NTNU – Trondheim
Norwegian University of
Science and Technology

# Improved Methods For Reliability Assessments Of Safety-Critical Systems

An Application Example For BOP Systems


## Remi Pinker


Subsea Technology
Submission date: June 2012
Supervisor: Mary Ann Lundteigen, IPK
Co-supervisor: Marvin Rausand, IPK


Norwegian University of Science and Technology
Department of Production and Quality Engineering

NTNU
Faculty of Engineering Science and Technology
Department of Production and Quality Engineering



Date 2012-01-10 Our reference MAL/LMS

**MASTER THESIS**
**2012**
**for**
**stud. techn. Remi Pinker**

# IMPROVED METHODS FOR RELIABILITY ASSESSMENTS OF SAFETY-CRITICAL SYSTEMS: AN APPLICATION EXAMPLE FOR BOP SYSTEMS

## (Forbedrede metoder for pålitelighetsvurdering av sikkerhetskritiske systemer: Med en utblåsningsventil (BOP) som anvendelseseksempel)

System reliability assessments provide important input to decision-making in relation to design-related issues as well as during operation and maintenance. The main purpose of a system reliability assessment is to provide realistic predictions of the future performance of the system, within the constraints of available data, operating conditions, and modeling capabilities. Special applications and operating conditions sometimes reveal inadequacies in current assessment methods. One such application is the blowout preventer (BOP), a safety-critical system that is used to ensure safe drilling and well interventions of oil and gas wells. The ability of the BOP system to function as a safety barrier depends on the ongoing operation, whether it is drilling, tripping-in, tripping-out, well logging, and so on. At the same time, the likelihood of demands to be handled depends on the same operations. An average estimate of the BOP's ability to function on demand is therefore not an adequate reliability parameter. A BOP system deviates from many other safety barrier systems since it does not have a fail-safe design (except for the choke and kill valves). Another deviation is due to the many different uses of the BOP and its components. Many of the components are operated much more often than during the periodic proof tests. The usual formulas for reliability calculations based on periodic proof testing can therefore not be used directly.

In this master thesis, the main objective is to propose solutions to some of the challenges indicated above, using the BOP as an example. More specifically, the candidate shall:

1. *Give a presentation of a typical (standard) BOP system, its requirements and reliability challenges*
    a. Describe and classify the main functions and the associated performance requirements of a BOP system.

b. Identify and discuss the main operating situations of a BOP in light of the ability of the BOP to stop well kicks.
c. Identify recent BOP stack configurations and describe the pros and cons of these related to a standard BOP configuration.

2. *Suggest improved approaches to reliability assessment of BOP systems that can incorporate some of the above challenges*
   a. Carry out and document a literature survey on how reliability analyses of BOPs have been performed in the past, and discuss the limitations of these approaches.
   b. Suggest alternative methods for BOP reliability assessment and illustrate their pros and cons through a case study.
   c. Propose a new overall approach to risk and reliability assessment of a BOP system, which includes proposals for how to solve some of the identified challenges.
   d. Identify related issues that need further research, and give recommendations for such research.

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: June 11th 2012.

Two bound copies of the final report and one electronic (pdf-format) version are required.

Responsible supervisor at NTNU: Professor Mary Ann Lundteigen
Telephone: 73 59 71 01
Mobile telephone: 930 59 365
E-mail: mary.a.lundteigen@ntnu.no

Co-supervisor at NTNU: Professor Marvin Rausand
Telephone: 73 59 25 42
E-mail: marvin.rausand@ntnu.no

**DEPARTMENT OF PRODUCTION AND QUALITY ENGINEERING**

Per Schjølberg
Associate Professor/Head of Department

Mary Ann Lundteigen
Responsible Supervisor

# Preface

This master thesis is written by stud. Techn. Remi Pinker during the spring semester of 2012. It is written at the Norwegian University of Science and Technology (NTNU) as part of the 2-year master`s degree in Subsea technology. The project duration is 20 weeks.

The title of the master thesis is "Improved methods for reliability assessment of safety-critical systems: An application example for BOP systems", and will be written at the Department of Production and Quality Engineering (IPK).

I would like to thank my main supervisor Professor Mary Ann Lundteigen and my Co-supervisor Professor Marvin Rausand for their help and guidance with this thesis.

Trondheim, 11th of June, 2012

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Remi Pinker

# Summary

A blowout preventer is a safety critical system that is used during drilling and well interventions of oil and gas wells to make sure the operations are safe. The main function of a blowout preventer system is to seal the well in order to prevent a blowout. There are several different blowout prevent stack configurations in use, and each of these configurations have their pros and cons.

Giving an accurate representation of the reliability of a blowout preventer system can be challenging. A blowout preventer goes through many different operational situations, and the BOP`s ability to act as a safety barrier will vary for each of these situations. Giving an average estimate of the BOP`s ability to function on demand is therefore not an adequate reliability parameter. The main objective of this master thesis is therefore to propose a new and improved method for reliability assessment of blowout preventer systems.

A new approach to reliability assessment of blowout preventers is presented in this thesis. To account for the sequence of events, a fault tree analysis is combined with an event tree analysis. Fault tree analyses are performed to calculate the PFD for each of the branches in the event tree. The probability of each of the end states in the event tree can then be calculated. This will give a more accurate result then a fault tree analysis on its own.

Separate analyses are made for the two main operational situations. One for the operational situations “open hole” and another for the operational situation “drill pipe going through the BOP”. Having two separate analyses gives a more accurate representation of the reliability at the given times, because the barriers in effect vary depending on what operational situation the BOP is going through.

## Sammendrag

En utblåsningssikring er et sikkerhetskritisk system som brukes under boring og brønnintervensjoner av olje og gass brønner for å sørge for sikker drift. Hovedfunksjonen til en utblåsning er å forsegle brønnen for å hindre en utblåsning. Det finnes flere forskjellige sammensettinger av utblåsningssikringer, og hver av disse sammensettingene har sine fordeler og ulemper.

Å gi et presist estimat av påliteligheten til en utblåsningssikring kan by på utfordringer. En utblåsningssikring går gjennom mange forskjellige operative faser, og evnen til å fungere som en sikkerhetsbarriere vil variere for hver av disse fasene. Et gjennomsnittlig estimat av påliteligheten vil derfor ikke være presist nok. Hovedmålet med denne masteroppgaven er derfor å foreslå en ny og forbedret metode for pålitelighetsvurdering av utblåsningssikringer.

En ny metode for pålitelighetvurdering av utblåsningssikringer er presentert i denne oppgaven. En feiltreanalyse er kombinert med en hendelsestreanalyse for å ta hensyn til hendelsesforløpet. Feiltreanalyser er utført for å beregne PFD for hver av grenene i hendelsestreet. Sannsynligheten for hver av slutt-tilstandene i hendelsestreet kan da bergenes. Dette vil gi et mer nøyaktig resultat enn en feiltreanalyse ville gitt på egenhånd.

Separate analyser er gjort for de to viktigste operative fasene. En for den operative fasen "åpent hull" og en annen for den operative fasen "borerør gjennom BOP". Å ha to separate analyser gir en mer nøyaktig gjengivelse av påliteligheten, fordi hvilke barrierene som er tilgjengelig varierer avhengig av hvilken operativ fase utblåsningssikringen befinner seg i.

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**List of Abbreviations**

| | |
|---|---|
| AP | Annular preventer |
| BOP | Blowout preventer |
| BSR | Blind shear ram |
| CSR | Casing shear ram |
| CSU | Critical safety unavailability |
| DP | Dynamic position |
| FMEA | Failure mode and effect analysis |
| FMECA | Failure mode effect and criticality analysis |
| GoM | Gulf of Mexico |
| HPU | Hydraulic power unit |
| IBOP | Inside blowout preventer |
| LPR | Lower pipe ram |
| MFDT | Mean fractional dead time |
| MMS | Minerals Management Service |
| MPR | Middle pipe ram |
| NPD | Norwegian petroleum directorate |
| PFD | Probability of failure on demand |
| PR | Pipe ram |
| ROV | Remote operated vehicle |
| SEM | Subsea electronic module |
| SIL | Safety integrity level |
| SIS | Safety instrumented system |
| TIF | Test independent failure |
| UPR | Upper pipe ram |

# 1 Introduction

## 1.1 Background

System reliability assessment is used to gain important information used for decision-making in design related issues as well as during operation and maintenance. This helps predict how the system may perform in the future, within the constraints of available data and modeling capabilities. Having an accurate way of doing a reliability analysis is important, because it is a government requirement to know the reliability of the equipment.

However, for some complex systems, the current assessment methods in use sometimes prove to be insufficient. A blowout preventer (BOP) is an example of this. A BOP is a safety-critical system that is used during drilling and well interventions of oil and gas wells to make sure the operations are safe. The main function of a BOP system is to seal the well in order to prevent a blowout. The BOP is a very important component, and failure of the BOP can lead to catastrophically events. An example of what can happen if the BOP does not function when needed, is the Deepwater horizon accident. In this tragic event, eleven men died and almost five million barrels of oil leaked from the Macondo well and in to the Gulf of Mexico.

The BOP goes through many different operational situations, and the BOP`s ability to act as a safety barrier will vary for each of these situations. In addition to that, the probability that a situation occurs that require the BOP to act as a safety barrier also depends on the various operational situations. Because of this, the BOP`s average ability to function on demand may not be a sufficient reliability parameter. Another challenge is that the reliability calculations based on test intervals operates with a fixed test interval. In practice, the test interval may vary, so the result will be too optimistic.

These special conditions require a new and improved way of performing a reliability assessment. If a solution to some of the challenges mentioned above was found, it would make reliability assessment of BOP`s more accurate.

## 1.2 Objectives

The main objective of this master thesis is to propose an improved method of performing reliability analysis of a BOP system. More specifically:

1. Give a presentation of a typical (standard) BOP system, its requirements and reliability challenges
    a. Describe and classify the main functions and the associated performance requirements of a BOP system.
    b. Identify and discuss the main operation situations of a BOP in light of the ability of the BOP to stop well kicks.
    c. Identify recent BOP stack configurations and describe the pros and cons of these related to a standard BOP configurations

2. Suggest improved approaches to reliability assessment of BOP systems that can incorporate some of the above challenges
    a. Carry out and document a literature survey on how reliability analyses of BOPs have been performed in the past, and discuss the limitations of these approaches.
    b. Suggest alternative methods for BOP reliability assessment and illustrate their pros and cons through a case study
    c. Propose a new overall approach to risk and reliability assessment of BOP systems, which include proposals for how to solve some of the identified challenges
    d. Identify related issues that need further research, and give recommendations for such research.

## 1.3 Limitations

The BOPs studied in this master thesis are limited to subsea BOPs used during drilling. The main focus will be on applications of BOPs on the Norwegian continental shelf.

The analyses that are done are not that thorough, so the results do not give an accurate representation of how the systems will actually perform during real operations. The analyses are rather meant as an example to show how they should be performed. The analysis are qualitative analysis.

## 1.4 Research Approach

To solve the problems, information was gathered mostly through searching on the web through databases like Science Direct, OnePetro and Google scholar. Standards and articles on the subject was the main source of information. Books on the subject and similar papers were also used. To find this information, search words like BOP, reliability, requirements, subsea, etc. were used. Frequent meetings and discussions with my supervisor on how to solve the problems have also been done regularly.

## 1.5 Structure of the Report

The rest of the report is structured as follows.

| | |
|---|---|
| Chapter two: | A brief summary of the most relevant literature on the subject is presented. |
| Chapter three: | Gives a quick introduction to different reliability methods, SIL and classification of functions. |
| Chapter four: | Describes the operational situations that the BOP will go through during various parts of operations. What barriers that will be in effect during the different operational situations will be discussed. |

| | |
|---|---|
| Chapter five: | Gives a general overview of a BOP system and the main components. This is done so that the reader will understand what exactly a BOP is and how it function. |
| Chapter six: | Discusses the pros and cons with how different BOP stack configurations are put together. Three different BOP stacks are identified and compared. The stacks identified are; The Deepwater Horizon BOP stack, the classical BOP stack and a typical modern stack BOP stack. |
| Chapter seven: | Presents the main functions and requirements of a BOP system. The functions identified will also be classified as shown by Rausand and Høyland (2004) |
| Chapter eight: | Describes the challenges associated with performing a reliability assessment of a BOP system. |
| Chapter nine: | Presents an example of how a fault tree analysis can be performed, and gives a better overview of what component failures will lead to the top event. An FMECA analysis is also presented. |
| Chapter ten: | Discusses how reliability analyses have been performed in the past, and discusses the pros and cons of some of these methods. |
| Chapter eleven: | Introduces an alternatives method for reliability assessments. |
| Chapter twelve: | Suggests an overall new approach to risk and reliability assessment of a BOP system. |
| Chapter Thirteen: | Conclusion and further work. |

# 2 Literature Survey

This chapter presents the most relevant literature and standards on the subject that were found and used during this master thesis. This literature survey is presented so that the readers can get a good overview of what has been done on this subject in the past, and so that they will know where to look if they want to know more about the subject.

## 2.1 SINTEF`s BOP Reliability studies

The most thorough reliability study of BOP systems has been carried out by SINTEF. From 1981 to 2001, SINTEF carried out a number of reliability studies of subsea BOP systems on behalf of various oil companies and the Norwegian Petroleum Directorate (NPD). The studies that have been carried out are:

Phase I: Analysis of failure date from 61 exploration wells drilled from semisubmersible rigs and BOP system analysis (Rausand, 1983a).

Phase II: Analysis of failure data from 99 exploration wells from semisubmersible rigs and mechanical evaluation of BOP components (Rausand et al., 1985) & (Hals and Molnes, 1984).

Phase III: Evaluation of operation and maintenance of subsea BOP components, test procedures and operational control (Holand and Molnes, 1986).

Phase IV: Analysis of 58 exploration wells, drilled during the period 1982-1986. Fault tree analysis was used to assess the availability of the BOP (Holand, 1987).

Phase V: Analysis of 47 exploration wells, drilled during the period 1987-1989. The BOP failures were recorded and analyzed, and recommendations regarding test intervals were given (Holand, 1989).

Phase I DW: Analysis of 140 wells drilled from 1992 to 1997. Fault tree analysis was used to compare three types of control systems regarding their ability to close in a well when a kick occurred (Holand, 1997a) & (Holand, 1997b).

Phase II DW: Analysis of 83 wells drilled in water depths of 400-2000 meters during the period 1997-1998. The report is written for The Mineral Management Service (MMS), and evaluation of both the safety and downtime aspect of failures are presented (Holand, 1999).

Other: The report “Deepwater Kicks and BOP Performance” is a follow up study of Phase II DW. Fault tree analysis was used to analyze the BOP as a safety barrier based on BOP configurations and the relevant kick experience (Holand and Skalle, 2001).

## 2.2 BOEMRE

***Blowout Preventer Maintenance and Inspection in Deepwater Operations, (work in progress)***

BOEMRE is currently writing a report on the subject "Blowout Preventer Maintenance and Inspection in Deepwater Operations". The study will compare current BOP maintenance, inspection and testing practices to standards, regulations and recommended practices. Quantitative analysis will be performed in order to determine the criticality and reliability of the BOP system (BOEMRE, 2011a).

***Report regarding the causes of the April 20, 2010 Macondo well blowout, 2011***

This report sets forth in detail the investigation findings, conclusions, and recommendations regarding the reason for the Deepwater Horizon accident. The findings and conclusions are presented in the following subject areas: Well design, cementing, possible flow paths, temporary abandonment in the Macondo well, kick detection and rig response, ignition source and explosion, the failure of the Deepwater Horizon blowout preventer, regulatory findings and conclusions and company practices (BOEMRE, 2011b).

## 2.3 WEST Publications

***Blowout Prevention Equipment Reliability Joint Industry Project (phase I – Subsea), 2009***

A reliability study conducted to examine the historical reliability of subsea well control system operating in the GoM under the jurisdiction of the MMA. The goal of the study was to understand how testing impacts BOP reliability, and to determine a recommended optimal test frequency in order to improve efficiency while maintaining the reliability of the BOP (WEST, 2009).

***Evaluation of Shear Ram Capabilities, 2004***

This is a study of the BOP`s capability to shear a pipe ram at the most demanding conditions to be expected. Data from three BOP shear ram manufacturers and one drill pipe manufacturer were collected and a review and comparison of the manufacturer`s shear testing criteria, equipment failures and ram configurations were done (WEST, 2004).

***Evaluation of Secondary Intervention Methods in Well Control, 2003***

This report is a review of the design and capabilities of various secondary BOP intervention systems. In addition, the best systems and practices in use are defined, and recommendations on how to enhance their effectiveness are given (WEST, 2003).

## 2.4 Standards

***OLF 070 – Application of IEC 61508 and IEC 61511 in the Norwegian petroleum industry, 2004.***

The overall purpose of this document is to simplify the application and work as a guideline for the standards IEC 61508 and IEC 6151 for use in the Norwegian petroleum industry. Minimum SIL requirements for the most common instrumented safety functions on a petroleum production installation are provided (OLF-070, 2004).

***NORSOK D-001 – Drilling facilities, 1998.***

The main objective of this NORSOK standard is to contribute to an optimization of the design of drilling facilities, their systems and equipments with respect to utilization, operational efficiency, life cycle cost and to stipulate acceptable safety levels. It describes the design, installation and commissioning principles and requirements for the drilling facilities and their system and equipment on fixed and mobile offshore installations (NOROSK D-001, 1998).

***NORSOK D-010 - Well integrity in drilling and well operations, 2004.***

In this NORSOK standard, the focus is on well integrity. It defines the minimum functional and performance oriented requirements and guidelines for well design, planning and execution of well operations in Norway (NORSOK D-010, 2004).

***IEC 61508 – Functional Safety of Electrical/Electronic/Programmable Electronic Safety - related Systems, 2005.***

This is an international standard of rules applied in the industry. It is intended to be a basic functional safety standard applicable to all kinds of industry, with its origins in the process control industry sector. The standard has seven parts. Part 1-3 contain the requirements of the standard, and parts 4-7 are guidelines and examples for development. (IEC 61508, 2005).

***IEC 61511 – Functional Safety – Safety instrumented systems for the process industry sector, 2003.***

IEC 61511 is a technical standard that sets out practices in the engineering of systems that ensure the safety of an industrial process through the use of instrumentation. It converse the design and management requirements for a SIS through its lifetime. The standard consists of three parts (IEC 61511, 2003):

1. Framework, definitions, systems, hardware and software requirements

2. Guidelines in the application of IEC 61511-1

3. Guidance for the determination of the required safety integrity levels

# 3 Reliability Theory

A number of methods for system reliability analysis are presented by Rausand and Høyland (2004). A short description of each of these methods will now be given. Safety integrity level (SIL) and classification of function will also be introduced in this chapter. The information presented, is mostly based on Rausand and Høyland (2004).

## 3.1 Fault Tree Analysis

A fault tree analysis is one of the most common analysis tools when it comes to reliability studies. It is a deductive technique that starts with a specified system failure or accident, called the TOP event. Events that may lead to the top event are then identified. Next, one step backwards is taken, and events that leads to the previously identified events are now identified.  This process is continued backwards in the chain until we have enough details of the system. The failures and events are combined through logic gates in the fault tree. The result will be an illustration of the possible combination of failures and events that may lead to the top event. A combination of failures that leads to the top event is called a cut set. The fault tree may then be evaluated quantitatively or qualitatively, depending on the objective of the analysis. In chapter 9.1, a fault tree analysis is performed on a subsea BOP system.  An overview and description of the different symbols used in a fault tree, is presented in appendix B.

## 3.2 Cause and Effect Diagram

A cause and effect diagrams are often used to identify possible causes for a system failure, and is similar to a fault tree analysis, but it is less structured. The causes are arranged based on how important they are. Five main categories are often used. These are: manpower, methods, materials, machinery and environment.  A team of expert will then identify the factors within each category that could affect the system failure being studied. This method can only be performed as a qualitative analysis. Figure 3.1 shows an example of a cause and effect diagram.

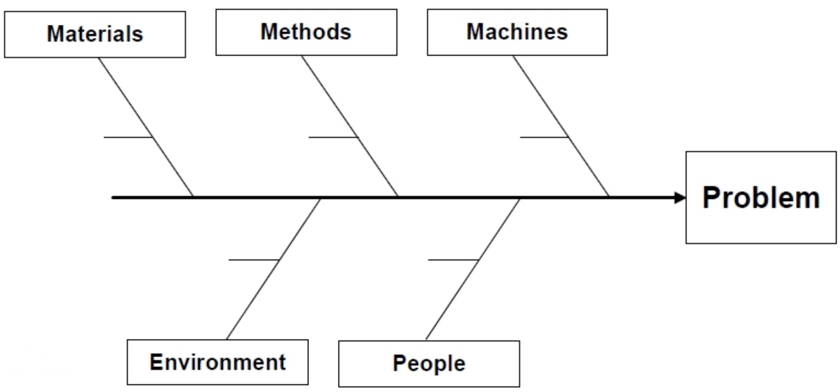


**Figure 3.1 Cause and effect diagram**
**Adapted from (Rausand and Høyland, 2004)**

## 3.3 Event Tree

An accident may have many different outcomes, depending on how the barriers of a given system will function. The most commonly used method to analyze the progression of an accident, is with the help of an event tree analysis. In the event tree, the possible outcomes resulting from failure or success of the different barriers are followed. An event tree analysis is often used in risk analysis, but can also be used during design phase of a project to demonstrate the effectiveness of the protective systems. The analysis may be both qualitative and quantitative, depending on the objective of the analysis. An event tree analysis of a subsea BOP system is performed in chapter 11.2.

## 3.4 Reliability Block Diagram

A reliability block diagram describes the function of the system with the help of a success oriented network. It shows the connections of components needed to fulfill a specific system function. For systems with more than one function, the different functions must be considered individually and a separate block diagram is needed for each of the functions. Reliability block diagrams are mostly used for systems with non-repairable components and when the order of failure is irrelevant. A reliability block diagram can be both qualitative and quantitative, depending on the objective of the analysis. A reliability block diagram of a subsea BOP system is shown in chapter 11.1.

## 3.5 Bayesian Belief Networks

A Bayesian belief network (BBN) is a good way of presenting the relationship between system failures and its causes and contributing factors. It is very similar to cause and effect diagram, but can also be used as a basis for quantitative analysis. Dependencies between the factors in the diagram, is illustrated by arrows. It may also be useful to group the different causes in categories. A BBN is shown in figure 3.2

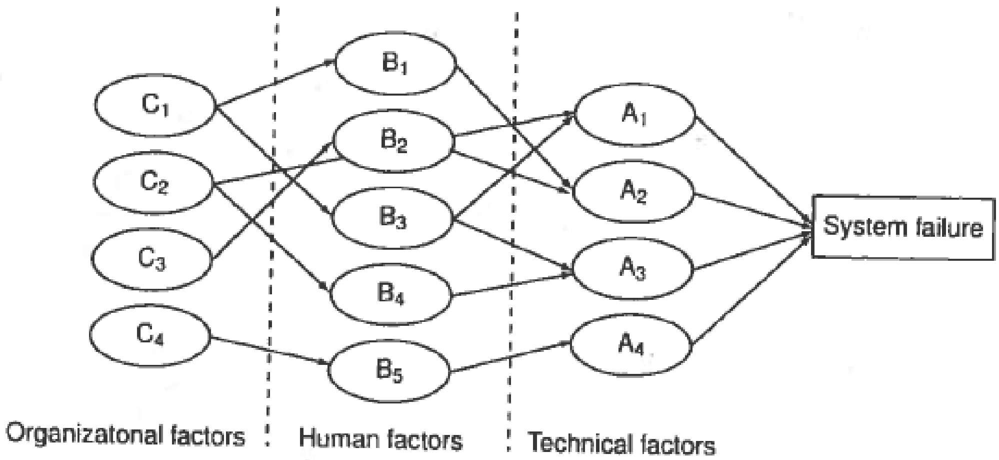


**Figure 3.2 Bayesian belief network**
**(Rausand and Høyland, 2004)**

## 3.6 Failure Mode and Effect Analysis

Failure mode and effect analysis (FMEA) is an analysis tool used to identify potential failure modes in a system. These failure modes are then analyzed to determine the effects they may have on the system. In an FMECA, the various failure effects are also ranked in terms of how critical they are. FMEA/FMECAs are usually carried out in the design phase of a system so that weaknesses and potential failures are identified at an early stage so that the designer can make corrections and include potential barriers in the system. It can also be used for maintenance planning and as a basis for a more detailed reliability analysis.

The FMEA work sheet used in chapter 9.2 to perform an FMEA on a subsea BOP system contains the following columns:

**Reference Number:** In this column the component is identified with a unique reference. This could for example be an I.D number, tag-number or the name of the component.

**Function:** The function of the component. For a pump, it could be to pump water from A to B with a rate of X l/min.

**Operational mode:** The different operational modes. For a valve, it might be “open” or “closed”

**Failure mode:** A failure mode is defined as a no fulfillment of the functional requirements of the functions specified in column 2. Note that different operational modes may have different failure modes.

**Failure causes or mechanism:** A failure cause is something that may cause or contribute to a failure mode. For every failure mode that is identified, all possible failure causes are listed.

**Detection of failure:** Describe possible ways you can detect the different failure modes. Examples of this can be human inspection and different alarm systems. 43

**Effect of failure on the system:** List the effect each failure mode may have on other components in the system.

**Effect of failure on the system function:** Describe how the systems main function is affected by the different failure modes.

**Risk reducing measures:** Actions that will correct the failure, and prevent serious consequences from occurring. You could also mention measures that will reduce the frequency of failure modes.

## 3.7 Safety Integrity Level

According to IEC 61508, safety integrity is the probability that a safety related system is able to perform the required safety functions under given conditions and within a specified period of time. Safety Integrity Level (SIL) is classified into four different levels, and is defined by the probability of failure on demand (PFD).

Minimum SIL requirements for BOP systems are specified in OLF-070 (2004), which is a document made to simplify the application of IEC 61508 and IEC 61511 standards for use in the Norwegian petroleum industry. IEC 61508 is widely accepted as the basis for specification, design and operations of a safety instrumented system (SIS). There are four different SIL levels as shown in table 4.1.

**Table 3.1 SIL for safety functions adapted from IEC 61511 (2003)**

| Safety Integrity Level | Demand Mode of Operation<br><br>(average probability of failure to perform its designed function on demand - PFD) |
|---|---|
| 4 | $\geq 10^{-5}$ to $<10^{-4}$ |
| 3 | $\geq 10^{-4}$ to $<10^{-3}$ |
| 2 | $\geq 10^{-3}$ to $<10^{-2}$ |
| 1 | $\geq 10^{-2}$ to $<10^{-1}$ |

## 3.8 Classification of functions

For complex systems with a lot of functions, it might be beneficial to classify the different functions. This gives a better overview of what functions are most important, and what effect they have on the system. The classification will be based on the classifications presented by Rausand and Høyland (2004). The type of functions that will be looked at here will be the essential functions, auxiliary functions and information functions. On-line and Off-line functions will also be looked at. BOP functions will be classified in chapter 7.3

*Essential functions* are the functions needed for the component to fulfill its purpose. For example, one of the essential functions of the BOP system would be to seal an open hole.

*Auxiliary functions* are supportive functions for the essential functions, but can be just as important. Failure of auxiliary functions can also be more safety critical then the failure of an essential function. For a BOP system an auxiliary function would be to contain the fluid.

*Information functions* gather information, like condition monitoring, alarms, etc. The information function of the BOP system is the pressure monitor.

*On-line* and *off-line functions* are used to distinguish between failures that are hidden, and failures that are evident. On-line functions are operating continuously so that the operator has current knowledge about their state. Off-line functions are functions so rarely used that the operator does not know the state of the function without some test being performed first.

# 4 Description of a Subsea BOP System

A BOP is used to seal, control and monitor oil and gas wells. They were developed to deal with erratic pressure and uncontrolled flow from the reservoir and in to the well during drilling, also known as a kick. A kick can potentially lead to a blowout. To accomplish this, the BOP system has the ability to close a well under pressure, and circulate out formation fluid that has moved into the well bore, while still maintaining control of the well. In case of emergency, it should also be able to shear the drill pipe.

BOPs are used on land, on offshore rigs and subsea. The main difference between subsea and dry BOPs is that the control system is more complex with subsea systems. There is also a higher number of valves dude to the requirement of higher redundancy. This reason for this is because of limited accessibility, due to it being placed at the bottom of the sea (Rausand, 1983b).

## 4.1 Main Components of a BOP Stack

A BOP system consists of several different components. The main components are; annular preventer, ram-type preventer, hydraulic connector, flexible joint, choke/kill valves and the control system.  How each of them work and a description of their function will be given. The following chapter is mainly based on information taken from the "*Reliability of Subsea BOP systems*" reports from SINTEF.

### 4.1.1 Ram-Type Preventer

Ram-type preventers were the first type of BOP that was used. It was developed during the 1920`s by Cameron Iron Works. At this time, the BOP was mechanically operated, but during the 1940`s, they became hydraulically operated (Whitby, 2007). Ram-type Preventer uses two opposing elements that are forced towards the center of the wellbore to seal off the well. The rams are made of steel, with rubber seals. To help overcome the wellbore pressure when closing the rams, they are usually designed so that fluid from the wellbore is allowed to pass through a channel in the ram and exert pressure at the ram`s rear and towards the center of the wellbore. To make sure the rams stay in closed position, they are locked by a special locking device. This locking device will lock the rams in closed position, even if hydraulic pressure is lost.

The ram preventers come in three types; Pipe-, Blind shear- and casing shear rams.

Pipe rams are used to seal the well when there is a drill pipe or something similar in the well. It seals around the drill pipe and restricts flow in the annulus. Each pipe ram are designed to seal against a pipe of a specific size. That means that if a pipe ram is designed for a 5 inch drill pipe, and the drill pipe is changed to a different size, then the ram will no longer be able to seal. However, there exist pipe rams with variable bore size that can seal drill pipes of different sizes.

Blind shear rams (BSR) are used to seal the well when the well does not contain a drill string or any other objects running through the BOP, but it also have the capability of cutting through the drill string and then seal the well. Using the BSR to cut through the drill string is a last resort, when everything else has failed.

A casing shear ram (CSR) have the ability to cut through objects that the BSR cannot. It can cut through tool joints, drill collars, casing, etc (WEST, 2004). However, the CSR does not have the ability to seal the well.

### 4.1.2 Annular Preventer

The annular preventer was invented by Granville Sloan Knox in 1946(Oilfield Directory, 2009). The packing unit that closes the well is a hemispherical piece of rubber reinforced with steel. It is placed in the BOP housing between the head and the hydraulic piston. When the piston moves up, it will push against the packing unit, compressing it in to the annulus. This movement will seal off the well. Unlike the ram type preventers, the annular preventers do not have a locking device that will keep the preventers in locked position. The rubber in the packing unit is of high quality. It can either be natural, nitrile or neoprene, depending on the operational conditions.

Annular preventers can seal around any pipe size as well as tool joints, drill collars and non-cylindrical objects like the Kelly. It can even seal the well while the drill pipe is rotating and is also used during stripping operations, where the drill pipe is stripped into the well under pressure.

The lifetime of annular preventers is usually longer than that of ram-type preventers. It also requires less maintenance. One of the reasons for this is because it is a simpler design. It only has two moving parts, piston and the packing unit. Also, the way it closes around the drill pipe, smooth upward and inward motion, reduces the internal stress and friction between the BOP body and the sealing element.

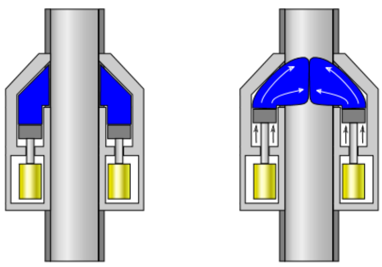

**Figure 4.1 Annular preventer (Wikipedia, 2011)**

### 4.1.3 Flexible Joint

During drilling, because of the weather conditions, the drilling rig will move laterally. This leads to a lot of stress on the BOP connection with the riser. To compensate for this movement, a flexible joint is installed at the top of the BOP stack. With an installation like this, angular motion up to 10 degrees is allowed. Below, a picture of a flexible joint by Oil States Industries is shown.

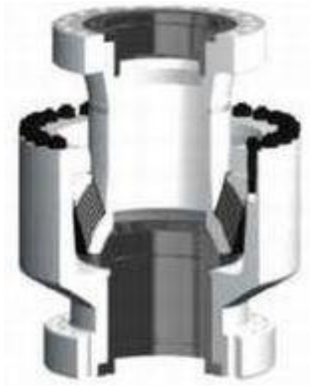

**Figure 4.2 Flexible Joint**
**(Oil States Industries)**

### 4.1.4 Hydraulic Connector

Hydraulic connectors are used to connect the BOP stack to the wellhead and the lower marine riser package (LMRP). The connection between the wellhead and the BOP stack is called the wellhead connector, and the connection between the LMRP and the BOP stack is called the LMRP connector or the riser connector.

### 4.1.5 Choke/Kill Valves

The kill and choke systems main function is to circulate out a kick and to kill a well when necessary. To do this, heavy mud is circulated down the kill line and into the annulus. The choke/kill system will also be used during pressure testing of the BOP system. Where the lines are attached on the BOP stack, depends on how the BOP stack is built up, and on the operator’s preference.

The choke/kill valves are used to close the choke/kill lines. Two valves are placed in series as close to the outlets as possible. They use two valves to increase the reliability of the system. These valves are hydraulically controlled by the BOP control system. To make sure that you always have control of the valves, the choke/kill valves are failsafe by design. That means that you need hydraulic pressure to keep them open. If the hydraulic pressure is lost, loaded springs will force them to closed position.

## 4.2 BOP Control System

There are two main types of control system being used; Hydraulic and electro-hydraulic multiplex system. The oldest of the two systems, the hydraulic system, transmit commands by hydraulic pressure through small hoses, called pilot lines (Figure 4.3). These pilot lines will transmit power to the pilot valves. With this system, you need one hose for each command. This system is mostly used in shallow water. In deeper water, the hydraulic control system is not practical to use because of the increased reaction time with increasing water depth. On the Norwegian continental shelf, the maximum response time for closing of BOPs located on the sea bed, is 45 second (NOROSK D-001, 1998). Response time refers to the time it takes from the signal is sent from the control panel, until the BOP function is in closed position.

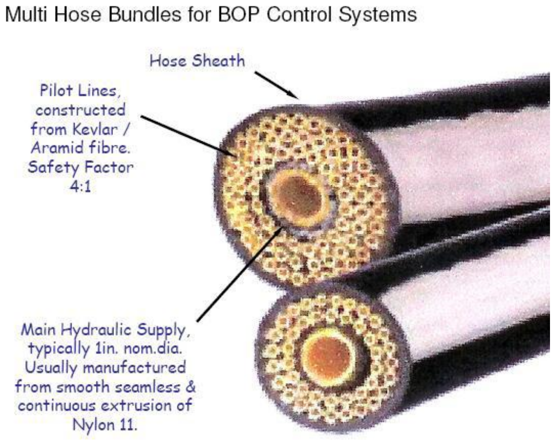


**Figure 4.3 Multi Hose Cable**
**(Potter, 2010a)**

Today, all floating drilling rigs that drill in water depths greater than 5000 ft, are equipped with a multiplex BOP control system and all new build rigs are fitted with this type of control system as a standard(Potter, 2010b).With the multiplex system, coded commands are transmitted by electrical signals through the control umbilical, from the surface to the subsea control pods. There, the signal will be received by the subsea electronic module (SEM). The SEM will then decode the signal, and energize or de-energize the appropriate solenoid valve. In this type of system, you have both hydraulic and electric parts. Records have shown that problems which leads to retrieving the BOP for maintenance is usually caused by the hydraulic parts (Shanks et al., 2003).

Figure 4.4 shows a simple sketch of a multiplex BOP control system. When activating a BOP function, it starts by initiating the signal at the control panel on the rig. The operator will have to choose if he wants to use the blue or yellow control pod. From the control panel, a coded electrical signal will travel down through the control umbilical to the SEM, where the signal will be decoded. An electrical signal will then be sent to the correct solenoid valves, and the valve will energize or de-energize. The solenoid valve will then send hydraulic pilot pressure to operate another valve, which will in turn lead the hydraulic high pressure from the surface to the BOP function you want to operate. The hydraulic pressure on the surface is delivered by a hydraulic power unit (HPU). There are also accumulators on the rig as a backup in case the HPU stops working. In addition, there are also accumulators placed on the seabed on the BOP stack. These accumulators are there as a backup in case of an emergency where the hydraulic connection between the surface and the BOP stack is lost. The accumulators on the seabed are required to have enough pressure to operate the shear ram and cut through the drill string, after having closed a pipe ram preventer. It should also have enough pressure left to disconnect the LMRP after cutting through the drill string(NOROSK D-001, 1998).

The subsea control pods are a vital part of the control system. The purpose of the control pods is to direct hydraulic power fluid and operate the BOP stack. It receives electrical signals and hydraulic power supply from the surface, and through those signals, gets information on where to direct the hydraulic fluid. Since the pods are such an important part of the BOP control system, every BOP subsea system has to be installed with two independent pods (API SPEC 16 D, 2004). Both pods should be capable of performing all the functions on the BOP. To make it easier to identify, the pods are named blue and yellow pod. During operations, it is common practice to alternate between using the blue and yellow pod every week, or after a BOP stack test. Both of these pods must be working at all times. So if there is a major problem with one of the pods, drilling will be suspended and the LMRP and riser will be retrieved to the surface so that the pod can be repaired and tested (Shanks et al., 2003).

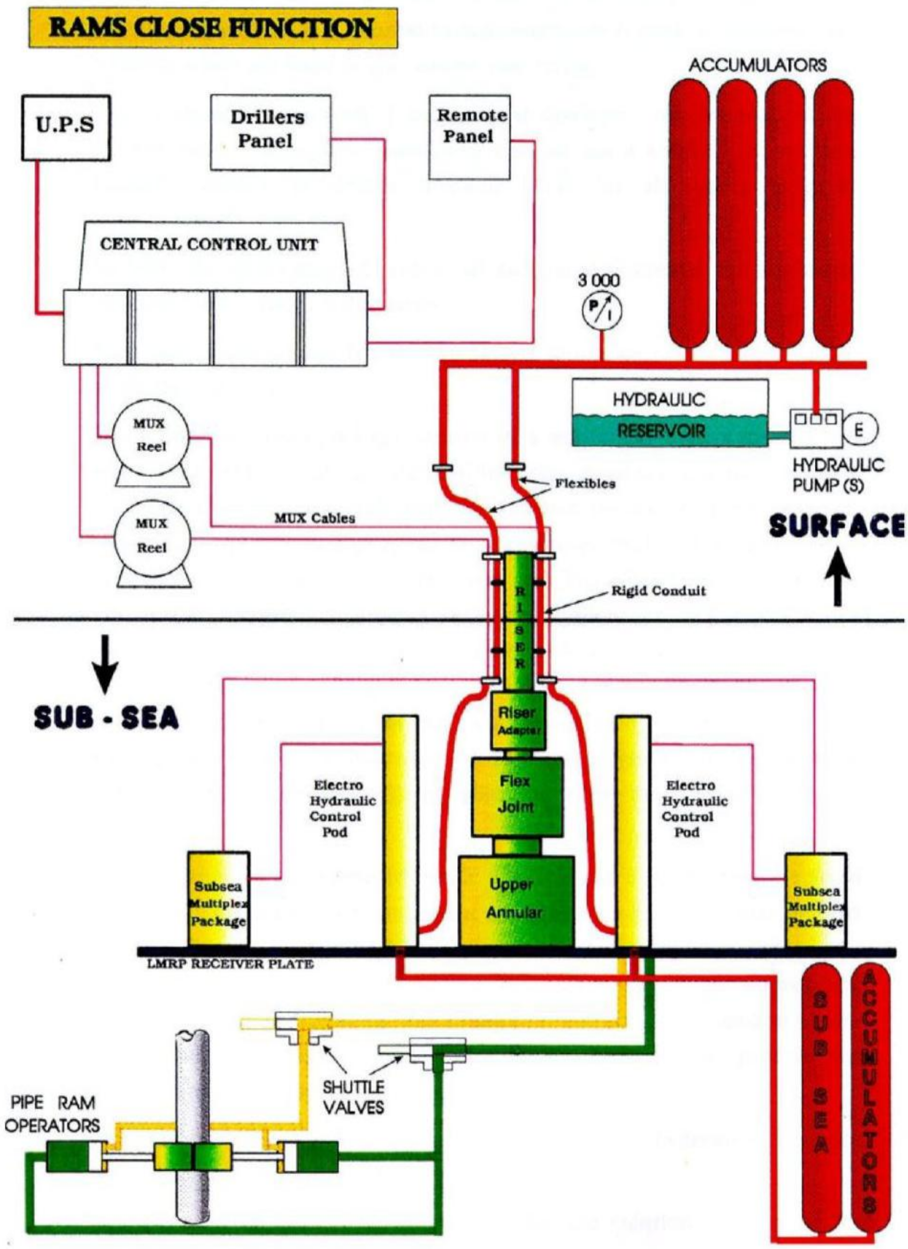


**Figure 4.4 Multiplex BOP Control System**
**(Potter, 2010a)**

### 4.2.1 Secondary Control Systems

In the event that the primary control system is incapable of activating the BOP functions, another way of operating the BOP is needed. Since the BOP is such an important unit when it comes to safety, it is necessary with secondary systems. The secondary systems can share some components, or it can be totally independent of the primary BOP control system. The most important secondary systems are acoustic control system and ROV activation by panel. A brief description of each of these systems will be given.

### 4.2.2 Acoustic Control System

On the Norwegian continental shelf, it is mandatory for oil companies to equip the BOP system with an acoustic control system (NOROSK D-001, 1998).The Acoustic control system is a backup for the conventional control system, and is only used for emergencies when the other systems fail, for example if the rig moves off location. It work independently, and therefore increases the reliability of the BOP system. To activate the system, a series of signal transmissions and transformations is sent from the initial surface command. It will keep sending out signals until the command is activated. The initial signal is then converted into an acoustic signal. Coded pulses of sound will be transmitted by and underwater transducer to the subsea control unit. The subsea control unit and surface control unit has a two-way communication. An electrical signal is sent from the subsea control unit that controls a solenoid valve. The solenoid valve will then supply hydraulic pressure from the subsea accumulators to the bop functions. In Figure 4.5 you can see the signal sequence for an acoustic control system. To initiate the signal, a permanently mounted control system on the platform or a portable unit like a stand-by vessel can be used.

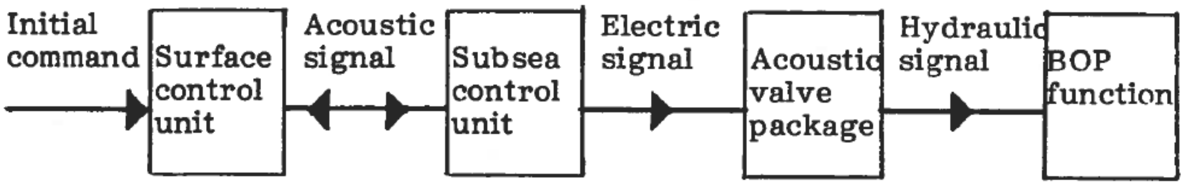


**Figure 4.5 Signal Sequence for Acoustic Control System (Hals and Molnes, 1984)**

### 4.2.3 ROV Activation by Panel

Another way to activate the BOP is with the use of a remotely operated vehicle (ROV). The ROV can mechanically control the valves through the ROV intervention panel, see figure 4.6, and will direct hydraulic pressure to the stack with the use of hot stabs. The ROV is equipped with a hydraulic pump and can directly operate a function like the ram type preventer. For lower volume functions, the ROV is equipped with a hydraulic reservoir, but high volume functions such as the preventers are usually operated with sea water (WEST, 2003).

**Figure 4.6 ROV Activation Panel**
**(Potter, 2010a)**

# 5 Operational Situations

A BOP stack has several different ways to deal with kick and seal off the well. There are usually several different pipe rams, two annular preventers and one or two blind shear ram. All of these different functions should be able to seal off the well. However, not all of those barriers will be in effect at the same time. When a BOP stack is in use, it will go through several different operational situations. Below, each of these situations will briefly be described, and which barriers that will be able to function at the given time will be discussed.

## 5.1 Empty Hole

While the BOP is located on the wellhead, there will be times where there are no objects going through the BOP, for example when the drill string has to be pulled to change the drill bit, or when pressure testing with an open hole. If there are no objects going through the BOP, then the blind shear ram will be used to shut down the well if needed. The BOP stack can have one or two shear rams, depending on the BOP stack configurations. Annular preventers can arguably be used if necessary, but will not be able to hold off the pressure alone for a long period of time, because there is no system that can lock the annular preventers in closed position. The pipe rams will have no effect in this situation. If the stack is equipped with a casing shear ram, it will not have any effect in this situation.

## 5.2 Drill Pipe through the BOP

During drilling operations, the drill pipe will be going through the BOP. During this operational situation, the pipe rams will be an effective barrier. However, fixed pipe rams are only designed for sealing against a drill pipe of a given size, so only the fixed pipe ram that is designed for that specific drill pipe size will be able to seal off the well. Variable bore rams are designed to cover a wide range of drill pipe sizes. Annular preventers have the capability of sealing against drill pipes of all sizes, so they will always be in effect with a drill pipe going through the BOP. The blind shear ram is designed to shear through a drill string, and seal off the well if needed. However, it does not have the capability of shearing through the tool joints which connects the different drill pipe sections. There are BOP stacks configurations with more than one shear ram. This configuration will make sure that least one of them will stay clear of a tool joint, but the majority of rigs in use today only have one blind shear ram (WEST, 2004). A casing shear ram would be able to shear through a drill string, and even through the tool joints, but it will not have the ability to seal the well.

## 5.3 Installing Casing

Another operational mode for the BOP is when the casing is being installed. When a casing is going through the BOP, ripe rams will not be able to seal off the well. Standard shear rams will not be able to shear through the larger diameter casing. For that, a special casing shear ram is needed. They have the capability to shear casing tubular up to 13”, in an 18 ¾” bore BOP (WEST, 2004). Annular preventers will increase the probability of successfully dealing with a kick in this situation(Holand and Skalle, 2001).

## 5.4 Emergency Disconnect

During an emergency, like a big storm or if a ship is on a collision course with the rig, it might be necessary to move the rig immediately. To do that, cutting through the drill string and disconnect the lower marine riser package (LMRP) is necessary. In a situation like this, the first thing that has to be done, is to cut through any objects in the BOP with the BSR or casing shear ram, and then seal off the well with the BSR. Often, the BSR will then be the only barrier against the well in a situation like this. On the Norwegian continental shelf, it is mandatory to drill with riser margin so that the mud column in the well will act as another barrier in case of an emergency disconnect. What that means, is that drilling must be done with mud heavy enough to keep the hydrostatic pressure in the well higher than the pressure in the formation, even if you disconnect with the LMRP. However, with increasing water depth, this becomes harder and harder to do, because the pressure will eventually be so high, that the hydrostatic pressure from the mud will fracture the formation. After a certain depth, it will be physically impossible to drill with riser margin. The operators can then apply for exemption to the NPD.

## 5.5 Wireline Operations

Wireline operations are used for many different tasks, like pulling and setting plugs, running production logging tools, perforating, re-perforating, etc. A normal BOP will not be very effective in this situation, so a special wireline BOP will usually be used during wireline operations.

## 5.6 Drill Collars and Heavy Weighted Drill Pipes

Drill collars and heavy weighted drill pipes are used at the bottom of the drill string, right above the drill bit, to add extra weight on the drill bit. Fixed pipe rams with the same size as the drill collars or heavy weighted drill pipes can be used to seal the well in the event of a kick. Variable bore rams can also be used to seal on a wide range of different sizes. Annular preventers can be used to close around all sizes. Standard blind shear rams cannot shear through drill collars and heavy weighted drill pipes. Casing shear ram can shear through, but does not have the ability to seal. Special types of drill collar, spiraled drill collar and squared drill collar, have been introduced in more recent years, and will help prevent the drill collar from getting stuck in the hole.  Neither the annular preventers nor pipe rams will be able to seal the well with this kind of drill collar going through the BOP (Hawker et al., 2001).

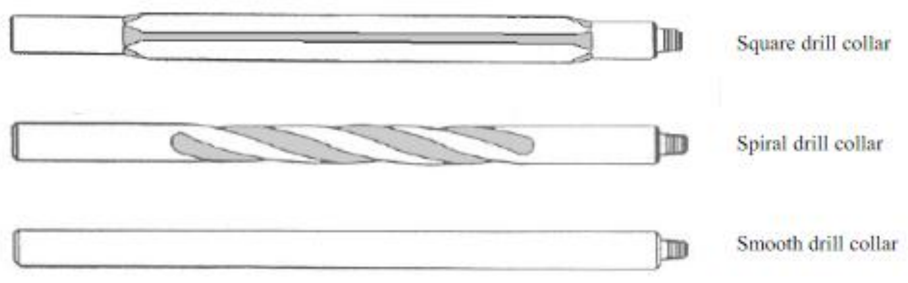


**Figure 5.1 Different Types of Drill Collars (Hawker et al., 2001)**

# 6 BOP Stack Configurations

The following chapter is mostly based on the results presented in the SINTEF report "*Deepwater Kicks and BOP Performance", written by Per Holand and Pål Skalle.*

A BOP stack can be put together in many different ways. Typically, it consists of one to six ram-type preventers, and one or two annular-type preventers. Annular preventers are placed on top of the ram-type preventers, since they are not rated for working pressure as high as the ram-type preventers and can close over a wide range of tubular sizes and the open hole(Oilfield Glossary, 2012). The BOP stack configuration is optimized to provide maximum pressure integrity, safety and flexibility in the event of a well control incident.

In this chapter, different BOP stack configurations in use will be identified, and their advantages and disadvantages related to a standard BOP configuration will be discussed.

## 6.1 One or Two Annular Preventers

Most BOP stacks are equipped with two annular preventers. Holand and Skalle (2001)evaluated the effect of using one or two annular preventers on the blowout probability. They found that there were no significant reductions in probability of a blowout by using two annular preventers instead of one. This is because the level of redundancy in a BOP stack with a drill pipe is running through, is already very high. In this calculation, it was assumed that annular preventers are not capable of sealing an open hole. If we assume that annular preventers can seal an open hole, having two annular preventers would reduce the probability of a blowout to some extent. In the event that a kick occurs when a casing is running through the BOP, having two annular preventers would also increase the probability of a successful shut-in of the well. However, it is very rare for a kick to occur at this stage. Another important point is that annular preventers will be subjected to a lot of wear during stripping. This might cause the annular preventer to fail. By having two annular preventers in the BOP stack, the BOP does not have to be pulled if this happens. The disadvantages of having two annular preventers, is the increased weight, as well as maintenance and investment cost.

## 6.2 One or Two Blind Shear Rams

On the Norwegian continental shelf, it is recommended to use two BSRs for deep water drilling. This is because deep water wells are often drilled with dynamic positioned (DP) rigs and without riser margin. When the water depth is too deep, drilling with riser margin is impossible. In an event that the DP system fails, or there is an emergency disconnect so that the LMRP has to disconnect from the BOP, the BSR will be the only barrier against a blowout. If a situation like this occurs, having two BSRs would reduce the probability of a blowout. If a kick occurs when there are no objects going through the BOP, having two BSRs will also be beneficial.

In the event that you are forced to cut through the drill pile to seal off the well, you might end up with trying to cut through the drill pile at a tool joint. Most BSRs will not be capable of cutting through a tool joint. Here, it would be critical with another BSR to make sure that the well is sealed. When adding a second BSR, it can either replace the upper pipe ram, or it can be added without replacing any of the existing preventers. If you replace the second BSR with the upper pipe ram, you will lose some redundancy with respect to sealing around a drill pipe. But because there is already so much redundancy here, this will have an insignificant effect. The disadvantages with using two BSRs are the same as with the annular preventers. Additional weight, and increased maintenance and investment cost.

## 6.3 Casing Shear Ram

Some BOPs are equipped with one blind shear ram and one casing shear ram. The advantages of the casing shear ram, is that it can cut through casing, tool joints, drill collars, etc. However, a casing shear ram does not have the ability to seal.

## 6.4 Fixed or Variable LPR

Some operators prefer to use a variable bore ram as the LPR, while others prefer to use a fixed LPR. The difference in blowout probability between using a fixed LPR with the size of the most commonly used drill pipe diameter, compared to a variable bore ram, is marginal. A fixed LPR will increase the probability of a blowout with 2-3%. The advantages of using a fixed LPR, is that is has a higher hang-off capacity then a VBR.

## 6.5 Lower Kill Line Above or Below LPR

In Norway, most rigs have the lower kill line below the LPR. With a kill line placed below the LPR, a kick will result in a blowout if there is an external valve leak, but it is very unlikely for such a leak to occur. The advantages of placing the kill line below the LPR, is that it is useful in kick killing operations.

## 6.6 Test Ram

Some BOP stacks have the LPR replaced with a test ram. The purpose of the test ram is to pressure test the rams above. Pressure testing can also be done without a test ram, but to do so, you will have to install a plug. Installing a plug requires a wire line operation, which results in more time used on the pressure testing, and increased costs. However, the test ram is not used for sealing from below and up, so it will not be used for sealing the well.

## 6.7 Recent BOP Stack Configurations Used

We will now take a closer look at three different BOP stack configurations, and what components they include. We will look at the Deepwater Horizon BOP stack, the classical BOP stack, and a typical modern BOP stack.

***Deepwater Horizon BOP Stack:***

- Two annular preventers, both apart of the LMRP
- One blind shear ram
- One casing shear ram
- Three variable bore rams, with the lower one being a test ram.

- Lower outlet below lower pipe ram

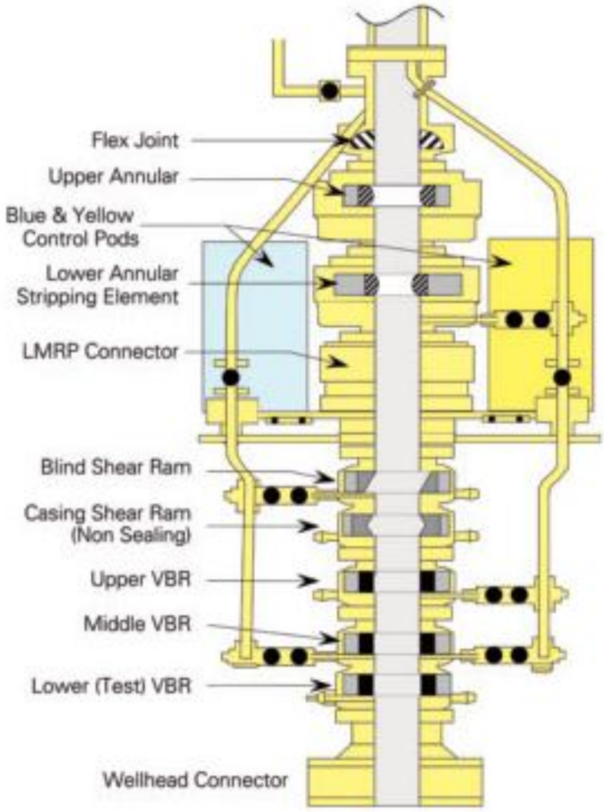


**Figure 6.1 Deepwater Horizon BOP Stack**
**(BP, 2010)**

***Classical BOP Stack:***

- Two annular preventers, with the upper annular preventer apart of the LMRP
- One blind shear ram
- Three fixed pipe rams
- Lower outlet below lower pipe ram

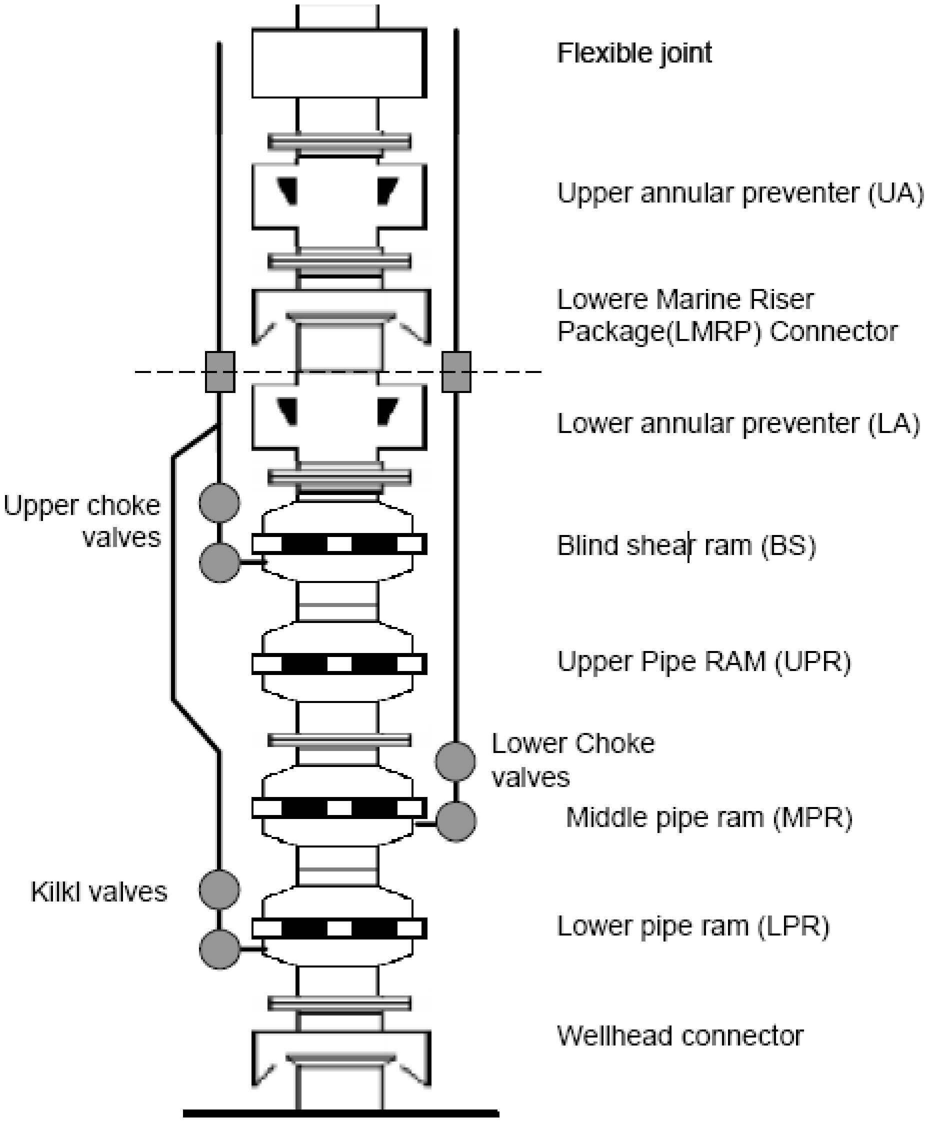


**Figure 6.2 Classical BOP Stack**
**(Holand, 1999)**

***Typical Modern BOP Stack:***

- Two annular preventers, with the upper annual apart of the LMRP
- Two shear rams
- Three pipe rams, with at least two of them being variable pipe rams.
- Lower outlet below lower pipe ram

***Overview of the Different Stacks:***

**Table 6.1 Overview of the different stacks**

| BOP Stacks | Annular preventer | Shear ram | Test ram | Pipe ram | Casing shear ram | Lower outlet below lower pipe ram |
|---|---|---|---|---|---|---|
| Classical | 2 | 1 | | 3 (fixed) | | Yes |
| Modern | 2 | 2 | | 3 (with at least two of them being variable bore rams) | | Yes |
| Deepwater Horizon | 2 (both being apart of the LMRP | 1 | 1 | 2 (variable) | 1 | Yes |

## 6.8 Pros and Cons for the Different BOP Stack Configurations

Three different BOP stack configurations have been identified; the classical BOP stack, the Deepwater Horizon BOP stack and the typical modern BOP stack. Each of them is put together in different ways, and we will now try to identify the advantages and disadvantages with the different configurations.

All three BOP stacks use two annular preventers. As discussed earlier, this does not give a significant reduction in blowout probability. However, it does provide redundancy in case of one annular preventer being damaged, and will allow operations to continue without having to pull the BOP to replace the damaged annular preventer. The cons of using two annular preventers, is the increased weight, as well as maintenance and investment costs.

Only the modern BOP stack is equipped with two shear rams. Two shear rams is important when drilling without riser margin. It is also critical if you try to shear through a tool joint. The shear ram will not be able to shear through a tool joint, so having another shear ram to make sure the well is sealed, can be the difference between a blowout or not.

Instead of using two blind shear rams, the Deep Water Horizon BOP used a special casing shear ram. The advantages of the casing shear ram, is that it can cut through casing, tool joints, drill collars, etc. However, a casing shear ram does not have the ability to seal. The classical BOP stack only have one shear ram and no casing shear ram, so it will be lighter and cheaper, but will have a lower probability of stopping a blowout in certain situations.

A test ram was installed in the Deep Water Horizon BOP. The advantages of the test ram, is that pressure testing takes less time. For the classical and modern bop stack, pressure testing will take much longer because a plug will have to be installed to perform a pressure test.

Both the Deepwater Horizon BOP stack and the modern BOP stack are equipped with variable pipe rams. Using a variable pipe ram as the LPR will reduce the probability of a blowout slightly. The classical BOP stack only consists of fixed pipe rams. The advantages of this setup, is that it has a higher hang off capacity.

### 6.8.1 Case Study

To get a better view of what barriers are available for the different BOP configurations, simple sketches were made. Two different cases are presented. Case 1 represents a situation with a standard drill pipe going through the BOP while case 2 represent a case with an open hole. Since it is a standard drill pipe going through the BOP in case 1, it is assumed that both variable bore rams on the Deepwater Horizon configuration and two variable bore rams on the modern configuration will fit around the drill pipe. The IBOP and the kill/choke line valves will also have to work in order to prevent a blowout, but these will not be shown in these sketches. The casing shear ram is included in the Deepwater horizon sketch. This is not a barrier that can seal the well on its own, but it will increase the probability of a successful isolation of the well by cutting through the drill pipe, and then allowing the BSR to seal the well without having to cut through the drill pipe first.

**Case 1 – Drill String Going Through the BOP:**

**DWH BOP Stack:**

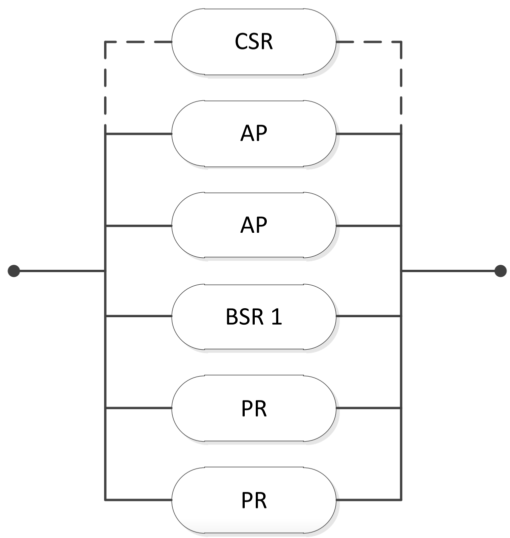


**Figure 6.3 Available barriers for the DWH stack with a drill string going through the BOP**

**Modern BOP Stack:**

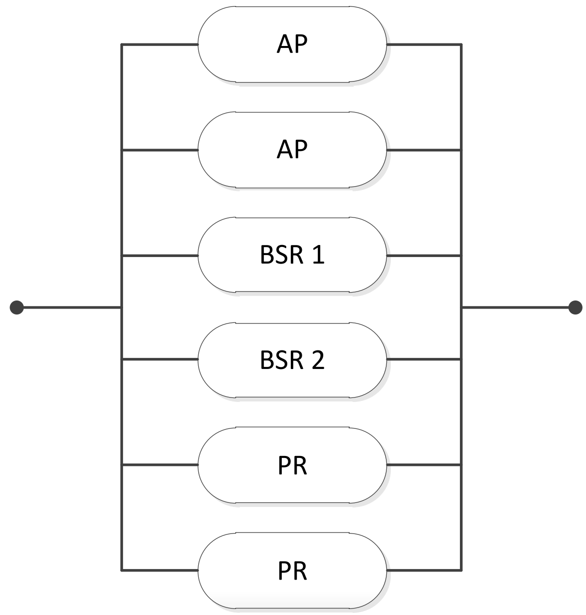


**Figure 6.4 Available barriers for the Modern stack with a drill string going through the BOP**

**Classical BOP Stack:**

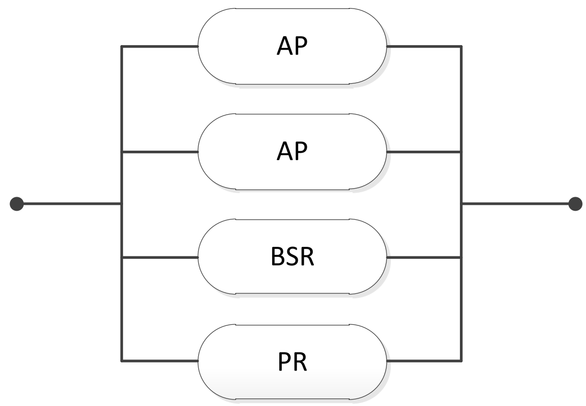


**Figure 6.5 Available barriers for the classical stack with a drill string going through the BOP**

**Case 2 – Open Hole:**

**DWH BOP Stack:**


**Figure 6.6 Available barriers for the DWH Stack with no objects going through the BOP**

**Modern BOP Stack:**

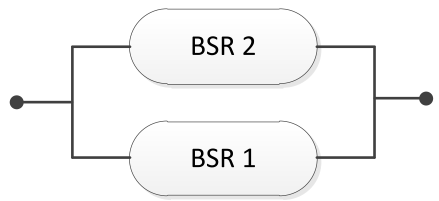


**Figure 6.7 Available barriers for the modern stack with no objects going through the BOP**

**Classical BOP Stack:**


**Figure 6.8 Available barriers for the classical stack with no objects going through the BOP**

This simple overview shows that in both case 1 and case 2, the modern configuration has more redundancy then the other configurations. The classical BOP is the configuration with the least redundancy. The BSR is the only barrier that can seal the well without a drill pipe going through the BOP. Failure of the BSR for the DWH and the classical configuration will in case 2 results in a blowout if there is a kick and control of the well is lost. It can also be seen that all BOPs have most barriers available when there is a drill pipe going through the BOP. The situation with a drill pipe going through the BOP is also the situations when the probability of a kick is highest. The reliability study performed by Holand and Skalle (2001) showed that 45 out 48 kicks occurred when there was a normal drill string running through the BOP.

# 7 Main Functions and Performance Requirements of a BOP System

To get a better understanding of the BOP system, the main functions and performance requirements will be identified. This will give a better overview of what exactly a BOP should be able to do in order to function as a safety-critical system. The functions identified here will also be classified.

## 7.1 Main Functions

The primary function of a BOP system, as described in NORSOK D-010, is to prevent well fluid from leaking from the well bore to the environment, and provide capabilities to close in and seal the well bore with or without tools/equipment going through the BOP. More specifically, it should be able to seal the annulus between the drill pipe and the casing, as well as being able to seal the well if no objects are going through the BOP. In an emergency situation, it should also have the ability to shear through a drill string going through the BOP before sealing the well. To be able to deal with kicks, a BOP system must also have the capability to add and withdraw controlled volumes of fluid from the well bore.

In OLF 070, the main functions for the BOP are defined as follow:

1. Seal around drill pipe
2. Seal an open hole
3. Shear drill pipe and seal off well

In addition to performing these main functions, the BOP system should also perform some non- safety activities. This includes using the rams to center the drill string and hanging off the drill string by closing a set of pipe rams to support its weight. It should also be able to monitor the well bore pressure (Transocean, 2011).

To sum up, the functions of a BOP system is:

- Contain well fluid
- Seal around drill pipe
- Seal an open hole
- Shear drill pipe and seal off well
- Add and withdraw controlled volumes of fluid from the well bore
- Center the drill string
- Hanging off the drill string on the pipe ram
- Monitor well bore pressure

## 7.2 Performance Requirements

To make sure that BOP systems are able to perform these functions to an acceptable level, they have to meet the associated performance requirements. There will be different requirements depending on where you are operating. Here, the requirements in place on the Norwegian continental shelf will be looked at. Functional requirements, SIL requirements and test requirements will be looked at.

### 7.2.1 Functional Requirements

According to the NPD guidelines, section 31, when a BOP is placed on the sea bed, the response time for closing the annular preventers and pipe rams, should be less than 45 seconds. The response time refers to the time it takes from when the command is initiated at the control panel, until the action is completed at the BOP (Oljedirektoratet, 1999).

To make sure the shear rams can cut through the drill strings, they should be capable of cutting through the pipe of the highest grade drill pipe in use, as well as closing off the bore. If an object that cannot be sheared is running through the BOP, there should be at least one pipe ram or annular preventer able to seal the actual size of the item (NOROSK D-001, 1998).

The BOP accumulators should have enough stored pressure to close one shear ram, two pipe rams, unlatch the LMRP and have 50% of its capacity left (Oljedirektoratet, 1999).

When drilling with a tapered drill string, there should be pipe rams fitted for each pipe size. If using variable bore rams, they must have sufficient hang off capacity (NORSOK D-010, 2004).

With a BOP system on the sea bed, an acoustic or alternative control system must be installed. The acoustic accumulators should have enough pressure to cut through the drill string after closing a pipe ram preventer and still have enough pressure left to disconnect the LMRP. To operate the acoustic control system, a portable unit that can be carried by a single person should be available, incase evacuation of the platform is needed (Oljedirektoratet, 1999).

### 7.2.2 SIL Requirements

OLF 070 differentiates between two main functions for the BOP when setting the SIL related to closing the well:

- The annular/pipe ram function (i.e. seal around drill pipe)
- The BSR function (i.e. seal and open hole, and shear drill pipe and seal off well)

The minimum SIL requirement given to both annular/pipe ram function and the BSR function, is SIL 2. As seen from table 3.1, that equals to a PFD of $\geq 10^{-3}$ to $< 10^{-2}$. The total safety function includes activation on the rig and the remotely operated valves needed to close the BOP in order to prevent a blowout or a well leak. This SIL requirement is based on experience, with a design practice that has shown to give a satisfactory safety level (OLF-070, 2004).

### 7.2.3 Test Requirements

By testing the equipment, it is verified that the equipment functions as required, that the pressure integrity is intact and that the control system is functioning. If all the requirements are not met, there is an opportunity to fix it before something goes wrong. In Norway, the government has established regulations for how a BOP should be tested. Norway requires the following BOP test schedule:

- Installation test
- Test after running casing
- There should never be more than 14 days since last pressure test
- There should never be more than 7 days since last function test
- The BOP should be tested to maximum expected working pressure at least every six months

Before all pressure tests, there should be a low pressure test to 200-300 psi. The pressure test requires that the equipment holds the low pressure tests for five minutes, and high pressure tests for 10 minutes. When the BOP is subsea, the acoustic system should be function tested during all BOP tests (Holand, 1999).

NORSOK D-010 and API RP 53 also propose recommended test practices for BOP`s. See appendix A for these recommendations.

## 7.3 Classifications of the Main Functions

The functions identified earlier, will now be classified according to the classifications described in chapter 3.8. The classifications are presented in table 7.1 and table 7.2.

**Table 7.1 Classification of functions**

| Class | Function |
|---|---|
| Essential functions | Seal the well with a drill string going through the BOP |
| | Seal the well with no objects going through the BOP |
| | Shear through a drill string and seal the well |
| | Add and withdraw controlled volumes of fluid from the well bore |
| | Hang off the drill string on the pipe ram. |
| Auxiliary functions | Contain the fluid |
| | Center the drill string |
| Information functions | Monitor well bore pressure |

**Table 7.2 Classifications of evident and hidden functions**

| Class | Function |
|---|---|
| On-line functions | Contain well fluid |
| | Monitor well bore pressure |
| Off-line functions | Seal the well with a drill string going through the BOP |
| | Seal the well with no objects going through the BOP |
| | Shear through a drill string and seal the well |
| | Add and withdraw controlled volumes of fluid from the well bore |
| | Hang off the drill string on the pipe ram |

The most critical functions here with respect to a blowout would be to seal the well with a drill string going through the BOP, seal the well with no objects going through the BOP, shear through a drill string and seal the well, and contain the well fluid. Failure of any of these functions would result in a blowout if control of the well is lost.

# 8 Reliability Assessment Challenges With a BOP System

Performing an accurate reliability assessment of a BOP system can be challenging for many reasons. The ability of the BOP system to function as a safety barrier will vary, depending on which operating situation it is going through. The likelihood of demand to be handled will also depend on these operating situations. Using an average estimate for the BOP`s ability to function on demand will therefore not give an accurate representation of the reliability of the BOP.

When calculating the availability of a BOP, it is common to assume a fixed test interval, $\tau$. In practice, this may not be the case and the test interval may vary. If variation in the test exists, and the $\tau$ value represents an average test interval, the formula gives a too optimistic result. (Holand and Skalle, 2001)

The formula for availability can be expressed by:

$$A = 1 - MFDT = 1 - \frac{\lambda * \tau}{2}$$

Another important point is that during drilling, it is not possible to perform a function test on the BSR. On top of that, it is not possible to test the BSR on the ability to shear and seal a pipe, because it is a destructive test, the BSR would be destroyed.

It is often assumed 100% test coverage for the BOP, but this will not be the case. Certain failures will not be identified during functional testing. To deal with this problem, the PDS method has introduced the $P_{TIF}$ to account for the probability that certain failures are not identified during testing. The $P_{TIF}$ is added to the PFD, and we get the critical safety unavailability (CSU). For a single system, CSU is given by (Stein Hage et al., 2010) :

$$CSU = PFD + P_{TIF}$$

A BOP system has many common components. This means that common cause failure will be an important factor when calculating the reliability of the BOP system. Common cause failures have not always been included in the reliability studies of BOPs. How to deal with common cause failures is described by Stein Hage et al. (2010).

# 9 Fault Tree and FMEA Analysis

In this chapter, two different reliability analysis methods are performed.  A simple qualitative fault tree analysis is made to give a better overview of what component failure will lead to the top event. Because the barriers in effect will depend on the operational situation of the BOP, two different fault trees are made; one when there is a drill string going through the BOP, and one with an open hole. The analysis will be based on the modern BOP stack. It is assumed that the annular preventer will not be able to seal an open hole. The branch "P2" is the same for both fault trees. The fault trees are made with the program Cara Fault Tree. The cut sets can be found in appendix C. For a more detailed fault tree analysis, see the report "*Deepwater Kicks and BOP Performances*" by Holand and Skalle (2001). A failure mode and effects analysis (FMEA) is also presented to show how the failures may occur, the effect of the failure and what can be done to prevent them from happening.

## 9.1 Fault Tree:

**Open Hole:**

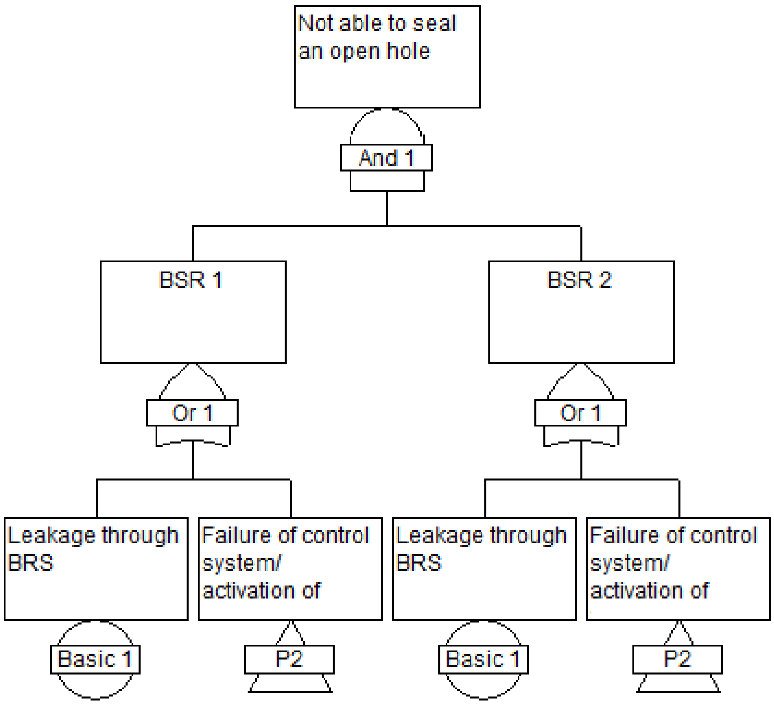


**Figure 9.1 Fault tree with top event "Not able to seal an open hole"**

**Drill Pipe Going Through the BOP:**

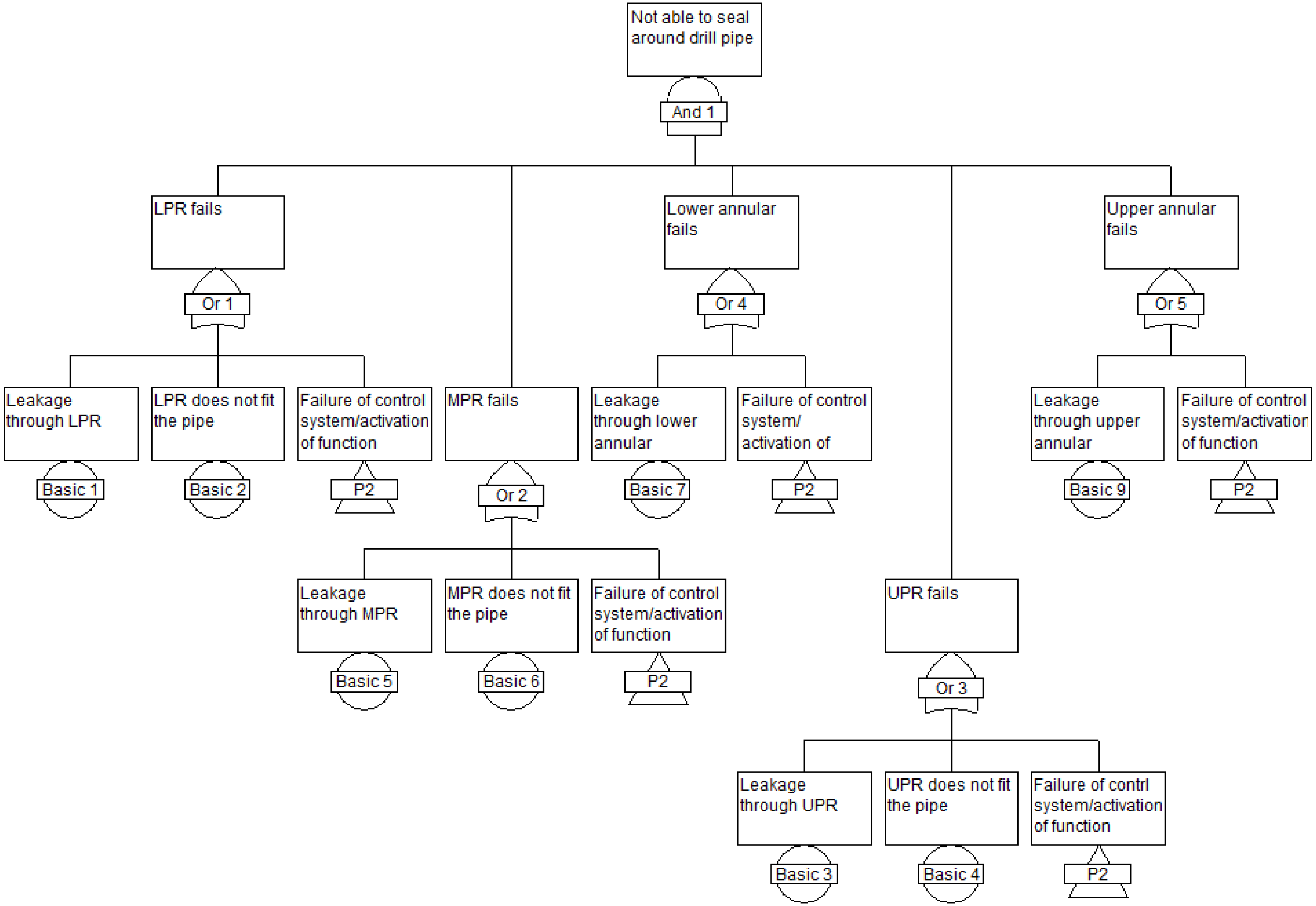


**Figure 9.2 Fault tree with top event "Not able to seal around drill pipe"**

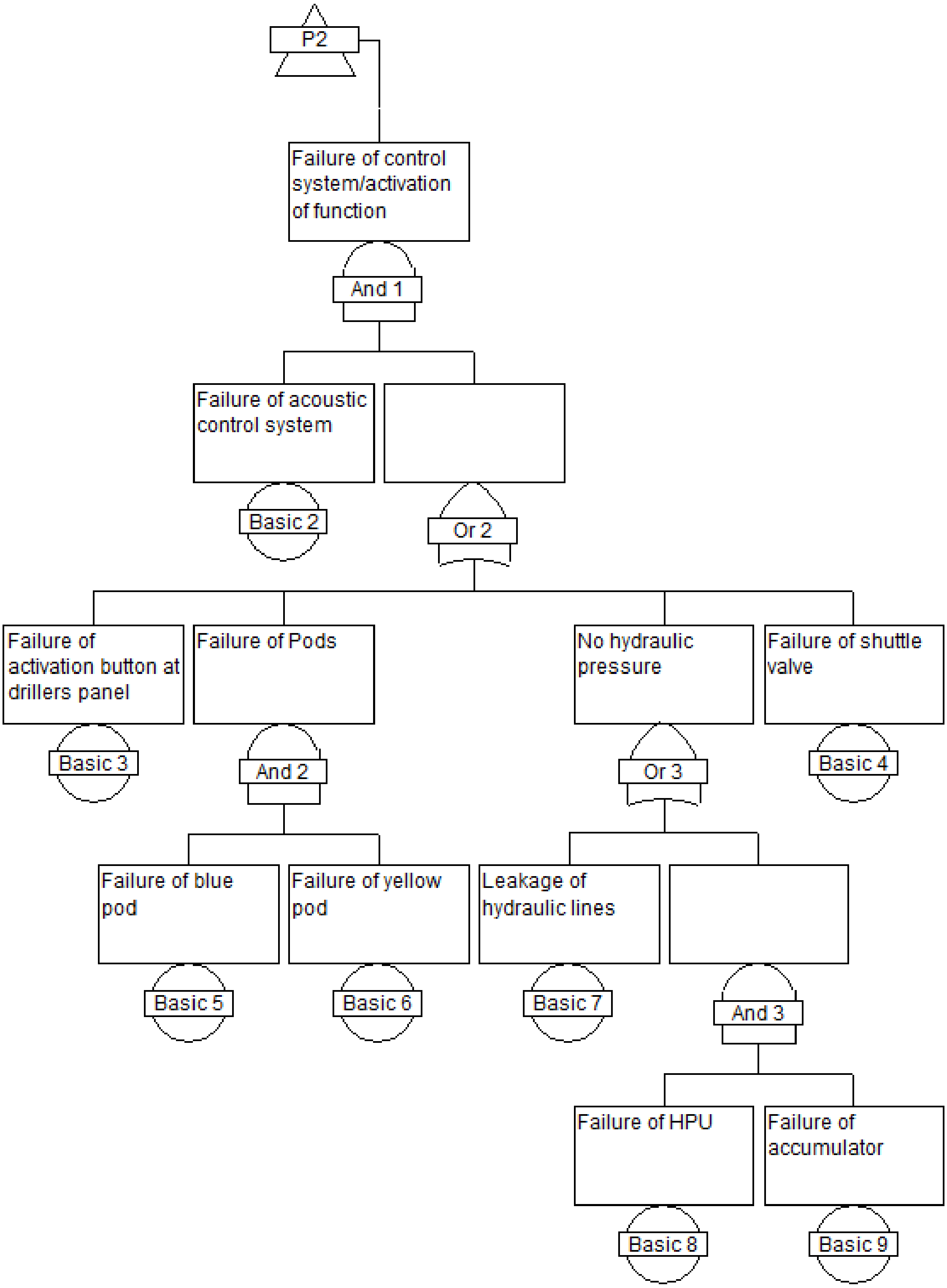


**Figure 9.3 P2 branch for the fault trees**

## 9.2 FMEA

| System: | Blowout preventer | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Description of unit | | | Description of failure | | | Effect of failure | | | |
| Ref. Nr. | Function | Operational mode | Failure mode | Failure cause or mechanism | Detection of failure | On the subsystem | On the system function | Risk reducing measures |
| Activation button at drillers panel | Send activation signal to the BOP | N/A | Fail to activate | Operator error | Testing/operation | Pods will not receive activation signal | BOP will not activate, use acoustic/secondary control system to activate the BOP | Improve operator training |
| | | | | No electrical power | | | | Frequent testing and inspection. Backup power |
| Yellow/Blue pod | Direct hydraulic power fluid and operate the BOP | Running | Fail to deliver hydraulic power | High pressure valve do not open | Testing/operation | | BOP will not activate, switch pod | Frequent testing, change damaged parts during maintenance. Always have one working pod |
| | | | | Solenoid valve does not activate | Testing/operation | | | |
| | | | | SEM do not to work | Testing/operation | | | |
| | | Standby | Fail to activate | failure at control panel | Testing/operation | | Not able to switch pod. Current pod will still work | Frequent testing and inspection, change parts if damaged |
| HPU | Deliver hydraulic pressure to operate the BOP and charge the accumulators | N/A | Does not deliver enough pressure | Leakage | Operations/pressure sensor | Accumulators will not be charged | BOP will not activate, use accumulators | Regular inspection and maintenance. Backup HPU |
| | | | | Pump failure | | | | |
| | | | | No electrical power | Operations | | | Regular inspection and maintenance. Backup power |
| Accumulators | Deliver hydraulic pressure to operate the BOP | Charged | Does not deliver enough pressure | Leakage | Operations/ Pressure sensor | | BOP will not activate, use HPU | Frequent testing |
| | | Uncharged | Does not charge | | Testing/operation | | | |

<table>
<tr><th>Ref. Nr.</th><th>Function</th><th>Operational mode</th><th>Failure mode</th><th>Failure cause or mechanism</th><th>Detection of failure</th><th>On the subsystem</th><th>On the system function</th><th>Risk reducing measures</th></tr>
<tr><td rowspan="5">Shuttle valve</td><td rowspan="5">Direct hydraulic power fluid from blue and yellow pod</td><td>Transition between blue and yellow</td><td>Not able to complete transition</td><td>Stuck due to corrosion</td><td rowspan="5">Testing/operation</td><td rowspan="5"></td><td>BOP will not activate</td><td rowspan="5">Frequent testing. Change during maintenance</td></tr>
<tr><td rowspan="2">Position to direct pressure from blue pod</td><td rowspan="2">Fail to change position</td><td>Object blocking movement</td><td rowspan="2">BOP will not activate, use the other pod</td></tr>
<tr><td>Stuck due to corrosion</td></tr>
<tr><td rowspan="2">Position to direct pressure from yellow pod</td><td rowspan="2">Fail to change position</td><td>Object blocking movement</td><td rowspan="2">BOP will not activate, use the other pod</td></tr>
<tr><td>Stuck due to corrosion</td></tr>
<tr><td>Acoustic control system</td><td>Backup activation system of BOP</td><td>N/A</td><td>Failure of acoustic signal</td><td>Electrical error</td><td>Testing/operation</td><td>Subsea control unit does not receive activation signal</td><td>BOP will not activate, use another secondary control system</td><td>Frequent testing</td></tr>
<tr><td>Hydraulic lines</td><td>Deliver hydraulic fluid</td><td>N/A</td><td>Leakage</td><td>Wear</td><td>Testing/operations</td><td>Hydraulic units does not receive enough hydraulic power</td><td>BOP will not activate</td><td>Frequent testing/change lines when damaged</td></tr>
<tr><td rowspan="3">Preventer</td><td rowspan="3">Close/open ram</td><td>Open</td><td>Fail to close</td><td rowspan="2">Failure of Control signal/activation</td><td>Testing/operations</td><td></td><td>BOP will not activate</td><td rowspan="2">Regular testing and inspection, replace damaged electrical parts</td></tr>
<tr><td rowspan="2">Closed</td><td>Fail to open</td><td></td><td>Tools will not be able to pass</td><td></td></tr>
<tr><td>Leakage</td><td>Damage on sealing element</td><td>Testing/operations</td><td></td><td>BOP will not be able to contain well pressure, activate another preventer</td><td>change sealing element frequently</td></tr>
</table>

# 10 Reliability Analysis of BOP System in the past

Reliability analysis of BOP systems have been performed in the past. The most thorough analysis was performed by Holand and Skalle (2001), were fault tree was used to calculate the reliability of BOP systems. Another mayor project were BOP reliability was calculated was done by Rausand (1983a). Information from many different rigs was gathered, and mean fractional dead time (MFDT) were calculated. FMECA analysis of the components of the system was also done.

Fault tree analysis is a very practical way of calculating the reliability, and it also gives a good overview of what combination of component failure will lead to the top event. However, a fault tree analysis does not take in to account the sequence of events. It views the system as a static situation, and does not take care of the dynamic effect. The result from a fault tree analysis will therefore not be 100% accurate.

An FMECA analysis is a qualitative analysis, and does not give numbers on how well the reliability of the system is. FMECAS are used to provide input to design related issues. MFDT calculation assume fixed test interval, but in practice, the test interval may vary. This will give a result that is too optimistic Holand and Skalle (2001).

# 11 Alternative Methods for BOP Reliability Assessment

## 11.1 Reliability Block Diagram

One way to perform a reliability analysis of a BOP system that is not often used is with the help of a block diagram. However, with complex systems, the block diagram will quickly become very large and complicated, so it is not that practical. Each function of the system must be considered individually, and a separate reliability block diagram has to be made for each function. The block diagram presented here, gives a rough overview of how it could be done, and is not very detailed. A separate block diagram will have to be made for the annular preventer, pipe ram and BSR. The “preventer” block, represents the probability that the preventer in question (annular, pipe ram or BSR) is able to seal the well once it is closed successfully. This value will be different for each preventer. By inserting the probability of success in each of the blocks, you can calculate the probabilities that the different functions are able to activate and seal the well.

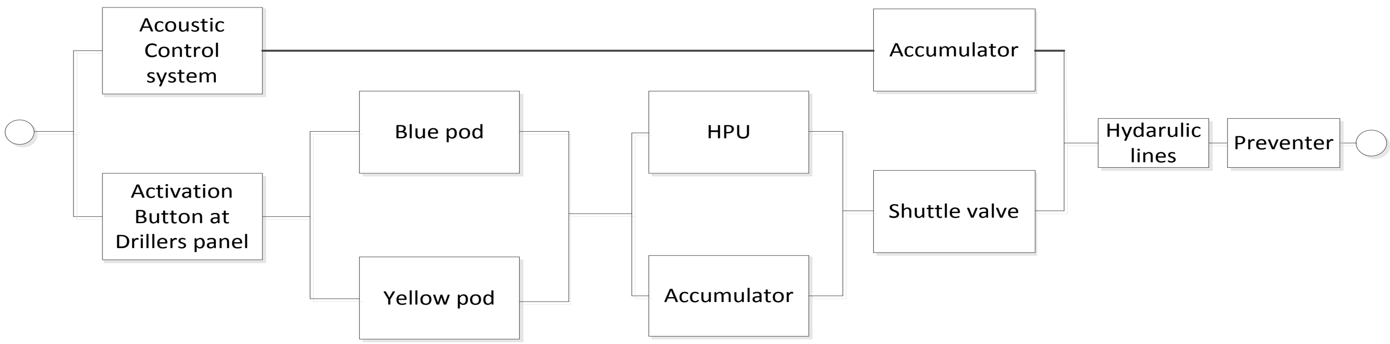


**Figure 11.1 Reliability Block Diagram for a BOP System**

## 11.2 Event Tree

Event tree analysis is a good way of presenting the different outcomes of an accident, depending on what barriers are able to work as intended. The probability that the different barriers will work when needed can for example be found with the use of the reliability block diagram shown in the previous chapter.

The event tree presented here is based on the modern BOP stack configuration. Two situations will be looked at. With a drill pipe is going through the BOP, and a situation where there is no objects going through the BOP.

### With a Drill Pipe Going Through the BOP:

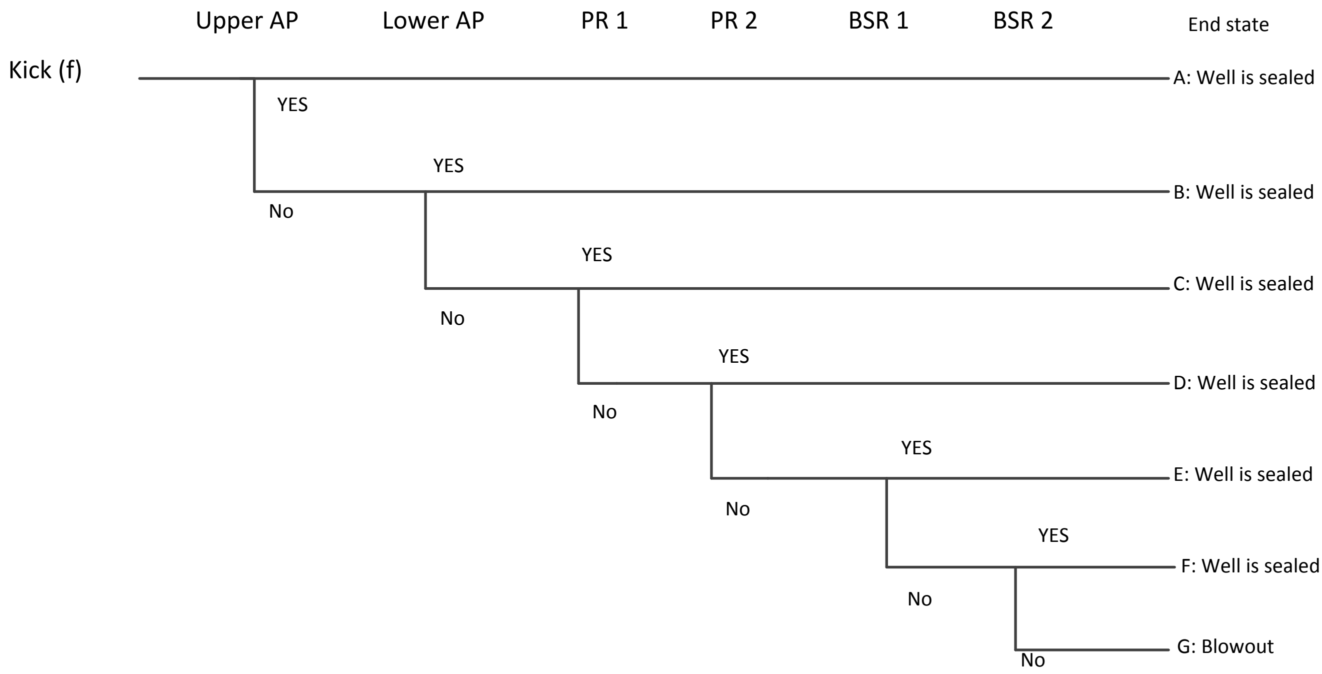


**Figure 11.2 Event tree for a situation with a drill string going through the BOP**

### Empty Hole:

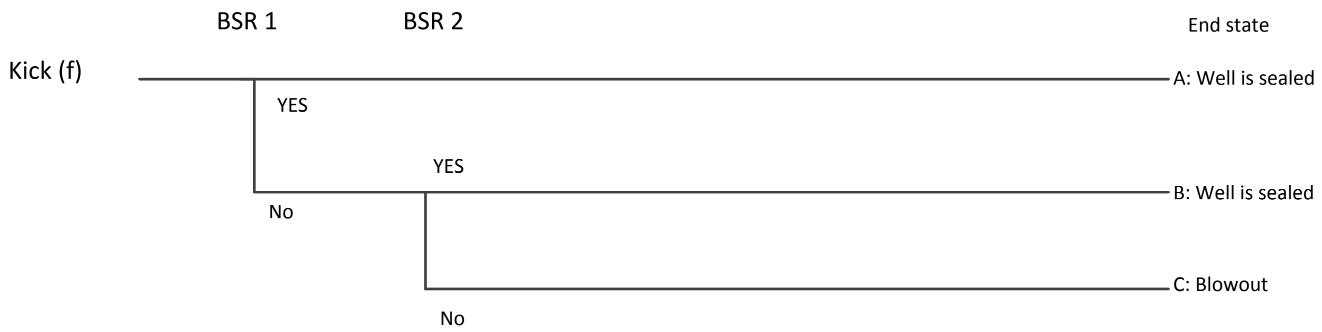


**Figure 11.3 Event tree for a situation with no objects going through the BOP**

# 12 New Approach to Reliability Assessment of a BOP System

## 12.1 A Combination of Fault Tree and Event Tree

In this chapter, a new approach to reliability assessment of BOP systems is presented. This approach is based on combining a fault tree analysis with an event tree analysis in order to get a more accurate result. One event tree is made for the situation with an open hole, and one for the situation where a drill pipe is going through the BOP. Fault tree analyses are then performed to calculate the PFD for each of the branches in the event tree. The probability of each of the end states in the event tree can then be calculated.

This approach will take in to account the sequence of events. The operational situations "open hole" and "drill pipe going through the BOP" will be analyzed separately to take in to account the fact that different barriers will be available during each of the situations. How the analysis can be done, is shown below.

**Case 1 - Open Hole:**

**Event Tree:**

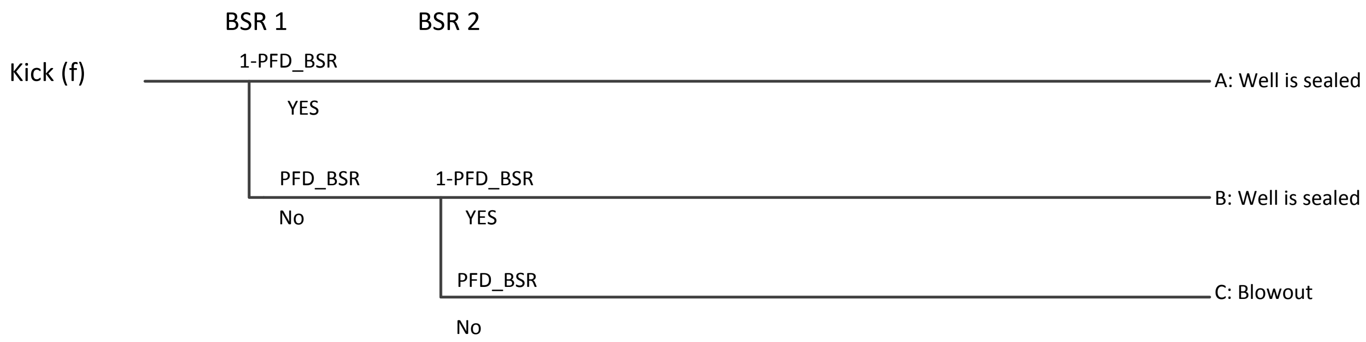


**Figure 12.1 Event tree for a situation with no objects going through the BOP**

**Fault Tree for BSR:**

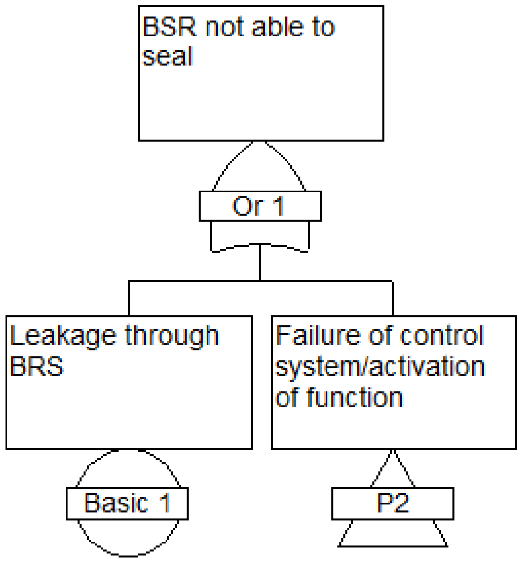


**Figure 12.2 Fault tree for the BSR branch of the event tree**

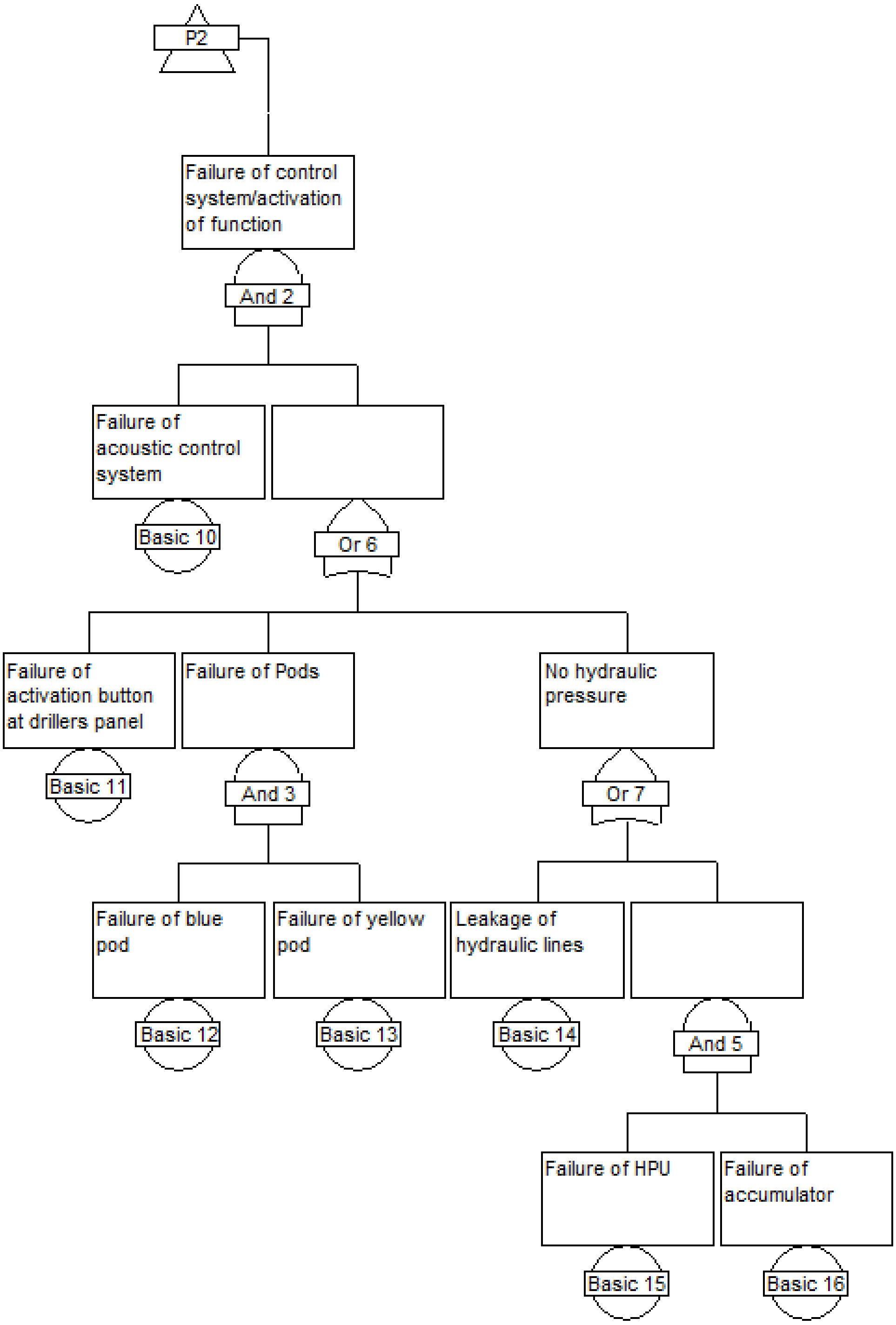


**Figure 12.3 P2 Branch for the fault tree**

## End State Calculations:

| | A | B | C | D |
|---|---|---|---|---|
| 1 | End state | A | B | C |
| 2 | BSR 1 | 1-PFD_BSR 1 | PFD_BSR 1 | PFD_BSR 1 |
| 3 | BSR 2 | | 1-PFD_BSR 2 | PFD_BSR 2 |
| 4 | Probability of end state | =B2 | =C2*C3 | =D2*D3 |

**Figure 12.4 End State Calculations**

## Case 2 - Drill Pipe in BOP:

### Event Tree:

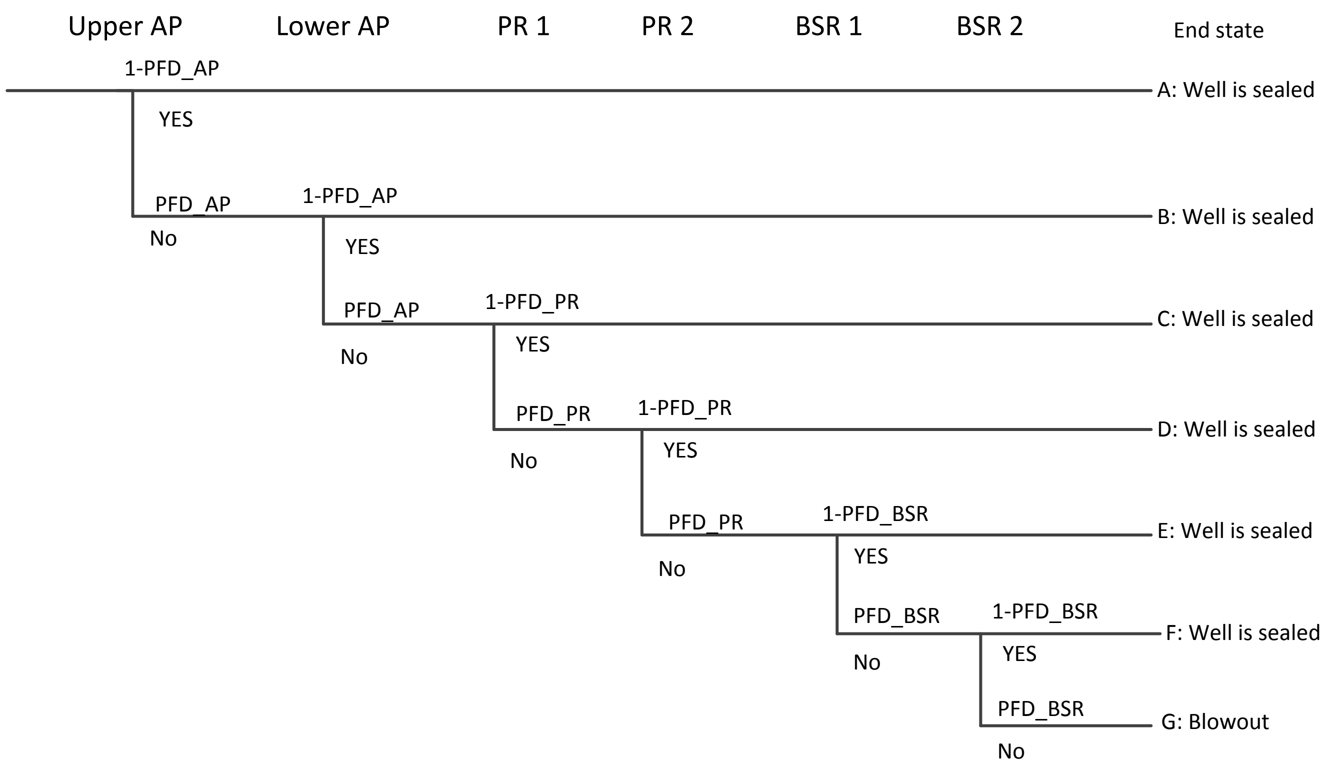


**Figure 12.5 Event tree for a situation with a drill string going through the BOP**

### Fault Tree for AP:

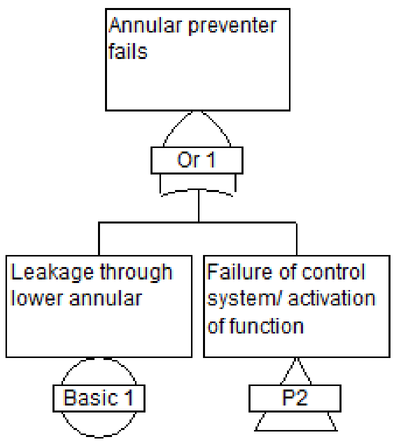


**Figure 12.6 fault tree for the AP branch of the event tree**

## Fault Tree for PR:

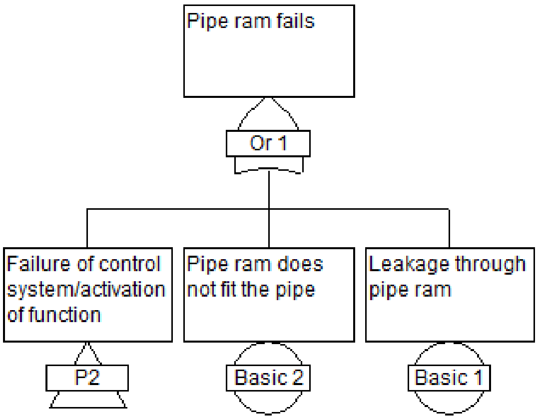


**Figure 12.7 Fault tree for the PR branch of the event tree**

## Fault Tree for BSR:

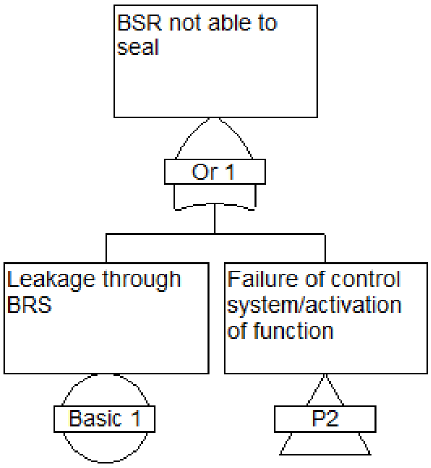


**Figure 12.8 Fault tree for the BSR branch of the event tree**

## End State Calculation:

| | A | B | C | D | E | F | G | H |
|---|---|---|---|---|---|---|---|---|
| 1 | End state | A | B | C | D | E | F | G |
| 2 | Annular preventer 1 | 1-PFD_AP1 | PFD_AP1 | PFD_AP1 | PFD_AP1 | PFD_AP1 | PFD_AP1 | PFD_AP1 |
| 3 | Annular preventer 2 | | 1-PFD_AP2 | PFD_AP2 | PFD_AP2 | PFD_AP2 | PFD_AP2 | PFD_AP2 |
| 4 | Pipe ram 1 | | | 1-PFD_PR1 | PFD_PR1 | PFD_PR1 | PFD_PR1 | PFD_PR1 |
| 5 | Pipe ram 2 | | | | 1-PFD_PR2 | PFD_PR2 | PFD_PR2 | PFD_PR2 |
| 6 | BSR 1 | | | | | 1-PFD_BSR1 | PFD_BSR1 | PFD_BSR1 |
| 7 | BSR 2 | | | | | | 1-PFD_BSR2 | PFD_BSR2 |
| 8 | Probability of end state | =B2 | =C2*C3 | =D2*D3*D4 | =E2*E3*E4*E5 | =F2*F3*F4*F5*F6 | =G2*G3*G4*G5*G6*G7 | =H2*H3*H4*H5*H6*H7 |

**Figure 12.9 End State Calculations**

# 13 Conclusion and Further Research

To improve the reliability assessment of a BOP system, it is suggested to combine a fault tree analysis with an event tree analysis. This takes the sequence of events in to account, and thus make the analysis more accurate. Further, while doing the analyses, it is recommended to conduct two separate analyses. One for the operational situations “open hole” and another for the operational situation “drill pipe going through the BOP”. This is done because the barriers in effect vary depending on what operational situation the BOP is going through.

For further research it is recommended that a more detailed fault tree analysis is done with the combination of an event tree analysis and with industry data used as input for the calculations. Common cause failures should also be taken in to account during the calculations.

Not all faults are found during testing, and some functions cannot be tested at all during some parts of the operations. For example, the shear ram cannot be function tested during drilling, and it is never possible to test the shear rams ability to shear, since that is a destructive test.  This is a factor that will influence the reliability analysis of the equipment, and needs to be taking in to account when doing the calculations for an accurate result.

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# Appendix A: Recommended Test Practices for Subsea BOP Stacks

Table 3—Recommended Pressure Test Practices, Floating Rigs With Subsea BOP Stacks

**Initial Test** *(diverter system prior to spud, et al, prior to running stack):*

| Component to be Tested | Recommended Pressure Test—Low Pressure, psi[a] | Recommended Pressure Test—High Pressure, psi[b,c] |
|---|---|---|
| 1. Diverter Element | Optional | Optional |
| 2. Annular Preventer(s) | 200-300 (1.38 - 2.1 MPa) | Minimum of 70% of annular BOP working pressure. |
| • Operating Chambers | N/A | Minimum of 1500 (10.3 MPa). |
| 3. Ram Preventers | | |
| • Fixed Pipe | 200-300 (1.38 - 2.1 MPa) | Working pressure of ram BOPs. |
| • Variable Bore | 200-300 (1.38 - 2.1 MPa) | Working pressure of ram BOPs. |
| • Blind/shear | 200-300 (1.38 - 2.1 MPa) | Working pressure of ram BOPs. |
| • Operating Chambers | N/A | Maximum operating pressure recommended by ram BOP manufacturer. |
| 4. BOP-to-WHD Connector | 200-300 (1.38 - 2.1 MPa) | Working pressure of ram BOPs. |
| 5. Diverter Flowlines | Flow Test | N/A |
| 6. Choke & Kill Lines & Valves | 200-300 (1.38 - 2.1 MPa) | Working pressure of ram BOPs. |
| 7. Choke & Kill Manifold | | |
| • Upstream of Last High Pressure Valve | 200-300 (1.38 - 2.1 MPa) | Working pressure of ram BOPs. |
| • Downstream of Last High Pressure Valve | 200-300 (1.38 - 2.1 MPa) | Optional |
| 8. BOP Control System | | |
| • Manifold | N/A | Minimum of 3000 (20.7 MPa). |
| • Accumulator Pressure | Verify Precharge | N/A |
| • Close Time | Function Test | N/A |
| • Pump Capability | Function Test | N/A |
| • Control Stations | Function Test | N/A |
| 9. Safety Valves | | |
| • Kelly, Kelly Valves, and Floor Safety Valves | 200-300 (1.38 - 2.1 MPa) | Working pressure of the component. |
| 10. Auxiliary Equipment | 200-300 (1.38 - 2.1 MPa) | Optional |
| • Riser Slip Joint | Flow Test | N/A |
| • Mud/Gas Separator | Flow Test | N/A |
| • Trip Tank, Flo-Show, etc. | Flow Test | N/A |

[a]The low pressure test should be stable for at least 5 minutes.
[b]The high pressure test should be stable for at least 5 minutes. Flow-type tests should be of sufficient duration to observe for significant leaks.
[c]The rig available well control equipment may have a higher rated working pressure than site required. The site-specific test requirement should be considered for these situations.

**Figure A1 Recommended test practices**
**(API RP 53, 2004)**

Table 4—Recommended Pressure Test Practices, Floating Rigs With Subsea BOP Stacks

**Subsequent Tests** *[(a) BOP stack initially installed on wellhead and (b) not to exceed 21 days]:*

| Component to be Tested | Recommended Pressure Test—Low Pressure, psi[a] | Recommended Pressure Test—High Pressure, psi[b] |
|---|---|---|
| 1. Diverter Element | Optional | Optional |
| 2. Annular Preventer | 200-300 (1.38 - 2.1 MPa) | Minimum of 70% of annular BOP working pressure. |
| • Operating Chambers | N/A | N/A |
| 3. Ram Preventers | | |
| • Fixed Pipe | 200-300 (1.38 - 2.1 MPa) | Greater than the maximum anticipated surface shut-in pressure. |
| • Variable Bore | 200-300 (1.38 - 2.1 MPa) | Greater than the maximum anticipated surface shut-in pressure. |
| • Blind/shear (initial installation) | 200-300 (1.38 - 2.1 MPa) | Greater than the maximum anticipated surface shut-in pressure. |
| • Operating Chamber | N/A | N/A |
| 4. BOP-to-WHD Connector and Casing Seals | 200 -300 (1.38 - 2.1 MPa) | Greater than the maximum anticipated surface shut-in pressure. |
| 5. Diverter Flowlines | Flow Test | N/A |
| 6. Choke & Kill Lines & Valves | 200-300 (1.38 - 2.1 MPa) | Greater than the maximum anticipated surface shut-in pressure. |
| 7. BOP Choke Manifold | | |
| • Upstream of Last High Pressure Valve | 200-300 (1.38 - 2.1 MPa) | Greater than the maximum anticipated surface shut-in pressure. |
| • Downstream of Last High Pressure Valve | Optional | Optional |
| 8. Control System | | |
| • Manifold and BOP Lines | N/A | Optional |
| • Accumulator Pressure | N/A | N/A |
| • Close Time | Function Test | N/A |
| • Pump Capability | Function Test | N/A |
| • Control Stations | Function Test | N/A |
| 9. Safety Valves | | |
| • Kelly, Kelly Valves, and Floor Safety Valves | 200-300 (1.38 - 2.1 MPa) | Greater than the maximum anticipated surface shut-in pressure. |
| 10. Auxiliary Equipment | N/A | N/A |
| • Riser Slip Joint | Flow Test | N/A |
| • Mud/Gas Separator | Optional | N/A |
| • Trip Tank, Flo-Show, etc. | Flow Test | N/A |

[a]The low pressure test should be stable for at least 5 minutes.
[b]The high pressure test should be stable for at least 5 minutes. Flow-type tests should be of sufficient duration to observe for significant leaks.

**Figure A2 Recommended test practices**
**(API RP 53, 2004)**

## Leak test pressures and frequency for well control equipment

### Table A.1 - Routine leak testing of drilling BOP and well control equipment

| | Frequency / Element | Stump | Before drilling out of casing: Surface | Before drilling out of casing: Deeper casing and liners | Before well testing | Periodic: Weekly | Periodic: Each 14 days | Periodic: Each 6 months |
|---|---|---|---|---|---|---|---|---|
| BOP | Annulars | MWDP 1) | Function | MSDP 1) | TSTP 1) | Function | MSDP 1) | WP x 0,7 |
| | Pipe rams | MWDP | Function | MSDP | TSTP | Function | MSDP | WP |
| | Shear rams | MWDP | Function | MSDP | TSTP | Function | | WP |
| | Failsafe valves | MWDP | Function | MSDP 3) | TSTP | Function | MSDP 3) | WP |
| | Well head connector | MWDP | MSDP | | TSTP | | MSDP | WP |
| | Wedge locks | Function | | | | | | |
| Choke/kill line and manifold | Choke/kill lines | MWDP | MSDP | MSDP | TSTP | | MSDP | WP |
| | manifold | MWDP | MSDP | MSDP | TSTP | | MSDP | WP |
| | Valves | Function | Function | Function | Function | | Function | |
| | Remote chokes | | | | | | | |
| Other equipment | Kill pump | WP 2) | | MSDP | | | MSDP | WP |
| | Inside BOP | MWDP 2) | | MSDP | TSTP | | MSDP | WP |
| | Stabbing valves | MWDP 2) | | MSDP | TSTP | | MSDP | WP |
| | Upper kelly valve | MWDP 2) | | MSDP | | | MSDP | WP |
| | Lower kelly valve | MWDP 2) | | MSDP | | | MSDP | WP |

**Legend**

| | |
|---|---|
| WP | working pressure |
| MWDP | maximum well design pressure |
| MSDP | maximum section design pressure |
| Function | Function testing: testing shall be done from alternating panels/pods. |
| TSTP | tubing string test pressure |
| 1) | Or maximum 70 % of WP |
| 2) | Or at initial installation |
| 3) | From above if restricted by BOP arrangement |

NOTE 1 All tests shall be 1,5 MPa to 2 MPa/5 min and high pressure/10 min.

NOTE 2 If the drilling BOP is disconnected/re-connected or moved between wells without having been disconnected from its control system, the initial leak test of the BOP components can be omitted. The wellhead connector shall be leak tested.

NOTE 3 The BOP with associated valves and other pressure control equipment on the facility shall be subjected to a complete overhaul and shall be recertified every five years. The complete overhaul shall be documented.

**Figure A3 Recommended test practices**
**(NORSOK D-010, 2004)**

# Appendix B: Fault Tree Symbols

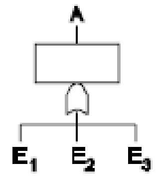
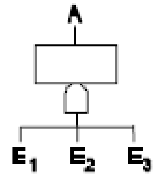
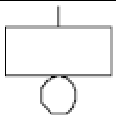
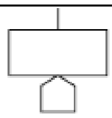
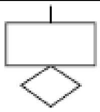
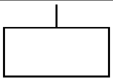
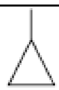
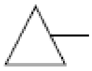
| Symbol | | | Description |
|---|---|---|---|
| Logic Gates | "OR" gate |  | The OR-gate indicates that the output event A occurs if any of the input events $E_i$ occurs. |
| | "AND" gate |  | The AND-gate indicates that the output event A occurs only when all the input events $E_i$ occur simultaneously. |
| 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. |
| | "HOUSE" event |  | The House event represents a condition or an event, which is TRUE (ON) or FALSE (OFF) (not true). |
| | "UNDEVELOPED" event |  | The Undeveloped event represents a fault event that is not examined further because information is unavailable or because its consequence is insignificant. |
| Description of State | "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 |  | |

**Figure A4 fault tree symbols (Holand and Skalle, 2001)**

# Appendix C: Cut sets

**Cut set for the fault tree "not able to seal around drill pipe":**

Cut set(s) with 2 components (Total: 2)
{Basic 10,Basic 14}
{Basic 10,Basic 11}

Cut set(s) with 3 components (Total: 2)
{Basic 10,Basic 12,Basic 13}
{Basic 10,Basic 15,Basic 16}

Cut set(s) with 5 components (Total: 8)
{Basic 1,Basic 5,Basic 7,Basic 3,Basic 9}
{Basic 1,Basic 5,Basic 7,Basic 4,Basic 9}
{Basic 1,Basic 6,Basic 7,Basic 3,Basic 9}
{Basic 1,Basic 6,Basic 7,Basic 4,Basic 9}
{Basic 2,Basic 5,Basic 7,Basic 3,Basic 9}
{Basic 2,Basic 5,Basic 7,Basic 4,Basic 9}
{Basic 2,Basic 6,Basic 7,Basic 3,Basic 9}
{Basic 2,Basic 6,Basic 7,Basic 4,Basic 9}

**Cut set for the fault tree "Not able to seal an open hole":**

Cut set(s) with 2 components (Total: 4)
{Basic 10,Basic 14}
{Basic 10,Basic 11}
{Basic 10,Basic 17}
{Basic 1,Basic 2}

Cut set(s) with 3 components (Total: 2)
{Basic 10,Basic 12,Basic 13}
{Basic 10,Basic 15,Basic 16}

## Appendix D: Pre-Study Report

# PREFACE

The pre-study report is meant as an overview of the activities that shall be performed in my master thesis, as well as a time schedule for the project. The master thesis is carried out during the spring of 2012, as part of the 2-year master`s degree in Subsea technology at NTNU. The duration of the project is 20 weeks.

The title of the master thesis is: "Improved methods for reliability assessments of safety-critical systems: An application example for BOP systems", and will be written at the Department of Production and Quality Engineering.

Professor Mary Ann Lundteigen will be the main supervisor for this project, and Professor Marvin Rausand will be the co-supervisor.

# BACKGROUND

System reliability assessments provide important input to decision-making in relation to design-related issues as well as during operations and maintenance. The main purpose of a system reliability assessment is to provide realistic predictions of the future performance of the system, within the constraints of available data, operation conditions, and modeling capabilities. Special applications and operating conditions sometimes reveal inadequacies in current assessment method. One such application is the blowout preventer (BOP), a safety-critical system that is used to ensure safe drilling and well interventions of oil and gas wells. The ability of the BOP system to function as a safety barrier depends on the ongoing operation, whether it is drilling, tripping-in, tripping-out, well logging, and so on. At the same time, the likelihood demands to be handled depends on the same operations. An average estimate of the BOP`s ability to of function on demand is therefore not an adequate reliability parameter. A BOP system deviates from many other safety barrier systems since it does not have a fail-safe design (except for the choke and kill valves). Another deviation is due to the many different uses of BOP and its components. Many of the components are operated much more often than during the periodic proof tests. The usual formulas for reliability calculations based on periodic proof testing can therefore not be used directly.

# OBJECTIVES

In this master thesis, the main objective is to propose solutions to some of the challenges indicated in the chapter about background, using the BOP as an example. More specifically:

3. Give a presentation of a typical (standard) BOP system, its requirements and reliability challenges
    d. Describe and classify the main functions and the associated performance requirements of a BOP system.
    e. Identify and discuss the main operation situations of a BOP in light of the ability of the BOP to stop well kicks.
    f. Identify recent BOP stack configurations and describe the pros and cons of these related to a standard BOP configurations

4. Suggest improved approaches to reliability assessment of BOP systems that can incorporate some of the above challenges
    a. Carry out and document a literature survey on how reliability analyses of BOPs have been performed in the past, and discuss the limitations of these approaches.
    b. Suggest alternative methods for BOP reliability assessment and illustrate their pros and cons through a case study
    c. Propose a new overall approach to risk and reliability assessment of BOP systems, which include proposals for how to solve some of the identified challenges
    d. Identify related issues that need further research, and give recommendations for such research.

# TASKS

The project has been divided in to 5 different main tasks. I will now go through each of them and analyze the work task's content.

**Task 1: Pre-study report**

The pre-study report is done at the start of the project. It will be handed in within three weeks after the date of the task handout. The pre-study report is meant as an overview of the activities that shall be performed in my master thesis, as well as a time schedule for the project.

The main challenges of writing the pre-study report will be to estimate the time needed to complete each of the tasks.

**Task 2: Literature survey**

I will conduct a literature survey to get an overview of the most relevant sources on the topic. This will be initiated before I start writing to make sure I do not miss important information. The literature survey will be an ongoing process through the starting phase of the project.

The challenges here will be to find the most relevant sources as early as possible. If you do not do a thorough literature survey, you might miss important information that could have helped you in your work.

**Task 3: Give a presentation of a typical BOP system, its requirements and reliability challenges**

Through earlier projects, I have gained knowledge of the main functions of a BOP system and how it works. This knowledge will make it easier for me to perform this task.

However, I believe it will be a challenge to identify recent BOP stack configurations, since this information is hard to find.

**Task 4: Suggest improved approaches to reliability assessment of BOP systems**

In this task, I will have to find out how reliability analysis of BOP`s have been performed in the past, and identify the limitations of these approaches. Based on this, I will suggest alternative methods for BOP reliability assessment present the pros and cons of these methods.

The main challenge here will be to suggest new methods of reliability assessment, and propose ways to solve identified challenges.

**Task 5: Conclusion and finalizing the report**

This is the last stage of the project. All other tasks should now be completed, and the time will be spent on putting everything together. The conclusion will also be written at this stage.

# PROJECT DURATION

This master thesis was started January 16$^{th}$ 2012, and the delivery date is June 11$^{th}$ 2012. The master thesis is scheduled for 20 weeks of work, but because of Easter, we have been given 1 more week. The recommended workload according the NTNU`s guidelines, is 48 hours each week. That gives a total of 960 hours of work.

# GANTT DIAGRAM

The figure below shows a Gantt-diagram, which illustrates the project schedule and important milestones.

| Task Name | Duration | Start | Finish |
|---|---|---|---|
| Task 1 | 16 days | Mon 16.01.12 | Mon 06.02.12 |
| Pre-study report delivery | 0 days | Mon 06.02.12 | Mon 06.02.12 |
| Task 2 | 21 days | Mon 16.01.12 | Mon 13.02.12 |
| Task 3 | 31 days | Mon 23.01.12 | Mon 05.03.12 |
| Task 4 | 66 days | Mon 05.03.12 | Mon 04.06.12 |
| Task 5 | 6 days | Mon 04.06.12 | Mon 11.06.12 |
| Master thesis | 106 days | Mon 16.01.12 | Mon 11.06.12 |
| Master thesis delivery | 0 days | Mon 11.06.12 | Mon 11.06.12 |