NTNU – Trondheim
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Science and Technology

Assessment of dynamic barriers in oil/gas well operations

Vurdering av dynamiske barrierer i olje/gass brønner

Jan Runar Tangstad

Subsea Technology
Submission date: September 2014
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Norwegian University of Science and Technology
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MASTER THESIS

Department of Production and Quality Engineering

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NTNU

Faculty of Engineering Science and Technology
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MASTER THESIS
Spring 2014
for stud. techn. Jan Runar Tangstad

Assessment of dynamic barriers in oil/gas well operations

(Vurdering av dynamiske barrierer i olje/gass brønner)

Well barriers in a stable wells may be analyzed and evaluated by different types of well barrier diagrams. Several categories of diagrams have been used, some of these illustrate the possible hydrocarbon flowpaths from the reservoir to the surroundings, whereas other types are based on physical diagrams illustrating the various physical barrier element. The last option is extensively used in NORSOK D-010 "Well integrity in drilling and well operations." All these well barrier diagrams can be easily transferred to fault trees and reliability block diagrams for further reliability assessment.

During drilling and well intervention, the barrier situation is dynamic and the well barrier diagrams above cannot be easily used. In these situations, the activation of the barrier depends on the current situation and there is no pre-made sequence of barrier activations (e.g., during the Macondo accident). In these situations it has been suggested to assess the barrier system by, for example, event trees and procedure HAZOPs, but most of these approaches have significant weaknesses.

The objective of this master thesis is to study, evaluate, and discuss possible approaches to the assessment of dynamic well barrier systems.

As part of this Master thesis, the candidate shall:

1. Identify and describe traditional well barriers and present a survey of requirements to well barriers in regulations and standards.
2. Establish static well barrier diagrams for a selected operation, and discuss approaches to illustrate the well barrier diagrams.
3. Identify and describe dynamic aspects of well barriers and illustrate the time/procedure-dependent barrier situation.

4. Suggest an analytical approach for the assessment of dynamic well barriers.
5. Carry out a case study based on the approaches suggested in item 4.
6. Identify and discuss challenges to dynamic well barrier assessment, for which further research is needed.

Following agreement with the supervisor(s), the questions may be given different weights.

The assignment solution must be based on any standards and practical guidelines that already exist and are recommended. This should be done in close cooperation with supervisors and any other responsibilities involved in the assignment. In addition it has to be an active interaction between all parties.

Within three weeks after the date of the task handout, a pre-study report shall be prepared. The report shall cover the following:

- An analysis of the work task's content with specific emphasis of the areas where new knowledge has to be gained.
- A description of the work packages that shall be performed. This description shall lead to a clear definition of the scope and extent of the total task to be performed.
- A time schedule for the project. The plan shall comprise a Gantt diagram with specification of the individual work packages, their scheduled start and end dates and a specification of project milestones.

The pre-study report is a part of the total task reporting. It shall be included in the final report. Progress reports made during the project period shall also be included in the final report.

The report should be edited as a research report with a summary, table of contents, conclusion, list of reference, list of literature etc. The text should be clear and concise, and include the necessary references to figures, tables, and diagrams. It is also important that exact references are given to any external source used in the text.

Equipment and software developed during the project is a part of the fulfilment of the task. Unless outside parties have exclusive property rights or the equipment is physically non-moveable, it should be handed in along with the final report. Suitable documentation for the correct use of such material is also required as part of the final report.

The student must cover travel expenses, telecommunication, and copying unless otherwise agreed.

If the candidate encounters unforeseen difficulties in the work, and if these difficulties warrant a reformation of the task, these problems should immediately be addressed to the Department.

The assignment text shall be enclosed and be placed immediately after the title page.

Deadline: 25 August 2014.

Two bound copies of the final report and one electronic (pdf-format) version are required according to the routines given in DAIM. Please see http://www.ntnu.edu/ivt/master-s-thesis-regulations regarding master thesis regulations and practical information, inclusive how to use DAIM.

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DEPARTMENT OF PRODUCTION AND QUALITY ENGINEERING

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Dedication

I would like to dedicate this master thesis to my father, who sadly passed away far too early, in the winter of 2013. Thank you for always being there for me, helping and supporting me in every possible way. May you rest in peace.

Preface

This report presents the master thesis in the course TPK 4900 Production and Quality Engineering, Master Thesis. The thesis is a part of the two year Underwater Technology study program at the Norwegian University of Science and Technology, and was mainly carried out during the spring and summer of 2014.

It is assumed that the reader should have a basic knowledge of system reliability theory and be familiar with well operations in oil and gas.

Trondheim, 2014-09-29

Jan Runar Tangstad

Jan Runar Tangstad

Acknowledgment

I would like to thank my responsible supervisor Marvin Rausand at NTNU for his guidance, and assistance with providing me knowledge and feedback during the project, and for always creating good mood at our meetings.

I would also like to thank my co-supervisor Geir-Ove Strand for his input to the thesis.

J.R.T

Summary and conclusion

Well integrity is an important topic in oil and gas well operations. The intention is to control the reservoir fluids and well pressures, by technical, operational and organizational barriers. Inadequate barriers can lead to unwanted influx and cause a kick, which can escalate further into a blowout.

The Deepwater Horizon accident in the Gulf of Mexico in 2010 raised concerns about the safety of offshore deepwater drilling. This rig was considered to be an efficient and safe drilling unit, until the fatal blowout occurred leading to the loss of eleven lives, and the worst environmental disaster in US history.

The main objective of a well barrier is to prevent leakage from the wellbore to the external environment during the various well operations. Well barriers are classified as primary or secondary barriers. The primary barriers are the barriers closest to the hydrocarbons and are the first obstacle to unwanted flow of formation fluid. The secondary barrier acts as a backup barrier. Barriers can further be classified as static or dynamic. The static barriers apply for the production phase, meaning that they are present over a longer period of time. Dynamic barriers occur during drilling and well intervention, and these are the once that are most difficult to assess because of the constantly changing parameters involved.

Various drilling types such as overbalanced (conventional) and underbalanced drilling are used in the search for oil and gas. The main difference between these types, is how the pressure in the wellbore is maintained, and for this different barriers are needed.

Laws and regulations dictate the requirements the industry has to follow. The Petroleum Safety Authority governs the regulations in Norway, and gives requirements to well barriers. In their regulations, they also refer to other guidelines and standards for more detailed requirements. NORSOK D-010 from 2013, “Well integrity in drilling and well operations”, is a widely used standard which defines requirements and guidelines relating to well integrity in drilling and well activities. Ways to regulate is found to vary between countries, such as for Norway and the US.

During drilling, a dynamic barrier situation applies, where the activation of the barrier depends on the current situation, and there is no pre-made sequence of barrier activation. Overall, this makes the assessment a difficult task. Various approaches have been suggested for the assessment of dynamic barriers over the years, with contributions to the topic from oil-companies, standards and research papers. Most of what has been suggested has some kind of weaknesses, and no common approach has been accepted and put into use by the industry. As

a contribution a new approach has been suggested in this thesis. An overbalanced drilling operation in deep waters initiated by a kick is selected as case study. The approach is based on using two different types of analysis, in combination. An event tree is used to illustrate the dynamics of the event, and various fault trees are used to analyze the barriers involved. To understand what can cause a kick, the possibility of avoiding it, and what to do if it happens are given attention. From the suggested approach, it emerges that the human factor plays an important role in the kick evaluation and to maintain the well integrity.

If the primary barrier is lost, there will be a kick. For this to escalate into a blowout, the secondary barrier must also be lost. If the control equipment functions as intended, lack of detection and understanding, together with insufficient training and competence of personnel can make this happen.

To prevent major accidents and hazardous events in the future, it is important to learn and gain experience from previous incidents and learn from each other, and the ability to work together, also between companies, on these difficult topics.

Contents

Chapter 1

Introduction

Offshore drilling is a high-risk operation. A main contributor to this risk is from blowouts. This uncontrolled flow of hydrocarbons can cause harm to both people and the surrounding environment. The Deepwater Horizon accident in 2010 was a strong reminder of the danger and the consequences this type of event can cause, and the importance of well integrity. Well integrity includes the design, installation, operation and maintenance of all well equipment involved in an operation.

In light of this accident, well barriers and the ability to ensure well integrity in the life-cycle of the well has got increased focus in the petroleum industry. Billions of dollars are lost each year, caused by ineffective well maintenance and unplanned shut-ins of the well. Money is one concern, but possible threats to the environment and the danger to human life and their safety, must be the main priority.

The importance of having the well barriers in place and the ability to understand them, and to test and maintain them during the life cycle of the well must not be underestimated.

Preventing a kick is the first line of defense to reduce the probability of getting a blowout. Unwanted influx of formation fluid into the wellbore comes from losing the well control, the primary barrier, thus creating a kick. If this kick is not detected or handled properly, it may result in a blowout if the secondary barrier fails or is not initiated. Preventive and risk reducing measures are important to mitigate and be able to control these undesired events. Knowledge of barriers and their behavior during drilling, with changing physical parameters and the time-dependent barrier situation is therefore becoming an important topic.

Generally, two independent barriers are required in all types of well operations. These are further divided into a primary and a secondary barrier.

In Norway, requirements to well barriers are given by the Petroleum Safety Authority (PSA). Various requirements to well barriers are also given in guidelines and standards, referred to by the PSA. Key requirement can be found in standards and guidelines such as NORSOK D-001 (2012), NORSOK D-010 (2013), OLF (2004), and API-RP-53 (2012).

Manuals and standards from various companies, and many reports have been published worldwide on the subject of well integrity. A widely used standard is the NORSOK D-010. The latest version, “Well integrity in drilling and well operations”, was released in 2013. This standard defines requirements and guidelines relating to well integrity in drilling and well activities.

The blowout in the Deepwater Horizon accident made the petroleum industry to examine their regulations and practices. They had to see what could be done to prevent this kind of accident to happen again. In 2011, the Norwegian Oil and Gas Association released the report, “Deepwater Horizon - Lessons learned and follow-up”, which contained recommendations for updating the existing NORSOK D-010. In the current version from 2013, more safety enhancements have been included, and these will have an impact on the well design, thus likely to drive up the costs for the operators. The NORSOK D-010 (2013) is considered to be the world-leading standard for well integrity, and covers the whole lifecycle of the well. This standard has been a good source when writing the current report. The most recent contribution to the subject of well integrity is ISO/TS 16530-2 “Well integrity for the operational phase” published in august 2014. This is a technical specification with the intension of giving requirements and information to well operators on managing well integrity for the operational phase.

In the production phase, the well is considered to be stable. The well barriers in this phase may be analyzed and evaluated by using different types of well barrier diagrams. If further reliability assessment is desired, these diagrams can be transferred to fault trees and block diagrams.

When it comes to the drilling- and intervention phase, the barrier situation is dynamic. This makes it more complicated, and the familiar diagrams cannot be easily used.
The barrier situation now depends on the current situation, and there is no pre-made sequence of barrier activations. This raises a demand for an approach to the assessment of these dynamic barriers. Several procedures have been developed for the assessment of barriers over the years, but none has fully succeeded. The procedures are not good enough, and there is a need for methods that are more suitable. In this report a method is developed for the assessment of dynamic barriers, and a case study is performed.

The overall objective of this master thesis is to study, evaluate, and discuss possible approaches to the assessment of dynamic well barriers.

To meet the overall objective, the following sub-objectives have been treated:

1. Identify and describe traditional well barriers and present a survey of requirements to well barriers in regulations and standards.
2. Establish static well barrier diagrams for a selected operation, and discuss approaches to illustrate the well barrier diagrams.
3. Identify and describe dynamic aspects of well barriers and illustrate the time/procedure-dependent barrier situation.
4. Suggest an analytical approach for the assessment of dynamic well barriers.
5. Carry out a case study based on the approaches suggested in item 4.
6. Identify and discuss challenges to dynamic well barrier assessment, for which further research is needed.

To try to make a useful contribution, it was decided to focus on mainly one specific operation. The new assessment approach is limited to offshore drilling in deep waters, using overbalanced drilling. Only the drilling-phase and its vertical movement downwards are considered.

In agreement with the responsible supervisor, a summary in Norwegian is not included in this thesis. The report is structured in such a way, that the sub-objectives are addressed in turns from 1 to 6, with corresponding chapters from 2 until 7.The sub-objectives are answered in best possible way, based on how they were interpreted. All figures, etc. were made in VISIO. Chapter 2 gives an insight in traditional well barriers and their requirements. In Chapter 3 various approaches for the illustration of well barrier diagrams are presented, and a new vertical approach is suggested. The approach has been illustrated based on a well barrier schematic for a selected production well. The fourth Chapter deals with dynamic well barriers, and the main focus is on the barriers during drilling. Various differences between overbalanced drilling and underbalanced drilling are also highlighted here.
Chapter 5 suggests various approaches for the assessment of dynamic barriers. A case study is performed based on a new suggested approach.

The most important issues related to kick`s in overbalanced drilling are presented in Chapter 6. The last chapter, Chapter 7, sums up the work done and results found in the project, and gives recommendations for further work.

Chapter 2

Traditional Well Barriers and Requirements

2.1 Introduction

This chapter describes the traditional *well barriers* and presents their requirements in various regulations and standards. The main focus is on the NORSOK D-010 (2013). A well barrier is a safety barrier used in the petroleum industry, and can be related to various well operations. The safety barrier is important to reduce the risk of accidents.

Sklet (2005) defines a safety barrier and the barrier function as:

Safety barriers are physical and/or non-physical means planned to prevent, control or mitigate undesired events or accidents.

A barrier function is a function planned to prevent, control, or mitigate undesired events or accidents.

Within the petroleum activities on the Norwegian Continental Shelf (NCS), the PSA governs the regulations concerning health, environment, and safety. PSA has developed requirements to the safety barriers, and the main features are reproduced in Section 2.5. There are many ways to classify barriers, and one of them is illustrated in Figure 1.

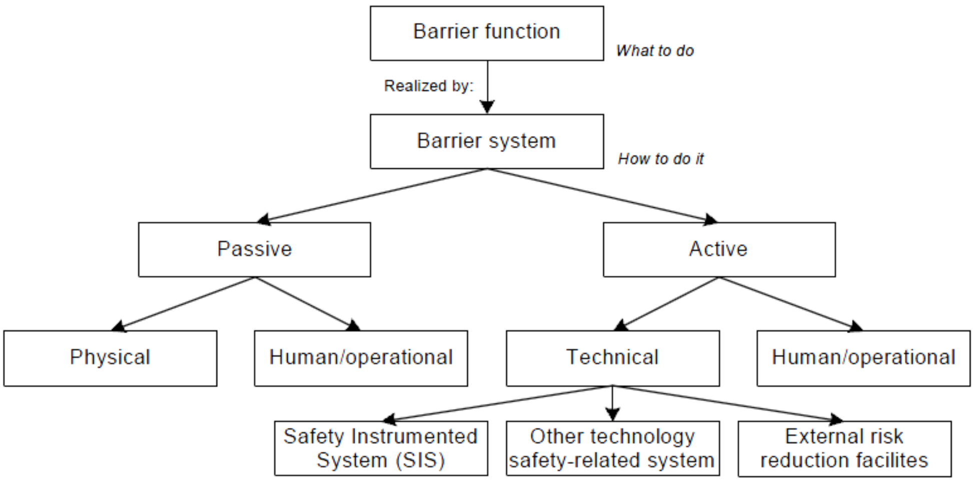


Figure 1: Classification of safety barriers (from Sklet, 2005).

The main objectives of a well barrier are according to Hauge et al. (2012):

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

2.2 NORSOK D-010

NORSOK D-010 (2013)**,** *Well integrity in drilling and well operations*, was developed with broad petroleum industry participation by interested parties in the Norwegian petroleum industry, and is owned by the Norwegian petroleum industry represented by the Norwegian Oil and Gas Association and the Federation of Norwegian Industries.

The standard focuses on establishing well barriers by use of *well barrier elements* (WBE), their acceptance criteria, and their use and monitoring of integrity during their life cycle. Testing procedures and operational requirements are described in the standard to ensure the quality of the WBEs. NORSOK D-010 (2013) contains 59 acceptance tables, representing the various WBEs. These include how to perform initial testing and verification, description of the functionality of the barrier element, design criteria, proper use and monitoring, and potential failure modes. The acceptance tables are based on API-, ISO-, and NORSOK standards. In this current version of the standard, more safety enhancements have been included, which will have an impact on the future well design.

NORSOK D-010 (2013) defines a well barrier as “an envelope of one or several well barrier elements preventing fluids from flowing unintentionally from the formation into the wellbore, into another formation or to the external environment”. A WBE is referred to as “a physical element which in itself does not prevent flow but in combination with other WBE`s forms a well barrier”.

Well integrity is an important topic when it comes to drilling, and other well operations. In this standard, well integrity is defined as “an application of technical, operational, and organizational solutions to reduce the risk of uncontrolled release of formation fluids throughout the life cycle of a well”.

According to NORSOK D-010 (2013) and PSA (2010) the well barriers shall be designed to prevent unintended influx and outflow to the external environment and designed so that their performance can be tested and verified.

OLF (2011) states that the well barriers shall be designed, manufactured and installed to withstand all loads they may be exposed to and maintain their function throughout the life cycle of the well. Further, the materials and functions should be selected to withstand the loads and environment to which the well barrier may be exposed, and the physical location and the integrity status/conditions of the barriers shall be known at all times. The well barrier can be defined in series or in parallel, as *primary* or *secondary*, temporary or permanent, active or passive, or as physical or non-physical (NORSOK D-010, 2013). Section 2.4 describes the primary and secondary barriers of a production well.

2.3 ISO/TS 16530-2

ISO/TS 16530-2, “Well integrity for the operational phase”, published in august 2014, is the most recent contribution to the subject of well integrity. The standard was developed by several companies together, for oil and gas. This is a technical specification (TS) with the intension of giving requirements and information to well operators in the petroleum and natural gas industry worldwide, on how to manage well integrity in the operational phase.

The TS must be seen as an addition to legal requirements, and not a replacement. All wells that are used by the oil and gas industry are included in the scope of this standard. This is regardless of age, type, or location. ISO/TS 16530-2 does not apply for work-over activities, or the periods during well intervention. The well intervention equipment required or used outside the well envelope for a wire-line or a coiled tubing operation are not included either.

Other standards in the same category includes ISO/AWI 16530-1, “Well integrity-Part 1: Life cycle governance manual” and the recommended practice API-RP-90, “Annular casing pressure management for offshore wells”.

Table 1 presents some barrier types. The table includes functions, how they are operated, and how their failures are observed. There are also other types of barriers, so these are only examples.

Table 1: Example of barrier types (from Holand, 1996).

Barrier type	**Description**	**Example**
Operational barrier	A barrier that functions while the operation is carried out. A barrier failure will be observed when it occurs.	Drilling mud, stuffing box
Active barrier (Standby barriers)	An external action is required to activate the barrier. Barrier failures are normally observed during regular testing.	BOP, X-mas tree, surface controlled subsurface safety valve (SCSSV)
Passive barrier	A barrier in place that functions continuously without any external action.	Casing, tubing, kill fluid, well packer
Conditional barrier	A barrier that is either not always in place or not always capable of functioning as a barrier.	Stabbing valve (WR-SCSSV)

2.4 Well barriers during production

Figure 2 shows a well barrier schematic, illustrating the primary and secondary well barriers with their barrier elements for a production well. The primary and secondary barriers are illustrated in blue and red, respectively.

Primary: This is the barrier closest to the pressurized hydrocarbons, and the first obstacle to unwanted flow of formation fluid.

Secondary: The secondary barrier acts as a backup barrier, and is located outside the primary barrier. This barrier will prevent outflow from the well if the primary barrier fails.

There may also be a tertiary barrier available to stop the flow of hydrocarbons, if the first two fails.

Appendix B provides a table describing the various primary well barrier elements, and their purpose. A similar table for the secondary well barrier elements is provided in Appendix C. Both are related to the production well shown in Figure 2, and the information has been found in NORSOK D-010 (2013).

The well barrier elements in-situ formation, casing cement and casing which act as a secondary well barrier in Figure 2, are listed in the table for the primary elements in Appendix B, because of their similarity to these elements.

There are typically two main types of barriers:

- *Static* barriers
- *Dynamic* barriers

A static barrier is in place over a "long" period of time, and applies typically during production/injection. Dynamic barriers vary over time, such as for well drilling and intervention. In this part of the thesis, the static barriers are considered. Barriers present in a production well are identified and described. The dynamic barriers are further discussed in Chapter 4.

PSA (2010) suggests that the performance of a well barrier may be characterized by its:

- *Functionality/efficiency*: the ability to function as specified in the design requirements.
- *Reliability/availability*: the ability to function on demand or continuously.
- *Robustness*: the ability to function as specified under given accident conditions.

2.5 Requirements

Laws and regulations dictate the requirements that the industry has to follow. Different rules exist in countries all over the world. In Norway, the regulations are governed by the PSA. PSA gives requirements in their regulations, but also refers to recognized guidelines and standards for more detailed requirements. Key requirement can be found in standards and guidelines, such as NORSOK D-001(2012), NORSOK D-010 (2013), OLF (2004), and API-RP-53 (2012).This section, lists the requirements from PSA and NORSOK D-010.

Well barrier requirements from PSA (2010):

- Well barriers shall be designed such that well integrity is ensured and the barrier functions are safeguarded during the well's lifetime.
- Well barriers shall be designed such that unintended well influx and outflow to the external environment is prevented, and such that they do not hinder well activities.

- When a production well is temporarily abandoned without a completion string, at least two qualified and independent barriers shall be present.
- When a well is temporarily or permanently abandoned, the barriers shall be designed such that they take into account well integrity for the longest period of time the well is expected to be abandoned.
- When plugging wells, it shall be possible to cut the casings without harming the surroundings.
- The well barriers shall be designed such that their performance can be verified.

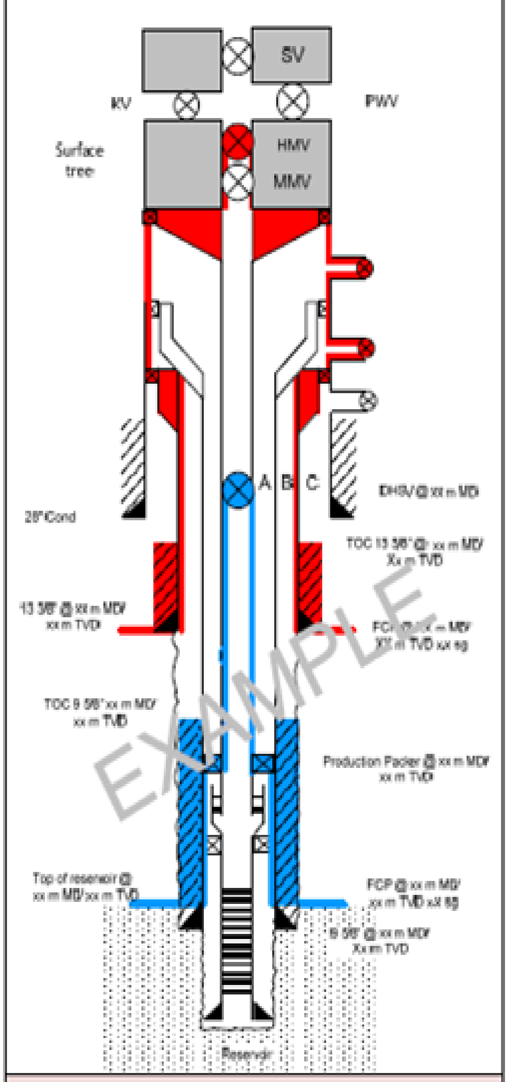
According to NORSOK D-010 (2013) the well barriers shall be designed, selected and constructed with capability to:

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

On the NCS all the operating companies are obliged by the regulations to have a management system. This system should reflect how the various activities are carried out, and how the companies operate. The companies also need a system to control the health, safety and environmental (HSE) level of their operations. A system for managing the well integrity for all the operators' wells during their life cycle, is also required on the NCS. The intension is to control and reduce the risk.

Competence and training requirements for personnel are specified in NORSOK D-010 (2013), and in the regulations.

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



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

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

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

Figure 2: Well barriers, production (from NORSOK D-010, 2013).

2.6 Comparison of regulation regimes

To demonstrate some differences in how to regulate, a study conducted by Det Norske Veritas (DNV), now DNV GL, has been considered. The study, (DNV, 2010), mapped the differences in regulations between the NCS and the US (Gulf of Mexico). DNV performed the study after the Deepwater Horizon accident, and was a neutral and technical comparison. A summary is presented in Table 2.

Table 2: Main differences in regulation regimes.

Main differences	
NORWAY	**US**
Mainly function based, where security and performance criteria are set, and with supplementary prescriptive requirements.	Mainly prescriptive.
Mainly risk based, meaning activities are always built on identified risks. Working to reduce risk levels, and priorities should reflect current risk levels.	No such requirements.
The health, safety and environmental management , and the resource management are controlled by different authorities.	Both handled by the same authority (April 2010).
PSA has a coordinating role in the development and monitoring of the implementation of HSE regulations.	No coordinating authority.
The operating company has the responsibility that all petroleum activities are following the given regulations.	Operator and the government sharing the responsibility of petroleum activities.

Chapter 3

Well Barrier Diagrams

3.1 Introduction

To assess oil well integrity, the oil and gas industry has used barrier diagrams, also called *well barrier diagrams*, for several decades. This chapter presents different approaches to illustrate these types of diagrams. Safety barrier diagrams are another name used in this chapter. Based on a selected oil/gas well operation, a well barrier diagram has been established.

3.2 Approaches

There are many different ways to illustrate the role of well barriers and their role in acting upon and preventing leakages. We can distinguish between:

- *Well barrier schematics (WBS)*
- Barrier diagrams

A WBS is a static illustration of the well and its main barrier elements. The various elements are marked with different colors. In Figure 2 in Section 2.4, a WBS is shown for a production well.

In Hauge et al. (2012) we can read that a well barrier diagram is a network illustrating all the possible leak paths from the reservoir to the surroundings. The meaning of the term surroundings depends on the situation. It may be the external environment, e.g., the sea for a subsea well. Well barrier diagrams are best suited for static situations, such as wells in production. An example of a well barrier diagram of such a situation has been made, and is shown in Section 3.3.

Different approaches to illustrate the possible leak paths exist. One option is to draw a horizontal diagram going from left to right, from reservoir to the surroundings. A selected example is shown in Figure 3. Appendix D provides a well diagram showing possible leak paths.

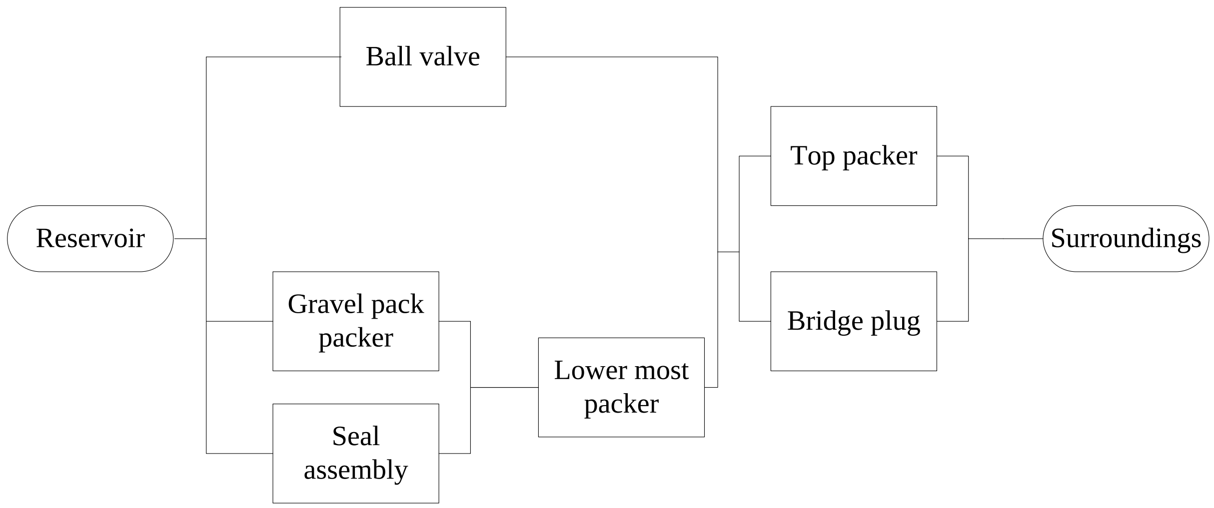


Figure 3: Barrier diagram for a temporary abandoned production well (from Holand, 1996).

A more common option is to draw a vertical diagram, from reservoir at the bottom to the surroundings at the top. This is the type of diagram used for the selected operation in Section 3.3 of this thesis. *Fault tree* (FT), *event tree* (ET) and *Bow-tie* can also be used for illustration. Regardless of which option selected, the logic of the diagram should be the same.

Duijm and Markert (2009) define a safety barrier diagram as:

"A graphical presentation of the evolution of unwanted events (initiating events or conditions) through different system states depending on the functioning of the safety barriers intended to abort this evolution."

The main objectives of a safety barrier diagram according to Rausand (2011) are:

- Identify barriers that are (or should be) present in a specified accident scenario (i.e., an event sequence from an initiating event or cause to a final consequence).
- Illustrate the sequence in which the various barriers are to be activated.
- Identify safety barriers that are common for several accident scenarios.
- Identify hazards for which protection is inadequate.
- Verify the adequacy of the existing barriers and indicate where improvements are needed.

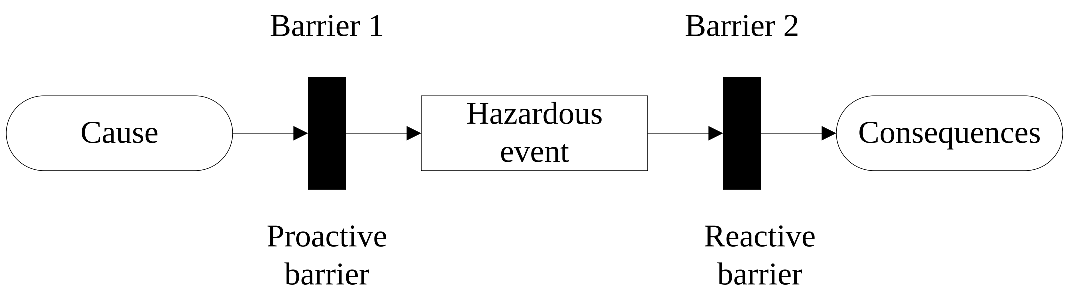


Figure 4: Example of safety barrier diagram (from Rausand, 2011)

In Figure 4 the basic elements of a safety barrier diagram are illustrated. These types of diagrams have similarities to both a FT and a FT, using the same logic. The safety barrier diagrams are easier to understand by non-experts because basic events and logic related to the functioning of the safety barriers are encapsulated in a single item. This causes fever symbols in a graph, and better to interpret. The different barriers are drawn as a rectangle. On the left-hand side of a barrier, we find the condition or event which triggers the barrier to function (condition on demand). On the right-hand side of the barrier, is normally the condition when the barrier has failed (condition on failure). Apart from this, one can also define other conditions on this side, typically the condition of success can be included, if that condition is not a normal (safe) state. The diagram shows possible accident scenarios. When a barrier is successful, the scenario stops there. If the barrier fails, the diagram shows the next barrier. This can go on until all the barriers have failed, and the accident occurs (Duijm and Markert, 2009).

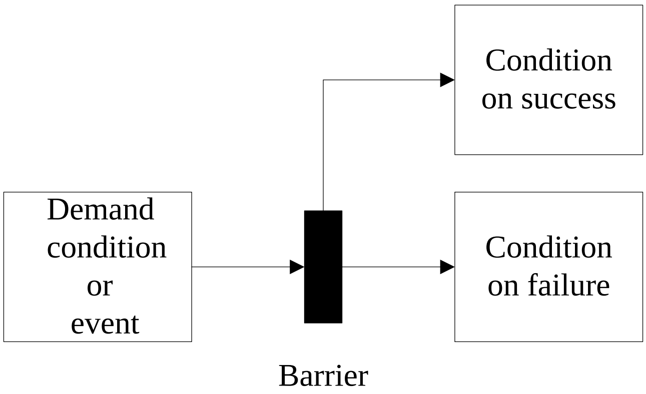


Figure 5: Graphical presentation of a safety barrier in safety-barrier diagrams with two output conditions (from Duijm and Markert, 2009).

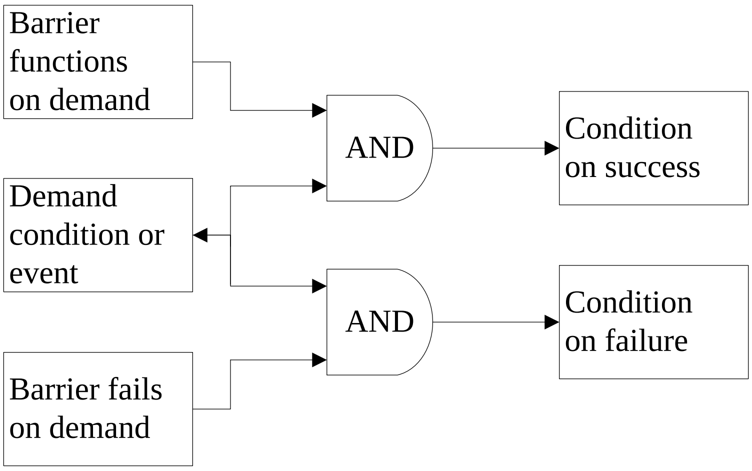


Figure 6: Representation of the barrier from Figure 5 by means of a FT (from Duijm, 2009).

In Figure 6, the barrier is represented by an AND gate. If both inputs are positive we will get a positive ("true") outcome, and only then. The inverted value of the statement "barrier fails on demand" is "barrier functions on demand". This means that if one of them is true, the other is false and vice versa. Among the main advantages of a barrier diagram compared to e.g., FT or ET is the relative simplicity. In Figure 6, a new input condition ("barrier works") and a logical gate are introduced to be able to show the condition on success.

In Corneliussen (2006) another method for constructing barrier diagrams is being presented. In his doctoral thesis the author uses a typical oil production well with the x-mas tree located on the surface as a basis, shown in Figure 7.

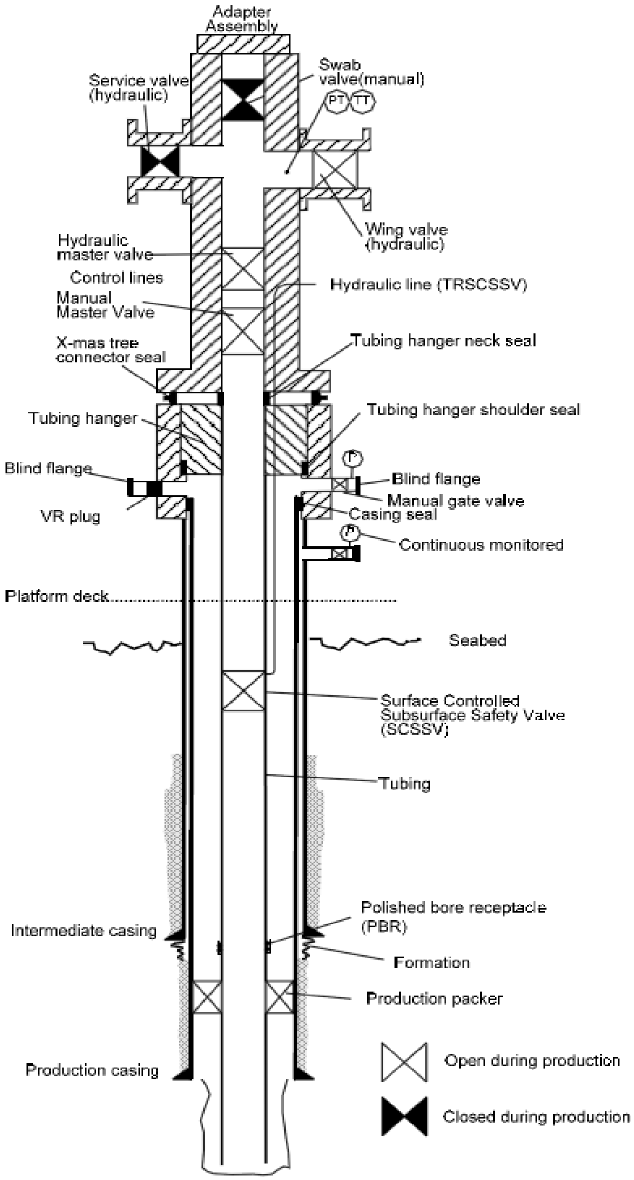


Figure 7: Example well (from Corneliussen, 2006).

A well barrier is regarded as a pressurized vessel (envelope), with the capability of containing the reservoir fluids. The well in Figure 7 is considered as several pressurized vessels (envelopes) preventing the fluid from entering the surroundings. This is illustrated in Figure 8.

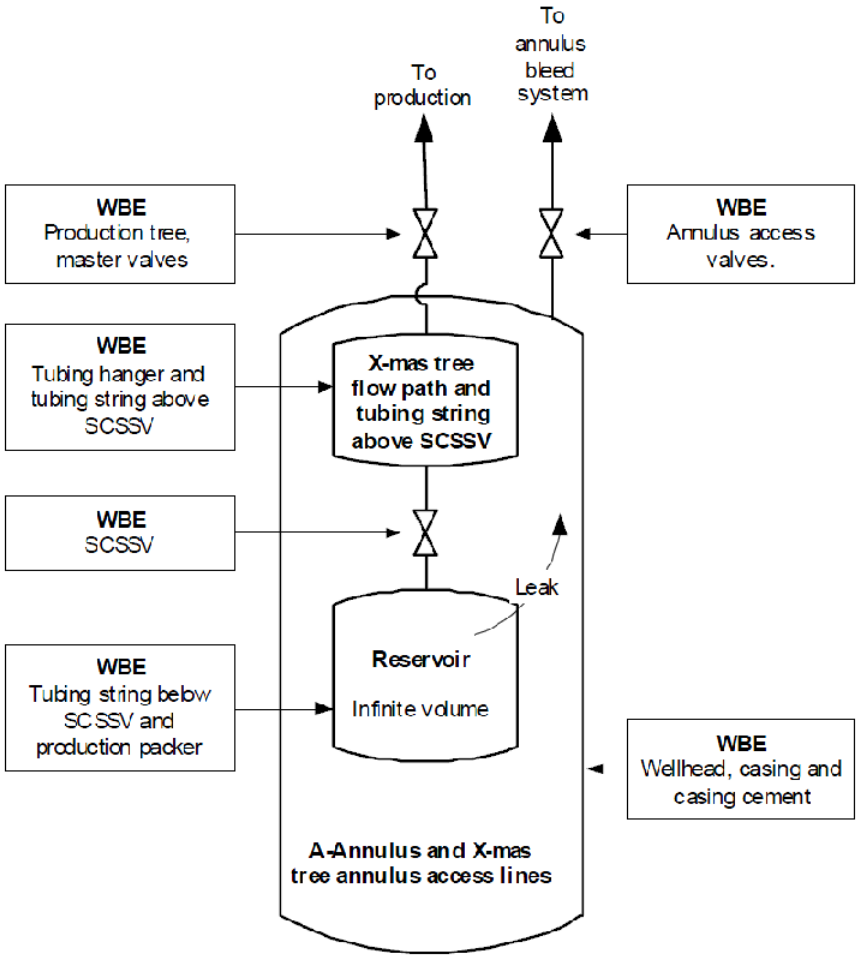


Figure 8: Well illustrated as several vessels (from Corneliussen, 2006).

The primary barrier, closest to the reservoir, is illustrated as the outlet valve in Figure 8. This is the innermost vessel with the SCSSV. The outer vessels illustrate the consecutive well barriers.

According to (Corneliussen, 2006) the main construction steps of this type of barrier diagram are:

1. *Define the hazardous event.*

   Before constructing the diagram, the hazardous event and the WBEs available to prevent it are clearly defined.

2. *Define cavities ("the pressurized vessels") where the pressure can be trapped between the reservoir and the surroundings.*

   In this step all the "pressurized vessels" surrounded by WBEs able to contain the reservoir fluids are identified.

3. *Identify the WBE failure modes and corresponding leak paths.*
   This step includes, as the headline implies, identification of all WBEs failure modes and their corresponding leak paths.

4. *Identify the fault tolerance of the well system.*
   The fault tolerance of the well is indicated by the number of WBE failures which must occur before having an uncontrolled leak (from reservoir to surroundings). This tolerance is defined by IEC 61508.

5. *Identify barrier vectors.*
   Intermediate step which includes identification of barrier vectors. This vector describes the start and end point (cavity) for each leak path.

6. *Identify minimal cut sets.*
   The vectors found in step 5 are used here to identify the minimal cut sets of the well system.

7. *Calculate leak probabilities.*
   Using the cut sets from step 6, approximate formulas can be used to calculate this probability.

The diagram is used to illustrate the structural relationship between well barriers. Construction rules are presented in seven steps, listed above, and there are also proposed five guidelines for validation of the barrier diagram. These guidelines are not listed in this thesis.

3.3 Barrier diagram for an oil/gas producing well

This section presents a new suggested version of a vertical barrier diagram. The well barrier diagram in Figure 10 is based on the production well in Figure 2, from Chapter 2. In this approach all the primary barriers have been assembled, and all the secondary barriers placed together. Arrows are used to point out the various pathways between the barriers, different annuli, to the surroundings.

The names used for the various well barriers elements in the diagram, refers to the ones used in Figure 2, but some names are changed. The completion string has become the c.string, and the wellhead/annulus access valves are now referred to as wellhead in Figure 10.

Some assumptions have been made before drawing the diagram:
The chemical injection valve (CIV) has not been included, because it is the same as consider leakage from under the downhole safety valve (DHSV) to the A-annulus. Because of its small diameter, the control line from the DHSV is also ruled out from the diagram. Cap rock is assumed to be impermeable, so there will be no leakage outside the casing-program. Only leak paths going inside out, are considered (e.g., from A-annulus to B-annulus, and not back from B to A). The 9 5/8” casing, above and below the production packer, are emerged to one “box” called 9 5/8” casing. It is here assumed that there will be plenty of good cement and no leakage through it. Figure 9 explains symbols and colors used in the well barrier diagram.

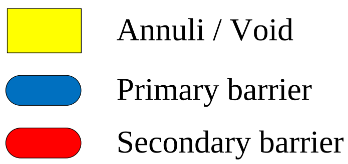


Figure 9: Symbol and color description for the well barrier diagram.

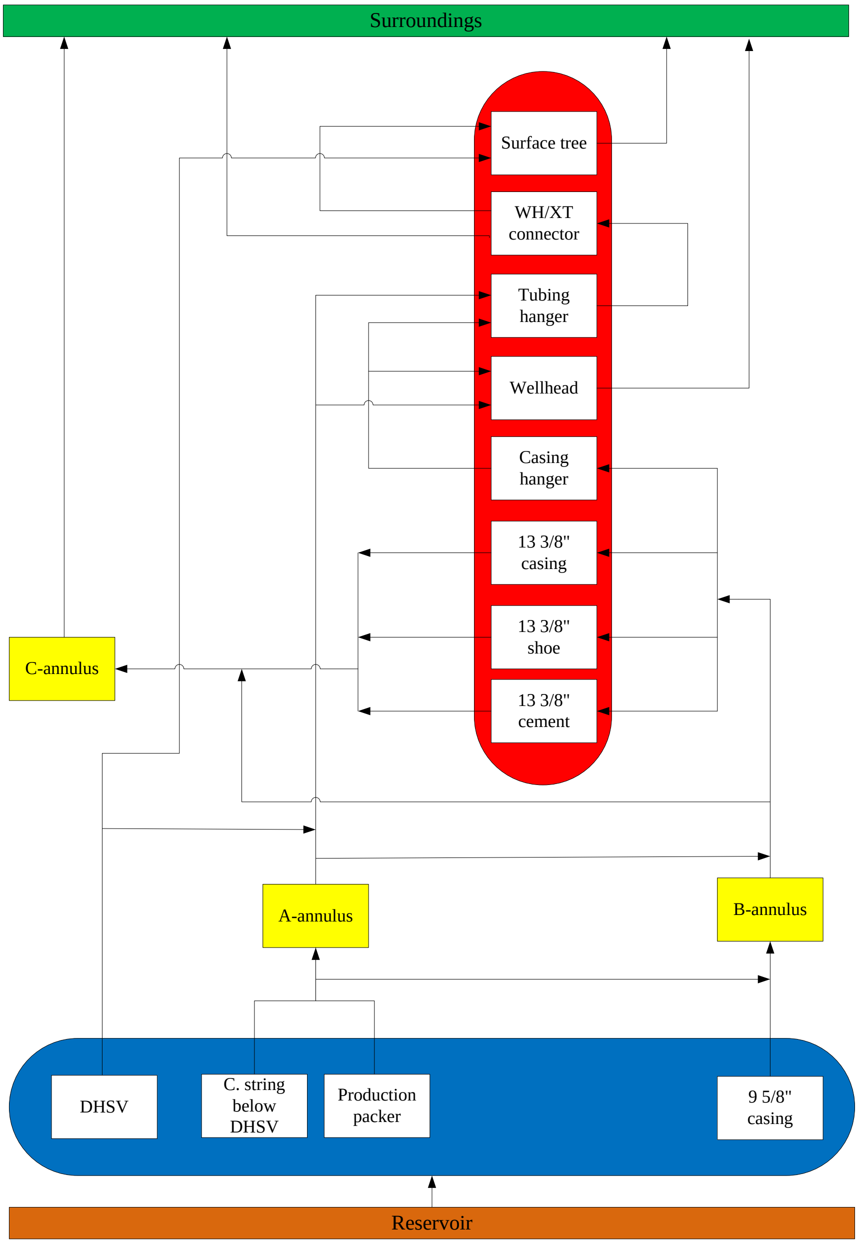


Figure 10: Well barrier diagram for a selected well.

Chapter 4

Dynamic Well Barriers during Drilling

4.1 Introduction

This chapter deals with dynamic well barriers. The main focus is on barriers during drilling. Both overbalanced /conventional drilling (OBD) and underbalanced drilling (UBD) are considered, with the main focus on OBD. In designing and execution of the drilling process, inflow prevention/inflow control is an important factor. The keyword is *pressure control*, control of the down-hole pressure.

NORSOK D-010 (2013) specifies the following:
"There shall be two well barriers available during all well activities and operations, including suspended or abandoned wells, where a pressure differential exists that may cause uncontrolled outflow from the borehole/well to the external environment."

The primary barrier during drilling activities is the mud column and its hydrostatic pressure (Ph). The secondary is the blowout preventer (BOP) combined with the casing and wellhead. These barriers are illustrated in Figure 12 and apply for OBD operations. When drilling the top hole for the conductor and the surface casing, this can according to NORSOK D-010 (2013) be done with the mud column as the only well barrier. Further, one of the secondary barriers, the BOP, must be installed prior to drilling out the surface casing.

The principle of modern rotary drilling

A rotary drilling method is used when drilling modern oil and gas wells. The three main ingredients are according to (Rigpass, 2012):

- Rotating torque on the drill-bit.
- Axial force on the drill-bit.
- Fluid circulation to clear the cuttings from the bit, and remove them from the wellbore.

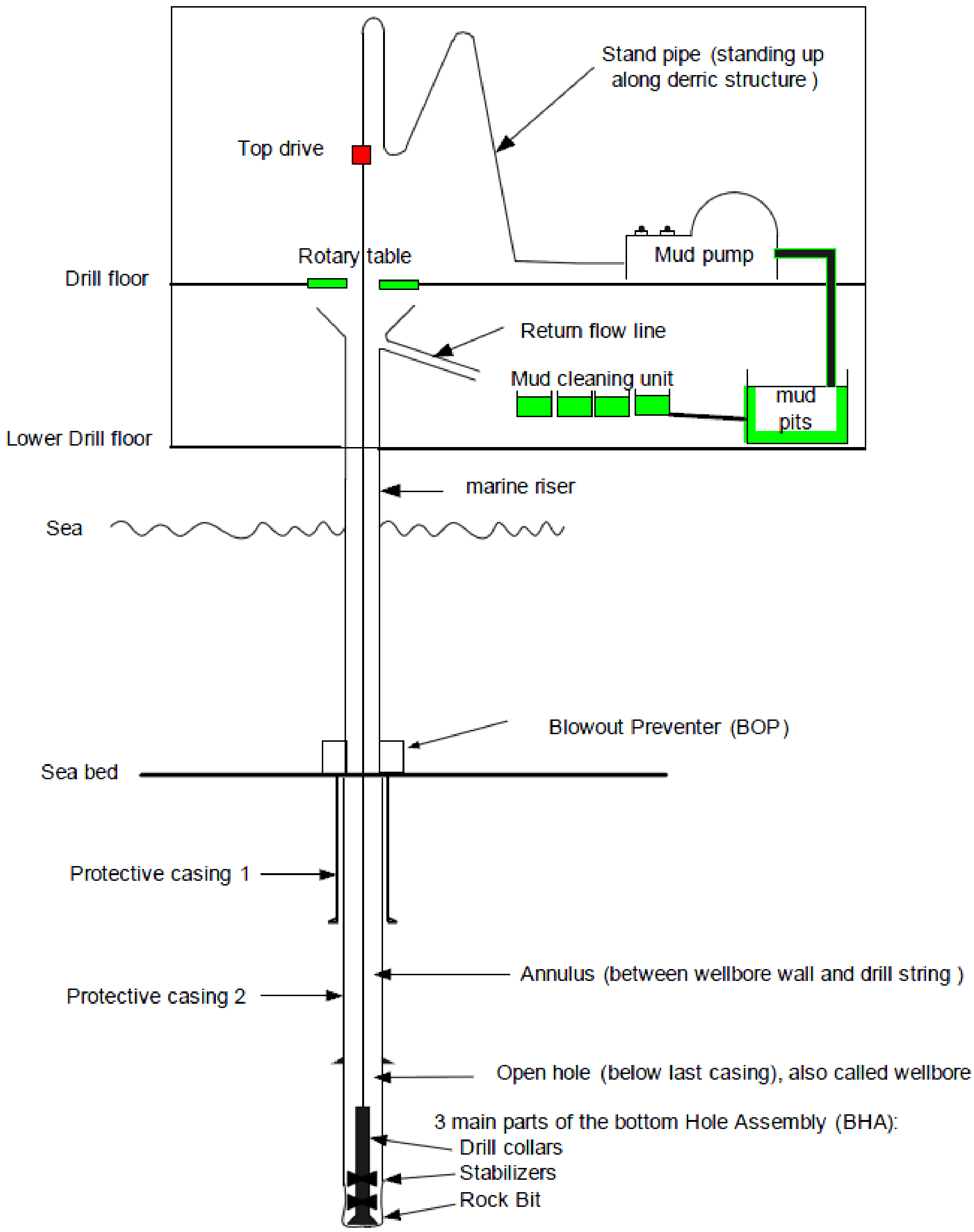


Figure 11: The drilling process (from Skalle, 2011).

Figure 11 illustrates a typical drilling process with its various components. The well is drilled by the teeth of the drill-bit (rock bit). Different types of energy are transmitted to the drill bit to able the crushing of the rock, and removal of the cuttings from the well. The drill-string and the drill collars create a downward force, the mud flows down inside the drill-string rotating the drill-bit (mud motor), and also helps to get the cuttings away from the wellbore.

4.2 OBD

4.2.1 Primary barrier

The mud column is the first line of defense against a blowout using OBD. Many drilling problems are due to situations or conditions that occur after drilling begins. The mud may not be designed for this, causing problems. By adjusting the properties of the mud, some of these problems can be solved. Most common is to change weight or density of the mud. Weighting materials are added when high-pressure formations are expected. In conventional drilling, wells are drilled overbalanced. Table 3 shows that the purpose of the mud column is to exert a Ph, which will prevent influx of formation fluid, and by that prevent a kick. If the well pressure falls below the pore pressure (Pp), reservoir fluids or gas will leak into the well. This is called an *influx*, and if this is above a certain size, we will get what is termed a *kick*. This may lead to a blowout, if not handled properly. Kick-handling and causes of kicks are further discussed in Chapter 6.

Hydrocarbons (HC) should not be able to flow out or into the well as long as the Ph exerts pressure on the formation that is higher than the Pp. When Ph > Pp, the well is said to be *overbalanced.* If this is not the case, the well is *underbalanced.* This means that the mud column is no longer capable on its own to prevent inflow of HC.

The hydrostatic pressure can be calculated from the formula:

$Ph = \rho g h$

Where ρ = fluid density [$\frac{kg}{m^3}$]

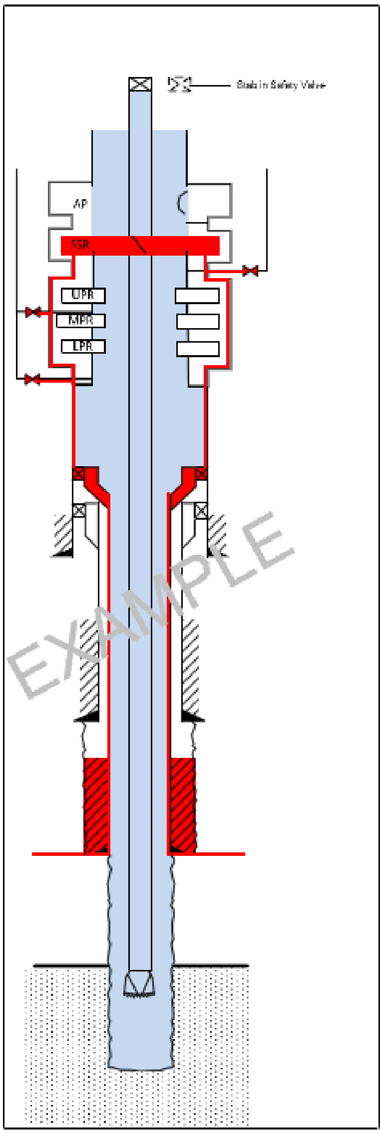
g = gravity [$9.8\frac{m}{s^2}$]

h = height, which is here the true vertical depth (TVD). [m]

Table 3, shown below, includes a description and the purpose of the primary barrier element during OBD, based on Figure 12.

Table 3: Primary well barrier. OBD.

Well barrier element	**Description**	**Function/Purpose**
Fluid(mud) column	The fluid in the wellbore.	To exert a hydrostatic pressure in the wellbore that will prevent well influx/ inflow (kick) of formation fluid.



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
Fluid column	1	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Wellhead	5	
High pressure riser	26	
Drilling BOP	4	

Figure 12: Well barriers, OBD (from NORSOK D-010, 2013).

For conventional drilling, Ph must be higher than Pp to avoid influx, but also below the fracture pressure. The Ph must be somewhere between the purple and blue line shown in Figure 13. This figure shows that with increased water depth the margin *m* between the pore pressure and the fracture pressure gradients reduces, and by this more casings are needed.

Usually, the Pp increases with depth, and is said to be normal when it is equal to the pressure of a column of water extending from the formation to the surface (Rigpass, 2012). The geological conditions determine if the Pp are subnormal or higher than the normal formation pressure.

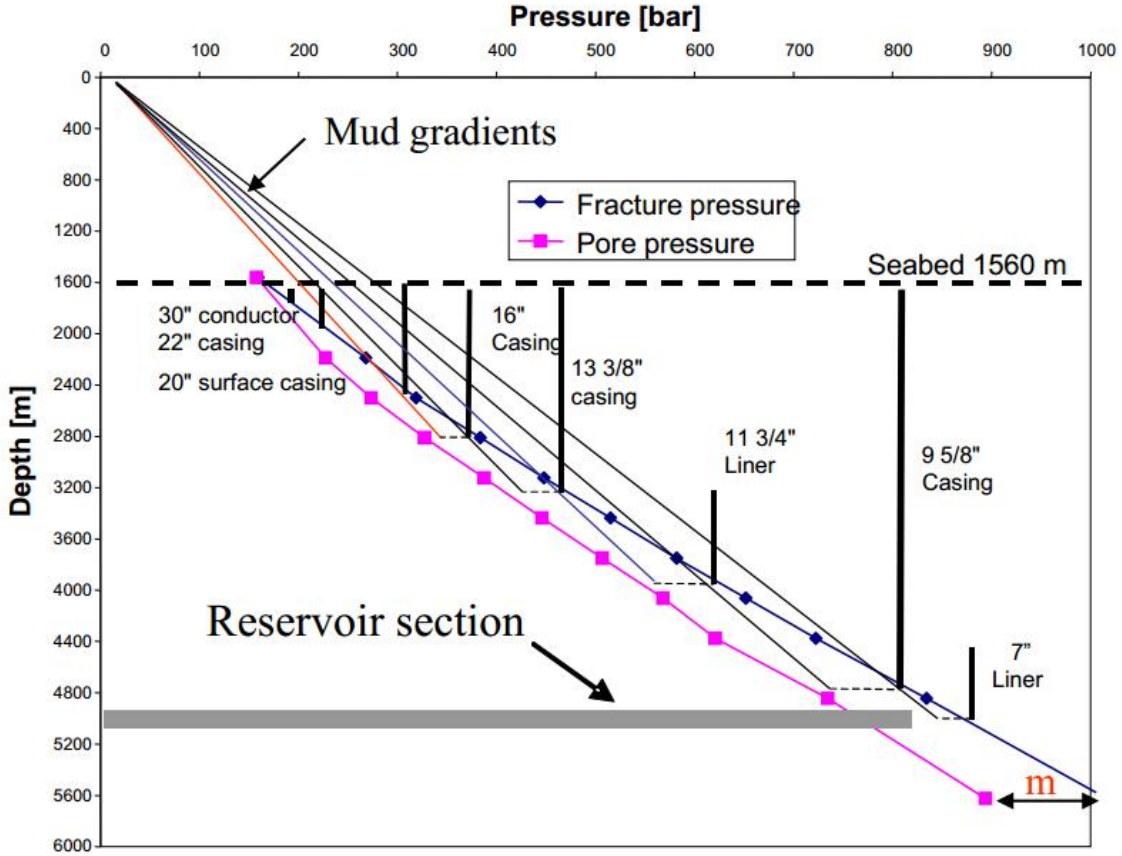


Figure 13: Typical casing program using a 18 ¾" wellhead system (from TPG 4200, 2012).

A leak off test (LOT) determines the fracture pressure. This test is also called a formation intake strength test, and is carried out at the casing shoe. The purpose is to investigate the wellbore capability to withstand pressures immediately below the casing shoe. By doing this, a proper well planning can be done with regard to safe mud weight, and to determine the setting depth of the next casing. When abnormal pressure is expected further down, this is especially important. Conducting a LOT is important to prevent lost circulation, which is a cause of kick, further described in Chapter 6. The procedure on how to conduct a LOT is further described by Skalle (2011).

Formation integrity test (FIT) is typically used to test the strength of the formation and the casing shoe. This is done by increasing the BHP to designed pressure, but not to break the formation.

4.2.2 Mud circulation system

An important function of the circulation system, both in OBD and UBD, is to control or eliminate the inflow of formation fluid into the wellbore during drilling operations. Drilling fluid is referred to as mud.

The mud circulation system in OBD consists of high pressure pumps, which pump a drilling fluid with proper density into the drill-string to overbalance the Pp.
The fluid goes down the drill-string, through the nozzles in the drill-bit, and back to the platform through the annular space between the drill-string and the borehole wall (annulus). On its way back to the surface, the fluid carries the formation cuttings upwards. At the surface, the fluid leaves the wellbore at an atmospheric pressure. Before being pumped back into the wellbore, the fluid goes through a cutting removal and mud condition system.

To maintain the primary barrier, the availability of the mud circulation system is very important. This is more or less a continuously running system, and a failure while running may cause a kick. This might be a pump failure, or mud with the wrong quality. If this is the case, the kick might develop into a blowout because of unavailability to circulate the mud. Circulating and controlling a kick in OBD can be a critical issue due to the limited capacity of surface facilities to handle a large quantity of produced HC evacuated from the wellbore. In UBD operations the flow of reservoir fluids into the wellbore and their circulation and evacuation at the surface, is a normal situation. Causes of kick`s, and how to handle them are further outlined in Chapter 6.

4.3 Drilling fluids

4.3.1 Purpose of drilling fluids

Drilling fluids suit several purposes. When heat is generated by the friction as the bit drills into the rock formation, the circulating mud dissipates the heat and also lubricates the bit. Another important function is the removal of cuttings. Mud transports the cuttings to a treating equipment where the cuttings are removed, and clean mud is again ready to be pumped down the drill-string. Sometimes, the mud circulation is lost or has to be stopped. In these cases, it is important to avoid the suspension of cuttings at the bit, as this may cause the drill-pipe to be stuck. The mud must have a gelling like characteristics to prevent this. Cuttings brought to the surface can tell what kind of formation being drilled, and the mud acts as a “data source”. The mud also creates an impermeable filter cake during drilling, which gives temporary support to the wall of the borehole.

4.3.2 Types of drilling fluids

Drilling fluids have complicated flow behavior, and can be referred to as "programmable fluids". They need to be thin with low resistance to be able to flow inside the long drill-string. Upwards in the annulus, they need to be thick and viscous to allow lifting and carrying of the cuttings. On the surface, the fluids needs to be thin again to make it easier to separate the cuttings, and also for making the pumping back into the drill-string more efficient (Rigpass, 2012).

There are several different types of drilling fluids, based on both their composition and use. The drilling fluid can be air, foam (a combination of air and liquid) and liquid. Liquid drilling fluids are as mentioned earlier, commonly called drilling mud. Drilling fluids, especially the mud, can have a wide range of chemical and physical properties. Which type of fluid to select depends on anticipated well conditions or on the specific interval of the well being drilled. Cost, technical performance and environmental impacts are also factors being considered. Water-based fluids are the most common, and used to drill approximately 80% of all wells. Oil-based and synthetic-based fluids are two other categories of drilling fluids being used.

4.4 Secondary barriers

Table 4 gives a description and the purposes of the secondary barrier elements during OBD, based on Figure 12.

Table 4: Secondary well barriers. OBD.

Well barrier element	Description	Function/Purpose
In-situ formation	The formation that has been drilled through and is located beside the casing annulus, isolation material or plugs set in the wellbore.	To provide a permanent and impermeable hydraulic seal preventing flow from the wellbore to surface/seabed or other formation zones.
Casing cement	Consists of cement in solid state located in the annulus between concentric casing strings, or the casing/liner and the formation.	To provide a continuous, permanent and impermeable hydraulic seal along hole in the casing annulus or between casing strings, to prevent flow of formation fluids, resist pressures from above or below, and support casing or liner strings structurally.

Well barrier element	Description	Function/Purpose
Casing	Consists of casing/liner, and/or tubing in case tubing is used for through tubing drilling and completion operations.	The purpose of casing/liner is to provide an isolation that stops uncontrolled flow of formation fluid or injected fluid between the casing bore and the casing annulus.
Wellhead	Consists of the wellhead body with annulus access ports and valves, seals and casing hangers with seal assemblies.	To provide mechanical support for the suspending casing and tubing strings and for hook-up of risers, or BOP or tree, and to prevent flow from the bore and annuli to formation or the environment.
High pressure riser	Consists of the riser including connectors and seals connecting the drilling BOP to the wellhead.	To act as an extension of the drilling BOP on platforms where the BOP and wellhead are positioned at different levels and thus prevent flow from the bore to the environment.
Drilling BOP	Consists of the wellhead connector and drilling BOP with kill/choke line valves.	The wellhead connector shall prevent flow from the bore to the environment, and provide a mechanical connection between drilling BOP and the wellhead. The function of the BOP is to provide capabilities to close in and seal the wellbore with or without tools/equipment through the BOP.

Key requirement can be found in standards and guidelines such as NORSOK D-001(2012), NORSOK D-010 (2013), OLF (2004), and API-RP-53 (2012).

4.4.1 Blowout preventer

The BOP is a part of the secondary barriers during drilling. These are safety-related instruments used mainly for the purpose of stopping kicks. Because of the kick`s ability to damage the environment and cause accidents to people and assets, it is desirable to stop or at least reduce the severity. We can distinguish between a rig BOP and a subsea BOP. This chapter focuses on the subsea BOP.

The BOP is designed to stop the flow from the well by closing and sealing the well bore under all conditions, i.e., with or without tools/equipment through the BOP (NORSOK D-010, 2013). Several types of valves/preventers are required to satisfy all the design parameters.

The subsea BOPs have increased in weight and size over the last decades, this due to the amount of equipment and increased redundancy. Weight has become a restrictive factor when it comes to the addition of “nice to have” equipment and redundancy, this because of how much load the wellhead can withstand. The BOP is placed on the seabed, on top of the wellhead and below the riser. According to Skalle (2011), the strongest BOP equipment is rated to withstand a pressure of 15000psi (1060 bars) from below.

4.4.2 BOP stack configurations

We usually distinguish between the classical and the modern configuration. The classical represents the basic concept of the BOP. The composition of the stacks is different, depending on company policy, preferences, and location, but the functions of the components are the same. The numbers of rams used varies, together with the control- and the backup control system. Organizing the stack causes advantages and disadvantages either way being done. Different components are added or omitted depending on the pressure rating needed. Annulars are typically not rated as high as ram preventers. Several manufactures make the components in a BOP configuration, such as Cameron, Shaffer and Hydrill.

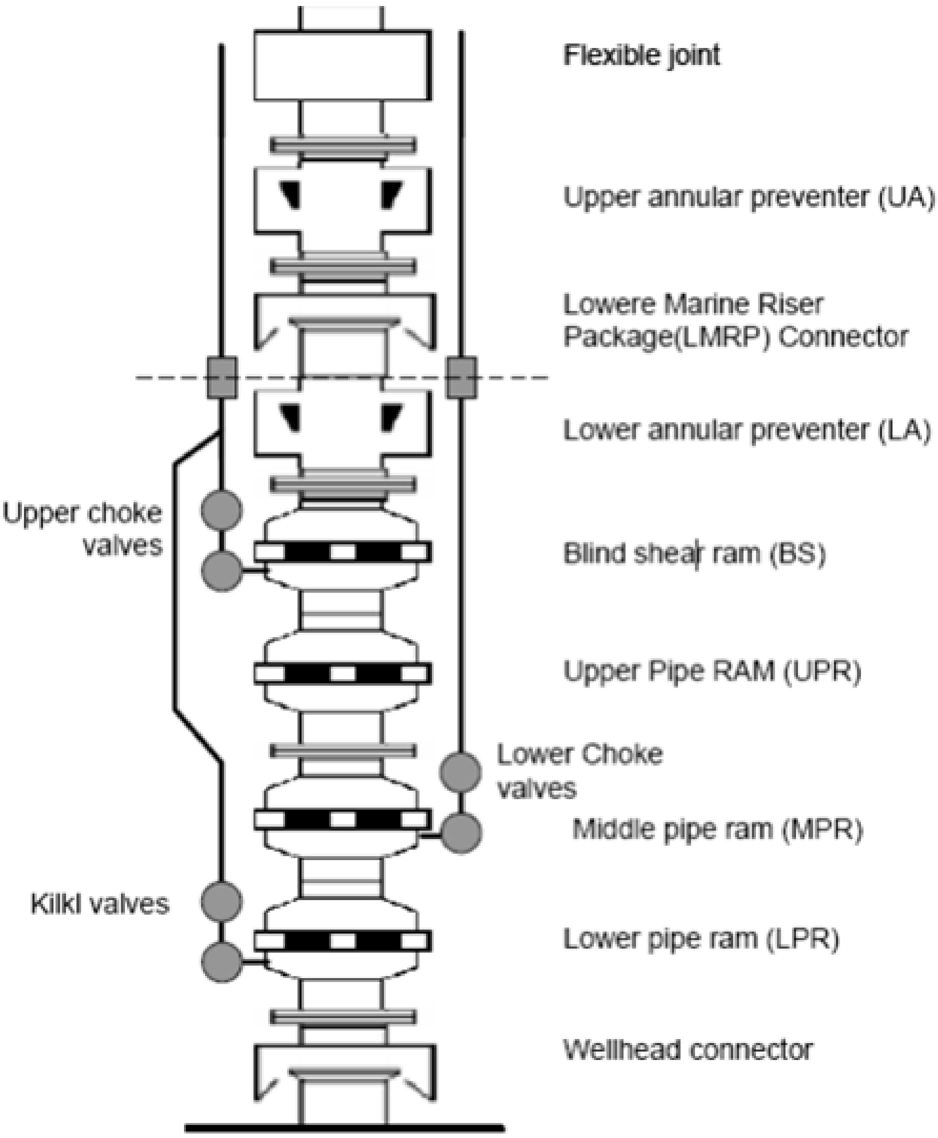


Figure 14: Classical BOP Stack (from Holand, 1999).

Figure 14 shows a typical classical BOP stack with six barrier elements. Seen from the top, there are two annular preventers, one upper annular preventer and one lower annular preventer. Further, there are one blind shear ram followed by three pipe rams, an upper pipe ram, middle pipe ram and a lower pipe ram. This classical stack is used constructing an event tree in Chapter 5.

4.4.3 Annular preventer

“A device that can seal around any object in the wellbore or upon itself. Compression of a reinforced elastomer packing element by hydraulic pressure effects the seal” (API-RP-53, 2012).

The *annular preventer* is a large valve used to control wellbore fluids. The sealing element in this type of valves resembles a large rubber doughnut. We usually find the annular preventer at the top of the BOP stack. These preventers are designed to seal off the annulus between the drill-string and the side of the hole. If a kick occurs while the pipe is out of the hole, the annular preventer may also seal off the open hole. The sealing element is mechanically squeezed by hydraulic force, and the flexibility of the doughnut allows the preventer to seal against many different shapes and sizes of tools in the well (drill-collar, drill-pipe, casing, or tubing). Retraction is also done using hydraulic fluid. It is possible to strip (move) the pipe in and out of the hole while closed. Annular preventers are often shut-in first due to their flexibility and position in the stack, but are not suited for holding in a kick for a long period of time alone.

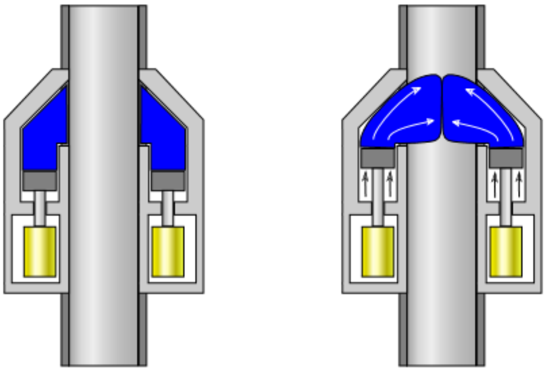


Figure 15: Annular preventer (from Wikipedia, 2014).

4.4.4 Ram Preventers

Normally, you will find *ram preventers* below the annular in the BOP stack. There are various types of rams, which are designed to perform different sets of tasks, but none are as flexible as the annular.

Pipe rams are designed to seal around the pipe to close the annular space. They work on a similar principle as the annular preventer. Separate rams are necessary for each size (outside diameter) pipe in use if not using a *variable bore ram*. The variable bore ram has the ability to close on pipes with different diameters.

Another type of ram preventer is the *blind ram*. This differs from the previous mentioned rams by its ability to seal on an open hole. They work in the same way, and the pressure from the hydraulic fluid pushes the flat opposing rams against each other to seal.

The *shear ram* preventer only have the capability to shear the pipe. These are made of hardened steel.

A type called *blind shear ram* is yet another type of preventer. This also possesses the ability to close an open hole. When there is no pipe in the hole, this ram works like the blind ram, but has cutting ability to shear off the pipe and seal the hole. Usually it can't shear the pipe joints/tool joint.

Finally, we have the *casing shear ram* which can shear the casing, but without sealing the wellbore.

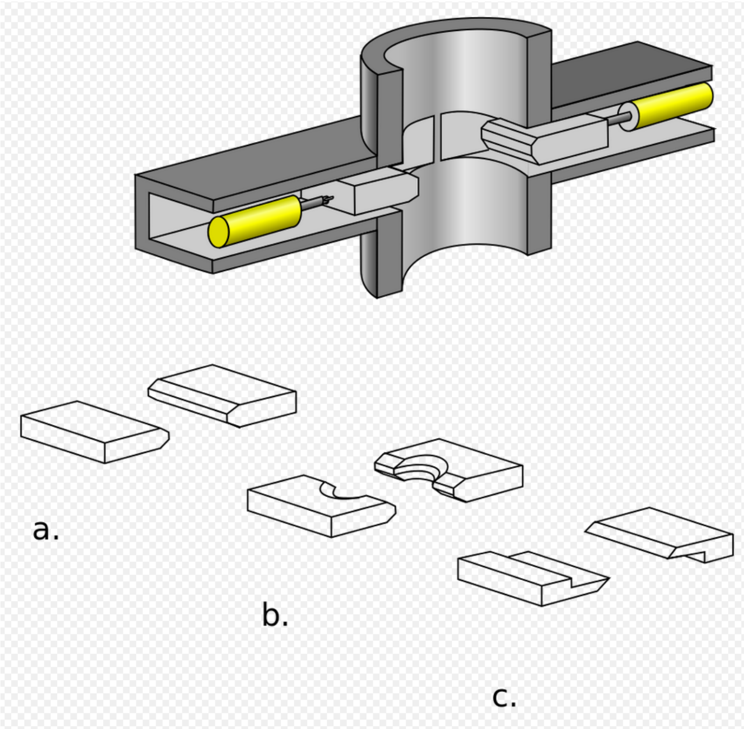


Figure 16: Illustration of the design for the blind ram (a), pipe ram (b), and the shear ram (c) (from Wikipedia, 2014).

From the description given about the annular and the pipe ram preventers, it is stated that they are designed to close the annulus when the drill pipe is in the hole. This means that a drill string safety valve (Kelly valve) is required to prevent flow from inside the drill string.

4.4.5 Flexible Joint

Due to different kind of weather, the drilling rig will move during drilling. This causes loads on the wellhead from the tension between the BOP-connection and the riser. A flexible joint is placed on top of the BOP to compensate for the applied movement, making it possible to drill under more difficult conditions. It allows angular motion up to 10 degree (NORSOK D-010, 2013). The joint consists of a metal housing with a large diameter, and with elastomeric element inside with two connectors.

4.4.6 Choke and Kill lines

When dealing with a well control event, the choke-line is used for circulating out the kick. The kill-line is used for pumping fluids into the well in a kick situation, and kill the well if necessary. This choke/kill system is also used during pressure testing of the BOP system. The attachment of the lines to the stack depends on the operator's preference, and type of stack being used. Choke/kill valves are used to close the choke/kill lines. Two failsafe valves are placed in series, and these are controlled by the BOP control system.

4.4.7 Test Ram

This device can be a part of the BOP stack, placed at the bottom of the BOP. The test ram is an inverted pipe ram, used in testing the element above it in the BOP stack with no pipe in the hole. It's designed to hold the pressure from above. Prior to the test ram, a plug was used. Setting and removing the plug was time-consuming, but still today many modern BOP stacks do not have a test ram.

4.4.8 Hydraulic connectors

The lower connector is between the BOP and the wellhead, and the upper connector is between the BOP and the lower marine riser package (LMRP). Their functions are to provide a mechanical connection between the mentioned parts, and prevent leakage to the environment. According to the Holand (2012) study, leakage in the wellhead connector is the most severe failure. Spurious opening of the LMRP was ranked second of the most severe failures reviled in the study.

4.4.9 Casing

The casings are the major structural component of a well. Steel tubular (casing strings) are run in hole to protect the formation and maintain the borehole stability. There are six basic types of casing strings in varying size, purpose, and placement in the well (see Figure 17). The handling process, composition, testing and qualification of casing connections are one of the most important key factors to casing integrity, together with what the connection threads are composed of.

Proprietary and API-connections are the two most commonly used connections in the oil industry today. The API-connections are designed in accordance with tolerances specified by The American Petroleum Institute (API), and the proprietary are designed by and manufactured by commercial manufactures. Proprietary connections are capable of handling higher pressure and temperature on greater depths compared with the connections from API.

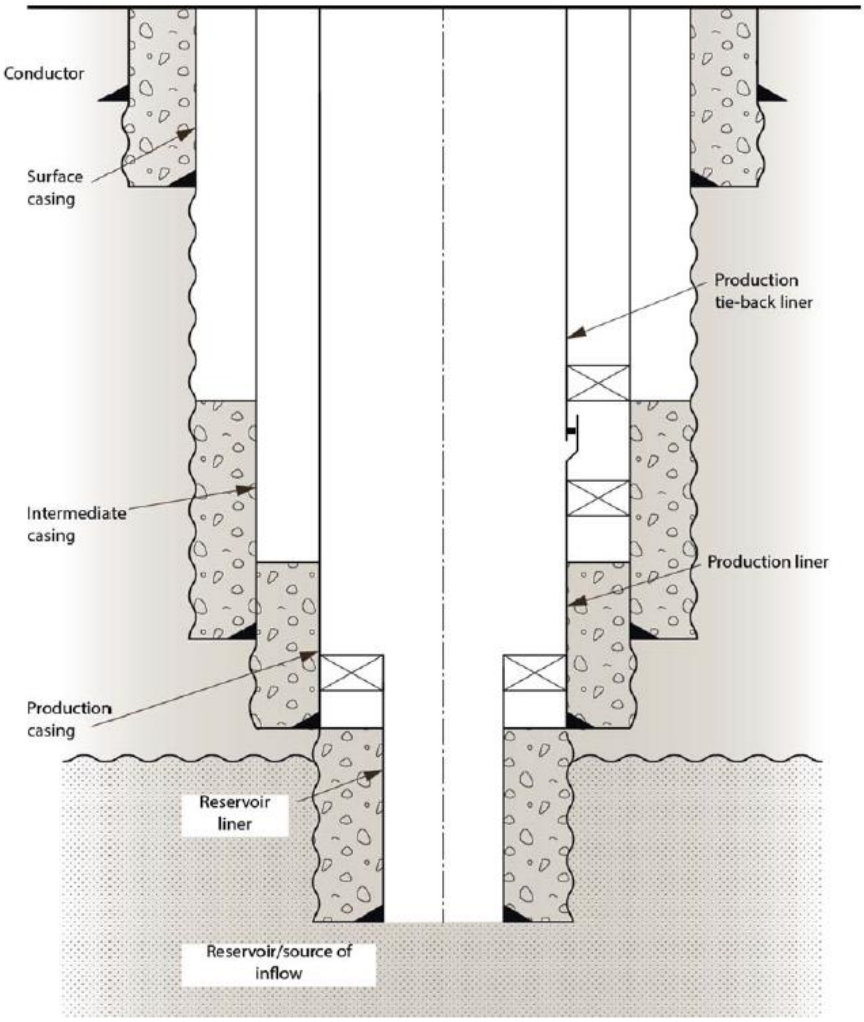


Figure 17: Casing illustration (from NORSOK D-010, 2013).

4.5 UBD

The pressure at the wellbore is maintained in a different manner when we go underbalanced. In OBD, the bottom-hole pressure (BHP) is determined by the mud density and the depth, this because the top of the column is not added any pressure except the atmospheric pressure. In UBD the BHP is controlled by a combination of the fluid density and the top column pressure.

$P_{bottom} = P_{top} + \Delta P_{Hydrostatic}$

This formula applies in a case where there is no flow. When the fluid is circulated, another element also needs consideration, the *flow friction.* In OBD the flow friction in the annulus is relatively small, and the Ph controls the wellbore pressure. However, in UBD the friction plays a much more important role because of the low Ph and the relatively light fluid being used. In these types of operations, the down-hole annulus pressure during circulation is controlled by a combination of back pressure at the surface, flow friction, and the hydrostatic fluid pressure.

$P_{bottom} = P_{top} + \Delta P_{Hydrostatic} + \Delta P_{Friction}$

However, if the mud is mixed with gas or formation fluids, the calculation of the BHP is becoming a more complex function, which will not be further discussed here.

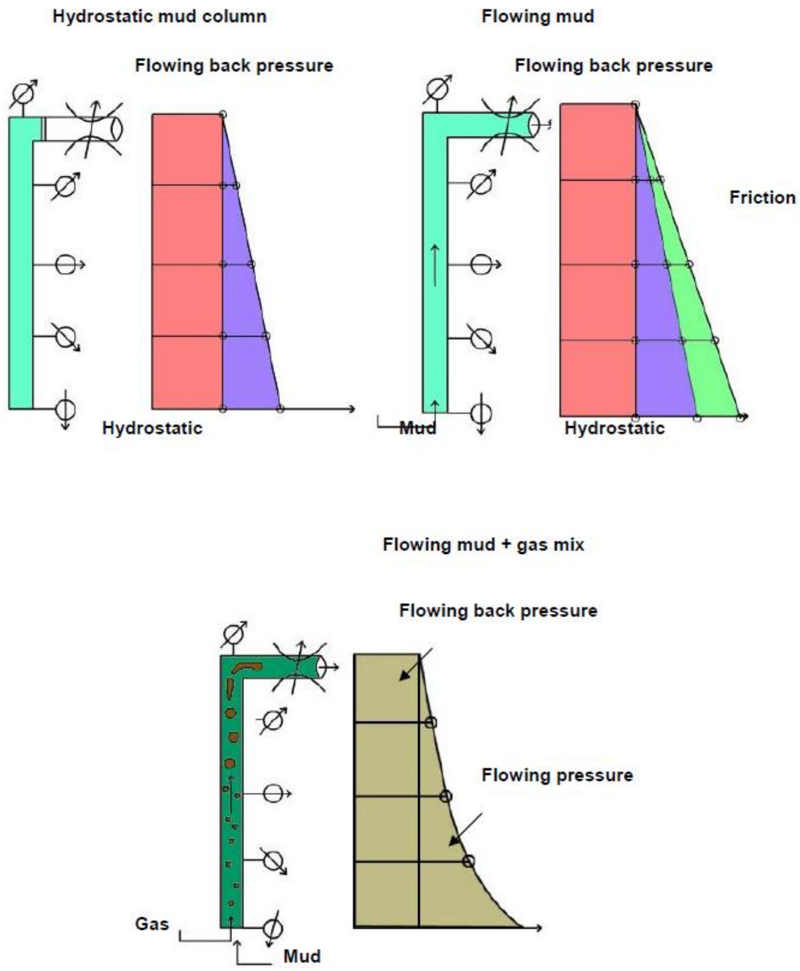


Figure 18: Illustration of the BHP in various situations in UBD (from Rigpass, 2012).

Depth, density and top column pressure are the three aspects involved in controlling the pressure at the bottom of the mud column. Based on this, there are three ways to manipulate the Ph at the bottom of the mud column: either change the density or the pressure applied at the top of the column, or a combination of these two.

There is a big difference if the well going underbalanced, or intentionally drilling underbalanced. In UBD operations influx is a normal situation. In this type of operations the BHP is below the Pp. However, if the BHP drops too much, the influx may exceed the handling capacity and the hole might also collapse. On the other hand, the probability of exceeding the fracture pressure is lower in UBD compared to OBD. The UBD approach has been used for drilling oil and gas wells for limited and particular applications in the past half century. Today, this approach is becoming more common, and is evolving with a wider range of applications offshore and onshore. According to (Rigpass, 2012), UBD is often preferred as method compared to conventional drilling constructing long horizontal wells.

Kick is defined different in UBD operations. API defines it as when the system is designed in a manner not capable of handling the formation pressure or flow rate that is experienced. The kick can be a result of poor choke control or formation characteristics, or engineering errors.

The choke valve has a very important function in controlling the pressure during UBD. It is basically a very robust control valve built as a variable flow restriction. By moving the trim of the choke relative to a fixed seat, one can vary the opening of the choke and thus increase or decrease the wellbore pressure.

4.5.1 Fluid introduction and circulation

According to (Rigpass, 2012) there are three basic methods to introduce and circulate light fluids in UBD:

- Drill-string injection
- Parasite string
- Parasite casing

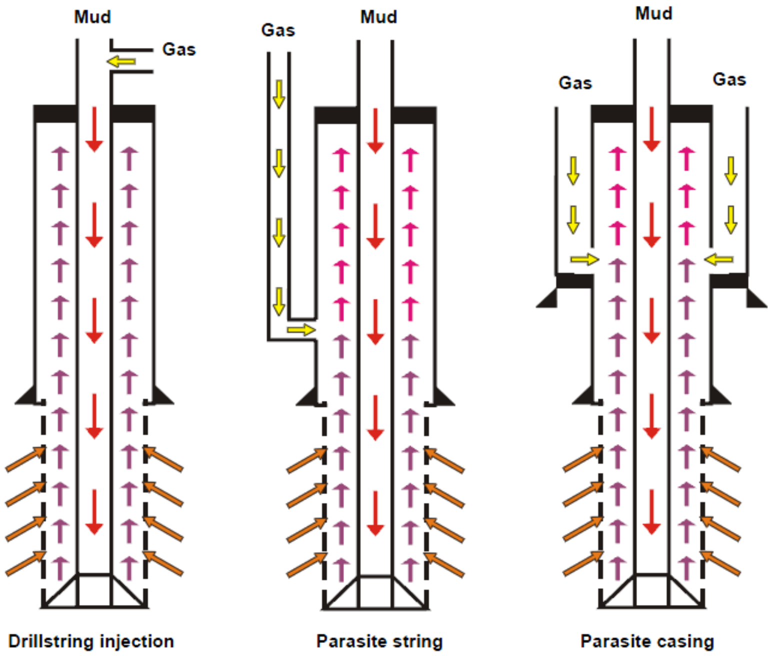


Figure 19: Methods for introducing and circulating fluid in UBD (from Rigpass, 2012).

The drill-string injection is used for drilling mud, and works in a similar manner as for the OBD. Gasified mud is being introduced by using the Parasite string or the Parasite casing method.

4.5.2 Barriers

The requirements of minimum two safety barriers present, also applies in UBD operations. The barrier function of the mud column from OBD is no longer intact, because the Ph is lower than the formation pressure. In UBD, the hydrostatic mud pressure barrier is substituted by a mechanical barrier.

At the top, the well is continuously pressurized, and the drill-string rotates and moves axially through a seal. The seal system is basically an annular BOP where the seal is in constant contact with the rotating drill-string, and rotates together with the string (Rigpass, 2012). Rotating annulus seal elements is basically divided into passive or active. *Rotating control heads* (passive) uses a rubber element with added energy from the well pressure. The *Rotating BOP* (active), which is used by Statoil in UBD, energizes the seal by hydraulic pressure from a hydraulic module, and is placed on top of the conventional BOP. The hydraulic module regulates the pressure automatically in line with the wellhead pressure.

The conventional BOP acts as the secondary barrier if the rotating BOP fails or leaks, or an abnormal drilling or circulation situation occurs.

4.6 Annulus vs. drill- string pressure

In drilling there are two parallel columns, the drill-string, and the annulus. These are linked in a U-Tube arrangement. They are like two branches sharing a common junction, where the pressure is equal at the junction for the two fluids. The liquid will rise to the same height in both columns, if the same liquid is used on either side. On the other hand, if a pressure should be applied on one side, thus raising the BHP, the liquid level on the other side will rise to compensate for the raise in BHP. The main concern in drilling and well control operations is regarding the annulus pressure. The annulus fluid is in contact with the formation and interface with the pressurized formation fluid.

4.7 Subsea BOP control system

The control system operates and controls the functions of the BOP stack. Operating valves and adjusting chokes is typically performed by the control system, and are important functions in maintaining barriers. There are different types of subsea control systems, and the main differences relates to how the surface and subsea installations communicate.

Conventional Hydraulic Control Systems can be divided into direct-, piloted-, and sequential- systems. These systems employ hydraulic signals to actuate subsea functions. The pilot and sequential are improved by using accumulators and subsea valves, compared to the direct system. Hydraulic fluid is sent from the surface, and stored in the accumulators and directed to the proper actuator when needed.

Water depth is regarded as the major limitation to the hydraulic systems, due to its relatively long response time. The closed circuit solution of the hydraulic arrangement, where the fluid is transported back to the hydraulic power unit (HPU), and not to the sea, is the preferred solution to use, at least from an environmental point of view. Fluids used are generally based on water/glycols or hydrocarbon.

Electro-hydraulic control systems and *Multiplexing control system (MUX)* are more complex systems, and are commonly used as the water depth increases. The electrical signals used by this systems, has a shorter response time compared to hydraulic signals covering the same distance. MUX uses solenoid valves which converts electrical energy into mechanical energy to open and close valves. In Figure 20 the differences between piloted hydraulic, electro-hydraulic and MUX control system are shown.

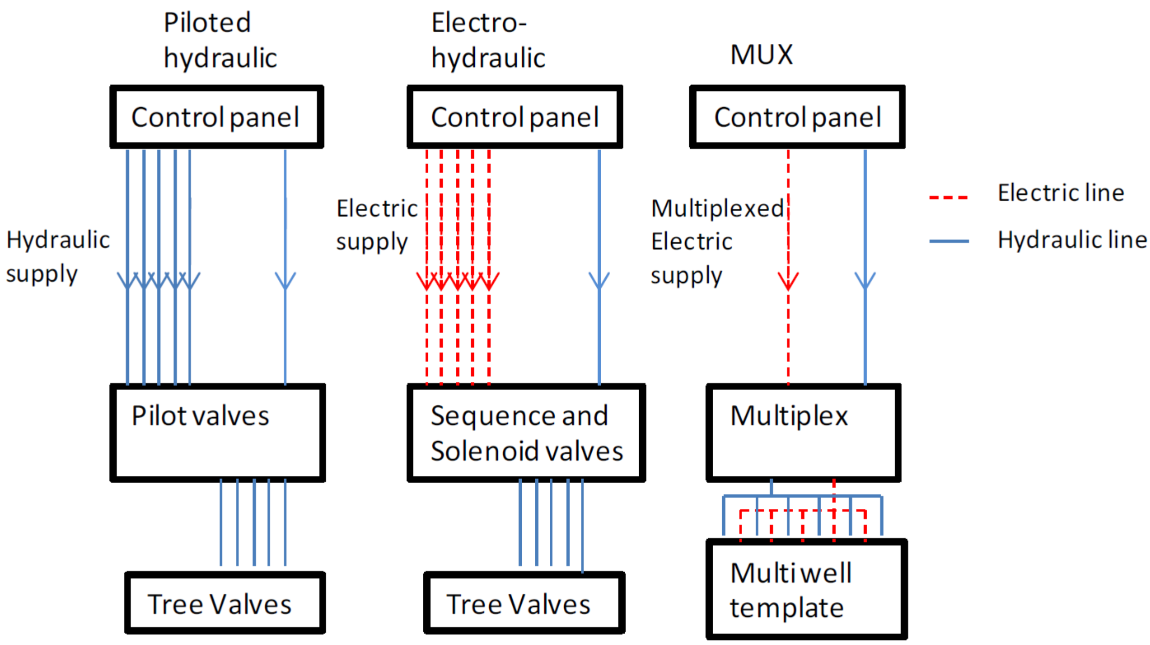


Figure 20: Control systems (from NORSOK D-001, 1998).

The MUX system transmits coded signals from the Central Control Unit (CCU) on surface to the Subsea Electronic Module (SEM) located subsea. In the SEM, a modem decodes the signal and returns it to the CCU for verification. Once verified, the signal will be sent back down to the SEM, and further to a solenoid for activation of the required BOP function. The basic principles are illustrated in Figure 21.

A blue and a yellow control pod are located on the LMRP, and these include the SEM and the solenoid valves. Only one pod is being used, but there are two pods present to secure redundancy. A shuttle valve is installed to make it possible to switch between the pods.

4.8 Back-up control systems

Which type of back-up system to use, will vary depending on the manufacturer of the BOP and the rig-type. In this section, various systems presented in Holand (2012) are listed, together with a briefly description.

ROV: Remotely operated vehicle, with intervention capability. The ROV can mechanically control the valves through the ROV intervention panel on the BOP. This can typically be to activate the BSR, or other rams or disconnect the LMRP connector.

EDS: Emergency disconnect system. This system activates at least one shear ram to seal the well, and disconnect the LMRP connector from the BOP stack.

AMF: Automatic mode function. Similar to the Deadman system.

EH: Electro hydraulic (back-up). Separate controls activated by electro hydraulic signals manually.

Acoustic back-up controls: Separate control system for selected functions. Activates by sending acoustic signals from the rig, or alternatively another vessel. Powered by a dedicated accumulator bank. No automatic activation.

Deadman: Initiates automatically, if the BOP is losing power signals and its hydraulic supply. Closes at least one blind shear ram and disconnect the LMRP from the BOP stack.

Autoshear: Automatic shear if LMRP disconnects spuriously.

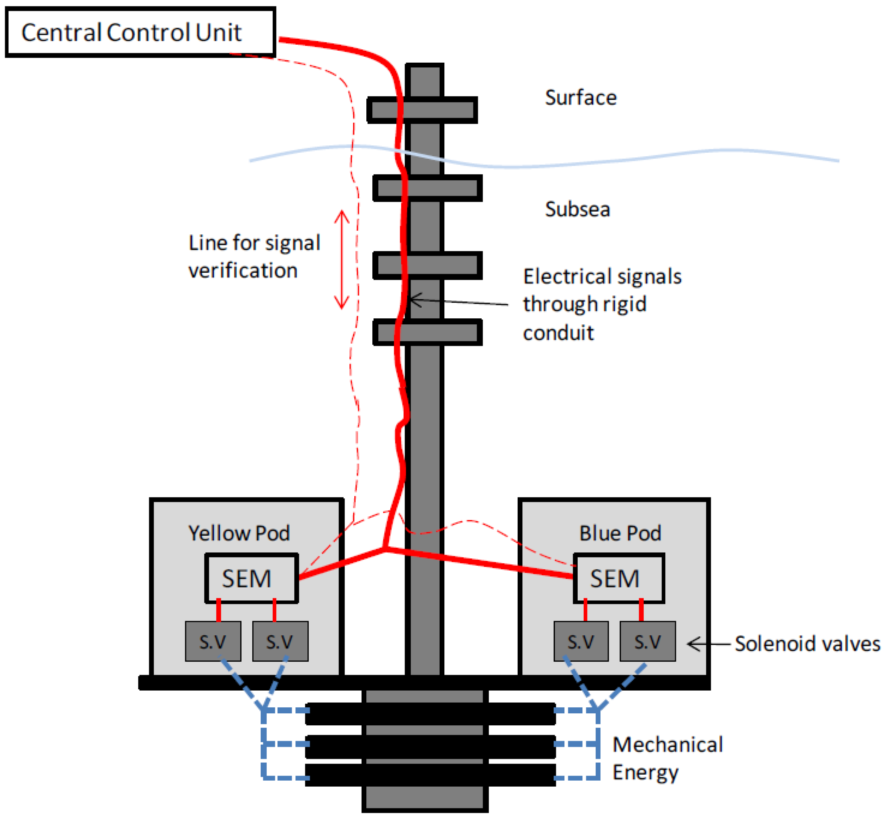


Figure 21: Basic principles of electro hydraulic/MUX control system (from Padøy, 2011).

Chapter 5

Approaches for the Assessment of Dynamic Barriers

5.1 Introduction

This chapter deals with approaches for the assessment of dynamic barriers. Different approaches are described, and one new approach is proposed and carried out as a case study. The method called *drillers* HAZOP has not been given as much weight as the other methods being described.

5.2 Event tree analysis

Event tree analysis (ETA) is a graphical and probabilistic method for modeling and analysis of accident scenarios. This method can be used to analyze all types of technical systems, with or without operator**.** It is an inductive method which follows a forward logic. The starting point of the tree is an identified hazardous event, and the end points are the possible outcomes or consequences. Various methods can be used to identify the hazardous event, such as a Hazard and Operability Study (HAZOP), and the Failure Modes, Effects, and Criticality Analysis method. According to Rausand (2011) the occurrences of the hazardous events are often modeled by a homogenous Poisson process with frequency $\boldsymbol{\lambda}$, which is the number of occurrences, per time unit. Depending on the objectives and the availability of relevant data, the ETA may be qualitative, quantitative, or both. The possible accident scenarios that may follow the hazardous event and the system`s response to these are displayed in a diagram**.** After starting with the hazardous event, the tree *splits* at certain stages in the structure. The splitting takes place when specified *pivotal events* occur. These events may be function or failure of barriers, but may also be certain events or states. The diagram is usually drown from left to right, with the pivotal events, formulated as a “negative” statement, and listed as headings above the tree diagram. In most cases, the pivotal events has a binary outcome, TRUE/FALSE or YES/NO, but multiple outcomes such as YES/PARTLY/NO are also possible. In most systems, the possible hazardous events are identified during the design process. To stop or mitigate the consequences from the hazardous event, a number of barriers have been provided. Typical barriers might be technical equipment, emergency procedures, human interventions, or a combination of these.

5.2.1 Objectives

In Rausand (2011) the main objectives of an event tree analysis are:

1) Identify the accident scenarios that may follow the hazardous event.
2) Identify the barriers that are (or planned to be) provided to prevent or mitigate the harmful effects of the accident scenarios.
3) Assess the applicability and reliability of these barriers in relevant accident scenarios.
4) Identify internal and external events that may influence the event sequences of the scenario – or its consequences.
5) Determine the probability of each accident scenario.
6) Determine and assess the consequences of each accident scenario.

5.2.2 Advantages and Limitations

The ETA is widely accepted, and simple in use. The structure of the method makes it easy to follow the development from the hazardous event, through the various pathways created by the barriers in place, to the end event. The pathways give different outcomes, thus giving an insight of the need for new or improved barriers.

A standard for drawing the tree is non-existent, this may be confusing and allows different interpretations. The ETA can only analyze one hazardous event at the time, and dependencies, such as common cause failures, are difficult to handle in the qualitative ETA.

5.3 Fault Tree Analysis

A FT is a top-down logic diagram that displays the interrelationships between a potential critical event in a system and the causes of this event (Rausand, 2011).

Fault tree analysis (FTA) is one of the most commonly used methods for risk and reliability studies. This method has traditionally been applied to mechanical and electromechanical systems, but can also be applied to other types of systems. Depending on the scope of the analysis, the FTA may be qualitative, quantitative, or both.

FTA is a deductive method starting with a specified potential critical event, called the TOP event. Deductive means that we reason backwards from the specified event. The causal events leading to the TOP event are identified, and connected through logic gates. This process is continued until a suitable level of details about the system is reached. At the lowest level we find such as component failures, environmental conditions and human errors, these are called *basic events.*

In Appendix E an overview of the most common symbols used in a FT and a description of these is presented.

No intermediate states are allowed in the FT. All events are assumed to be binary, meaning that the events either occur or not occur. For each potential TOP event in the system a separate FT must be constructed, this because a FT is *single event* – oriented.

For the TOP event to occur, the basic events or a combination of these must occur. The FT will provide information about these possibilities of events and such a combination of basic events is called a *cut set*. In Rausand (2004) a cut set is defined as: “A cut set in a fault tree is a set of basic events whose (simultaneous) occurrence ensures that the TOP event occurs”. Rausand (2004) defines a *minimal cut set* as:”A cut set is said to be minimal if the set cannot be reduced without losing its status as a cut set”. The minimal are the most interesting cut sets.

5.3.1 Objectives

According to Rausand (2011) the main objectives of a FTA are:

1) To identify all possible combinations of basic events that may result in a critical event in the system.
2) To find the probability that the critical event will occur during a specified time interval or at a specified time *t*, or the frequency of the critical event.
3) To identify aspects (e.g., components, barriers, structure) of the system that need to be improved to reduce the probability of the critical event.

5.3.2 Advantages and Limitations

The FTA is widely accepted and easy to use, with a logical form of presentation. It is suited for failures of both technical and human nature, and capable of handling complex systems. By breaking down failures in this manner, potential sources are revealed, and re-thinking of both design and how the system is operated can be done.

A drawback performing the FTA is the static picture being given between failures and the event being looked at. This makes it less suitable for dynamic systems. The method only treats anticipated events, and can become time-consuming and complicated when large systems are being analyzed.

5.4 Drillers HAZOP

A *drillers`* HAZOP is a method for performing Hazard and Operability studies of drilling systems and procedures developed by Comer et al. (1986). This method uses the same basic approach as the traditional process HAZOP, but other guidewords are introduced. Novel features are introduced for drilling operations which are essentially sequences of mechanical and manual handling operations by teams of people. For these operations a *Multiple Activity Chart* (MAC) has been developed. The traditional set of guide words was found to be unsuitable for analysis of the MAC, and an alternative set was developed. Traditional guidewords are NO, MORE, LESS, REVERSE in combination with the names of the one-dimensional variables FLOW, PRESSURE and TEMPERATURE. This basic deviation set is supplemented if required, by the variables: LEVEL, COMPOSITION, PHASE and the non-specific guideword CHANGE. One-word descriptions of deviations such as CORROSION and MAINTENANCE have also been used as supplement.

Since many drilling activities can be related to problems with manual or mechanical handling, which the traditional set, has little relevance to, the drillers` HAZOP method has developed an alternative set. The basic variable in this is MOVEMENT. This variable is split into three: MOVEMENT UP, MOVEMENT DOWN and MOVEMENT ACROSS. These create the basic set of deviation, and are combined with the traditional guide words NO, MORE, LESS and REVERSE.

The main features of the HAZOP analysis are that it is conducted by a team of people working together in so called brainstorming sessions. To support the participants *guidewords*, *process parameters*, and various checklists are used. The system being considered is divided into *study nodes*. These are examined one by one, and the *design intent* and the normal state are defined for each of them. All possible *deviations* are examined during the sessions with help from the guidewords and the process parameters, in order to identify possible hazardous situations. As in the traditional HAZOP, identification and assessment of deviations from the desired state is the center of discussion. A set of recommendations and questions is the output from the study.

5.5 New approach

This suggested approach is a combination of FTA and ETA. ETA is used to show the dynamics of the hazardous event, and the involvement of different barriers and the development of different paths towards the end event. The end event will give an insight of the success of the barrier involvement, and the need for any necessary changes.

FTA is used for breaking down the different elements involved in the barriers, and finding out what makes the TOP event of the tree happening. *Failure rates* and *Probability of failure on demand* (PFD) are calculated for some selected outcomes in the ET using FTA.

5.6 Case study

In this section, the suggested approach is used for reliability assessment of the barriers during drilling. A kick is considered a hazardous event for this case, and it is assumed that the primary barrier is lost, which is essential to get this kick. It is further assumed that this is an OBD-operation with pipe in the hole, and performed in deep waters with a classical BOP-stack in place (see Figure 14 in Section 4.4.2).

In Figure 22, all the barrier elements during drilling are placed in an ET showing various outcomes (end events) depending on the functionality of the barriers. The ET shows various pathways from a kick to a secure close-in of the kick, or an escalation into a blowout. The elements with the ability to identify a possible kick are also been included. It is important to be able to recognize the kick signs, how to react and take action upon them if this is necessary. All this, and other measures surrounding a kick, together with explanations for the kick- and kick identification fault tree are further elaborated in Chapter 6.

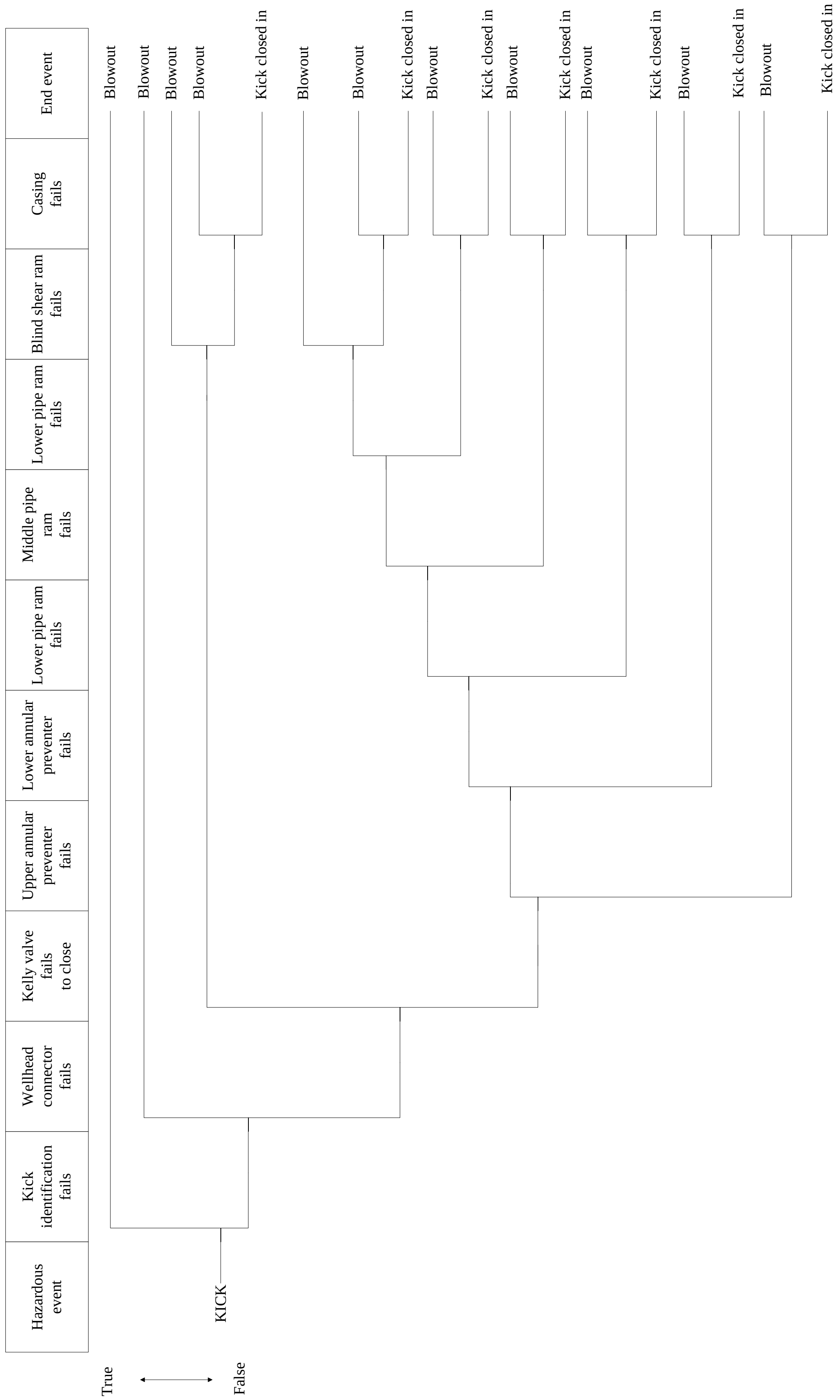


Figure 22: Event tree of barrier elements involved from a kick to blowout during drilling.

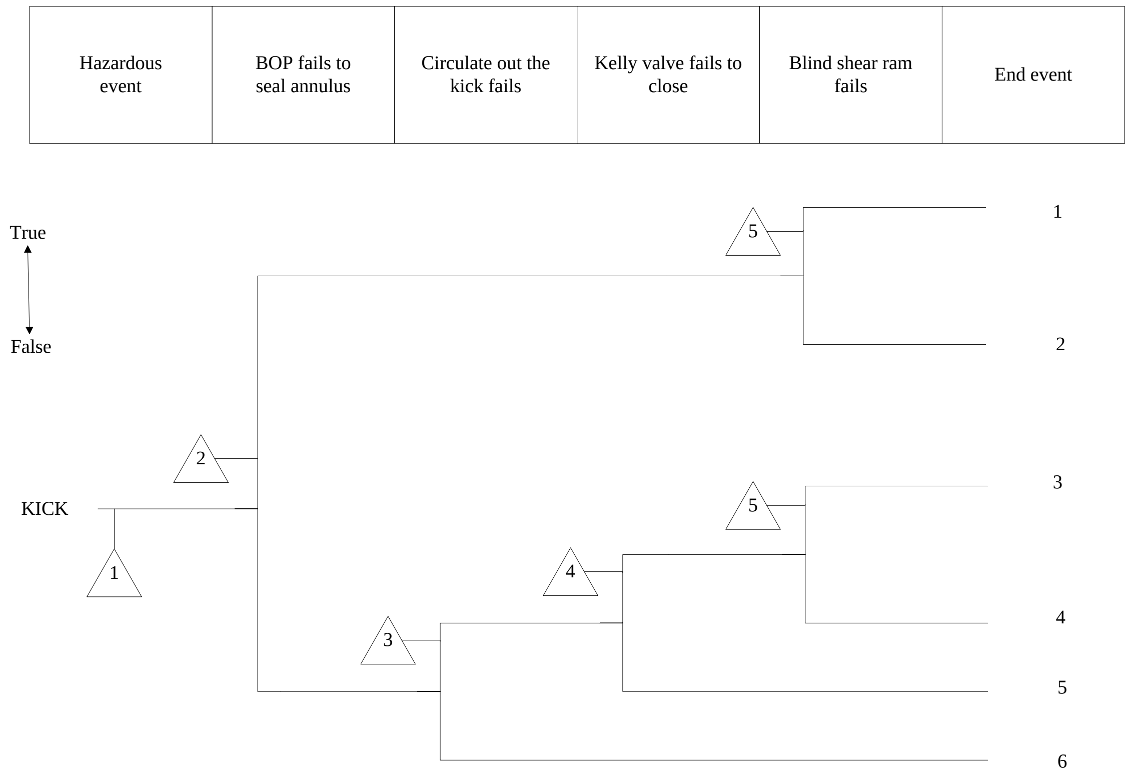


Figure 23: Simplified event tree. Drilling

Figure 23 illustrates a simplified ET for the escalation from a kick to a blowout during drilling, involving kick circulation. Here it is assumed that the kick is detected, and proper actions engaged. The “Transfer in” symbols used in Figure 23, means that this event is further developed using a FT later in this section.

Outcomes/ end events for Figure 23:

1. Full blowout.
2. Kick killed with HC below the blind shear ram.
3. Full blowout.
4. Kick killed with HC below the blind shear ram.
5. Kick killed with HC in drill-pipe and below the BOP.
6. Balance in well restored.

5.6.1 Failure rates

Figure 23 is used to calculate the failure rate $\boldsymbol{\lambda}$ for the outcomes 1 and 6. Failure rate is the numbers of failures per time unit. Estimating failure rates in this chapter, the unit *per day* is used, meaning per BOP-day (number of days from the BOP was landed on the wellhead the first time until it was pulled from the wellhead the last time).

Kick: λ_1

The kick frequency used comes from the study performed by Holand (2012), and states 5.4 kicks/1000 BOP-days, which is $5.4 * 10^{-3}$ per day.

BOP fails to seal annulus: λ_2

$\lambda_2 = 2.49 * 10^{-3}$ per day (calculated in Section 6.6.2).

Circulating out the kick fails: λ_3

For estimating the failure rate for ”Circulating out the kick fails”, data from Holand (2001) is used. In this study, 48 kick were reported. For 42 of the kicks, circulation was tried to regain control, and of these circulation alone was used in 29 of them. For calculating the failure rate, it is argued that the circulation failed in 13 of 42 kicks, because additional measures had to be used to regain control. The number of BOP-days is 4009 for this study.

$\lambda_3 = \frac{13}{4009} = 3.2 * 10^{-3}$ per day

Kelly valve fails to close: λ_4

This failure rate must be based on a comparable component, using a topside valve (Sintef, 2013). The value only includes the valve itself.

$\lambda_4 = 5.28 * 10^{-5}$ per day

Blind shear ram fails: λ_5

The calculated failure rate for the ram preventers are being used here, because of lack of other, more specific data. $\lambda_5 = 1.29 * 10^{-4}$ per day.

Outcome calculations:

1: $\lambda_T = \lambda_1 + \lambda_2 + \lambda_5$

$= 5.4 * 10^{-3} + 2.49 * 10^{-3} + 1.29 * 10^{-4} = 8.02 * 10^{-3}$ per day $= 2.2 * 10^{-5}$ per year, or approximately once every 45455 years.

2: $\lambda_T = \lambda_1 + \lambda_2 + (1 - \lambda_5)$

3: $\lambda_T = \lambda_1 + (1 - \lambda_2) + \lambda_3 + \lambda_4 + \lambda_5$

4: $\lambda_T = \lambda_1 + (1 - \lambda_2) + \lambda_3 + \lambda_4 + (1 - \lambda_5)$

5: $\lambda_T = \lambda_1 + (1 - \lambda_2) + \lambda_3 + (1 - \lambda_4)$

6: $\lambda_T = \lambda_1 + (1 - \lambda_2) + (1 - \lambda_3)$

= $5.4 * 10^{-3}$ + (1- 2.49 *10^{-3}) + (1- $3.2 * 10^{-3}$) = 1.99971 per day = $5.47 * 10^{-3}$ per year, or approximately once every 183 years.

Remark: Seen in retrospect, perhaps calculating the probability would be a more adequate measure here.

5.6.2 PFD

PFD is the measure for loss of safety caused by dangerous undetected failures. PFD is the average probability of failure on demand over a period of time (Sintef, 2013).

A rough PFD assessment of "BOP fails to seal annulus" is being made here. It is assumed that there are two annular preventers, three ram preventers, and a control system, and that these are independent and only these can affect the TOP event. It is further assumed that there is no possibility to switch for the control system.

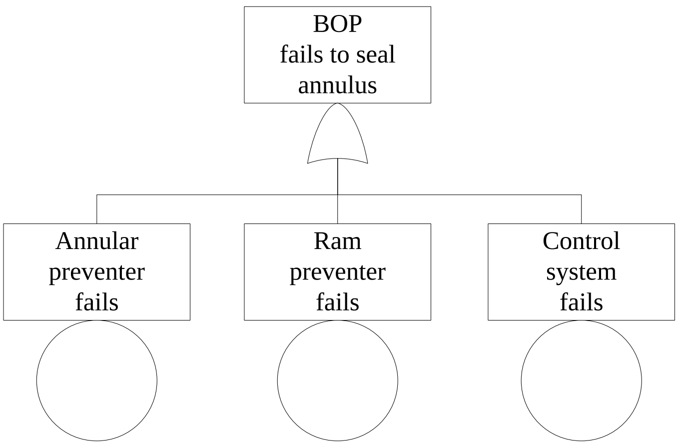


Figure 24: FT for BOP fails to seal annulus.

To estimate the critical failure rate for these items, information from Holand (2012) has been used. According to Holand (2012) the failure rate can be calculated as follows:

$$\boldsymbol{\lambda} = \frac{Number\ of\ failures}{Accumulated\ operating\ time} = \text{X failures per day in service}$$

The number of BOP days multiplied with the number of items is used as the *accumulated operating time* or *days in service* for the BOP failures. E.g., if the BOP stack has been in service for 2000 BOP-days, and there are three rams present, the accumulated operating time will be 2000 BOP-days multiplied by three rams, which equals 6000 days in service.

Table 5: Observation of BOP failures (from Holand, 2012).

BOP subsystem	BOP is on the rig		While running (or pulling) BOP			BOP is on the wellhead					Total
	Test prior to running the BOP	Other/-unknown	Test while running BOP	Normal operation	Other/-unknown	Installation test	Test after running casing or liner	Test scheduled by time	Normal operation	Other/-Unknown	
	Safety non-critical failures						Safety critical failures				
Flexible joint									1		1
Annular preventer	3	1				6	2	5	7		24
Ram preventer	4	1				8	5	4		1	23
Connector, LMRP	1								2		3
Connector, WH	1					2	1		1		5
Choke & kill valve			1			2	1				4
BOP attached line		1	2			2					5
Riser attached line			4			1	1	2	3		11
Jumper hose line						1					1
Multiplex electro hydraulic	7	4	5	3	1	7	2	9	16	1	55
Pilot hydraulic control system	1			1	1	4	2	4	4		17
Dummy item	3				1	2	1				7
Total	20	7	12	4	3	35	15	24	34	2	156
	17%		12%			71%					

Table 6: Overview of BOP failures (from Holand, 2012).

BOP Subsystem	BOP-days in Service	Item days in service	No of failures	Total lost time (hrs)	MTTF (Item days in service)	MTTF (BOP-days)	Avg. Downtime per failure (hrs)	Avg. Downtime per BOP day (hrs)
Annular preventer	15056	28150	24	2344,5	1173	627	98	0,156
Connector	15056	31142	8	638	3893	1882	80	0,042
Flexible joint	15056	15056	1	288	15056	15056	288	0,019
Ram preventer	15056	77264	23	1765,5	3359	655	77	0,117
Choke & kill valve	15056	160310	4	136	40078	3764	34	0,009
Choke & kill lines, all	15056	15056	17	1992	886	886	117	0,132
Main control system	15056	15056	72	4712	209	209	65	0,313
Dummy Item	15056	-	7	1572	-	2151	225	0,104
Total	15056	-	156	13448	-	97	86	0,893

Table 6 takes into account the number of items for each subsystem- component in the stack, so the days in service can be read directly from the table. A multiplex electro-hydraulic has been chosen as control system. All failures that occur in the BOP after the installation test are regarded as safety critical failures, and these are used to calculate the different failure rates. This is when the BOP acts as a well barrier. Calculation of the critical failure rates per day for the annular preventers, the ram preventers and the control system can be done as follows:

$$\lambda_{Annular} = \frac{no.of\ critical\ failures}{days\ in\ service} = \frac{14}{28150} = 4.97 * 10^{-4} \text{ per day}$$

$$\lambda_{Ram} = \frac{10}{77264} = 1.29 * 10^{-4} \text{ per day}$$

$$\lambda_{Control\ system} = \frac{28}{15056} = 1.86 * 10^{-3} \text{ per day}$$

$$\lambda_T = \lambda_A + \lambda_R + \lambda_C$$

$$\lambda_T = \lambda_2 = 4.97 * 10^{-4} + 1.29 * 10^{-4} + 1.86 * 10^{-3} = 2.49 * 10^{-3} \text{ per day}$$

When estimating the PFD, the test frequency must be known. NORSOK D-010 (2013) states that the annular and the pipe ram shall be function tested weekly. Since we use the control system to activate them, the same frequency is used here. Figure 25 shows the type of system being considered, and the numbers indicate the *k-out -of- n structure* (*k*oo*n*). The number of components is represented by *n*.

$$PFD_A = \frac{(\lambda_A * \tau_A)^2}{3} = \frac{(4.97*10^{-4} * 7)^2}{3} = \frac{1.21*10^{-5}}{3} = 4.03 * 10^{-6}$$

$$PFD_R = \frac{(\lambda_R * \tau_R)^3}{4} = \frac{(1.29*10^{-4} * 7)^3}{4} = \frac{7.36*10^{-10}}{3} = 2.45 * 10^{-10}$$

$PFD_C = \frac{(\lambda_C * \tau_C)}{2} = \frac{(1.86*10^{-3} * 7)}{2} = \frac{1.3*10^{-2}}{3} = 4.33 * 10^{-3}$

P (TOP) = 1- (1- PFD_A) (1- PFD_R) (1- PFD_C)

P (BOP fails to seal annulus) = 1- (1- $4.03 * 10^{-6}$) (1 - $2.45 * 10^{-10}$) (1 - $4.33 * 10^{-3}$)

= $4.33 * 10^{-3}$ = 0.00433

For this PFD calculation only the equipment are being considered, with no influences from humans, etc.

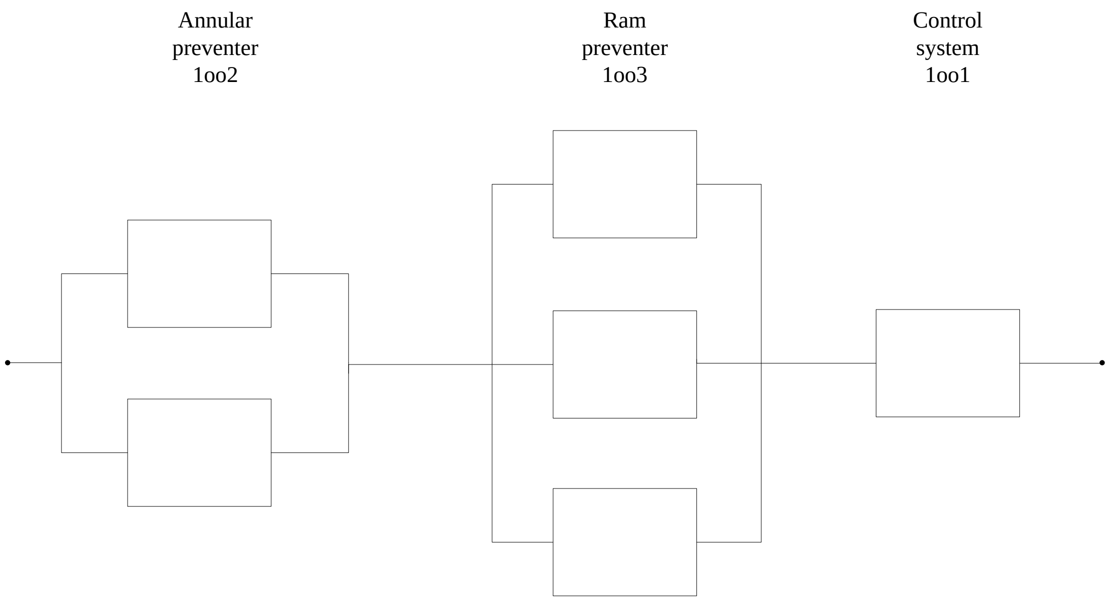


Figure 25: Block diagram of “BOP fails to seal annulus”.

5.6.3 Fault trees

The following pages show various fault trees from the “Transfer in” symbols used in Figure 23, and events related to this.

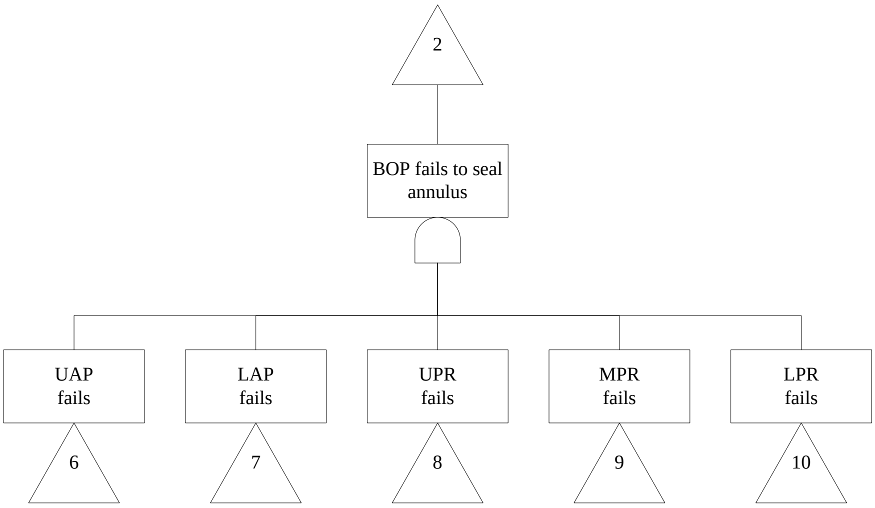


Figure 26: FT “BOP fails to seal annulus”

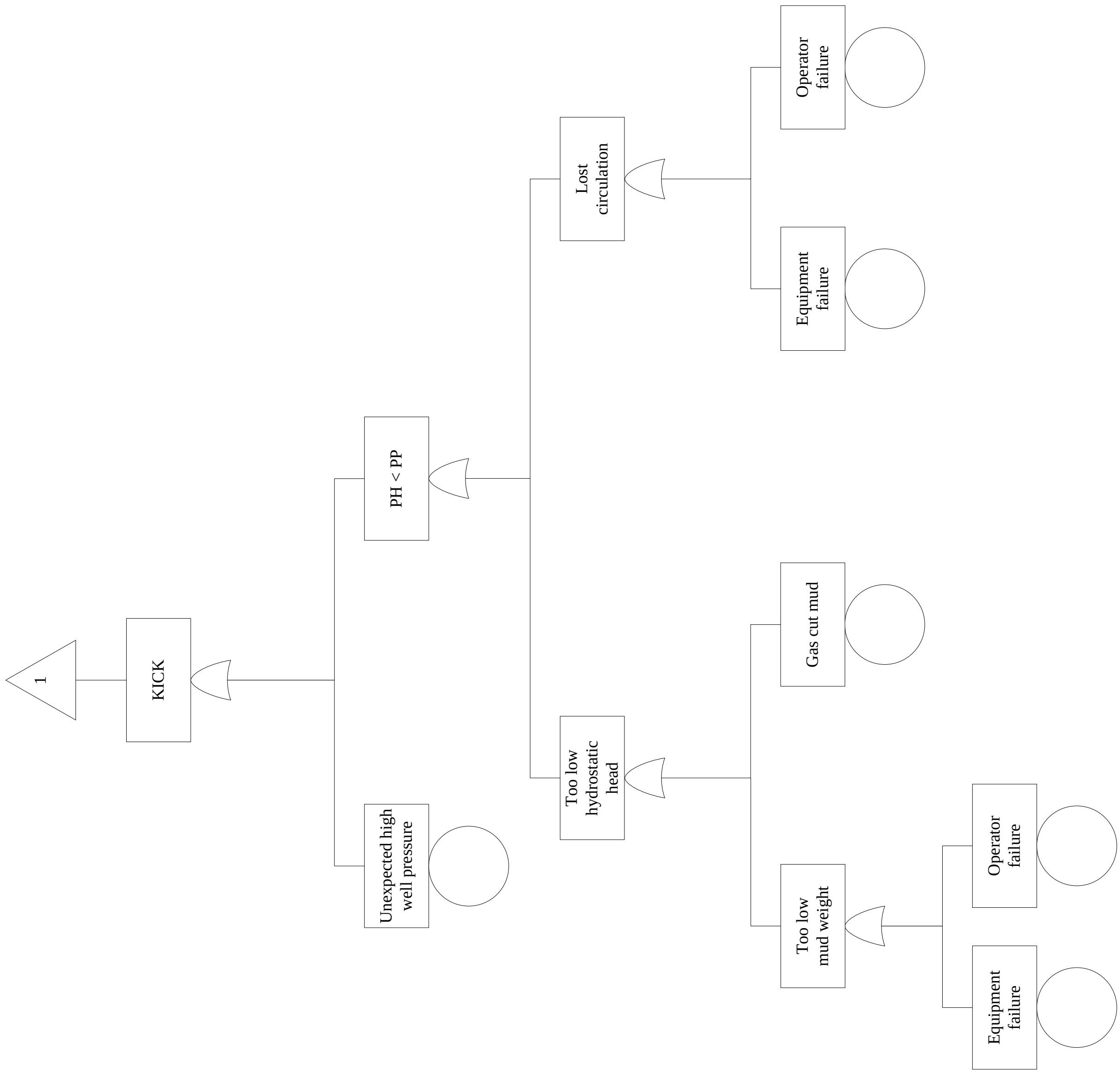


Figure 27: FT “Kick”.

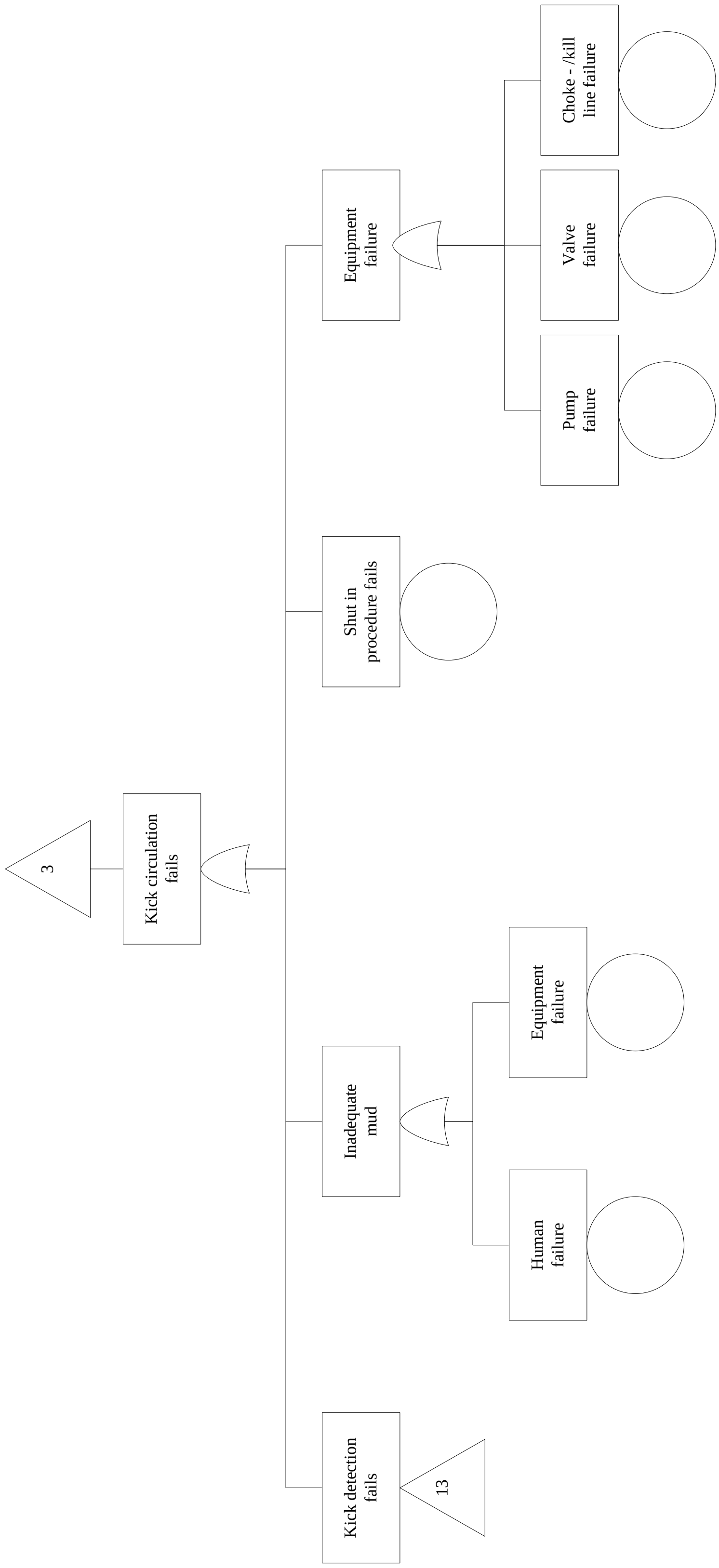


Figure 28: FT “Circulating out the kick fails”.

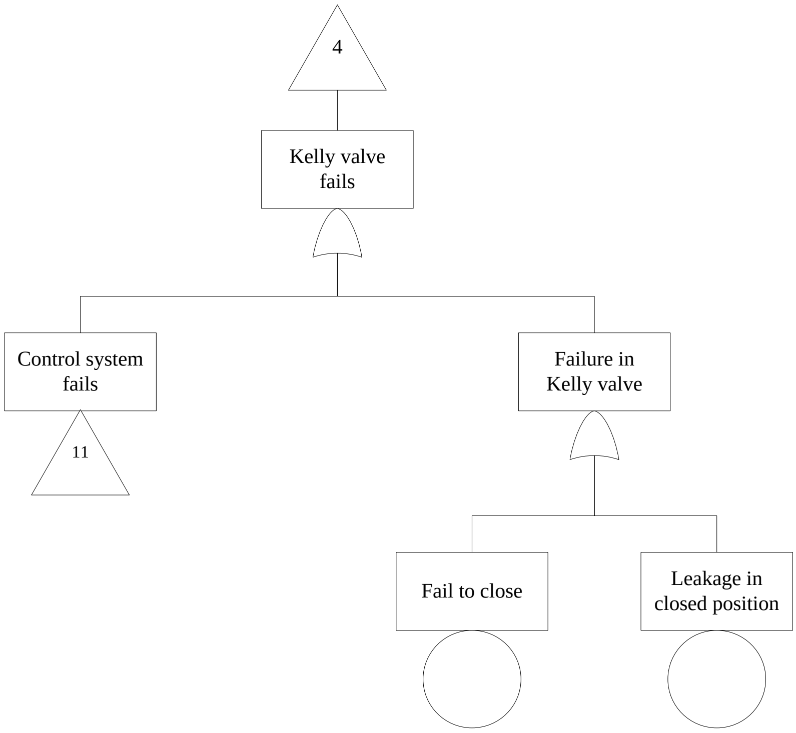


Figure 29: FT “Kelly valve fails”.

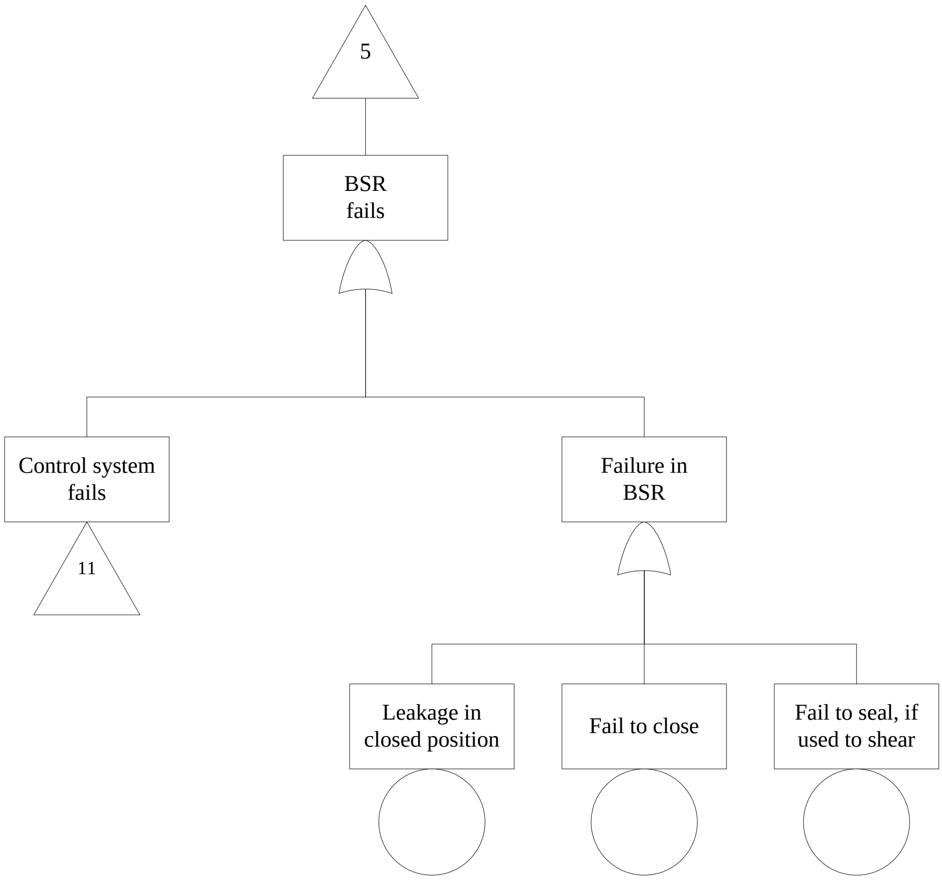


Figure 30: FT “Blind shear ram fails”.

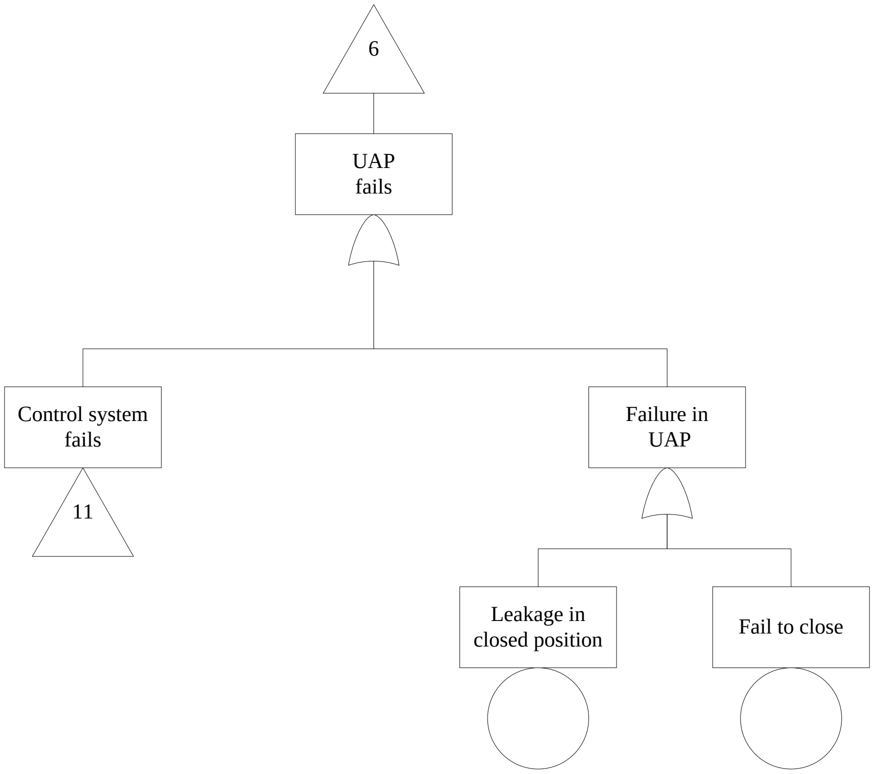


Figure 31: FT “Upper annular fails”.

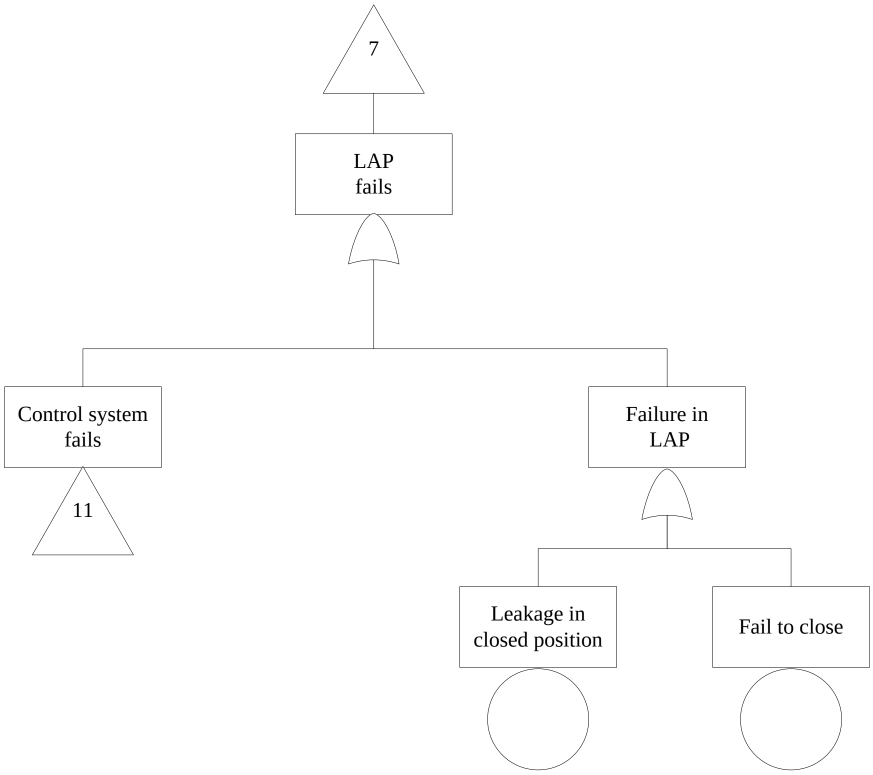


Figure 32: FT “Lower annular fails”.

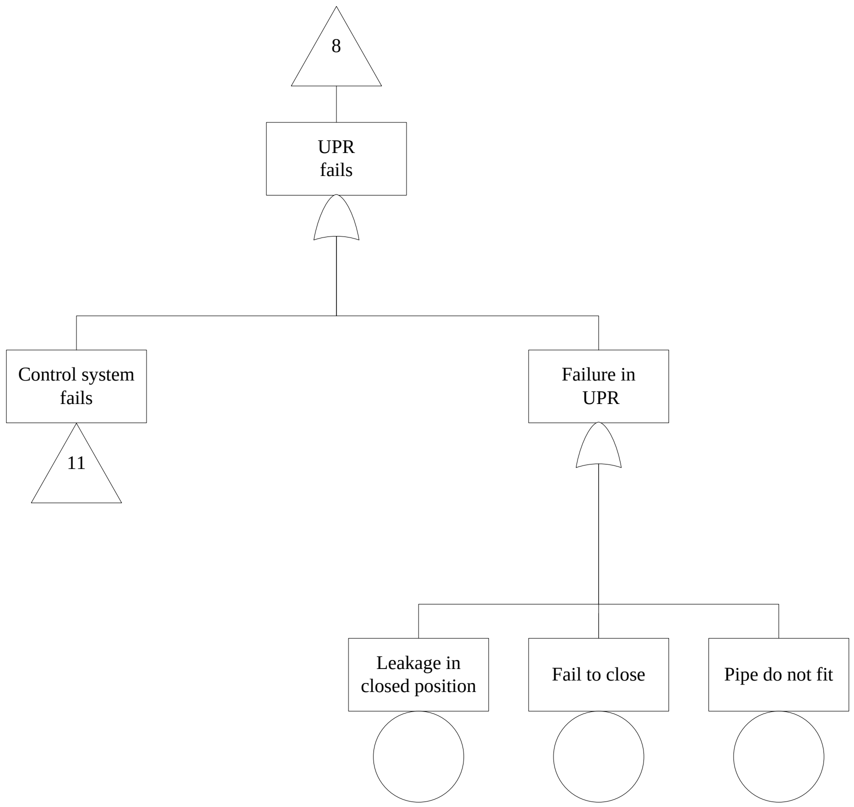


Figure 33: FT “Upper pipe ram fails”.

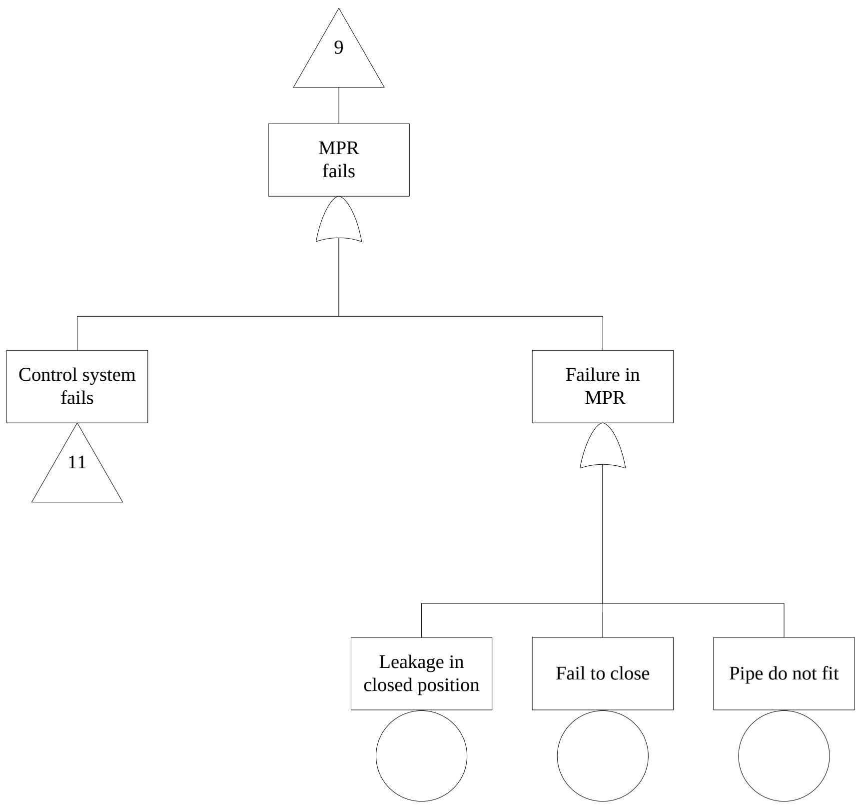


Figure 34: FT “Middle pipe ram fails”.

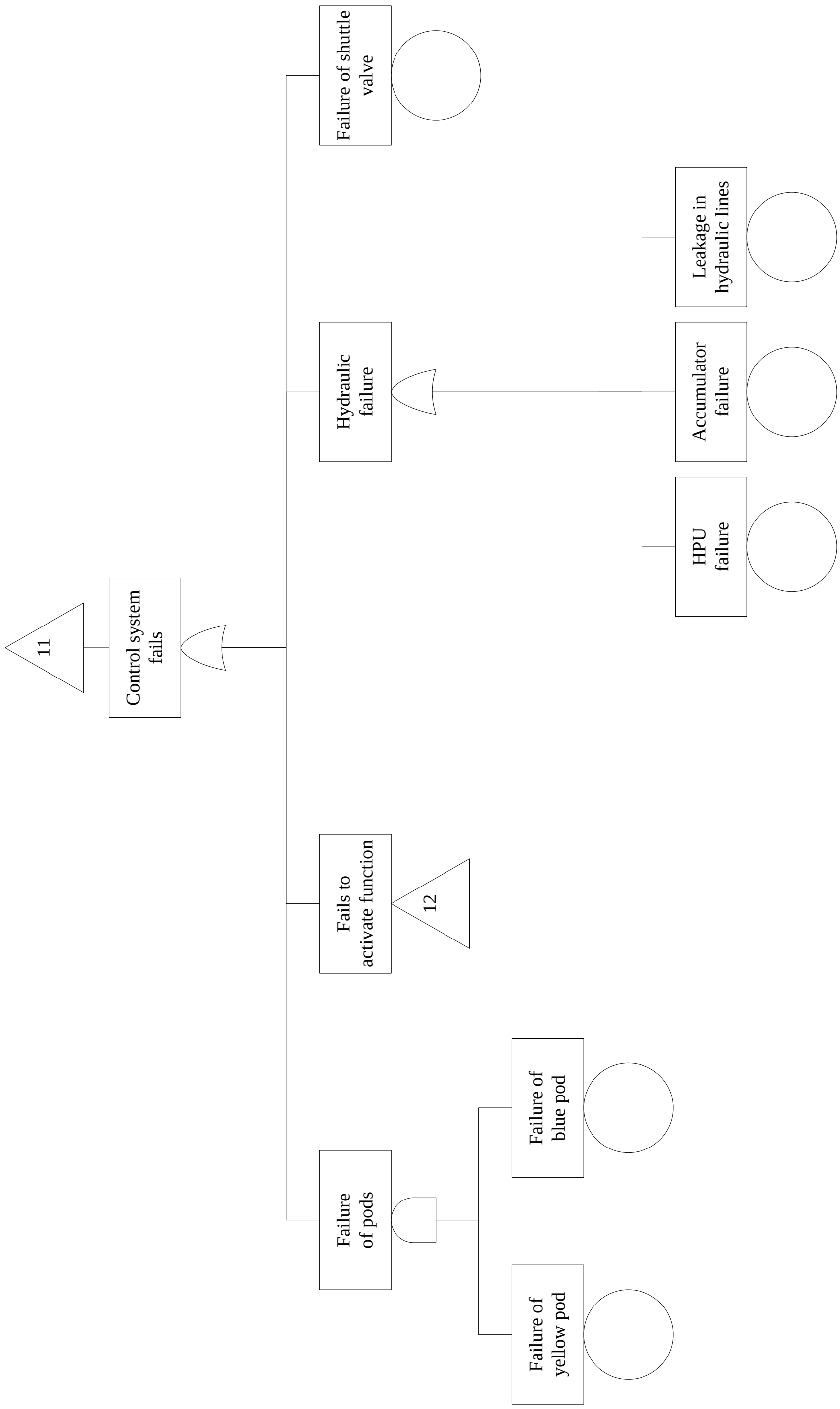


Figure 35: FT “Control system fails”.

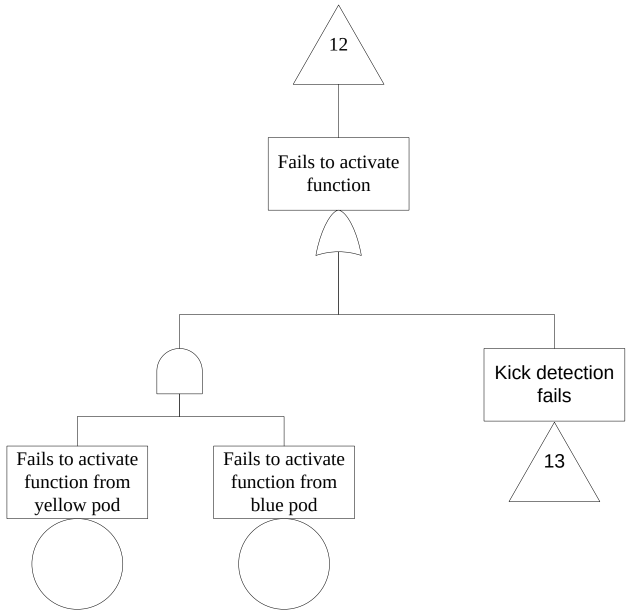


Figure 36: FT “Fails to activate function”.

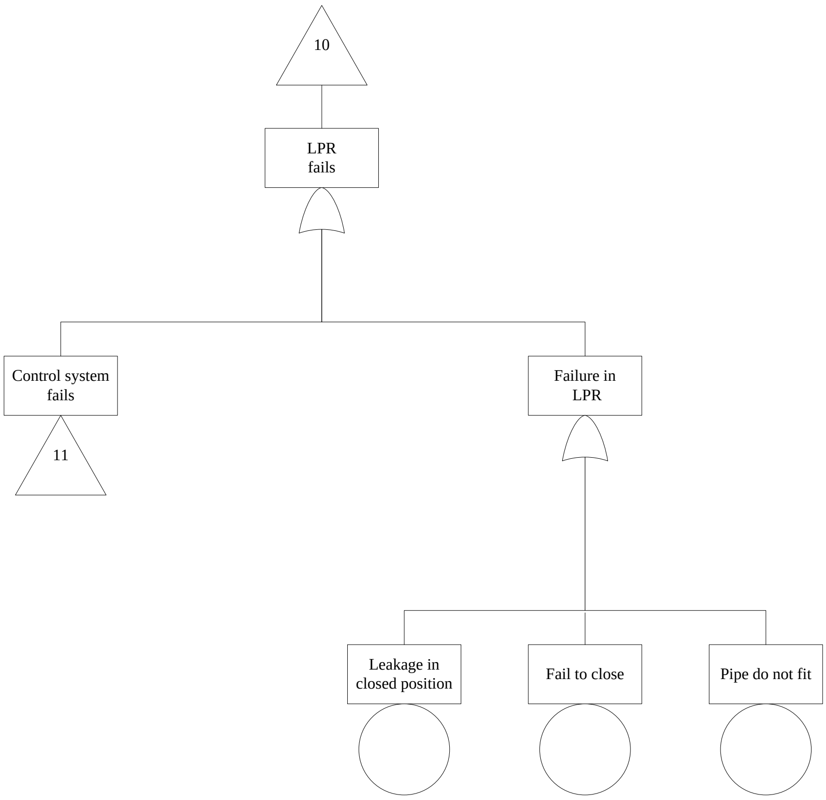


Figure 37: FT “Lower pipe ram fails”.

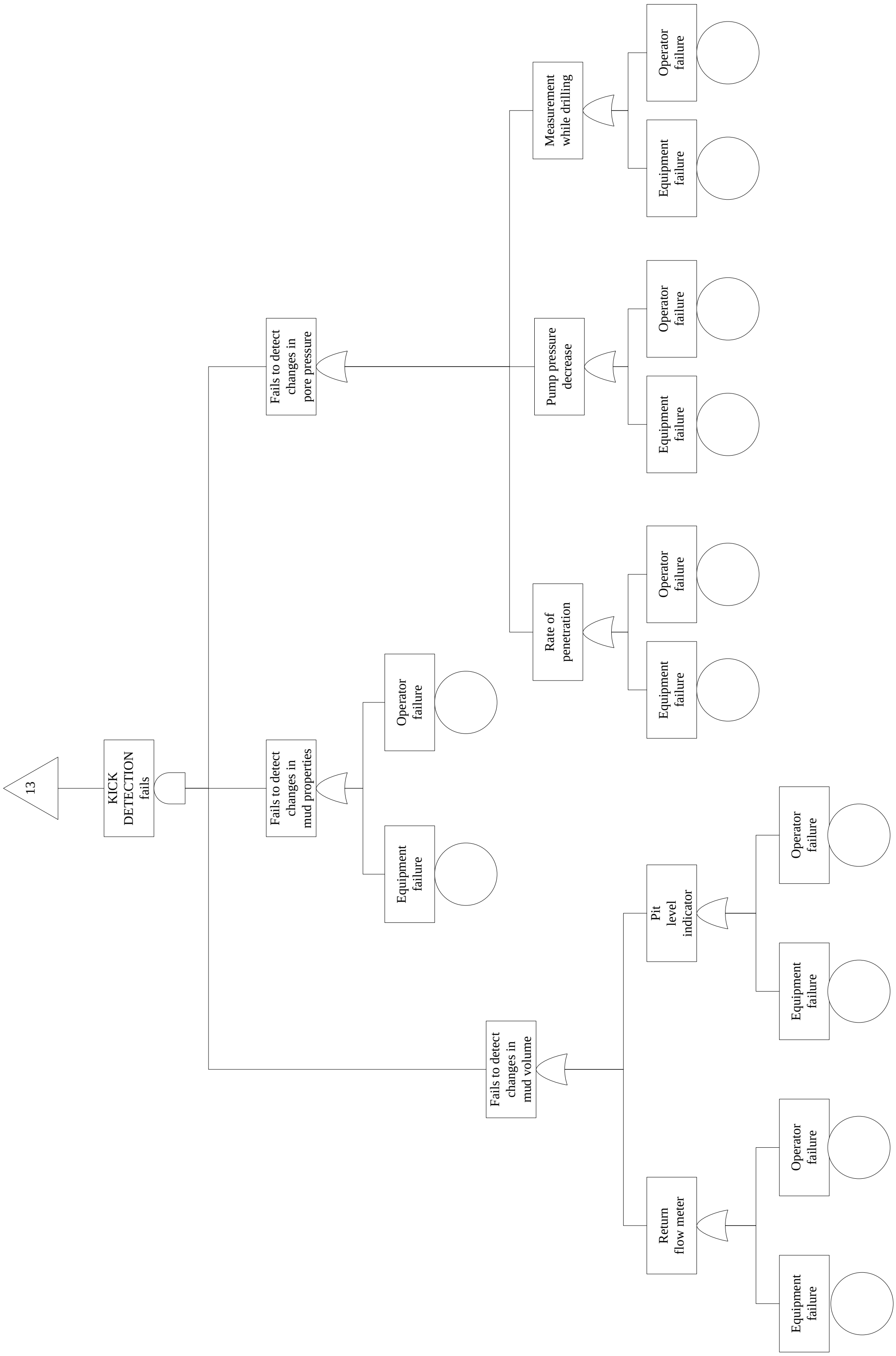


Figure 38: FT “Kick detection fails”.

Chapter 6

Kicks - categories, Causes, and Handling

6.1 Introduction

Kick is unwanted influx to the well, and is an important factor when addressing well barriers. This chapter deals with the most important issues related to kicks in OBD.

The primary barrier in OBD, is as previously mentioned, the mud column. If you lose this barrier, a kick may occur. The kick can be controlled or escalate into a blowout. Kicks may develop as a result of non-detection, or too late response, and thereby not putting barriers into action. Even if the kick is detected, the proper action may not be initiated because of improper training or lack of knowledge. Malfunction or lack of control equipment may also be reasons for the development of a kick. The potential blowout can be classified as a surface, subsurface, or underground blowout.

6.2 Warning signs of kicks

Warning signs and possible kick indicators may be observed at the surface. It is crucial to recognize and interpret these signals, and to take proper actions. Early detection is important to be able to reduce the possibility of a blowout. Not all signs positively identify a kick, some are warnings of potential kick situations.

Signs to watch for:

- Flow rate increase
- Pit volume increase
- Flowing well with pumps off
- Pump pressure decrease and pump stroke increase
- String weight change
- Drilling break
- Cut mud weight

6.3 Kick detection

The human factor in detection is very important in reading instruments and recognizing and interpreting kick signals. Time of detection is also an important factor for the outcome of a potential kick. If we assume that the time of kick detection will affect the BOP reliability, it is important to close with the HC below the BOP, and not after it has entered the riser. According to Hauge et al. (2012), the probability of BOP failure is higher with flow up the riser. Once again the timing is important.

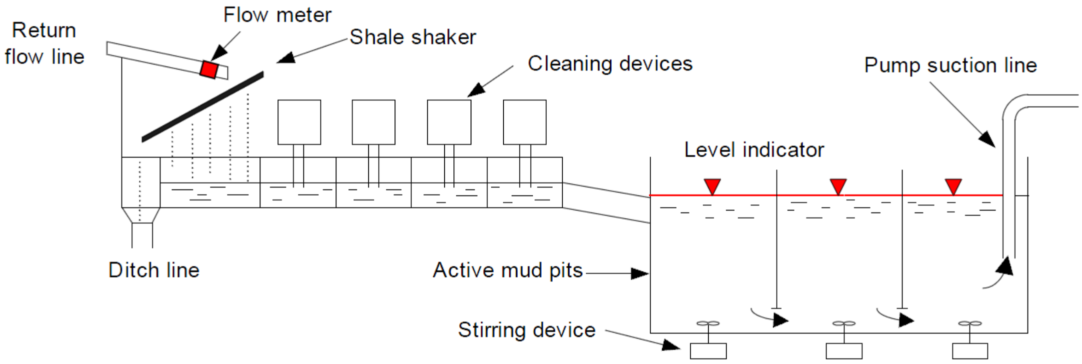


Figure 39: Surface metering of flow out compared to input flow, and of volume change in the pit (from Skalle, 2011).

During the drilling process various parameters are monitored to gain geological information and to determine the well integrity. Figure 39 shows two instruments that can detect a possible kick, the return flow meter, and the pit level indicator located in the active mud pit. These are monitoring the flow rate and the pit volume, which are operational parameters. An increase in these two is considered a warning sign. Drilling parameters such as drill-string torque and drilling rate of penetration (ROP) are also continuously monitored, together with properties of the mud, such as content and temperature. The information about the drilling parameters can be gained from several sources. Seismic data, measurement while drilling (MWD) and mud logging can be ways of monitoring and record the parameters mentioned.

6.4 Factors affecting kick severity

There are several factors affecting the severity of a kick. The *permeability* of the rock/formation is one factor to consider. By this means the rock`s ability to allow fluid to move through it. Another factor is *porosity*, which measures the amount of space in the rock containing fluids. A rock with high permeability and high porosity has greater potential for a kick than a rock with low permeability and low porosity. Sandstone is an example of this, compared with shale.

The *pressure differential* is also a factor affecting kick severity. By this means the difference between the Pp and the Ph. If the Pp is much greater than the Ph, there is a negative differential pressure, and this combined with high permeability and high porosity, can cause the occurrence of a severe kick.

6.5 Categories of kicks

A kick can be categorized in several ways. Categorizing according to the type of formation fluid entering the borehole is one of them. This is done by dividing into liquid or gas entering. If a gas enters the borehole, the kick is called a “gas kick”.

Gas expands when approaching the lower pressure near the surface, a small volume of gas at the bottom is potentially dangerous. When the gas expands it will displace a corresponding amount of mud from the well, thus reducing the BHP, which in turn allows more gas to flow in from the pores. For those who control kicks, the understanding of gas behavior under different well conditions is important, and the driller will be dependent upon this knowledge. Salt-water and oil are incompressible, and are therefore not as hard to handle as gas.

Another way of categorizing is by identifying the required mud weight increase necessary to control the well and kill a potential blowout.

6.6 Kick causes

This section deals with the causes leading to a kick, illustrated in Figure 27 in Chapter 5. The causes are for drilling downwards only, and do not take into consideration other types of operations.

6.6.1 Unexpected high well pressure

The main reason for experiencing a kick caused by *unexpected high well pressure* seems to be lack of reservoir knowledge. This can be a result of having wrong Pp prognosis, or poor preparations in the well planning phase. According to Holand (1996) this cause for losing the primary barrier is reported more frequently for exploration drilling than for development drilling.

6.6.2 Too low mud weight

Holand (2012) explains the occurrence of a kick caused by *too low mud weight* by the relatively small difference between the fracture pressure and the Pp. It is also pointed out that the annulus friction during circulation is likely to affect this problem.

One of the most obvious ways to “invite” a kick into the wellbore is to use/operate with a mud with insufficient density. The drilling mud is mixed continuously using different types of additives. The density of the mud is reduced if the amount of solids is less than it should be, or planned to be. The wrong density of the mud can be caused by equipment failure, such as improper mixing of the mud, causing e.g., Barite to settle at the bottom of the mud pit. If this happens, mud with a lower density than calculated will be circulated down the hole. Human errors such as miscalculations and too much dilution of the mud may also occur.

6.6.3 Gas cut mud

Gas cut mud occurs when formation gas mixes with the mud while drilling. This mixture reduces the mud density and reduces the Ph. When the Ph reaches a certain level, the hydrostatic control of the well will be lost, and a kick may occur.

6.6.4 Lost circulation

Lost circulation usually occurs because the Ph exceeds the formation fracture gradient. When this happens, the mud enters the formation. The amount of mud pumped down the hole does not equal the amount being brought to surface again. There can be a partial or total loss of circulation. Usually, all the mud is not lost, the formation partly returns the losses, and this is called *the ballooning effect.*

The formation can be naturally fractured or having high permeability, or there can be equipment failures or human errors causing the formation to fracture and thereby invite mud into the formation.

Other significant contributors to the occurrence of the kick are *swabbing* and *improper fill up* which occur during tripping out of the hole. *Disconnecting of the riser* is also a complicated issue that must be considered. These contributors are outside the scope of this project, and are not further elaborated.

6.7 Kick handling

When a kick has been detected and verified, necessary steps to circulate the kick out of the well must be taken. Generally, the well will be shut-in to limit the influx of formation fluids, and circulation started. Experience and training together with knowledge are crucial in these situations to get it done in a controlled manner.

6.7.1 Shut-in procedures

There are two main procedures for shutting in a well in drilling operations. The major difference between these is whether to close the BOP with the choke open or closed.
The *hard shut-in* is where the BOP is closing in the well while the choke is in a closed position. A phenomenon called *the water-hammer effect* is a concern using this method. It can be compared with shutting off running water from a tap with a sudden move, which is a common, every day thing, which is easy to relate to. By doing so, the water pipes make noise due to the sudden pressure pulse sent through the water. An analogy to the tap, is believed to sometimes occur in the sudden shutting in a well. The sudden closure of the BOP will cause pressure pulses to move down the wellbore, and possibly cause formation damage. This is not the case using old taps, as these must be turned downwards, and this can be compared to gradually closing the choke.

A *soft shut-in* involves closing the BOP with the choke open, and then shutting in the well by closing the choke.

Formation damage and added influx-time are the main concerns with these methods. The hard shut-in is less time consuming, which able the possibility of a quicker stop of influx and reduces the risk of human errors controlling the choke.

Both methods have their advantages and disadvantages, so past experience, geologic environment and personal preferences must be used for discussion making.

6.7.2 Conventional Kick Circulation

After one of the two previous shut-in methods, the next step is to safely circulate the kick out of the well. The *driller`s method* and the *wait and weight method* (W&W) are the conventional methods used today. W&W is also referred to as the Engineer`s method. According to Skalle (2011), the most commonly used method to restore an overbalanced situation after a kick is the driller`s method.

6.7.3 Driller`s Method

In the driller`s method the pore fluid is displaced before kill mud is injected. In other words, the technique uses two circulations to kill the well. First the kick is circulated to the surface (out) using the original weight mud (OWM). (By doing this, further influx is prevented, and it ensures that the process can start right away.) Kill weight mud (KWM) is prepared while the kick is circulated out, and then the second circulation kills the well. The method induces higher pressure in the un-cased annulus, and compared with W&W more time is required for the entire operation.

6.7.4 W & W

Using the W & W method, the mud weight is being increased and pumped into the well immediately. The killing is executed in only one circulation. When the kick is detected, verified, and shut-in, the KWM is prepared. After the KWM is ready, the kick is circulated out by displacing the OWM with KWM. This method is more complex than the driller`s method, as circulating out the kick and killing the well is done in one operation.
The added time using this method might invite further influx, and as a result the pressures might increase.

Which method to use in the killing of the well depends on many factors. Well design, type of kick, location, rig and well type are among the things being considered. But most of all it comes down to earlier experiences and personal preferences.

Bullheading is also a method being used. When applying this method, mud is pumped back into the wellbore with the intent of reversing the flow and fracturing the formation, making paths the kick can flow into, and thereby prevent the kick from reaching the surface.

Skalle (2011) purposes the use of the W &W method if there is a risk of fracturing the casing shoe. The annular pressure becomes higher when applying the driller`s method, and the choke nozzles erode quicker. W & W is used in long open hole sections to reduce the pressure in the annulus, otherwise the driller`s method is preferred.

If the kick circulation is a success, the balance in the well is restored, as can be seen from Figure 23 in Chapter 5. The same figure also shows that other elements/barriers must be initiated to avoid a blowout if the circulation fails.

Chapter 7
Summary and Recommendations for Further Work

7.1 Introduction

This final chapter sums up the content and the result of the master`s project. The results are discussed and recommendations for future work are given.

7.2 Summary and conclusions

The overall objective was to study, evaluate, and discuss possible approaches to the assessment of dynamic well barriers. All the sub-objectives stated in Chapter 1 have been answered, at least in the way the author has interpreted them.

This report is based on books and literature, and the use of various databases. The second chapter uses information found mainly in NORSOK D-010 (2013) when identifying and describing traditional well barriers. For the survey of requirements, references to NORSOK D-010 (2013) and PSA (2010) are made. Two independent barriers are found to be required in all types of well operations, and various other requirements exist in standards and guidelines.

The new standard, ISO/TS 16530-2, has also been mentioned, together with a study from DNV GL. In this study, the differences in regulations between the NCS and the Gulf of Mexico have been mapped, showing several differences between Norway and the US.

Well barrier diagrams have been used in the oil and gas industry for decades to assess well integrity. Chapter 3 presents various approaches to illustrate well barrier diagrams. A horizontal diagram from Holand (1996), a version from Duijm and Markert (2009) and a method from Corneliussen (2006) are presented. A new suggested version of a vertical diagram, from reservoir at the bottom to the surroundings at the top, is also being illustrated. In this approach all the primary barriers have been assembled, and all the secondary barriers placed together. Arrows are used to point out the various pathways between the barriers, different annuli, to the surroundings.

Dynamic well barriers during drilling are the main topic in Chapter 4. Overbalanced drilling, also referred to as conventional drilling, is the drilling type devoted most time/attention, but underbalanced drilling and its main barriers are also introduced and highlighted.

The mud circulation system is important for both overbalanced and underbalanced drilling, and a basic system description is given, together with the purpose of the drilling fluid and its most common categories.

For overbalanced drilling, only one primary barrier is in place, which is the mud column. The secondary barriers are identified in this report, and the purposes and descriptions for each one are listed in a table. Furthermore, the BOP and its various components are described. The main differences between the two types of drilling are highlighted in the report.

To operate and control the functions of a BOP stack, a control system is needed. Some existing control systems are briefly described, and different types of backup control systems mentioned.

As a part of the report, approaches for the assessment of dynamic well barriers are suggested in Chapter 5. Four approaches are described, included a new approach. This new approach is a combination of event tree- and fault tree analysis. A case study is selected for the use of this approach, and this is an overbalanced drilling operation taking place in deep waters, after a kick has occurred. Two event trees are used to illustrate the dynamics of the hazardous event, the kick, and various fault trees are used for the purpose of illustrating and breaking down the barriers involved in the simplified event tree. This event tree (Figure 23) has also been the basis for calculation of failure rates, and the probability of failure on demand for a selected barrier. Studies by Holand (2012) and Holand (2001) are used to gain information for the calculations. Calculations for two of the end events are made. For the end event, "full blowout", the calculation showed a failure rate of $2.2 * 10^{-5}$ per year, or approximately once every 45455 years. "Balance in well restored" showed a failure rate of $5.47 * 10^{-3}$ per year, or approximately once every 183 years. Comparing these results with reliability studies, such as Holand (2012), and the use of common sense, these results must be assumed to be unrealistically low. A rough PFD assessment of "BOP fails to seal annulus" was made, with a result of 0.00433. This is a SIL 3 level, and is higher than the minimum SIL 2 level, for isolation using the annulus function, set by OLF (2004). Holand (1999) fault tree data shows that the probability to seal the annulus, closing in the kick, only with two annular preventers available is estimated to be 0.0018.

The elements in the fault trees illustrating a "kick" and "kick detection fails" are further described in Chapter 6. The content of this chapter are included in the report to create a better understanding of the issues surrounding a kick. From the research in this chapter it becomes clear that the human factor is important when it comes to detect, interpret signs, and take actions when it comes to a kick. The human decisions being taken during the drilling process will have affect on the outcome of hazardous events.

7.3 Discussion

Section 5.5.1 deals with calculation of failure rates. The results from the calculations seem high for the outcomes that have been calculated. A reason for this may be common cause failures, and the event tree analysis capability of handling these dependencies. Another reason for this can be the placement of the various barriers in the event tree, the activation of the barriers are conditional, and assume that another/previous event has occurred. A different layout for the event tree, would have given a different result. But seen in retrospect, perhaps a more appropriate measure would have been calculating the probability instead, as remarked in the report. Determining the probability would probably be a more adequate measure. E.g., we do not know if the circulation equipment has worked before, or if it will function as intended, when it is needed. The failure rates were calculated to illustrate how it could be done, and not using a program to calculate.

The PFD calculation only considers the reliability of the equipment, and the result shows a relatively low probability. This may be due to the relatively frequent testing of the equipment, and not including the human factor.

The new suggested approach for the assessment of dynamic barriers must be tested more before a conclusion of its ability can be taken. But maybe it’s becoming a little bit too static, only using an event tree to show the dynamic of the hazardous event. The approach is limited to a certain operation, and has to be more developed to include other types of drilling operations.

7.4 Recommendations for further work

This thesis was carried out within a limited period of time. The new suggested approach can be further developed and tested, thus also be used in other operations.

There are many operations during drilling, and thereby many topics and possible case studies to examine. Tripping out of the hole is one of them, and a large contributor to kick occurrence. Improper filling of mud, is one of the causes of lost primary barrier in this situation. Disconnecting of the riser is another difficult topic, how to maintain the density of the mud and thereby provide an overbalance in the well, called drilling with riser margin. Issues surrounding cement and the kick cause, too low hydrostatic head, while the cement setting, can also be one. These are just some topics to lock into, and each can be further related to various types of drilling, such as overbalanced and underbalanced. Each drilling types will have own “problems” in the assessment of their barriers.

The assessment of dynamic barriers has proven not to be a simple task, and further work must be done on the subject. Here are some suggestions for further assessment of the barriers:

Simulation

The use of computer programs to simulate the various conditions in the well, may be helpful to better understand, when and how, the different barriers need more attention. Various parameters can be changed easily, and worst case scenarios and kick-conditions can be provoked. Existing well procedures can be controlled, and their limitations reveled.

Procedure HAZOP

This approach is used to review procedures or operational sequences, and can also be seen as an extension of a job safety analysis (JSA). The JSA-analysis can be used because the drilling process is a nonroutine job with high risk involved, and has lead to several incidents or accidents. A further development of the drillers HAZOP may also be possible.

Quantitative requirements

Only some of the barriers have been awarded SIL requirements in OLF (2004), for various reasons. Events such as kick detection and mud circulation have been recommended not to be set with a minimum SIL requirement. The reasoning may be questionable, and maybe this can be developed/challenged for the next version. Perhaps only parts of the barrier system can be given quantitative requirements. It would be easier to look for deviations with something to compare with.

The human factor

What if we could eliminate the human factor in the decision-making-process? Let the computer take crucial decisions, such as take proper action surrounding a kick, or to push the button to initiate the BSR and close down the well. The computer could be given parameters to operate between, and further make a move, when the deviation from the settings is getting to large. Would this make things better? A human makes mistakes, but have often the capability to understand that, and try to correct it. Risk will always be a part of the petroleum industry as long as there are so many risk influencing factors present at all times in various operations.

Appendix A

Acronyms

AMF	Automatic mode function
API	American Petroleum Institute
BHP	Bottom hole pressure
BOP	Blowout preventer
BSR	Blind shear ram
CCU	Central control unit
CIV	Chemical injection valve
DHSV	Downhole safety valve
DNV	Det Norske Veritas
DNV GL	Det Norske Veritas, Germanischer Lloyd
EDS	Emergency disconnect system
EH	Electro hydraulic
ET	Event tree
ETA	Event tree analysis
FIT	Formation integrity test
FT	Fault tree
FTA	Fault tree analysis
HAZOP	Hazard and operability study
HC	Hydrocarbons
HPU	Hydraulic power unit

HSE	Health, safety and environment
ISO	International Organization of Standardization
JSA	Job safety analysis
KWM	Kill weight mud
LAP	Lower annular preventer
LOT	Leak off test
LMRP	Lower marine riser package
LPR	Lower pipe ram
MAC	Multiple Activity Chart
MUX	Multiplexing control system
MPR	Middle pipe ram
MWD	Measurement while drilling
NCS	Norwegian Continental Shelf
OBD	Overbalanced drilling
OLF	Oljearbeidernes Fellessammenslutning (The Norwegian Oil Industry Association)
OWM	Original weight mud
PFD	Probability of failure on demand
Ph	Hydrostatic pressure
Pp	Pore pressure
PSA	Petroleum Safety Authority
ROP	Rate of penetration
ROV	Remotely operated vehicle

SEM	Subsea electronic module
SIL	Safety Integrity Level
SCSSV	Surface controlled subsurface safety valve
TS	Technical specification
TVD	True vertical depth
UAP	Upper annular preventer
UBD	Underbalanced drilling
UPR	Upper pipe ram
W & W	Wait and weight
WBE	Well barrier element
WBS	Well barrier schematic
WR-SCSSV	Wireline Retrievable Surface controlled subsurface safety valve

Appendix B

Primary well barrier elements during production

Well barrier element	Description	Function/Purpose
In-situ formation Primary: cap rock Secondary: 13 3/8 shoe	The formation that has been drilled through and is located beside the casing annulus isolation material or plugs set in the wellbore.	To provide a permanent and impermeable hydraulic seal preventing flow from the wellbore to surface/seabed or other formation zones.
Casing cement Primary: (9 5/8”) Secondary: (13 3/8”)	Consists of cement in solid state located in the annulus between concentric casing strings, or the casing/liner and the formation.	To provide a continuous, permanent and impermeable hydraulic seal along hole in the casing annulus or between casing strings, to prevent flow of formation fluids, resist pressures from above or below, and support casing or liner strings structurally.
Casing Primary: (9 5/8”) Secondary: (13 3/8”)	Consists of casing/liner and/or tubing in case tubing is used for through tubing drilling and completion operations.	The purpose of casing/liner is to provide an isolation that stops uncontrolled flow of formation fluid or injected fluid between the casing bore and the casing annulus.
Production packer	Consists of a body with an anchoring mechanism to the casing/liner, and an annular sealing element which is activated during installation.	1. Provide a seal between the completion string and the casing/liner, to prevent communication from the formation into the A-annulus above the production packer. 2. Prevent flow from the inside of the body element located above the packer element into the A-annulus as part of the completion string.
Completion string	Consists of tubular pipe	One purpose is to provide a conduit for formation fluid from the reservoir to surface, or vice versa. Another purpose is to prevent communication between the completion string bore, and the A-annulus.

Completion string component (Chemical injection valve), CIV	Consist of a housing with a bore. The completion string component is designed to prevent undesired communication between the completion string bore and the A-annulus.	Its purpose may be to provide support to the functionality of the completion, e.g. gas-lift or side pocket mandrels with valves or dummies, nipple profiles, gauge carriers, control line with seals/connections, etc.
Downhole safety valve (incl. control line)	Consists of a tubular body with a close/open mechanism that seals off the tubing bore.	Its purpose is to prevent flow of hydrocarbons or fluid up the tubing.

Appendix C

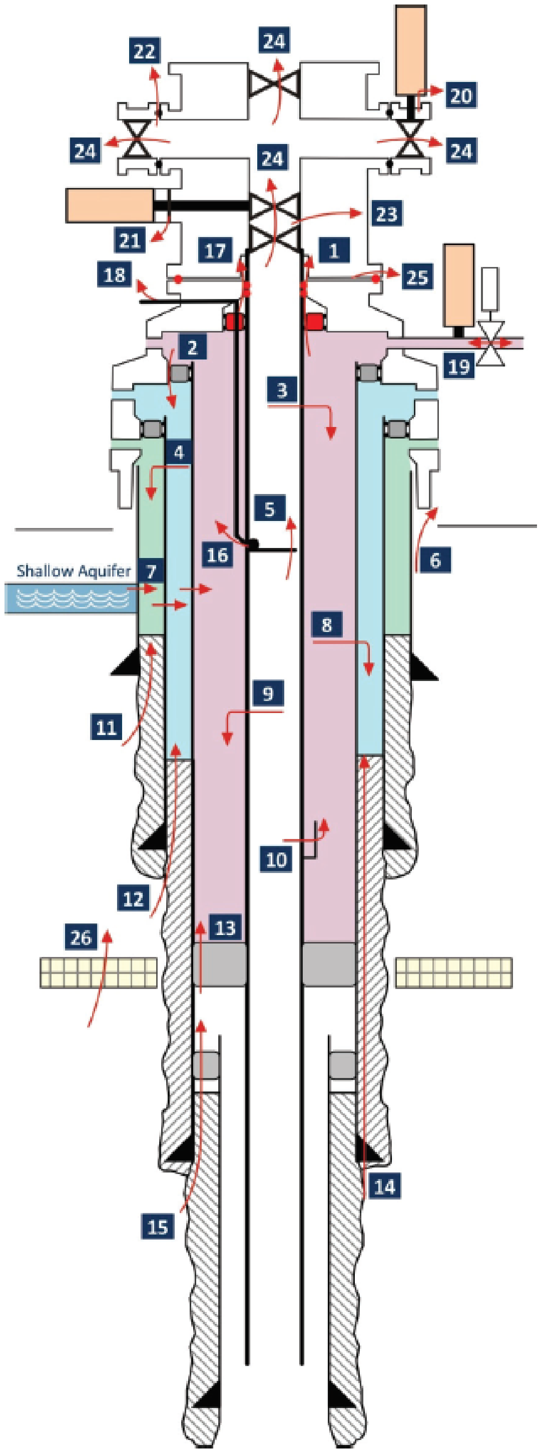
Secondary well barrier elements during production

Well barrier element	Description	Function/Purpose
Wellhead (Casing hanger with seal assembly)	Consists of the wellhead body with annulus access ports and valves, seals and casing hangers with seal assemblies.	To provide mechanical support for the suspending casing and tubing strings and for hook-up of risers or BOP or tree and to prevent flow from the bore and annuli to formation or the environment.
Wellhead / annulus access valves	Consists of an annulus isolation valve(s) and valve housing(s) connected to the wellhead.	To provide ability to monitor pressure and flow to/from the annuli.
Tubing hanger (body seals and neck seal)	Consists of a body, seals, feed throughs, and bore(s) which may have a tubing hanger plug profile.	1. Support the weight of the tubing; 2. Prevent flow from the bore and to the annulus; 3. Provide a hydraulic seal between the tubing, wellhead and tree; 4. Provide a stab-in connection point for bore communication with the tree. 5. Provide a profile to receive a BPV or plug to be used for nippling down the BOP and nippling up the tree.
Wellhead (WH / XT Connector)	Consists of the wellhead body with annulus access ports and valves, seals and casing hangers with seal assemblies.	To provide mechanical support for the suspending casing and tubing strings and for hook-up of risers or BOP or tree and to prevent flow from the bore and annuli to formation or the environment.
Surface tree	Consists of a housing with bores that are fitted with swab-, master valves, kill/service valves and flow valves.	1. provide a flow conduit for hydrocarbons from the tubing into the surface lines with the ability to stop the flow by closing the flow valve and/or the master valve;

Surface tree (continues..)		2. provide vertical tool access through the swab valve; and 3. provide an access point where kill fluid can be pumped into the tubing.

Appendix D

Example of possible well leak paths



1 Tubing Hanger/Sea Leak
2 Wellhead Seal Leak
3 Tubing Leak Above SSSV
4 Intermediate Casing Leak
5 SSSV Leak
6 External Leak Or Seep Outside Conductor
7 External Corrosion from Aquifer
8 Production Casing Leak
9 Tubing Leak Below SSSV
10 Leak Through The SPM Accessory
11 Leak into an Outer Annulus From Casing Shoe
12 Leak Into B - annulus From Casing Shoe
13 Leak Around the Production Packer
14 Leak Via Through Poor Cement or Micro Annulus Channel
15 Leak through the Liner Hanger or Liner Cement
16 Hydraulic Control Line Leak to A - annulus
17 Hydraulic Leak Line At Xmas Tree Void/Tubing Hange
18 Leak At Wellhead Outlet
19 Leaks through Xmas Tree and Wellhead Valves to or from the Process Facilities
20 Stem Packing Leak
21 Bonnet Seal Leak
22 Flange Leak
23 Xmas Tree Body Leak
24 Xmas Tree Valve Leak
25 Xmas Tree Connector Leak
26 Leak Through Cap Rock

Note: Often two or more simultaneous modes of failure can complicate diagnosis, and also lead to a significant worsening of the Well Integrity condition.

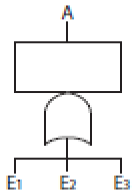
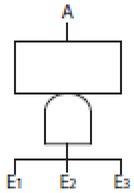
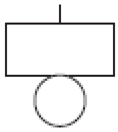
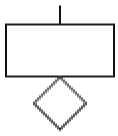
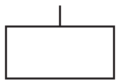
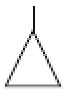
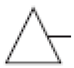
Figure: Well diagram showing some typical modes of well failure

(from ISO/TS 16530-2, 2014

Appendix E

Fault tree symbols

(from Rausand, 2004)

Type	Symbol	Description
Logic gates	OR-Gate 	The OR-gate indicates that the output event A occurs if any of the input events Ei occur.
	And-Gate 	The AND-gate indicates that the output event A occurs only when all the input events Ei occur simultaneously.
Input events	Basic event 	The basic event represents a basic equipment fault or failure that requires no further development into more basic faults or failures.
	Undeveloped event 	The undeveloped event represents an event that is not examined further because information is unavailable or because of insignificant consequences.
Description	Comment rectangle 	The comment rectangle is for supplementary information.
Transfer symbols	Transfer out 	The transfer out symbol indicates that the fault tree is developed further at the occurrence of the corresponding transfer in symbol.
	Transfer in 	

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