NTNU – Trondheim
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Control of Major Accident Scenarios in the Åsgard Subsea Compression Project

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Master of Science in Engineering Cybernetics
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MASTEROPPGAVE

Kandidatens navn:	Linn Ingrid Berggård
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Oppgavens tittel (norsk):	Kontrollering av storulykkescenarier i prosjektet Åsgard havbunnskompresjon
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One of oil and gas producing companies' biggest fears is the occurrence of a major accident. The consequences of such an accident may be catastrophic and could potentially involve fatalities, damage to the environment and asset, as well as huge economic impact. After the Deepwater Horizon accident in 2010, where 11 people were killed and more than 780 000 m^3 of oil was released into the sea, there has been an increased industry focus on the prevention of major accidents.

The world's first subsea compression system will be installed on the Åsgard field in the Norwegian Sea. Reservoir simulations show that Midgard/Mikkel will experience declined production in 2014/15 unless mitigating actions are implemented. A subsea compression system will be installed west of the Midgard Y template for compression of the Midgard (X-, Y- and Z-templates) and Mikkel well streams, both to maintain the flow rates in the subsea production systems above their critical minimum and to maximise reservoir recovery. Minimum flow problems occur at low gas production rates causing the liquid phases consisting of MEG, water and condensate to accumulate in the pipelines. The subsea compression concept uses subsea boosting as a permanent solution to overcome the minimum flow problem.

When introducing new technology such as this, it is important to identify the various events which could potentially lead to a major accident. This thesis should investigate how these major accident scenarios play out and what measures are taken to prevent and control them.

The following problems should be addressed:

- A literature study of the subsea compression process at Åsgard
- A hazard identification to assess which incidents might lead to a major accident
- A review of how the identified initiating events might escalate to a major accident
- An identification of what risk reducing measures are implemented and how the risk is controlled

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Tor Onshus
Faglærer

Abstract

The world's first subsea compression system will be installed at the Åsgard field in the Norwegian sea. This will be done to maintain the flow rates of the hydrocarbons above their critical minimum and to maximise reservoir recovery. Because this is the first subsea compression system in the world, there are uncertainties as to the risks involved in the installation and operation of the system. This thesis adresses the part of the risk picture which involves major accident risk.

An identification and description of the major accident scenarios related to the new subsea equipment at Åsgard has been given. In order to control the risk, Statoil will prepare emergency preparedness plans for the identified major accident scenarios. As a preliminary work, this thesis identifies the different risk reducing measures/barriers which are relevant for each scenario.

The overall risk level for the Åsgard Subsea Compression project is low, but operational procedures must be followed in order to keep the risk at this level. The risk related to the different major accident scenarios are all within Statoil's risk acceptance criteria.
The different barriers in place for controlling each major accident scenario has been identified and described. The most important barriers were found to be:

- The process shutdown (PSD) system, which shuts down the production after a significant leak has been detected.
- That the installation and maintenance vessels have a reliable dynamic positioning system.
- Positioning installation or maintenance vessels at a safe distance from subsea hydrocarbon equipment during lifts.
- Relocation of installation or maintenance vessel after a significant subsea leak is detected.

Sammendrag

Verdens første kompresjonssystem på havbunnen vil bli installert på Åsgard-feltet i Norskehavet. Dette vil bli gjort for å opprettholde strømningshastigheten til hydrokarbonene over et kritisk minimum og for å maksimere utvinningen. Fordi dette er verdens første havbunnskompresjonssystem, er det usikkerhet rundt risikoen involvert i installasjon og operasjon av systemet. Denne masteroppgaven adresserer den delen av risikobildet som involverer risikoen for en storulykke.

En identifisering og beskrivelse av storulykkescenariene relatert til det nye undervannsutstyret på Åsgard har blitt gjennomført. For å kontrollere risikoen, vil Statoil utarbeide beredskapsplaner for de identifiserte storulykkescenariene. Som et forarbeid til dette, identifiserer denne masteroppgaven de forskjellige risikoreduserende tiltakene/barrierene som er relevante for hvert scenario.

Det samlede risikonivået for Åsgard Subsea Compression prosjektet er lavt, men operasjonelle prosedyrer må følges for å holde risikoen på dette nivået. Risikoen i forbindelse med hvert av storulykkescenariene er alle innenfor Statoils akseptkriterier.
De forskjellige barrierene som er på plass for å kontrollere hvert storulykkescenario har blitt identifisert og beskrevet. De viktigste barrierene er:

- Prosessnedstengingssystemet (PSD) som stopper produksjonen etter at en betydelig lekkasje har blitt oppdaget.
- At installasjon- og vedlikeholdsfartøy har et pålitelig dynamisk posisjoneringssystem.
- Posisjonering av installasjon- eller vedlikeholdsfartøy på trygg avstand fra hydrokarbonutstyr på havbunnen ved løft.
- Flytting av installasjon- eller vedlikeholdsfartøy etter at en betydelig lekkasje har blitt oppdaget.

Preface

This thesis has been submitted as the diploma in my Master of Science degree in Engineering Cybernetics at the Norwegian University of Science and Technology (NTNU).

I would like to thank my supervisor, Professor Tor Onshus at the Department of Engineering Cybernetics, for getting me in contact with Statoil and for providing me with information. I would also like to thank my supervisor at Statoil, David Watt, for all his help during my work on this thesis, for providing me with all the information I could possibly need and for taking the time to meet with me. Also a thanks to Knut Ola Staver, for taking the time to explain about the PSD system at Åsgard.

I would like to give a special thanks to Petter Norgren, for constructive criticism and support during this semester.

Trondheim, Norway, 6. July 2011

Linn I. Berggård

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List of Abbreviations

AIS	Automatic Identification System
ALARP	As Low As Reasonably Practicable
AMF	Automatic Mode Function
API	American Petroleum Institute
BHP	Bottom Hole Pressure
BOP	Blowout Preventer
BSR	Blind Shear Ram
ESD	Emergency Shutdown
FAR	Fatal Accident Rate
FBS	Flat Bottom Structure
FPSO	Floating, Production, Storage and Offloading
GoM	Gulf of Mexico
HSE	Health, Safety and Environment
HTVM	Hot-Tap Valve Module
IMO	International Maritime Organization
IMR	Inspection Maintenance and Repair
IMSF	Impairment of Main Safety Functions

MAE	Major Accident Event
MEG	Mono-Ethylene Glycol
MGS	Mud Gas Separator
MODU	Mobile Offshore Drilling Unit
MSF	Main Safety Functions
MTO	Human, Technology and Organisation (Menneske, Teknologi og Organisasjon)
NCS	Norwegian Continental Shelf
NMD	Norwegian Maritime Directorate
NPT	Non-Productive Time
PLEM	Pipeline End Manifold
PLL	Potential Loss of Life
PS	Performance Standard
PSA	Petroleum Safety Authority
PSD	Process Shutdown
PSV	Process Safety Valves
RAC	Risk Acceptance Criteria
RFO	Ready For Operation
ROV	Remotely Operated Vehicle
RRM	Risk Reducing Measure
SC	Subsea Compression
SCMS	Subsea Compression Manifold Station
SCp	Subsea Compression project

SCSt	Subsea Compression Station
SEM	Subsea Electronic Module
STS	Subsea Transformer Station
TLP	Tension Leg Platform
UPS	Uninterruptible Power Supply

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Chapter 1

Introduction

Åsgard is a gas and condensate field on Haltenbanken in the Norwegian Sea. It is operated by Statoil and has been in production since 1999. By 2014/15, however, it is assessed that there will be problems with the flow rate and slugging in the pipelines due to water break-through and increased pressure loss.
To deal with these issues, and to maximise the recovery, it has been decided to install a compression station at the seabed at Åsgard, which will increase the pressure of the production flow, and thus minimise the problems with pressure loss and slugging.

This will be the first subsea compression station in the world, and thus there are uncertainties as to the risks related to such an installation. The worst thing that could happen is the occurence of a major accident. Major accidents in the petroleum activities may have dramatic consequences regarding loss of lives and environmental and economical damage.

The management of major accident risk is one of the main focus areas of the Petroleum Safety Authority (PSA) in Norway. The specific areas where the probability of a major accident is the greatest, have been identified by the PSA to be:

- Hydrocarbon leaks
- Serious well incidents
- Damage to load-bearing structures and maritime systems
- Ships on collision course

The accident scenarios which will be adressed in this thesis are related to the equipment which will be installed subsea at Åsgard, thus damage to load-bearing structures is not particularly relevant. There will be no well operations and the ship traffic is modest, thus the most relevant major accident categories are hydrocarbon leaks and damage to maritime systems.

In order to control the major accident risk on Åsgard, safety systems and barriers are implemented. According to Statoil's governing document TR1055, the principle objective of safety systems and barriers offshore are, in order of priority[62]:

- Safety of personnel
- Protection of the environment
- Protection of assets
- Minimisation of financial consequences of fire and explosions

In order to reduce the probability of hazardous events, and reduce the consequences of them if they happen, Statoil will prepare emergency preparedness plans for the major accident scenarios. These will comprise information about what measures should be taken if a specific hazardous event occurs.
As a first step in this process, Statoil has identified 12 major accident scenarios which are relevant for the Åsgard Subsea Compression project (Åsgard SCp). This is to map how dangerous situations can occur and develop - and which consequnces the various scenarios may have. In this thesis, these findings will be presented and elaborated.

An important element in risk management is to implement safety systems and risk reducing measures/barriers in several layers to reduce both the probability of hazardous events and limit their consequences. In this thesis, Statoil's efforts to control the major accident risk at Åsgard SC, through barriers and safetey systems, has been identified and described.

As this thesis is about major accident scenarios related to subsea production equipment, scenarios related to topside modifications at Åsgard A or Åsgard B, such as drop of transformer module during lifting to Åsgard A or increased risk of fire in transformers on Åsgard A, will not be discussed. The risk related to the new modifications will be incorporated in the risk assessments of Åsgard A and Åsgard B.

This thesis focuses on major accident scenarios related to installation, intervention and production on the subsea compression system.
Operations related to the existing subsea equipment at Åsgard, such as interventions on the existing templates, will not be considered here because it is not directly related to the Åsgard SCp.

1.1 Report structure

Part I - Theory

Chapter 2 - Åsgard Subsea Compression describes the Åsgard field, the concept of subsea gas compression and how it will be used at Åsgard.

Chapter 3 - Major Accidents in the Offshore Industry gives an insight into the Snorre A blowout in 2004, which could have had severe consequences, and the Deepwater Horizon accident in 2010, which was truly a major accident.

Part II - Method

Chapter 4 - Risk defines the term major accident, describes barriers and gives an insight into the concept of risk, including Statoil's risk acceptance criteria.

Chapter 5 - MTO - Human, Technology and Organisation describes the MTO technique, which is used in this thesis to present the identified barriers systematically.

Part III - Major Accident Scenarios

Chapter 6 - Installation of New Equipment - Marine Operations provides a summary of the most important installations which will be executed at Åsgard, and assesses the major accident events that may arise during the installations. The relevant barriers related to the scenario is also identified.

Chapter 7 - Dropped Objects discusses the major accidents which can be caused by dropped objects, and identifies the most important barriers present at each scenario.

Chapter 8 - Ship Related Hazards gives an insight into the major accident scenarios which could be caused by ships, and gives an insight into the most important barriers for each scenario.

Chapter 9 - Hydrocarbon Leakage assesses the major accident scenarios related to hydrocarbon leakage during normal operation, and presents the most important barriers related to the different scenarios.

Chapter 10 - Accident Scenario - Subsea Gas Leak describes a specific subsea gas release scenario. Wind and current conditions affecting the release is discussed and a MTO analysis of the accident scenario is conducted.

Part IV - Risk Reducing Measures/Barriers

Chapter 11 - Human barriers gives an insight into the general human barriers which are important during operations offshore.

Chapter 12 - Technological barriers describes the technological barriers which are present during the different major accident scenarios in Part III.

Chapter 13 - Organisational barriers describes the most important organisational barriers which are relevant for the different major accident scenarios in Part III.

Part V - Results

Chapter 14 - Results gives a summary of the results of the thesis.

Chapter 15 - Discussion discusses the results of the thesis.

Chapter 16 - Conclusion summarises the conclusions reached in Chapter 14 and 15.

Chapter 17 - Further work gives recommendations for further work.

Part I

Theory

Chapter 2

Åsgard Subsea Compression

Conventional gas compression is used on offshore installations to boost the pressure of the gas which is recovered, in order to transport it to its final destination. The technical development of subsea compressors enables the compressors to be placed closer to the reservoir, resulting in a more effective compression process. This means that the production from new fields, which earlier would have been non-profitable due to low reservoir pressure, and the production from existing fields which experience a decline in pressure, can be maintained for several more years.

2.1 The Åsgard and Mikkel Fields

The oil, gas and condensate development Åsgard is located on Haltenbanken in the Norwegian Sea[59]. The development copmrises the fields Smørbukk, Smørbukk Sør and Midgard, as seen in Figure 2.1. Åsgard is one of the largest developments on the Norwegian Continental Shelf (NCS), comprising 52 wells drilled through 16 templates[1] on the seabed.

Figure 2.2 shows the present layout of the Midgard field, which comprises the three templates, X, Y and Z. The gas field Mikkel, which is located 40 km south of Åsgard, was attached to the infrastructure on Midgard in 2003 through the Z-template[54].

[1] A template is a steel structure that is placed on the seabed and provides structural support to wells.

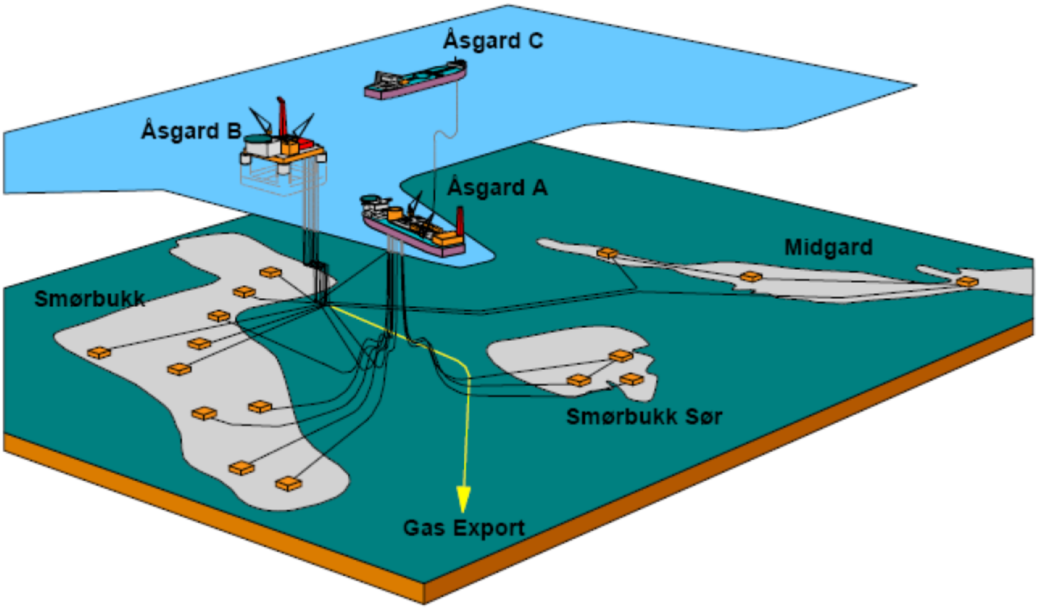

Figure 2.1: Overview of the Åsgard field

Yttergryta is presently connected to the X-template, but will be shut down before the subsea compression system is ready for production[58].

Statoil is the operator of Åsgard and Mikkel; the license interests are shown in Table 2.1.

Company	Åsgard (%)	Mikkel (%)
Statoil ASA (Operator)	34.57	43.97
Total E&P Norge AS	7.68	7.65
ENI Norge AS	14.82	14.90
ExxonMobil Production Norway Inc.	7.24	33.48
Petoro AS	35.69	0

Table 2.1: License interests in Åsgard and Mikkel[57]

The Mikkel and Åsgard fields are developed using subsea wells connected to the floating production, storage and offloading unit (FPSO) Åsgard A for oil, the semisubmersible production platform Åsgard B for gas, and the vessel Åsgard C for storage of condensate[54], as seen in Figure 2.1.

Production was started on Åsgard A in May 1999 and Åsgard B and C in October 2000[53]. Gas from Åsgard B is transported through the Åsgard Transport gas pipeline to the Kårstø processing plant north of Stavanger[59], while oil and condensate is exported using tankers[54].

The production from Mikkel and Midgard consists of gas and condensate, which is transported to Åsgard B through the pipelines Y-101 and Y-102, as can be seen in Figure 2.2. The pipelines connect the templates X, Y and Z in a loop called the “Midgard Loop”[54]. The loop is 97 km long and is connected to Åsgard B.

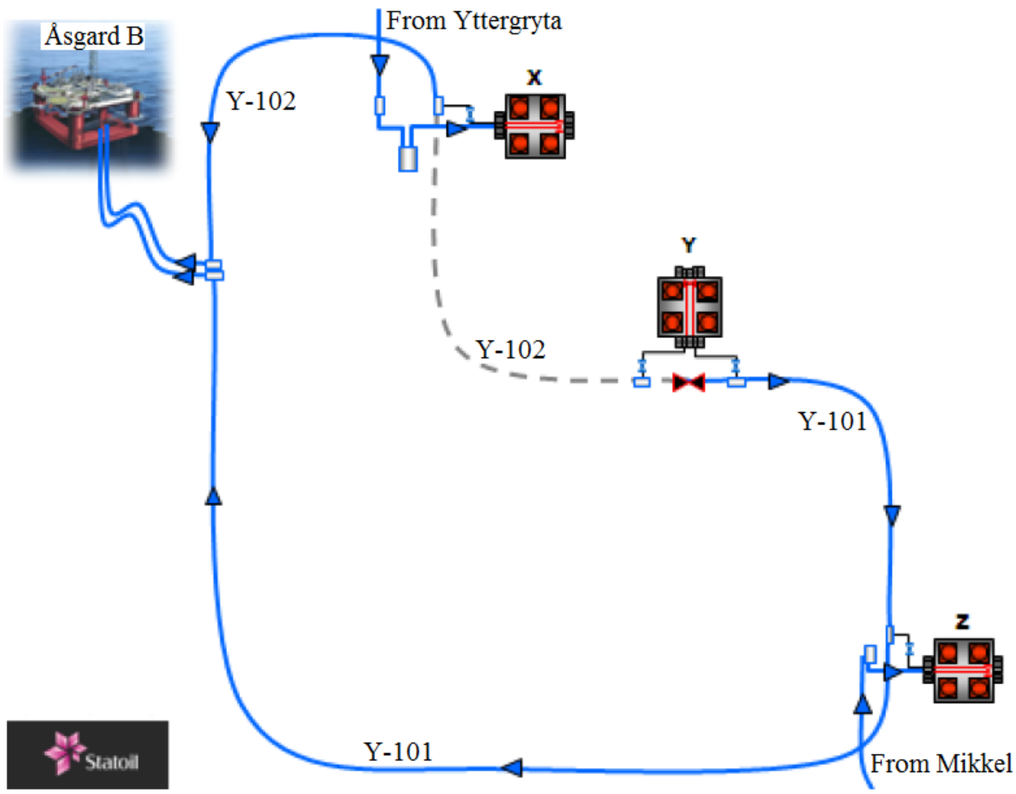

Figure 2.2: The present Midgard field layout[41]

Table 2.2 shows the characteristic data for the fields. Sm^3 means 1 cubic meter of gas during normal circumstances, and BHP stands for Bottom Hole Pressure.

Field	**Water depth (m)**	**Number of wells**	**Template pressure (bara)**	**Maximum flowing BHP (bara)**	**Gas production (MSm^3/d)**
Midgard X	298	4	88.7	126.1	6.6
Midgard Y	257	3	101.1	132.5	4.2
Midgard Z	245	0	N/A	N/A	N/A
Mikkel	N/A	3	105	145.6	4.9

Table 2.2: Expected data for the fields for 2013[46]

An overview of the future layout of the Åsgard field is shown in Figure 2.3.

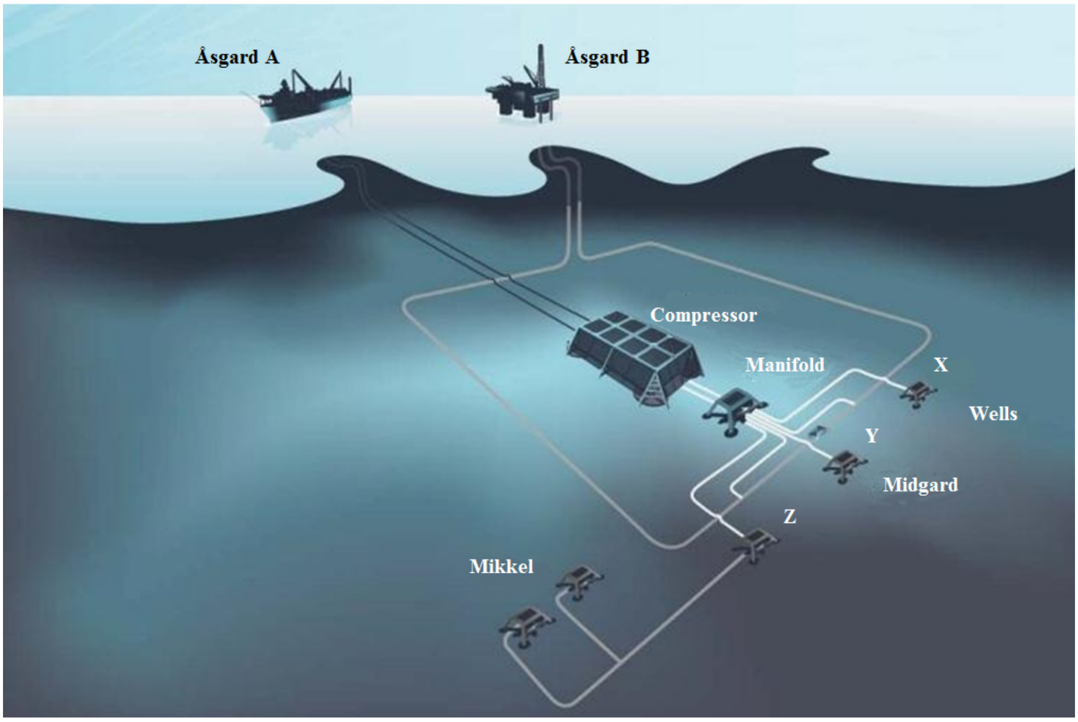

Figure 2.3: The Åsgard and Mikkel fields connected to Åsgard A and B[13]

2.2 “Minimum Flow Problem”

During the early years of production from a reservoir, the pressure in the reservoir is usually high enough to maintain a steady flow of gas in the pipelines from the reservoir to a processing facility on a platform or land. This is because the pressure in the reservoir is bigger than the backpressure from the well and the flowlines. When gas is produced, however, the natural pressure in the reservoir declines gradually, and will eventually become too low to sustain the production profile[60]. When this happens, it becomes necessary to introduce gas compression in order to keep the production going.

Analyses show that the pressure in the wellstream from Mikkel and Midgard will be too small to maintain the gas flow rate above a critical minimum by 2014/15[54]. When this happens, the hydrocarbon flow will no longer be stable and different problems arise. As a consequence of the unstable flow, Mono-Ethylene Glycol (MEG)[2], water and condensate will accumulate in the pipelines, resulting in increased slugging[3]. This problem is referred to as the “minimum flow problem”.

Before this technology was developed, production from fields where the pressure of the wellstream had dropped below the critical minimum, where stopped. This, however, results in great amounts of hydrocarbons never being recovered.

By introducing subsea compression, the flow rate can be maintained for several more years, resulting in an increased recovery factor.

[2]MEG is used as an antifreeze and anticorrosion agent in the wellstream[8].
[3]Slugging refers to varying irregular flows of gas and liquids in pipelines.

2.3 Subsea Gas Compression

2.3.1 Gas Compression

The pressure of the gas which is produced from a reservoir is the driving force for transporting the gas off the field to a nearby facility either on a platform or on land[10]. On the facility, the gas is processed and compressed for export.
Conventionally, gas compression is done on a platform or on land, but recently, technological advances has made subsea compression available.

Compressors are the most expensive equipment used in the processing of oil and gas[26]. They are also very sensitive and occupy a big footprint on the facility, thus it is preferable to use as few as possible while still making sure the production is maintained. If the production is completely shut down, there could be a huge economical loss.
On installations which primarily produce oil, one single compressor is used[26]. This is because if the compressor stops, the oil production can be maintained and the gas can be captured. On installations primarily producing gas, however, two compressors which cover 50% of the production each, are used. If a failure on one of the compressors should occur, the production can be maintained, but with a reduced capacity.

2.3.2 Two Development Alternatives

Two alternatives to increase the pressure in the multiphase wellstream from Mikkel and Midgard has been assessed by Statoil. The first was to utilise a floating compression platform with its own power supply, either with minimum functionality or with extended functionality aimed at future needs and flexibility[54]. The second alternative was to utilise subsea compresson with imported power from a platform.

The different alternatives were evaluated according to health, safety and environment (HSE) criterias, as well as economical and technical aspects. Based on this evaluation, Statoil chose the subsea compression solution.
By placing the compressor system as close to the wells as possible, the efficiency and the production rates are maximised[60]. Other reasons for not choosing a

platform alternative is the need for a crew on the platform, the big footprint a topside compressor occupies, the need for extra gas lift from the seabed and the fact that subsea compression is less invasive on nature[54]. Subsea compression is also a technology step-change.

2.3.3 Subsea Gas Compression System at Åsgard

Subsea gas compression can either be implemented to boost the gas in new fields with low reservoir pressure and/or long tie-backs, or to increase the recovery from fields with declining pressure[23]. The former is especially relevant for the development of fields in the arctic, where snow and ice make it difficult to use platforms for production.

By introducing subsea compression at Åsgard, the desired flow rate may be maintained for several more years, resulting in an estimated recovery of 33.5 Sm^3 oil equivalents, primarily gas.
In addition to the increased revenues, another important reason to maintain the gas production at Midgard and Mikkel is that the gas produced from these reservoirs has a very low content of CO_2 compared to other fields at Haltenbanken[58]. Due to restrictions on the CO_2 percentage in the gas transported to Kårstø, gas production from Midgard and Mikkel is a premise for production from the other fields at Haltenbanken, which are transporting gas via the Åsgard Transport pipeline.

The subsea compression system will be installed west of the Midgard Y template, as can be seen in Figure 2.4, and will compress the well stream from Midgard and Mikkel. The compressed wellstream will then be transported through the new "Midgard Loop" consisting of the existing pipeline Y-101 and the new pipelines SC-101 and SC-102 to Åsgard B.
The power to run the gas compression system will be generated at Åsgard A, while the compression station will be operated and monitored from Åsgard B[58].

The subsea equipment will consist of a subsea step-up transformer located close to Åsgard A, a flat bottom structure (FBS), a subsea compression manifold station (SCMS), a subsea compression station (SCSt) and pipelines, risers and umbilicals.

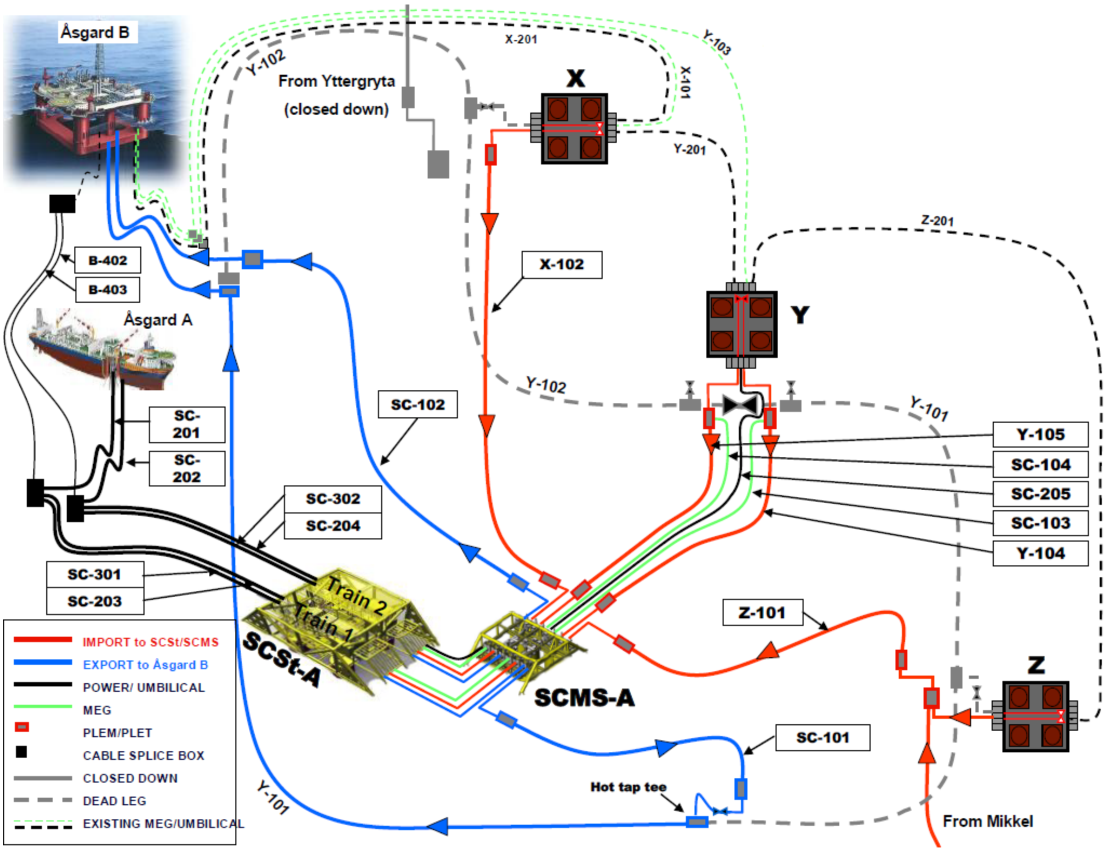

Figure 2.4: Future Åsgard Subsea Compression field layout[64]

The compression station will comprise a main frame and two identical compression trains which will be able to handle about 70 % of the total production each[58]. The compression trains will be placed in parallell in the beginning, but may be switched to serial production at later stages of the lifetime to maximise production. When the trains are placed in parallell, one of the trains can be shut down for intervention, while the production is maintained in the other train.

Each of the compression trains will consist of 4 independently replaceable process modules, which each can be extracted and replaced without affecting the other modules during intervention[58]. Extra modules, corresponding to a complete compression train, will be stored at a dedicated onshore facility, ready to replace any defect modules, thus decreasing the likelihood of non-productive time (NPT).

Intervention using a remotely operated vehicle (ROV) and tooling deployed from a standard inspection, maintenance and repair (IMR) vessel, may be executed on some of the modules, to replace different components such as sensors, detectors, control modules and actuators.

Since the compression system will be installed downstream of the wellheads and templates, there will be no need for additional drilling and well interventions[54].

Figure 2.5: The SCSt placed in a football stadium (Ullevaal)[64]

The size of the SCSt, which is shown in Figure 2.5, will be significant: 70.3 m long, 36.9 m wide and 18.9 m high[54]. In dry condition, the station will have a mass of circa 3500 tonnes, while it will be circa 2,500 tonnes when immersed in water. The compression station will be one of the largest structures placed on the NCS.

The SCMS will be installed to connect the new pipelines to the existing infrastructure on the seabed[54]. It will be controlled from Åsgard B and will be able to control the wellstream from the X, Y and Z templates to the compression station indepentently. One of the two pipelines exporting gas to Åsgard B can also be shut down, such that the whole wellstream is routed through either SC-101 and Y-101 or through SC-102.

The SCSt will be all-electric. This means that all valves, pumps, compressors and coolers will be electric equipment. This places a huge requirement on the power supply, because if the power to the compression station is cut, then the whole production is shut down.
It is also very important to be able to close the different valves whenever it is required, though it is also possible to operate them by ROVs.

To avoid power loss subsea, the SCSt will have an uninterruptible power supply (UPS). The UPS shall be able to replace the main power supply, without interruption, in the case of a power failure. The UPS shall, as a minimum, be able to provide the compression station with power for 30 minutes. Thus, if the power supply from Åsgard A is lost, the production can be maintained for a limited period of time[7][62].

The Compression Process

The compression process in one of the two identical compression trains is shown in Figure 2.6. The compression station will comprise transformers, power inlets, gas coolers, scrubbers, pumps and a control system.

The multiphase wellstream will enter the compression system and move into the inlet/anti-surge cooler. The inlet/anti-surge cooler cools the wellstream along with recirculated gas from the anti-surge system. The anti-surge system is there to neutralise sudden pressure surges in the fluids which may occur[47]. The fluids then enter the gas-liquid separator, also called a scrubber, for separation of the gas and liquid phases. The liquid consists of condensate, water and MEG[54].
The gas compressor is placed downstream the gas outlet of the separator, and after compression, the gas will proceed to the discharge cooler before it is

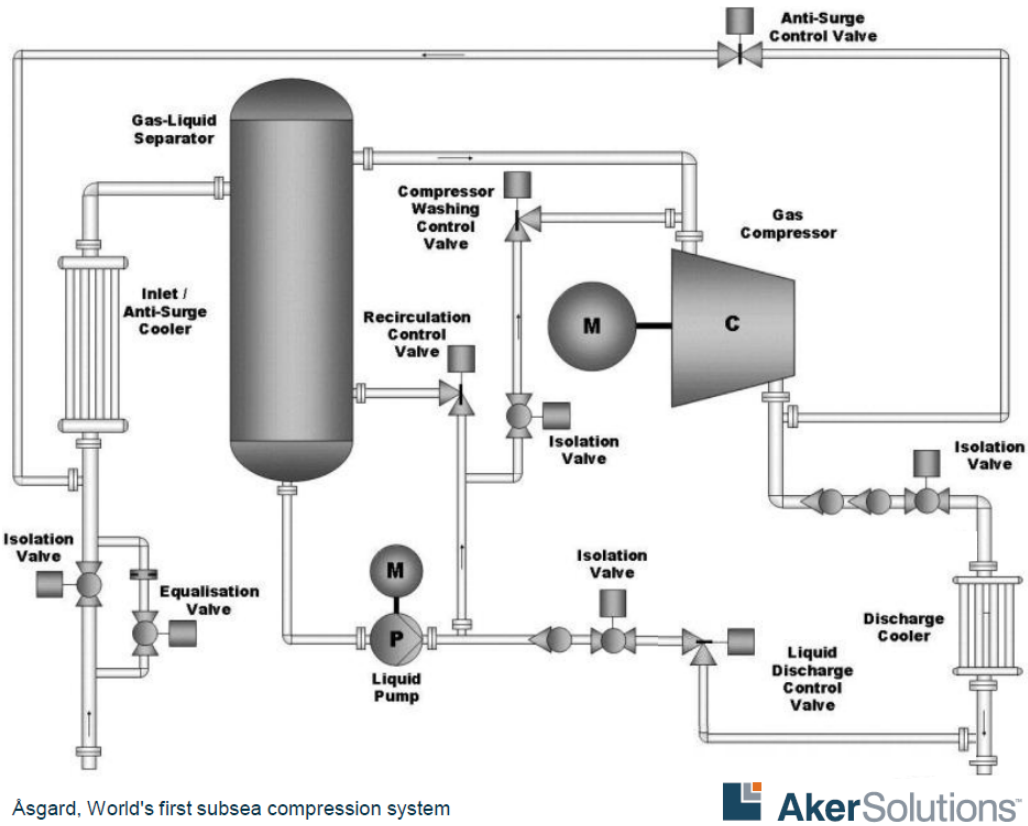

Figure 2.6: Sketch of the compression process in one of the two compression trains[64]

mixed with the liquid. The compressor is a centrifugal compressor which can deliver a pressure increase of about three times the inlet pressure[54]. If the two compression trains are placed in series, the maximum pressure increase is about seven to nine times the inlet pressure.
The liquid pump increases the pressure in the liquid and pumps it into the gas stream. The multiphase wellstream is then transported through the SCMS to Åsgard B[54].

Installation of new Equipment

The subsea compression station will be installed and connected to the subsea structures already in place on the seabed at Åsgard. The first installation will be carried out in 2012, while the last will be done in 2014.

The main installations which are planned at this point – shown in Figure 2.4 – are[40][41]:

- Removal of spools; one at Template X towards Yttergryta PLEM[4] and two at Template Y (Y-101 and Y-102).
- Installation and tie-in of spools; two at Template Y, six between SCMS and different PLEMs, one between Mikkel PLEM and PLEM at Template Z and six between SCMS and SCSt.
- Installation of PLEM.
- Hot-tap into pipeline Y-101.
- Installation of pipelines.
- Installation and tie-in of SCMS and SCSt.
- Installation of new riser base at Åsgard B.
- Disconnection and re-routing of existing riser to the new riser base.
- Installation of fibre optical umbilicals between Åsgard A and Åsgard B.
- Installation of subsea transformer station, umbilicals and power cables.
- Installation and tie-in of two new MEG lines between SCMS and Template Y.
- RFO[5] and testing activities.

The only operation which will be performed in 2012 is the installation of a hot-tap tee on pipeline Y-101[40]. The hot-tap tee will be installed to enable the connection between the new pipeline SC-101, which will be installed in 2013, and the existing pipeline Y-101. This will be done while Y-101 is still on stream and having a pressure of approximately 90 bars[39]. By doing this, the production will be maintained during the operation, thus avoiding expensive shutdowns.

In 2013, the new pipelines between the templates and the SCMS, and between the SCMS and Åsgard B, will be installed. The main frames of the SCSt and the SCMS will also be installed, along with 13 spools and one PLEM. Tie-in operations will then be executed to connect the equipment.

[4] A PLEM is a Pipeline End Manifold which is a connection point between a pipeline and a subsea structure or branch pipeline.

[5] RFO stands for Ready For Work, and is a generic term for making the equipment ready for operation.

The rest of the installations will be carried out in 2014. Then the modules of the SCSt and SCMS will be installed to complete the compression station and the manifold station. A subsea transformer station will be installed near Åsgard A, along with umbilicals and power cables between Åsgard A and the SCSt. Umbilicals will also be installed between Åsgard A and Åsgard B to improve the connection between the two. Installation and tie-in of two MEG lines between the SCMS and Template Y, and installation and tie-in of five more spools completes the installation phase.

There will also be installed a new riser base at Åsgard B, and existing riser will be disonnected and re-routed to the new riser base. The schedule for this operation was however not available for this thesis.

To make the equipment ready for operation, flooding, cleaning and gauging of all new piplines will be done. Flushing and leak/pressure testing of the spools will also be conducted.

Chapter 3

Major Accidents in the Offshore Industry

Throughout history, there have been many accidents in the offshore industry. When the oil industry started to look to the sea to find new reservoirs in the late 19th century, safety was not their biggest priority. As the years have gone by, and the industry has moved to deeper waters and encountered bigger challenges, the necessity and requirements for safety has become more prominent.
In this chapter, there will be given a summary of the blowout at Snorre A in 2004 and the Deepwater Horizon accident in 2010 to demonstrate how seemingly controlled situations can escalate into a major accident.

3.1 The Snorre A Gas Blowout

Snorre A is a tension leg platform (TLP) placed on the Statoil-operated Snorre field in the Norwegian North Sea[55]. The field has been producing hydrocarbons since August 1992.
One of the wells connected to Snorre A is P-31A. It was drilled in 1995 and was used for oil production for one year before it was converted into a gas injection well. Gas injection is performed in order to increase the pressure in the reservoir such that more oil may be extracted from neighboring wells.
In November 2004, Snorre A experienced a gas blowout from P-31A. Due to expertise in the platform management and quite a bit of luck, the release was stopped within 24 hours with no damage to the personnel or the environment.

3.1.1 Chain of Events

P-31A was shut down in December 2003 because of damage in the casing[37], and a mechanical plug was inserted to withstand the pressure from the reservoir, see Figure 3.1. After the shut-in, an operation was planned to recover and reuse the slot in the drilling template by drilling a sidetrack, P-31B, from the abandoned well. In order to do this, P-31A had to be permanently abandoned, thus a more permanent barrier than the mechanical plug had to be installed to withstand the pressure from the reservoir.
The original plan was to cut the production tubing above the mechanical plug and place an additional cement plug above the cut. This plan, however, was changed in October 2004. The new plan was to fill the reservoir tail pipe under the mechanical plug with concrete in order to prevent unwanted cross flows between P-31A and the new sidetrack, P-31B.

A meeting was planned for 12 November to review the risk for the entire program, but was postponed to 19 November because of collision of meetings. The slot recovery was scheduled for 21 November, but because the rig was ready for the operation two days earlier, the operation was started on 19 november to avoid rig downtime, and the risk review meeting was canceled.

In the evening of 28 November 2004, during the execution of the slot recovery, there was discovered problems with the well integrity. At about 15:30, gas rose up through the blowout preventer (BOP), and it was apparent that mud, which was the primary security barrier, was leaking out of the well, and thus the first barrier was breached.
At about 18:00 the pressure started to increase due to gas entering the well from the reservoir. Production at Snorre A was shut down by the platform manager at around 19:30, and notifications were made to the relevant parties. Around 21:20, several gas alarms went off and it was discovered that the sea was “boiling with gas” beneath the platform. The emergency shutdown (ESD) was activated to remove possible ignition sources.

The gas was released in two places, through the BOP and through the casing. Figure 3.1 gives an indication of how the blowout occured. The arrows show where

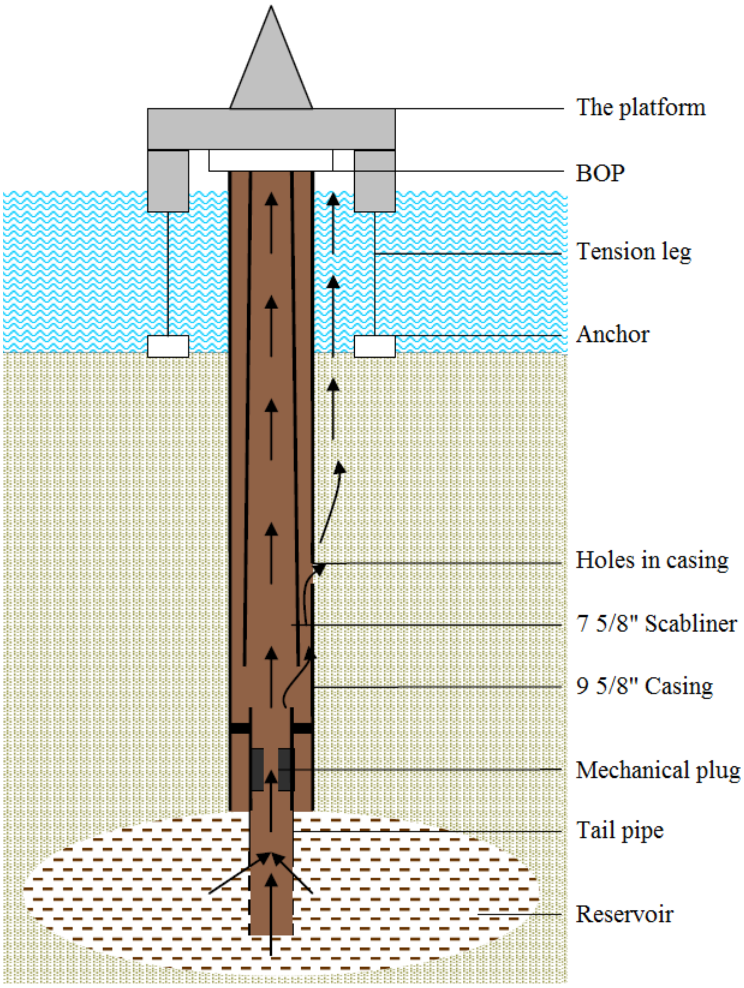

Figure 3.1: Well P-31A. Sketch of the gas blowout at Snorre A[37]

the gas entered the well from the reservoir and how it flowed uncontrollably through the casing and up to the surface. The release through the BOP was stopped by increasing the pressure in the hydraulic line to the annulus safety valve in the BOP, which is a valve designed to prevent gas from flowing up through the well.

The platform manager had a hard decision to make; should he evacuate all personnel, or stay and try to stop the blowout. If he evacuated, the worst case scenario involved multiple blowouts and major oil release which could have lasted for months. If they stayed, he risked the life of all the personnel on the platform, looking at a worst case scenario where the gas ignited and the platform was lost.

The platform manager decided to evacuate all non-essential personnel, and gave the members of the platform management the option to stay voluntarily and try to stop the release of gas.

To stop the blowout, heavy drilling mud with high viscosity was pumped into the well to reduce the pressure from the reservoir. The operation was successfull, and at about 10.30 the next day, the pressure in the well had been reduced to 0 bar.

3.1.2 Aftermath

Due to the risk of ignition, there were many precautions which had to be made during the attempts to control the blowout. Among others, the main power supply had to be shut down, air intake to the cement pumps had to be modified because they took in air from the underside of the platform, and ships could not go close to the platform. For more details, see SINTEFs recount of the incident in [37] or PSA's investigation report, [30].

PSA conducted an investigation to identify non-conformities and improvement areas. Through the investigation, the PSA uncovered failures in all parts of Statoil's planning and execution of the intervention on well P-31A[37], which are related to:

- Failure to comply with governing documentation
- Deficient understanding and implementation of risk assessments
- Deficient involvement of management
- Breach of well barrier requirements

Because the list of discrepancies is so extensive, there are no indications that the blowout was caused by mere chance. It is not that uncommon that a barrier fails, but failure of so many different barriers at the same time is very rare. These failures should have been discovered and corrected earlier.

3.2 Deepwater Horizon Accident

Deepwater Horizon was a semi-submersible mobile offshore drilling unit (MODU) owned by Transocean, which was under contract to BP in the Gulf of Mexico (GoM) in the 2000s[18]. At the beginning of 2010, the rig replaced Marianas as the drilling rig for the exploration well Macondo. The exploration well was designed so that it could be transformed into a production well later on, if profitable.

On 20 April 2010, a blowout occurred from the Macondo well and onto Deepwater Horizon. Upon reaching the rig, the hydrocarbons ignited, resulting in explosions and fire. 11 people were killed and about 780,000 m^3 of crude oil was released into the sea during the 87 days the oil spill lasted[4][18].

3.2.1 Chain of Events

In April 2004, the drilling of the Macondo well was finished, and the well was to be temporarily abandoned until production from the well could be started[63]. To abandon a well, the riser connecting the wellhead to the rig has to be disconnected and lowered to the seabed. Before this is done, the toxic drilling mud, which is present in the riser, has to be displaced by sea water, such that the toxic mud is not released into the sea when the riser is disconnected.

The blowout on Deepwater Horizon occured during such a displacement operation. 30 minutes into the operation, sea water and mud was pushed out of the riser and onto the rig by oil and gas entering the well from the reservoir[28]. The BOP was activated by workers to detach the rig from the well, but it failed. The crew then diverted the flow to the mud gas separator (MGS), which was overwhelmed by the fast flow of oil and gas[18]. This resulted in gas being vented directly onto the rig. Methane flowed out and ignited, resulting in several explosions and fire on the rig.
All of the fire pumps on the rig were electrical, so when the main power was lost right before the first explosion, they were unusable. Personnel were sent to activate the emergency generator, but they couldn't get it started. Evacuation of the crew was started, 115 people were evacuated, but 11 were missing.

After burning for 36 hours, the rig sank on 22 April[18]. The blowout lasted for several months, until it was finally stopped, after many attempts, in September 2010[63].

The different attempts to seal the well included using ROVs to control valves on the BOP, and the drilling of two relief wells. In the end, the blowout was stopped by installing a custom-built wellhead on the pipe socket of the wrecked BOP. Heavy drilling mud was then pumped into the well, forcing oil and gas back into the reservoir. Finally, the well was sealed using a cement plug in the upper part of the well.

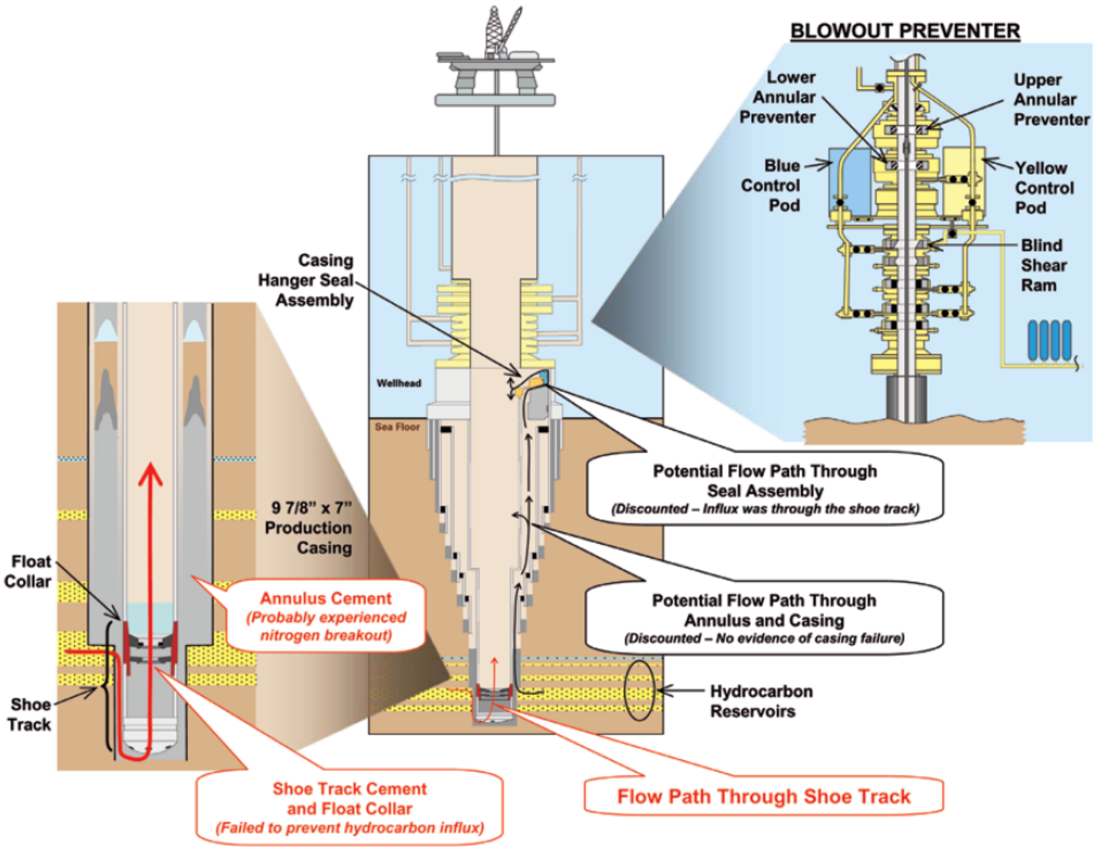

Figure 3.2: Sketch of the Macondo well with potential flow paths[18]

Figure 3.2 shows the possible flow paths for the oil and gas in the reservoir into the well.

3.2.2 Debatable Decisions

During the drilling of the Macondo well, the personnel encountered several problems such as gas seeping into the well, a measuring device getting stuck in the well and brittle rock resulting in drilling mud being released into the sea[24]. These problems caused the drilling operation to exceed the target time of about 51 days. By 20 April, the project was in its 80th day. This delay cost BP a lot of money: Each additional day of rig lease and contractor fees cost $1 million, in addition came the $15 million worth of fluid which had been released. These expences probably influenced BP to choose the cheapest and quickest alternatives to save time and money.

After the drilling was done, foam cement was pumped down to fill the space between the outside pipe and the rock to prevent gas from flowing up the sides of the pipe. Halliburton, the cementing contractor, recommended BP to install 21 devices to make sure the pipe was centered in the well before cementing in place the steel pipe running into the oil reservoir. BP decided to install six[24].
BP also chose to run a single pipe from the sea floor to the oil reservoir, instead of the normal industry practice of using two pipes sealed together, with the smaller one inside of the bigger one, and the smaller one sticking into the reservoir. This way gas, which tries to get up the outside of the pipe meets two barriers: The cement and the seal between the two pipes[24].

Before a cement job is performed on a well, it is customary to do a "bottoms up"[24]. This is a procedure to circulate the mud in the well to investigate whether the mud in the well has been absorbing gas. If it has, the mud will not be as viscous as it should to be able to contain the oil and gas in the reservoir, thus the gas is cleaned out before the mud is put back into the well. Circulating all the mud in a well of this depth, 5,596 metres[63] plus 1500 metres of water depth, would take between six and 12 hours, but BP only ran the circulation for 30 minutes.

A negative-pressure test was conducted to check the well's integrity and whether gas was seeping in. In retrospect, well-control experts said it is clear that gas was entering the well, but at the time, BP was satisfied with the test and proceeded as planned[24].

Before the disconnection and lowering of the riser to the seabed, a cement plug had to be set in the well and the toxic mud in the riser had to be displaced by sea water$_{[28]}$. Either the plug could be installed with the mud barrier present in the well, or the mud could be replaced by sea water before setting the plug. The latter alternative saves time, but is more hazardous because the mud weighs much more than sea water and is thus a stronger barrier against the hydrocarbons in the reservoir.
Because there were no indications that gas or oil would flow up to cause a kick, it was decided to displace the drilling mud before setting the plug. About 30 minutes into the displacement, sea water and drilling mud gushed out from the riser and onto the rig, pushed by the oil and gas entering the well from the reservoir. The mud didn't plug the well as it should have because it was made lighter by the gas which had seeped into the well.

3.2.3 Aftermath

BP conducted an internal investigation after the accident on Deepwater Horizon$_{[18]}$. During their investigaion, the team uncovered eight key findings related to the causes of the accident. The technical failures; 1, 2, 7 and 8, are shown in Figure 3.2. For a full account of the findings, please refer to [18].

1. The annulus cement barrier did not isolate the hydrocarbons: There were weaknesses in the cement design and testing, quality assurance and risk assessment.

2. The shoe track barrier did not isolate the hydrocarbons: The influx of hydrocarbons was through the shoe track, thus the cement and the float collar did not stop the influx.

3. The negative-pressure test was accepted although well integrity had not been established: The test results were misinterpreted as positive and well integrity was established incorrectly.

4. Influx was not recognised until hydrocarbons were in the riser: The influx was not discovered until the hydrocarbons had passed through the BOP and into the riser.

5. Well control response actions failed to regain control of the well: If the fluids had been diverted overboard instead of to the mud gas separator, there might have been more time to respond, and thus smaller consequences of the accident.

6. Diversion to the mud gas separator resulted in gas venting onto the rig: The MGS system allowed for the diversion of the fast flowing fluids even though it overwhelmed the system immediately.

7. The fire and gas system did not prevent hydrocarbon ignition: A gas-rich mixture was probably transferred beyond the electrically classified areas by the heating, ventilation and air conditioning system.

8. The BOP emergency mode did not seal the well: There were three methods which failed:

    - The emergency disconnect sequence was probably disabled by the explosions and fire
    - The automatic mode function (AMF), which should have sealed the well upon loss of hydraulic pressure, was probably prevented from activation by the condition of the yellow and blue control pods in the BOP
    - The blind shear ram (BSR) was probably closed through initiation of the autoshear function by ROVs. However, the BSR failed to seal the well.

    There were also potential weaknesses in the testing regime and maintenance management system for the BOP.

As outlined in the eight key findings, there was "a complex and interlinked series of mechanical failures, human judgements, engineering design, operational implementation and team interfaces" that caused the blowout at Deepwater Horizon.

A series of recommendations related to each of the eight key findings has been given by the investigation team. These can be found in [18].

3.3 Focus on Prevention of Major Accidents

3.3.1 Snorre A

If things had gone a bit differently, the gas blowout at Snorre A could have escalated into a major accident. This made Statoil look into the causes of the accident and identify several measures to make the operation at Snorre A safer. According to [37], the main measures identified by Statoil are:

- Strengthening of the Snorre organisation on land and offshore
- Enforcement of the use of Statoil's best practice during planning and drilling of wells
- Improved training of Snorre's personnel in Statoil's governing documents
- Improvement of the quality of planning and risk assessment
- Requirement that the Snorre management is more involved in all operations

A project was also initiated to improve and simplify the in-house procedures in Statoil.

3.3.2 Deepwater Horizon

The Deepwater Horizon accident was a wake up call for the offshore industry, resulting in a renewed focus on the prevention of major accidents.
The PSA released a preliminary status report regarding the Deepwater Horizon accident in the summer of 2011. In this report, the PSA investigates the causes of the accident and gives general recommendations to which areas that need improvement in order to reduce the risk of a major accident in the GoM as well as on the NCS[33]:

- **Organisation and management:** Several areas were identified to have weaknesses; among others, decision- and prioritisation processes, management decisions characterised by short-term profits and changes in the organisation resulting in unclear responsibilities.

- **Risk management:** There should be developed better tools for controlling the major accident risk. It is important to improve the analyses, assessments and understanding of the risk related to changes: Organisational and structural changes as well as deviations between plan and execution in individual activities.

- **Barrier control:** An improved control of barriers is needed. The whole industry should unite in developing a general approach for barrier control in accordance with current regulations.

According to PSA, the Deepwater Horizon accident confirms a need to develop risk analysis tools to understand and handle changes in the risk picture[63]. When changes occur, such as technical modifications, changes in plans and procedures or changes in the organisation, the risk of a major accident is affected. This should be taken into consideration when the risk is assessed.

Part II

Method

Chapter 4

Risk

There are different ways in assessing risk and different methods of quantifying and visualising it. In this chapter, some common methods used by Statoil are discussed. Statoil has also defined specific risk acceptance criteria which are important in the process of evaluating whether or not the risk of a specific operation is acceptable.
Different definitions of the term major accident will however be discussed first, along with an explanation of how barriers are viewed in this thesis.

4.1 Theory

4.1.1 Definition of a Major Accident

There is no universal definition of exactly what a major accident is. Different organisations use different definitions, but they usually result in basically the same understanding of what defines a major accident.
According to the Norwegian Petroleum Directorate, there are two prominent definitions[19]:

- A major accident is an accident where at least five people could potentially be exposed.
- A major accident is an accident caused by failure of one or more of the system's built-in safety and emergency barriers.

These are also mirrored in the definitions used by NORSOK and PSA.

In NORSOK Z-013[1] – a standard developed by the Norwegian petroleum industry to, among other things, ensure adequate safety in the industry – the following definition is given: "Acute occurrence of an event such as a major emission, fire, or explosion, which immediately or delayed, leads to serious consequences to human health and/or fatalities and/or environmental damage and/or larger economical losses$_{[9]}$".

The Norwegian Major Accident Regulation[2] is a regulation regarding the prevention of major accidents and the limitations of their consequences in industries where dangerous chemicals are used$_{[11]}$.
PSA uses a revised version of their definition of a major accident: "A major accident is defined as an acute incident, such as a major discharge/emission or a fire/explosion, which immediately or subsequently causes several serious injuries and/or loss of human life, serious harm to the environment and/or loss of substantial material assets$_{[34]}$". The Norwegian Major Accident Regulation's definition of a major accident is given in norwegian in [11].

4.1.2 Barriers

It is not always easy to find out and understand the underlying causes of a major accident. SINTEF establishes six different perspectives on organisational resilience to try to understand the organisational mechanisms that are involved in major accidents$_{[36]}$.
One of these perspectives is the energy-barrier perspective. This perspective derives from the energy transfer principle, which involves looking at an initiating event as an energy which needs to be stopped in order to prevent an accident. By adding barriers to the scenario, it is possible to separate the potential victims from the hazardous energy.

According to SINTEF, barriers are defined as physical and procedural measures to avoid or control hazards$_{[36]}$. By being able to predict potentially dangerous sequences, it is possible to assess where barriers are needed, and where there

[1]Competitive Standing of the Norwegian Offshore Sector (Norsk Sokkels Konkurranseposisjon).
[2]Norwegian regulation: Storulykkeforskriften.

should be redundant barriers, that is, a secondary barrier in case the primary barrier fails.

A barrier can either be a measure which reduces the frequency of an event, reduces the consequences of the event, or a combination of the two[66]. The best outcome of an initiating event/hazard is that it does not escalate into a hazardous event, thus barriers which reduces the frequency of an event should be prioritised.

The energy-barrier perspective is illustrated in Figure 4.1, where an incident may escalate from a hazard on the left, through the frequency reducing barriers to a hazardous event in the middle. Then it is up to the consequence reducing barriers to the right, to minimise the consequences of the event.

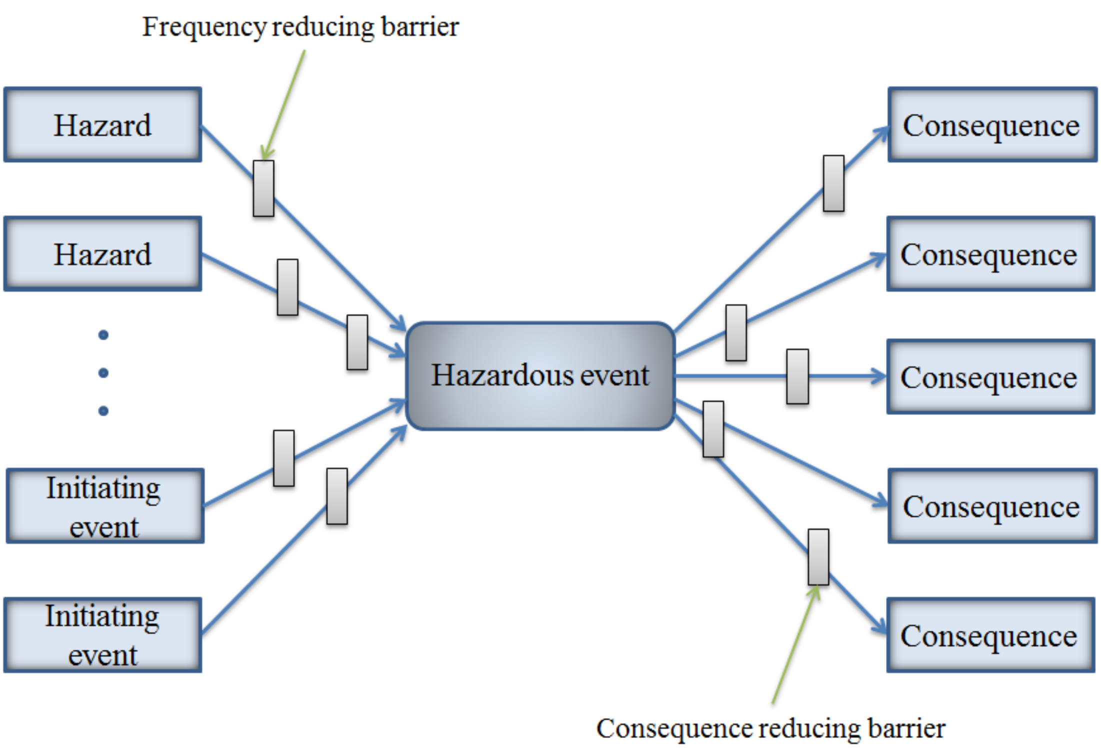

Figure 4.1: Bow-tie diagram

Barriers can also be divided into passive - also called static - barriers, and active - also called dynamic - barriers. A passive barrier is a barrier which is present over a significant amount of time, while an active barrier is present at certain points in time[29]. As opposed to passive barriers, active barriers need to change state in order to fulfill their role as a barrier.

Barriers will be further discussed in Part IV.

4.2 Risk Acceptance Criteria

For all high-risk operations, such as intervention on live subsea equipment, there shall be conducted individual risk analyses to assess the risk of the particular operation[53]. Risk acceptance criteria (RAC) are set by the individual company based on rules and standards, and are used to assess whether or not a specific operation has an acceptable risk level.

4.2.1 Impairment of main safety functions

Main safety functions are defined in NORSOK Z-013 as "functions that need to be intact in order to ensure the safety for personnel and/or limit pollution"[9]. The probability for impairment of main safety functions shall, according to NORSOK, be lower than 10^{-4} per year. Statoil also uses this criterion[52].

4.2.2 Potential Loss of Life

Potential Loss of Life (PLL) is the statistically expected number of fatalities due to accidents per year[65]. PLL is equal to the hazard frequency, that is the frequency of a fatality per year, times the potential number of fatalities.
The calculation of PLL is more uncertain than for instance loss of main safety functions, but it is more accurate than FAR, which is described in the next section, because it does not require taking the average over a group of people[9].

4.2.3 Fatal Accident Rate

Fatal Accident Rate (FAR) is the frequency with which fatalities occur for a specified activity or for a group of people[65]. It is the statistically expected number of fatalities due to accidents per 100 million (10^8) exposed hours.

$$\mathrm{FAR} = \frac{\mathrm{P(Fatal\ accident)}}{\mathrm{Exposure\ time}} \cdot 10^8 = \frac{\mathrm{PLL}}{\sum_{i=1}^{n} \mathrm{t}_i} \cdot 10^8 \tag{4.1}$$

where t_i is the exposure time in hours for person i, for $i = 1, 2, ..., n$.

The requirement for average risk to an individual which is working on any of Statoils installations offshore is FAR < 10[52]. The criterion is defined for the operational phase and for a one year period. For the most exposed group, however, the following risk acceptance criterion applies: FAR < 25.

4.2.4 ALARP

The ALARP principle, short for As Low As Reasonably Practicable, is a way of categorising the risk to assess how important it is to implement risk reducing measures. ALARP is based on the principle “reversed burden of proof”[25], which means that it has to be proven why an identified risk reducing measure should *not* be implemented. This means that identified measures shall be implemented unless it can be documented that there is an unreasonable disproportion between costs/disadvantages and benefits.

As seen in Figure 4.2, the risk is usually divided into three categories.
Unacceptable Region: Risk which is categorised to be in this area, typically $>10^{-3}$[25], cannot be accepted except under extraordinary circumstances.
Tolerable Region (ALARP region): Risk in this area is tolerable if a reduction is practically impossible, or if the cost of reducing the risk is grossly disproportionate to the improvement gained.
Broadly Acceptable Region: No additional risk treatment is necessary except for making sure that the risk remains in this region.

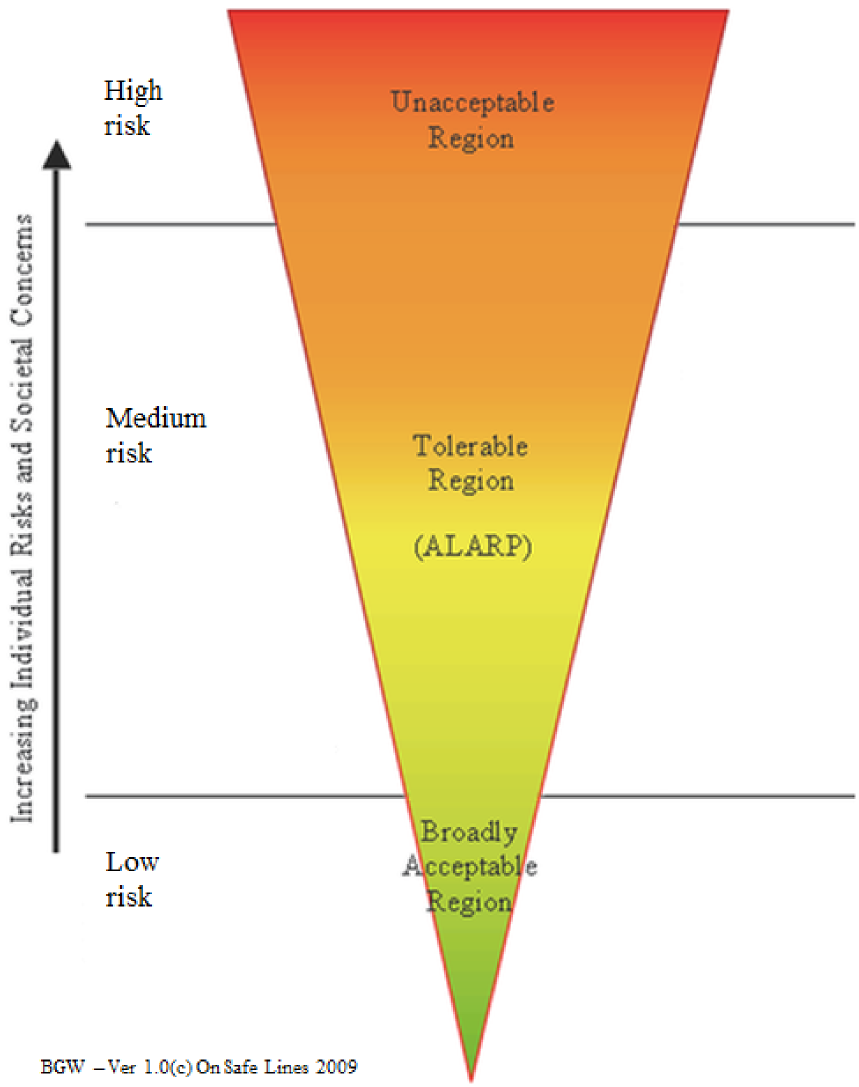

Figure 4.2: The ALARP principle[1]

Figure 4.2 is based on British regulations. If the figure was to reflect the Norwegian regulations, there would be only two regions: The unacceptable region and the tolerable/ALARP region. This means that no matter how small or insignificant the risk is, identified risk reducing measures shall be implemented unless it is proven to be an unreasonable disproportion between cost and benefit. A cost-benefit calculation may be performed in order to decide the economic effects of a risk reducing measure[66].

4.2.5 Summary of Statoil's Risk Acceptance Criteria

Statoil's risk acceptance criteria as per 2012, are summarised in Table 4.1.

Method	Criteria
Impairment of main safety functions	$< 10^{-4}$
FAR	< 10
FAR most exposed group	< 25
ALARP - unacceptable region	$< 10^{-3}$

Table 4.1: Statoil's risk acceptance criteria

4.2.6 Acceptance Criteria for Environmental Risk at Åsgard

The installation specific risk acceptance criteria regarding environmental issues on Åsgard has been defined by Statoil as given in Table 4.2[54].

Environmental damage	Recovery time	Highest acceptable probability per year
Minor	1 month - 1 year	$< 1.0 \cdot 10^{-2}$
Moderate	1 - 3 years	$< 2.5 \cdot 10^{-3}$
Large	3 - 10 years	$< 1.0 \cdot 10^{-3}$
Very large	> 10 years	$< 2.5 \cdot 10^{-4}$

Table 4.2: Installation specific environmental risk acceptance criteria for Åsgard[54]

These criteria were defined based on the principle that the restitution time - after the environmental damage - of the most vulnerable resource, shall be negligible compared to the return period of harm to that resource[54].

Chapter 5

MTO - Human, Technology and Organisation

As was seen in Chapter 3, it is usually a combination of events which causes a major accident. To understand the different aspects of an accident, it is important to identify these events. This chapter discusses a method used to analyse accidents; namely, MTO analysis.
In this thesis, MTO will primarily be used to categorise the different barriers which are important to prevent a major accident at Åsgard.

PSA states that it is important to gain a better understanding of the interaction between organisational, operational and technical elements in barriers[32]. Because failure or weakening of barriers often is a causal factor in accidents and incidents, a good understanding of the different barriers is important in risk management.
MTO is a method which can be used to systematise the different barriers in order to better understand their functionality and requirements, and to better understand the interaction between the different barriers.

MTO is short for human, technology and organisation[48], and was initially used in the nuclear power industry. Before 1979, only the technology factor was evaluated. However, after the nuclear power accident in Harrisburg in 1979[1], the human factor was added to the evaluation.

[1]Mechanical failures and human errors caused a partial meltdown, releasing radioactive gases[6].

The organisational factor was added after the Chernobyl accident in 1986[2], and thus the three factors were seen in context for the first time[42].

The MTO method is based on the energy-barrier perspective and is used to analyse accidents; to understand how they occur and how they progress. The method is based on identifying and categorising the different events leading to an accident. To categorise the events, MTO distinguishes between technical barriers, human decisions and the procedures in the organisation.

MTO can also be used to categorise barriers and assess the different decisions and actions which lead to barrier failure, by focusing on the interactions between human, technical and organisational factors. By using this method, it is possible to identify the root causes related to a major accident[65].

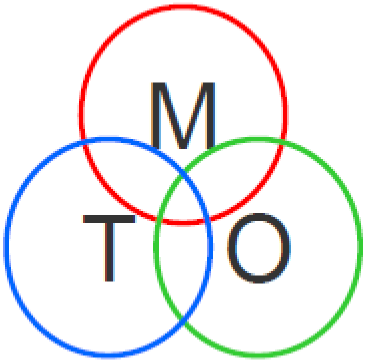

Figure 5.1: Interaction between man, technology and organisation[27]

The venn diagram in Figure 5.1 gives an indication of how human, technological and organisational factors can coincide.

A MTO analysis comprises three main elements[65]:

1. A structured analysis of the accident by using an event- and cause diagram
2. A change analysis to describe how events are deviating from earlier events or common practice.
3. A barrier analysis to uncover technological and administrative barriers which have failed or are missing.

[2]Several explosions and partial meltdown in the nuclear power station was caused by experimentation by technicians[2].

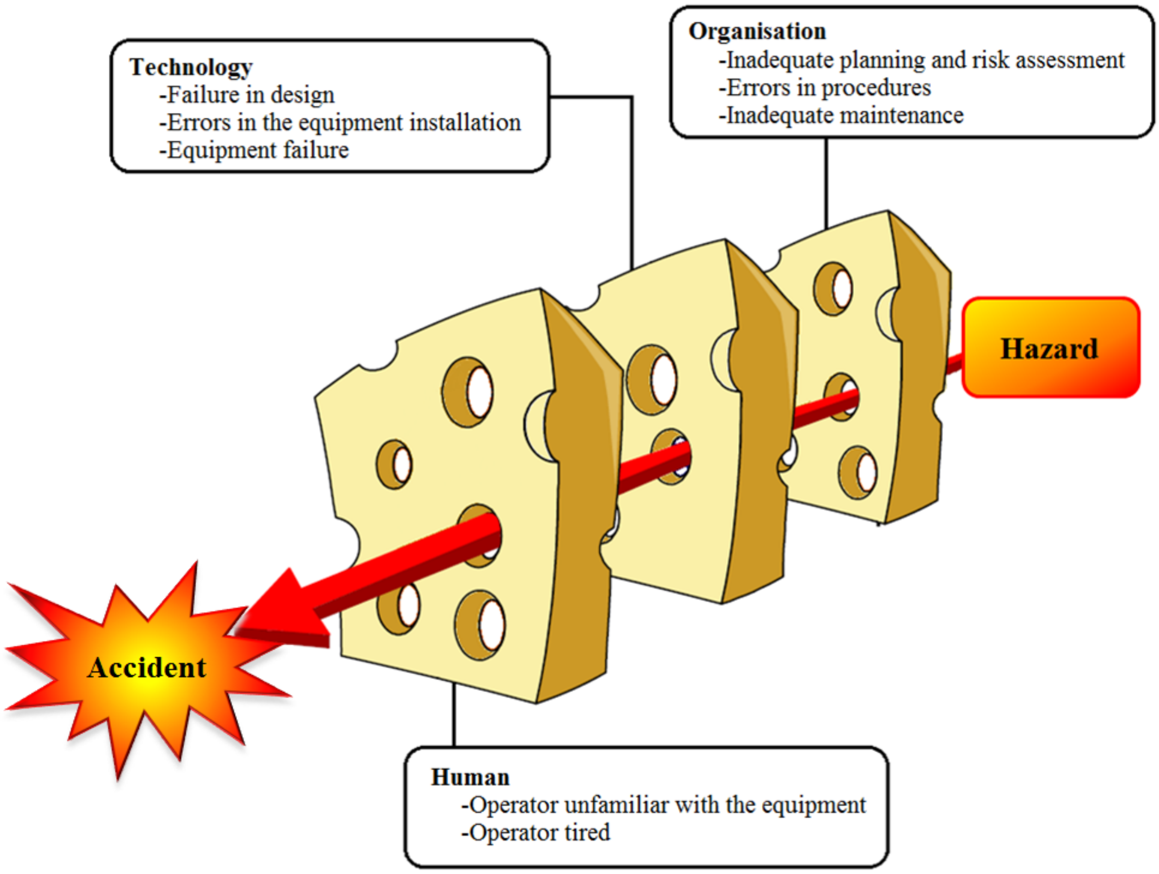

Figure 5.2: Sketch of Reason's swiss cheese model, based on [12]

Figure 5.2 shows Reason's swiss cheese model. It is a sketch of how different barriers are in place to prevent an accident from happening.
Each chunk of cheese represents the barriers related to human, technology and organisation.
The holes represent active failures or latent conditions, which appears at different locations and times during the lifetime of the system. It is an example of the energy-barrier perspective and shows how different barriers must fail for a hazard to become an accident. The holes appear in different places at different times, as different barriers malfunction, and if the holes in the three chunks of cheese align, a hazard will escalate into an accident.

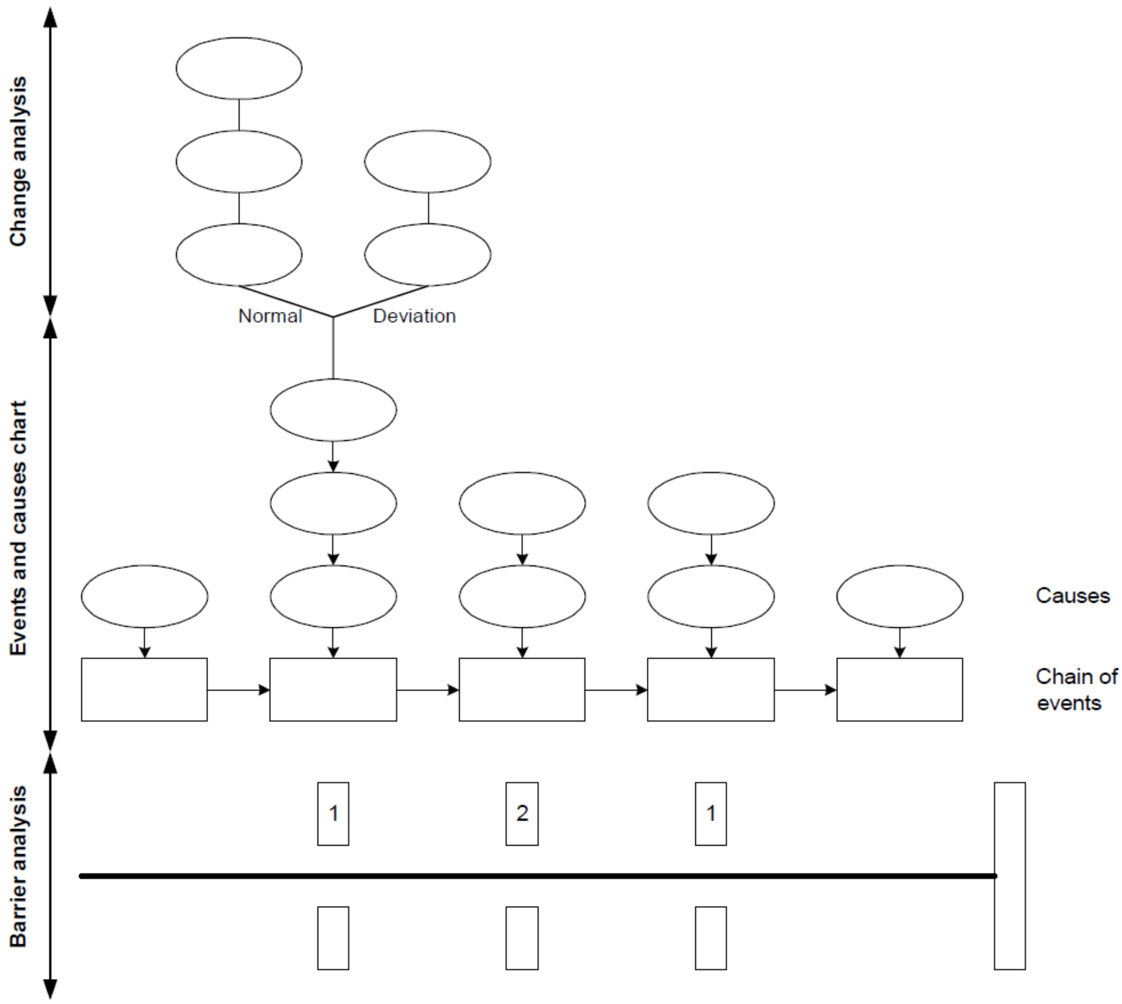

Figure 5.3: Worksheet for the MTO analysis[48]

A typical worksheet for a MTO analysis is shown in Figure 5.3. The first step in the MTO analysis is to identify the events which have occured[65], and illustrate them in the events and causes chart in the block diagram. For each event, technical and human factors which affect the event shall be identified and connected to the event by a vertical arrow.

Technical, human or organisational barriers which failed or were missing during the course of events must be identified and added below the event in question in the diagram[65]. Eventually, an assessment of which deviations or changes that has occured during the course of events, must be conducted and added to the diagram.

The most important questions that need to be answered during a MTO analysis is:

- What barriers could have been in place to stop the hazardous event from escalating into an accident?
- What could the organisation have done in order to prevent the accident from happening?

Usually, MTO analysis is used to investigate the causes of an accident which has already happened, and is widely used in the offshore industry[65]. In this thesis, it will mainly be used to identify which barriers are in place for each major accident scenario and how these mitigate the risk.

Part III

Major Accident Scenarios

Major Accident Scenarios

In this part, the major accident scenarios related to the Åsgard Subsea Compression project will be examined.
Through risk analysis, Statoil defined 12 major accident events (MAEs) which are related to the Åsgard Subsea Compression project. The MAEs are summarised below, and are further discussed in Chapter 6 through 9, respectively.

Installation of New Equipment - Marine Operations - Chapter 6

- Hydrocarbon leakage during hot-tapping
- Hydrocarbon leakage during tie-in
- Impact on existing riser during riser base installation

Dropped Objects - Chapter 7

- Dropped object during intervention of SCMS and SCSt
- Dropped objects during installation of PLEM and spools
- Uncontrolled lifting/dropped objects during installation of SCMS and SCSt

Ship Related Hazards - Chapter 8

- Collision between vessel and Åsgard A or Åsgard B during installation of umbilical/fibre cable
- Vessel drift-off during installation and removal of start up anchor/pile within platform safety zone
- Potential drive off during intervention of modules

Hydrocarbon Leakage - Chapter 9

- Leakage from production system after installation

MAEs related to the installation and operation of an extra transformer module on Åsgard A were also defined[40]. These will, however, not be examined here, since they are not directly related to the subsea equipment.

At the end of each section regarding a major accident scenario, the different risk reducing measures/barriers, which are important for that exact scenario, are presented in a table by using the MTO technique. Only the technological and the organisational barriers are included in the table, because the human barriers are not specific to one particular scenario. The human barriers are instead presented together in Chapter 11.
The risk reducing measures related to each major accident scenario is described in detail in Part IV, along with the general human barriers.

Many of the major accident scenarios involve subsea gas leaks, thus such a scenario is described in Chapter 10.1. A MTO diagram of the accident scenario is given, and risk reducing measures and barriers implemented by Statoil is presented.

Chapter 6

Installation of New Equipment - Marine Operations

Some of the installations of new equipment, which will be done at Åsgard, have the potential to result in a major accident. These operations will be discussed in this chapter, along with the risk related to the installations, and the different barriers which are established to control the different major accident scenarios.

6.1 Installations

The main installations which are planned at this point are[40][41]:

- Removal of spools; one at Template X towards Yttergryta PLEM and two at Template Y (Y-101 and Y-102).
- Installation and tie-in of spools; two at Template Y, six between SCMS and different PLEMs, one between Mikkel PLEM and PLEM at Template Z and six between SCMS and SCSt.
- Installation of PLEM.
- Hot-tap into pipeline Y-101.
- Installation of pipelines.
- Installation and tie-in of SCMS and SCSt.
- Installation of new riser base at Åsgard B.
- Disconnection and re-routing of existing riser to the new riser base.
- Installation of fibre optical umbilicals between Åsgard A and Åsgard B.

- Installation of subsea transformer station, umbilicals and power cables.
- Installation and tie-in of two new MEG lines between SCMS and Template Y.
- RFO and testing activities.

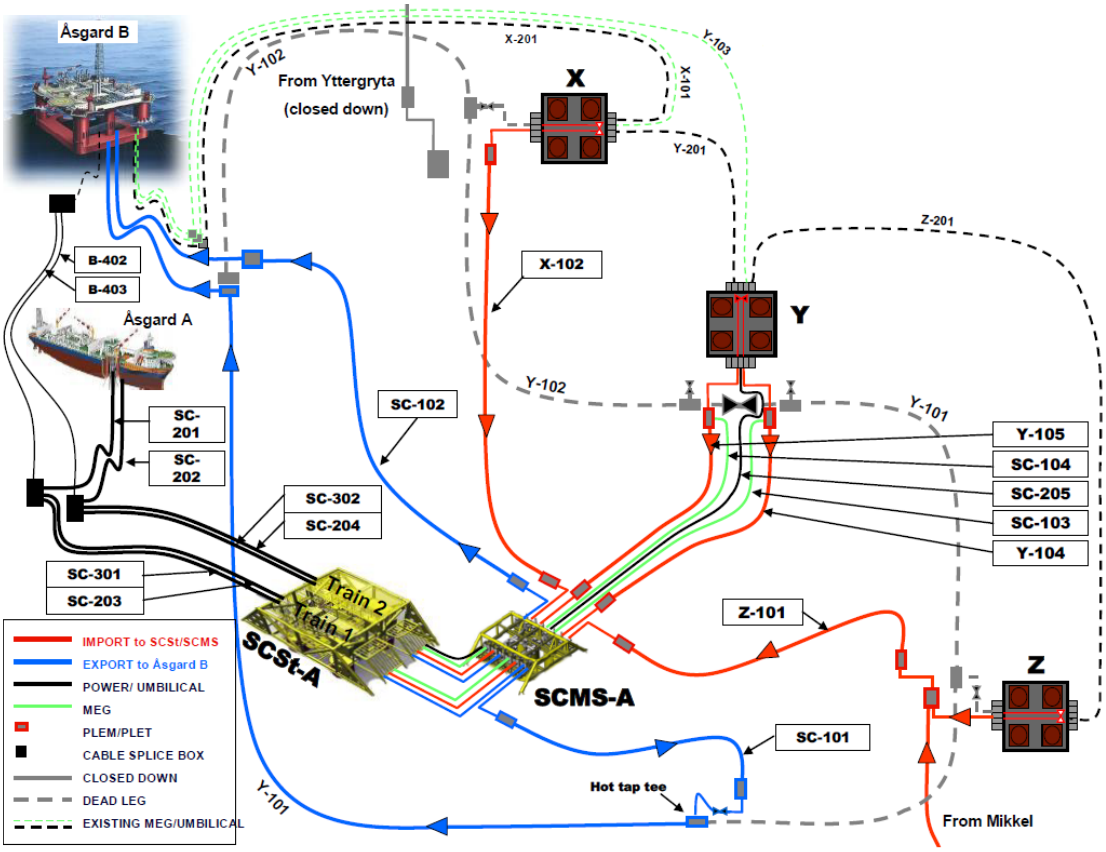

Figure 6.1: Future Åsgard Subsea Compression field layout[64]

Figure 6.1, which is reproduced here from Section 2.3.3 for convenience, shows most of the equipment which is planned to be installed at Åsgard.

6.2 Hydrocarbon leakage during hot-tapping (A9)

To connect the SCMS to the pipeline Y-101, which will contain hydrocarbons at a pressure of approximately 90 bars[39], hot-tapping will be executed.
First, a T-clamp will be installed on the pipeline. Then a valve system will be installed on the T-clamp using a Hot-Tap Valve Module clamp, called the HTVM Lower Clamp. At the top of the valve system, there is a clamp called the HTVM Upper Clamp which will be used to connect the valve system to the pipeline from the SCMS. A hot-tap drilling machine is then used to drill a hole in pipeline Y-101, and the valve system is then ready for connection with the new pipeline, SC-101.

The hot-tap at Åsgard will be the world's first remote, diverless hot-tap conducted on a pipeline that was not originally pre-prepared for hot-tapping. Usually the T-clamp is installed on the pipeline before the pipeline is layed, and the hot-tapping operation is usually assisted by divers. At Åsgard, however, the pipeline is not pre-prepared for a hot-tap, and it is too deep for divers.

The incident that could cause hydrocarbon leakage during this operation, although extremely unlikely, is equipment failure, namely the HTVM clamps around the hot-tap valve, or the 3/4" Bell housing port at the top of the hot-tap machine.
Dropped objects will probably not result in hydrocarbon leakage during this operation due to the protection of the pipelines.

Scandpower executed a consequence study for the Ormen Lange hot-tap operation in 2009[45]. This study has been used by Safetec in [41] to assess the risk related to the hot-tap at Åsgard, where the difference in depth between Ormen Lange and Åsgard has been accounted for.

During a hot-tap operation, the maximum hole size which could occur is 200 mm, which is the size of the hot-tap cutter. If the hot-tap clamp fails, the maximum amount of gas that can escape is limited by the diameter of the hot-tap.

By looking at Table 10.3 in Chapter 10, it is seen that the time it takes for the gas to reach the surface is assessed to be 92 s for a hole size of 254 mm. This shows that the minimum amount of time to relocate a potential vessel above the leak point, if a leak occurs, is circa 1 minute and 30 seconds. If the vessel fails to relocate, it could be exposed to the gas. This could result in a fatal accident if the gas is ignited.

Three leakage scenarios where identified:

- HTVM Lower clamp: Mechanical failure
- HTVM Upper clamp: Mechanical failure
- Bell Housing Port (x2): Component installation/assembly

By using a gas dispersion analysis performed by Scandpower in [46], it was found that a hole size of 20 mm could lead to a dangerous gas cloud on the surface under given wind conditions. For more details about the gas dispersion in water and how the wind and current conditions affect it, see Chapter 10.

Dangerous scenarios for the Bell Housing Port

For small hole sizes, circa 20 mm, the wind has to be below 2 $^{m}/_{s}$ for a dangerous gas cloud to form. For larger hole sizes between 20 mm and 100 mm, however, the wind has to be between 2 $^{m}/_{s}$ and 10 $^{m}/_{s}$.

It was thus assessed that for the Bell housing port fitting, only a rupture of 19 mm would be able to give dangerous gas clouds for wind speeds below 2 $^{m}/_{s}$. The probability of a rupture for one Bell Housing Port was found to be $\mathrm{P}_{r,b} = 3.5 \cdot 10^{-11}$ per hour.

Dangerous scenarios for the clamp connections

For the clamp connections, it was found that a rupture of 200 mm will give a dangerous gas cloud for all wind speeds. The probability of a rupture for one clamp connection during one hour was found to be $\mathrm{P}_{r,c} = 2.6 \cdot 10^{-10}$.

Because the clamp connections are much bigger than the Bell housing ports, major leaks can also pose a danger for the vessel for given wind speeds. By using the average wind speed of 6 m/s, and including all major leaks in the risk calculations, a conservative estimate of the risk related to major leaks from clamp connections was found to be $P_{m,c} = 7.9 \cdot 10^{-10}$ per hour.
Wind speeds below 6 m/s is expected for 31.3 % of the time, which gives $P_w = 0.313$.

According to [45], the hot-tap operation at Ormen Lange is expected to last for t = 12 hours, and the same is assumed for the hot-tap at Åsgard.
The leak frequencies which could pose a danger to the vessel is summarised in Table 6.1.

Category	**Clamp connections (x2)**	**Bell Housing Port (x2)**
Major leak	$1.9 \cdot 10^{-8}$	-
Rupture	$6.3 \cdot 10^{-9}$	$8.3 \cdot 10^{-10}$

Table 6.1: Leak frequencies for the 12 hour operation

The probability of ignition of the gas cloud is assessed by Scandpower to be $P_i = 0.5$. If the gas cloud is ignited, it is assessed that the probability of a fatality is $P_f = 1$, which means that the probability of impairment of main safety functions and the probability of a fatal accident are the same.

Based on this, the probability of a fatal accident is found to be:

$$P_{fat} = [(P_{m,c} + P_{r,b}) \cdot P_w + P_{r,c}] \cdot P_i \cdot P_f \tag{6.1}$$
$$= [(1.9 \cdot 10^{-8} + 8.3 \cdot 10^{-10}) \cdot 0.313 + 6.3 \cdot 10^{-9}] \cdot 0.5 \cdot 1 = 6.2 \cdot 10^{-9} \tag{6.2}$$

where $P_{m,c}$, $P_{r,c}$ and $P_{r,b}$ are the leak frequencies given in Table 6.1.

6.2.1 Controlling the risk

Risk area	**Risk area**	**RAC**
Probability of a fatal accident	$6.2{\cdot}10^{-9}$	N/A
Impairment of main safety functions	$6.2{\cdot}10^{-9}$	10^{-4}

Table 6.2: Risk and risk acceptance criteria for A9

Table 6.2 shows the risk which is related to the hot-tap operation at Åsgard. The probability of impairment of main safety functions is well within the risk acceptance criterion.

The probability of a fatal accident is only $6.2{\cdot}10^{-9}$, and thus quite small. It is however not so small that it is negligible, thus risk reducing measures should be assessed according to the ALARP principle.

Technology	**Organisation**
PSD	Safe lifting distance
Weak link in umbilical from vessel to hot-tap	Safe relocation of vessel
Dropped object protection	Leak detection by ROV
	Place vessel outside potential -gas plume radius
	Place vessel upwind of any -potential gas leak

Table 6.3: Barriers for A9

Table 6.3 shows the main barriers which are present during the execution of the hot-tap operation. PSD and the other barriers are discussed in Part IV.

If safe relocation of the vessel is applied, and the vessel manages to move away from the gas zone, the probability of a fatal accident will be reduced further[41].

By looking at the maximum radius for a gas cloud caused by a rupture of 200 mm in Table 10.3 in Chapter 10, and the displacement of the center of the release area due to an average current of 15 m/s in Table 10.4 in Section 10.2.2, the minimum safe distance is found to be 179 m. This relates to all the major accident scenarios which involves a subsea gas leak of this magnitude.

It is possible to install the hot-tap machine and then relocate the vessel outside the gas leak area prior to cutting the pipe, thus the risk to personnel can be eliminated through implementation of organisational barriers.

6.3 Hydrocarbon leakage during tie-in (A21)

During the installation of the new subsea equipment at Åsgard, several tie-in operations are required to connect the different equipment. The wells are assumed to be in production during these operations, thus there is a risk of hydrocarbon leakage.

Tie-in at Åsgard is considered to be a hazardous operation due to the fact that there will be critical barriers present during the operation. A barrier is called critical when there is only one barrier present between the hydrocarbon flow and the environment.

According to Statoil's risk assessment of critical barriers, [46], there are 14 critical barriers present during the tie-in operations. All of the critical barriers were identified to be valves.
In the assessment, risk due to internal failures of the critical barriers were evaluated. Risk associated with external impact such as dropped objects or drift-off/drive off, however, were not assessed. Such events are considered to increase the operationsl risk considerably[41].

According to [46], the critical barriers are present for t = 960 hours during the tie-in procedures. The total risk of failure of critical barriers during tie-in is thus assessed to be $P_{failure} = 1.2 \cdot 10^{-5}$.

With an ignition probability of $P_i = 0.5$, the frequency of impairment of main safety functions due to tie-in is assessed to be $P_{imp,op} = 8.2 \cdot 10^{-7}$ per operation, and $P_{imp,year} = 5.1 \cdot 10^{-6}$ per year.

The FAR value is estimated to be FAR = 0.029 per 10^8 exposed work hour[46].

Based on this, the PLL is found to be

$$\text{PLL} = \frac{\text{FAR} \cdot \text{N} \cdot \text{t}}{10^8} = \frac{0.029 \cdot 105 \cdot 960}{10^8} = 2.9 \cdot 10^{-5} \tag{6.3}$$

where N = 105 is the number of people on the vessel, here estimated to be the same as for the hot-tap operation.

The probability of a fatal accident has been estimated to be

$$\text{P}_{\text{fat,year}} = \frac{\text{FAR} \cdot \text{t}_{\text{year}}}{10^8} = \frac{0.029 \cdot 8760}{10^8} = 2.54 \cdot 10^{-6} \tag{6.4}$$

where t_{year} is the number of hours in a year.

6.3.1 Controlling the risk

Risk area	**Risk area**	**RAC**
Probability of a fatal accident	$2.54 \cdot 10^{-6}$	N/A
Impairment of main safety functions	$5.1 \cdot 10^{-6}$	10^{-4}
FAR	0.029	10

Table 6.4: Risk and risk acceptance criteria for A21

The risk presented in Table 6.4 shows a relatively small risk, which is well within the acceptance criteria. It is still important to implement risk reducing measures in alignment with the ALARP principle.

Technology	**Organisation**
PSD	Safe lifting distance
Leak detection on vessel	Safe relocation of vessel
Weak link	Leak detection by ROV
	Testing of critical barriers

Table 6.5: Barriers for A21

The most important frequency reducing barrier in Table 6.5 is the testing of critical barriers. This is because there are 14 critical barriers present during the tie-in operations, and they represent the biggest risk of a hydrocarbon release. By testing them prior to the operations, the risk of failure of any of the critical barriers is reduced.

The risk presented in Table 6.4 is reduced further if relocation of vessel is executed properly when a leak is detected. This is an important consequence reducing barrier which can prevent the vessel from being exposed to gas from a potential leak.

6.4 Impact on existing riser during riser base installation (A30)

During the installation of a new riser base near Åsgard B, there is a possibility of impact on existing risers if the riser base is dropped[39].

Originally, it is decided that the new riser base will be installed while the production is shut down, but if risk analyses show that it is justifiable, the installation might be evaluated to be done while the existing risers are in production. By doing the latter, there is a risk of hydrocarbon release if there is an impact between existing riser and the new riser base. This could result in a riser fire, which could, in the worst case, cause loss of main safety barriers and multiple fatalities.

According to [66], the frequency of dropping an object with a mass between 20 and 100 tonnes during heavy lift from a supply vessel into the sea is $1.6{\cdot}10^{-5}$. According to [40], the riser base, which is to be installed at Åsgard, will have a mass greater than 20 tonnes, thus the probability of dropping the new riser base during the installation is assessed to be $1.6{\cdot}10^{-5}$[41]. This number is based on accident data issued by the UK Department of Energy for the period 1980-86.

However, in [38], Reinertsen presents frequencies for dropped objects for the period 1999-2007 based on the most recent UK HSE data. Because the drop frequencies in general have declined over the years, the most recently acquired frequencies are the most relevant, and also the least conservative. The drop frequency of a module with a mass between 20 and 100 tonnes was found to be $4.3 \cdot 10^{-6}$ in [38], thus the risk of a drop is very small.

If the existing risers and the pipeline to be rerouted are depressurized before the new riser base is installed, the probability of a fatal accident is negligible.

6.4.1 Controlling the risk

Technology	Organisation
PSD	Safe lifting distance
Leak detection on vessel	Safe relocation of vessel
Position/heading of vessel	Leak detection by ROV
Depressurize risers	Position/heading of vessel

Table 6.6: Barriers for A30

If the riser base is dropped, it will probably result in damage to the equipment, but if the safe lifting distance principle is applied by the installation vessel, there will probably not be any damage to nearby pipelines. If the risers and pipeline to be rerouted are depressurized, which is planned, the risk of a fatal accident is practically negligible[41].

Chapter 7

Dropped Objects

During installation and intervention, dropped objects is a potential threat which could lead to a major accident if hitting pressurized hydrocarbon equipment. This chapter describes these scenarios, the risk involved, and the different barriers present to control the risk.

7.1 Dropped object during intervention of SCMS and SCSt (A7)

One of the advantages of installing two separate compression trains is that intervention on one of the trains can be executed while the other train is running. This way the production may be maintained during interventions.

As described in Section 2.3.3, the SCSt will consist of a main frame and several separate modules. Each of the modules is covered with a hatch, thus during intervention, only the hatch covering the equipment which needs intervention, will be lifted. Then the module underneath will be depressurised by a hose, which is connected to the intervention vessel. This way, the rest of the SCSt is protected[39].
The SCMS will be constructed in the same way.

When intervention is needed on the SCSt, the module in need of maintenance is lifted out and transported to an onshore facility where maintenance will be conducted. A spare module stored onshore will be used to replace the removed module[58].
Intervention of the SCMS is not expected to require lifting operations, thus there is negligible risk of dropped objects on the SCMS.

The probability of a drop during intervention of the SCSt is $2.0{\cdot}10^{-5}$[41], and it has been assumed that the intervention vessel performs eight lifts during this period. This gives a drop frequency of $P_{drop} = 8 \cdot 2.0{\cdot}10^{-5} = 1.6{\cdot}10^{-4}$ per year.

The probability of hitting subsea equipment in production is less than $P_{hit} = 0.01$, as long as the safe lifting distance principle is followed.

If the vessel is in the area above the leak point when gas reaches the surface, it will be exposed to flammable gas. The probability of ignition is then assessed to be $P_{i,1} = 0.6$[44] for one vessel, and $P_{i,2} = 0.84$[40] for two vessels. If the flammable gas is ignited, the probability of one or more fatalities is $P_f = 1$, which gives a total probability of a fatal accident and impairment of main safety functions during intervention of the SCSt and the SCMS:

$$P_{fat,1} = P_{imp,1} \cdot P_f = P_{drop} \cdot P_{hit} \cdot P_{i,1} \cdot P_f = 1.6 \cdot 10^{-4} \cdot 0.01 \cdot 0.6 \cdot 1 \quad = 9.6 \cdot 10^{-7} \tag{7.1}$$

$$P_{fat,2} = P_{imp,2} \cdot P_f = P_{drop} \cdot P_{hit} \cdot P_{i,2} \cdot P_f = 1.6 \cdot 10^{-4} \cdot 0.01 \cdot 0.84 \cdot 1 \quad = 1.3 \cdot 10^{-6} \tag{7.2}$$

7.1.1 Controlling the risk

Risk area	**Risk**	**RAC**
Probability of a fatal accident, 1	$9.6{\cdot}10^{-7}$	-
Probability of a fatal accident, 2	$1.3{\cdot}10^{-6}$	-
Impairment of main safety functions, 1	$9.6{\cdot}10^{-7}$	10^{-4}
Impairment of main safety functions, 2	$1.3{\cdot}10^{-6}$	10^{-4}

Table 7.1: Risk and risk acceptance criteria for A7

The risk related to dropped objects during intervention of the SCSt using one or two vessels is shown in Table 7.1. Because intervention on the SCMS is not expected to require lifting, the risks presented in the table are related to the intervention of the SCSt.
The risks are well within the acceptance criterion, but not so small that they are negligible.

Technology	Organisation
PSD Leak detection on vessel/subsea structures Pressure reading at SCSt Crane Technical specification Rigging design	Safe lifting distance Safe relocation of vessel Leak detection by ROV

Table 7.2: Barriers for A7

As mentioned above, the probability of hitting pressurized subsea equipment, when the safe lifting principle is applied, is very low, $P_{hit} = 0.01$. This is an important frequency reducing barrier for this scenario, and for the other scenarios involving dropped objects.

The operation is monitored by ROV, thus if a dropped object causes a subsea leak, it will be discovered immediately and the PSD can be initiated quickly[40]. When the vessel is alerted of a gas leak, it shall immediately move away from the leak point and to a predefined safe distance. If the vessel is able to relocate to a safe distance, the probability of a fatal accident, is reduced further.

7.2 Dropped objects during installation of PLEM and spools (A10)

During the installation of one PLEM and 18 spools, and during the removal of two spools, there is a risk of dropped objects hitting subsea equipment. Such an impact could result in hydrocarbon leakage and gas exposure of vessels. If the gas is ignited, explosion and fire may occur, resulting in damage to personnel and vulnerable equipment.

If existing subsea equipment is not hit, a drop will probably just result in total loss of the PLEM or spool being lifted[41].

The probability of dropping a PLEM or a spool during installation is estimated to be $P_{drop} = 1.2 \cdot 10^{-5}$[41].

7.2.1 Controlling the risk

Technology	Organisation
PSD	Safe lifting distance
Leak detection on vessel/subsea structures	Safe relocation of vessel
Dropped object protection	Leak detection by ROV
Crane Technical specification	Wet storage areas
Rigging design	

Table 7.3: Barriers for A10

By using the safe lifting distance principle during the lifts, it is assessed that pressurized equipment on the seabed will not be hit, thus the risk of hydrocarbon leakage, and thus a fatal accident, due to drop of a PLEM or a spool is assessed to be negligible[41].

7.3 Uncontrolled lifting/dropped objects during installation of SCMS and SCSt (A12)

There is no live hydrocarbon equipment on the seabed near the new location of the SCMS and the SCSt. This means that if the main frame or one of the modules of the SCMS or the SCSt is dropped in the water, there will be no risk of a gas leak or fatalities[41].

If the SCMS or the SCSt is damaged, there could be delays and extra costs to the project. It may not be possible to recover a big module which have been damaged under water if water intrusion has occured, because then the mass of the module has increased considerably.

It is assumed that the frames will be installed first, and then the modules[40].

If one of the modules of the SCMS or the SCSt is dropped on the vessel, it will probably not cause any damage to the vessel due to the dimensions and mass of the modules.
If one of the main frames is dropped on the vessel, however, it is assumed to cause total loss of the vessel and claim the lives of the entire personnel[40].
This means that the probability of impairment of main safety functions and the probability of a fatal accident are the same.

According to [66], the probability of dropping an object onto the deck of a vessel instead of dropping it into the sea is 30 %, thus the probability of fatalities due to the drop of one of the main frames is $\mathrm{P}_{vessel} = 0.3$.

The International Association of Oil and Gas Producers has assessed the probability of dropped objects with different masses and using different lifting devices[35]. When lifting a load with a mass exceeding 100 tonnes with a crane, the risk of dropping the load is assessed to be $2.8{\cdot}10^{-4}$.
The probability for dropping the main frame of the SCMS or the SCSt is thus assessed to be $\mathrm{P}_{frame} = 2.8{\cdot}10^{-4}$, while the probability of dropping one of the modules is assessed by Safetec to be $\mathrm{P}_{module} = 4.2{\cdot}10^{-5}$[41].
The risk of dropping a main frame is bigger than the risk of dropping a module because the main frame is much heavier than the modules.

The risk of a fatal accident during the lifting of the main frames is conservatively estimated to be

$$\mathrm{P}_{fat} = \mathrm{P}_{imp} = 2 \cdot \mathrm{P}_{frame} \cdot \mathrm{P}_{vessel} = 2 \cdot 2.8 \cdot 10^{-4} \cdot 0.3 = 1.68 \cdot 10^{-4}. \tag{7.3}$$

The installation of the two main frames will be executed in two separate operations, thus the risk for a fatality during each operation is

$$\mathrm{P}_{fat,SCMS} = \mathrm{P}_{fat,SCSt} = \mathrm{P}_{fat} \cdot 0.5 = 8.4 \cdot 10^{-5} \tag{7.4}$$

7.3.1 Controlling the risk

Risk area	Risk	RAC
Risk of a fatal accident	$1.68 \cdot 10^{-4}$	N/A
Impairment of main safety functions, each frame	$8.40 \cdot 10^{-5}$	10^{-4}
Risk of a fatal accident, drop of SCMS frame	$8.40 \cdot 10^{-5}$	N/A
Risk of a fatal accident, drop of SCSt frame	$8.40 \cdot 10^{-5}$	N/A

Table 7.4: Risk and risk acceptance criteria for A12

The risk of a fatal accident during the lifting of the main frame of the SCMS and the SCSt is shown in Table 7.4.
The risk of a fatal accident during the operation is relatively high, but by assessing the probability of impairment of main safety functions, it is seen that the risk is within the acceptance criterion.

When the frames have been installed, they will not be lifted again, except perhaps in the future, when the production at Åsgard is terminated and the equipment needs to be removed.

Technology	Organisation
Crane Technical specification Rigging design	Safe lifting distance

Table 7.5: Barriers for A12

The safe lifting distance does not mitigate the risk of a fatal accident, since drop of one of the main frames on the vessel does not involve gas leakage. The barrier does, however, contribute to making the risk of hitting hydrocarbon equipment, if dropping a main frame or a module into the sea, negligible.

The crane technical specification and the rigging design barriers reduces the probability of a drop during the lift.

Chapter 8

Ship Related Hazards

Drive off/drift-off by a vessel executing an installation or an intervention, is a potential hazard which could evolve into a major accident. This chapter discusses the different scenarios related to drive off and drift-off, the risks involved and the different barriers in place to mitigate them.

8.1 Collision between vessel and Åsgard A or Åsgard B during installation of umbilical/-fibre cable (A28)

Åsgard A

The power needed by the subsea compression station will be generated at Åsgard A, thus new umbilicals from Åsgard A to the SCSt will be installed and tied in. If the vessel executing the installation experiences a drive off or a drift-off during the installation, the umbilical could be torn off such that it hits a riser on Åsgard A[41].

There is also a risk of the installation vessel hitting Åsgard A, but according to [41], such a scenario will not cause fatalities, but may cause damage to equipment. If an umbilical is torn off, however, it could hit a riser which is on stream, resulting in fire and fatalities.

It is assumed that the installation vessel will be inside the safety zone of Åsgard A for t_A = 12 hours, and thus in a position where it is likely to hit the FPSO[40]. The probability of a drive off has been estimated to be $P_{drive} = 6.3 \cdot 10^{-5}$, and for a drift-off: $P_{drift} = 4.8 \cdot 10^{-9}$ for a period of 12 hours[40].
The probability of damaging a producing riser is P_d = 1 %[41].

During the installation at Åsgard A, there will be two vessels present, thus the ignition probability is $P_{i,A}$ =0.84[40].
In case of a riser fire, the probability of fatalities is assumed to be $P_{f,A}$ = 26 % at Åsgard A[1].

The probabilities of impairment of main safety functions are:

$$P_{imp,drive,A} = P_{drive} \cdot P_d \cdot P_{i,A} = 6.3 \cdot 10^{-5} \cdot 0.01 \cdot 0.84 = 5.3 \cdot 10^{-7} \tag{8.1}$$

$$P_{imp,drift,A} = P_{drift} \cdot P_d \cdot P_{i,A} = 4.8 \cdot 10^{-9} \cdot 0.01 \cdot 0.84 = 4.0 \cdot 10^{-11} \tag{8.2}$$

The probabilities of a fatal accident are:

$$P_{fat,drive,A} = P_{imp,drive,A} \cdot P_{f,A} = 5.3 \cdot 10^{-7} \cdot 0.26 = 1.4 \cdot 10^{-7} \tag{8.3}$$

$$P_{fat,drift,A} = P_{imp,drift,A} \cdot P_{f,A} = 4.0 \cdot 10^{-11} \cdot 0.26 = 1.1 \cdot 10^{-11} \tag{8.4}$$

Åsgard B

A fibre optical cable connecting the control systems on Åsgard B and Åsgard A shall be installed. A drift-off or drive off of the installation vessel during the installation of the top side module at Åsgard B could result in a collision, or the vessel may hit a riser.
If a pressurized riser on Åsgard B is hit, it may cause a hydrocarbon leakage which could ignite, resulting in a riser fire and multiple fatalities.

It is assessed that a collision between the installation vessel and Åsgard B will not cause any fatalities[41].

[1]Found in the QRA for Åsgard A[40]

Only one vessel will be used during the operation, thus if a riser is damaged, the probability of ignition of released gas is $P_{i,B} = 0.6$[44]. The probability of fatalities if a riser fire occurs is assumed to be $P_{f,B}$= 30 % at Åsgard B[2].

Due to the similar circumstances and assumed equal duration of operation, the probability for damage to the riser, and the probabilities for drive off and drift-off within the safety zone of Åsgard B, are assessed to be equal to the probabilities for Åsgard A.

The probabilities of impairment of main safety functions are:

$$P_{imp,drive,B} = P_{drive} \cdot P_d \cdot P_{i,B} = 6.3 \cdot 10^{-5} \cdot 0.01 \cdot 0.6 = 3.8 \cdot 10^{-7} \tag{8.5}$$

$$P_{imp,drift,B} = P_{drift} \cdot P_d \cdot P_{i,B} = 4.8 \cdot 10^{-9} \cdot 0.01 \cdot 0.6 = 2.9 \cdot 10^{-11} \tag{8.6}$$

The probabilities of a fatal accident are:

$$P_{fat,drive,B} = P_{imp,drive,B} \cdot P_{f,B} = 3.8 \cdot 10^{-7} \cdot 0.30 = 1.1 \cdot 10^{-7} \tag{8.7}$$

$$P_{fat,drift,B} = P_{imp,drift,B} \cdot P_{f,B} = 2.9 \cdot 10^{-11} \cdot 0.30 = 8.6 \cdot 10^{-12} \tag{8.8}$$

8.1.1 Controlling the risk

Installation	**Risk area**	**Risk**	**RAC**
Åsgard A	Impairment of MSFs, drive off	$5.3 \cdot 10^{-7}$	10^{-4}
	Impairment of MSFs, drift-off	$4.0 \cdot 10^{-11}$	10^{-4}
Åsgard B	Impairment of MSFs, drive off	$3.8 \cdot 10^{-7}$	10^{-4}
	Impairment of MSFs, drift-off	$2.9 \cdot 10^{-11}$	10^{-4}

Table 8.1: Risk and risk acceptance criteria for A28

The probability of impairment of main safety functions (MSFs) presented in Table 8.1 shows that the risk is well within the risk acceptance criterion.

[2]Found in the QRA for Åsgard B[40]

Installation	Risk area	Risk	RAC
Åsgard A	Probability of fatality, drive off	$1.4{\cdot}10^{-7}$	N/A
	Probability of fatality, drift-off	$1.1{\cdot}10^{-11}$	N/A
Åsgard B	Probability of fatality, drive off	$1.1{\cdot}10^{-7}$	N/A
	Probability of fatality, drift-off	$8.6{\cdot}10^{-12}$	N/A

Table 8.2: Probability of a fatal accident for A28

The total probability of this major accident scenario is found, by summarising the probabilities in Table 8.2, to be $P_{fat,total} = 2.5{\cdot}10^{-7}$.

The risk presented in Table 8.2, shows that the risk of a fatal accident during these operations is small. The risk related to drift-off is so small that it is negligible. This is mainly due to the small drift-off frequency, which is due to the robustness of the DP system.

Technology	Organisation
Vessel DP Class	Safe relocation of vessel
ESD	Position/heading of vessel

Table 8.3: Barriers for A28

If the vessels are safely relocated in the event of a producing riser being severely damaged, the personnel will not be exposed to the gas, and a fatal accident is avoided.

During the operation, the vessel should be placed as far as possible away from producing risers, and with a heading such that it moves away from the installation if a drift-off or drive off occurs. This means that wind and current conditions must also be taken into account.

In the event of a producing riser being severely damaged, the ESD system will be initiated topside.

8.2 Vessel drift-off during installation and removal of start up anchor/pile within platform safety zone (A43)

This scenario is basically the same as the collision scenario related to drift-off described in Section 8.1 (A28) except for the procedure enabling the drift-off. Installation and removal of start up anchor/pile within the safety zone of Åsgard A or Åsgard B could result in fatalities and material damage, but with lower probability than A28[40]. If a riser is severely damaged, a gas leak could occur, which could result in exposure of the intervention vessel, and if ignited, fire and fatalities.

See A28 in Section 8.1 for more details.

8.2.1 Controlling the risk

According to Safetec in [40], the probability of this scenario is lower than the probability of A28.
In the previous section, the probability for a drift-off for scenario A28 where found to be negligible. Based on this, the probability of a major accident being caused by drift-off during installation and removal of start up anchor/pile within the platform safety zone is assessed to be negligible.

Technology	Organisation
Vessel DP Class ESD	Safe relocation of vessel Position/heading of vessel

Table 8.4: Barriers for A43

The barriers controlling the risk of this accident scenario are the same as for A28 in Section 8.1.

8.3 Potential drive off during intervention of modules (A34)

An intervention of the SCSt involves lifting modules up from the seabed and replacing them. If a drive off occurs, due to an error in the DP system, when a module is being lifted or lowered, there is a risk of hitting the SCSt with the module. Such an impact could result in severe damage to the compression station, which could lead to a gas leak.

By assuming there will be intervention on all four modules, the intervention equipment will be close to the compression station for about four hours[41], that is 30 minutes for lifting and 30 minutes for lowering of each module.
Based on this, the drive off probability with potential to cause impact is assessed to be[40] $P_{drive} = 2.1 \cdot 10^{-5}$.

If a drive off occurs with equipment in position to damage the compression station, it is assumed to be a 50 % probability of hitting the station, damaging it and causing a leak.
As stated earlier, the probability of ignition is assessed to be $P_i = 0.6$ and the probability of fatalities to be $P_f = 1$, if ignition occurs.

The probability of impairment of main safety functions and the probability of a fatal accident is assessed to be[40]:

$$P_{fat} = P_{imp} \cdot P_f = P_{drive} \cdot P_i \cdot 50\ \% \cdot 1 = 2.1 \cdot 10^{-5} \cdot 0.6 \cdot 0.5 \cdot 1 = 6.3 \cdot 10^{-6} \tag{8.9}$$

8.3.1 Controlling the risk

Risk area	**Risk**	**RAC**
Impairment of main safety functions	$6.3 \cdot 10^{-6}$	10^{-4}
Probability of a fatal accident	$6.3 \cdot 10^{-6}$	N/A

Table 8.5: Risk and risk acceptance criteria for A34

Table 8.5 shows that the risk is well within the risk acceptance criterion.
It is, however, not close to being negligible, thus risk reducing measures should be implemented if practicable.

Technology	**Organisation**
PSD	Safe relocation of vessel
Vessel DP Class	Leak detection by ROV
Leak detection on vessel/subsea structures	Weak link
Pressure reading at SCSt	

Table 8.6: Barriers for A34

The probability of a fatal accident is small, and will be further reduced by implementing the organisational barrier safe relocation of vessel. If the vessel is relocated when a gas leak is detected, the vessel should not be exposed to gas, and the probability of a fatal accident is minimal.

Chapter 9

Hydrocarbon Leakage

There is a possibility that the subsea production system might start leaking during the operational phase. This chapter discusses this scenario, the risk involved and the mitigating barriers in place.

9.1 Leakage from production system after installation (A26)

After the subsea equipment has been installed, leakage could occur due to for example equipment failure. If a fatal accident is to occur, however, there must be a vessel in the area above the leak point.

Ship traffic could also pose a threat to the subsea installations with dragged ship anchors and sinking ships.

9.1.1 Controlling the risk

If a leak occurs near the SCMS or the SCSt, acoustic gas detectors will initiate an alarm on Åsgard B, and PSD shall be initiated. The compression station will also be able to detect a drop in the pipeline pressure, and thus initiate a shutdown[41]. All vessels in the area should be alerted from Åsgard B if a pressure drop/leak is detected.

Technology	Organisation
PSD Leak detection on vessel/subsea structures Pressure reading at SCSt	Safe relocation of vessel

Table 9.1: Barriers for A26

Based on registrations done by the Automatic Identification System (AIS), which is an automatic tracking system used on ships, there is only modest ship traffic in the area. Because of this, the risk of dragging ship anchors and sinking ships is found to be negligible[41]. Because of the modest ship traffic, there are few vessels in the area which could be exposed to a potential gas leak.
Due to this, the risk of fatalities due to leakage from production system after installation is very small and practically negligible.

Environmental risk

Because the compression station will never contain more than 50 tonnes of condensate, the risk of environmental impact due to a hydrocarbon leak is negligible. This is because released gas will not cause direct harm to the environment, and any condensate on the surface will, according to an environmental impact assessment conducted by Statoil in 2011, evaporate within a few hours[54].

The existing production at Åsgard has an environmental risk that amounts to 4 % of the environmental risk acceptance criteria. It is assessed in [54] that the installation of the compressor system will not increase the environmental risk at Åsgard significantly.

Chapter 10

Accident Scenario - Subsea Gas Leak

Many of the described major accident scenarios involve a subsea release of gas and potential exposure of installation or intervention vessel. This chapter will address a potential accident scenario related to a significant subsea gas release. First, the accident scenario will be described, then the effect the wind and current has on the gas will be discussed, before a MTO analysis of the major accident scenario will be performed.

10.1 Scenario description

Six of the ten major accident scenarios described in Chapters 6 through 9 involve a subsea gas leak:

- Hydrocarbon leakage during hot-tapping (A9)
- Hydrocarbon leakage during tie-in (A21)
- Dropped object during intervention of SCMS and SCSt (A7)
- Uncontrolled lifting/dropped objects during installation of PLEM structures (A10)
- Potential drive off during intervention of modules (A34)
- Leakage from production system after installation (A26)

All these cases are well within the risk acceptance criteria, and thus this scenario has a very small probability of happening.

When gas is released under water, it will form a spherical cap, which will be fed with more gas from underneath, as it rises towards the surface[46]. When it reaches the surface, it will generate a circular area where the water is “boiling” with gas. The maximum mass flow will occur right after the spherical cap reaches the surface, and the highest gas concentration is at the center of the release area. The gas will disperse into the atmosphere, forming a cloud of gas.
Some of the gas will be dissolved in the water on its way towards the surface, thus a small gas release might not be detectable at the surface.

If the gas cloud is big enough, it may reach the lower deck of a potential vessel positioned above the leak point, and thus reach an ignition source. If the gas cloud is ignited, there will first be an explosion and then fire. An explosion will cause fatalities and major damage to the vessel[39].

Many factors affect the extent of a gas release, such as how big the release rate is, the current in the area, the wind conditions and whether or not there is a vessel above the leak point.

10.2 Gas Dispersion

Gas leakage simulations has been used to estimate how big the gas cloud will be for different hole sizes and leakage rates. The time it takes for the gas to reach the surface and how currents and wind will affect the dispersion and displacement of the gas in the atmosphere, has also been assessed.

In the next sections, gas dispersion in water and the effects of wind and current, will be described.

10.2.1 Simulation Case

Statoil states that for high-risk operations, a risk analysis shall be carried out to establish the risk level for the operation[53].

Risk related to the tie-in operations which will be executed at Åsgard has been assessed earlier in [46]. In this assessment, gas leaks of different sizes during different conditions were simulated to find out how fast the gas will reach the surface, how big the maximum mass flow will be and the maximum radius of the release area. Three different cases were used in the simulation, but only one of them was assessed in detail.
The simulation case is given in Table 10.1.

Length of piping downstream leak (km)	Length of piping upstream leak (km)	Flowing BHP (bara)	Additional gas production into flowline (MSm^3/d)	Total gas production (MSm^3/d)	Pressure at leak location (bara)
50	0	135	5	9.5	99

Table 10.1: Simulation case[46]

Additional input parameters to the model is given in Table 10.2.

Input paramter	**Value**
Release depth	260 m
Gas density at sea surface	0.854 kg/m^3
Gas density at 260 m	24.597 kg/m^3

Table 10.2: Input parameters[46]

Some of the results of the simulation are shown in Table 10.3 to 10.5.

10.2.2 Gas Dispersion in Water

The simulations in [46] show that the rate of the gas released to the atmosphere increases rapidly after the first gas hits the surfaces. Then, after the spherically shaped cap of gas has been released to the atmosphere, the release rate decreases to the rate of the jet.

Hole size, diameter	Delay, seabed to surface	Max mass flow through the surface	Max radius
20 mm	431 s	18 kg/s	97 m
30 mm	333 s	37 kg/s	105 m
40 mm	278 s	60 kg/s	114 m
60 mm	216 s	117 kg/s	123 m
100 mm	156 s	277 kg/s	138 m
254 mm	92 s	994 kg/s	165 m
473 mm	80 s	1180 kg/s	169 m

Table 10.3: Results of the gas dispersion simulations[46]

Table 10.3 shows how big the resulting radius on the surface is expected to be for different hole sizes. The maximum mass flow through the surface gives an estimate of how big the gas rate into the atmosphere is at its maximum.

According to [46], the length of a vessel is assumed to be between 100 and 160 m. By comparing this to the radii given in Table 10.3, it is seen that the different subsea releases may pose a significant threat to any vessel stationed above the release point. Intervention and installation vessels will typically be placed directly above the leak point.

The delay is the time it takes from the leak occurs on the seabed to the gas reaches the surface. This delay makes it possible to move the vessel away from the gas exposure area before the gas reaches the surface, if the leak is discovered quickly enough.

10.2.3 Current Conditions

If a gas leak occurs in still water, that is, water without currents, the gas will reach the surface directly above the release point. However, there are always currents in the ocean, thus the point where the gas reaches the surface will be horizontally displaced from the point directly above the gas release.

The average current at Åsgard is about 15 cm/s, it is usually below 30 cm/s and almost never above 50 cm/s[46]. By using the simulated results of the delays from the leak occurs to the gas reaches the surface given in Table 10.3, the horizontal displacement of the release area for different hole sizes and different currents has been calculated. The results are shown in Table 10.4.

Hole size	**15 m/s**	**30 m/s**	**50 m/s**
20 mm	65 m	129 m	216 m
30 mm	50 m	100 m	167 m
40 mm	42 m	83 m	139 m
60 mm	32 m	65 m	108 m
100 mm	23 m	47 m	78 m
254 mm	14 m	28 m	46 m
473 mm	12 m	24 m	40 m

Table 10.4: The horizontal displacement of gas release area for average currents and different hole sizes[46]

The table shows that the only situations where the displacement exceeds the assumed length of a vessel on the field, is for the hole sizes of 20 and 30 mm, with a current of 50 m/s. This illustrates that if the vessel is positioned directly above the release point, the vessel will be exposed to the gas cloud despite of the potential horizontal displacement of the gas due to the currents in the area for almost all cases.

Based on this, the impact the current has on a subsea gas release is very small related to major accidents. During relocation of vessels after a gas leak, the potential displacement of the gas cloud due to wind should be accounted for in the planning of the safe distance.

10.2.4 Wind Conditions

Subsea gas releases of different sizes with different wind conditions have been simulated, and are given in Table 10.5. The simulation results reflect the case when gas is being released without a vessel above the release point.

A sensitivity analysis also performed in [46] shows that the presence of a vessel directly above the leak point affects the dispersion of the gas. If the flammable gas cloud has a Lower Explosion Limit (LEL) above 3 m without a vessel present, the presence of a vessel may result in the gas cloud reaching the lower deck, assumed to be 5-6 m above sea level, and thus potential ignition sources. This means that simulation cases with a LEL of about 3 m and more are considered dangerous[46].

Hole size (d)	**Wind**	**LEL height**	**½ LEL height**
20 mm	1 m/s	1.1 m	8.7 m
	2 m/s	0.3 m	1.9 m
30 mm	1 m/s	4.9 m	28.6 m
	2 m/s	1.5 m	4.1 m
	3 m/s	0.7 m	2.1 m
40 mm	1 m/s	15.3 m	46.8 m
	2 m/s	2.7 m	7.7 m
	3 m/s	1.3 m	3.5 m
	5 m/s	0.2 m	1.5 m
	8 m/s	0.0 m	0.6 m
60 mm	1 m/s	46.8 m	97.1 m
	2 m/s	6.8 m	24.4 m
	3 m/s	2.7 m	6.0 m
	5 m/s	1.0 m	3.1 m
	8 m/s	0.2 m	1.5 m
	10 m/s	0.1 m	1.1 m
100 mm	3 m/s	6.8 m	24.4 m
	5 m/s	2.9 m	6.8 m
	8 m/s	1.3 m	4.1 m
	10 m/s	1.0 m	3.3 m
	12 m/s	0.7 m	2.7 m
473 mm	5 m/s	17.8 m	46.8 m
	10 m/s	6.8 m	13.2 m
	15 m/s	4.9 m	10.0 m
	20 m/s	3.8 m	7.7 m
	25 m/s	2.9 m	6.8 m
	30 m/s	2.1 m	5.4 m

Table 10.5: Simulation results[46]

The lower explosion limit is the lowest concentration of a gas in the air which could be ignited. If the concentration is above the Upper Explosion Limit (UEL), it is too rich to be ignited[5].

If the LEL height is between 1 m and 3 m, the gas may still pose a danger to the personnel, but it is not very likely. If the LEL height is below 1 m, there is no danger to the personnel.

Based on the assumption that vessels will not operate on the field if the significant wave height exceeds 2 m, which is assumed to correspond to a wind speed of 10 m/s[44], the incidents resulting in a LEL height of about 3 m and up and a wind speed of 10 m/s or less, are shaded in Table 10.5. These are tagged as dangerous cases.

Figure 10.1 shows how the gas cloud is affected by the wind after it reaches the surface.

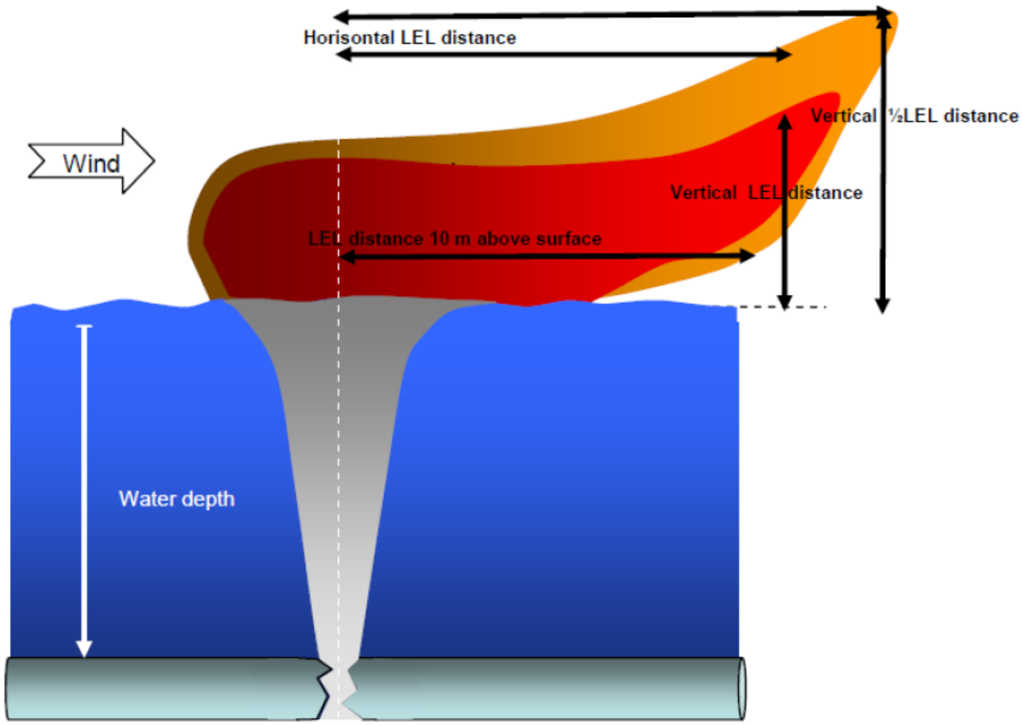

Figure 10.1: The effects of wind on a gas cloud[40]

10.3 MTO Diagram of a Major Accident Scenario

A MTO diagram has been made of a more specific version of the major accident scenario described in Section 10.1. This is to show how a major accident scenario might play out, and how MTO is used in analysing accidents.

Scenario

A heavy object, such as a SCSt module, is dropped into the sea from a vessel located above pressurized subsea equipment during intervention of the SCSt (A10). The module reaches the assumed maximum velocity of 7 m/s on its way towards the bottom. Because the vessel is located above pressurized equipment, the module hits a subsea structure with an impact that causes severe damage to the equipment and thus a gas leak.
The acoustic detectors around the subsea equipment detects the leak, and the pressure drop is detected by the SCSt. A ROV assisting during the installation also detects the leak.

The vessel shall start moving away from the loction within 30 seconds, but fails to do so in this case due to human error. This causes the vessel and its personnel to be exposed to the gas that reaches the surface. The gas reaches an ignition source on the vessel, causing an explosion and subsequent fire.

Upon detecting the leak, the PSD system is initiated and shuts down the power to the compression station. This way the production is shut down and the leak is stopped.

An MTO diagram of this major accident based on the diagram presented in Figure 5.3 in Section 5 is given in Figure 10.2 to 10.4.

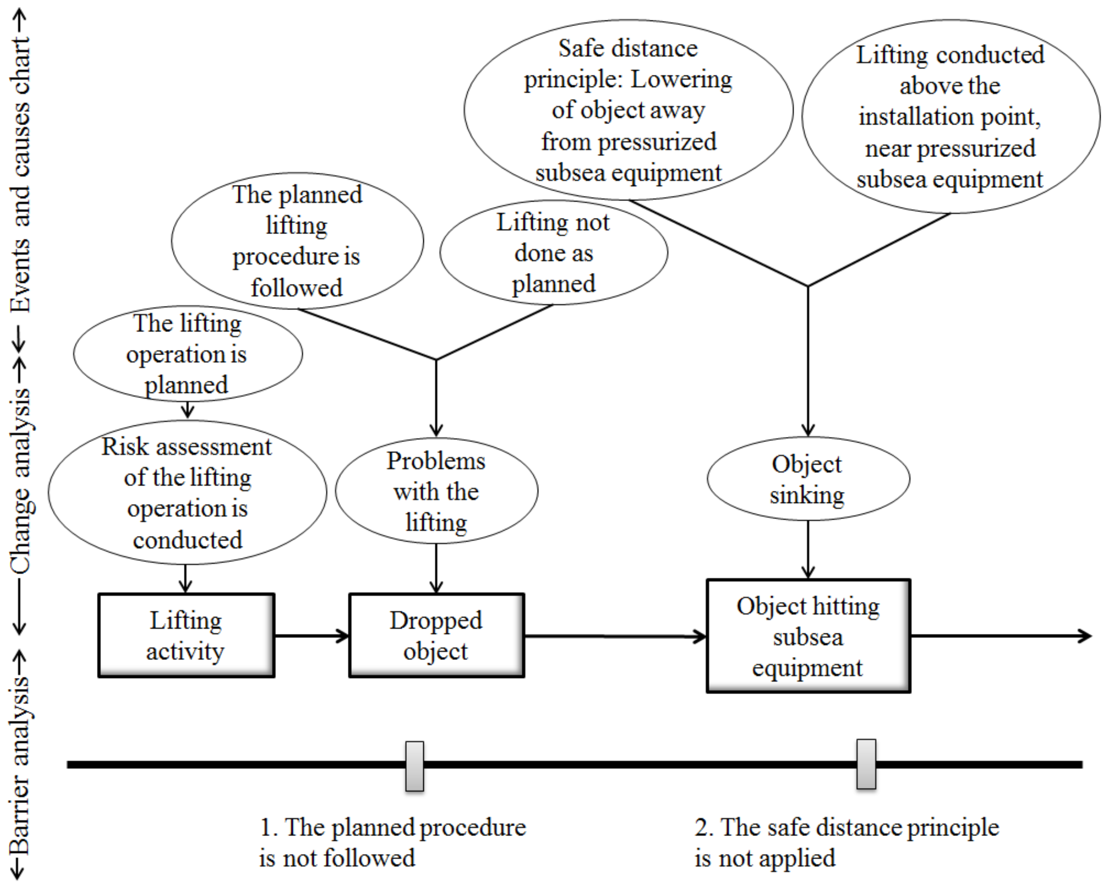

Figure 10.2: MTO diagram I

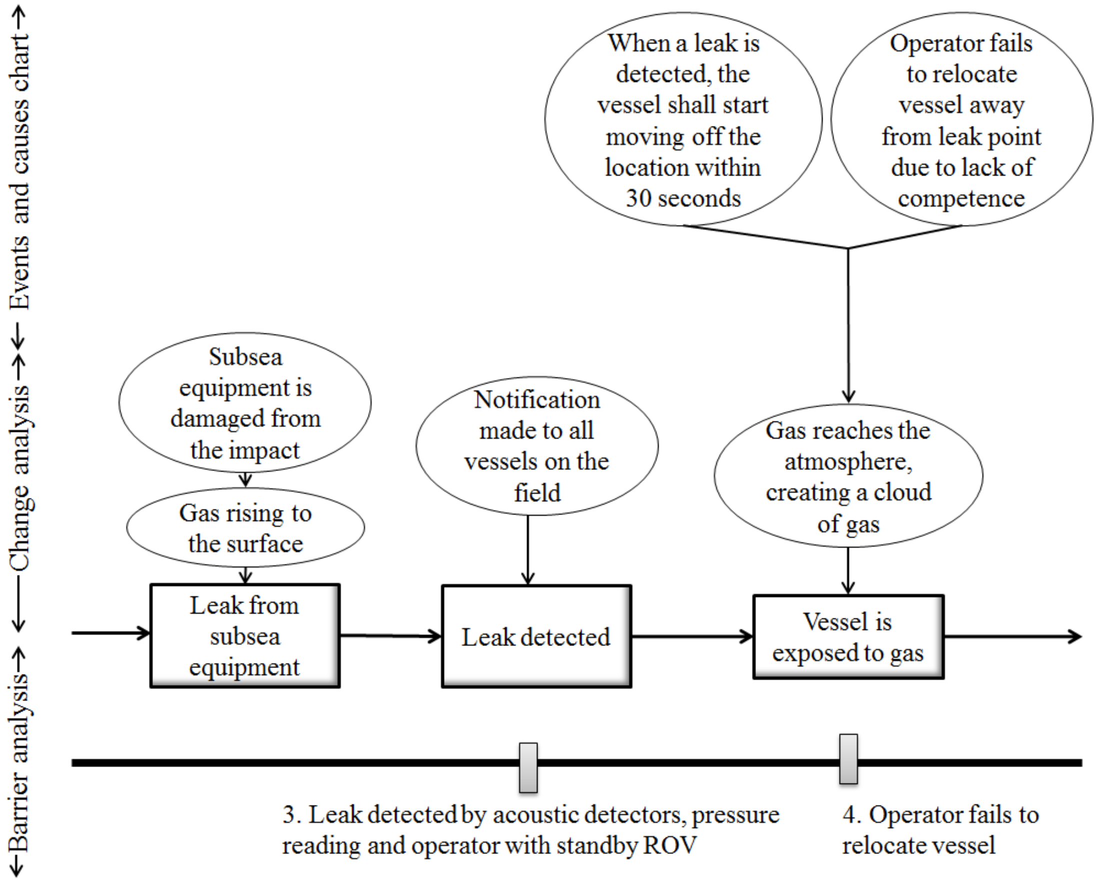

Figure 10.3: MTO diagram II

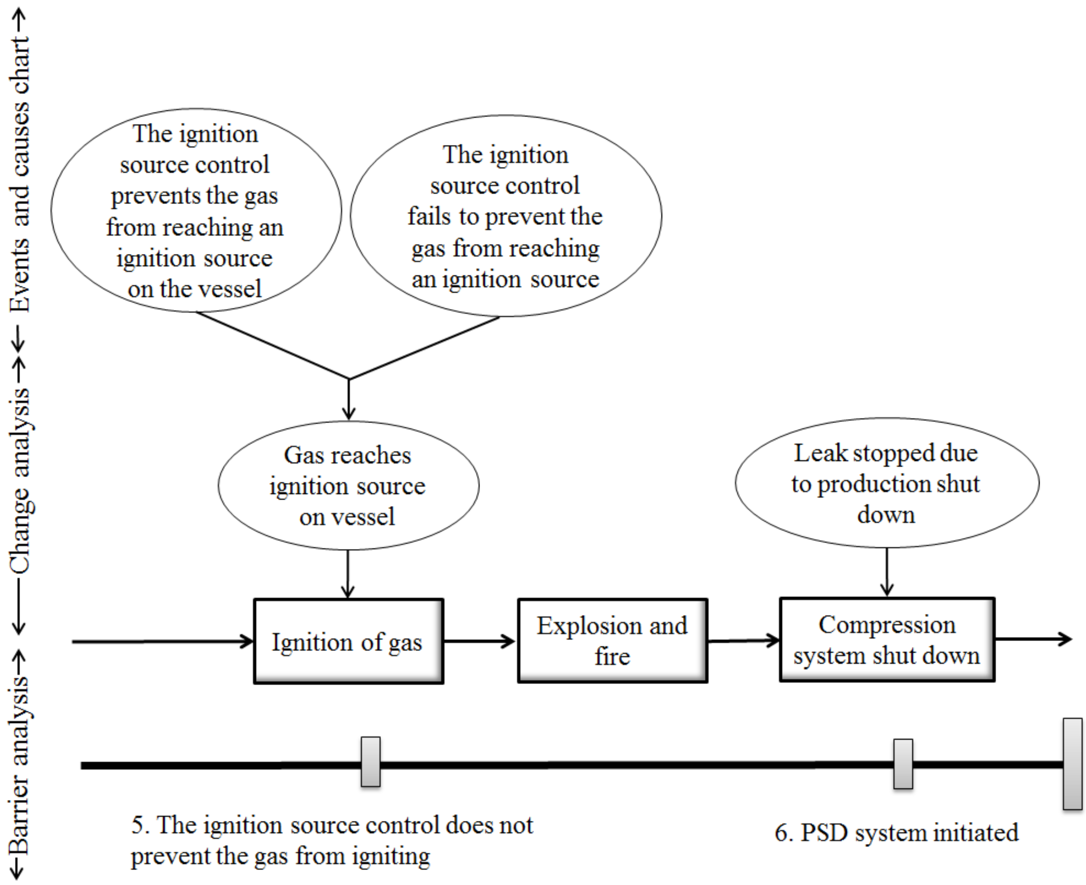

Figure 10.4: MTO diagram III

10.4 Investigation

Table 10.6 shows the barriers related to this major accident scenario.

Human	Technology	Organisation
Competence	Leak detection by -vessel/SCSt, SCMS Pressure reading by SCSt PSD Ignition source control -on vessel	Lifting procedure planned Risk assessment of -lifting procedure Safe lifting distance Safe relocation of vessel Leak detection by ROV

Table 10.6: Barriers for subsea gas leak scenario due to dropped module during intervention of SCSt (A7)

These are the same barriers as for the major accident scenario A7 - Dropped object during intervention of SCMS and SCSt, but here, the more general organisational and human barriers have been added. The specific barriers are described in Part IV.

The barriers which failed on this occasion are shown in Table 10.7.

Human	Technology	Organisation
Operator lacks -essential competence	Ignition source control -on vessel fails	Lifting procedure -not done as planned Safe lifting distance -not followed Vessel not relocated -as planned

Table 10.7: Barriers for the subsea gas leak scenario which failed

It is easy to see the connection between the three MTO factors and the importance of viewing them in context with each other, and not as separate factors, by assessing the MTO diagram and the failing barriers.

By looking at the organisational barriers which failed in this scenario, it is seen that errors by the personnel in planning and execution is a big contributor to the failure of these barriers. However, the organisation is responsible for planning the procedures and operations in an understandable way, such that they are easy for the personnel to understand and follow.

Technological barriers fail due to design, incorrect installation or lack of maintenance and repair.
It is highly unlikely that all the acoustic detectors on the SCSt and the SCMS will fail to detect a substantial gas leak. The pressure drop in the pipelines will also be easily detectable by pressure gauging in the SCSt.

In this scenario, it is the organisational barriers which could have reduced the likelihood of the accident, and which could have reduced the consequences significantly, had they not failed.
If the frequency reducing organisational barriers "Lifting procedure" and "Safe lifting distance" had been followed as planned, the lift would not have been conducted above pressurized hydrocarbon equipment, and the leak would probably never have occured.
If the consqeunce reducing organisational barrier "Safe relocation of vessel" had not failed, the consequences of the leak might have been reduced significantly. If the vessel had been relocated as planned, it would not have been exposed to the gas, and there would not have been a fatal accident.

The organisational barriers are dependant on the personnel which shall execute them, thus the organisational and the human barriers are highly correlated.

This scenario highlights the fact that organisational and human barriers are more vulnerable to error than the technological barriers. It is highly unlikely that a technological barrier, which has gone through design and testing procedures, fails. An organisational barrier, however, can fail due to a wrong human decision at a crucial moment.
The uncertainty related to the organisational and human barriers influences the ability to control the risk.

Part IV

Risk Reducing Measures/Barriers

Risk reducing measures/Barriers

The governing document TR1055 describes Statoil's principles regarding risk reduction as follows:
"In concept optimisation and design development, priority shall be given to use of preventive measures that are inherent in design. Furthermore, probability reducing measures shall be given priority over consequence reducing measures. The objectives of risk reduction principles and inherent safety design are to:

- Eliminate or reduce potential hazards/increase inherent safety:
  - Reduction, for example reducing the hazardous inventories or the frequency or duration of exposure.
  - Substitution, for example substituting hazardous materials with less hazardous ones.
  - Attenuation (moderation), for example using the hazardous materials or processes in a way that limits their hazard potential.
  - Simplifications, for example making the facility and process simpler to design, build and operate, hence less prone to equipment, control and human failure.
- Reduce probability of hazardous events.
- Implement mitigating measures, for example by safety barriers.

Solutions offering the lowest risk shall be chosen provided the associated costs are not significantly disproportionate to the risk reduction achieved."
The selection of risk reducing measures is thus done by employing the ALARP principle, which is described in Section 4.2.4.

In this part, the barriers identified in Part III will be elaborated on.
In order to present the barriers systematically, they are categorised using the MTO technique, thus this part comprises three chapters: Human barriers (M), Technological barriers (T) and Organisational barriers (O), respectively.

In Section 4.1.2, two other ways of categorising barriers, in addition to the MTO technique, were presented: Frequency reducing versus consequence reducing, and passive versus active. In order to fully understand the different barriers and their function, they will be identified based on these principles as well.

Frequency reducing and consequence reducing barriers

In Figure 4.1 in Section 4.1.2, two types of barriers are shown; frequency reducing/preventive barriers and consequence reducing/reactive barriers. Frequency reducing barriers reduce the probability of hazardous events, while consequence reducing barriers reduce the consequences of the hazardous event after it has occured.
According to Statoil's governing document TR1055, frequency reducing barriers shall be given priority over consequence reducing barriers. This is because the optimal outcome of a potential hazard is that it never develops into a hazardous event in the first place.

By assessing each barrier and deciding whether they are frequency reducing or consequence reducing, the importance of the different barriers becomes evident.

Passive and active barriers

Passive barriers, also called static barriers, are barriers which are present for a significant time period, and which are constant barriers towards for example hydrocarbon fluid. Passive barriers are not required to take any action in order to act as a risk reducing measure, hence the name[49].
An important apsect of passive barriers is that they are embedded in the design, and are independent of the operational control system.

Active barriers, also called dynamic barriers, are only present for a time-limited period. Active barrier systems are often a combination of technical and human elements, and they are required to change state in response to an event in order to achieve their function in reducing the risk[49]. This means that they are dependant on actions by operators or on a technical control system in order to function as intended.

Chapter 11

Human Barriers

The human barriers are usually not unique for a specific operation, but are defined for a work place as a whole. According to Mowitz in [31], the most important human barriers are competence, knowledge of task and equipment, motivation and work satisfaction. These are factors which are important in all procedures and operations at all times.

Competence in the personnel and knowledge of the task which is about to be performed is very important during major installations or interventions subsea. If the personnel is not capable of handling the equipment properly or following planned procedures, there is an increased risk of failure in the operation, which can lead to hazardous events. The personnel needs to be familiar with the procedures related to the actual operation and to the security measures which shall be followed. Thus many of the technological and all of the organisational barriers are dependent on the human barriers.

A rested and motivated personnel reduces the risk of human errors. Work satisfaction is also important to ensure that the personnel performs their work satisfactorily.

It is the personnel that executes the organisational barriers, thus it is important that the personnel is well aware of the procedures developed through the organisation. Without a well-functioning set of human barriers, the organisational barriers will not have any effect.

Human errors is the most common cause of accidents. Typical causes or error-producing factors are[31]:

- Time pressure
- Sleepiness/work hours
- Poor ergonomics
- High vigilance and mental demands
- Poor training
- Problems with rules and procedures
- Work environment - untidy work place
- Problems with communication
- High workload and stress
- Problems with planning and control
- Inadequate allocation of resources
- Management
- System goals incompatible with safety

These are not case-specific, but general factors which apply to the entire organisation. During the execution of critical operations offshore, it is especially important that these factors are non-present.

Chapter 12

Technological Barriers

In order to describe the technological barriers present during the different major accident scenarios, Statoil's Governing document TR1055 is the main reference.

According to TR1055, Technical Safety Management in project development and design processes comprises activities to identify risks and develop safety strategies and performance requirements for safety systems and barriers.
Requirements for the individual safety systems and barriers in Statoil is also given in TR1055, and represents a generic performance standard for the different safety systems and barriers. For each performance standard (PS) which describes a specific system or barrier, the following elements are adressed in TR1055:

- **Role** gives a short description of the safety aspects related to the specific systems and barriers.
- **Interfaces** lists the interface with other safety systems and barriers.
- **Required Utilities** describes utilities required for the safety systems and barriers to fulfil its role.
- **Functional Requirements** specifies the performance normally required by the safety systems and barriers to fulfil its role.
- **Survivability Requirements** defines requirements for the safety systems and barriers to function in or after a dimensioning accidental event.
- **Integrity Requirements** are covered in section 2.4, Integrity – availability and reliability.

The individual project or installation must perform a specific hazard identification and risk evaluation process, and supplement/modify the requirements as necessary to manage the actual risk picture.

For technical barriers in Statoil, the following flowchart describes the key activities in design of technical barriers.

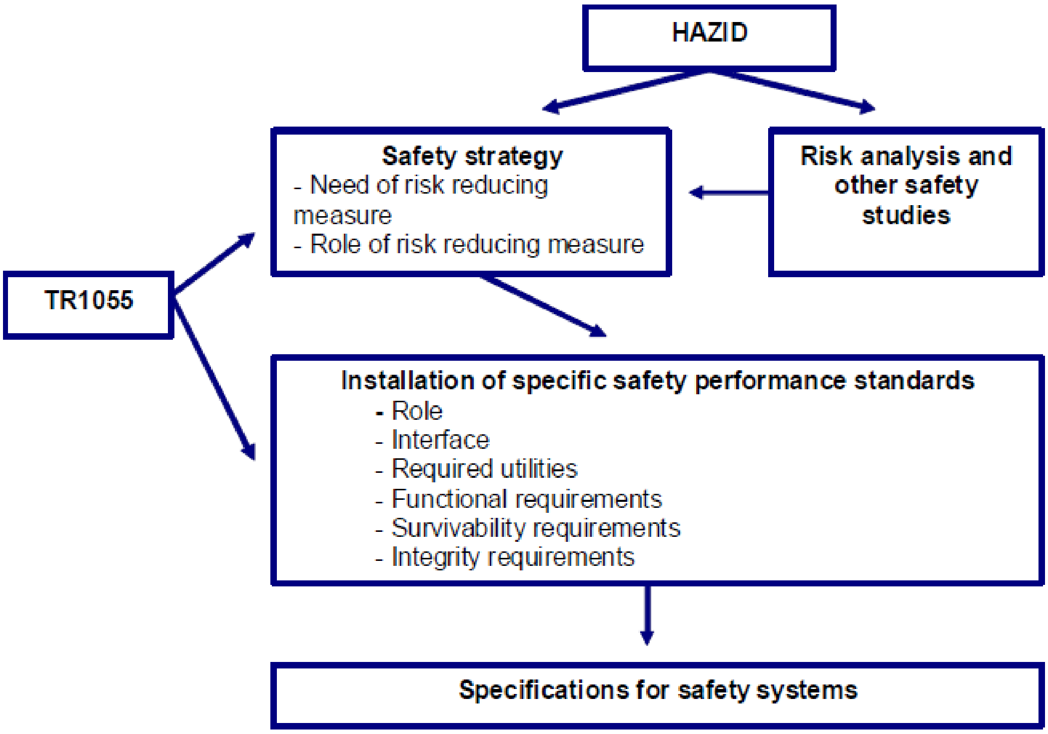

Figure 12.1: Activities related to technical safety design in Statoil[62]

The specific safety performance standards shall ensure that the barrier, safety system or safety function:

- Is suitable and fully effective for the type of hazard identified.
- Has sufficient capacity for the duration of the hazard or the required time to provide evacuation of the installation.
- Has sufficient availability to match the frequency of the initiating event.
- Has adequate response time to fulfil its role.
- Is suitable for all operating conditions.

Technological barriers are usually the most important type of barriers. According to MTO, it is safe to rely on technological barriers alone, but not on human or organisational barriers alone[7].

Technological barriers can be mechanical, such as thick pipes, or automatic, such as a pipeline protection system. The main technological barriers to prevent fatalities and environmental damage during installation, production and intervention at Åsgard SC are described in this chapter.

12.1 Process shutdown (PSD) and emergency shutdown (ESD)

The PSD system is an active barrier which needs to be activated in order to function as a barrier. It is the most important consequence reducing barrier which will be implemented at Åsgard SC, and it is an important part of process safety.

Statoil defines the role of process safety in Performance Standard PS 12 – Process Safety, in TR1055:

"Process safety means of protection, incorporating mechanical protection devices and safety instrumented functions, shall ensure that the process conditions do not exceed specified process safety limits.
The aim is to control any abnormal process operating conditions to prevent and/or minimise possible accidental releases of hydrocarbon – or other toxic substances. Typical actions, by means of protection such as PSD functions and Pressure Safety Valves (PSV) include:

- Stop hydrocarbon flow
- Shutdown process and utility equipment
- Isolate leaks
- Shut down heat input to the process
- Pressure relief

The extent of a PSD situation will depend on type of abnormality, and may vary from equipment shutdown with minimum effect on the production rate, to a total process shutdown."
In short, this means that the process safety functions shall provide a reliable and fast detection of process upsets and execute the actions that are considered necessary to control the situation and avoid escalation.

The PSD is, along with the UPS system, part of the safety critical equipment at Åsgard, which means that it has to be in operation to prevent the escalation of abnormal conditions into hazardous events[62]. If such hazardous events do occur, the PSD shall limit the extent and duration of the event.

When the subsea PSD at Åsgard is initiated, the power to the compression station is cut. When this happens, the entire production shuts down, and the flowlines are gradually drained of hydrocarbons. The compression station needs power to maintain the production, thus a cut in power results in a shut down of the entire production.

Emergency Shut Down

The purpose of the emergency shutdown system is according to the Performance Standard PS 4 – Emergency Shut Down (ESD), in TR1055 to prevent escalation of abnormal conditions into a major hazardous event, and to limit the extent and duration of any such events that do occur.

The main difference between the ESD and the PSD is that the ESD shuts down everything, while the PSD is more sophisticated and shuts down the production and isolates the leak.

There will be no ESD system subsea at Åsgard SC[7], but the topside ESD gives input signals to activate the PSD subsea. The PSD can also be initiated directly without involving the ESD, either manually from topside, or automatically due to abnormal conditions subsea. According to TR1055, PSD actions shall be initiated automatically when process or equipment protection limits are exceeded.

The ESD and PSD are arranged in a tree-structured level hierarchy[62]. Once one of them is initiated, actions shall be automatically executed, with a superior level initiating lower levels. A signal on a certain level should not initiate shutdowns on higher levels.

A general ESD structure can be seen in Figure A.2 in Appendix A.1, while the PSD hierarchy is discussed below.

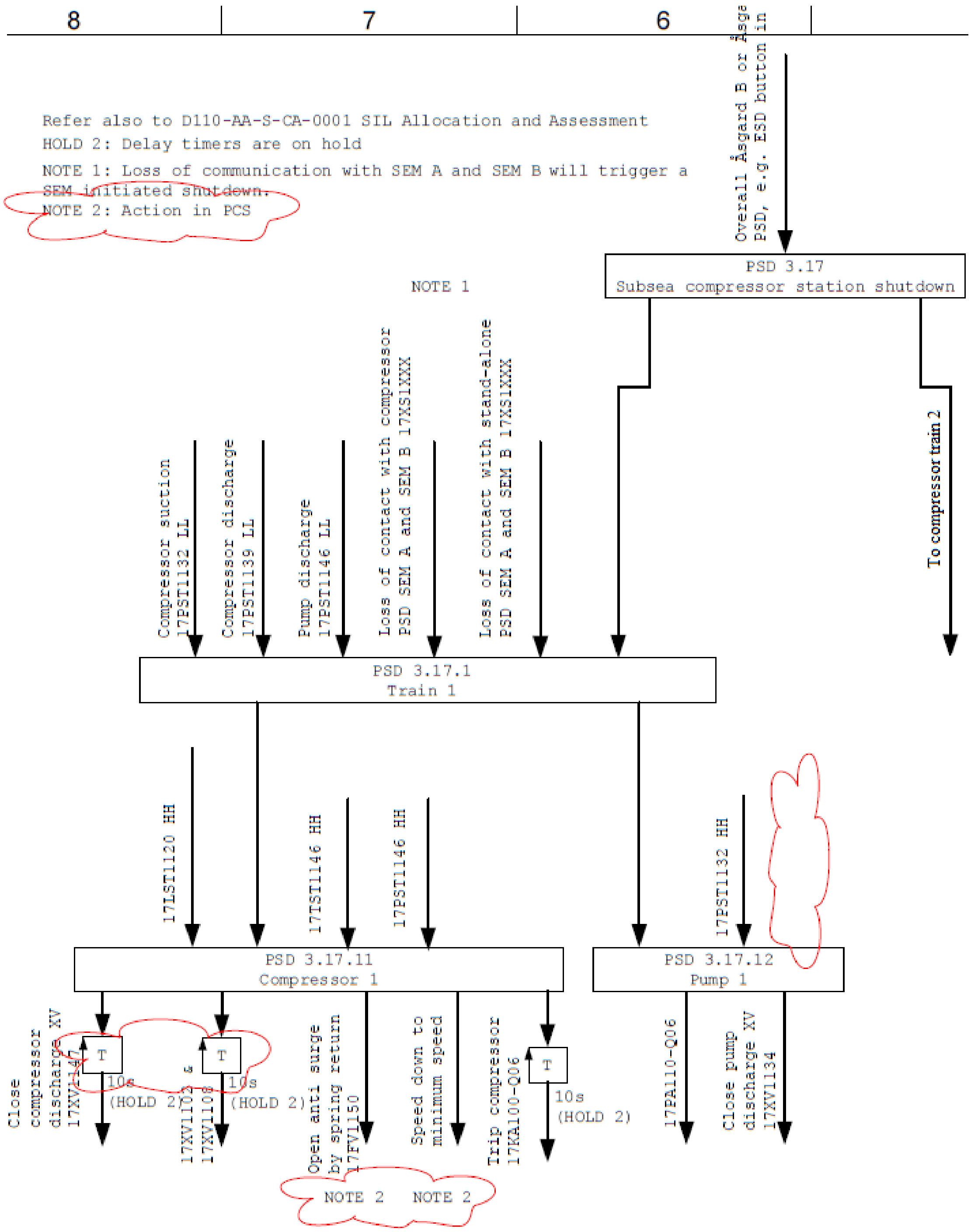

Figure 12.2: PSD for compression train 1[56]

PSD hierarchy at Åsgard

The PSD hierarchy of the subsea production at Åsgard consists of three levels. Each level, except the first, has several inputs and outputs. The inputs which are not coming from the level above, are measurements, while the outputs are actions which are taken at that level[7]. The PSD hierarchy is identical for the two compression trains and is shown in Figure A.1 in Appendix A.1.
Figure 12.2[1] shows a section of Figure A.1 containing the PSD hierarchy for Compression Train 1.

Level one - Subsea compression station shutdown

The first level, PSD 3.17, initiates the PSD in each compression train after an ESD or a PSD has been initiated topside. This level has no measurements as inputs, and can thus only be initiated manually or through the ESD.

Level two - Train 1

The second level, PSD 3.17.1, can be initiated by several incidents, as can be seen in Figure 12.2. First, it may be initiated directly from PSD 3.17 in level one.

Second, discrepancies in measurements in the compression station can initiate the PSD 3.17.1. Several elements in the compression train are monitored continuously through measurements. According to [50], incidents which will initiate a PSD at the second level are related to "low pressure at the compression station; downstream pump, upstream/downstream compressor".
As seen in Figure 12.2, three of the measurement inputs to PSD 3.17.1 are compressor suction, compressor discharge and pump discharge. If any of these have serious discrepancies, it may indicate external leakage of hydrocarbons to the environment. A signal is thus sent to the existing PSD system topside, which controls the upstream wells, to close the subsea wells, and thus shut down the production[50].

Third, a shutdown is initiated if the connection between the compression station and topside is lost.

[1]Please disregard the red "clouds"

Ideally, there should be redundancy in accessibility and safety in subsea systems[7]. This is usually just implemented for accessibility due to the difficulties in double coverage of safety measures. This means that the connection between the compression station and topside is redundant, as can be seen in Figure 12.3.

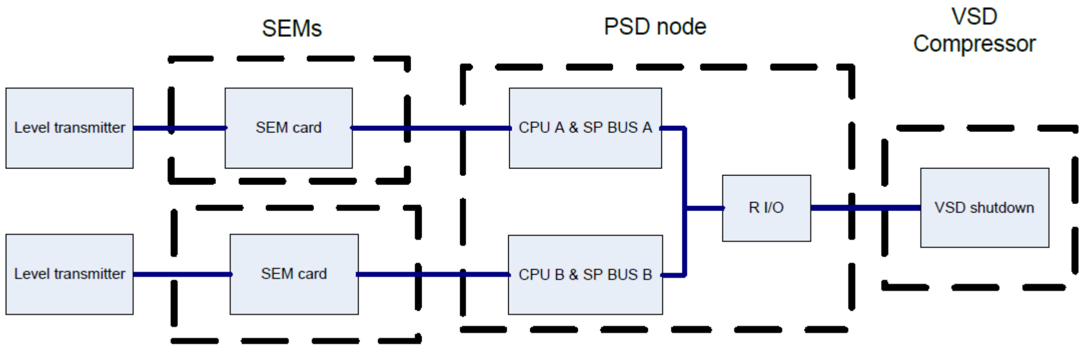

Figure 12.3: Simplified block diagram of subsea connections[50]

There are two subsea electronic modules (SEMs) which are connected to the PSD node. The SEMs house the control electronics (logic solver), power supplies and communications circuits[17], while the PSD executes the actions directed by the SEMs.
If one of the connections between SEM and PSD node is broken, no actions will be taken except to reestablish the connection, thus the production is kept going. If both the connections are broken, however, there is no way of immediately knowing what is going on subsea, thus the power is cut and the compression station is shut down.

Level three - Compressor 1 and Pump 1

Level three is divided into PSD 3.17.11 for the compressor and PSD 3.17.12 for the pump. Apart from the inputs from level two, there are several events that can initiate the PSD at level three.

For the compressor, a high level in the scrubber, high pressure downstream of the compressor and high temperature downstream of the compressor results in a shutdown of the compressor[17].
For the pump, high pressure downstream of the pump will initiate shutdown of the pump.

In the compressor, the following actions are initiated; close compressor discharge and other process shutdown valves, open anti surge valve, speed down to minimum speed and trip compressor. In the pump, the pump discharge is closed, and the pump is shut down.

At this point, the compression station is shut down, and the production is stopped.

12.2 Leak detection on subsea structures

The leak detection system consists of permanent detectors placed on subsea structures, and it is dependent on the UPS, which is briefly discussed in Section 12.5[62].
Leak detection on subsea structures is a passive barrier because the detection system is in operation continuously. It is a consequence reducing barrier which plays a big part in the efforts to reduce the consequences of a hazardous event by quickly detecting leaks.

To be able to detect a gas leak as early as possible, the SCMS and the SCSt will be equipped with acoustic gas detectors[39]. If a gas leak is detected, an alarm will be initiated at Åsgard B immediately and all vessels in the area will be notified.

It is assumed that active acoustic detectors will be used due to the fact that passive acoustic detectors are disturbed by background noise. Because they will be placed on producing structures subsea, there will be a considerable amount of background noise.

Acoustic leak detectors are sonar detectors which emit pulses of sound which are reflected if they hit a bubble of gas or a droplet of oil[21]. The technology has a high sensitivity for gas, and the bigger the leak, the easier detection.
A limitation to this is that the range of the acoustic signal may be limited by shadowing from the subsea structures, but by employing more than one acoustic detector, this limitaion may be overcome.

According to DNV, subsea facilities that need to be monitored for leaks are manifolds, PLEMs, PLETs, riser bases, Xmas trees and processing stations[21]. By monitoring these subsea structures, it is a high probability that subsea leaks are discovered quickly.

Ideally, the reponse time should be as short as possible for big leaks, but for smaller leaks, longer reponse times should be accepted to minimise the risk of false alarms.
It is important to minimise the number of false alarms so that the operator does not become hesitant when the alarm goes off. Due to the high sensitivity of the acoustic leak detectors, it is important to make sure that an actual gas leak is occuring, before sounding the alarm.

According to Statoil in TR1055, the response time of acoustic detectors, including delays employed to detect false alarms, should not exceed 30 seconds. The time between a gas leak is detected and an alarm is presented on the operator station should be less than 2 seconds[62].

12.3 Leak detection on vessel

Vessels on the field have equipment which is able to detect gas leaks after the gas has reached the surface. Gas detectors on the vessel will sound an alarm if gas is detected[39].
As with the leak detection on subsea structures, this is a passive consequence reducing barrier.

12.4 Pressure reading by SCSt

The compression station is equipped with pressure gauges, which will detect a potential pressure drop in the pipelines quickly. If this happens, a shutdown will be initiated through the PSD.
Pressure reading by the compression station is a passive barrier which is present in the system continuously. Since a pressure drop in the pipelines is an indication of a gas leak, pressure reading is a consequence reducing barrier.

12.5 Dynamically Positioned Vessels

Dynamic positioning (DP) is an automatic position keeping system for vessels. In the Performance Standard regarding position keeping, PS 18 – Ballast Water and Position Keeping, in TR1055, Statoil states that the position keeping system shall "enable the floating installation to maintain position and heading within given operational limits".

Dynamic positioning uses a mathematical model of the vessel and external forces, to calculate the required steering angle and thruster ouput for each thruster on the vessel. This way, the vessel may be kept stationary, regardless of for example wind.

There are three classes to classify the requirements for dynamic positioning defined by the International Maritime Organisation (IMO): Class 1, Class 2 and Class 3[3]. DNV operates with four classes, DPS 0 - DPS 3, where DPS 1 - DPS 3 corresponds to Class 1 to 3. DPS 0 is DP without any redundancy[22]

Class 1 has an independent joystick system back-up, but the actual DP system might fail if a single failure occurs.
Class 2 has redundancy in active components. This means that if a single failure occurs in an active component such as generators or thrusters, the system shall still be working properly. If there is a failure in a passive component such as cables or pipes, however, there is no guarantee that the DP system will continue working.
Class 3 shall have redundancy in all components. With this class, the DP system shall be able to keep the vessel's position even if there is a fire or a flood in a compartment. This means that if the generator and all thrusters inside one compartment are destroyed, the vessel should still not lose position.

DP Class 2 and 3 shall have UPS. This means that if the main power fails, there is a backup system to power all computers and reference systems.

In PS 18 – Ballast Water and Position Keeping, Statoil states the following requirements to the position keeping system:

- The power system shall have sufficient redundancy so that power can be immediately provided following any single failure in any sub-system or component.
- Power demand changes in normal operation and fault situations shall be met by the power management system with an adequate response time.
- Upon loss of a generator, the power management system shall ensure sufficient power on remaining generators avoiding overloading.
- All computer systems shall be backed up by UPS/battery supplies which shall have at least 30 minutes battery capacity.
- The thruster system shall have sufficient redundancy such that thrust can be provided following any single failure in any sub-system or component.
- A failure in the thruster control system shall not make the thruster rotate or give increased thrust.

By comparing these requirements with the class descriptions, the Statoil requirements to the DP system is that it should be at least DP Class 2. This is also stated in Governing document TR2351 - Requirements for offshore construction vessels: For DP operations, minimum Equipment Class 2 is required.
By utilising DP Class 3, the risk of a major accident is reduced the most.

The use of a high DP Class is a passive barrier which reduces the frequency of a hazardous event.

The Norwegian Maritime Directorate (NMD) has specified some guidelines to assess which DP class should be used in different situations based on the risk of fatalities, environmental damage and economical consequences if the DP system fails. According to the NMD, DP Class 3 should be used "during operations where loss of position could cause fatal accidents, severe pollution or damage with major economic consequences"[3]. This applies to the three major accident scenarios involving drift-off or drive off; A43, A28 and A34, thus DP Class 3 should be used during these operations.

12.6 Dropped object protection

Dropped object protection is a passive barrier which is present at all times. It is a consequence reducing barrier which reduces the consequences of an impact on subsea structures, umbilicals and pipelines from a dropped object.

The impact capacity which the subsea structures shall be able to withstand are designed according to NORSOK U-001:

- For multi well structures, that is templates, the impact energy 50 kJ for a point load with a diameter of 700 mm.
- For other structures, the impact energy 20 kJ for a point load with a diamter of 500 mm.

The subsea structures at Åsgard is designed to comply with these requirements.

The subsea equipment which will be placed at Åsgard has potential energy which surpasses these design criteria when dropped from full height, that is circa 300 meter above the seabed. For instance, one of the smallest spools which will be installed has a weight in water of 0.5 tonnes. After a drop, the maximum velocity subsea is asessed to be 7 m/s, and the impact energy is found to be 22 kJ[40]. One of the heavier spools, with a weight of 10.6 tonnes in water, will cause an impact energy of 380 kJ[40].

Because spools are considered the lightest objects which will be placed on the seabed at Åsgard, it is unprofitable and unpractical, or even impossible, to implement dropped object protection of the subsea equipment which could withstand the impact of large modules such as spools, PLEMs and the frames and modules of the SCSt and the SCMS from full water depth.

The result of this is that risk reducing measures must be implemented in the operational procedures - such as the organisational barrier Safe lifting distance, which is described in Section 13.1 - instead of in the technical design for these heavy structures.

If the safe lifting distance principle is applied, the equipment is at a height of one to three meters above the seabed when it is directed above subsea structures. If small spools are dropped from this height, the dropped object protection shall absorb the impact energy. If larger structures are dropped, however, the dropped object protection is redundant.

Protection of umbilicals and pipelines

According to [53], the pipeline material specification is X65 with concrete coating. X65 is a pipeline grade specified by the American Petroleum Institute (API), where the pipe should be able to withstand a certain amount of pressure related to the thickness of the pipe.
DNV states in [66] that the concrete coating has an impact resistance of 5 - 20 kJ, and are well suited for low energy impacts.

Due to the protection of the pipelines and the defined safety zones, which is described in Section 13.1, the risk of hydrocarbon leakage due to damage to the pipelines caused by dropped objects, is assumed to be negligible.
The ship traffic in the area is found to be modest, based on AIS registrations, thus the risk of dragging ship anchors and sinking ships is found to be negligible as well.

12.7 Weak link between vessel and subsea equipment

During hot-tapping, tie-in, intervention or installation, subsea equipment is connected to a vessel. If there are problems with the DP system and a drive off or drift-off occurs during such operations, it could result in severe damage to subsea equipment, and even rupture of pipelines. However, if the link connecting the subsea equipment and the vessel is weak, the link will break before any damage is caused to the subsea equipment during a drive off or drift-off. This reduces the consequences of a potential drive off/drift-off considerably.

The use of a weak link reduces/eliminates the consequences of a drive off or drift-off, thus this is a consequence reducing barrier. The availability of the barrier is continuous and the barrier is present during the entire operation, thus it is a passive barrier.

12.8 Crane Technical Specification

The crane technical specification comprises a number of barriers whose role is, according to performance standard PS 16 - Offshore Cranes, in TR1055: To reduce the probability that errors and hazards will arise during crane operation, and reduce the possibility of boom or load fall.

In TR2351, regarding requirements for offshore construction vessels, it is stated that cranes used for subsea operations shall be designed for the purpose. All personnel involved in the lifting operation should also be trained, have required experience for the type of lift to be executed and be formally assessed as competent[43].

This is a passive frequency reducing barrier, which reduces the frequency of dropping an object during a lift.

12.9 Rigging Design

Rigging design refers to the design of the lifting equipment, such as shackles and lifting slings. It is a passive barrier which, together with the crane technical specification, reduces the frequency of dropped objects during lifts.

12.10 Ignition Source Control on Vessel

Ignition source control involves isolating potential ignition sources physically, thus this is a passive barrier. By preventing a potential cloud of gas from being ignited, it reduces the consequences of a potential gas leak, thus it is a consequence reducing barrier.

All vessels shall follow the technical requirements related to ignition source control stated by Statoil in Performance Standard PS 6 – Ignition source control in TR1055.

The role of the ignition source control is stated in PS 6 to be: “The ignition probability of flammable liquids and explosive gas atmospheres shall be minimised by rendering the sources of ignition harmless or reducing the likelihood of occurrence of effective ignition sources.”
Thus the ignition sources shall be identified and isolated to reduce the ignition probability. By shutting down electrical systems and engines when a leak is detected, the ignition probability may be reduced[41].

12.11 Testing of Critical Barriers

Testing of critical barriers is an active and time-limited way of reducing the probability of failure, thus this is an active frequency reducing barrier.

Statoil’s Governing document TR1230 states the requirements for single barriers during intervention tasks. It states that for temporary and time limited operations, the use of a single valve as a barrier may be acceptable. However, certain precautions shall be taken[51]:

- The valve shall be leak and pressure tested prior to the operation.
- The valve shall be secured in closed position, and shall not be operable during the operation.
- An overall safety assessment shall be conducted.

The operation shall be supervised by ROV for leak detection and for visual confirmation of the position of the valves.
All ROV operated valves shall be colored orange for simplicity and safety, and shall have visual indicators displaying the function status of the valve, such that it can be observed by ROV[61].

12.12 Depressurize risers

During the installation of the new riser base near Åsgard B, the nearby risers will be depressurized. It might be evaluated to be keep the risers pressurized during the installation, if a risk analysis shows that it is justifiable.
This barrier reduces the consequences of a drop of the riser base significantly, by removing the risk of a hydrocarbon release during the installation.

Chapter 13

Organisational Barriers

Organisational barriers are barriers which are established through organisational procedures and planning. Several organisational barriers have been established by Safetec in [39]. These are relevant for most of the major accident scenarios described in Part III, and are mentioned here as a whole instead of at the specific major accident scenarios.

- Åsgard A and B, installation vessels, intervention vessels and rigs in the area should be included in a common communication plan.
- An emergency channel between Åsgard A and the installation vessel should be included in the communication plan.
- Åsgard B should alert all vessels in the area about potential subsea gas leakage if subsea gas detection is triggered at the SCSt.
- There should be a direct line to the bridge/control room from the subsea supervisor.
- All major operations should be planned thoroughly.
- Risk assessment of all major operations, including HAZID for installaion operations should be conducted.
- Installation vessels shall have emergency perparedness plans.
- When a modification has been done on a pipeline system, it shall be tested for a minimum of 24 hours to ensure that there are no leaks[20]. This shall be done in accordance with DNV-OS-F101, which is an offshore standard regarding submarine pipeline systems.

In addition to these general requirements, there are several organisational barriers which are only relevant to some specific major accident scenarios. These have been identified in Part III, and will be described in this chapter.

13.1 Safe lifting distance

By using the safe lifting distance principle while lifting or lowering equipment to/from the seabed, the frequency of hitting pressurised subsea equipment, and thus risking a hydrocarbon leak, is reduced, thus this is a frequency reducing barrier. However, it could also be assessed to be a consequence reducing barrier, because it reduces the consequences of a potential dropped object.
Safe lifting is a passive barrier because it is present during the entire lifting operation, and it does not need to be activated in order to fulfill it's role as a barrier.

Statoil states in Performance Standard PS 16 – Offshore Cranes, in TR1055, that there shall be no lifting zones above unprotected equipment or piping, containing hydrocarbons[62]. It is also unpractical to implement dropped object protection for the kind of impact which are generated by dropping heavy equipment from a full height of circa 300 m above the seabed during a lift, as discussed in Section 12.6. Thus, instead of lifting the heavy equipment directly down to its permanent position, it is first lowered down to a few meters above the seabed in an area which does not contain any subsea structures. Once the structure has been lowered, it is transported horizontally, at a height of a few meters above the seabed, to its location without passing over hydrocarbon equipment on the seabed[41]. This is done in reverse order for lifting equipment up from the seabed.

The principle is applied during all lifts, typically during installation and removal of subsea structures, and during intervention of the SCSt.

When an object is dropped in water, it drifts a certain distance. It is thus important to conduct lifting operations at a sufficient distance away from subsea structures. As the distance is increased, the probability of hitting subsea structures decreases.

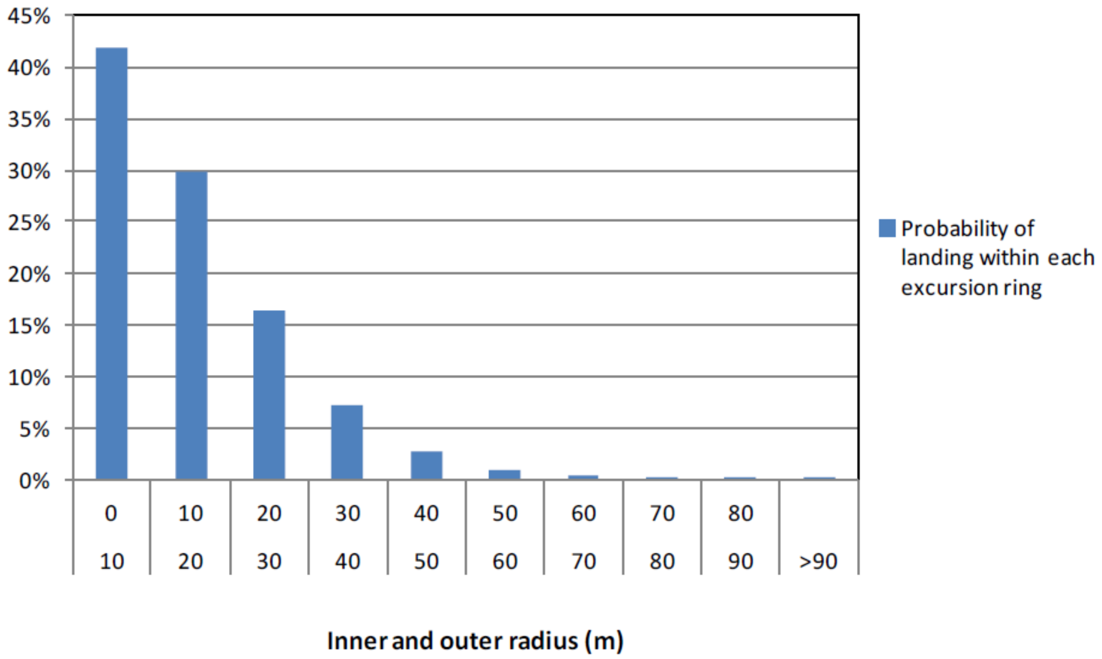

Figure 13.1: Probability of hitting subsea structures[40]

Safetec has in accordance with DNV-RP-F107, calculated the probability of hitting subsea structures with dropped objects at different distances under the conditions at Åsgard[40]. The probabilities have been calculated for a depth of 280 m, and within rings of 10 m in width. The results are shown in Figure 13.1.

As can be seen in Figure 13.1, the probability of hitting a subsea structure declines significantly as the distance to the structure is increased. When the distance is 90 m, the probability of a hit is below 0.02 %, thus 90 m is recommended as a safe distance[40].
To account for the size of the object being lifted, half the length of the object needs to be added to the safe distance. The safe distance for some relevant equipment types is shown in Table 13.1.

Equipment	Shape	Safe distance
Spool	Pipe	130 m
Module	Box	105 m
Station	Box	105 m

Table 13.1: Safe distance for relevant equipment types

Rig load handling zones at Åsgard are shown in [14], [15] and [16]. They show anchoring zones, load handling zones, wet storage areas, flowlines and umbilicals. The figures show 20 m and 45 m load handling zones around the subsea equipment, where it is allowed to perform lifting procedures. 45 m is preferred, while 20 m is a minimum. The load handling zones are located in areas where the seabed is as level as possible and where no umbilicals or pipelines are located.
Based on the results from the Safetec report, these zones should be extended and made to include the new subsea structures which will be installed at Åsgard.

By employing the safe lifting distance principle, and by planning the operations carefully, the probability of hitting live hydrocarbon equipment if dropping a heavy structure is negligible[40].

13.2 Relocation of vessel after leak detection

Relocation of vessel after leak detection is an active barrier which needs to be activated at the moment it is needed. It is consequence reducing because it is used after a gas leak is detected.

When a leak is detected, it is important to relocate all vessels in the vicinity of the leak point as quickly as possible. If there is an intervention vessel or an installation vessel directly above the leak point when a leak is detected, the relocation is essential to avoid exposing the vessel to flammable gas.

When the vessels near the leak point have been notified, they shall immediately start to move upwind and away from the leak point. However, an intervention or installation vessel might be connected to equipment which hangs beneath the vessel. If the vessel crosses subsea facilities as it moves off the field, the equipment might hit the facilities, which could result in damage to both equipment and facility[39]. It is thus important that there is established a safe relocation route, such that the vessel may move away from the leak point without crossing pressurized equipment on the seabed.

Relocation routes should be established for all the installation and intervention activities, and should consider wind and current conditions.

13.3 Operation at safe distance

During the hot-tap operation, there is a vessel present on the field which is connected to the hot-tapping machine. There is a low risk of hydrocarbon release during the operation, which could expose the vessel if it is located above the leak point.
This barrier reduces the consequences of a potential gas leak continuously during the operation, thus it is a consequence reducing passive barrier.

Vessel placed outside potential gas plume radius

If the vessel is displaced horizontally from the potential leak point during the operation, the risk of gas exposure of the vessel is reduced significantly. Thus the vessel should be located at a safe distance outside the gas plume radius.

Vessel placed upwind of any potential gas leak

By placing the vessel upwind from the potential leak during the operation, the probability of being exposed to the gas cloud is significantly reduced. Figure 10.1 in Section 10.2.4 shows how a gas cloud will be affected by wind, and thus how important it is to locate the vessel upwind.

13.4 Leak detection by ROV

ROVs are used to detect leaks during installation, testing and intervention. By monitoring the area with one or more ROVs, it is possible to detect a leak almost immediately after it has occured. By detecting a leak as early as possible, it leaves more time to relocate vessels in the area and initiate the PSD. When the ROV supervisor detects a leak, the bridge of the installation or intervention vessel shall be alerted immediately[39].

As the presence of a ROV is time-limited and is dependent on an operator, this is an active barrier. It is also consequence reducing since it does not reduce the probability of a hazardous event.

13.5 Wet storage area

A wet storage area is an area on the seabed which is intended for placing heavy subsea modules temporarily. The area should be as level as possible and resemble the topography of the area where it will be permanently placed.
Basically, this means that the wet storage areas are specifically designed for one or more specific modules.

By having wet storage areas available for the heavy subsea modules, it is possible for an installation or intervention vessel, which is lifting or lowering a module, to put down the module in a safe place, in order to relocate, if a gas leak is detected.

Wet storage areas are defined for the modules on Template X, Y and Z in [14], [15] and [16], respectively. These layouts are of the existing subsea structures and does not include the new structures. These, however, should be included in an updated version.

The wet storage area is a passive barrier because it is always present and available on the seabed. It is not used until a hazardous event has taken place, thus it is consequence reducing.

13.6 Position and heading of vessel

The position and heading of vessels on the field is a passive barrier which is present during the entire operation. It reduces the probability of a collision, thus it is a frequency reducing barrier.

When a vessel needs to move into the safety zone around a topside installation, it is important to evaluate the vessel's position and heading, such that it will drift away from the installation if it experiences a blackout.
The heading of vessels within the safety zone should always be decided based on the current and wind conditions in the area. If the heading is optimal, then the vessels will automatically move away from the installation, if they experience a drift-off[39].

During activities involving vessels inside the safety zones of Åsgard A, Åsgard A should be in such a position that a blackout does not cause significant rotation of the FPSO, because such a rotation could cause a collision.

Part V

Results

Chapter 14

Results

14.1 Probability of a fatal accident for each major accident scenario

The probability of a fatal accident for each major accident scenario was presented in Chapter 6 to 9 in Part III, and are reproduced in Table 14.1.

For scenario A7, it has been assumed that there will be two vessels present during the intervention og the SCMS and the SCSt. If there is only going to be one vessel present, the probability of a fatal accident is $9.6 \cdot 10^{-7}$.

For scenario A28, there are different probabilities of a fatal accident for drive off/drift-off and for collision with Åsgard A and Åsgard B. Table 14.1, however, gives the total probability of a fatal accident for this major accident scenario.

Risk related to installation of new equipment

Major accident scenario	**Probability**
A9 - Hydrocarbon leakage during hot-tapping	$6.2 \cdot 10^{-9}$
A21 - Hydrocarbon leakage during tie-in	$2.54 \cdot 10^{-6}$
A30 - Impact on existing riser during riser base installation	Negligible

Risk related to dropped objects

Major accident scenario	**Probability**
A7 - Dropped objects during intervention of SCMS and SCSt	$1.3 \cdot 10^{-6}$
A10 - Dropped objects during installation of PLEM and spools	Negligible
A12 - Uncontrolled lifting/dropped objects during installation of SCMS and SCSt	$1.68 \cdot 10^{-4}$

Risk related to ship related hazards

Major accident scenario	**Probability**
A28 - Collision between vessel and Åsgard A or Åsgard B during installation of umbilical/fibre cable	$2.5 \cdot 10^{-7}$
A43 - Vessel drift-off during installation and removal of start up anchor/pile within platform safety zone	Negligible
A34 - Potential drive off during intervention of modules	$6.3 \cdot 10^{-6}$

Risk related to hydrocarbon leakage

Major accident scenario	**Probability**
A26 - Leakage from production system after installation	Negligible

Sum	$\mathbf{1.8 \cdot 10^{-4}}$

Table 14.1: Probability of a fatal accident

14.2 Probability of impairment of main safety functions for each major accident scenario

The probability of impairment of main safety functions have been reproduced in Table 14.2, and are compared with Statoil's risk acceptance criterion for impairment of main safety functions.

Risk related to installation of new equipment

Major accident scenario	Risk	RAC
A9 - Hot-tapping	$6.2{\cdot}10^{-9}$	10^{-4}
A21 - Tie-in	$5.1{\cdot}10^{-6}$	10^{-4}
A30 - Riser base	Negligible	-

Risk related to dropped objects

Major accident scenario	Risk	RAC
A7 - Drop at SCSt, 2 vessels	$1.3{\cdot}10^{-6}$	10^{-4}
A10 - Drop of PLEM/spools	Negligible	-
A12 - Drop of SCMS onto barge	$8.4{\cdot}10^{-5}$	10^{-4}
A12 - Drop of SCSt onto barge	$8.4{\cdot}10^{-5}$	10^{-4}

Risk related to ship related hazards

Major accident scenario	Risk	RAC
A28 - Collision, Åsgard A, drive off	$5.3{\cdot}10^{-7}$	10^{-4}
A28 - Collision, Åsgard A, drift-off	$4.0{\cdot}10^{-11}$	10^{-4}
A28 - Collision, Åsgard B, drive off	$3.8{\cdot}10^{-7}$	10^{-4}
A28 - Collision, Åsgard B, drift-off	$2.9{\cdot}10^{-11}$	10^{-4}
A43 - Drift-off	Negligible	-
A34 - Drive off, intervention	$6.3{\cdot}10^{-6}$	10^{-4}

Risk related to hydrocarbon leakage

Major accident scenario	Risk	RAC
A26 - Leakage	Negligible	-

Table 14.2: Probability of impairment of main safety functions

14.3 Barriers

The different barriers which where identified in Chapters 6 to 9 in Part III and described in Chapters 11 to 13 in Part IV are reproduced in Table 14.3 to 14.6.

14.3.1 Barriers for major accident scenarios related to installation of new equipment - Marine operations

Hydrocarbon leakage during hot-tapping (A9)	
Technology	**Organisation**
PSD Weak link in umbilical from vessel to hot-tap Dropped object protection	Safe lifting distance Safe relocation of vessel Leak detection by ROV Place vessel outside potential -gas plume radius Place vessel upwind of any -potential gas leak
Hydrocarbon leakage during tie-in (A21)	
Technology	**Organisation**
PSD Leak detection on vessel Weak link	Safe lifting distance Safe relocation of vessel Leak detection by ROV Testing of critical barriers
Impact on existing riser during riser base installation (A30)	
Technology	**Organisation**
PSD Leak detection on vessel Position/heading of vessel Depressurize risers	Safe lifting distance Safe relocation of vessel Leak detection by ROV Position/heading of vessel

Table 14.3: Barriers for major accident scenarios related to installation of new equipment - Marine operations

14.3.2 Barriers for major accident scenarios related to dropped objects

Dropped objects during intervention of SCMS and SCSt (A7)	
Technology	**Organisation**
PSD Leak detection on vessel/subsea structures Pressure reading at SCSt Crane Technical specification Rigging design	Safe lifting distance Safe relocation of vessel Leak detection by ROV
Dropped objects during installation of PLEM and spools (A10)	
Technology	**Organisation**
PSD Leak detection on vessel/subsea structures Dropped object protection Crane Technical specification Rigging design	Safe lifting distance Safe relocation of vessel Leak detection by ROV Wet storage areas
Uncontrolled lifting/dropped objects during installation of SCMS and SCSt (A12)	
Technology	**Organisation**
Crane Technical specification Rigging design	Safe lifting distance

Table 14.4: Barriers for major accident scenarios related to dropped objects

14.3.3 Barriers for major accident scenarios related to ship related hazards

Collision between vessel and Åsgard A or Åsgard B during installation of umbilical/fibre cable (A28)	
Technology	**Organisation**
Vessel DP Class ESD	Safe relocation of vessel Position/heading of vessel
Vessel drift-off during installation and removal of start up anchor/pile within platform safety zone (A43)	
Technology	**Organisation**
Vessel DP Class ESD	Safe relocation of vessel Position/heading of vessel
Potential drive off during intervention of modules (A34)	
Technology	**Organisation**
PSD Vessel DP Class Leak detection on vessel/subsea structures Pressure reading at SCSt	Safe relocation of vessel Leak detection by ROV Weak link

Table 14.5: Barriers for major accident scenarios related to ship related hazards

14.3.4 Barriers for major accident scenarios related to hydrocarbon leakage

Hydrocarbon leakage from production system after installation (A26)	
Technology	**Organisation**
PSD Leak detection on vessel/subsea structures Pressure reading at SCSt	Safe relocation of vessel

Table 14.6: Barriers for major accident scenarios related to hydrocarbon leakage

Chapter 15

Discussion

Four of the scenarios - impact on existing riser during riser base installation, dropped objects during installation of PLEM and spools, vessel drift-off during installation and removal of start up anchor/pile within platform safety zone and leakage from production system after installation - have such a small probability of happening that they are negligible, typically in the area 10^{-11} and smaller. The risk related to the first two scenarios are negligible because the installations will be executed without pressurized equipment nearby. The vessel drift-off scenario is negligible due to the very low drift-off frequency experienced with DP Class 2 or 3 vessels, while the risk related to leakage from production system after installation is negligible because of the very low probability of a leakage after installation, the PSD system and the moderate ship traffic in the area.

This means that there are no requirements to implement further risk reducing measures for these scenarios, but according to the ALARP principle, risk reducing measures should still be evaluated and implemented as long as there is not an unreasonable disproportion between the costs and the risk reducing benefits.

The risk related to the hot-tapping, $6.2{\cdot}10^{-9}$, is considered to be very small. As can be seen in Table 14.2, it is well within the risk acceptance criterion, thus this risk is under control. This is mainly due to the risk reducing measure of placing the vessel at a safe distance upwind from the potential leak point.
However, since hot-tapping has never been conducted in this way before, remotely, without divers and completely unprepared for, unexpected situations could arise.

Four of the scenarios - hydrocarbon leakage during tie-in, dropped objects during intevention of SCMS and SCSt, collision between vessel and Åsgard A or Åsgard B during installation of umbilical/fibre cable and potential drive off during intervention of modules - have a relatively small probability of happening; in the area of 10^{-6}-10^{-7}.

The risk related to the tie-in operations is mainly controlled by the extensive testing of the critical barriers, and by the PSD system. For the dropped object during intervention of SCMS and SCSt scenario, the organisational barrier safe lifting distance is the most important barrier in place, in addition to the PSD system, to avoid a major accident. For the collision and the drive off scenarios, the small risk is mainly due to the small probability of drift-off or drive off with a DP Class 2 or 3 vessel.

The risks related to these scenarios are well within the risk acceptance criterion for impairment of main safety functions established by Statoil. The probability of a fatal accident shows that there is expected to be a fatality during these operations circa every 1 million years, which is quite rare.
Even though the risk is small, risk reducing measures should still be evaluated according to the ALARP principle.

The major accident scenario related to the installation of the frames of the SCSt and the SCMS has a risk of $1.68 \cdot 10^{-4}$. This is considered a relatively high risk. By looking at the installation of the two frames separately, however, it is seen that the risk of impairment of main safety functions is $8.4 \cdot 10^{-5}$, which is within the risk acceptance criterion.

This major accident scenario is controlled through the robustness of the equipment, such as through the crane technical specification and rigging design. This operation is hazardous, but because the frames will only be lifted down to the seabed once each, the high risk of the operation can be tolerated. Additional risk reducing measures should, however, be considered, though many of these barriers can be organisational.

Important barriers

All of the major accident scenarios presented in Part III - except dropped objects during installation of PLEM and spools, uncontrolled lifting/dropped objects during installation of SCMS, collision between Åsgard A or Åsgard B during installation of umbilical/fibre cable and vessel drift-off during installation and removal of start up anchor/pile within platform safety zone - are related to subsea gas leaks. This means that it is very important to reduce the probability of such a leak as much as possible, and to limit the consequences.

In this regard, an important consequence reducing barrier in place to reduce the probability of a major accident is the PSD. The PSD is a technical barrier which is able to reduce the consequences of a hydrocarbon release significantly. By shutting down the production quickly, the PSD limits the amount of hydrocarbons which are released during the leak, and thus the probability of exposing a vessel to the gas.
The effectiveness of the PSD barrier is dependent on the leak being detected quickly. This means that the different leak detection methods - acoustic detectors on the subsea structures, pressure reading in the SCSt and detection by ROV - are important for scenarios related to subsea gas leaks.
It does, however, take time to activate the PSD, and it does not reduce the initial consequence unless the scenario has not escalated to full potential yet, and it does not prevent the leak.

If a gas leak is detected, all vessels in the area shall relocate to a safe distance. This is an important consequence reducing organisational barrier for the scenarios related to a hydrocarbon leak. By relocating the vessel, the probability of gas exposure, and thus the probability of a fatal accident, is significantly reduced.

For all the major accident scenarios involving ship related hazards, the most important barrier is vessels that are equipped with a high DP class, that is Class 2 or 3. This is a frequency reducing barrier, which will reduce the risk of drive off/drift-off significantly.
For safety critical vessel operations, where it is important that the vessel does not experience a drive off or drift-off, it should be evaluated to utilise DP Class 3.

For all scenarios involving lifting of heavy equipment, the most important barrier is the safe lifting distance. This barrier is relevant for all the scenarios related to installation of new equipment and dropped objects. By applying this barrier, the risk of hitting hydrocarbon equipment on the seabed after dropping an object is very small. Thus this is the most important barrier to reduce the frequency of a hazardous event which could escalate into a major accident.

The major accident scenario presented and investigated in Chapter 10, highlights the fact that human and organisational barriers are more vulnerable to error than technological barriers. This means that there are more uncertainties related to the organisational barriers: Relocation of vessel and safe lifting distance, than the technical barriers: PSD and the use of DP Class 2 or 3 vessels. This is especially relevant for the relocation barrier, because that is an active barrier which needs to be activated by the operator after a leak has been detected, which is a very stressful situation.

Environmental risk

The environmental risk at Åsgard is practically negligible. This is because of the low amount of condensate which is present in the SCSt and due to the characteristics of the condensate. Gas which is released, does not pose a danger to the environment, and released condensate will evaporate within a few hours on the surface.

Chapter 16

Conclusion

Statoil has many barriers in place to control the risk of a major accident scenario, and is successful in the efforts of keeping the risk at a low level. The identified major accident scenarios have risk levels within the risk acceptance criteria, but risk reducing measures should still be implemented in accordance with the ALARP principle.

The different barriers identified in this thesis all contribute to controlling the risk, but the most important barriers are:

- The process shutdown (PSD) system, which shuts down the production after a significant leak has been detected.
- That the installation and maintenance vessels have a reliable dynamic positioning system.
- Positioning installation or maintenance vessels at a safe distance from subsea hydrocarbon equipment during lifts.
- Relocation of installation or maintenance vessel after a significant subsea leak is detected.

Either the PSD or the DP barrier is present at all the major accident scenarios except A12. Due to the fact that technological barriers are more reliable than human and organisational barriers, the presence of these two barriers is very important.

The overall risk level for the Åsgard SCp is low, but operational procedures must be followed in order to keep the risk at this level. This places a requirement on Statoil to facilitate that the organisational procedures are followed.

Chapter 17

Further Work

This thesis is a part of Statoil's ongoing work of managing potential major accidents in the Åsgard Subsea Compression project.

From here, Statoil will further develop strategies for implementing the barriers and risk reducing measures identified, and develop detailed plans of action for the scenarios.

Because many of the barriers identified are organisational, it is especially important that there exists good procedures, such as emergency preparedness plans, which shall be followed by the personnel on the account of a hazard/initiating event.

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Appendix A

Appendix

A.1 PSD hierarchy at Åsgard and general ESD hierarchy

PSD hierarchy

Both compressor trains of the PSD hierarchy at Åsgard SC is shown in Figure A.1.

General ESD hierarchy

The general ESD hierarchy from TR1055 is shown in Figure A.2. APS stands for Abandon Platform Shutdown and is the most severe safety measure in the hierarchy.

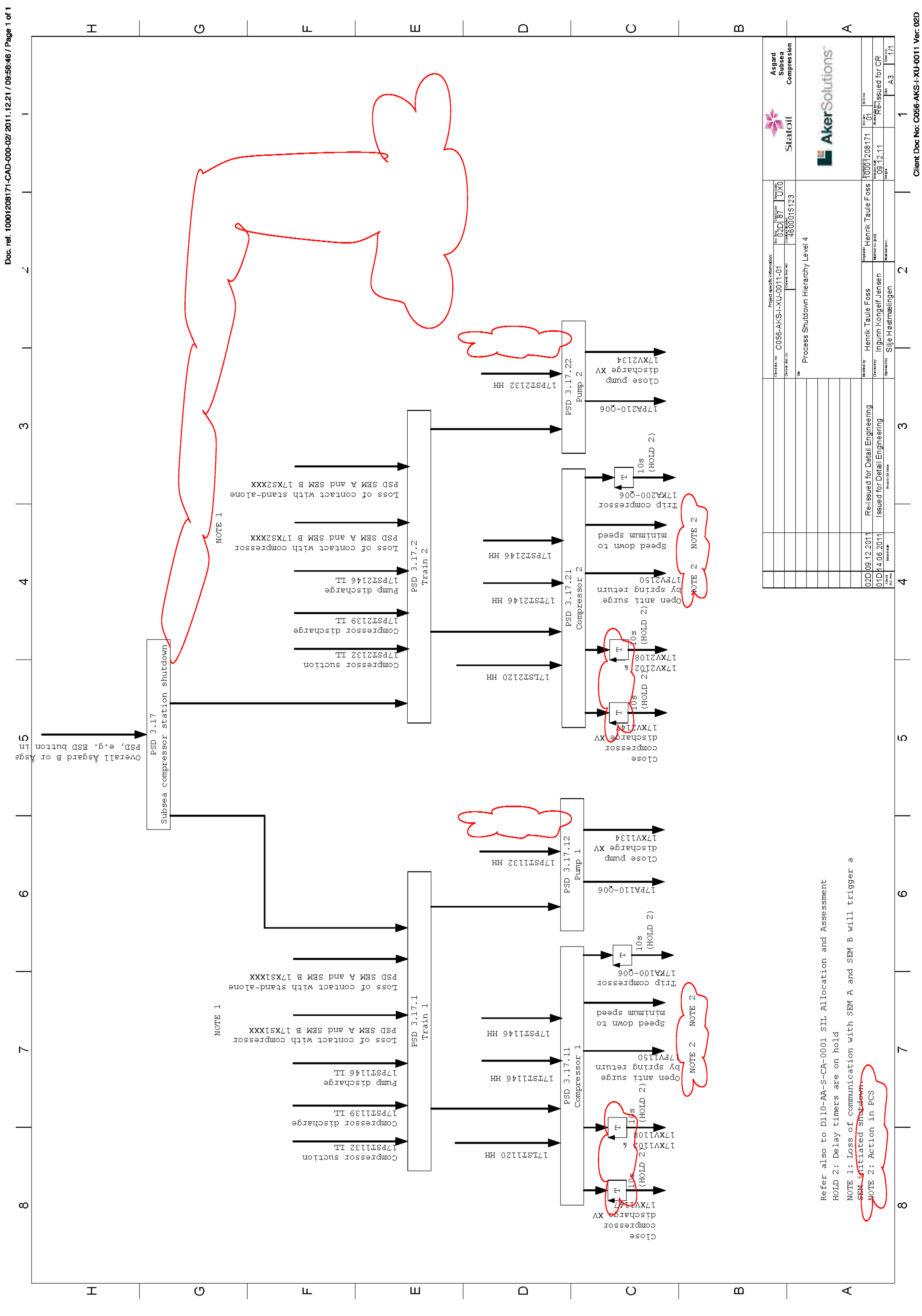

Figure A.1: Åsgard subsea compression PSD hierarchy[56]

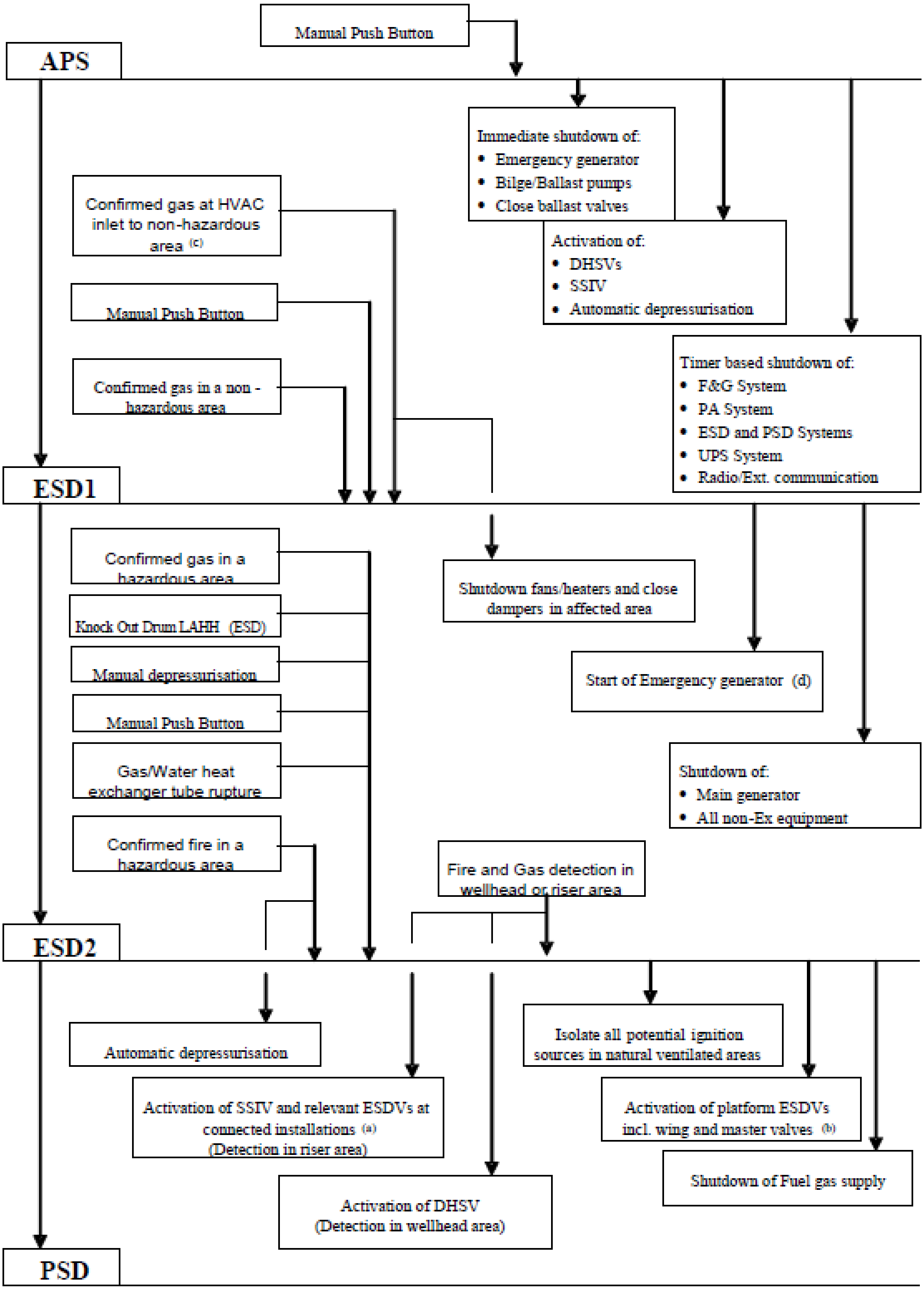

Figure A.2: General ESD hierarchy from TR1055[62]