the mud return flowline to measure metal and assess changes in the nature of the metal filings. 5. If drilling through an old casing: a) Prior to drilling activity commences, casing wear log(s) should be run (calliper and/or sonic). The logs shall be verified by qualified personnel and documented. b) Logs that can identify localised (1 m interval between measurements) doglegs (gyro or similar) should be run.	

15.5 Table 5 – Wellhead

Features	Acceptance criteria	See
A. Description	The element consists of the wellhead body with annulus access ports and valves, seals and casing hangers with seal assemblies.	
B. Function	Its function is to provide mechanical support for the suspending casing and tubing strings and for hook-up of risers or BOP or tree and to prevent flow from the bore and annuli to formation or the environment.	
C. Design construction selection	1. The WP for each section of the wellhead shall exceed the maximum well shut-in pressure the section can become exposed to plus a defined safety factor. 2. For dry wellheads, there shall be access ports to all annuli to facilitate monitoring of annuli pressures and injection/bleed-off of fluids. 3. For subsea wellheads, there shall be access to the casing by tubing annulus to facilitate monitoring of annulus pressure and injection /bleed-off of fluids. 4. Wellheads that will be used as a flow conduit for continuous or intermittent production from or injection into annulus/annuli, shall be designed and qualified for such functions without impairing the well integrity function of the wellhead. For gas lift applications, gas expansion and the resulting temperature should be addressed. 5. The casing hanger shall be locked down to ensure seal integrity during normal working loads as well as well control situations.	ISO 10423
D. Initial test and verification	6. The wellhead body (or bodies and seals), annulus ports with valves and the casing seal assemblies shall be leak tested to design pressure for the specific hole section or operation.	
E. Use	A wear bushing should be installed in the wellhead when movement of tools/work-strings can inflict damage to seal areas.	
F. Monitoring	1. Annulus valves shall be leak and function tested frequently. 2. The A-annulus shall be continuously monitored for pressure anomalies. Other accessible annuli shall, if applicable be monitored at regular intervals. 3. Movements in the wellhead during work over (shut-in/start-up) should be observed and compared to design values. 4. Accessible seals (land- and platform wells) shall be periodically leak tested, first time within 1 year then at a maximum frequency of 2 years. 5. Periodically inspections for sign of external leaks or deterioration based on installation risk (visual and ROV for subsea). The frequency shall as a minimum be yearly for subsea wells, if not otherwise defined in a risk assessment.	
G. Common well barrier	1. Stress analysis due to UBD/MPD equipment/operations shall be performed. Effect of extra loads and tie-ins shall be analysed. 2. Visual inspections shall be done based on a predefined inspection frequency 3. During drilling activities with a surface BOP, the annulus outside the current casing shall be monitored continuously and alarm levels be defined.	

15.7 Table 7 – Production packer

Features	Acceptance criteria	See
A. Description	This element consists of a body with an anchoring mechanism to the casing/liner, and an annular sealing element which is activated during installation.	
B. Function	Its purpose is to: 1. provide a seal between the completion string and the casing/liner, to prevent communication from the formation into the A-annulus above the production packer; 2. prevent flow from the inside of the body element located above the packer element into the A-annulus as part of the completion string.	
C. Design, construction and selection	1. The production packer shall be qualified and tested in accordance to principals given in recognized standards, i.e. ISO14310 V1 as minimum and V0 if the well contains free gas at the setting depth. The production packer shall be qualification tested in unsupported, non-cemented casing. 2. The setting depth shall be such that any leak through the casing below the packer, will be contained by the well barrier system outside the casing. The formation integrity and any annulus seal (e.g. cement) shall be able to withstand the pressures or temperatures expected throughout the lifetime of the well. 3. It shall be permanently set (meaning that it shall not release by upward or downward forces), with ability to sustain all known loads. 4. Mechanically retrievable production packers shall be designed to protect against unintentional activation. 5. The packer (body and seal element) shall withstand maximum differential pressure, which should be based on the highest of: a) pressure testing of tubing hanger seals; b) reservoir-, formation integrity- or injection pressures less hydrostatic pressure of fluid in annulus above the packer; c) shut-in tubing pressure plus hydrostatic pressure of fluid in annulus above the packer less reservoir pressure; d) collapse pressure as a function of minimum tubing pressure (plugged perforations or low test separator pressure) at the same time as a high operating annulus (maximum allowable) pressure is present.	ISO 14310
D. Initial test and verification	It shall be leak tested to the maximum differential pressure in the direction of flow, if feasible. Alternatively, it shall be inflow tested or leak tested in the opposite direction to the maximum differential pressure, providing that ability to seal both directions can be documented.	
E. Use	Running of intervention tools shall not impair its ability to seal nor inadvertently cause it to be released.	
F. Monitoring	Sealing performance shall be monitored through continuous recording of the A-annulus pressure measured at wellhead level.	
G. Common well barrier	None	

15.8 Table 8 – Downhole safety valve

Features	Acceptance criteria	See
A. Description	This element consists of a tubular body with a close/open mechanism that seals off the tubing bore.	
B. Function	Its purpose is to prevent flow of hydrocarbons or fluid up the tubing.	
C. Design, construction and selection	1. It shall be positioned minimum 50 m below seabed. 2. The setting depth shall be dictated by the pressure and temperature conditions in the well with regards to forming of hydrates and deposition of wax and scale. 3. It shall be: a) surface controlled; b) fail-safe closed. 4. It should be placed below the well kick-off point in order to provide well shut-in capabilities below a potential collision point. 5. The fail-safe closing function (maximum setting depth) should be calculated based on the highest density of fluids in the annulus. 6. The DHSV should pass 5 slam closures where minimum 2 (two) slam closures are at the maximum theoretical production rate of the well where the system is to be installed. This to prove the DHSV is designed for and can withstand the force generated by the slam closure without deformation of vital parts	API Spec 14A/ISO10432 API RP 14B
D. Initial test and verification	It shall be tested with both low and high differential pressure in the direction of flow. The low pressure test shall be maximum 70 bar (1000 psi).	
E. Use	When exposed to high velocities or abrasive fluid, increased testing frequency shall be considered.	
F. Monitoring	1. The valve shall be leak tested at specified regular intervals as follows: a) monthly, until three consecutive qualified tests have been performed; thereafter b) every three months, until three consecutive qualified tests have been performed; thereafter c) every six months; d) test evaluation period is volume and compressibility dependent and shall be held for a period that will give measurable pressure change for the allowed leak rate, minimum 30 min. 2. Acceptance of downhole safety valve tests shall meet the following ANSI/API RP 14B requirements: a) 0,42 Sm^3/min (25,5 Sm^3/hr) (900 scf/hr) for gas; b) 0,4 l/min (6,3 gal/hr) for liquid. 3. If the leak rate cannot be measured directly, indirect measurement by pressure monitoring of an enclosed volume downstream of the valve shall be performed. 4. The emergency shutdown function shall be tested yearly. It shall be verified acceptable shut down time and that the valve closes on signal.	API RP 14B ISO 10417
G. Common well barrier	None	

15.9 Table 9 – Annulus safety valve

Features	Acceptance criteria	See
A. Description	The element consists of a tubular and an annulus sealing element which can be activated to seal off the annular wellbore.	
B. Function	Its purpose is to: a) prevent flow of media up the A-annulus; b) provide a pressure seal in the A-annulus between the casing and the tubing.	
C. Design, construction and selection	1. It shall be designed and tested in accordance with API RP 14B. 2. It shall be located minimum 50 m below seabed. If annulus is used for production, the setting depth shall be determined by the possibility of forming of hydrates and deposition of wax and scale. 3. It shall be subject to flow erosion resistance verification for all relevant fluids, if it will become exposed to high production/injection rates. 4. When part of the annulus safety system, the packing element shall comply with the same requirements as for a production packer. 5. It shall have a WP which exceeds the WDP. The WDP should be based on reservoir pressure less gas gradient below packer and evacuated A-annulus above. 6. It shall be: a) surface controlled; b) fail-safe closed. 7. It should be placed below the well kick-off point in order to provide well shut-in capabilities below a potential collision point. 8. The fail-safe closing function (maximum setting depth) should be calculated based on the highest density of fluids in the annulus.	API Spec 14A API RP 14B ISO 14310
D. Initial test and verification	It shall be leak tested in the direction of flow to: 1. a low pressure which shall maximum be 70 (~1000 psi) bar; 2. WDP.	
E. Use	When exposed to high velocities or abrasive fluid, increased testing frequency shall be considered.	
F. Monitoring	1. The valve shall be leak tested at specified regular intervals as follows: a) monthly, until three consecutive qualified tests have been performed; thereafter b) every three months, until three consecutive qualified tests have been performed; thereafter c) every six months; d) the test evaluation period is dependent upon volume and compressibility and shall be held for a period that will give measurable pressure change for the allowed leak rate, minimum 30 min. 2. Acceptance of downhole safety valve tests shall meet the following API RP 14B requirements: a) 0,42 Sm^3/min (25,5 Sm^3/hr) (900 scf/hr) for gas; b) 0,4 l/min (6,3 gal/hr) for liquid. 3. If the leak rate cannot be measured directly, indirect measurement by pressure monitoring of an enclosed volume downstream of the valve shall be performed. 4. The valve shall be periodically function tested including the emergency shutdown function based on reliability analysis but as a minimum yearly. It shall be verified acceptable shut down time and that the valve closes on signal.	API RP 14B ISO 10417
G. Common well barrier	None	

15.10 Table 10 – Tubing hanger

Features	Acceptance criteria	See
A. Description	This element consists of a body, seals, feed throughs, and bore(s) which may have a tubing hanger plug profile.	
B. Function	Its function is to: a) support the weight of the tubing; b) prevent flow from the bore and to the annulus; c) provide a hydraulic seal between the tubing, wellhead and tree; d) provide a stab-in connection point for bore communication with the tree; e) provide a profile to receive a BPV or plug to be used for nippling down the BOP and nippling up the tree.	
C. Design, construction and selection	1. The tubing hanger shall be designed, qualified, tested, and manufactured in accordance with recognized standards. 2. When used in conjunction with annulus injection (gas lift, cutting injection, etc.) any low temperature cycling effects need to be taken into consideration.	ISO 13533 ISO 13628-4 ISO 10423
D. Initial test and verification	The locking of the tubing hanger shall be verified by overpull and/or pressure from below exceeding the string weight. All seals shall be leak tested to the WDP, and should be tested in the direction it is designed to hold pressure.	
E. Use	None	
F. Monitoring	1. Continuous monitoring of A- annulus pressure. 2. Accessible seals (land- and platform wells) shall be pressure tested at installation, within 1 year after installation and then at a maximum frequency of 2 years.	
G. Common well barrier	None	

15.12 Table 12 – Wellhead annulus access valve

Features	Acceptance criteria	See
A. Description	This element consists of an annulus isolation valve(s) and valve housing(s) connected to the wellhead.	
B. Function	Its function is to provide ability to monitor pressure and flow to/from the annuli.	
C. Design, construction and selection	1. The housing shall have a material grade and specification compatible with the materials which it is attached to. 2. The housing and valve(s) shall be fire resistant. 3. The access point and valve shall have a pressure rating equal to or higher than the wellhead/tree system. 4. The valve shall be: a. designed, qualified, tested and manufactured in accordance with recognized standards; b. gas tight. 5. The access point and valve shall have a pressure rating equal to or higher than the wellhead/tree system. 6. When used in conjunction with annulus injection (gas lift, cuttings injection, etc.) the valve shall be: a) surface controlled; b) automatically operated; and c) fail-safe closed. Low temperature cycling effects should to be taken into consideration.	ISO 10423/API Spec 6A ISO 15156 API Spec 17D ISO 10497/API Spec 6FA
D. Initial test and verification	The valve shall be tested in the direction annulus to process piping.	
E. Use	The valve shall normally be open for monitoring purposes, with another valve isolating the access to the platform system, which should only be opened for the purpose of adjusting the annulus pressure.	
F. Monitoring	1. Sealing performance shall be monitored through continuous recording of the annulus pressure measured at wellhead level. 2. The test evaluation period is dependent upon volume and compressibility and shall be held for a period that will give measurable pressure change for the allowed leak rate, minimum 10 min. 3. Manual valves exposed to injection or production fluids shall be leak tested every 6 months. For passive annuli, the manual valves shall be tested yearly. 4. Injection valves shall be leak tested at regular intervals as follows: a) monthly, until three consecutive qualified tests have been performed; thereafter b) every three months, until three consecutive qualified tests have been performed; thereafter c) every six months. 5. If the leak rate cannot be measured directly, indirect measurement by pressure monitoring of an enclosed volume downstream of the valve shall be performed. 6. The emergency shutdown function shall be tested yearly. It shall be verified acceptable shut down time and that the valve closes on signal.	
G. Common well barrier	None	

15.22 Table 22 – Casing cement

Features	Acceptance criteria	
A. Description	This element consists of cement in solid state located in the annulus between concentric casing strings, or the casing/liner and the formation. NOTE The shoe track cement is covered in table 24.	
B. Function	The purpose of the element is to provide a continuous, permanent and impermeable hydraulic seal along hole in the casing annulus or between casing strings, to prevent flow of formation fluids, resist pressures from above or below, and support casing or liner strings structurally.	
C. Design, construction and selection	1. A cement program shall be issued for each cement job, minimum covering the following: a) casing/liner centralization and stand-off to achieve pressure and sealing integrity over the entire required isolation length; b) use of fluid spacers; c) effects of hydrostatic pressure differentials inside and outside casing and ECD during pumping and loss of hydrostatic pressure prior to cement setting up; d) the risk of lost returns and mitigating measures during cementing. 2. For critical cement jobs, HPHT conditions and complex/foam slurry designs the cement program shall be verified independent (internal or external), qualified personnel. 3. The cement recipe shall be lab tested with dry samples and additives from the rigsite under representative well conditions. The tests shall provide thickening time and compressive strength development. 4. The properties of the set cement shall provide lasting zonal isolation, structural support, and withstand expected temperature exposure. 5. Cement slurries used for isolating sources of inflow containing hydrocarbons shall be designed to prevent gas migration, including CO_2 and H_2S, if present. 6. Planned casing cement length: a) Shall be designed to allow for future use of the well (sidetracks, recompletions, and abandonment). b) **General**: Shall be minimum 100 m MD above a casing shoe/window. c) **Conductor**: Should be defined based on structural integrity requirements. d) **Surface casing**: Shall be defined based on load conditions from wellhead equipment and operations. TOC should be at surface/seabed. e) **Production casing/liner**: Shall be minimum 200m MD above a casing shoe. If the casing penetrates a source of inflow, the planned cement length shall be 200m MD above the source of inflow. a. Note: If unable to fulfil the requirement when running a production liner, the casing cement length can be combined with previous casing cement to fulfil the 200m MD requirement.	API RP 10B ISO 10426-1

Features	Acceptance criteria	
D. Initial verification	Cement should be left undisturbed until it has reached sufficient compressive strength. 1. The cement sealing ability shall be verified through a formation integrity test when the casing shoe/window is drilled out. 2. The cement length shall be verified by one of the following: a) Bonding logs: Logging methods/tools shall be selected based on ability to provide data for verification of bonding. The measurements shall provide azimuthal/segmented data. The logs shall be verified by qualified personnel and documented. b) 100 % displacement efficiency based on records from the cement operation (volumes pumped, returns during cementing, etc.). Actual displacement pressure/volumes should be compared with simulations using industry recognized software. In case of losses, it shall be documented that the loss zone is above planned TOC. Acceptable documentation is job record comparison with similar loss case(s) on a reference well that has achieved sufficient length verified by logging. c) In the event of losses, it is acceptable to use the PIT/FIT or LOT as the verification method <u>only</u> if the casing cement shall be used as a WBE for drilling the next hole section. (This method shall not be used for verification of casing cement as a WBE for production or permanent abandonment.) 3. Critical casing cement shall be logged and is defined by the following scenarios: a) the production casing/production liner when set into/through a source of inflow with hydrocarbons; b) the production casing/production liner when the same casing cement is a part of the primary and secondary well barriers; c) wells with injection pressure which exceeds the formation integrity at the cap rock. 4. Actual cement length for a qualified WBE shall be: a) above a potential source of inflow/ reservoir; b) 50 m MD verified by displacement calculations or 30 m MD when verified by bonding logs. The formation integrity shall exceed the maximum expected pressure at the base of the interval. c) 2 x 30m MD verified by bonding logs when the same casing cement will be a part of the primary and secondary well barrier. d) The formation integrity shall exceed the maximum expected pressure at the base of each interval. e) For wells with injection pressure exceeding the formation integrity at the cap rock: The cement length shall extend from the upper most injection point to 30 m MD above top reservoir verified by bonding logs.	
E. Use	None	
F. Monitoring	1. The annuli pressure above the casing cement shall be monitored regularly when access to this annulus exists. 2. Surface casing by conductor annulus outlet should be observed regularly.	
G. Common well barrier	It is not acceptable for use as a common WBE. When casing cement is a part of the primary and secondary well barriers, this is defined as critical casing cement and the criteria in D. Initial verification applies.	

15.24 Table 24 – Cement plug

<table>
<tr><th>Features</th><th>Acceptance criteria</th><th>See</th></tr>
<tr><td>A. Description</td><td>The element consists of cement in solid state that forms a plug in the wellbore.</td><td></td></tr>
<tr><td>B. Function</td><td>The purpose of the plug is to prevent flow of formation fluids inside a wellbore between formation zones and/or to surface/seabed.</td><td></td></tr>
<tr><td>C. Design, construction and selection</td><td>
1. A program shall be issued for each cement plug installation.
2. For critical cement jobs, HPHT conditions and complex slurry designs the cement program should be verified by independent (internal or external) qualified personnel.
3. The cement recipe shall be lab tested with dry samples and additives from the rigsite under representative well conditions. The tests shall provide thickening time and compressive strength development.
4. Cement slurries used in plugs to isolate sources of inflow containing hydrocarbons should be designed to prevent gas migration and be suitable for the well environment (CO_2, H_2S).
5. Permanent cement plugs should be designed to provide a lasting seal with the expected static and dynamic conditions and loads.
6. It shall be designed for the highest differential pressure and highest downhole temperature expected including installation and test loads.
7. A minimum cement batch volume shall be defined to ensure that a homogenous slurry can be made, taking into account all sources of contamination from mixing to placement.
8. The minimum cement plug length shall be:
<table>
<tr><td>Open hole cement plugs</td><td>Cased hole cement plugs</td><td>Open hole to surface plug (installed in surface casing)</td></tr>
<tr><td>100 m MD with minimum 50 m MD above any source of inflow/leakage point. A plug in transition from open hole to casing should extend at least 50 m MD above and below casing shoe.</td><td>50 m MD if set on a mechanical/ cement plug as foundation, otherwise 100 m MD</td><td>50 m MD if set on a mechanical plug, otherwise 100 m MD.</td></tr>
</table>
9. Placing one continuous cement plug in a cased hole is an acceptable solution as part of the primary and secondary well barriers when placed on a verified foundation (e.g. pressure tested mechanical/cement plug).
10. Placing one continuous cement plug in an open hole is an acceptable solution as part of the primary and secondary well barriers with the following conditions:
a. The cement plug shall extend 50m into the casing.
b. It shall be set on a foundation (TD or a cement plug(s) from TD). The cement plug(s) shall be placed directly on top of one another.
11. A casing/liner shall have a shoe track plug with a 25 m MD length.
</td><td>API Spec 10A Class 'G'</td></tr>
</table>

<table>
<tr><th>Features</th><th>Acceptance criteria</th><th>See</th></tr>
<tr><td>D. Initial verification</td><td>1. Cased hole plugs should be tested either in the direction of flow or from above.
2. For the shoe track to be used as a WBE, the following applies:
a. the bleed back volume from placement of casing cement shall not significantly exceed the calculated volume; and
b. it shall be either pressure tested and supported by overbalanced fluid (see EAC 1) or inflow tested.
3. The strength development of the cement slurry should be verified through observation of surface samples from the mixing, cured on site in representative temperature.
4. The plug installation shall be verified through evaluation of job execution taking into account estimated hole size, volumes pumped and returns.
5. The plug shall be verified by:
<table>
<tr><th>Plug type</th><th>Verification</th></tr>
<tr><td>Open hole</td><td>Tagging.</td></tr>
<tr><td>Cased hole</td><td>Tagging.
Pressure test, which shall:
a) be 70 bar (1000 psi) above estimated leak off pressure (LOT) below casing/ potential leak path, or 35 bar (500 psi) for surface casing plugs; and
b) not exceed the casing pressure test and the casing burst rating corrected for casing wear.
If the cement plug is set on a pressure tested foundation, a pressure test is not required. It shall be verified by tagging.</td></tr>
</table></td><td></td></tr>
<tr><td>E. Use</td><td>None.</td><td></td></tr>
<tr><td>F. Monitoring</td><td>For temporary abandoned wells: The fluid level/pressure above the shallowest set plug shall be monitored regularly when access to the bore exists.</td><td></td></tr>
<tr><td>G. Common well barrier</td><td>If one continuous cement plug (same cement operation) is defined as part of the primary and secondary well barriers, it shall be verified by drilling out the plug until hard cement is confirmed.
1. An open hole cement plug extended into the casing shall be pressure tested.</td><td></td></tr>
</table>

15.25 Table 25 – Completion string

Features	Acceptance criteria	See
A. Description	This element consists of tubular pipe.	
B. Function	The purpose of the completion string is to provide a conduit for formation fluid from the reservoir to surface or vice versa, and prevent communication between the completion string bore and the A-annulus.	
C. Design, construction and selection	1. All components in the completion string (pipe/housings and threads) shall have ISO13679 CAL III connections or CAL IV connections when exposed to free gas during its lifetime. 2. Dimensioning load cases shall be defined and documented. 3. The weakest point(s) in the string shall be identified. 4. Minimum acceptable design factors shall be defined. Estimated effects of temperature, corrosion, wear, fatigue and buckling shall be included in the design factors. 5. The tubing should be selected with respect to: a) tensile and compression load exposure; b) burst and collapse criteria; c) tool joint clearance and fishing restrictions; d) tubing and annular flow rates; e) abrasive composition of fluids; f) buckling resistance; g) metallurgical composition in relation to exposure to formation or injection fluid; h) Strength reduction due to temperatures effects.	ISO 11960/API Spec 5CT ISO 13679
D. Initial test and verification	Pressure testing to WDP.	
E. Use	None	
F. Monitoring	Pressure integrity is monitored through the annulus pressure.	
G. Common well barrier	None	

15.28 Table 28 – Mechanical tubular plugs

Features	Acceptance criteria	See
A. Description	This element consists of a body with a locking or anchoring device and a seal between the bore of the casing/tubing and the plug body. This is a mechanical plug set in a profile or anywhere inside steel conduits (casing/tubular).	
B. Function	The purpose of the plug is to prevent flow of formation fluids and resist pressure from above or below, inside tubulars and in the annulus space between concentric positioned tubulars.	
C. Design, construction and selection (rating, capacity, etc.)	1. The mechanical plug shall be designed and qualified to withstand maximum differential pressure, minimum and maximum temperatures, number of pressure and temperature cycles, number of settings, well medium, life time expectations and all loads it will be exposed to during the installation time. 2. Down hole fluids and conditions (temperature, H_2S, CO_2, etc.) shall be considered in estimating the life time of the plug. 3. The plug shall comply with ISO 14310, as follows: a) Grade V1 for design validation; b) Grade Q1 for quality control. 4. The plug shall be designed such that pressure can be equalized across the plug in a controlled manner, if removed mechanically or by drilling out. 5. Inadvertent release of the plug by mechanical motion/impact shall not be possible. 6. The plug is not accepted as a WBE alone in permanent plugging of wells or branches of wells, where integrity in an eternal perspective is required. 7. It shall only be installed in a tubular section of the well which is cemented or supported by sufficient wall thickness to withstand loads from the plug.	ISO 14310
D. Initial verification and verification	It shall be leak tested to the maximum differential pressure in the direction of flow, if feasible. Alternatively, it shall be inflow tested or leak tested in the opposite direction to the maximum differential pressure, providing the ability to seal in both directions can be documented.	
E. Use	The plug shall be set as close as possible to the source of inflow and set at a depth where the hydrostatic pressure above the plug balances the pressure under the plug.	
F. Monitoring	Plug integrity shall be monitored regularly if access is available.	
G. Common well barrier	None	

15.31 Table 31 – Sub-sea tree

Features	Acceptance criteria	See
A. Description	1. Subsea horizontal tree consists of a housing with bores that are fitted with production and annulus master valves, crown plugs, flow valves and crossover valves. 2. Subsea vertical tree consists of a housing with bores that are fitted with production and annulus master valves, swab or crown plug and flow valves.	
B. Function	Its function is to: a) provide a flow conduit for hydrocarbons from the tubing into the subsea tree to surface lines with the ability to stop the flow by closing the flow valve and/or the master valve; b) provide monitoring and pressure adjustment of the annulus; c) provide vertical tool access through the swab valve(s) for vertical trees or through crown plug(s) for horizontal trees.	
C. Design, construction and selection	1. The subsea tree shall be equipped with: a) one fail-safe closed automatic master valve and one fail-safe closed automatic wing valve in the main flow direction of the well; b) if the tree has side outlets, these shall be equipped with fail-safe closed automatic valves; c) one swab valve and tree cap (vertical tree) or two crown plugs (horizontal tree) for each bore at a level above any side outlets; d) isolation valves on downhole control lines which penetrates the tree block; and 2. The tree shall be designed to withstand dynamic and static loads it may be subjected to including normal, extreme and accidental load conditions.	ISO 10423 ISO 13628-1 ISO 13628-4 ISO 13628-7
D. Initial test and verification	The valves shall be tested with both low and high maximum differential pressure in the direction of flow. The low pressure test shall be maximum 35 bar (500 psi). The connection between the subsea tree and the wellhead shall be tested to maximum differential pressure.	
E. Use	1. Employ a strategy for use of antifreeze/hydrate agents during shut-ins and testing. 2. Beware of equalization during opening and closing of valves.	
F. Monitoring	1. The automatic valves shall be tested at regular intervals as follows: a) monthly, until three consecutive qualified tests have been performed; thereafter b) every three months, until three consecutive qualified tests have been performed; thereafter c) every six months. 2. If the leak rate cannot be measured directly, indirect measurement by pressure monitoring of an enclosed volume downstream of the valve shall be performed. 3. Test duration shall be minimum 10 min. 4. The emergency shutdown function shall be tested yearly. It shall be verified acceptable shut down time and that the valves close on signal.	
G. Common well barrier	None	

15.33 Table 33 – Surface tree

Features	Acceptance criteria	See
A. Description	This element consists of a housing with bores that are fitted with swab-, master valves, kill/service valves and flow valves.	
B. Function	Its function is to: 1. provide a flow conduit for hydrocarbons from the tubing into the surface lines with the ability to stop the flow by closing the flow valve and/or the master valve; 2. provide vertical tool access through the swab valve; and 3. provide an access point where kill fluid can be pumped into the tubing.	
C. Design, construction and selection	1. The surface tree shall be equipped with the following: a) one fail-safe closed automatic master valve and one fail-safe closed automatic wing valve in the main flow direction of the well; b) if the tree has flowing side outlets, these shall be equipped with automatic fail-safe valves; c) one manual swab valve and tree cap for each bore at a level above any side outlets; d) isolation valves on downhole control lines which penetrates the tree block. 2. All primary seals (inclusive production annulus) shall be of metal-to-metal type. 3. All connections, exit blocks etc. that lie within a predefined envelope shall be fire-resistant. 4. The tree shall be designed to withstand dynamic and static loads it may be subjected to including normal, extreme and accidental load conditions.	ISO 10423 (API Spec 6A) API Spec 6FA API Spec 6FB API Spec 6FC
D. Initial test and verification	The valves shall be tested with both low and high maximum differential pressure in the direction of flow. The low pressure test shall be maximum 35 bar (500 psi). The connection between the surface tree and the wellhead shall be tested to maximum differential pressure.	
E. Use	1. Employ a strategy for use of antifreeze/hydrate agents during shut-ins and testing. 2. Beware of equalization during opening and closing of valves.	
F. Monitoring	1. The automatic valves shall be tested at regular intervals as follows: a) monthly, until three consecutive qualified tests have been performed; thereafter b) every three months, until three consecutive qualified tests have been performed; hereafter c) every six months. 2. The manual valves shall be tested yearly. 3. If the leak rate cannot be measured directly, indirect measurement by pressure monitoring of an enclosed volume downstream of the valve shall be performed. 4. Test duration shall be minimum 10 min. 5. The emergency shutdown function shall be tested yearly. It shall be verified acceptable shut down time and that the valve closes on signal.	
G. Common well barrier	None	

15.51 Table 51 – In-situ formation

Features	Acceptance criteria	See
A. Description	The element is the formation that has been drilled through and is located adjacent to the casing annulus isolation material or plugs set in the wellbore.	
B. Function	The purpose of the in-situ formation is to provide a permanent and impermeable hydraulic seal preventing flow from the wellbore to surface/seabed or other formation zones.	
C. Design construction selection	The following applies for the formation at the required depth: 1. The formation shall be impermeable with no flow potential. 2. The wellbore shall be placed away from fractures and/or faults that may lead to out of zone injection or crossflow. 3. The formation integrity shall exceed the maximum wellbore pressure induced. See 4.2.3.6.7 Table 2 – Formation Integrity requirements. 4. The formation shall be selected such that it will not be affected by changes in reservoir pressure over time (depletion, compaction, fracturing, re-activation of faults). 5. The formation shall bond directly to the casing/liner annulus material (e.g. casing cement) or plugs in the wellbore. 6. If the formation is bonding directly to the casing (e.g. the formation has extruded into the casing annulus), then the requirements in table 15.52 Creeping formation also shall apply.	
D. Initial test and verification	Formation integrity pressure shall be verified by one of the following methods (See 4.2.3.6.7): 1. a PIT; 2. a LOT should be followed by a shut-in phase; 3. an XLOT, if the minimum formation stress is not already known; or 4. a documented field model.	
E. Use	None	
F. Monitoring	None	
G. Common well barrier	None	

APPENDIX C: Model 3 formulas

ENERGY (fill in)

	fi (1= yes)	wi	Wi	fi * wi * Wi
Energy source			3	
Injection		6		=$E$5*C6*D6
Gas lift		8		=$E$5*C7*D7
Reservoir		10		=$E$5*C8*D8
Reservoir / injection pressure			10	
≤ Normal		1		=$E$10*C11*D11
Abnormal		5		=$E$10*C12*D12
Abnormal high		10		=$E$10*C13*D13
Flow potential from reservoir			10	
None		1		=$E$15*C16*D16
Some		2		=$E$15*C17*D17
Medium		5		=$E$15*C18*D18
High		10		=$E$15*C19*D19
Leakage fluid (mainly)			10	
Water		1		=$E$21*C22*D22
Oil		5		=$E$21*C23*D23
Condensate		8		=$E$21*C24*D24
Gas		10		=$E$21*C25*D25
∑ Energy factors			SUM	=SUM(F6:F25)

SURROUNDINGS (fill in)

	fi(1=yes)	wi	Wi	fi * wi * Wi
Type of installation			5	
Subsea		1		=$K$5*J6*I6
Subsea below platform		5		=$K$5*J7*I7
Platform		10		=$K$5*J8*I8
Installation activity			5	
Unmanned facility / location		1		=$K$10*J11*I11
Manned facility / location		10		=$K$10*J12*I12
Water depth			3	
Deep (> 300 m)		1		=$K$14*J15*I15
Medium (100 - 300 m)		5		=$K$14*J16*I16
Shallow (< 100 m)		10		=$K$14*J17*I17
∑ Surroundings factors			SUM	=SUM(L6:L17)

BARRIER (fill in)

	fi(1=yes)	wi	Wi	fi * wi * Wi
Leakage path			10	
Inside well ("internal")		3		=$Q$5*P6*O6
Inside --> outwards in well ("external")		5		=$Q$5*P7*O7
Outside well (external surroundings)		10		=$Q$5*P8*O8
Potential leak rate			10	
Low leak rate (≤ API RP 14B)		2		=$Q$10*P11*O11
Medium leak rate (≥ 2x API RP 14B)		5		=$Q$10*P12*O12
High leak rate / blowout		10		=$Q$10*P13*O13
Escalation factors (can fill in none or several)			5	
Corrosion / erosion in the well		4		=$Q$15*P16*O16
Mechanical pressure loads > design		8		=$Q$15*P17*O17
Unacceptable HC storage in the well		10		=$Q$15*P18*O18
Challenge relating recoverability / well kill		10		=$Q$15*P19*O19
∑ Barrier factors			SUM	=SUM(R6:R19)

FINAL CONSEQUENCE SCORE =F27+L19+R21

=IF(L27<300;"Low impact";IF(L27>500;"High impact";"Medium impact"))