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Operational Barrier Elements in Critical Drilling Operations

Understanding Failure Mechanisms in the Primary Well Barrier

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Preface

This report concludes my studies at the Department of Marine Technology at the Norwegian University of Technology and Science. The thesis has been written in the first and second quarter of 2014. Its final grade will be based solely upon the evaluation of this report. The work has been very interesting, seeing as how several of its main topics were new to me prior to start-up. Throughout the process I have been faced with many challenges, chief of which is perhaps the vast literature in the two fields of study discussed in this report. The amount of available information occasionally makes finding specific pieces of information a time-consuming process. A further challenge has been the taxonomy used in the two disciplines. Both fields are riddled with definitions and descriptions of what at times may seem to be ambiguous concepts. I have tried to remain consistent in my use of these words.

In relation to my submitting the thesis, I would like to express my gratitude towards the people who have helped me complete it. I would like to thank my supervisor, Professor Jan Erik Vinnem at the Department of Marine Technology for many valuable conversations and for helping me keep a focus on the structure of the thesis. I would also like to thank my co-supervisors Snorre Sæternes and Marius Fernander, as well as Sondre Øie, at DNV GL, for kindly taking the time to discuss my work with me, and for giving me useful input. I also owe thanks to Pål Skalle, Associated Professor of Department of Petroleum Engineering and Applied Geophysics (IPT), NTNU. He kindly agreed to review my results and comment on their validity. I am also indebted to Kristian S. Gould, PhD, leading advisor organizational safety and human factors at Statoil ASA, for discussing the use of HRA methods in Norway with me. Lastly, I would like to express my heartfelt gratitude to Jan Ove Strandos, experienced driller and teacher at Bergen Maritime College. He agreed to show me around on the simulator at Bergen Maritime. He also answered my numerous questions. Without him, my efforts to describe and understand the operations on a drilling rig would have been futile.

Georg D. Tuset

Georg D. Tuset,
Trondheim, May 30, 2014.

Summary

This thesis concerns the use of human reliability analysis in offshore quantitative risk analysis (QRA). A QRA is a risk analysis which produces numerical values for probabilities of, and consequences from, undesired events. It typically analyzes several entire accident sequences, each originating from various hazards that are present on an offshore installation. From a QRA, assessments regarding the level of risk can be made. Criticism has however been directed towards offshore QRAs, for their lack of focus on Human and Organizational Factors (HOFs) (Skogdalen and Vinnem, 2011). A feasible way of including HOFs in QRA is by using human reliability analysis (HRA). A HRA is '*a systematic identification and evaluation of the possible errors that may be made by operators, maintenance personnel, and other personnel in the system*' (Rausand, 2011). The three essential parts from a quantitative HRA is human error identification, quantification and reduction.

The goal of the thesis is to apply HRA to a precursor of one of the hazards present on a drilling rig; the uncontrolled release of hydrocarbons to the installation and surroundings - a *blowout*. In order to do this, pressure control during drilling is discussed. A qualitative human reliability analysis of a operation performed in offshore drilling is subsequently performed using the discussed HRA methods. The operation is called 'trip out of hole' and constitutes all actions required by rig personnel to retrieve the entire drillstring, bottom hole assembly and bit from the bottom of the well. Maintaining primary well control throughout the operation means ensuring there is a positive pressure differential between the column of mud in the well and the pressure of the fluid inside the pore spaces of the exposed formation. If overbalance is lost, formation fluid will rush into the well and the situation must be controlled by means of a blowout preventer. The thesis makes use of HRA methods to identify and causally represent potential human errors which may cause such an influx to occur. A hierarchical task analysis has been developed, upon which human error identification has been performed. Lastly, the relevant errors have been combined with technical faults in a fault tree for the top event 'primary well control failure occurs during trip out of hole'. The fault tree logically depicts the basic events which by themselves, or in combination with other basic events, are sufficient to cause the top event to occur. The results from the analysis show that human error causing dynamic pressure changes in the mud column are the most critical for primary well control during the operation.

Sammendrag

Denne oppgaven dreier seg om bruk av menneskelig pålitelighetsanalyse i kvantitative risikoanalyser for offshore operasjoner. En QRA er en risikoanalyse som setter tall på sannsynligheten for, og konsekvensene av, uønskede hendelser. Den tar vanligvis for seg flere ulykkesekvenser som hver springer ut fra de ulike faremomentene som er tilstede på en offshore installasjon. Fra en QRA kan vurderinger vedrørende risiko foretas. Kritikk har imidlertid vært rettet mot offshore QRAer, for et manglende fokus på menneskelige og organisatoriske faktorer (Skogdalen and Vinnem, 2011). En måte å inkludere slike faktorer i QRA er å anvende menneskelig pålitelighetsanalyse (HRA). En HRA er '*en systematisk identifisering og vurdering av mulige feil som kan gjøres av operatører, vedlikeholdspersonnel og annet personell i systemet*' (Rausand, 2011). Hoveddelene i en kvantitativ HRA er identifisering, kvantifisering og reduksjon av menneskelige feil.

Målet med denne oppgaven er å bruke HRA på en forløper til et av faremomentene tilstede på en borerigg; et ukontrollert utslipp av hydrokarboner til installasjonen og omgivelsene - en *utblåsning*. For å få til dette er trykkontroll under boring diskutert. En kvalitativ menneskelig pålitelighetsanalyse av en operasjon som utføres under boring blir deretter utført ved hjelp av HRA metodene som er blitt gjennomgått. Denne operasjonen kalles for 'trip out of hole', og omfatter alle handlinger som kreves av riggpersonnel for å løfte borestrengen, bunnhullsammensetningen og borekronen ut av brønnen. Opprettholdelse av primær brønnkontroll under denne operasjonen innebærer å sikre at det er en positiv trykkforskjell mellom søylen av slam i brønnen og trykket i fluidet inne i hulrommene i den eksponerte formasjonen. Hvis overbalansen tapes vil fluider fra formasjonen strømme inn i brønnen. Situasjonen må da kontrolleres ved bruk av utblåsningssikring (BOP). Oppgaven tar i bruk HRA metoder for å identifisere, samt å representere, potensielle menneskelige feil som kan føre til at en slik innstrømning oppstår. En hierarkisk oppgaveanalyse har blitt utviklet, hvorpå identifisering av menneskelige feil er blitt gjort. Til slutt har de aktuelle feilene blitt kombinert med tekniske feil i et feiltre for topphendelsen 'tap av primær brønnkontroll under trip out of hole'. Feiltreet viser de ulike hendelsene som i kraft av seg selv, eller i kombinasjon med andre hendelser, er tilstrekkelige for å få topphendelsen til å skje. Resultatet fra analysen viser at menneskelige feil knyttet til dynamiske trykkforandringer i slamsøyla er mest kritisk for brønnspark under operasjonen.

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Chapter 1

Introduction

1.1 Background

The Petroleum Safety Authority (PSA) in Norway has established barriers as one of their main priority areas in 2014 (PSA, 2013b). Section 5 of the Management Regulations requires the establishment of barriers that both (1) reduce the likelihood of failures and hazard and accident situations developing and (2) limit possible harm and disadvantages. In their document on barrier management in the offshore industry, the PSA presents a functional view of the term 'barrier'. This means that a barrier is defined in a holistic and hierarchical way, wherein the barrier function defines the task or role of the barrier, while the barrier itself is an envelope of barrier elements of the technical, operational or organizational nature. The focus of this thesis lies in operational barrier elements.

Prior to writing this thesis, a literature study was undertaken. The study was concerned with two separate fields of study; Quantitative Risk Analysis (QRA) and Human Reliability Analysis (HRA). It was found that QRA studies generally tend to model initiating events in a coarse manner, and further that they are particularly focused on technical safety systems. The purpose of both the literature study, and the subsequent Master's Thesis is to evaluate how HRA can be implemented in a QRA model, so as to make the QRA reflect human and organizational factors. The object of study is the primary barrier against an unwanted influx of hydrocarbons into the well during drilling of offshore wells. The rationale behind the decision to study the drilling mud is that the reliability of this barrier is not easily modeled in a risk analysis. It is located at the very start of an accidental sequence, it is highly operational, and it requires a great deal of human intervention and control. These are characteristics that make the barrier intrinsically difficult to model in a QRA.

HRA is essentially a subset of the science of human factors, which concerns itself with understanding how people interact with the non-human elements of a complex system. What HRA provides in this context is a method to assess the impact of potential human errors on the proper functioning of a system (OGP, 2010). The assessment, depending on the scope, may also include quantification of human errors. This feature should, at least theoretically, make HRA a viable candidate for implementation in QRA models. The benefit with a successful combination of these methods is obvious; we could measure the human contribution to overall risk. This would enable human factors safety specialists to target the human actions with the greatest risk contribution, and not concern themselves with actions that have a limited effect on the risk-level. An additional benefit would be that the implementation of error-reducing measures could be measured in terms of contribution to risk. This would strengthen the ability of a QRA to provide decision-support.

In the search for guidelines and requirements on how to successfully implement HRA in offshore QRAs, little information was found. There are examples of research studies being conducted in Norway, such as the Petro-HRA project (Rasmussen, 2013), which aim to adjust HRA methods for use in offshore accident scenarios. However, for publicly available literature on the combinations of risk analysis and HRA one has to turn to the nuclear industry, where the HRA methods were first developed. Some of the most thorough descriptions are found in NUREG CR2300 (NRC, 1983) and NUREG-1792 (NRC, 2005). The adaption of the methodology outlined in these documents for offshore applications is a challenge yet to be met by the risk analysis community working in the petroleum industry. The nature of the operations, the equipment used, and the environment they are conducted in, is drastically different for the two industries. Many of the techniques used for risk analysis and human reliability analysis are customized for the nuclear industry. This entails that they are not imminently applicable for use in the offshore industry.

1.2 Objective

The objective of the thesis is to describe failure mechanisms in the control of the primary well barrier during drilling operations. More specifically, potential for human and technical failure causing barrier failure shall be identified, represented and discussed. This shall be done by utilizing HRA techniques.

1.3 Tasks to be carried out

In fulfillment of the objective, the following tasks shall be performed:

1. Provide an introduction into QRA:
   (a) What is it?
   (b) What accident types is it used for?
   (c) Present QRA's weaknesses, as pointed out in the literature.
   (d) Discuss how QRA reflects the regulatory focus on barriers.
2. Discuss the theory and use of HRA:
   (a) Provide an introduction to HRA.
   (b) Present the definitions used in HRA terminology.
   (c) Describe the governing classification systems for human error.
   (d) Present an outline of the process of conducting a HRA.
   (e) Describe one selected method for human error quantification.
3. Present the theory of well integrity with emphasis on well barriers.
4. Present an understanding of the physics of pressure control during drilling operations, with respects to the following:
   (a) The pressure types in sedimentary rock
   (b) Static and dynamic pressure in drilling mud
   (c) Safety margins commonly applied in drilling
   (d) Methods for re-establishing primary well control
   (e) The principle of the circulation system
5. Describe the causes of primary well control failure and how they can be detected.
6. Perform a HRA case study for a selected task during drilling:
   (a) Describe the system used.
   (b) Perform a task analysis.
   (c) Perform a human error identification.

   (d) Develop a fault tree containing both the relevant human errors and technical failures. The fault tree's top event should be primary well barrier failure.

7. Discuss results from the case study:
   (a) What does the results say on the human contribution to primary well control failure during the operation?
   (b) Point out any weaknesses and limitations in the case study
   (c) How could the basic events be quantified?
8. Give concluding remarks:
   (a) On the case study
   (b) On the use of HRA in QRA in general
9. Provide suggestions for further work

The text shall, in so far as possible, be structured chronologically according to the tasks outlined above.

1.4 Delimitations

The following delimitations apply:

- The thesis is concerned with conventional overbalanced drilling. Underbalanced drilling/managed pressure drilling is not covered in this report.
- The thesis is exclusively concerned with major hazard accidents. No other hazards than the blowout hazard are considered.
- The thesis discusses regulations and standards pertaining to risk analysis and safety on the Norwegian Continental Shelf (NCS). International regulations and standards are not referred to except where found necessary.
- The basic theory of fault tree construction is assumed to be known to the reader of this text, and is thus not included in this report. For the basic theory, the reader is referred to specialized literature such as e.g. (Vesely et al., 1981) or textbooks containing the topic such as (Rausand and Høyland, 2004).

1.5 Abbreviations

BOP:	Blowout Preventer
DP:	Drill pipe
ETA:	Event Tree Analysis
FAR:	Fatal Accident Rate
FOSV	Full Open Safety Valve
FIT:	Formation Integrity Test
FTA:	Fault Tree Analysis
HEP:	Human Error Probability
HFE:	Human Failure Event
HRA:	Human Reliability Analysis
HTA:	Hierarchical Task Analysis
IRPA:	Individual Risk Per Annum
LOT	Leak Off Test
MD:	Measured Depth
PIF:	Performance Influencing Factor
PLL:	Potential Loss of Life
PRA:	Probabilistic Risk Analysis
PSF:	Performance Shaping Factor
QRA:	Quantitative Risk Analysis
RIF:	Risk Influencing Factor
RKB:	Rotary Kelly Bushing
SPAR-H:	Standardized Plant Analysis Risk Human Reliability Analysis
TD:	Top Drive
TT	Trip Tank
TVD:	True Vertical Depth
WB:	Well Barrier
WBE:	Well Barrier Element

Chapter 2

Theory

2.1 Quantitative Risk Analysis

2.1.1 About QRA

A quantitative risk analysis is a risk analysis that produces numerical values for probabilities and consequences of undesired events. It expresses the level of risk in specific units, so that the impact of decisions, regarding for instance the placement of safety functions, on the overall risk level can be measured. Furthermore, it enables comparison between alternatives in terms of their contribution to risk. QRA is first and foremost used as a decision support tool, although it can also be used in a passive manner to demonstrate compliance with regulations.

The use of QRAs in Norway dates back to the second half on the 1970s, where the first QRAs were based upon methods developed for use in the nuclear industry (Rausand and Øien, 2004). Since then, a series of guidelines and regulations issued by the authorities have caused a rapid expansion in the use of risk assessments in the offshore activities (Vinnem, 2007). The QRA is now widely acknowledged as being a powerful tool for ensuring safe design and operation of offshore structures. It is the tool the authorities are basing their acceptance of offshore safety off of (Vinnem, 1998). The recommended standard for risk assessment of offshore and onshore oil and gas production facilities is the NORSOK Z-013 standard (NORSOK, 2013b).

2.1.2 Major Accident Hazards

A QRA typically analyzes the entire installation with respects to a minimum of 9 predefined major accident[1] hazards (NORSOK, 2013b):

1. Process accidents
2. Risers/landfall and pipeline accidents
3. Storage accidents (liquid and gas)
4. Loading/offloading accidents
5. Blowouts and well releases
6. Accidents in utility systems, e.g. leaks of chemicals, fires, explosion of transformers etc.
7. Accidents caused by external impact and environmental loads, e.g. collision, falling/swinging loads, helicopter crash, earthquake, waves.
8. Structural failure (including gross errors)
9. Loss of stability and/or buoyancy (including failure of marine systems)

2.1.3 Risk metrics

Risk is a combination of probability of occurrence and consequences. The consequences may be related to people, the environment or assets. There are various ways by which risk can be expressed; e.g. by distributions, expected values or single consequences (Vinnem, 2007). Perhaps the most widely recognized formula for calculating risk is the one shown in Eq. 2.1 below. Here, risk is expressed as the product of probability and consequence, summed over all potential accident sequences:

$$R = \sum_{i \epsilon I} (p_i \cdot C_i) \tag{2.1}$$

where

i	represents the i'th accident sequence
I	represents all possible accident sequences
p_i	probability of accident i
C_i	consequence of accident i

[1]**Major Accident:** Acute occurrence of an event such as a major emission, fire, or explosion, which immediately or delayed, leads to serious consequences to human health and/or fatalities and/or environmental damage and/or larger economic losses (NORSOK, 2013b).

Offshore QRAs tend to be focused on either individual or societal risk. To express the individual risk one uses the following risk metrics:

- **Fatal Accident Rate (FAR):** Number of fatalities per 100 million exposed hours (NORSOK, 2013b).
- **Individual Risk Per Annum (IRPA):** Probability that the individual will be killed due to the specified hazards a during one year's exposure (Rausand, 2011).

The IRPA can be estimated from the following formula (Rausand, 2011):

$$IRPA_a^* = \frac{\text{observed no. of fatalities due to hazards a}}{\text{total no. of person-years exposed}} \tag{2.2}$$

Societal risk is commonly expressed by either the parameter Potential Loss of Life (PLL), or by so-called f-N curves:

- **Potential Loss of Life (PLL):** Expected number of fatalities per year (NORSOK, 2013b).
- **f-N curve:** curve representing the frequency (f) of accidents causing $\geq$ N fatalities (NORSOK, 2013b).

The PLL for a specific area A may be calculated from the following relationship (Rausand, 2011):

$$PLL_A = \int\int_A IRPA(x,y)m(x,y)dxdy \tag{2.3}$$

where

$IRPA(x,y)$	IRPA for individual located at position (x,y)
$m(x,y)$	Population density at position (x,y)

2.1.4 Weaknesses of QRA

In the wake of the Deepwater Horizon Accident (Bartlit et al., 2011) the risk analysis communities around the world were reminded that human and organizational factors (HOFs) play an important part in the initiation and escalation of major accidents. Since a QRA should measure the level of risk, it would be natural to expect that such factors are expressed in them. This is however not necessarily the case. Skogdalen and Vinnem (2011) reviewed a random sample of 15 QRAs and categorized them by their level of HOF incorporation. The level of HOF was measured in four levels, with criteria as shown in Table 2.1.

Level of HOF	Requirement
Level 1	HOFs not existing
Level 2	HOFs explained but models are not adjusted
Level 3	HOFs explained and the models are adjusted
Level 4	HOFs explained, models adjusted and included in the overall risk management

Table 2.1: Level of integration of HOF in QRAs reviewed by Skogdalen and Vinnem (2011).

The result of the study showed that five installations satisfied the criteria for level 1, eight were level 2 and the last two installations satisfied the requirements for level 3. None of the QRAs satisfied level 4. It should be duly noted that the requirements for a level 4 analysis were specified in accordance with what the authors of the article interpreted governing guidelines, requirements and research to prescribe (Skogdalen and Vinnem, 2011). Hence, the study indicates that the criticism related to HOFs in offshore QRAs is valid.

The weakness in terms of HOF incorporation could also be viewed in terms of barriers. There is no explicit focus on barriers in an offshore QRA. Rather, the focus remains on developing accident sequences. The most frequently used technique for this process is Event Tree Analysis (ETA) (see e.g. Rausand (2011)). According to Vinnem (2007), the following hazards are the main types of hazards for which ETA is used:

- Blowouts
- Hydrocarbon leak events from process equipment
- Hydrocarbon leak events from riser
- Fires in utility system, mud process and quarters
- Structural and marine accidents

As was stated in the introduction, this thesis is concerned with the blowout hazard. More specifically it is focused at a precursor to the blowout hazard - a kick. The kick, which will be thoroughly described later, is a failure of the primary well barrier during drilling; the drilling mud. Although the drilling mud serves a number of functions in the drilling process, the most safety critical function is to prevent kicks from occuring. We say that it is a **barrier** against kicks. But what exactly do we mean when we use the term 'barrier'?

2.1.5 Barriers

The topic of barriers is central to the efforts of increasing industrial safety. Barriers are in essence the means we use to protect ourselves from undesirable events. Describing exactly what constitutes a barrier, and what does not, has however proven to be difficult, if not impossible. Consequently, a single unambiguous and universally accepted definition of the word 'barrier' does not yet exist. In order to explain the term, it is judged best to present barriers in relation to risk analysis. Kaplan and Garrick (1981) states that a risk analysis is conducted to answer three questions:

1. What can happen? (i.e., what can go wrong?)
2. How likely is it that that will happen?
3. If it does happen, what are the consequences?

Barriers relate to these questions in the following way. A barrier is something that either (1) completely prevents something bad from happening, (2) makes it less likely to happen, (3) completely eliminates the consequences, given that something bad has already occurred or (4) reduces the severity of the consequences, again given that something bad has happened. The bow-tie model in Figure 2.1 provides a comprehensive graphical view of these properties. The

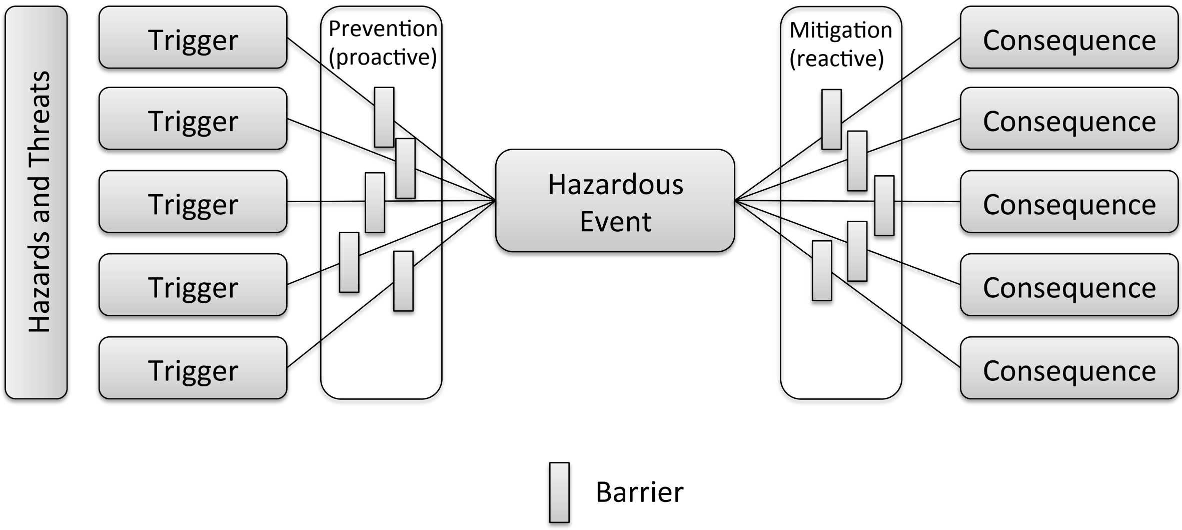


Figure 2.1: Bow-tie model. Image reproduced from Rausand (2011).

bow-tie model is used to visualize all the possible accident sequences which *might* occur. In this model, an accident sequence progresses from left to right. To the far left we have the hazards and threats which might, given some triggering condition or event, develop into an accident. At the center of the diagram, we have a so-called hazardous event. One definition of such an event is that it is '*the first event in a sequence of events that, if not controlled, will lead to undesired consequences (harm) to some assets*' (Rausand, 2011). NORSOK Z-013 uses the definition shown on the next page.

Hazardous event: Incident which occurs when a hazard is realized (NORSOK, 2013b).

The proactive barriers are there to prevent the hazardous event from occurring. The reactive barriers' purpose is to control the hazardous event - terminating the progress of the event sequence before the defined end-consequences are reached. What is considered to be the hazardous event is however largely dependent on the resolution of the analysis. An initiating event in one bow-tie model may well be considered a consequence in another model. We may therefore find barriers at all levels of resolution.

The PSA uses the following definitions pertaining to barriers:

Barrier: Technical, operational and organizational elements which are intended individually or collectively to reduce possibility for a specific error, hazard or accident to occur, or which limit its harm/disadvantages (PSA, 2013a).

The technical, operational and organizational elements referred to in the definition above, are defined as follows:

Barrier element: Technical, operational or organizational measures or solutions which play a part in realizing a barrier function (PSA, 2013a).

The barrier function defines the purpose of the barrier. It is the 'what to do' part of the barrier definition:

Barrier function: The task or role of a barrier. Examples include preventing leaks or ignition, reducing fire loads, ensuring acceptable evacuation and preventing hearing damage (PSA, 2013a).

But what exactly do we mean when we say that a barrier element is 'operational'? The PSA (2013a) discusses an example for the barrier sub-function 'blow down of the leaking segment'. In this example, technical barrier elements are push buttons, Fire & Gas logic and valves. If the system requires an operator to perform manual actions to initiate and thus realize the 'blow down of the leaking segment' function, that person would be included as an organizational barrier element. His actions, i.e. the instances where this person interacts with the system so that it can perform its intended function, will then be an example of an operational barrier element according to the PSA.

Traditionally, QRAs have had a limited ability to assess operational barriers. The Barrier and Operational Risk Analysis (BORA)-project (Aven et al., 2006), and the subsequent Risk OMT project (Gran et al., 2012), was initiated in response to these limitations. BORA is a method for assessing the risk of hydrocarbon release, utilizing risk influencing factors[2] in conjunction with a basic risk model. The Risk OMT project is a continuation of the BORA project, in which the network of risk influencing factors used to calculate the hydrocarbon release frequency has been further developed. Both projects have been aimed at making the QRA reflect human and organizational factors. The same goal is potentially achieved by applying HRA methods.

2.2 Human Reliability Analysis

2.2.1 Introduction

A Human Reliability Analysis (HRA) is '*a systematic identification and evaluation of the possible errors that may be made by operators, maintenance personnel, and other personnel in the system*' (Rausand, 2011). The vast literature concerned with HRA can be thought to be an indication of a widespread agreement on the significance of the human contribution to risk in both industry and transport. Hollnagel (1998) state that there seems to be an agreement that somewhere between 60-90% of all system failures can be attributed to erroneous human actions. Although such statements have been subject to criticism, relatively recent events such as the Deepwater Horizon accident (Bartlit et al., 2011) have clearly demonstrated that the human contribution to major accident risk remains substantial. This despite the technical development seen in recent years. The purpose of this chapter is to present an understanding for the basic taxonomy used in HRA, to describe the HRA process and to present an outline of the SPAR-H method for human error quantification.

2.2.2 Definitions

Various authors have attempted to define the concept of 'human error'; the topic around which the entire field of HRA is centered. One frequently cited definition is that proposed by Swain (1989) which reads:

> **Human Error:** Any member of a set of human actions or activities that exceeds some limit of acceptability, i.e. an out of tolerance action [or failure to act] where the limits of performance are defined by the system (Swain, 1989).

[2]**Risk Influencing Factor:** A relatively stable condition that influences the risk (Hokstad et al., 2001).

So what exactly is a 'human action'? We can borrow the definition provided by IEEE (1997) which states that a human action is '*the observable result (often a bodily movement) of a person's intention*'. A 'set of human actions', as referred to in the definition above, is encompassed by the term *task* which Rausand (2011) defines as follows:

> **Task:** Collection of actions carried out by operators in order to achieve an objective or a goal state (Rausand, 2011).

A task may be decomposed into subtasks, sub-subtasks and all the way to the lowest level at which *actions* are located. A human error is therefore understood as being a deviation from what we want to achieve, or '*a failure to act as required*' (Kirwan, 1994), be it on a task-level or an action level. Another important facet of human intervention in complex systems is what we call diagnosis. Diagnosis is defined as follows:

> **Diagnosis:** A cognitive assessment of the state of the system (IEEE, 1997).

It follows from the definition that when faced with adverse events such as an emergency situation, operators required to recover from the event must perform a diagnostic before performing any type of action. Another way of saying this is that people will not do what is required if they have not firstly considered what needs to be done.

Reason (1990) states that a theory capable of predicting human error must combine three elements; the nature of the task and its environmental circumstances, the mechanisms governing performance and the nature of the individual. These elements are by several HRA methods treated by so-called 'performance influencing factors' (PIFs), also called 'performance shaping factors' (PSFs). Rausand (2011) provides the following definition on PIFs:

> **Performance Influencing Factor:** A factor that influences human performance and human error probabilities. Performance-influencing factors may be external to humans or may be a part of their internal characteristics (Rausand, 2011).

2.2.3 Human error classifications

A classification is nothing more than a partitioning of a group of phenomena into various categories, based upon a set of descriptors which can be applied reliably (Kirwan, 1994). It is however a necessity when trying to advance the knowledge on these phenomena. The most used classification systems for human error in use today are the ones proposed by Rasmussen (1983), Swain and Guttmann (1983) and Reason (1990). These will briefly be discussed here.

Behavior model proposed by Rasmussen (1983)

Rasmussen (1983) proposed a model in which human behavior is divided in three levels according to the cognitive effort involved:

- Skill-based behavior
  - Performance is controlled by stored patterns of behavior.
  - Operator reacts to stimuli with little conscious effort or consideration. He is, in some sense, operating in an 'automatic mode'.
- Rule-based behavior
  - Performance, in a familiar work situation, is controlled by a stored (i.e. readily available) rule.
  - The rule is a composition of a sequence of skill-level acts, selected from previous successful performances.
- Knowledge-based behavior
  - Unfamiliar situations in which rules from previous experiences are unavailable.
  - Successful performance requires problem-solving, goal selection and planning.

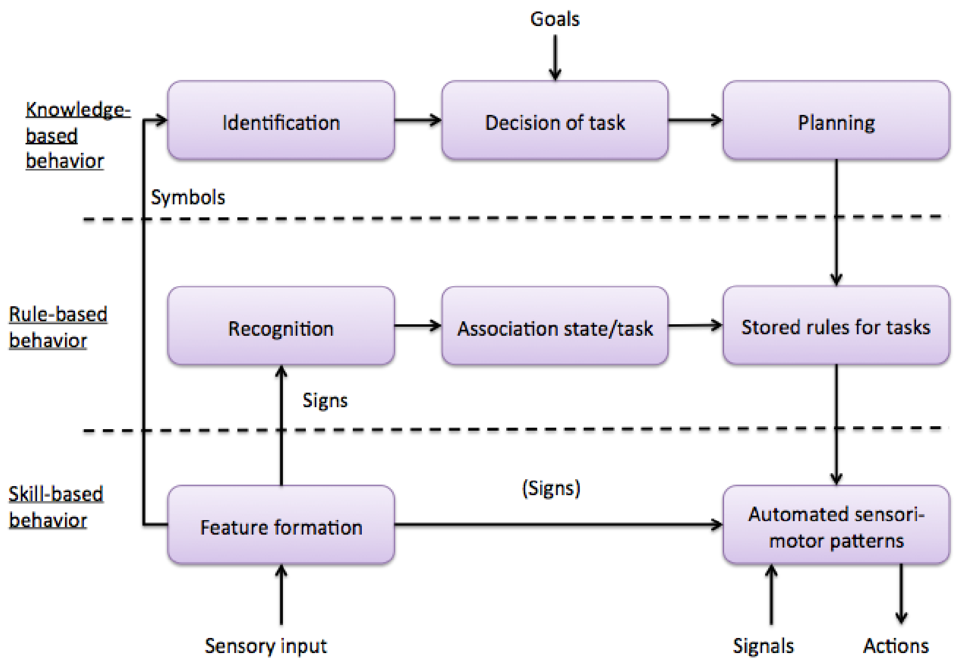


Figure 2.2: Human behavior model. Figure reproduced from (Rasmussen, 1983).

The model is summarized in Figure 2.2. Each category or level of behavior is characterized by different uses of available information. Signals are, according Rasmussen (1983) '*sensory data* *representing time-space variables from a dynamical spatial configuration in the environment*'. Whereas signals can be processed as continuous variables, signs are higher level indications which serve to activate stored patterns of behavior - they indicate a requirement for action. Symbols, lastly, represent other information, variables, relations and properties. They can be formally processed, but present an initiative for action in yet a more ambiguous or abstract way. Taking on this view of human performance, we may talk about errors at the skill, rule or knowledge level. Human performance in well structured tasks, such as those found in the skill-and rule domains, lends itself better to quantitative modeling than do performance in knowledge-based tasks, according to Rasmussen (1983).

Human error classification by Reason (1990)

Reason (1990) distinguishes between four types of human error; namely slips, lapses, mistakes and violations. The first two types appear during the execution of a familiar, i.e. skill/rule based, task. The distinction between the two types is made in that slips are externally observable, while lapses occur internally as memory failures. A mistake is understood as being an error in planning, meaning that the failure of an intended action to meet its desired end is due to an inadequate or erroneous intention rather than execution. Finally, violations refer to a conscious and deliberate failure to follow rules or procedures. Examples of the error types, as classified by Reason (1990), are provided in Table 2.2. The examples concern the operation of a pump.

Error type	Example
Slip	Failing to stop a pump at a pre-determined number of strokes
Lapse	Skipping a step in the start-up procedure of a pump
Mistake	Turning on the wrong pump
Violation	Deliberately omit to turn on the pump

Table 2.2: Slips, lapses, mistakes and violations.

Errors of omission and commission by Swain and Guttmann (1983)

Swain and Guttmann (1983) splits human errors into the two categories errors of commission and errors of omission. Errors of commission are, according to Kirwan (1994), human actions which may result in unsafe consequences. Another way of defining this category of errors is by calling it 'extraneous' or 'uncalled for' actions. These errors are very difficult to predict and they can have severe consequences. Errors of omission generally refers to omitting a step in a task or procedure. Such an error would fall in Reason (1990)'s category of 'lapse'. An error of commission on the other hand, will either be a slip, mistake or violation.

2.2.4 The HRA process

Kirwan (1994) provides an outline of the HRA process which is summarized in Figure 2.3. A brief introduction to the various stages of the HRA process is provided in this section, beginning with setting the scope of the HRA.

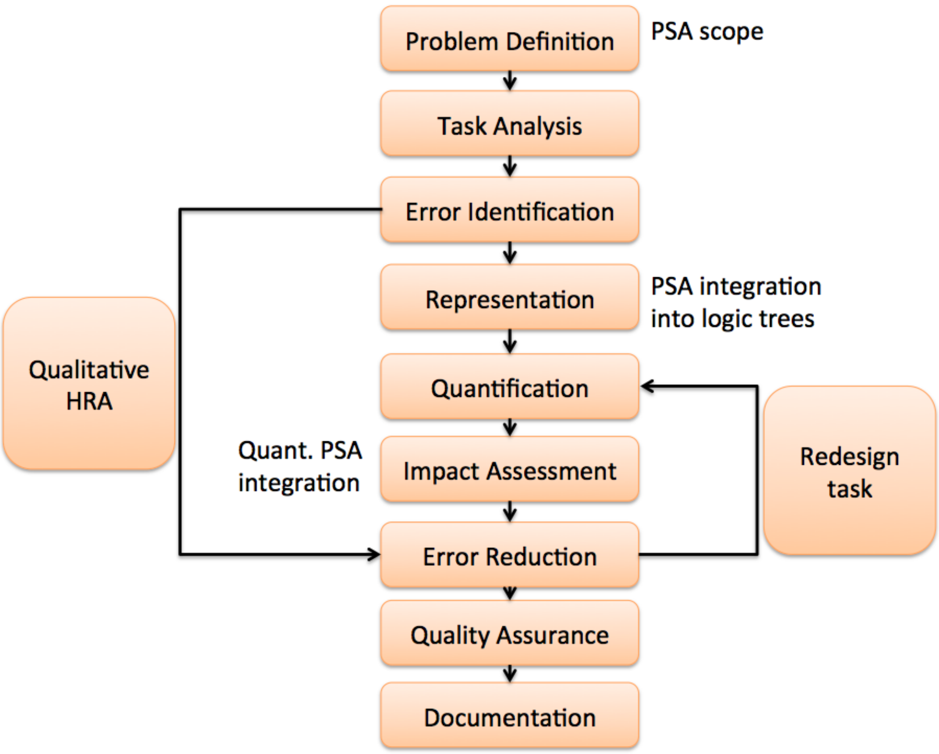


Figure 2.3: The HRA process. Image reproduced from (Kirwan, 1994).

Problem definition

Problem definition consists of deciding and documenting what kind of human involvements the analysis should be concerned with, and what output is required from it. If the HRA is PRA/QRA driven, the scope of the assessment may be limited to human reliability in emergency situations. It may also be limited to a particular human error 'targeted' by the PRA/QRA - requiring only quantification. If, on the other hand, the scope is broader, the HRA may also assess latent failures introduced in maintenance, testing or calibration of critical systems. In the general case, HRA is used for evaluating human acts *required* in system context (Swain and Guttmann, 1983). That is to say, the system function and its requirements for human actions dictates which actions are considered and which are not. The problem definition stage naturally necessitates a trade-off between the desired level of accuracy and detail, against the available resources and time for the project.

Task analysis

The task analysis is the process in which the correct course of action in the human involvement is determined. In addition to defining what should occur in these events, a task analysis also often defines the equipment and interfaces the operators should make use of (Kirwan, 1994). A popular method for task analysis, called hierarchical task analysis, is described in (Rausand, 2011). The HTA, as the name suggests, is a hierarchical decomposition of a task into smaller and more manageable subtasks. The level of decomposition required is an issue left to the analyst's judgement. If a subtask is well-understood and confirmed to be without inherent risks, the subtask need not be decomposed further. This feature allows the analysis to be economic, in the sense that only the critical tasks are decomposed further. The task analysis, once completed, provides the input to the human error identification stage.

Error identification

Error identification is arguably the most critical stage in the HRA process, according to Kirwan (1994). It is the stage in which the potential for human error is revealed, and each error is classified. Failure to identify an important error at this stage may result in a gross underestimation of risk. So how is it done?

The task analysis reveals the nature of the job at hand. It states clearly what should be done, how it is to be performed, with what equipment, in what order, and so on. Most HEI techniques use a set of guide words which, when applied to each element of the task analysis, reveals a potential for various errors of the types described in section 2.2.3. The guide words prompt the analyst to consider both errors of commission and errors of omission in an array of categories of human activity; communication, planning, checking, action, diagnosis, information retrieval, etc. The hierarchical task analysis, when sufficiently detailed, should distinctly place each subtask, or sub-subtask etc., in one of these categories. Human Error Identification will also usually involve the identification of performance shaping factors, as these directly relate to the occurrence of each error. Care should also be given to identify the potential for error recovery at this stage. Opportunities for recovery may come in the form of visual and/or audible alarms and secondary checking. These will have to represented in the logic trees, which are developed during the representation stage of the HRA.

Representation

Representation involves the use of logic trees, i.e. event trees or fault trees, in order to depict the causal relationship between errors. It also allows quantification and integration of both errors and recovery into PRA/QRA models. Kirwan (1994) mentions four main issues concerning representation in HRA:

- **Format:** Should fault trees or event trees be used?
- **Dependence:** Assessing and representing dependence between human errors.
- **Screening:** Which human errors do we leave out?
- **Test and maintenance errors:** Does hardware failure data already include these?

The choice of format will depend upon the format used in the PRA/QRA. Using the particular PRA/QRA's favored format makes integration between the HRA and PRA/QRA easier. The main drawback of the fault tree is that it does not depict a sequence in time. Event trees do not have this limitation. ETA will be a natural choice if we are interested in various consequences of human errors, whereas FTA is used when causes of an event is deductively investigated. Note however that any event in an event tree may be chosen as top event for fault tree evaluation, so that the risk model becomes a hybrid between the two.

Kirwan (1994) distinguishes between type-1 and type-2 dependence. Type-1 dependence is a direct dependence between two actions. Failure to respond to two different alarms can for instance not be considered independent events if the same person is responsible for both errors. Type-1 dependence can be modeled by either formal methods (e.g. THERP) or the use of conditional probabilities. Type-2 dependence occurs at a higher level and is in some sense similar to that of common-cause failures as found in traditional system reliability theory. One way of treating type 2 dependence is to use human performance limiting values (HPLV). A HPLV is an upper limit for human reliability. If the HRA produces reliability estimates for human performance which exceed the HPLV, the HPLV is used instead. The application of HPLVs therefore ensures that the HRA does not produce an overly optimistic prediction of human performance.

A screening refers to a process where one identifies, among all the identified potential human errors, those errors which can be ignored for the rest of the HRA. Kirwan (1994) discusses the methods provided in SHARP for screening. These methods are summarized as follows:

1. Method 1: Screen out human errors which occur in a minimal cut-set containing an extremely unlikely event (hardware failure or environmental event).
2. Method 2: Give each human error a probability of 1 and examine the effect on overall risk. Screen out the errors which are seen to have a negligible effect on the risk, as calculated by the model (e.g. fault tree or event tree).
3. Method 3: Assign broad human error probabilities according to a error-categorization framework. Screen out errors which are seen to have a negligible effect on the risk, as

calculated by the model (e.g. fault tree or event tree).

The latter method, which also may be called *fine screening*, uses a coarse error-categorization framework like the one seen in Table 2.3. According to Kirwan (1994) there are two major

Category	**Failure probability**
Simple, frequently performed task, minimal stress	$1 \cdot 10^{-3}$
More complex task, less time available, some care necessary	$1 \cdot 10^{-2}$
Complex, unfamiliar task, with little feedback and some distractions	$1 \cdot 10^{-1}$
Highly complex task, considerable stress, little time to perform it	$3 \cdot 10^{-1}$
Extreme stress, rarely performed task	$1 \cdot 10^{0}$

Table 2.3: Generic human-error probabilities. Table reproduced from (Kirwan, 1994).

pitfalls within the process of screening. The first is underestimation of human error probability as a direct result of applying incorrect fine-screening values. The second major pitfall is under-modeled dependence. A fine-screening error probability of 0.1, may if highly dependent on another error in the tree, actually have a value closer to 0.5 (Kirwan, 1994). Care should therefore be exercised so that potentially significant human errors are not ruled out.

Quantification

The measure of a human reliability analysis is the human error probability (HEP). If we let X be the number of n task executions which result in error, and further assume that the executions are independent, then X is binomially distributed: X $\sim$bin(n,HEP). An estimate for the HEP is then given by Equation 2.4 (Rausand, 2011):

$$\text{HEP}^* = \frac{X}{n} = \frac{\text{number of errors}}{\text{number of opportunities for error}} \tag{2.4}$$

Here the HEP is assumed to be an on-demand probability which does not change with time. This means that the operators are considered 'as good as new' prior to each new task execution (Rausand, 2011). The estimate, as given by Equation 2.4, is however not practical to obtain. Possible reasons for why industrial studies using Equation 2.4 have not been conducted or made available include (Kirwan, 1994):

1. It is not practically possible to count all the number of opportunities for error.
2. Confidentiality issues prevents such studies from being published.
3. Companies are unwilling to publish data on *poor* performance.
4. Companies lack awareness of why such data would be useful. This leads to a lack of financial support for such studies.

Many HRA techniques such as THERP, HEART, CREAM and ASEP use a set of nominal HEPs for a particular type of human performance. They adjust these nominal values by applying multipliers. These multipliers represent PSFs.

Impact assessment

Impact assessment is in essence the use of risk models. The models are run and the risk level for the accident scenario calculated and evaluated against an acceptance criteria. For the particular case of fault trees, minimal cut sets can be found, which give the analyst a qualitative insight into the contributors to top event probability or frequency. Component importance measures such as e.g. Birnbaum's measure or Fussel-Vesely's measure (see e.g. (Rausand and Høyland, 2004)) can also be computed. The evaluation of fault trees by component importance measures allows for a prioritization of basic events if the risk level is unacceptable. Impact assessment serves as a basis for the error reduction stage. It identifies which errors need error reduction, and which do not.

Error Reduction

Error reduction, which Kirwan (1994) denotes error reduction analysis (ERA), is the identification and implementation of error-reduction measures (ERMs). The most effective ERMs are those that incorporate a design which prevents the error from occurring (Mosleh et al., 2006). Table 2.4 shows examples of such ERMs.

Error prevention	
• Automatic sequencer (prevent human's mis-sequencing) • Automation (prevents human's calculation errors) • Automation (prevents human's monitoring errors) • Boundary/barrier to entry (prevents entry into area) • Breakaway (prevents system overload errors) • Button/switch cover (prevents inadvertent activation) • Constraint (limits movement) • Control limit (prevents exceeding boundaries) • Dead man switch (prevents use) • Dissimilar shape connectors (prevents incorrect connection) • Dissimilar size connectors (prevents incorrect connection) • Exclusion design (design makes it impossible to make error) • Guards (prevents entry into area) • Guides (prevents going out of boundary) • In-process feedback (feedback embedded in task step)	• In-process verification (self-check embedded in task step) • Interlock (prevents action out of sequence) • Keyed connector (prevents incompatible connections) • Limiters (limits human action) • Load limiting fuses (prevents overloads) • Lock-in (prevents premature stopping of process) • Lockout (prevents access) • Machine guards (prevents entry into area) • Rate limiter (prevents excess rate) • Safeguards (prevents use, will not operate under unexpected conditions) • Selection limits (prevent incorrect selection) • Shields (prevents access) • Speed restrictor/governor (prevents excess speed) • Time lockouts (prevents activation of equipment at wrong time) • Torque limiter (prevents excess torque)

Table 2.4: Error prevention. Table reproduced from NASA report by Mosleh et al. (2006).

If prevention by design change is infeasible, then error recovery enhancement may be opted for. Extra procedural checks, use of 'check-off' sheets or an extra level of supervision are examples of error recovery enhancements (Kirwan, 1994). Such recoveries need to be modeled in logic trees to measure the effect of their implementation.

2.2.5 SPAR-H

The Standardized Plant Analysis Risk (SPAR) HRA (SPAR-H) method was first developed as a response to the U.S. Nuclear Regulatory Commission (NRC) identifying a need for an improved, traceable, easy-to-use HRA method. This happened in the early 1990s (Gertman et al., 2005). Since the early 90s the method has been updated on several occasions, the last time being in 2002-2003. Updates included better guidance to practitioners, a suitable approach to treating uncertainty and additional detail regarding assignment of HEP dependencies. This section presents an outline of the present version of the method. The text is based solely upon the SPAR-H guidance document (see (Gertman et al., 2005)) available at the NRC's webpage.

SPAR-H is a simplified HRA method. It is designed to quantify human errors at the task level. It can however also be used to characterize pre-initiating actions, initiating event-related actions and post-initiating event interactions, according to its authors (Gertman et al., 2005). The method does not contain guidance on representation, nor does it provide guidance on the level of decomposition required. The basis for quantification in SPAR-H lies in the distinction between **action** and **diagnosis**. These are given the nominal human error probabilities below:

$$\begin{array}{lll} \textbf{Action:} & \text{HEP}_n = & 1 \cdot 10^{-3} \\ \textbf{Diagnosis:} & \text{HEP}_n = & 1 \cdot 10^{-2} \end{array}$$

Each HEP, when categorized as either action or diagnosis, is then modified by the assignment of relevant PSFs. SPAR-H has a set of eight PSFs. These are summarized in Figure 2.4.

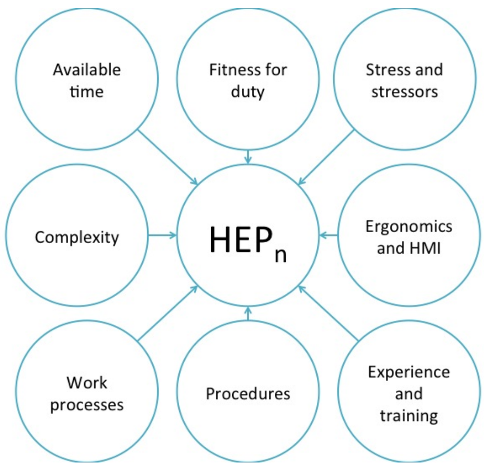


Figure 2.4: Performance Shaping Factors found in SPAR-H.

Available time refers to the relative amount of time the operators have available to respond to an abnormal event. The ranking ranges from *inadequate time* to *expansive time*. There are different multipliers for action and diagnosis.

Stress and stressors cover both internal and external elements. Mental stress, excessive workload and physical stress are examples of stress elements which are internal to the operator. Environmental factors, or *stressors*, include excessive heat, noise and poor ventilation. These are external elements which impose stress on the operator.

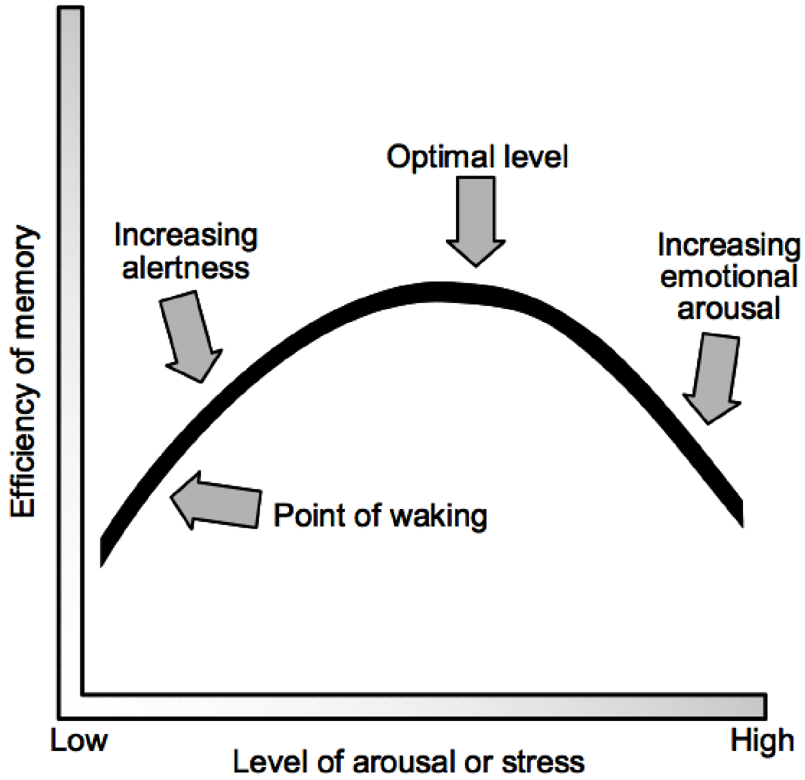


Figure 2.5: Arousal effect on memory. Figure: (Gertman et al., 2005).

Human performance varies as a quadratic function of stress, as shown in Figure 2.5. Some level of stress serves to improve performance, whereas excessive stress has a negative influence on performance. This is in the field of psychology known as Yerkes-Dodson's Law (1908). The PSF for stress can thus reduce the HEP.

Complexity is a PSF which measures how difficult the task is to perform. Both the difficulty of the task itself, and the environment in which it is performed must be considered. The more ambiguous the task is (i.e. requiring more knowledge-based performance) the greater the chance of error. The sub-factors giving rise to complexity are summarized in Table 2.5 on the next page.

Complexity in SPAR-H	
• Parallel tasks • Multiple equipment unavailable • Transitioning between multiple procedures • Large number of actions required • Large amount of communication required • Large number of distractions present • System interdependencies not well defined	• Misleading or absent indicators • Mental calculations required • Multiple faults • Low fault tolerance levels • High degree of memorization required • Symptoms of one fault mask other faults • Task requires coordination with ex-control room activities

Table 2.5: Subfactors of complexity in SPAR-H (Gertman et al., 2005).

Experience and training relates to the 'stored rules' discussed by (Rasmussen, 1983). If operators are trained and/or have faced the particular scenario in question before, they are more likely to have rules for coping with it available in memory. Consideration of this PSF includes years of experience, time passed since training and whether or not the scenario is novel or unique.

Procedures covers formal procedures and their use. If formal written procedures for the task are absent, or of low quality, they have a negative influence on human reliability. Conversely, if such procedures are available - they improve performance and thus lower the HEP (multiplier assigned is lower than unity). The use of multiple procedures adds to the complexity of the task. If this is the case, Gertman et al. (2005) suggest that the complexity PSF should be adjusted, not the rating of the procedures PSF.

Ergonomics/HMI refers to the interaction between the human and the equipment needed for the task. Displays, controls, layout, quality and quantity of information available from instrumentation are all part of this PSF.

Fitness for duty refers to the operator's mental and physical capacity to perform the task. Factors which may degrade this capacity, such as fatigue, sickness, drug use, overconfidence and personal problems are encompassed by this PSF.

Work processes includes any aspect of doing work which is believed to affect performance. Examples include safety culture, work planning, communication, management support and policies. Broadly speaking, this PSF represents what risk analysts often refer to as organizational factors.

When a task has been categorized as action or diagnosis, the PSFs are assigned as follows:

$$\text{HEP} = \text{HEP}_n \cdot \prod_{i=1}^{k} \text{PSF}_i \tag{2.5}$$

where k is the number of PSFs applied and PSF_i is the value of the multiplier for PSF number i. If $k \geq 3$ the HEP is modified:

$$\text{HEP} = \frac{k \cdot \prod_{i=1}^{k} \text{PSF}_i}{k \cdot [(\prod_{i=1}^{k} \text{PSF}_i) - 1] + 1} \tag{2.6}$$

If a task contains both diagnosis and action, these are evaluated separately using equations 2.5 and 2.6 and a joint HEP is calculated by summing the HEP for action and the HEP for diagnosis. An assessment of dependency is then the next step in the SPAR-H quantification process. The SPAR-H method contains a dependency condition table, where the dependency between the task in question and success of previous tasks is rated as being either *zero*, *low*, *moderate*, *high* or *complete*. The table contains columns which ask the analyst to assess whether or not it is the same crew performing the task, if it is close in time to the previous task, if the location is the same and if additional cues are present or not. Depending on the analyst's answer, the rating is found at the right column of the table. The HEP, which now is denoted probability without formal dependence $P_{w/od}$, is then modified according to Table 2.6.

Dependence level	**Final HEP**
Complete	1
High	$(1 + P_{w/od})/2$
Moderate	$(1 + 6 \cdot P_{w/od})/7$
Low	$(1 + 19 \cdot P_{w/od})/20$
Zero	$P_{w/od}$

Table 2.6: Dependency in SPAR-H.

The entire process of calculating a HEP, that is the assignment of PSFs and multipliers and the calculations which follow, are done on worksheets. These allow for analyst consistency and also make the process more auditable. Separate worksheets are given for 'at power' and 'low power/shutdown'.

Uncertainty in SPAR-H is represented by taking on a bayesian view of the HEP. The calculated final HEP is assumed to be a mean value, and uncertainty is represented by using a constrained non-informative (CNI) prior distribution developed by Atwood (1996). A beta distribution which approximates the CNI prior for binomial data is given in (Atwood, 1996) . The distribution requires two parameters; α and β. Atwood (1996) tabulates the parameter α for beta approximation (restricted family; which is the relevant one in the case of HEPs) to the mean

p_0 = HEP. So, when a HEP has been calculated we may find α in (Atwood, 1996) directly or by interpolation (a plot is also given in (Gertman et al., 2005)). We next calculate β by Equation 2.7:

$$\beta = \frac{\alpha(1 - \text{HEP})}{\text{HEP}} \tag{2.7}$$

The uncertainty distribution can now be presented as a confidence interval. It is easily calculated by any software package containing the beta distribution. In the case of using Excel, the call 'BETA.INVERS($0,05$;α,β)[3]' returns the 5th percentile of the distribution (Gertman et al., 2005).

SPAR-H has been applied in Norway in the analysis of a blow-down scenario, a well-control scenario and three ballasting/stability scenarios (Gould et al., 2012). The application of SPAR-H in these studies focused upon post-initiating events and subsequent recovery. Gould et al. (2012) state that they see the method as having the highest utility when used to determine relative HEP values, as opposed to absolute values. This is because the method is developed for nuclear power plants, with its PSFs (and multipliers) being only partially validated. In an article on SPAR-H used for normal operations on a managed pressure drilling concept, van de Merwe et al. (2012) further argues that the PSFs for available time, HMI and experience training need to be adjusted before becoming applicable to offshore operations. In the case of using HRA for a drilling scenario, the human actions are related to conditions down in the well. More specifically, they are related to the safety functions of a well. The following section will discuss one of these safety functions in depth.

[3]This call is used for norwegian versions of Microsoft Excel.

2.3 Well Integrity

A well has two main safety functions, the first of which is to prevent an unwanted influx of well fluids into the wellbore. This function is commonly referred to as **well integrity** (Corneliussen, 2006). In Norway, the regulations issued by the PSA require that well integrity is ensured, and that barrier functions are safeguarded, throughout the lifetime of a well. The recommended standard containing requirements and guidelines relating to well integrity is the NORSOK D-010 standard. NORSOK D-010 defines the concept of well integrity as follows:

> **Well Integrity:** The application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well (NORSOK, 2013a).

As can be read from the definition, ensuring well integrity requires the simultaneous application of three different types of solutions. Only one of these types of solutions are explicitly defined as barriers; namely the technical solutions. These solutions, called well barriers, are the technical means to prevent an unplanned flow of reservoir fluids from the surroundings to the wellbore, another formation, or to the external environment. The formal definition of a well barrier is this:

> **Well Barrier:** Envelope of one or several well barrier elements preventing fluids from flowing unintentionally from the formation into the wellbore, into another formation or to the external environment (NORSOK, 2013a).

The well barriers are numbered according to their proximity to the reservoir fluids. The barrier closest to the reservoir is called the primary well barrier, whereas the next line of defense is the secondary well barrier, and so on. The principle of redundancy, otherwise known as the two barrier principle, is followed in Norway. This is to ensure that no single failure of a well barrier element could lead to a release of reservoir fluids. Corneliussen (2006) states that one can picture a well as being a system of two pressurized vessels, one being inside the other, each of which are capable of containing the reservoir fluids. Should the inner most pressure vessel fail, the outer vessel will prevent the hazard from being released to the surroundings.

The well barriers are comprised of well barrier elements. These are single, identifiable, technical components such as e.g. casing, drill string, wellhead, safety valves, BOP, or casing cement. The definition of a WBE is shown on the next page.

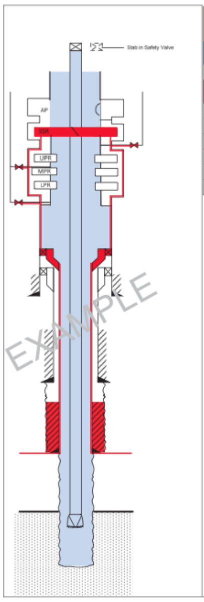
Well Barrier Element: A physical element which in itself does not prevent flow but in combination with other WBEs forms a well barrier (NORSOK, 2013a).

Prior to commencement of an activity or operation, NORSOK D-010 requires that well barriers shall be defined and that the WBEs are in place, along with acceptance criteria and monitoring methods (NORSOK, 2013a). A graphical representation of the envelope of WBEs, called a well barrier schematic (WBS), is to be prepared for each well activity and operation. The WBS contains the following information (NORSOK, 2013a):

- A drawing illustrating the primary WB in blue color and the secondary WB in red color.
- The formation integrity, if the formation is part of a well barrier.
- Potential sources of inflow
- A table of WBEs with requirements to initial verification and monitoring methods.
- All casings and cement. Casing and cement (including TOC) defined as WBEs should be labelled with its size and depth (TVD and MD).
- Components should be shown relatively correct position in relation to each other.
- The following well information: field/installation, well name, well type, well status, well/section design pressure, revision number and date, ”prepared by”, ”verified/approved by”.
- Clear labeling of actual well barrier status - planned or as built.
- Any failed or impaired WBE to be clearly stated.
- A note field for important well integrity information (anomalies, exemptions, etc.).

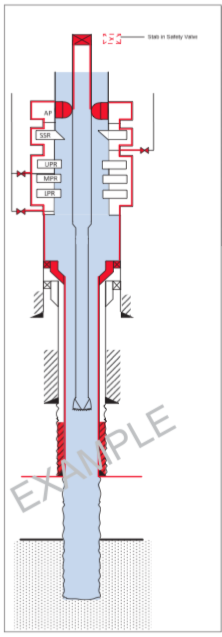
Figures 2.6 and 2.7 on the next page show examples of a WBS for drilling with shearable, and non-shearable drillstring, respectively.

Each WBE is associated with an Element Acceptance Criteria (EAC) table. These tables contain both technical requirements such as for instance design capacity, rating, function, as well as operational requirements such as testing, verification, monitoring and use of the WBE. Failure to meet these criteria means the WBE should not be accepted as a WBE. The requirements to the fluid column is found in Table 1, section 15 of the standard. This table is shown in appendix A. It is included in this report because it specifically specifies the requirements to the fluid column as a barrier. Note also that in addition to the requirements in this EAC table, requirements regarding marine riser disconnect is found in Table 8, section 5.4 of the standard. These requirements are however not reproduced in this report.



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

Figure 2.6: Drilling, coring and tripping with shearable string. Figure: (NORSOK, 2013a).



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
Fluid column	1	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Wellhead	5	
High pressure riser (J/P)	26	
Drilling BOP	4	
Drill string	3	
Stab-in safety valve	40	

Figure 2.7: Running non-shearable drill string. Figure: (NORSOK, 2013a)

A deviation from these requirements will increase the probability of the barrier failing to perform its barrier function. In drilling terms, such a barrier failure is referred to as a **well control incident**. NORSOK D-010 provides the following definition of such an event:

> **Well control incident:** Incident in which a failure of barrier(s) or failure to activate barrier(s), results in an unintentional flow of formation fluid into the well, into another formation or to the external environment

At the occurrence of such an event, mitigative measures shall be taken immediately. The failed well barrier must be restored, or an alternative well barrier established, before activities or operations can be resumed (NORSOK, 2013a). For the case of the fluid column, this will in practice mean activating the shut-in function and circulating the well with a heavier fluid (kill mud). The two most common methods for re-establishing the fluid column barrier will be discussed in the following chapter.

Chapter 3

Pressure control and causes of kicks

To investigate the human contribution to failures in the primary well barrier, it is found necessary to describe the basic physics of pressure control. This section aims to explain the main principles of pressure control during drilling operations. The theory presented in this section is taken from Skalle (2013), unless explicitly stated otherwise.

3.1 Pressures in sedimentary rock

An understanding of pressure control during drilling operations requires an understanding of four different types of pressures, only one of which is the pressure exerted by the column of drilling fluid (see Figure 3.1). The three other types are the overburden pressure, the fracture pressure and the pore pressure.

The pressures in a formation can be determined by either *predictive* methods or by *verification* methods. Verification methods are however only available once the desired depth is reached. This means that either predictive methods, or empirical correlations, or a combination of these are the only available means to predict the formation pressure during the planning stage. In the text that follows, each of the pressure types along with their relation to each other will be described. Some predictive methods will also be discussed.

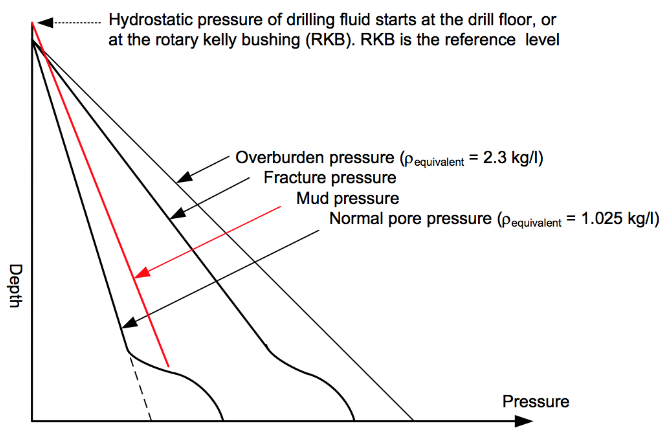


Figure 3.1: Pressure types in sedimentary rocks. Figure: (Skalle, 2013)

3.1.1 Overburden pressure

The overburden pressure, also called lithostatic pressure or vertical stress, is the pressure imposed on a layer of rock by the combined weight of formation materials and fluids in the geological formations above the particular depth of interest. There are several ways of determining the local overburden pressure (Skalle, 2013):

- Using the overburden density from neighboring wells
- Core sample
- Cuttings density
- Sonic log

In terms of mathematics, it is possible to obtain an expression for the overburden pressure by adding the weights of solid material and fluids in the pores, then dividing this sum by the area that is supporting this weight. If we let $\rho(z)$ be the local or in situ overburden density of the fluid-saturated formation at depth z, we can find the overburden pressure, i.e. the vertical stress, from the following formula (Skalle, 2013):

$$\sigma_{ovb} = g \int_0^z \rho(z) dz \tag{3.1}$$

where

$\rho(z)$	local or in situ overburden density	$[kg/m^3]$
g	acceleration of gravity	$[m/s^2]$
z	depth	$[m]$

The density can be found directly by density logs, or it can be calculated by utilizing sonic logs, which display the transit time of P-waves[1] versus depth (Schlumberger, 2013a). If one assumes the formation to be clean and consolidated with uniformly distributed small pores, there will be a linear relationship between porosity and transit time:

$$\Delta t_{log} = \Delta t_{matrix} \cdot (1 - \phi) + \Delta t_{fluid} \cdot \phi \tag{3.2}$$

or, expressed by the porosity ϕ, which now becomes a function of depth:

$$\phi(z) = \frac{\Delta t_{log} - \Delta t_{matrix}}{\Delta t_{fluid} - \Delta t_{matrix}} \tag{3.3}$$

where

[1] **P-waves**: A P-wave, or primary wave, is a seismic body wave that compresses the ground in the direction the wave is moving (USGS, 2012).

$\phi(z)$	fractional porosity	[-]
Δt_{log}	reading on sonic well log	$[\mu s/m]$
Δt_{matrix}	transit time of rock matrix	$[\mu s/m]$
Δt_{fluid}	transit time of rock-saturating fluid	$[\mu s/m]$
z	depth	$[m]$

The two terms Δt_{matrix} and Δt_{fluid}, the transit time in the rock and the fluid, can be looked up in data-tables and are therefore assumed to be known. This means we can express the local overburden density, or bulk density, as a function of the density of the rock matrix and the density of the pore fluids:

$$\rho(z) = \rho_{matrix} \cdot (1 - \phi(z)) + \rho_{fluid} \cdot \phi(z) \tag{3.4}$$

and the overburden vertical stress is thus:

$$\sigma_{ovb} = g \cdot \int_0^z [\rho_{matrix} \cdot (1 - \phi(z)) + \rho_{fluid} \cdot \phi(z)] \cdot dz \tag{3.5}$$

For offshore wells, this integral must be split into two parts; one from the mean sea level to the sea bottom, and one from the sea bottom down to the depth of interest (Constant and Bourgoyne, 1988).

$$\sigma_{ovb} = g \cdot \int_0^{d_{sw}} \rho_{sw} dz + g \cdot \int_0^z [\rho_{matrix} \cdot (1 - \phi(z)) + \rho_{fluid} \cdot \phi(z)] \cdot dz \tag{3.6}$$

where ρ_{sw} is the seawater density and d_{sw} is the water depth.

3.1.2 Pore pressure

The pore pressure, also called the formation pressure, is the pressure of the fluids contained inside the pore spaces of the reservoir. Normal pore pressure equals the hydrostatic pressure exerted by a column of subsurface water above the depth of interest. This hydrostatic condition means there is pore to pore communication, so the fluids are free to move. The normal pore pressure thus only varies with the density of the pore fluids, assuming constant gravity. The slope of the straight line in Figure 3.1 is the gradient, typically expressed in [psi/ft] or [kPa/m], for the normal pore pressure. Deviations from this straight line are called subnormal pore pressure and abnormal pore pressure, respectively. From a safety perspective, the abnormal pore pressure, having a higher gradient than the normal pore pressure, is considered the most critical. Abnormal pore pressure occurs when impermeable rock form as sediments and are compacted (Schlumberger, 2013b). This results in a situation where the fluid in the pores can not escape and must carry a part of the overburden pressure. According to Skalle (2013), the pore pressure can be determined with information from the following sources:

- Seismic data (measuring transit time Δt)
- Wire-line logs (measuring e.g. resistivity R)
- Drilling rate of penetration (used in calculation of d exponent d_c)
- Mud properties (gas content, temperature)

Prediction of abnormal pore pressure is essential in avoiding unwanted influxes during drilling operations, so a brief description of one way of doing it is included here. This method, which perhaps is the most popular model for predicting abnormal pore pressure, was developed by Eaton (1975). In his paper, Eaton (1975) proposed an empirical equation for pressure prediction based on so-called trends[2]:

$$\rho_{pore} = \rho_{ovb} - [\rho_{ovb} - (\rho_{pore})_n] \cdot \left(\frac{R_o}{R_n}\right)^{1.2} \tag{3.7}$$

$$\rho_{pore} = \rho_{ovb} - [\rho_{ovb} - (\rho_{pore})_n] \cdot \left(\frac{\Delta t_n}{\Delta t_o}\right)^{3} \tag{3.8}$$

$$\rho_{pore} = \rho_{ovb} - [\rho_{ovb} - (\rho_{pore})_n] \cdot \left(\frac{d_{c,o}}{d_{c,n}}\right)^{1.2} \tag{3.9}$$

where

ρ_{pore}	formation pressure gradient	$[psi/ft]$
ρ_{ovb}	overburden stress gradient	$[psi/ft]$
R	shale resistivity	$[ohm-m]$
Δt	sonic transit time	$[\mu s/ft]$
d_c	corrected d exponent	$[-]$

Subscript o in the equations denotes observed value and n denotes normal (average) value. The equations simply state that the formation pressure gradient is equal to the overburden gradient minus the matrix stress gradient. The expression enclosed in brackets [..] is the normal matrix stress gradient. This term is reduced by the empirical dimensionless expression(s), e.g. $\left(\frac{R_o}{R_n}\right)^{1.2}$, when abnormal pore pressure is encountered. Note however that the ability for this method to successfully predict abnormally pressurized zones is dependent on the analyst's ability to interpret trends. This can be difficult, and erroneous interpretations will lead to incorrect predictions, which again may lead to kicks. In fact, encountering unexpectedly high pore pressure is reported to be one of the major reasons for kicks on the NCS (PSA, 2012). This entails that pressure prediction has failed.

[2]**Trending:** Generally refers to monitoring and plotting one or several parameters over time.

The corrected d exponent in Equation 3.9 is a very important parameter in formation pressure analysis. It relates the penetration rate to bit weight, rotary speed and bit size, provided that all other drilling variables are kept constant. The simple relationship between these parameters (without conversion factors) is expressed as:

$$\frac{R}{N} = a \cdot \left(\frac{W}{D}\right)^d \tag{3.10}$$

where

a	constant in general drilling equation	$[-]$
D	bit diameter	$[in]$
d	exponent in general drilling equation	$[-]$
N	rotary speed	$[rpm]$
R	penetration rate	$[ft/hr]$
W	bit load	$[lb]$

Jorden and Shirley (1966) proposed that one could use trending of the d exponent in Equation 3.10 to predict abnormal formation pressures, since changes to rate of penetration would be governed by changes in the differential pressure ($p_{mud} - p_{pore}$), when all other drilling parameters were kept constant. A simple rearrangement of the equation, including the conversion factors, yields:

$$d = \frac{\log\left(\frac{R}{60 \cdot N}\right)}{\log\left(\frac{12 \cdot W}{10^6 \cdot D}\right)} \tag{3.11}$$

What Jorden and Shirley (1966) found was that a plot of normalized rate of penetration, either by d exponent or by keeping all drilling variables constant, will show a trend of continually decreasing rate of penetration with depth. A reversal in this trend is synonymous with the penetration of an abnormally pressurized region. With this knowledge, one can *potentially* avoid influxes by identifying over-pressures before logging the well. The subscript c in d_c denotes a correction of the d exponent, making it account for increasing mud weight:

$$d_c = d \cdot \frac{\rho_n}{\rho} \tag{3.12}$$

where

d_c	corrected d exponent	$[-]$
d	d exponent	$[-]$
ρ_n	mud density equivalent to normal formation pore pressure	$[psi/ft]$
ρ	equivalent mud density at the bit while circulating	$[psi/ft]$

3.1.3 Fracture pressure

The fracture pressure is the pressure by which the open hole will hydraulically fracture. The fractures in the exposed formation will accept drilling fluid, meaning that drilling fluid will be *lost* to the formation. The formation fracture resistance is directly related to the weight of the formation overburden. It also depends on the intergranular strength of the formations, and the formation type (Skalle, 2013). There are many correlations and models available for fracture pressure, or fracture gradient, prediction. Several of these make use of stresses and strains, assuming the sediments to behave elastically (see e.g. Constant and Bourgoyne (1988); Eaton (1969)). These will however not be discussed any further here.

To determine the actual fracture pressure, one conducts a Leak Off Test (LOT). The Leak Off Test, or formation intake test, is used to determine the maximum pressure the wellbore wall/casing cement can be subjected to. The test is usually performed after each casing is set. A LOT involves the following steps (Skalle, 2013):

1. Lowering of drillstring inside casing and above cement.
2. Closing BOP and performing pressure tests on casing shoe.
3. Drilling through the cement and 3 m into the new formation.
4. Pulling bit back into casing, checking proper hole fill up, and closing BOP around drill pipe again.
5. Pumping mud at slow rates with a high-pressure low-volume pump while plotting pump pressure against pumped volume.
6. Stop once the pump pressure deviates from the linear trend in the $p(V)$-curve. The pressure at which the curve deviates from the straight line is the leak off pressure.

A formation strength test for which a predetermined upper limit for applied pump pressure is set is called a formation integrity test (FIT). To determine the minimum in-situ formation stress, an extended leak-off test is performed (NORSOK, 2013a).

3.2 Mud pressure

The pressure in the wellbore from the presence of the mud can be divided into two separate conditions; a static condition and a circulating condition. In the static condition, with mud pumps off, the pressure will be:

$$P_{mud,s} = \rho_{mud} \cdot g \cdot h \tag{3.13}$$

Once the mud pumps are switched on, there will be a pressure loss due to friction between the drilling mud and the wall of the annulus.

$$P_{mud,c} = \rho_{mud} \cdot g \cdot h + \Delta P_f \tag{3.14}$$

Where the frictional loss can be determined as (Osisanya and Harris, 2005):

$$\Delta P_f = \frac{2f\rho v^2}{d} \Delta L \tag{3.15}$$

where

ρ	fluid density	$[kg/m^3]$
v	fluid velocity	$[m/s]$
f	fanning friction factor	$[-]$
d	diameter of conduit	$[m]$
ΔL	length of flow conduit	$[m]$

From the equation we see that the frictional loss is inversely proportional to the diameter of the hole, and proportional with the square of the circulating velocity. Increased pump rates thus increase the BHP, and the effect will be more prominent for narrower sections. An interpretation of the frictional loss, or annular pressure loss, is to say that the frictional loss is the extra amount of pressure the mud pumps need to apply, in order to overcome friction and move the mud from the bit and up the annulus. This pressure loss acts on the bottom hole, increasing the BHP. Pressure losses in surface piping, drill pipe and across bit nozzles do not affect the BHP.

3.2.1 Equivalent Mud Weight

It is common to express the various pressures presented in the current section in terms of gradients, or equivalent mud weights. The conversion is quite straight forward:

$$\rho_{EMW}[kg/m^3] = \frac{P[bar]}{9.81 \cdot 10^{-5} \cdot h_{TVD}[m]} \tag{3.16}$$

Or, alternatively, expressed in US pounds per gallon:

$$\rho_{EMW}[ppg] = \frac{P[psi]}{0.052 \cdot h_{TVD}[ft]} \tag{3.17}$$

Where h_{TVD} is the true vertical depth. Naturally, if the mud pumps are on, the pressure P will have to include the annular friction loss. The density is then referred to as equivalent circulating density (ECD).

3.2.2 Trip Margin

A trip margin is an increase in EMW, which is added to the originally planned mud weight program. It is added so that swabbing will be avoided when pulling the drill string out of the hole. Swabbing will be discussed later in the thesis. An empirical formula sometimes used for calculation of trip margin is this (Skalle, 2013):

$$\rho_{TM} = \frac{0.01 \cdot \tau_y}{(d_{bit} - d_{drillcollar}) \cdot g} \tag{3.18}$$

where

τ_y	yield point of mud	$[Pa]$
d_{bit}	diameter of bit	$[m]$
$d_{drillcollar}$	diameter of drill collar	$[m]$

3.2.3 Riser Margin

A riser margin is applicable only to drilling operations which utilize a subsea BOP stack. The reason for this safety margin is that in the event of an emergency disconnect or a riser rupture, the column of mud inside the riser will be replaced by seawater. The seawater will typically have a lower density than the mud, which means that there will be a reduction in the BHP. To counteract this effect, one adds a safety margin to the mud gradient called a riser margin. Figure 3.2 shows the principle of the riser margin. To the left we have the situation where the entire well and riser is filled with mud. Assuming we have a static pressure balance, we then have:

$$\rho_{mud} \cdot g \cdot (h_1 + h_2 + h_3) = p_{pore} \tag{3.19}$$

When the upper connector of the BOP is disconnected and the BOP is not closed, we need a new mud weight to balance the pore pressure:

$$\rho_{sw} \cdot g \cdot h_2 + \rho_{mud,new} \cdot g \cdot h_3 = p_{pore} \tag{3.20}$$

The difference between this new mud weight and the previous mud weight is called riser margin. It is expressed as follows:

$$(\rho_{mud,new} - \rho_{mud}) = \rho_{mud} \cdot \frac{h_1 + h_2}{h_3} - \rho_{sw} \cdot \frac{h_2}{h_3} \tag{3.21}$$

To clarify, we can say that the riser margin is the extra density we need to add to our mud so that losing the riser mud column will not result in underbalance. A typical value for a safety

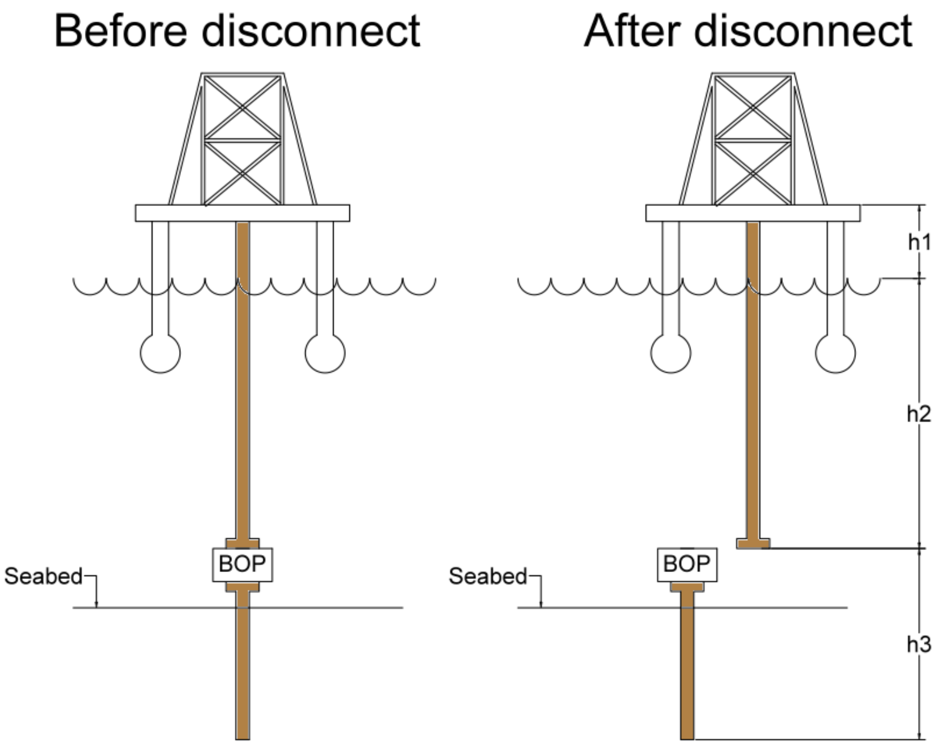


Figure 3.2: Riser Margin.

margin towards the pore pressure gradient is 30 kg/m^3. A typical margin towards the fracture gradient will be 10 kg/m^3 (Sangesland et al., 2012). The safety margin against fracture pressure is however not concerned with swabbing or other pressure *reductions*. The PSA normally requires riser margin, but there are areas where drilling with riser margin would be difficult or even impossible due to the small window between the pore pressure and the fracture pressure. Operators drilling in these areas have to apply the PSA for dispensation (Sangesland, 2008).

3.2.4 Slow Circulation Rates

Slow circulation rate (SCR) refers to, as the name suggests, pumping the mud through the system at low velocities. The pressure reading on the mud pump is then a measure of the pressure loss in the system, i.e. the pressure required to push the mud through the drill pipe, drill collar and nozzles of the bit. Due to the low velocity, the pressure drop in the annulus can be neglected (Skalle, 2013). Slow circulation is used in well control operations, and since the pressure loss at slow circulation rates varies with the well depth and routing through the circulation system, it must be measured frequently. A well control procedure used in the next chapter of this report requires SCR measurements to be taken on the following occasions (……., 2013):

- On the beginning of every tour

- At any time the mud properties are changed
- At any time the configuration of the bit nozzle is changed
- After bottoms up[3] from a trip is performed
- Every 300 m (1000 ft) drilled into new formation

Typical speeds for taking SCR measurements on floating rigs are 30 or 40 SPM. A SCR of 15 SPM may also be used when gas is entering the choke line (Skalle, 2013).

3.3 Kick tolerance

Kick tolerance is the maximum volume of influx the well can take before it fractures at its weakest point. It expresses the volume of fluid intrusion which would cause the pressure exerted on the wellbore wall to exceed the fracture pressure at the well's weakest point - the casing shoe. The kick tolerance is used during drilling to determine whether a casing string should be run, or if drilling can continue. It is also used to decide whether or not a kick can be circulated out safely during well control operations (Santos et al., 2011).

3.4 Kill procedures

Upon detection of a kick, the driller will shut in the well by closing the uppermost annular preventer in the BOP stack. The well is then sealed by the mud pumps in the drill string end, and by the BOP and choke valve on the annulus side (Skalle, 2013). The task is now to circulate the kick out safely, thus restoring primary well control. There are two common ways of performing this operation, both of which rely upon an important principle: keeping the bottom hole pressure constant.

3.4.1 Driller's method

The driller's method is a two-step process. First, the pore fluid is circulated out through the choke with the mud weight that was used when the kick was first encountered. Next, the new kill mud is circulated in the hole. The hydrostatic overbalance will gradually be restored as kill mud enters the well. In preparation of this kill method, one must first determine the required

[3]See section 5.4 for an explanation of the term.

mud weight to kill the well:

$$\rho_{KMW} = \frac{P_{SIDPP}}{h_{TVD} \cdot g \cdot 10^{-5}} + \rho_{OMW} \tag{3.22}$$

where

ρ_{KMW}	kill mud weight	$[kg/m^3]$
P_{SIDPP}	shut-in drillpipe pressure	$[bar]$
h_{TVD}	true vertical depth	$[m]$
ρ_{OMW}	original mud weight	$[kg/m^3]$
g	acceleration of gravity	$[m/s^2]$

The shut-in drill pipe pressure can be read on both the driller's console and the choke operator console (see appendix E). The initial circulating pressure, i.e. the pressure in the well before the killing operation starts, is the sum of the slow circulation rate pressure and the shut in drill pipe pressure.

$$P_{ICP} = P_{SCRP} + P_{SIDPP} \tag{3.23}$$

The final circulating pressure, after the kick has been circulated out through the choke, will be:

$$P_{FCP} = P_{SCRP} \cdot \frac{\rho_{KMW}}{\rho_{OMW}} \tag{3.24}$$

The required number of pump strokes to remove the kick from the well is calculated as:

$$n_1 = \frac{V_A[liters]}{\dot{Q}[liters/stroke]} \tag{3.25}$$

where V_A is the volume of the annulus and $\dot{Q}$ is the capacity of the mud pump. One also needs to know the number of strokes until the mud reaches the bit when kill mud is injected into the drill string. This can be calculated as:

$$n_2 = \frac{V_{DP}[liters]}{\dot{Q}[liters/stroke]} \tag{3.26}$$

where V_{DP} is the inside volume of the drill string.

3.4.2 Wait and weight method

The wait and weight method circulates the kick out of the well while at the same time replacing the mud in the well with the kill mud. In other words, the goal of removing the kick is achieved through a single full circulation as opposed to two. The kill mud weight is first determined by Eq. 3.22. The initial circulating pressure is again given by Equation 3.23. The final circulating pressure is also the same, as given by Equation 3.24. After these pressures are determined, one calculates the number of pump strokes n from surface to the bit which is equal to:

$$n = \frac{V_{DP}[liters]}{\dot{Q}[liters/stroke]} \tag{3.27}$$

Now, one calculates the required time T for pumping from surface to the bit.

$$T = \frac{n[strokes]}{\dot{Q}[strokes/minute]} \tag{3.28}$$

What now remains is to plot pump pressure versus pump strokes and time on a drill pipe graph schedule. The pressure decreases linearly from the initial circulating pressure to the final circulating pressure over the calculated time, or correspondingly; the number of strokes pumped.

3.5 Circulation System

The circulation system has been mentioned several times in the preceding text without being properly explained. The working principle of a drilling mud circulation system is actually quite simple (see Figure 3.3). If we begin at the mud pits onboard the rig, the mud will be picked up by the suction from one or more of the mud pumps. These pumps are the power sources which push mud through the entire system.

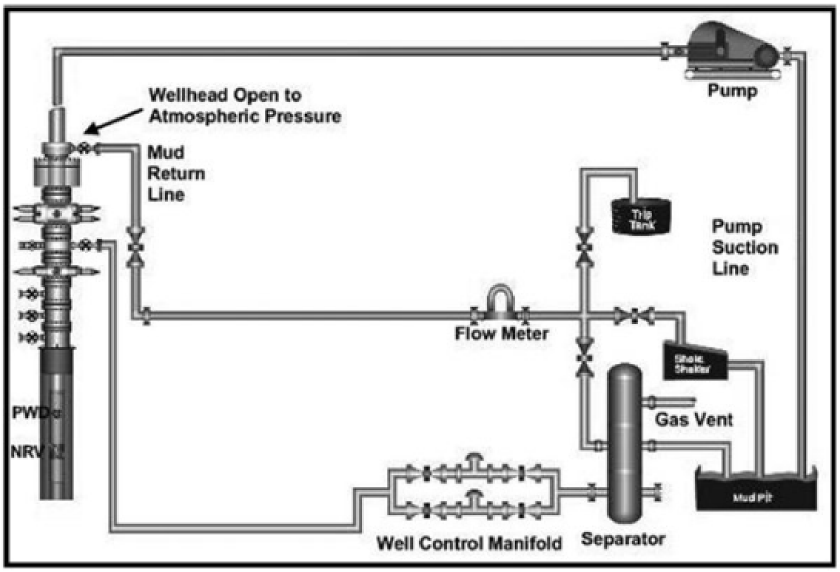


Figure 3.3: Open circulation system. Image: (Rehm et al., 2009).

From the mud pumps, the mud will go through an assembly of valves called the standpipe manifold (not shown in Figure 3.3). Depending on the configuration of the valves, mud from this manifold will be routed to a standpipe. The standpipe connects to a strong but flexible hose, which again is connected to the top drive suspended from the derrick. In the top drive, the mud is injected into the drillstring. When the mud exits the nozzles on the bit, it picks up the cut rock and moves it up the annulus of the well, through the BOP and up the annulus of the riser. At the surface, a flow line, or mud return line, from the annulus directs the mud back to the rig's shale shakers. A shale shaker is a vibrating wire-cloth screen. The liquid phase of the mud, as well as solids that are smaller than the distance between each wire in shaker, will pass through this screen. Solids that are larger than the mesh will be retained (Schlumberger, 2013c). From the shale shakers, the mud may be further treated by a degasser, desanders, desilters, before it is returned to the mud tank. This principle of circulation is called an 'open' circulation system because the mud is exposed to atmospheric pressure at the surface.

3.6 Overview of causes of kicks

A kick of gas or oil occurs at the simultaneous fulfillment of two conditions:

1. Penetration of a porous and permeable reservoir with hydrocarbons present
2. The pore pressure is greater than the BHP

This is important to emphasize. There may be a range of causes leading up to an underbalance, but no kick will ever occur if a porous, permeable and hydrocarbon-bearing reservoir has not been penetrated. As was pointed out by Andersen (1996), any fault tree model for a kick should start with these two conditions at the top level. From there, the under balance (condition 2) could be causally investigated. Keeping this very important point in mind, the following text describes the various ways in which the pressure in the hole could fall below the pore pressure.

3.6.1 Inacurrate pressure prediction

Running into abnormally pressurized regions unexpectedly is essentially a failure to predict abnormal pore pressure. Prior to spudding, a mud program and casing program will be planned. These programs are based upon pressure prediction, as previously discussed. Hornung (1990) state that the accuracy with which pressure can be predicted depends upon quality of data, the number of neighboring wells and the interpretation of the data. If there is great uncertainty in the information about subsurface geology, as is the case with a wildcat well, kicks would be more likely to occur. Although there is a potential for human failure here (e.g. incorrect interpretation of data), this is a failure in planning and design, not an operational failure at the 'pointy end' of the operation.

3.6.2 Too low mud density

The BHP is directly related to the density of the mud. A mud gradient lower than the formation gradient will therefore lead to a kick. There are various ways in which this could happen. First, if drilling is conducted with a mud weight very close to the formation pressure, the pressure drop when turning off the pumps (ΔP_f in Eq. 3.14) may be large enough to cause under balance. Proper understanding of the ECD and its relation to static pressure is therefore important.

Another possible reason for an insufficient mud weight is that a mud mixing error has occurred. When preparing a mud for a particular section, calculations must be performed to decide how much barite to add to the mud in order to achieve the desired density. An incorrect calculation will obviously lead to an incorrect density. A second reason for an insufficiently weighted mud could be insufficient agitation. If the mud is not properly agitated, or 'stirred', while stored in the tanks the barite could clump together and fall to the bottom of the tank. This phenomenon is called barite settling. Note however that Holand (1997) describes a mud mixing error as an unlikely cause for the blowout entries reported as due to 'too low mud weight' in the Sintef Blowout Database.

The third possible cause for an insufficient mud density is that the mud is mixed with gas. This situation is termed 'gas cut mud' and occurs at the bit when drilling through a gas bearing layer (Holand, 1997). The mixture of gas and mud has a lower density than pure mud, making the pressure exerted on the well correspondingly lower. So, to sum up we see there are three distinct causes of under balance due to too low mud density:

1. Transition from circulating density to static density
2. Mud mixed out of specifications
3. Gas cut mud

3.6.3 Swabbing and surging

Swabbing refers to the 'piston-like' effect caused by moving equipment up the wellbore. When pulling the pipe out of the well, there will be a no-slip boundary between the surfaces of the equipment in the wellbore and the mud. This means that mud in the immediate vicinity of the pipe will tend to follow the pipe, whereas the surrounding mud will rush to replace the pulled volume. The net effect is that the pressure exerted on the walls of the well is reduced. This reduction might be large enough to cause an influx. The safety measure taken to avoid such an influx is the trip margin which was mentioned in the previous chapter.

Surging is quite the opposite to the swabbing effect. Surging refers to a transient pressure increase in the mud, as a result of moving equipment towards the bottom of the well. A pressure surge exceeding the rock's tensile strength can fracture the formation, making it accept drilling fluid. If enough drilling mud is lost to the formation a kick may occur.

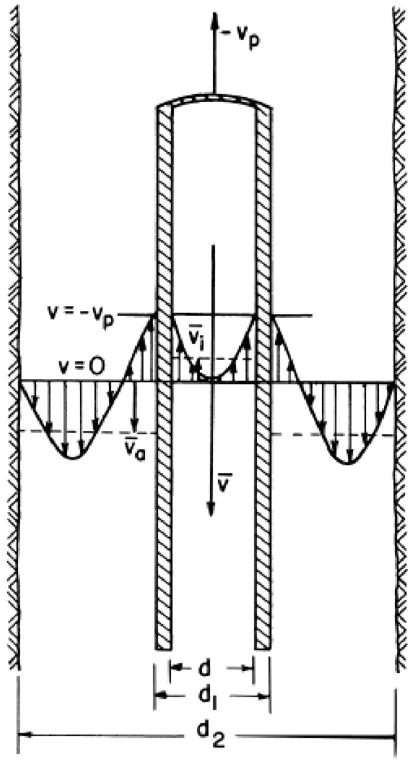


Figure 3.4: Velocity profiles for laminar flow pattern when pipe is pulled out of hole. Figure: (Bourgoyne, 1986).

Hornung (1990) state that pressure changes due to surging and swabbing are functions of fluid velocity and acceleration, which in turn are functions of friction, mud properties and pipe speed and acceleration.

3.6.4 Reduction in height of fluid column

The pressure in the mud is proportional to the height of the mud column. If the height of the column is reduced, the pressure will fall correspondingly. Such a column drop could occur in three ways. The first is termed 'improper hole fill-up'. Improper hole fill-up is a problem related to pulling equipment out of the well. While drilling ahead the well and riser is full of mud. The equipment present in this column of mud, e.g. the drill pipe and BHA, displaces a certain volume of mud. When the equipment is pulled out of the hole, such as on a trip, the level of mud in the riser will fall. This will reduce the pressure exerted on the bottom of the well. To counteract this effect, one must refill or 'top up' the riser with the pulled volume of mud during a trip. Failure to do so may result in underbalance.

A riser disconnect is the second way of effectively loosing mud column height. This cause was discussed under the section on riser margin. The third, and final way, of reducing the column of mud is to loose mud to formation. This is often referred to as 'lost circulation'. If the mud pressure for some reason exceeds the fracture pressure, the wall of the well will fracture and mud will 'lost to the formation'.

3.6.5 While cement setting

Holand (1997) states that when the cement used to cement a casing in place is in the transition phase from fluid to solid, it will start to stick to the wall of the well and to the casing. This reduces the hydrostatic pressure exerted on the formation, making it possible for gas to flow either through or along the sheet of cement. Eight of the shallow gas blowouts discussed by Holand (1997) occurred during cement setting.

3.7 Kick indicators

Kick indicators are simply stated the signs the crew onboard a drilling rig will take as indications that a kick is occurring. Some of them are presented to the crew directly by the use of instrumentation, whereas other are indirect and more subtle. The key kick indicators during drilling are, according to Hornung (1990):

1. Drilling break
2. Increased flow
3. Pit gain
4. Pump pressure decrease/pump speed increase
5. Mud weight decrease

The drilling break refers to the penetration of a layer with a different pressure regime, called a 'transition zone'. When a drilling break occurs the driller may experience changes in the following drilling parameters (Hornung, 1990):

1. Rate of penetration (ROP) or, if control drilling, weight on bit (WOB)
2. Torque
3. Drag

4. Pump pressure or speed
5. Fill

The drilling break is instantaneous, whereas other indicators for a transition zone penetration may lag the drilling depth (Hornung, 1990). Examples are gas, chlorides, mud weight decrease and percent sand.

During tripping, improper hole fill-up and flow are the primary kick indicators (Hornung, 1990). Improper hole fill-up refers to the well not accepting a volume of mud equal to the volume displaced by the equipment which is removed or introduced into the well. The mud pumps are off during a trip, which means that mud should not flow out from the well unless equipment (drill pipe and BHA) is lowered into the well. If it does, the most plausible explanation is an influx.

Chapter 4

Case study

In order to evaluate the actions required by humans onboard a rig, it is found necessary to perform a case study. We need to know how, when and where humans interact with the equipment in order to ensure the continued reliability of the mud column during the operations. To do this requires a sufficiently detailed system description and information regarding responsibilities and procedures onboard the rig. Obtaining such detailed information regarding pressure control equipment and standard procedures for well control has proved to be a somewhat difficult task, since this information is not publicly available. Luckily, Bergen Maritime College agreed to show the author around on their drilling simulator Drillsim6000. They also provided the author with a procedure for well control during drilling activities (. . . . ., 2013)[1]. The equipment and system configuration presented in the following is largely based upon one of the rigs modeled on the Drillsim6000. The rig is a semisubmersible offshore drilling unit (MODU) fitted with a top drive system, semi-automated pipe handling, iron roughneck and single derrick racked with stands of 3x9[m] drill pipe.

4.1 System description

The following text describes the pressure control system onboard the rig. System schematics have been reproduced from images taken of them. The description is limited to hardware such as pipes, valves and pumps and does not contain details on software systems used in well monitoring or remote control of hardware such as choke valves, top drive or iron roughneck.

[1]The company is kept anonymous due to commercial confidentiality considerations.

4.1.1 Mud alignment

Figure 4.1 shows the mud alignment system. The mud alignment system is used to line up the mud pits with the various mud pumps. These in turn deliver mud to the standpipe manifold. Pump 4 is a transfer pump, enabling the transfer of drilling fluid from the reserve system into the active system. The active system represents a computerized aggregation of the active mud pits. There are in fact several pits onboard the rig, but a computer combines the volume of these tanks into one active volume. This makes volume control easier.

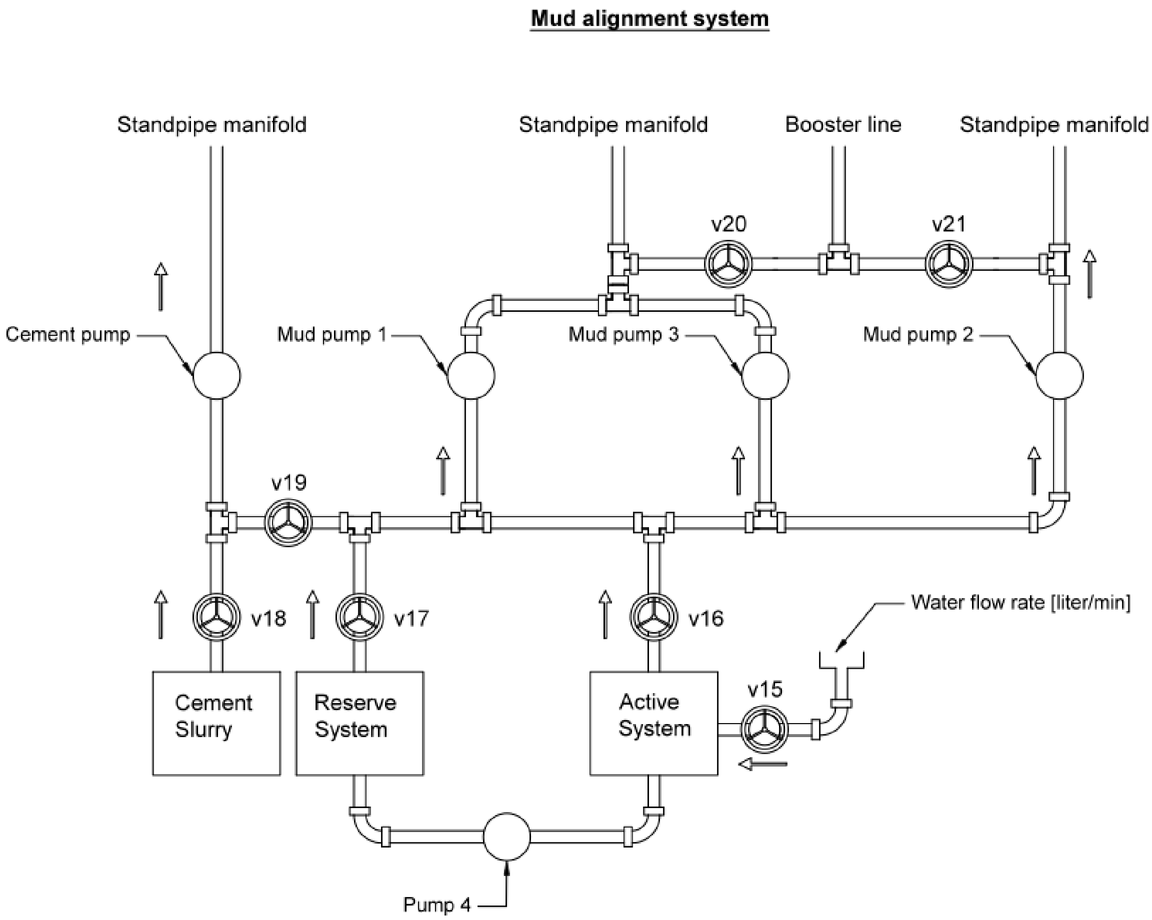


Figure 4.1: Mud alignment system schematic.

The driller has remote control of all the pumps from the driller's console (touchscreen).

4.1.2 Trip and strip tank alignment

The trip and strip tank alignment system is shown on Figure 4.2 below. The flow line, i.e. the mud return line, conducts the drilling mud from the top of the riser and back to the mud processing system. While drilling ahead, the entire trip tank assembly will be bypassed and mud will be routed directly to the active mud system (see Appendix B). After the split between v13 and v14, i.e. in the 'active system', the mud will be exposed to atmospheric conditions. This is where the solids removal equipment (shale shakers etc.) are located. Flow from the well is measured by the flowmeter on the return line, and presented to the driller on the driller's screen in the units liters per minute.

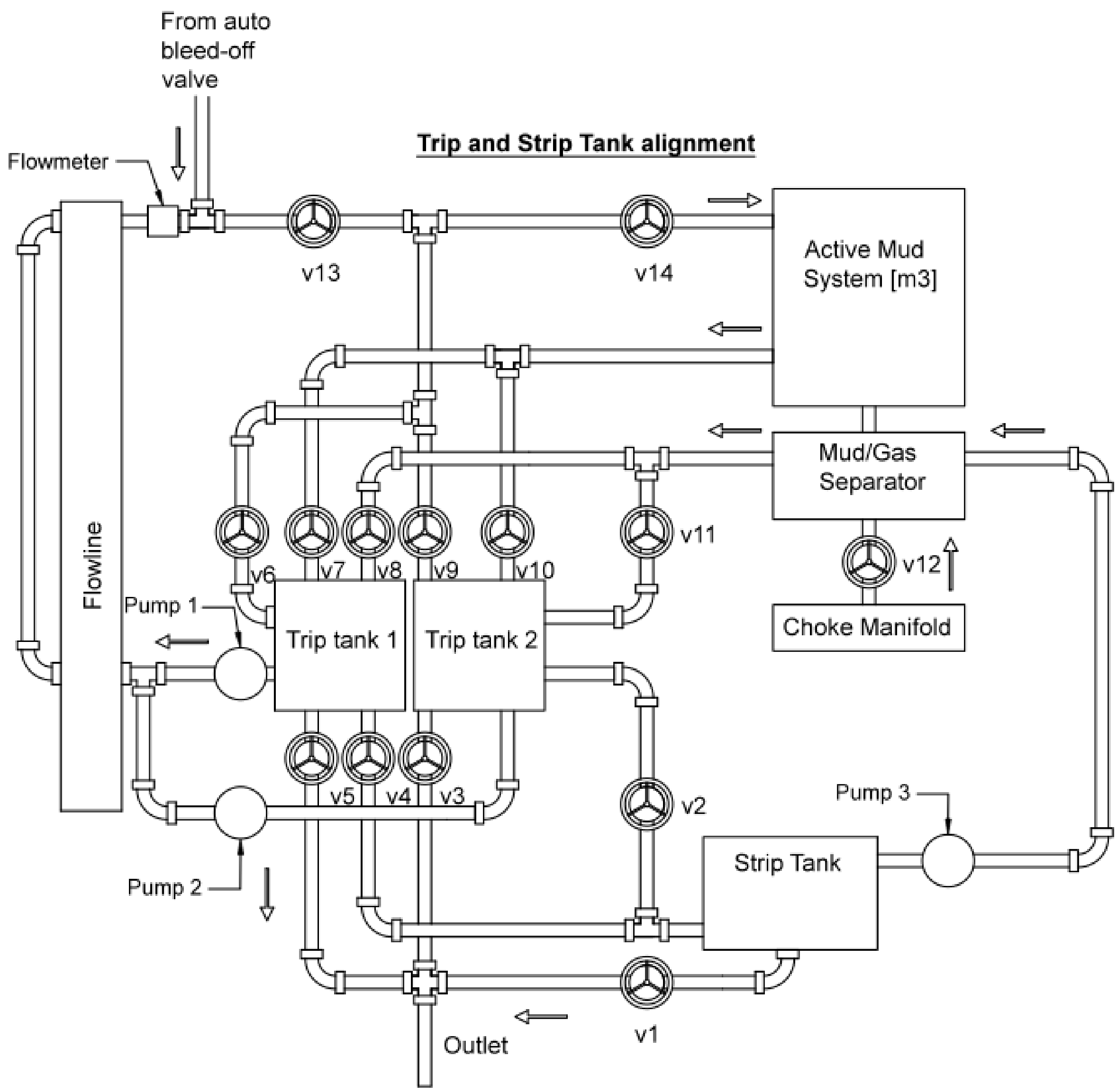


Figure 4.2: Trip and strip tank alignment.

When a trip is performed, the entire active mud system will be bypassed (see Appendix C). The main reason for this is that the active mud pits are large, making accurate volume control more difficult. The smaller trip tanks give a finer resolution of volume measurement because of the smaller free surface area in these tanks. During the trip, mud returns will be routed from the flow line and into the trip tanks. Pump 1 or 2 will pump the mud back into the flow line, thus ensuring that the annulus of the riser remains filled during the trip. Note that this configuration also means that the entire mud processing system is bypassed; there is no solids removal equipment in-line with the system. The auto bleed-off valve is used to bleed off pressure from the standpipe manifold. This is v33 in Figure 4.3 on the next page. The pumps on the trip tanks are centrifugal pumps powered by an electric motor.

When it comes to tank dimensions and performance requirements, NORSOK D-001 gives the following requirements regarding dual trip tanks:

Description	**Value**	**Unit**
Trip tank capacity minimum	2 x 5	$[m^3]$
Trip tank pump capacity	100	$[m^3/h]$
Accuracy of volume variation measurement	0,05	$[m^3]$

Table 4.1: Trip tank system requirements (NORSOK, 1998).

The tanks in this case are assumed to be 10 m^3 each, making the total trip tank volume 20 m^3. Further, the pump capacity and accuracy of volume variation measurement is assumed equal to what is specified in Table 4.1.

The strip tank is used when forcing the drill string down through a closed BOP. When the bit is out of the well and the upper annular preventer is closed, the driller will try to get the bit back on the bottom of the well. This is because the preferred way of killing the well is with the bit on bottom, as opposed to using the kill and choke lines (. . . . ., 2013). Since the volume below the annular preventer is a closed volume, there will be a pressure increase in the mud due to the volume displaced by the BHA and drill pipe as it is forced into the well. This displaced mud is bled off through the choke line, into the mud gas separator and routed through a trip tank and into the strip tank. This gives the operators a dual check of the bled-off volume[2]. To check whether or not the well is flowing after having closed the BOP, a flow path can be created from the choke line, through the MGS, and into the trip tank. This is done by opening v12.

[2]**Explanation:** The bled-off volume is routed into a closed trip tank. The volume corresponding to a closed-ended stand of drill pipe is then bled from the trip tank and into the strip tank. This way, the excess volume can be measured in the trip tank (. . . . ., 2013).

4.1.3 Standpipe and choke manifold

The standpipe manifold (Figure 4.3) is located to the left on the drilling floor as seen from the drilling cabin. The purpose of the standpipe manifold is to conduct drilling mud from the mud pumps, up through one of the two standpipes, through a flexible hose and up to the top drive where mud is injected in to the drill pipe. During a normal killing operation, the kill mud would be circulated through the drillpipe. The choke line is then used to bleed off pressure during killing. To clarify, we can say that when kill mud is injected into the well, the displaced mud (and influx of oil/water/gas) is circulated out through the choke. If for some reason the bit is out of the well, the kill line could be used to introduce kill mud into the well below the closed BOP. This kill mud will then fall by the force of gravity, displacing the lighter original mud and the kick.

All the taps on the manifold measure pressure. These measurements are presented both on the driller's screen and the choke operator console (see Appendix E). All the valves are manually operated except for valves v43 and v46. These are controlled remotely from the choke operator console.

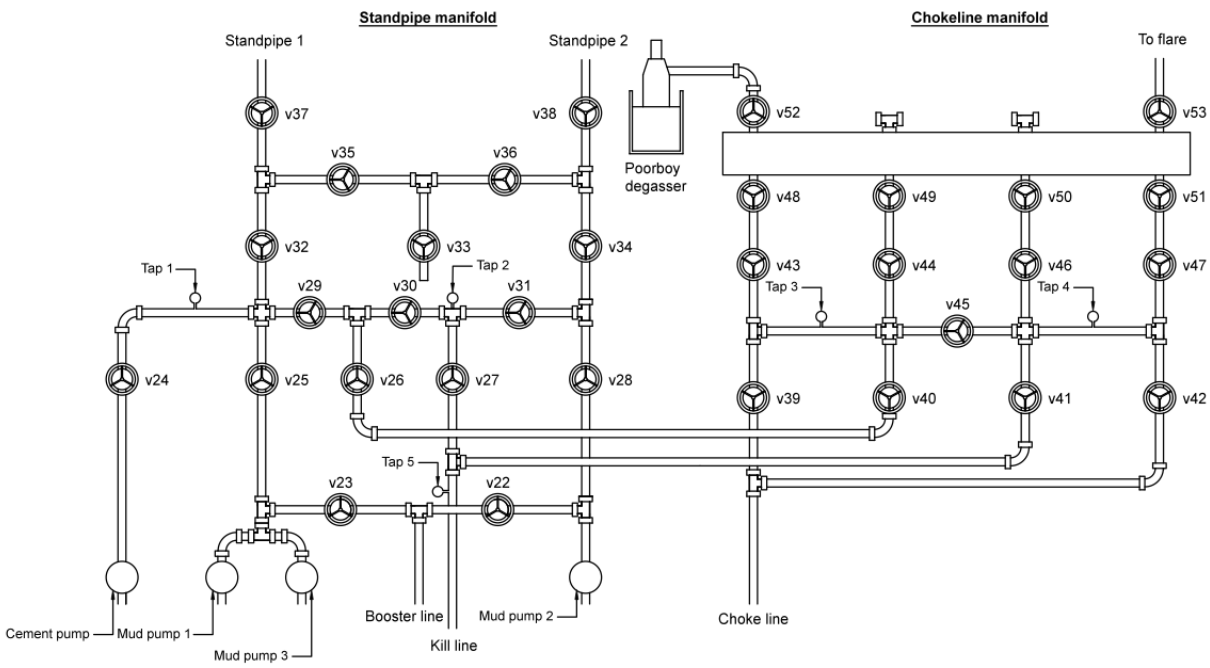


Figure 4.3: Standpipe and choke manifold.

4.2 Choosing a particular operation

Due to limitations on available time, and the complex nature of drilling operations, it is thought best to limit the analysis to one particular operation. To be able to choose such an operation, we first need an overview of the various sub operations performed during the drilling of a well. Generally, drilling can be divided into the following sub-operations (Ø.Arild et al., 2009):

- Drilling ahead
- Tripping operations
- Static conditions
- Casing operations
- Cementing operations

Where one also might add testing operations such as FIT/LOT/XLOT. Furthermore, if primary control is lost, well control operations would also be added to the list. For the analysis to be useful, the operation must be directly associated with a risk of fluid intrusion. This means we can rule out static conditions. Another requirement would be that the operation should be sufficiently complex in order to suit analysis, but not *too* complicated. Based on these assessments, and in light of the discussed causes for kicks, it is decided to look at tripping operations. More specifically, tripping out of the hole.

4.3 Tentative description of tripping out

The following text will describe how tripping out of the hole is performed on the rig. The purpose of this description is to provide an understanding of what goes on on the drill floor during a trip. First however, some relevant drill-floor located items must be presented. These are shown on the image below. Starting with the slips; the remotely controlled slips is a device located in the drill floor. When activated by the driller, it grasps around the drill string, making it possible to suspend the string from the drill floor.

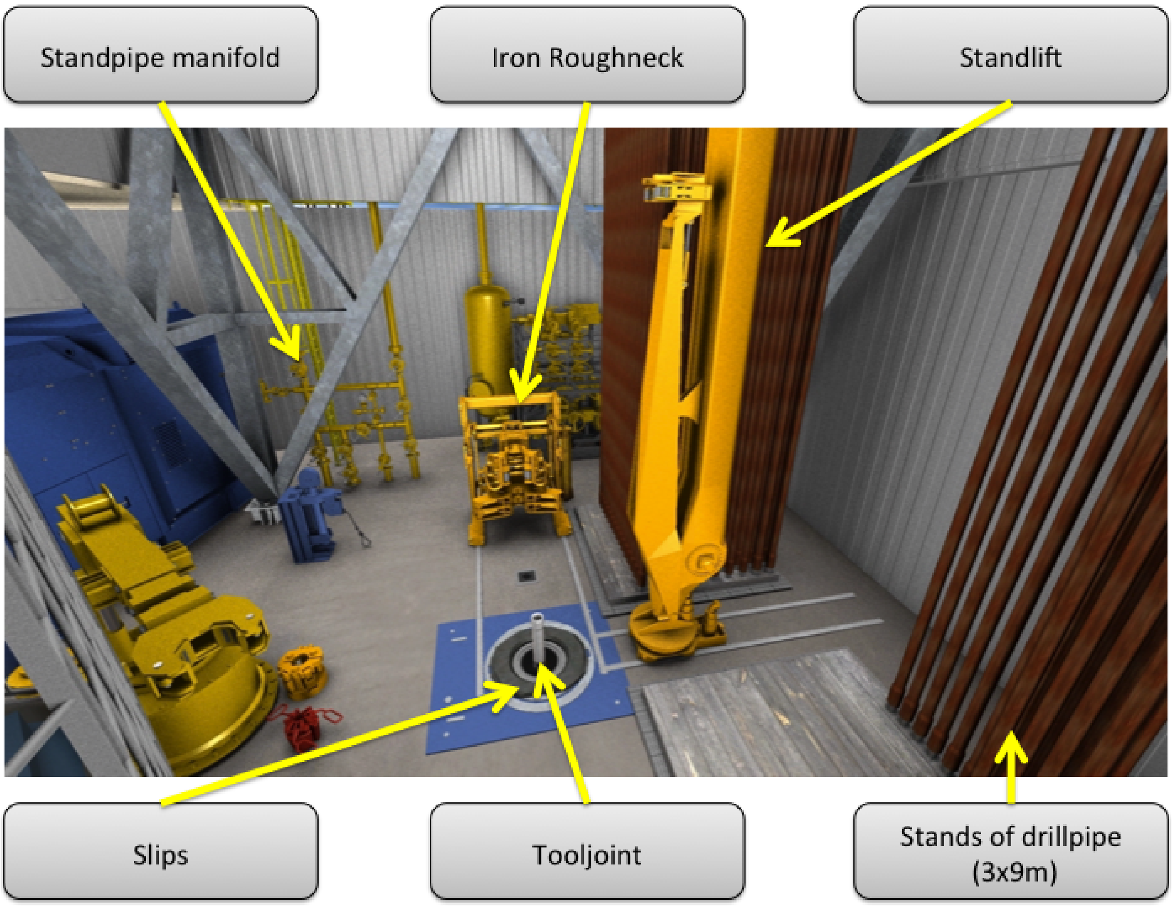


Figure 4.4: Drillfloor. Image captured from animation available at (China Oilfield Services Limited Europe, 2007).

The iron roughneck is used to break or make up a connection between two lengths of drill pipe. When used to break a connection, it grabs hold of both the upper and lower part of a connection, and applies a counter clockwise torque on the upper pipe while holding the lower pipe fixed. The stand lift, located to the right in Figure 4.4, is in essence a pipe handling robotic arm used either to place stands in the so-called fingerboard, or to take a stand from the fingerboard and lower it into the opening in the drill floor. A tool joint is simply the reinforced and threaded end of a drill pipe.

We will in the following assume that drilling has halted, with the bit being on bottom. The job is now to retrieve the entire drill string and the bottom hole assembly.

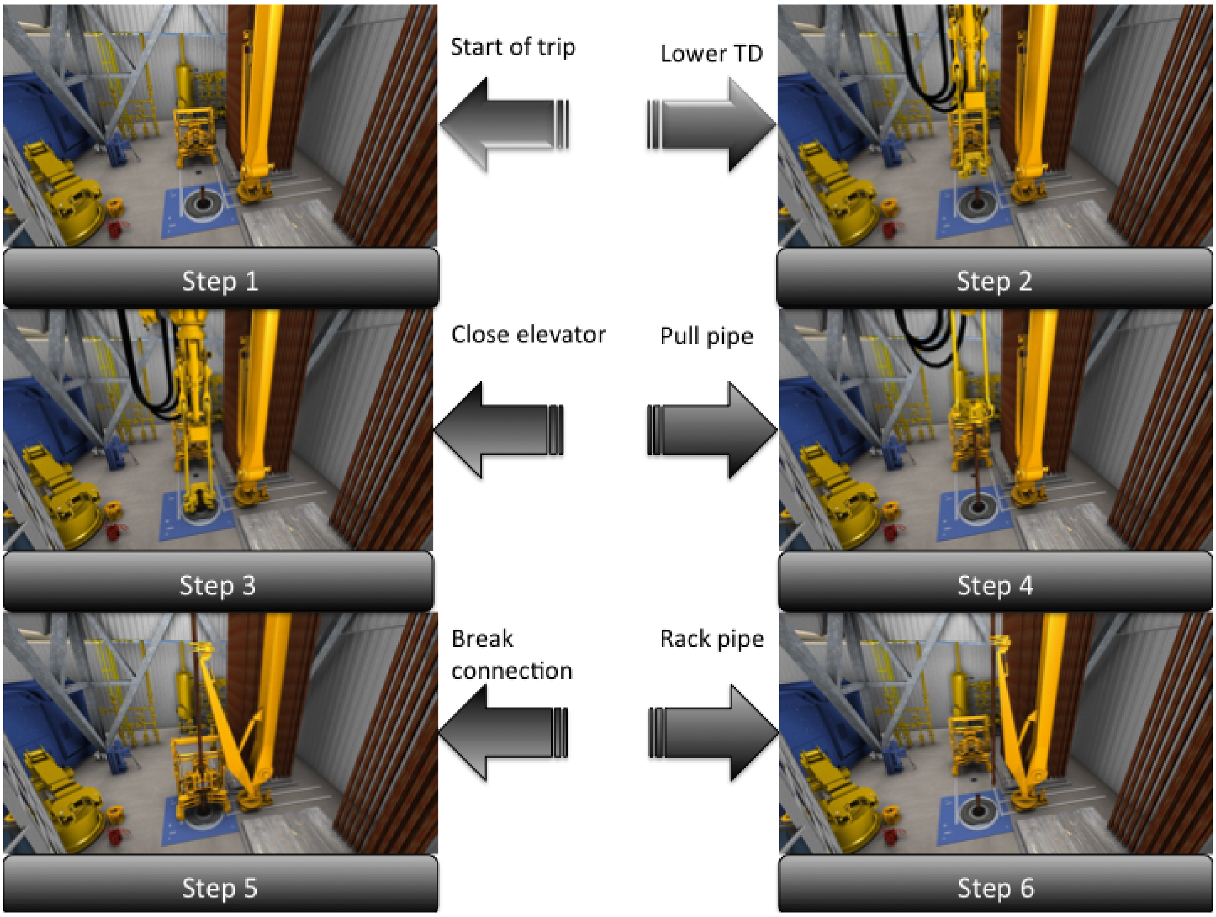


Figure 4.5: Pulling out of hole (POOH). Images captured from animation available at (China Oilfield Services Limited Europe, 2007).

To start the operation, the driller will lower the top drive and the so-called elevator, which is the hinged device suspended below the top drive. This step is shown in step 2. The driller will now guide the elevators towards the tool joint, and lock it around the tapered profile of the lower part of the tool joint as depicted in step 3. Once the elevator is locked around the pipe, the slips can once again be opened and the weight of the string transferred to the draw-works. From this position, the top drive will be hoisted up the derrick (step 4) until the last tool joint on the stand is positioned just above the drill floor. At this point, the slips will once again be set. The iron roughneck will now move along rails on the drill floor and approach the tool joint. Once it grabs the pipe and breaks the connection, the stand will be freed from the rest of the drill string. Having broken the connection, the assistant driller will now grab the stand hanging from the drill string with the stand lift and place the stand in an available slot in the fingerboard. The process of pulling one stand is now complete, and it will be repeated until the entire string is out of the well. A drilling crew will typically pull pipe at a rate of 1000 [ft/hr], which means that tripping out can be a day-long process if the well is deep (Bartlit et al., 2011).

Chapter 5

Human Reliability Analysis

5.1 Preconditions

The tripping operation will take place after drilling has stopped, and the driller has been informed by the on-duty toolpusher the reason for the trip. It is not found necessary to specify what section is being drilled, since the potential causes for kicks are similar for all the sections drilled with the use of a BOP. The analysis consequently does not concern shallow kicks; only 'deep' kicks (water depth $\geq$ 1200 m) as defined by Holand (1997). The mud pumps have been shut off and the well has been monitored on the TD for a sustained period in excess of 15 minutes. No flow has been observed. The bit is located on the bottom of the well bore. The drill string present in the hole is shear-able, making it possible to utilize the blind shear ram of the BOP if necessary. Two manually activated alarms have been set to trip if the following two thresholds are breached:

1. Gas returns threshold
2. Trip tank volume gain/loss threshold

The alarms present both audible and visual cues. These cues are presented in the mud loggers shack and in the drillers cabin.

5.2 Assumptions

In the analysis we will assume that the preconditions discussed above apply. It is found necessary to make an assumption regarding the use of the trip tank system. With dual trip tanks, one has the possibility to fill one of the tanks while using the other tank to fill up the well. This means that the POOH operation need not be paused due to a refill. However, in this analysis we have assumed that only one tank and one pump is active at the time. The other tank is in passive standby, providing redundancy in the trip tank system. It is only used in the event that the active trip tank system fails. We also assume that the mud gradient currently in use includes a riser margin.

5.3 Scope and level of detail

The analysis is focused on the normal execution of the tripping operation. It does not encompass human response (i.e. recovery actions) to initiating events which are technical failures, nor does it cover latent failures introduced by e.g. human failures in maintenance. The scope of the analysis is limited to answering three distinct questions:

1. What actions are required of the operators, in order to successfully complete the operation?
2. How can the operators conceivably fail to carry out these actions?
3. What are the consequences of the possible failures with respects to:
   (a) Kick occurence?
   (b) Kick detection?
   (c) Secondary well control?

Since this is a case study, it is beyond the scope of this analysis to propose measures to reduce the likelihood of error and measures to reduce the consequences of errors. These elements have therefore been excluded from the analysis.

The level of detail adopted should be justified according to the assessors familiarity to the operation. An atomistic approach requiring the assessor to obtain in-depth knowledge about every little detail of the operation is not necessary if the hazards and potential human errors are well-known prior to carrying out the HRA. However, since the author was unfamiliar to the operation it was found necessary to adopt a detailed in-depth approach.

5.4 Task Analysis of the operation

The HTA shown in appendix G was built firstly on information contained in the previously mentioned well control drilling procedure manual (........, 2013). Secondly, a short walk-through of the operation was done on the Drillsim6000 simulator. Thirdly, Jan Ove Strandos at Bergen Maritime College has aided the author in the efforts of developing the HTA. The HTA has also been reviewed and verified by Pål Skalle, Associated Professor of Department of Petroleum Engineering and Applied Geophyics at NTNU. The text in the remainder of this section will describe the task in words, hopefully giving the reader a better understanding for the information summarized in the HTA diagram.

At the top level, the task is divided between preparing for tripping and actually pulling the drillstring out of the well. Preparing for tripping starts with a bottoms up circulation. 'Bottoms up' means, as the name suggests, pumping mud from the bottom of the well, up the annulus and back to the pits. To perform one bottoms up circulation, the driller will calculate the volume of the annulus in liters. He[1] will then divide this volume by the mud pump capacity in the unit [liters/stroke]. This gives him the required number of pump strokes to displace all the mud which is present in the annulus with new mud. Next, he resets the meter which counts the number of strokes pumped, so he can easily keep track of the number of strokes pumped at any given time. Before starting the mud pumps, the procedures require the operators to evaluate whether or not there is a possibility for gas returning to surface. If this is found to be a possibility, the last quarter of the annulus should be circulated out through the choke (see Figure 4.3). The evaluation is diagnostic, meaning that the driller, mud logger, tool-pusher and company representative must review the available kick indicators. Although this step could be argued to be safety critical, it has not been developed further because the crucial error is failing to conduct the evaluation (task 1.1.3). Pumping of mud (task 1.1.4) is done in three steps; starting the pumps, observing the strokes counter and stopping the mud pump at the predetermined number of strokes. Bottoms up is then complete and the mud in the annulus is conditioned, meaning that any cuttings suspended in the mud have been removed from well.

The next 4 subtasks may be conducted in any order. The swab-calculation (1.2) done by the mud logger is important because it determines the maximum speed at which each stand of drill pipe can be pulled. Task 1.3 is to prepare the trip tank. Once one of the tanks have been chosen, it must be filled with mud. This can be done in two possible ways. One way is to pump mud through the drill string and into the well and using the returning mud to fill the trip tank. The other possibility is to transfer mud directly from the active volume. When tripping into the well,

[1]The third person pronoun 'he' used henceforth simply refers to 'the driller', and is not intended to give an indication as to whether the person is male or female.

the first method is utilized. When tripping out, the second method is used. Filling the trip tank with mud from the active volume, as opposed to using returning mud from the well, provides a double-check of the volume required to fill the well. To fill the tank, one opens valve number 7 or 10, depending on which tank to use (see Figure 4.2). Then the operator, typically the assistant driller (Strandos, 2014), starts a transfer pump which transfers mud from one of the active pits and into the trip tank while observing the liquid level gauge. After the tank has been filled, he closes the open valve and stops the transfer pump. Note that it is necessary to re-fill the trip tank during POOH when the well has taken a mud volume corresponding to the trip tank volume. Now, valve 14 is closed and the active system is separated from the trip tank system. To line up trip tank 1, one has to open valve 6. To line up trip tank 2 one has to open valve 9. Once this has been done the operator turns on the pump corresponding to the chosen trip tank.

Task 1.4 concerns the trip sheet, which is a crucial element of kick detection during the trip. The trip sheet is a computerized spreadsheet in which the driller calculates the theoretical volume the hole should accept when equipment is pulled out of the hole. He then uses this sheet to compare the actual mud volume the hole is taking to the calculated volume. If the hole is taking less mud than what the calculations show, something must have displaced a certain volume in the well - most likely a kick. If on the other hand the hole is taking too much mud it is likely that mud has been lost to the formation. This may in turn also cause a kick.

The first five stands are pulled wet, which means that each of these stands will be full of mud when they are elevated above the drill floor. Since these stands are closed ended (by a float valve) they require a fill-up volume equal to $V_{stand} \approx \frac{\pi}{4} d_{outer}^2 \cdot L$ (neglecting the tool joints). The next stands are pulled dry, which means that they displace a volume equal to the steel volume, i.e. $V_{stand} \approx \frac{\pi}{4}(d_{outer}^2 - d_{inner}^2) \cdot L$. The driller chooses the type of drill pipe used in the spreadsheet, and the program automatically calculates the theoretical displacement. The expected hole fill-up is calculated for each of the first five stands, then in increments of 5 stands for the stands which are pulled dry. Lastly, the stands of heavy wall drill pipe (HWDP) and drill collars (DC) are included in the calculations.

Task 1.5 is done to make sure that the drill crew have equipment available to close off the drill pipe if a kick comes up the drill string. If a kick occurs when the top drive is not made up, the drill crew must quickly respond by screwing either a full opening safety valve (FOSV) or a grey valve onto the tool joint sticking up through the drill rig floor. Since mud is likely to flow out from the pipe, the safety valve must be in the open position when it is mounted on the tool joint. After the valve is fastened to the drill pipe, a wrench is used to close it.

Task 1.6 is named 'Pull 5-10 stands of DP wet'. The precise number of stands to pull is decided by the on-duty toolpusher. To pull one stand, the driller must first set slips below the top tool joint. This is done at the push of a button. Next, he will disconnect the top drive and connect the elevator. He will then open the slips so that the weight of the entire drill string assembly is transferred to the draw works via the top drive suspended from the hook. While elevating the top drive with the joystick he must monitor the pulling speed and make sure that it does not exceed the speed calculated in task 1.2. After the first stand is elevated, he will set slips below the top tool joint of the lowermost drill pipe. Next, the iron roughneck will be activated and brought in to break the connection. This sequence is completely automated. Once the stand has been loosened from the drill string, a mud bucket will be closed around the broken connection. The mud bucket is hydraulically operated. It is lined up with a return line to the active system. The assistant driller will next grab the stand with the stand lift and, with the help of the drill crew, carefully place it into the fingerboard. Now, the driller will compare the volume drop in the trip tank to what has been calculated in the trip sheet (task 1.6.10). This whole operation, that is task 1.6.3-1.6.10 is then repeated until the desired number of wet stands has been pulled. After pulling 5-10 stands, a high-density slug of mud is pumped through the drill string. Naturally, the top drive must be made up in order to achieve this. This task is however not developed any further, since it has been confirmed to have no causal link to kicks (Strandos, 2014). The slug is pumped so that the height of the mud in the drill string will drop and the subsequent lengths of pipe can be pulled dry.

After having completed the preparations for the trip, the driller can begin the actual tripping out of the hole. The process is similar to pulling wet stands, but there are two important differences. First of all, a mud bucket is not necessary since the pipes are pulled dry. Secondly, the driller must conduct a flow check before pulling the bit through the lowest casing shoe and before pulling through the BOP. To do this, he shuts of the trip tank pump and observes the flowmeter indicator as well as the trip tank volume trend (see Appendix F) for a period in excess of 15 minutes (........, 2013). Once the bit has been pulled up into the riser, the driller will have limited control of the well. A kick with the bit out of the hole is more difficult to handle; requiring firstly an attempt at stripping the bit back in to the well. If this fails, secondary well control (kill circulation) must be carried out by the use of the kill and choke lines.

5.5 Human Error Identification

Human Error Identification has been done by the use of a spreadsheet. The author has followed the guidance provided in the Energy Institute's guidance on human factors safety critical task analysis (Smitha and Koop, 2011). Each step and each plan in the HTA has been assessed with a set of guide words. The set of guide words is divided in the categories action failures, checking, information retrieval, communication, selection/decision, planning, diagnosis/decision making and non-compliances. Examples of words used include 'operation performed too early/late', 'operation omitted', 'check omitted', 'check incomplete' and 'wrong information obtained'. For the full list of the guide words, see the Energy Institute's guidance on SCTA.

The application of suitable guide words to each action and plan in the HTA reveals the potential for human error during the execution of the task. The immediate and visible consequences of each respective human failure event[2] are documented in each row together with the responsible operator (OP), relevant performance shaping factors, recovery potential and additional comments. Having completed the human error identification, the HRA proceeds with screening out irrelevant HFEs, leaving only HFEs with relevance to kick occurrence, kick detection or secondary well control behind. This is presented in the next section. For the complete table of the identified *potential* human errors, see appendix H.

5.6 Screening

Screening is the step in the HRA process in which we leave out those potential HFEs that do not require quantification. Had a risk model containing the HFEs existed prior to executing the HRA, the specific human errors requiring quantification would already be known. In this case, such a risk model does not exist. It is therefore judged best to screen out those human errors which do not have consequences pertaining to either kick occurrence, kick detection or secondary well control. The various HFEs have been divided into these categories for convenience. Table 5.1 shows the potential human errors which may cause a kick to occur.

Task ID.	Description	Potential HFE	Recovery potential	Potential consequences
1.2	Determine max pulling speed	Incorrect calculation; calculated max speed higher than actual max speed.		Swabbing in a kick.
1.3	Prepare trip tank	Fail to prepare trip tank before POOH.		Improper hole fill-up. Unable to monitor well.
1.3.2.3	Observe fluid level	Determine that tank is full before it actually is.	Redundancy in TT monitoring; mud-logger and drillers cabin.	Insufficient volume in trip tank; may lead to improper hole fill-up if not detected.
1.3.2.5	Stop transfer pump(s)	Stop transfer pump(s) before tank is filled.	Driller (o4) and mud logger (s1) monitor trip tank volume and find it insufficient.	Insufficient mud volume in trip tank; may lead to improper hole fill-up if not detected.

[2]**Human Failure Event (HFE):** A basic event that represents a failure or unavailability of a component, system, or function that is caused by human inaction or an inappropriate action (Gertman et al., 2005).

Task ID.	Description	Potential HFE	Recovery potential	Potential consequences
1.3.3	Line up trip tank	Fail to line up trip tank before POOH.	Driller (o4) and mud logger (s1) notice no flow from return line after starting TT pump.	Improper hole fill-up and kick detection impossible.
1.3.3.1	Close v14.	Close v14 before TT is full of mud.	Driller (o4) and mud logger (s1) monitor trip tank volume and find it insufficient.	Insufficient mud volume in trip tank; may lead to improper hole fill-up if not detected.
1.3.3.2	If TT1[3]: Open v6. Else: Open v9.	Open v6 when supposed to open v9.	Driller (o4) and mud logger (s1) notice either (1) gain in wrong TT or (2) no flow from return line.	Returns will be taken to one tank, and active pump lined up to another. Will lead to improper hole fill-up when pulling.
1.3.3.2	If TT1: Open v6. Else: Open v9.	Open v9 when supposed to open v6.	Driller (o4) and mud logger (s1) notice either (1) gain in wrong TT or (2) no flow from return line.	Returns will be taken to one tank, and active pump lined up to another. Will lead to improper hole fill-up when pulling.
1.3.3.2	If TT1: Open v6. Else: Open v9.	Fail to open valve	Driller (o4) and mud logger (s1) notice either (1) gain in wrong TT or (2) no flow from return line.	Overflow at return line, TT quickly emptied then improper hole fill-up when pulling.
1.3.4	If TT1: Turn on pump 1. Else: Turn on pump 2.	Turn on pump 1 when supposed to turn on pump 2.	Mud logger (s1) notices either (1) TT pump has not started or (2) no flow from return line.	No TT circulation; will lead to improper hole fill-up if not detected.
1.3.4	If TT1: Turn on pump 1. Else: Turn on pump 2.	Turn on pump 2 when supposed to turn on pump 1.	Mud logger (s1) notices either (1) TT pump has not started or (2) no flow from return line.	No TT circulation; will lead to improper hole fill-up if not detected.
1.3.4	If TT1: Turn on pump 1. Else: Turn on pump 2.	Fail to start pump before POOH.	Mud logger (s1) notices either (1) TT pump has not started or (2) no flow from return line.	No TT circulation; will lead to improper hole fill-up if not detected.
1.6.5.1	Elevate TD.	Pull pipe too fast.		Swabbing in a kick.
1.6.5.1	Elevate TD.	Deliberately pull pipe too fast.		Swabbing in a kick.
1.6.5.1	Elevate TD.	Inadvertently lower TD.		Surge pressure leading to lost circulation, which again can cause a kick.
1.6.5.2	Check that pulling speed is within limits from 1.2.	Fail to continuously monitor pulling speed during pull.		Swabbing in a kick.
2.5.1	Elevate TD.	Pull pipe too fast.		Swabbing in a kick.
2.5.1	Elevate TD.	Deliberately pull pipe too fast.		Swabbing in a kick.
2.5.1	Elevate TD.	Inadvertently lower TD.		Surge pressure leading to lost circulation, which again can cause a kick.

[3] **Explanation:** The if/else condition refers to having chosen trip tank 1 (TT1), or trip tank 2 (TT2).

Task ID.	Description	Potential HFE	Recovery potential	Potential consequences
2.5.2	Check that pulling speed is within limits from 1.2.	Fail to continuously monitor pulling speed during pull.		Swabbing in a kick.
1.3.2	Fill tank with mud from active volume.	Fail to re-fill TT during POOH.	Low-level alarm goes off on TT and on driller's panel.	Improper hole fill-up.

Table 5.1: Potential human errors leading to kick.

The next category of potential human errors concerns the human errors with consequences associated solely with kick detection. Table 5.2 shows a summary of the HEI for this category.

Task ID.	Description	Potential HFE	Recovery potential	Potential consequences
1.3	Prepare trip tank (TT)	Start to fill tank with mud from active volume with TT pump on.		Volume control lost; will appear as if mud has 'disappeared', i.e. lost returns.
1.3.2.1	If TT1: Open v7. Else: Open v10.	Open v6 when supposed to open v7.	Driller (o4) notices flow from return line.	Loss of volume control.
1.3.2.1	If TT1: Open v7. Else: Open v10.	Open v9 when supposed to open v10.	Driller (o4) notices flow from return line.	Loss of volume control.
1.4	Prepare trip sheet	Fail to prepare trip sheet before POOH.	Driller (o4) and mud logger (s1) prepare trip sheet independently	Unable to monitor hole fill-up; kick detection impossible.
1.6.10	Check that hole is taking calc. amount of mud.	Fail to compare volume drop in trip tanks to trip sheet.	Driller (o4) and mud logger (s1) both check that hole is taking calc. amount of mud.	Unable to detect improper hole fill-up; will not stop pull to conduct flow check.
1.6.11	Conduct flow check.	Fail to conduct flow check.		Unable to detect kick.
1.6.11	Conduct flow check.	Complete flow check in less than 15 min.		Unable to detect kick; well deemed static even though it is not.
2.9	Check that hole is taking calc. amount of mud.	Fail to compare volume drop in trip tanks to trip sheet.	Driller (o4) and mud logger (s1) both check that hole is taking calc. amount of mud.	Unable to detect improper hole fill-up; will not stop pull to conduct flow check.
2.10	Conduct flow check.	Fail to conduct flow check.		Unable to detect kick.
2.10	Conduct flow check.	Complete flow check in less than 15 minutes.		Unable to detect kick; well deemed static even though it is not.
2.10	Conduct flow check.	Fail to conduct flow check prior to pulling BHA and bit through BOP.		Unable to detect kick; well deemed static even though it is not.

Table 5.2: Potential human errors preventing kick detection.

The entries in the table where the same consequences appear in different rows are due to applying guide words such as e.g. 'action too early' and 'action too late' at two successive actions noted in the HTA. Again, see appendix H for the complete tables with the guide words used.

Notice that the HEI concerning kick detection does not contain incorrect trip sheet calculations. If the trip sheet is followed, but the calculations are incorrect the driller will suspect either lost circulation or a kick. He will then shut-in the well and initiate secondary well control procedures, even though these are potentially unnecessary actions. The essential human error is therefore failing to compare the trip sheet with the trip tank measurements (omission).

Arguably, all the human errors identified in Table 5.1 which concern either preparations or direct use of the trip tank system also prevent kick detection. This is due to the fact that the trip tank system serves a dual purpose; (1) it ensures that the annulus side of the riser is continuously filled and (2) it is a monitoring device, which accurately measures the volume going in/out of the well during trips. The errors noted in Table 5.2 are therefore the errors which compromise kick detection without preventing the trip tank from ensuring proper hole fill-up.

Lastly, the task analysis contained a check for safety valve equipment; so-called stab-in safety valves. The application of guide words to this check revealed consequences which are relevant for secondary well control during tripping. These are shown in the table below.

Task ID.	Description	Potential HFE	Recovery potential	Potential consequences
1.5.1	Check that suitable safety valves are on drill floor and in 'open' position.	Fail to verify that suitable safety valves are on drill floor and in 'open' position.	Driller (o4) make up TD with returns to active system: then close iBOP.	Unable to stab safety valve in drill pipe if kick occurs; possible blowout through drill pipe.
1.5.1	Check that suitable safety valves are on drill floor and in 'open' position.	Fail to check that valves are in 'open' position.		Unable to quickly stab safety valve in drill pipe because pressure from flowing mud is too great.
1.5.1	Check that suitable safety valves are on drill floor and in 'open' position.	Fail to check that suitable crossover subs are readily available.		Unable to quickly stab safety valve in DP/HWDP/DC.
1.5.1	Check that suitable safety valves are on drill floor and in 'open' position.	False verification that suitable valves are on drill floor.		Unable to stab safety valve in drill pipe if kick occurs; possible blowout through drill pipe.
1.5.2	Check that closing/opening wrench is readily available on drill floor.	Fail to check that closing/opening wrench is readily available on drill floor.		Unable to close safety valve once it is stabbed. Possible blowout through drill pipe.

Table 5.3: Human errors with consequences for secondary well control.

5.7 Representation

For the purpose of causally investigating kick occurrence during tripping out, a fault tree model has been developed (see appendix I). The tree has been built in the software program CARA. The analysis was performed by following the ground rules for fault tree construction as found in e.g. (Vesely et al., 1981) and (Rausand, 2011). The top event has been defined as 'primary well control failure during trip out of hole' and the immediate-cause concept has been followed throughout the construction of the tree. In combining technical faults or failures with human errors, a simple approach was adopted. The 'complete-the-gates' rule (see Vesely et al. (1981)) states that the analysis should not progress before all immediate causes sufficient to cause the output of a gate has been included. The incorporation of human errors was therefore done as follows: for each intermediate event analyzed, all the screened HFEs were read to see if any of them were sufficient by themselves, or in combination with other events, to cause the event under investigation to occur. If this was found to be the case, they were included as basic events.

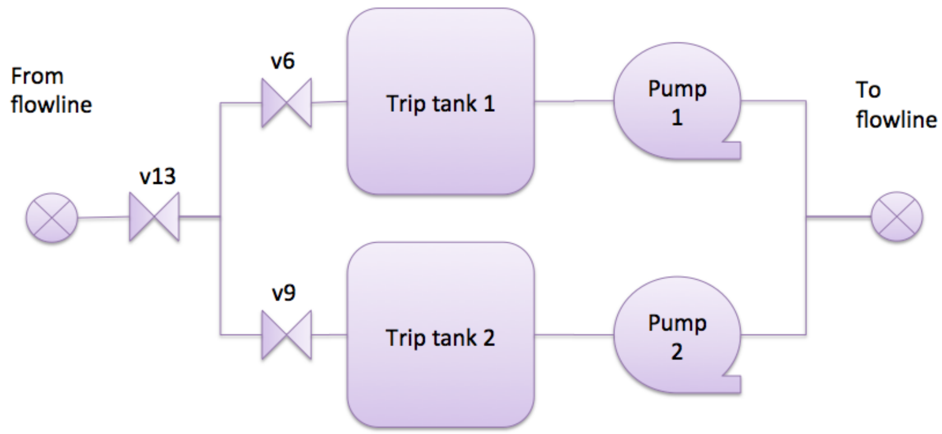


Figure 5.1: Simplified schematic of trip tank system.

When it comes to the trip tank system, the fault tree is based upon a simplified representation of the system as depicted in Figure 5.1. Since all gates are manually operated gate valves, they have not been included in the fault tree. Potential failure modes of the valves, e.g. internal leakage, fail to close and fail to open are thus omitted. The system then corresponds to an imperfect switch and two pumps in parallel, one of which is in cold standby.

The fault tree also contains some assumptions. A brief description of its structure will highlight these and is therefore included here. First off, the operational modes are summarized in Figure 5.2. We see from the figure that there are no requirements for opening/closing of valve 13; it

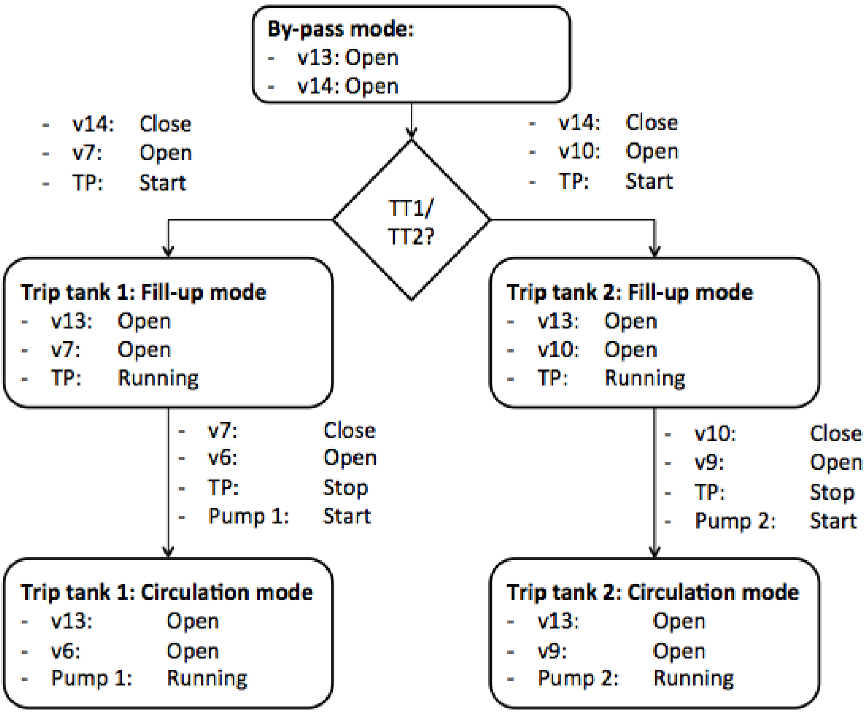


Figure 5.2: Operational modes.

should remain open all the time. We have tacitly assumed that the valve is located some distance away from valve 14, so that an error of commission during the closing of valve 14 resulting in the closing of valve 13 is highly unlikely.

The top event ’Primary well control failure during trip out of hole’ occurs when the event ’bottom hole pressure falls below pore pressure’ coincides with the conditions ’porous and permeable reservoir exposed’ and ’trip out of hole occurs’. The BHP might drop below the pore pressure as a result of either (OR-gate) the fluid column becoming too low (static) or swabbing (dynamic). The column reduction is a result of either (OR-gate) the trip tank system failing to replace the removed volume of equipment with mud or a loss of mud to the formation. In the WBS shown in Figure 2.6, we see that in essence all WBEs in the secondary barrier all function as part of a containment vessel for the mud. A WBE’s failure might therefore present a leakage path from the well and out to the formation or sea. However, the use of riser margin eliminates the potential for kicking due to disconnect or leakage at the BOP or above. Moreover, the preconditions of the HRA included a static well. This means that any leakage of mud from the annulus, be it inside the casing or in the open hole, must be caused by a breakdown of the formation. Thus, the only loss of mud considered is that which is caused by surging.

The minimal cut-sets are shown in Table 5.4. One can see that we have four minimal cut sets of first order. This result means we have four basic events whose individual occurrence is capable of causing the top event. The first event 'surging occurs due to o4 inadvertently lowering the drillstring' is an error of commission-type event. The initiation of an accident sequence from this event is conditionally dependent on the change in wellbore pressure exceeding the margin to the fracture pressure. This is represented by a house-event (on/off), since the breach of the margin to fracture pressure is not a fault per se. So, although it may appear as if the system is unprotected from this human error; this is not the case. It is just the breach of the margin to the fracture pressure that does not fit the fault tree logic, nor lend itself particularly well to quantitative modeling. A kick from surging will **not occur** with a probability equal to the HEP.

Cutset no.	Basic Event(s)	Order
1	{Basic 1}	1
2	{Basic 2}	1
3	{Basic 3}	1
4	{Basic 4}	1
5	{Basic 10, Basic 20, Basic 21, Basic 22, Basic 23}	5
6	{Basic 9, Basic 20, Basic 21, Basic 22, Basic 23}	5
7	{Basic 7, Basic 20, Basic 21, Basic 22, Basic 23}	5
8	{Basic 8, Basic 20, Basic 21, Basic 22, Basic 23}	5
9	{Basic 16, Basic 20, Basic 21, Basic 22, Basic 23}	5
10	{Basic 15, Basic 20, Basic 21, Basic 22, Basic 23}	5
11	{Basic 13, Basic 20, Basic 21, Basic 22, Basic 23}	5
12	{Basic 14, Basic 20, Basic 21, Basic 22, Basic 23}	5
13	{Basic 19, Basic 20, Basic 21, Basic 22, Basic 23}	5
14	{Basic 11, Basic 12, Basic 20, Basic 21, Basic 22, Basic 23}	6

Table 5.4: Minimal cut-sets: Primary well control failure during trip out of hole.

The next basic event in a minimal cut-set of first order is 's1 calculates max pulling speed which is higher than actual max pulling speed'. Implicit in this basic event is the assumption that the driller (o4) will always pull at the maximum allowable speed - as communicated to him by the mud logger (s1). The incorrect calculation needs to err on the high side, since a calculated max speed which is lower than the actual max speed would not lead to swabbing. A calculation like this includes both diagnosis (evaluation of state of system; especially drill pipe and BHA geometry) and action (input of values to software; use of software etc.). Arguably, the conditional probability of error on the high side, given incorrect calculation, could be assumed to be 0.5. This means that a calculated value which is lower than the correct value is equally as likely as a value higher than the correct one. Whether or not this is a valid assumption, is however unclear.

Basic 3 'o4 deliberately pulls pipe too fast due to time saving' is a violation; a purposeful deviation from required practices due to risk taking. HRA methods generally do not attempt to quantify such errors, although the human error classification schemes presented in the theory section covers them. For instance, an action which is performed to too great an extent (i.e. too fast/slow/much/little) falls within the error of commission category (Kirwan, 1994, p. 84).

The last critical event, basic 4 'o4 fails to continuously monitor pulling speed during pull' is arguably a slip occurring at the skill-based level. Reading a number from a visual display constitutes diagnosis, not action. Again, the error must be on the side which allows for a higher pulling speed than tolerated by the drilling window. It would not be correct to assume that a driller who does not check the pulling speed during a pull automatically would pull *faster*. He could just as well pull *slower*, or even retain his speed. So, though not explicitly stated in the fault tree (due to space-limitations) this important distinction needs to be made.

The classification of basic events appearing in first order cut-sets are summarized in Table 5.5 below. Since errors of commission are very difficult to both predict and quantify, HRA methods making use of expert judgement should be used for quantification of these. ATHEANA (see NUREG-1880 (Forester et al., 2007)) would be suitable for such purposes, as it enables quantification of unsafe acts including EOCs. SPAR-H does not distinguish between EOOs and EOCs. Instead it applies the same base error rates across both types of errors.

Basic event no.	**Action/Diagnosis**	**EOC/EOO**
1	Action	Error of commission
2	Both	Error of commission
3	Action	Error of commission
4	Diagnosis	Error of omission

Table 5.5: Classification of basic events 1, 2, 3 and 4.

The guidance provided for SPAR-H state that '*the explicit representation of omission versus commission is an issue left to the analyst and is part of the error identification and modeling process constituting HRA. This is in contrast to other, more in-depth methods such as ATHEANA, which focuses on the identification and quantification of errors of commission.*'(Gertman et al., 2005, p. xviii). The author interprets this to say that SPAR-H *can* be used for EOCs, but ATHEANA is likely to be more accurate.

Chapter 6

Discussion

The main result from this qualitative study indicates that the probability of kick occurrence during tripping out of the hole is likely to be dominated by human error causing surging/swabbing. These errors are individually capable of causing a kick, whereas the errors pertaining to the trip tanks are not. The minimal cut-sets do not contain the house events which reflect the breach of the margin to the pore and fracture pressure. As stated previously, neither surging or swabbing will occur with a probability equal to the HEPs associated with these events. Despite this, it would not be an implausible proposition to say that the lower the pressure margins are, the less room for human error there will be. The *limits of acceptability* (see sect. 2.2.2) become narrower. In this view, the HEP can be viewed as an upper-bound probability for surging. The effect of a trip tank system failure on kick probability is marginal, as shown by the fifth and sixth order minimal cut sets. This is due to the extensive human redundancy modeled.

To question this result, we can compare it to other research on kick causes. In a study by Holand and Awan (2012), kicks recorded on 259 wells spudded in the period 2007-2009 in the US Gulf of Mexico OCS are analyzed. Out of five kicks occurring during POOH, 1 kick is listed with 'annular losses, swabbing' as primary causes. Two kicks are due solely to swabbing, and one kick is due to a combination of swabbing and gas cut mud. The primary cause of the last kick is unknown. Holand and Awan (2012) states that '*Swabbing is typically a main contributor to kicks during tripping out of the hole. If the trip margin is low, the mud weight is cut by gas, or the well is improperly filled up, it is more likely that swabbing will cause a kick*' (Holand and Awan, 2012). This observation seems to be in correspondence with the results from the qualitative FTA. Yet, the binary split between improper hole-fill up and swabbing in the FTA is perhaps not. It is acknowledged that the HRA, which comprised task analysis, human error identification, screening and representation contains several assumptions and possible shortcomings. These will be discussed here in the order they appear in the main text. Lastly, a discussion regarding quantification will be given.

6.1 Chosen approach and limitations in the HTA

The task analysis analyzes a normal routine operation which is performed several times on every well drilled. It depicts what the operators *should* do to achieve the goal 'trip out of hole'. The task is not as much a safety critical one[1], as for instance a shut-in or kill circulation would be. The chosen approach is therefore somewhat unconventional, seeing as how HRA methods and QRA methods alike generally focus upon post-initiator response and recovery. Although there was prior knowledge that the task was related to a possibility of influx, the HRA revealed several potential HFEs with consequences further down the chain of events. These would not have been found if the HTA was directed at the right side of the bow-tie (post-kick). Making normal routine operations subject for analysis serves to broaden the consequence spectrum revealed by the HRA as a whole. An obvious disadvantage of adopting this approach, is that one spends a lot of time trying to understand and describe actions which are *not* relevant for major accident hazards.

There are some limitations of the HTA. If any abruption in the form of a technical failure or human error occurs during the sequence of actions, decisions and diagnosis activities depicted, the diagram is no longer valid. Such an abruption could occur at any time during the execution of the task. The required response could be very different depending on what occurs and when in the original sequence the abruption occurs. The diagram therefore depicts no more than a 'perfect performance'. A second limitation lies on the drilling technology side. When performing POOH in areas where swabbing is likely, top drive rigs can be used to pump mud out of the bit while pulling a stand. This limits the risk of swabbing (Holand, 1997). The precaution is not included in the HTA because it does not correspond to the normal performance of the 'trip out of hole' operation. 'Pumping out' is done in high risk intervals only, where the possibility of swabbing has been identified and assessed (........, 2013). In the study by Holand and Awan (2012), one kick occurred during the activity 'POOH and circulate'. This kick is listed as a separate activity from 'POOH'. Not including 'POOH while circulating the well' in the HTA should consequently not represent the normal execution of 'trip out of hole' inaccurately.

The reader might also have noticed an illogical element in the HTA diagram. At the top level, the diagram is split between 'preparing for tripping' and 'pull out of hole'. In the further decomposition of the first subtask, we see that the operators are required to 'pull 5-10 stands wet'. One might argue that this action belongs to 'pull out of hole'. The reason it is not placed there is that pulling 5-10 stands wet is a precaution. To pull dry pipes, one displaces the mud in the

[1]From NORSOK D-010: **critical operation or activity:** activity or operation that potentially can cause serious injury or death to people, or significant pollution of the environment or substantial financial losses (NORSOK, 2013a).

string with a slug of heavy mud. This degrades the ability to sustain volume control to some extent, due to the u-tubing effect (pressure equalization). The operators therefore pull some pipes wet, flow check the well and *then* pump the slug. The first stands are more likely to cause swabbing, which makes accurate volume control all the more important.

6.2 Comprehensiveness of the HEI

The human error identification (HEI) was performed by applying guide words deemed appropriate to each step in the HTA. Guide-words applied to an action or diagnosis will always represent failure of the parent (i.e. subtask or sub subtask) of the action or diagnosis in question. This justifies not applying guide words to some of the higher-level entries in the HEI sheet.

The HEI is the most critical stage in the HRA (Kirwan, 1994). Failing to identify an important error is congruent with an underestimation of risk. A natural question is therefore to ask if the HEI presented here is exhaustive; have indeed all possible errors been identified? This question is difficult to answer, particularly due to the methodology used in this report. Incident logs and databases can be valuable supplements to an HEI, but no such sources of information have been available to the author. The HEI is therefore somewhat subjective, in that it simply states what the author finds to be credible errors.

Another very important weakness in the HEI lies in errors of commission. If we consider for instance the action 'close v14' and apply the guide words 'right operation on wrong object', how do we know what other valves or similar equipment we should consider? An error of omission is a single point in failure-space, but an error of commission can theoretically represent an infinite set of points. To overcome this severe limitation, judgement must be exercised. We assumed that an EOC on 'close v14' would not lead to closing of v13. If the two valves are located in separate rooms, this would be a good assumption. It is however impossible to evaluate the validity of the assumption without seeing e.g. drawings of the system as built.

There are several PSFs from SPAR-H noted in the rows of the HEI sheet. These are to be interpreted as being potentially relevant for the particular HFE, **not absolute**. For instance, when monitoring the pulling speed on a visual display it is intuitively obvious that ergonomics/HMI will be important. When calculating volume per stand of pipe pulled, experience and training is judged to be a key factor. Furthermore, when performed on a computer the HMI will likely be central. If for instance pipe volumes for typical pipes are tabulated in a clear manner, it becomes easier for the operators to fill out the sheet. In this manner, performance is increased and the HEP is lowered. Errors without PSFs assigned are not to be understood as having a nominal

HEP. There has just not been enough information available to assign PSFs. Coming up with a valid assignments of PSFs would require one or several observation(s) of the task on an actual rig. Then, and only then, can all relevant factors influencing performance be assessed. This is obviously a limitation of the study.

6.3 Weaknesses and limitations in the fault tree

There are several weaknesses and limitations in the fault tree which need to be addressed. First of all, a discussion regarding HFEs, faults or environmental events or conditions not included in the tree is found necessary. Secondly, the extensive human redundancy in the fault tree is discussed.

6.3.1 Contribution to surging and swabbing

Beginning at the top level, we see that the contribution to surging is entirely human. The control system on the driller's chair and the draw works were not part of the system description. The result therefore assumes that a draw work failure does not cause the string to be dropped from an elevated position. The top drives on modern rigs such as the one described in this text are mounted on rails. They are not freely suspended by wires below the crown block. Should the brakes on the draw works fail, a wire fail in tension, or other relevant failures occur emergency brakes on the top drive itself will prevent it from falling. There is considerable amount of hardware redundancy preventing the top drive and elevators from falling. This is why it has been neglected as contributor to surging. Had it been included, we would have to specify that the drop must occur from a sufficiently elevated position. If a failure occurs with the elevators just above the drill floor, the peak downward velocity of the pipe will be low. The velocity required to cause surging, and hence the critical position of failure, would have to be determined by modeling the physics of the problem.

A relevant environmental condition to surging would be rig heave. It could theoretically cause both surge and swab. The reason it is not explicitly modeled as a contributor is that swab calculations by the mud logger will include rig heave velocities. To the extent we can talk about operational barrier elements preventing heave motion from influencing kick probability, the calculation by the mud logger is the only one. The same also holds true for hole geometry, mud properties and well inclination. These factors have been accounted for indirectly.

6.3.2 Hardware modeling

A good way to question the validity of the technical part of the tree is to compare it to its corresponding reliability block diagram. The overall structure should correspond to the RBD found in Figure 6.1, where we have assumed it to be equally likely that the switch starts up in position 2 as position 1. By trip tank *system*, we mean pump, piping and alignment of valves. The switch is in our case the human operator (usually assistant driller).

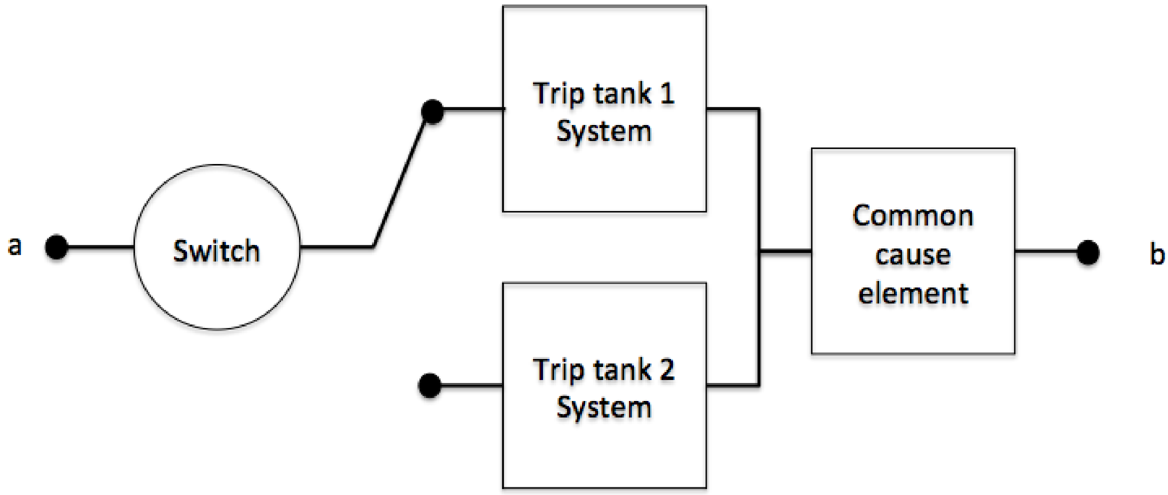


Figure 6.1: Reliability block diagram corresponding to the fault tree.

From the RBD we see that system failure occurs in five distinct ways:

1. Trip tank system 1 fails, and switch (i.e. operator) fails to line up trip tank 2.
2. Trip tank system 1 fails, and switch (i.e. operator) lines up trip tank 2. Trip tank 2 then fails.
3. Trip tank system 2 fails, and switch (i.e. operator) fails to line up trip tank 1.
4. Trip tank system 2 fails, and switch (i.e. operator) lines up trip tank 1. Trip tank 1 then fails.
5. Common cause failure occurs, putting both systems out of operation[2].

If the components in TT system 1 are identical to those in TT system 2, system failures 3 and 4 would be identical to 1 and 2. The fault tree does however not contain all the events above.

[2]**Example:** Power-outage and failure of emergency power generation would render both pumps inoperable. This would be a common cause failure.

It could therefore be argued that page 2 of the tree is incorrect, since it does not reflect the reliability of the trip tank system. This argument is in fact valid. We understand reliability as *'the ability of an item to perform a required function, under given environmental and operational conditions and for a stated period of time (ISO 8402)*' (Rausand and Høyland, 2004). The fault tree does not reflect the system's reliability, specified in terms of fixed functional requirements. The reason lies in the system's physical link to well pressure. Failing to line up the redundant equipment, e.g. 'fail to line up trip tank 2' is not stated in the tree. Instead, it says 'fail to stop tripping operation'. This is because we are only interested in the top event 'primary well control failure'. A pump failure does not cause pressure reduction in the well if the driller stops pulling drill pipe. That is to say, when the tripping operation is paused the 'hole fill-up' criteria to *avoid* a kick would be 0 $[m^3/h]$. Thus, 'fail to stop tripping operation' *does* correspond to detecting trip tank failure and then performing line up of the other tank. The essential thing with respects to kick occurrence is however stopping the operation. This is also the reason why secondary failures are not included in the tree. The 1-out-of-2 gate on the trip tanks' individual failures reflects the fact that both lines can not fail individually at the same time. An ordinary OR-gate would have credited the union of the trip tank failures (TT1 $\cup$ TT2) for contributing to 'fail to ensure hole fill-up'. When running only one tank at a time, it is logical that the tree demands that exactly one out of the two tanks fail.

6.3.3 Human Redundancy

A third point to address regarding the fault tree is the considerable amount of human redundancy modeled. Kirwan (1994) warns against excessive use of AND-gates to reflect human redundancy. He states that during quality assurance of a HRA, all events beneath an AND-gate should be double-checked to ensure that they *must* occur before the event above the gate occurs (Kirwan, 1994, p. 304). In this study, four basic events appear in each cut-set describing failure of the trip tank system. The modeling suggests that the driller and mud logger individually monitor two separate indicators from the trip tank; namely the flowmeter and the trending of the volume in the tank. A good way to question the validity of this modeling is to look at its corresponding path-set. To do this, we simply turn each human error into its logical opposite, and replace the AND-gate with an OR-gate. The tree then says that the cut-sets for the trip tank system will *not occur* if one or more of the following basic events occurs:

1. The mud logger notices that there are no returns from the well between slips[3].
2. The mud logger notices that the fluid level remains stable when pipe is being pulled.

[3]**Explanation:** When between slips (i.e. when breaking connection and racking pipe) with the TT pump on, excess returns should be observed on the flowmeter. This is an indication that the riser is full.

3. The driller notices that there are no returns from the well between slips.

4. The driller notices that the fluid level remains stable when pipe is being pulled.

This is in correspondence with the assessed procedures (. . . . ., 2013). In discussing this topic with Strandos (2014), he further added that if the well is particularly challenging, it is common that the tool-pusher and drilling supervisor also monitor these indicators on their respective screens. The AND-gates are therefore deemed appropriate.

6.4 Combining human error and hardware failure

In general SPAR-H, as well as several other HRA methods, decompose a task into smaller and more manageable elements of behavior. The HEI and quantification is performed on these small elements (e.g. action or diagnosis), and they are combined by the use of logic trees to produce a HEP for the task as a whole. In (Gould et al., 2012), predicted HEPs for high-level tasks including *Monitor well status*, *Stop drilling*, *Verify in-flow*, *Close BOP* and *Kill well* are presented. Had such an approach been adopted for this case study, the HRA would produce one single HEP for the task 'trip out of hole'. We would then have calculated the mean probability of human error in tripping operations. This 'task error', as opposed to the 'action errors' or 'diagnosis errors' it constitutes, could not easily have been combined with basic events containing hardware failure. The effective use of the method therefore relies heavily on the identification and definition of tasks. In a QRA/PRA context, this task definition would fall within the system reliability analyst's area of responsibility. If for instance a Safety Instrumented System (SIS), comprising sensors, a logic voting unit and actuators, has a manual switch, the identification of the task (or possibly even the HFE of interest) would be easy. The task would be 'press manual switch when required[4]' and the HFE of interest would be 'Operator fails to operate manual switch when required'. Such an isolated and precisely defined task would be well-suited for HRA. However, in the context of pressure control in drilling operations, the tasks are far more diverse. Many of them do not conform to a static, unambiguous and clearly bounded success criterion. Consequently, the identification of HFEs in relation to system failure becomes more difficult.

[4]'When required' would naturally have to be specified in terms of some system parameter, environmental event or accident scenario.

6.5 Performing quantification

Quantification for the human errors by SPAR-H require the assignment and rating of PSFs. The author has identified some potential problems in performing human error quantification. These will be discussed here, along with suggestions for potential solutions. Suggestions for quantification of hardware faults is also given.

6.5.1 Nonorthogonality of PSFs

The PSFs used by SPAR-H are nonorthogonal. Another way of stating this is that they are not mutually independent. Consider for instance a task with a 'nominal' complexity. If the operator is required to perform this action on a piece of equipment that has a poor HMI, it would obviously make the task more difficult for him to perform. A poor HMI would add to the difficulty and possibly ambiguity in performing the task; elements which are supposed to be covered by the complexity PSF. Although Gertman et al. (2005) does provide qualitative guidance on these issues, no quantitative way of accounting for interdependencies is given. This is seen as a problem, as it raises requirements for experience and knowledge on the part of the HRA analyst. As with any HRA method, different HRA analysts analyzing the same task *should* produce the same HEP(s). In the BORA project, such dependencies were modeled using a Bayesian Belief Network (BBN) (Aven et al., 2006). This is however a different approach to QRA/HRA.

6.5.2 Dependency between HEPs

Another quantification issue is that the errors, as they are modeled, are divided between the assistant driller (opening/closing valves), the driller and the mud logger. All detection errors regarding trip tank system/hole fill-up are attributed to the driller and mud logger. There is thus a considerable amount of dependency between the separate errors committed by each of these persons. For instance, the driller failing to respond to low-level alarm and driller failing to notice no flow from flow return meter can not be considered independent events. The two errors concern the same person at the same point in time and they occur at the same location. A complete dependency level is therefore warranted in the HEP adjustment, according to the guidelines in the SPAR-H method (Gertman et al., 2005). Both the diagnosis activities (i.e. watching pit volume trend and flowmeter) should in theory be carried out in parallel. However, the trending on the volume is more likely to dominate during POOH. The flowmeter is predominantly used to flow check the well (i.e. turning of the trip tank pump) and automatic calculation of inflow through software. Thus, dependency between basic event 20 and 21 should be so that basic event 20 is completely dependent upon occurrence of basic event 21. For the mud logger the same applies. Basic 22 should be adjusted for dependency upon basic event 23.

6.5.3 Hardware data

Quantification of the pump and low-level alarm should be performed by standard methods from reliability theory found in e.g. Rausand and Høyland (2004). The pump was not broken down further into e.g. shaft, impeller, bearing, casing, electrical motor etc., in the fault tree because it is likely that data (lifetime distribution parameters) will be available at the *unit* level, as opposed to *component* levels. Common cause failure rate can be modeled by the β-factor model (Rausand and Høyland, 2004). If the failure rate(s) (λ) for the pump(s) are field data, which is the case with e.g. OREDA data, common cause failures will be included. Then, $\lambda^{(i)} = \beta(1-\lambda)$ should be input for pump failures in the fault tree, and $\lambda^{(c)} = \beta\lambda$ should be used for the common cause basic event. β, the ratio of common cause failures to all failures for the unit, must be estimated.

6.5.4 Top event probability

CARA Fault Tree, and several other softwares like it, uses what is called the upper bound approximation in quantifying top event probability (Rausand and Høyland, 2004). In this approximation, the fault tree's top event is calculated by an OR-gate whose inputs are the various minimal cut-sets of the tree. Mathematically, this means that top event probability at time t is expressed as (Rausand and Høyland, 2004):

$$Q_0(t) \approx 1 - \prod_{j=1}^{k}(1 - \hat{Q}_j(t)) \qquad (6.1)$$

where

$Q_0(t)$	probability that top event occurs at time t
$\hat{Q}_j(t)$	probability that minimal cut parallel structure j fails at time t
k	total number of minimal cut-sets

The term $\hat{Q}_j(t)$ represents an AND-gate of basic events with probability $q_i(t)$, such that:

$$\hat{Q}_j(t) = \prod_{i \epsilon K_j} q_i(t) \qquad (6.2)$$

where K_j denotes cut-set number j. This means that $Q_0(t)$ is approximated as:

$$Q_0(t) \approx 1 - \prod_{j=1}^{k}[1 - \prod_{i \epsilon K_j} q_i(t)] \tag{6.3}$$

What we mean by '*upper bound approximation*' is the fact that $Q_0(t)$ will be lower than the term at the right side of equation 6.3 if one or more basic events appear in several minimal cut-sets. In the fault tree developed in this thesis, the four basic events for detection errors occur in all the minimal cut-sets for the trip tank system. Thus, the upper bound might produce an overly pessimistic top event probability. Moreover, if any of the basic events in the tree are given a probability $q_i(t)$ of the order 10^{-2} or larger, the upper bound approximation might no longer be a good one (Rausand and Høyland, 2004). This should be kept in mind when assigning HEPs for the tree. It is however most likely that basic events 1, 2, 3 and 4 will dominate the top event probability. The inaccuracy rooted in the trip tank system will in that case be negligible.

Chapter 7

Conclusion

7.1 Results from the analysis

The case study presented in this report indicates that continuous pressure control during trip out of hole is vulnerable to human error. In particular, the errors of commission relating to movement of drill string are not hindered by any technical means other than the design capacity of the draw works. As a consequence of this, requirements on the reliability of the actions performed by the driller are high. This in turn shows that operational barrier elements play a very direct role in the control of the primary well barrier. The barrier definition presented by the PSA seems to be well-suited for primary well control. This because operational barrier elements play an important part in realizing the barrier function. Using HRA methods to describe failure mechanisms in such holistic barriers is beneficial because the results can be used to suggest practical ways of preventing human error.

It can not be claimed that all relevant human errors for trip out of hole have been identified and assessed in this study. Deviations from expected performance may occur in an infinite number of ways, each potentially requiring its own task analysis and human error identification. The work has been aimed at identification and representation of human-induced initiators. Pre-initiator events (maintenance, calibration, testing etc.), human-induced initiators and post-initiator events are all possible to analyze with HRA methods (IEEE, 1997). The case study covers only one of these categories. Consequently several potential human errors, perhaps most notably in calibration and maintenance, may also affect the trip tank system and thus hole fill-up and kick-detection. The tripping operation itself is dominated by skill-based behavior, but the decision to initiate secondary well control is rule and knowledge-based. Hence, kick detection and response is likely to be more error-prone than the task studied here.

7.2 On the combination of QRA and HRA

The overall subject of this thesis has been the use of HRA in offshore QRAs. The motivation for using HRA methods such as those described in this text in a QRA is two-fold:

- Offshore legislation, guidelines and recommended standards require that they be accounted for (Skogdalen and Vinnem, 2011).
- The human potential for initiation and escalation of, as well as mitigation and recovery from, accidental events is an empirical fact.

NORSOK (2013b) states that '*an evaluation of the effect of human and organizational factors shall be performed. This may range from a qualitative discussion to a detailed analysis of human and organizational factors, depending on the criticality of such aspects for the risk picture.*'. Based upon the current work the author would argue that the criticality of HOFs in relation to pressure control is high. The requirements for evaluation of HOFs in the initiating event in a blowout QRA should therefore also be high. It is believed that a detailed quantitative analysis will serve to communicate the human contribution to risk better than a qualitative discussion, seeing as how the QRA itself is quantitative. Despite this, the true insight and value of any QRA or HRA remains in its qualitative parts. Quantification is merely a means to prioritize and communicate the various contributors to the total risk, so we know where our efforts of risk-reduction will be most effective.

In a conversation with Gould (2014) regarding this topic, it was mentioned that if the human contribution to event frequencies or probabilities remains in aggregated form, we have no basis for proposing error reducing measures. In the case of an initiating event such as a kick, this entails that we are unable to propose measures to avoid the very event we are spending a lot of effort on protecting ourselves from; namely a blowout. Although it is easy to agree with this notion, it also possible to object to it. Prediction and quantification of human errors is subject to considerable uncertainty. Furthermore, it is difficult to validate estimates provided by a HRA. How could we for instance empirically validate the probability of a human error under moderate complexity, poor HMI, extreme stress and inadequate time? Gertman et al. (2005) make the following statement: '*Historically, in quantifying HEPs, HRA practitioners have treated these influencing factors as independent. In reality, dependence is unknown when simultaneously considering such a large group of factors (PSFs).*'. The author would further add that PSFs, their interdependencies and effect on a particular HEP, can not be measured. In observing the occurrence of an error PSFs will already be present. Their status and potential variability with time will however be unknown. In this view, the HEP becomes a bayesian probability, measuring the degree of belief a HRA analyst has about the occurring value of the HEP.

The reliability of technical components is typically based on collecting failure rate data and fitting this data to a probability density function for the lifetime of a component. Reliability block diagrams or fault trees are used to express reliability and unreliability on subsystem or system level. To include human failure events in such a calculation, we must accept the following assumptions:

1. Human actions can be treated as components in a system
2. The probability for a particular action or inaction can be estimated
3. The factors influencing this probability can be identified and their influence on the probability expressed mathematically

We must also accept the potential double-counting effect which occurs if HFEs are already present in the data from which we base our calculations. Unless the human contribution is explicitly stated in the metadata, we are obliged to be conservative - and accept a potential overestimation of risk. The benefits from a thorough evaluation of human performance should outweigh the inconvenience that is a conservative (pessimistic) estimate of event probability. In the author's humble opinion, they are likely to do so.

Chapter 8

Suggestions for further work

A natural extension of the work presented in the thesis would be to repeat the process of task analysis, human error identification and representation for kick-detection and shut-in during trip out of hole. These responses to a kick are different from the ones required when a kick is taken during e.g. drilling ahead. It would be convenient to extend the fault tree by event tree analysis, since such a post-kick response is very sequence dependent. The fault tree's top event should be the initiating event in this event tree. Kick-detection, requiring firstly a shut-down of the trip tank pumps to check for flow, should be a pivotal event also subject to fault tree analysis. In the work presented here, a common cause potential has been identified between kick occurrence, kick-detection and secondary well control. This must be modeled, preferably by the β-factor model discussed previously. The author would also suggest quantification of the tree, but a prerequisite for this would be that each PSF is assessed during walkthrough, talk-through and observation of the tasks on an actual rig. Little value can be gained from quantification if the task is not observed in the actual environment in which it takes place.

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Appendix A

EAC: Fluid Column

Features	**Acceptance criteria**	**See**
A.Description	This is the fluid in the wellbore	NORSOK D-001
B. Function	The purpose of the fluid column as a well barrier/WBE is to exert a hydrostatic pressure in the wellbore that will prevent well influx/inflow (kick) of formation fluid	
	(table continues on next page)	

Features	Acceptance criteria	See
C. Design construction selection	1. The hydrostatic pressure shall at all times be equal to the estimated or measure pore/reservoir pressure, plus a defined safety margin (e.g. riser margin, trip margin). 2. Critical fluid properties and specifications shall be described prior to any operation. 3. The density shall be stable within specified tolerances under down hole conditions for a specified period of time when no circulation is performed. 4. The hydrostatic pressure should not exceed the formation fracture pressure in the open hole including a safety margin or as defined by the kick margin. 5. Changes in wellbore pressure caused by tripping (surge and swab) and circulation of fluid (ECD) should be estimated and included in the above safety margins.	ISO 10416
D. Initial test and verification	1. Stable fluid level shall be verified. 2. Critical fluid properties, including density shall be within specifications.	

Features	Acceptance criteria	See
E. Use	1. It shall at all times be possible to maintain the fluid level in the well through circulation or by filling. 2. It shall be possible to adjust critical fluid properties to maintain or modify specifications. 3. Acceptable static and dynamic loss rates of fluid to the formation shall be predefined. If there is a risk of lost circulation, lost circulation material should be available. 4. There should be sufficient fluid materials, including contingency materials available on the location to maintain the fluid well barrier with the minimum acceptable density. 5. Simultaneous well displacement and transfer to or from the fluid tanks should only be done with a high degree of caution, not affecting the active fluid system. 6. Parameters required for re-establishing the fluid well barrier shall be systematically recorded and updated in a ”kill-sheet”.	
	(table continues on next page)	

Features	Acceptance criteria	See
F. Monitoring	1. Fluid level in the well and active pits shall be monitored continuously. 2. Fluid return rate from the well shall be monitored continuously. 3. Flow checks should be performed upon indications of increased return rate, increased volume in surface pits, increased gas content, flow on connections or at specified regular intervals. The flow check should last for 10 min. HTHP: All flow checks should last 30 min. 4. Measurement of fluid density (in/out) during circulation shall be performed regularly. 5. Measurement of critical fluid properties shall be performed every 12 circulating hours and compared with specified properties. 6. Parameters required for killing of the well.	
G. Common well barrier	None	

Table A.1: Element Acceptance Criteria - Fluid Column. Table reproduced from NORSOK D-010 (NORSOK, 2013a).

Appendix B

Drilling: configuration

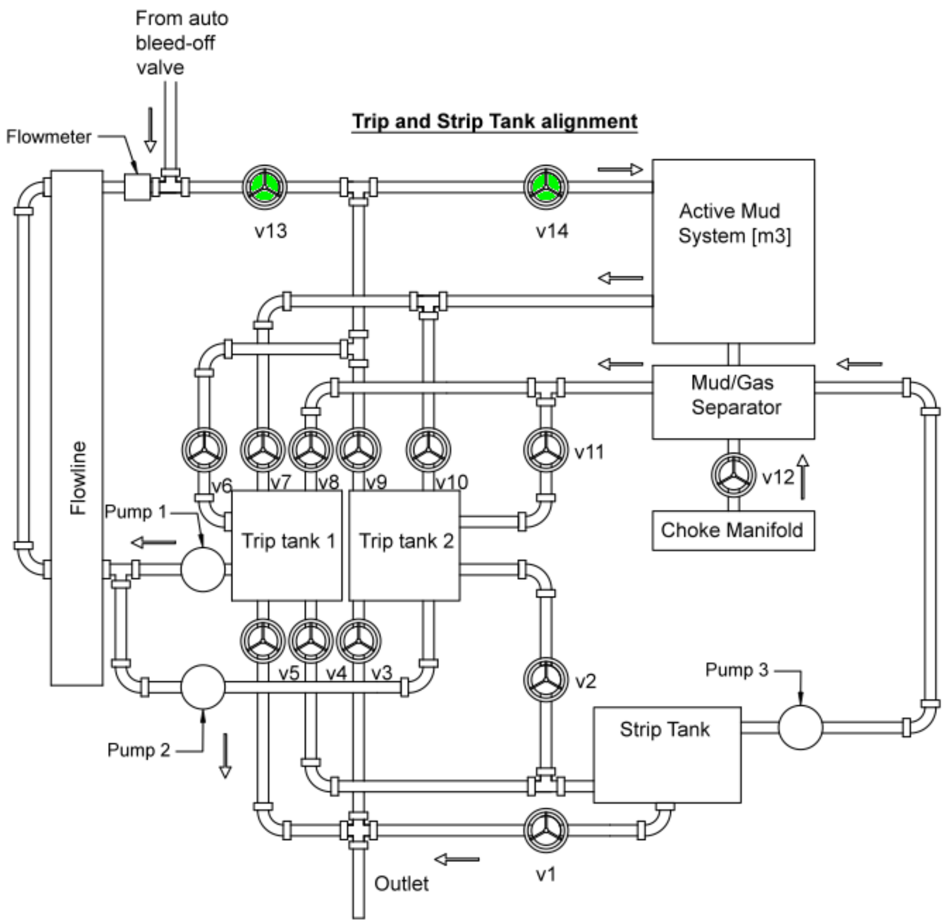

Figure B.1: Trip and strip tank alignment during drilling.

Note: Green color on a valve indicates the valve is in **open position**. Green color on a pump indicates the pump is **on**.

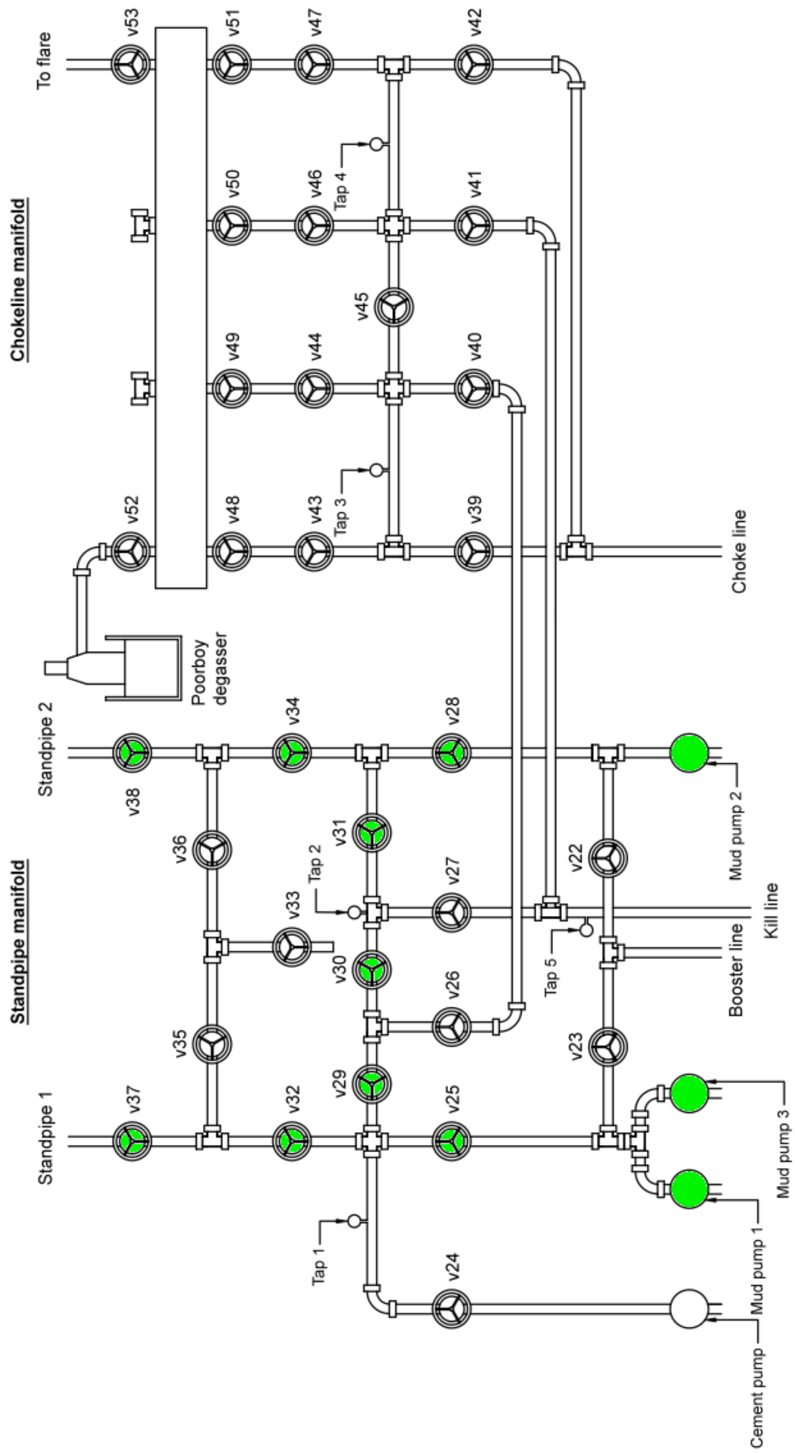

Figure B.2: Standpipe manifold and choke manifold during drilling.

Appendix C

Tripping: configuration

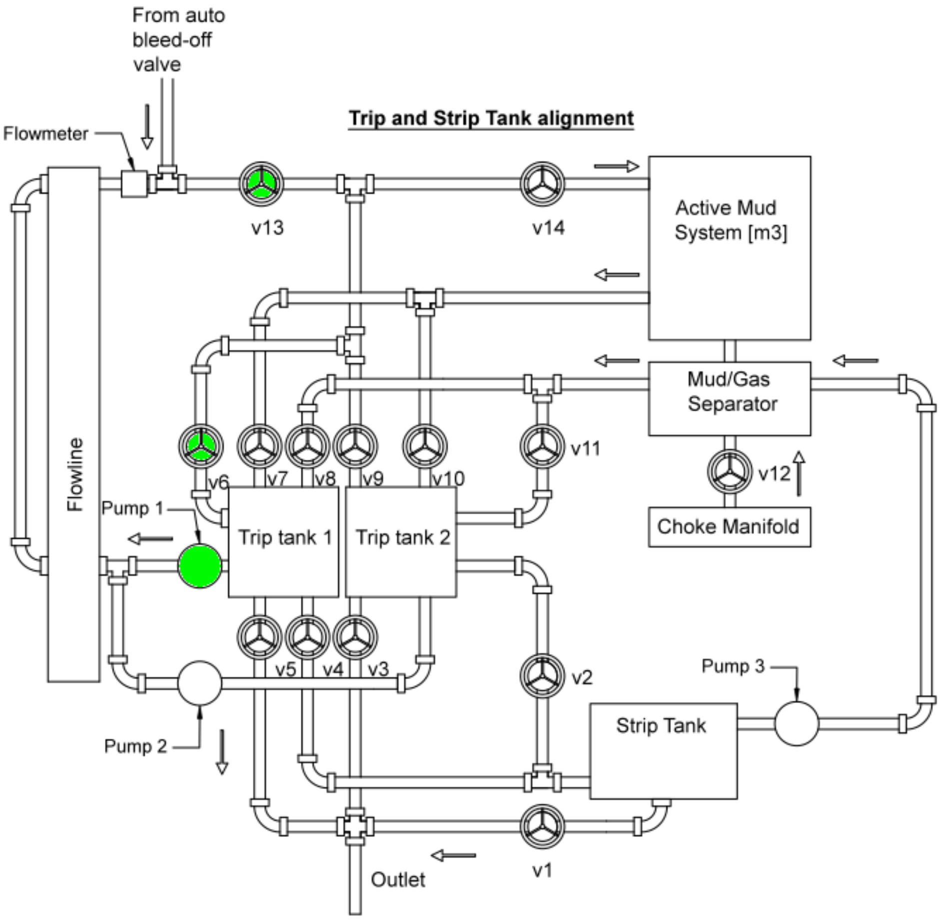

Figure C.1: Line up of trip tank 1.

Note: Green color on a valve indicates the valve is in **open position**. Green color on a pump indicates the pump is **on**.

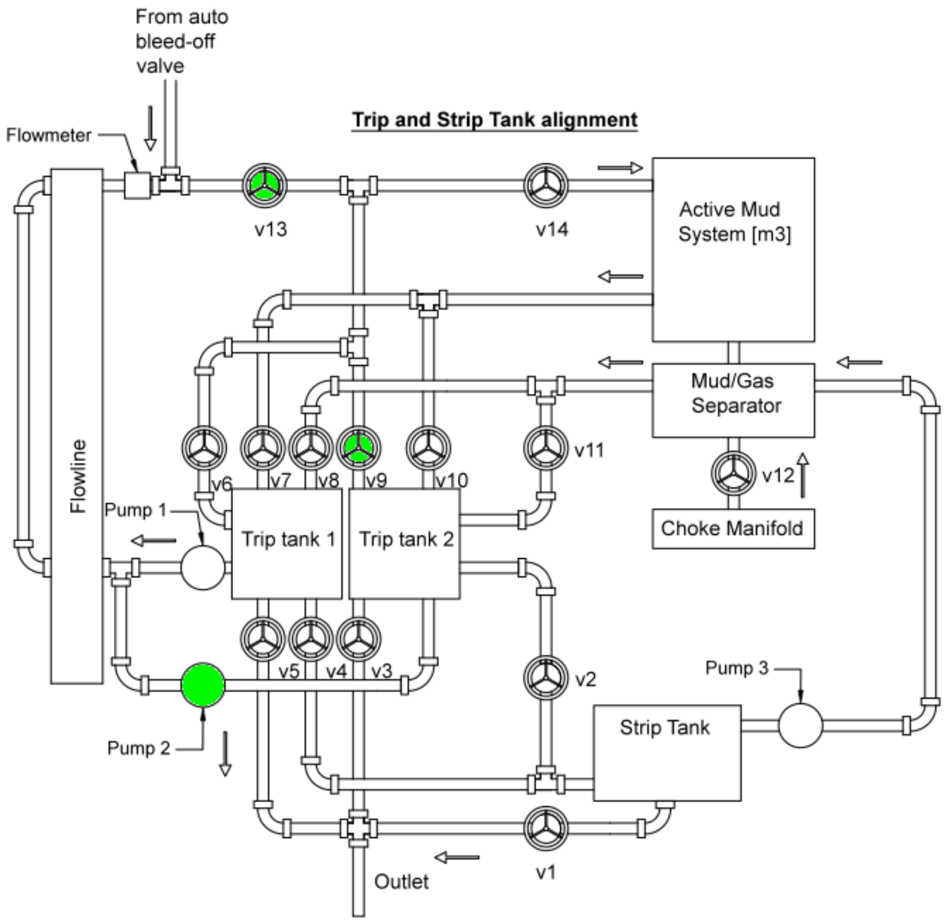

Figure C.2: Line up of trip tank 2.

Note: Green color on a valve indicates the valve is in **open position**. Green color on a pump indicates the pump is **on**.

Appendix D

Personnel and organization

Operator		Service Companies	
Ref.	**Position**	**Ref.**	**Position**
o1	Company representative	s1	Mud logging
o2	Captain	s2	Electric logging
o3	Toolpusher	s3	MWD logging
o4	Driller	s4	Mud engineer
o5	Assistant driller	s5	Cementing
o6	Derrick man	s6	Casing
o7	Drill crew	s7	Wireline
o8	Stability section leader	s8	Survey
o9	Crane operator	s9	Perforation
o10	Roustabouts	s10	DST services
o11	Subsea engineer	s11	Diving
o12	Marine department operators	s12	Wellhead manufacturer
o13	Standby boat captain	s13	Directional drilling
		s14	Equipment services

Figure D.1: Personnel and organization.

Appendix E

Choke operator console

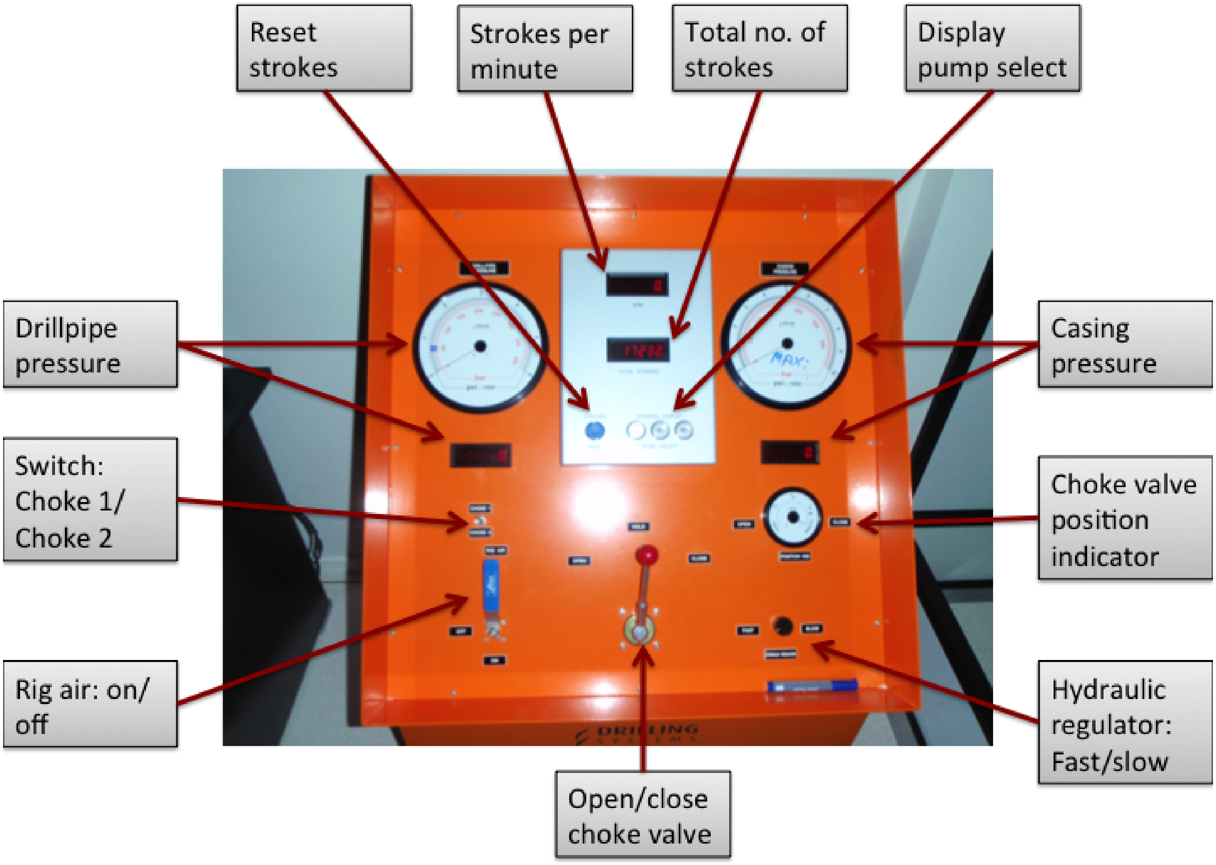

Figure E.1: Choke operator console. Image taken on Drillsim6000 at Bergen Maritime College.

Appendix F

Trending on driller's screen

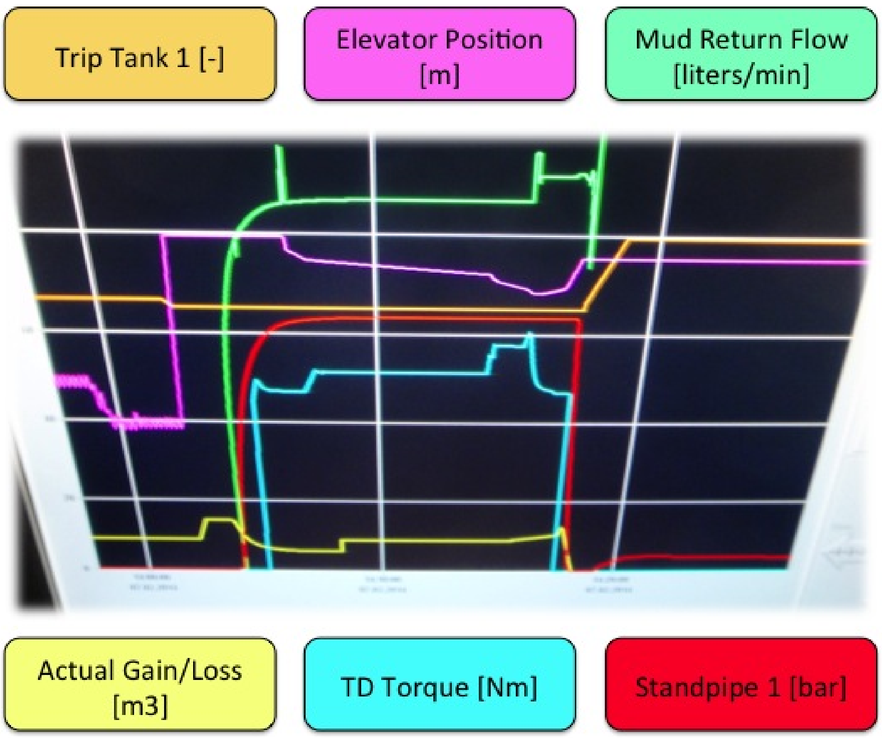

Figure F.1: Driller's right screen showing trends of drilling parameters. Image taken on Drill-sim6000 at Bergen Maritime College.

Appendix G

Hierarchical Task Analysis

Assessor:	Georg D. Tuset
Date:	March 4, 2014
Preconditions:	BOP installed
	Bit on bottom
	Top drive made up
	Mud pumps off
	Positive flow check
	Drilling stopped

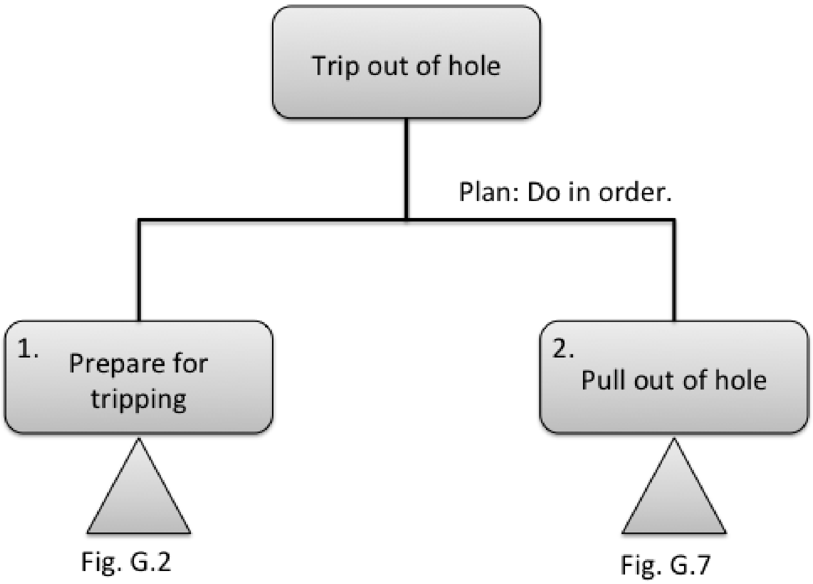

Figure G.1: HTA: Trip out of hole.

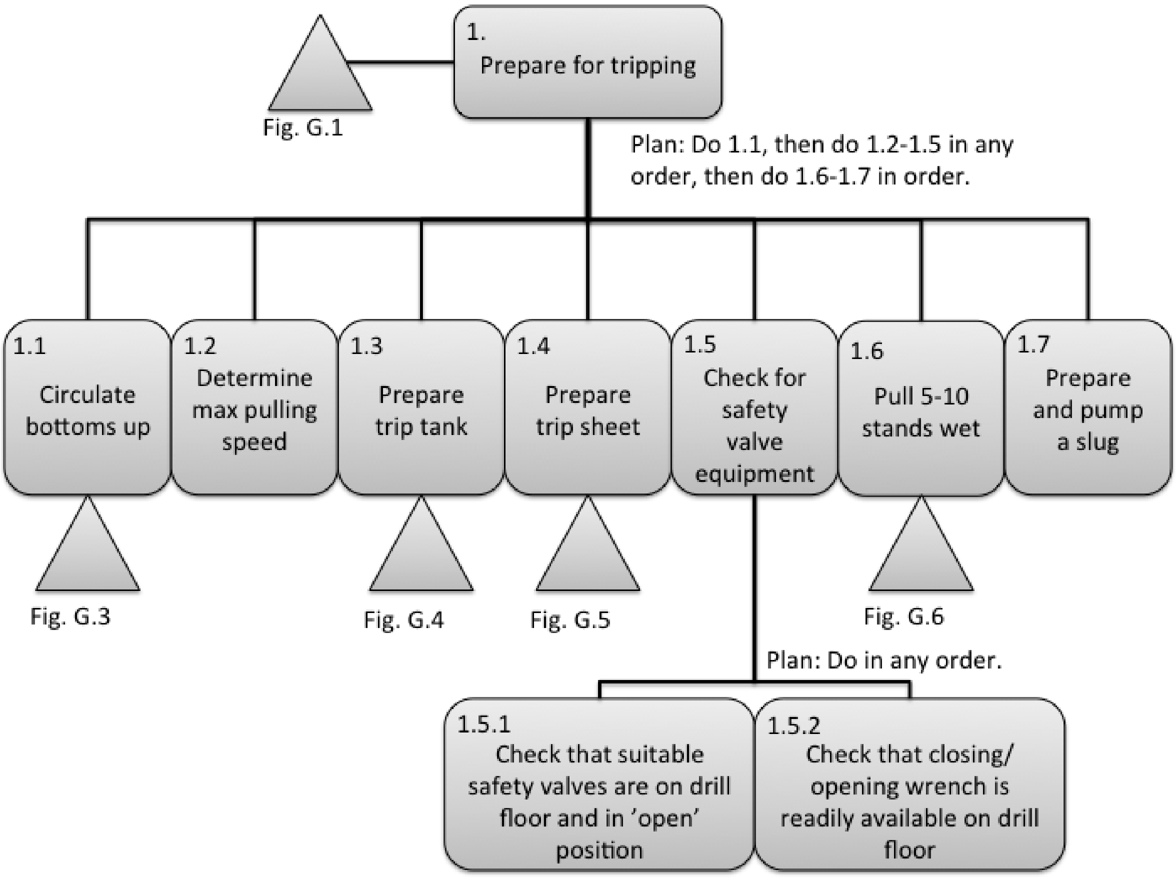

Figure G.2: HTA: Task 1: Prepare for tripping.

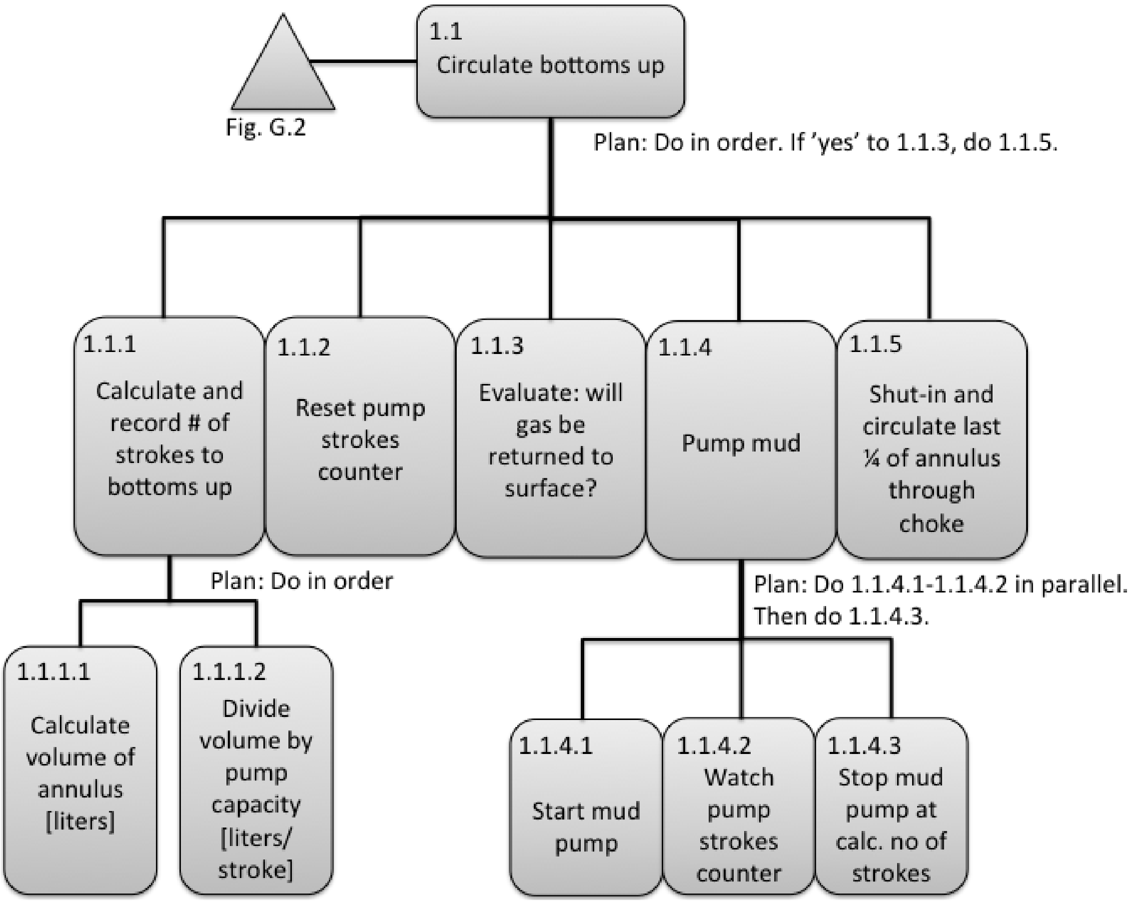

Figure G.3: HTA: Task 1.1 Circulate bottoms up.

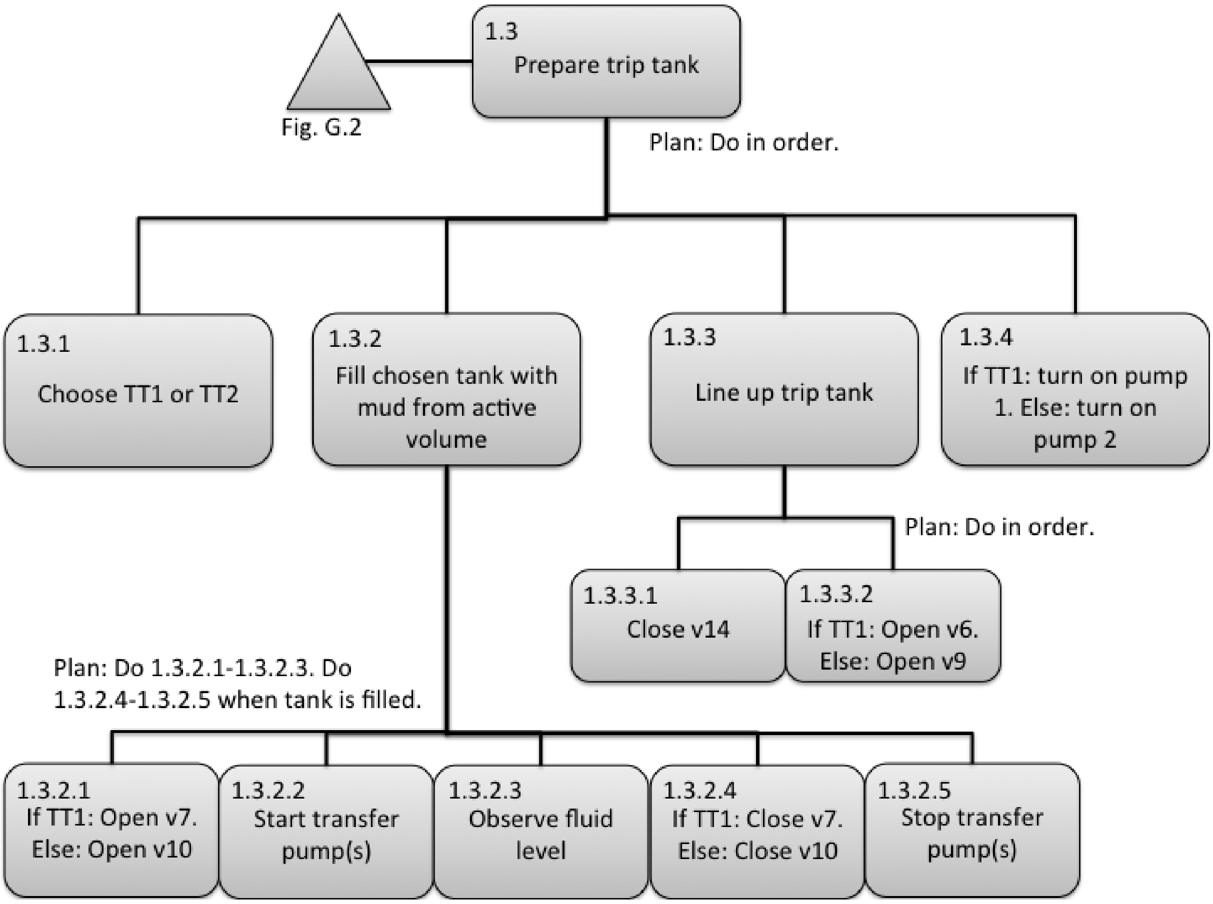

Figure G.4: HTA: Task 1.3 Prepare trip tank.

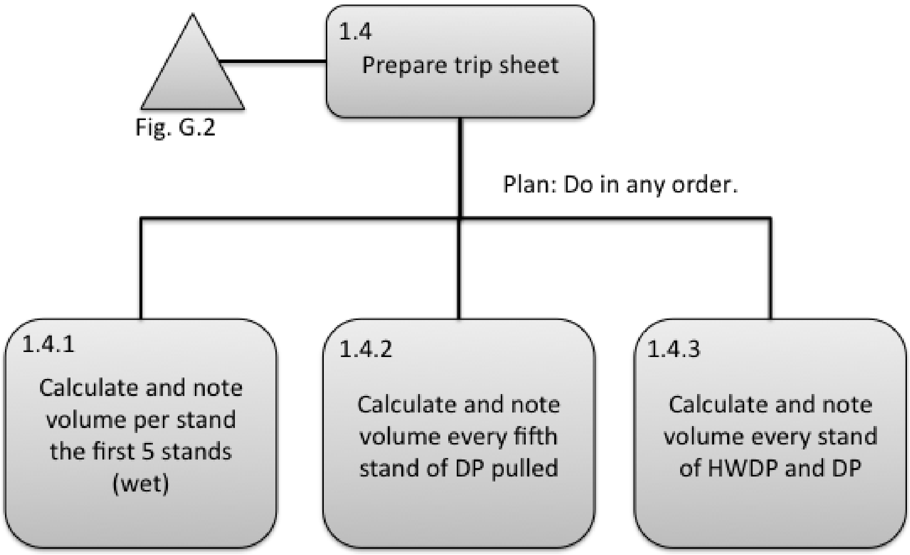

Figure G.5: HTA: Task 1.4 Prepare trip sheet.

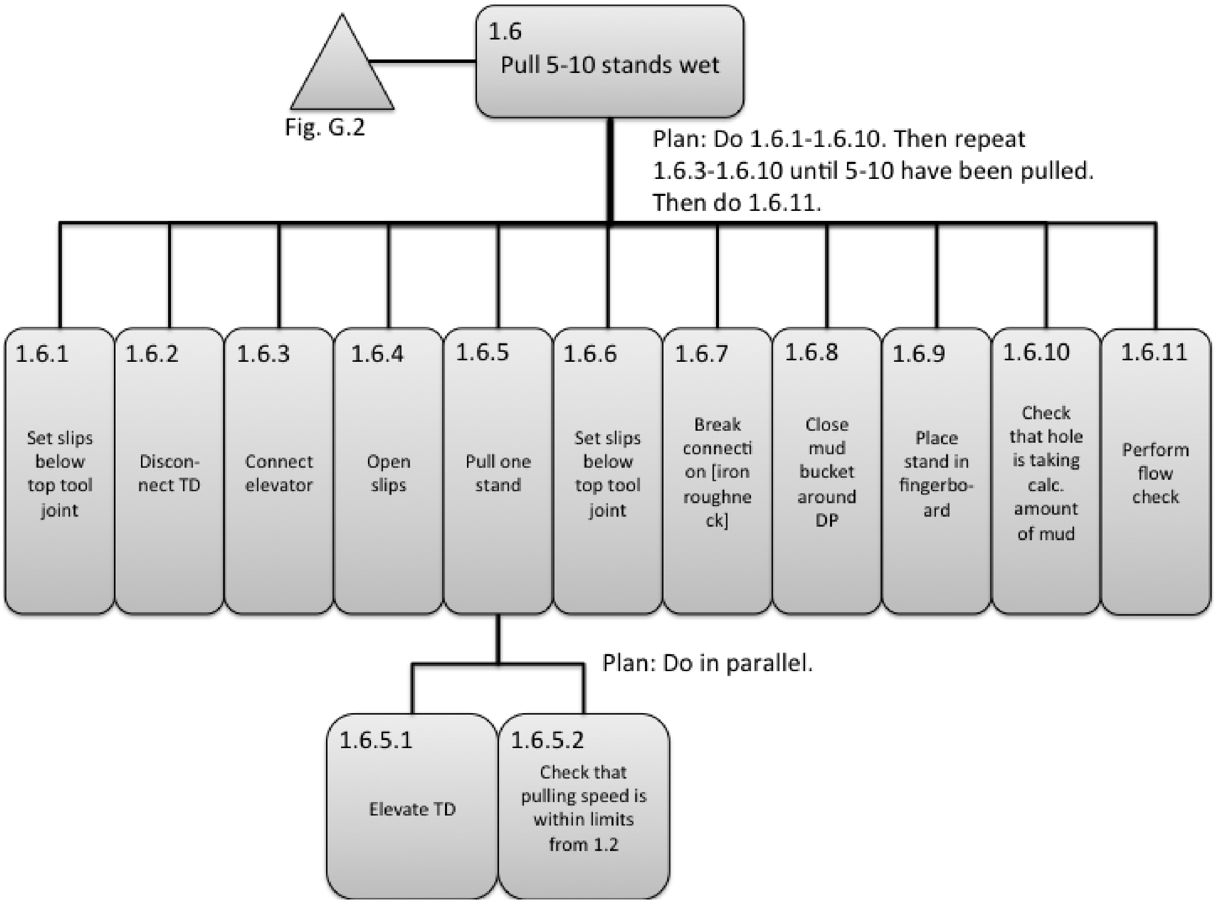

Figure G.6: HTA: Task 1.6 Pull 5-10 stands of DP wet.

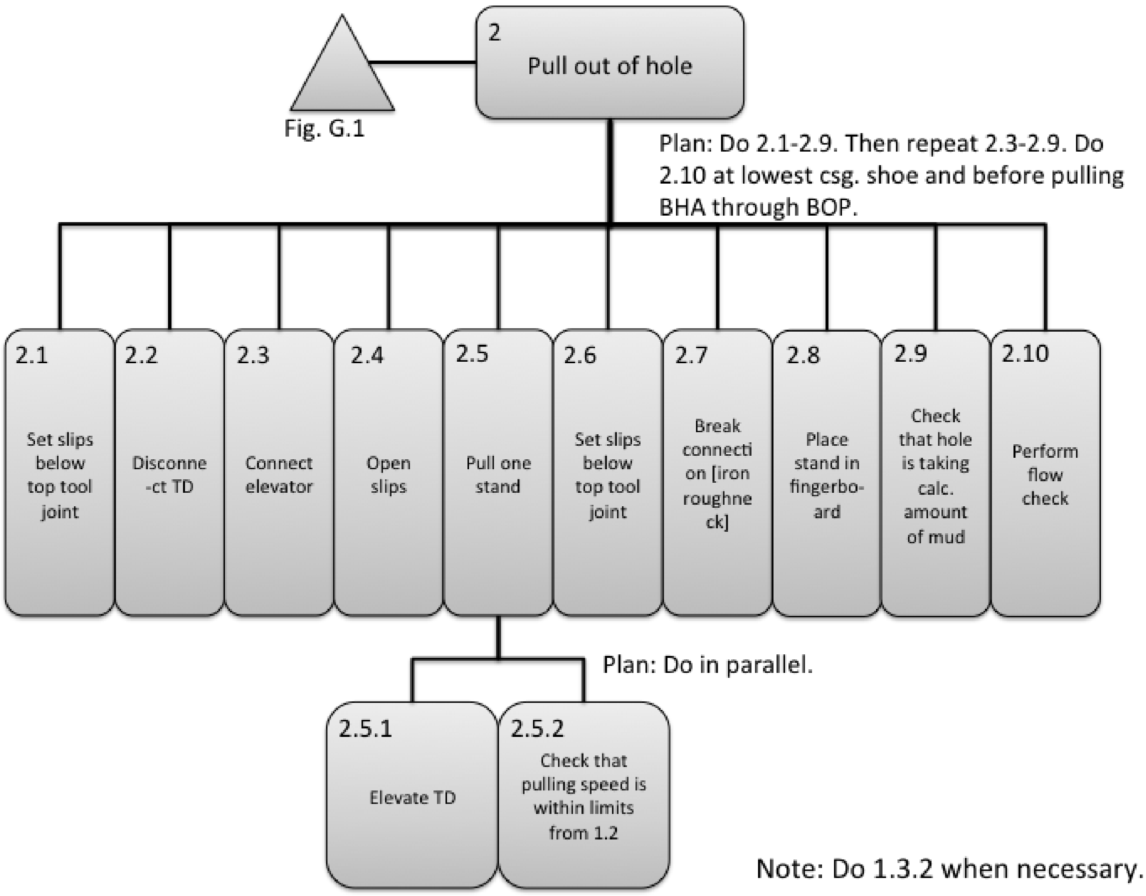

Figure G.7: HTA: Task 2 Pull out of hole.

Appendix H

Human Error Identification

Task ID. 1st level	2nd level	3rd level	Description	OP	Guideword	Potential human failures	PSFs	Potential to recover from the failure before consequences occur	Potential consequences if the failure is not recovered	Comments
1.1			Circulate bottoms up							
	1.1.1		Calculate and record # of strokes to bottoms up	o4	A9 Operation omitted	Fail to calculate and record # of strokes to bottoms up	Procedures, Experience/ training		Unable to determine when bottoms up is complete	
		1.1.1.1	Calculate volume of annulus [liters]	o4	S2 Wrong selection made	Calculation error: fail to select correct DP type in spreadsheet	Complexity, Experience/ training		Bottoms up not complete, mud not conditioned	
		1.1.1.2	Divide volume by pump capacity [liters/stroke]	o4	R2 Wrong information obtained	Calculation error: Fail to use correct pump capacity in bottoms up calculation	Complexity, Experience/ training		Bottoms up not complete, mud not conditioned	Perform operation with a different pump capacity than what was used in calculation.
	1.1.2		Reset pump strokes counter	o4	A2 Operation mistimed	Reset pump strokes counter after mud pumps are started	Ergnomics/ HMI, Stress/stressors	Observe that strokes counter meter is not nullified, then stop pumps and reset	Control of pumped volume lost	Action performed on push buttom
	1.1.3		Evaluate: will gas be returned to surface?	o1, o3, o4, s1	C1 Check omitted	Fail to evaluate if gas will be returned to surface		Review kick indicators; pit gain alarm and gas-returns alarm will go off at drillers cabin and mud loggers office.	Gas release in shaker-room	
					C1 Check incomplete	Insufficiently thorough evaluation		Review kick indicators; pit gain alarm and gas-returns alarm will go off at drillers cabin and mud loggers office.	Gas release in shaker-room	
	1.1.4		Pump mud		A5 Operation too slow	Use lower pump rate than used in calculations (see 1.1.1.2)			Bottoms up not complete, mud not conditioned	Failure has common cause with 1.1.1.2
		1.1.4.1	Start mud pump	o4	A5 Operation mistimed	Start mud pump before strokes counter is reset		Observe that pump strokes counter is not nullified, then stop pumps and reset.	Control of pumped volume lost	
		1.1.4.2	Watch pump strokes counter	o4	R1 Information not obtained	Fail to continously monitor strokes counter			Control of pumped volume lost	Total volume pumped and total number of strokes pumped visible on left screen in driller's chair
					R4 Information wrongly interpreted	Read wrong number of strokes due to faulty gauge			Control of pumped volume lost	Total volume pumped and total number of strokes pumped visible on left screen in driller's chair
		1.1.4.3	Stop mud pump at calc. # of strokes	o4	A11 Operation too early	Stop circulation before bottoms up is complete			Bottoms up not complete, mud not conditioned	

Task ID. 1st level	2nd level	3rd level	Description	OP	Guideword	Potential human failures	PSFs	Potential to recover from the failure before consequences occur	Potential consequences if the failure is not recovered	Comments
	1.1.5		Shut-in and circulate last 1/4 of annulus through choke	o4	A9 Operation omitted	Fail to shut-in and circulate last 1/4 of annulus through choke			Gas release in shaker-room	Failure has common cause with 1.1.3
1.2			Determine max pulling speed	s1		Incorrect calculation; calculated max speed higher than actual max speed			Swabbing in a kick	
1.3			Prepare trip tank	o4, o5	A9 Operation omitted	Fail to prepare trip tank before POOH			Improper hole fill-up	
					A12 Operation in wrong order	Start to fill tank with mud from active volume with TT pump on			Volume control lost; will appear as if mud has 'disappeared', i.e. lost returns	
	1.3.2		Choose TT1 or TT2							Inform o5 of decision and order him to start fill-up
	1.3.2		Fill tank with mud from active volume							1.3.2 is done both in preparations for POOH and during actual POOH
		1.3.2.1	If TT1: Open v7. Else: Open v10	o5	A7 Right operation on wrong object	Open v10 when supposed to open v7		Driller (o4) notices volume gain in TT2	No serious consequences	
					A7 Right operation on wrong object	Open v6 when supposed to open v7		Driller (o4) notices flow from return line	Loss of volume control	
						Open v8 when supposed to open v7			No serious consequences; v12 is closed and so is choke	
						Open v7 when supposed to open v10		Driller (o4) notices volume gain in TT1	No serious consequences	
						Open v9 when supposed to open v10		Driller (o4) notices flow from return line	Loss of volume control	
		1.3.2.2	Start transfer pump(s)	o4						
		1.3.2.3	Observe fluid level	o4, o5, s1	R1 Information not obtained	Fail to monitor fluid level during mud transfer to trip tank		Danger-full alarm will trip	Trip tank will overflow	
					R2 Wrong information obtained	Determine that tank is full before it actually is		Redundancy in TT monitoring; mud-logger and drillers cabin	Insufficient mud volume in trip tank; may lead to improper hole fill-up if not detected	Failure may be due to technical fault on level-metering (e.g. incorrect calibration)
		1.3.2.4	If TT1: Close v7. Else: Close v10	o5	A7 Right operation on wrong object	Close v10 when supposed to close v7		Danger-full alarm will trip	Trip tank will overflow	
					A7 Right operation on wrong object	Close v7 when supposed to close v10		Danger-full alarm will trip	Trip tank will overflow	

Task ID. 1st level	2nd level	3rd level	Description	OP	Guideword	Potential human failures	PSFs	Potential to recover from the failure before consequences occur	Potential consequences if the failure is not recovered	Comments
					A10 Operation incomplete	Closes valve, but not entirely			No serious consequences given that either v14 will be closed, and/or transfer pump(s) stopped prior to trip. If they are not: Volume control degraded	See 1.3.2.5, 1.3.3.1
		1.3.2.5	Stop transfer pump(s)	o4	A9 Operation omitted	Fail to stop transfer pump before starting line up of trip tank		Danger-full alarm will trip	No serious consequences given that v14 will be closed. If it is not: Volume control degraded	See 1.3.3.1
					A11 Operation too early	Stop transfer pump(s) before tank is filled		Driller (o4) and mud-logger (s1) monitors trip tank volume and find it insufficient	Insufficient mud volume in trip tank; may lead to improper hole fill-up if not detected	This is essentially the same failure as 1.3.2.3 (R2)
	1.3.3		Line up trip tank	o5	A9 Operation omitted	Fail to line up trip tank before POOH		Driller (o4) and mud-logger (s1) notices no flow from return line after starting TT pump	Improper hole fill-up and kick detection impossible	
		1.3.3.1	Close v14	o5	A7 Right operation on wrong object	Close wrong valve		Driller (o4) notices flow to active system has not stopped	None; since almost all other valves are already closed	
					A9 Operation omitted	Fail to close valve		Driller (o4) and mud-logger (s1) notices flow to active system has not stopped	None if transfer pumps are turned off. If transfer pumps are on, mud will be continously supplied to TT during POOH (see 1.3.2.5)	
					A10 Operation incomplete	Closes valve, but not entirely		Driller (o4) and mud-logger (s1) notices flow to active system has not stopped	None if transfer pumps are turned off. If transfer pumps are on, mud will be continously supplied to TT during POOH (see 1.3.2.5)	
					A11 Operation too late	Close v14 before TT is full of mud		Driller (o4) and mud-logger (s1) monitors trip tank volume and find it insufficient	Insufficient mud volume in trip tank; may lead to improper hole fill-up if not detected	
		1.3.3.2	If TT1: Open v6. Else: Open v9	o5	A7 Right operation on wrong object	Open v6 when supposed to open v9		Driller (o4) and mud-logger (s1) notices either (1) gain in wrong TT or (2) no flow from return line	Returns will be taken to one tank, and active pump lined up to another. Will lead to improper hole fill-up when pulling	Very unlikely since valves are located directly above tank, making diagnosis (i.e. "pairing" of valve and tank) easier
					A7 Right operation on wrong object	Open v9 when supposed to open v6		Driller (o4) and mud-logger (s1) notices either (1) gain in wrong TT or (2) no flow from return line	Returns will be taken to one tank, and active pump lined up to another. Will lead to improper hole fill-up when pulling	Very unlikely since valves are located directly above tank, making diagnosis (i.e. "pairing" of valve and tank) easier

Task ID. 1st level	2nd level	3rd level	Description	OP	Guideword	Potential human failures	PSFs	Potential to recover from the failure before consequences occur	Potential consequences if the failure is not recovered	Comments
					A9 Operation omitted	Fail to open valve		Driller (o4) and mud-logger (s1) notices either (1) volume loss in chosen TT or (2) no flow from return line	Overflow at return line, TT quickly emptied then improper hole fill-up when pulling	
					A10 Operation incomplete	Valve opened, but not entirely			Restricted flow from return line into TT; time for TT level to stabilize after setting slips lengthened	
					A11 Operation too late	Open valve after pump is turned on			Vacuum in TT, might damage piping, tank and pump	
	1.3.4		If TT1: Turn on pump 1. Else: Turn on pump 2	o4	A7 Right operation on wrong object	Turn on pump 1 when supposed to turn on pump 2		Mud logger (s1) notices either (1) TT pump has not started or (2) no flow from return line	No TT circulation; will lead to improper hole fill-up if not detected	
					A7 Right operation on wrong object	Turn on pump 2 when supposed to turn on pump 1		Mud logger (s1) notices either (1) TT pump has not started or (2) no flow from return line	No TT circulation; will lead to improper hole fill-up if not detected	
					A9 Operation omitted	Fail to start pump before POOH		Mud logger (s1) notices either (1) TT pump has not started or (2) no flow from return line	No TT circulation; will lead to improper hole fill-up if not detected	
1.4			Prepare trip sheet	o4, s1	A9 Operation omitted	Fail to prepare trip sheet before POOH		Driller (o4) and mud logger (s1) prepares trip sheet independently	Unable to monitor hole fill-up; kick detection impossible	
	1.4.1		Calculate and note volume per stand the first 5 stands (wet)	o4, s1		Incorrect volume calculation	Experience/ training, HMI	Driller (o4) and mud logger (s1) prepares trip sheet independently	Expected hole fill-up incorrect: will make driller suspect either lost returns or kick: unnecessary shut-in	Greatest consequence is non-productive time
	1.4.2		Calculate and note volume every fifth stand of DP pulled	o4, s1		Incorrect volume calculation	Experience/ training, HMI	Driller (o4) and mud logger (s1) prepares trip sheet independently	Expected hole fill-up incorrect: will make driller suspect either lost returns or kick: unnecessary shut-in	Greatest consequence is non-productive time
	1.4.3		Calculate and note volume every stand of HWDP and DP	o4, s1		Incorrect volume calculation	Experience/ training, HMI	Driller (o4) and mud logger (s1) prepares trip sheet independently	Expected hole fill-up incorrect: will make driller suspect either lost returns or kick: unnecessary shut-in	Greatest consequence is non-productive time
1.5			Check for safety valve equipment	o4						
	1.5.1		Check that suitable safety valves are on drill floor and in 'open' position	o4	C1 Check omitted	Fail to verify that suitable safety valves are on drill floor and in 'open' position	Procedures, Experience/ training, Stress/stressors	Driller (o4) can make up TD with returns to active system; then close iBOP	Unable to stab safety valve in drill pipe if kick occurs; possible blowout through drill pipe	
					C2 Check incomplete	Fail to check that valves are in 'open' position	Procedures, Experience/ training, Stress/stressors, Available time		Unable to quickly stab safety valve in drill pipe because pressure from flowing mud is too great	Potential consequences conditionally dependent on (1) kick has occurred and (2) kick has been detected

Task ID. 1st level	2nd level	3rd level	Description	OP	Guideword	Potential human failures	PSFs	Potential to recover from the failure before consequences occur	Potential consequences if the failure is not recovered	Comments
					C2 Check incomplete	Fail to check that suitable crossover subs are readily available	Procedures, Experience/ training, Stress/stressors, Available time		Unable to quickly stab safety valve in drill pipe because pressure from flowing mud is too great	Potential consequences conditionally dependent on (1) kick has occurred and (2) kick has been detected
					C3 Right check on wrong object	False verification that suitable valves are on drill floor.	Procedures, Experience/ training		Unable to quickly stab safety valve in DP/HWDP/DC	Potential consequences conditionally dependent on (1) kick has occurred and (2) kick has been detected
	1.5.2		Check that closing/opening wrench is readily available on drill floor	o4	C1 Check omitted	Fail to check that closing/opening wrench is readily available on drill floor	Procedures, Experience/ training		Unable to close safety valve once it is stabbed. Possible blowout through drill string	Potential consequences conditionally dependent on (1) kick has occurred and (2) kick has been detected
1.6			Pull 5-10 stands wet							Number of wet stands to be decided by on-duty toolpusher
	1.6.1		Set slips below top tool joint	o4	A9 Operation omitted	Fail to set slips before TD disconnect			Drillstring dropped; fishing job to retrieve it	
	1.6.2		Disconnect TD	o4	A11 Operation too early	Fail to set slips before TD disconnect			Drillstring dropped; fishing job to retrieve it	Same failure as 1.6.1
	1.6.3		Connect elevator	o4						
	1.6.4		Open slips	o4	A9 Operation omitted	Fail to open slips before elevating TD			Damage to slips and DP when elevating TD	
	1.6.5		Pull one stand	o4						
		1.6.5.1	Elevate TD	o4	A5 Operation too fast	Pull pipe too fast	Stress/stressors, available time, Experience/ training		Swabbing in a kick	
					V2 Deliberate action	Deliberately pull pipe too fast			Swabbing in a kick	
					A3 Operation in wrong direction	Inadvertently lower TD			Surge pressure leading to lost circulation, which again can cause a kick	
		1.6.5.2	Check that pulling speed is within limits from 1.2	o4	C1 Check omitted	Fail to continously monitor pulling speed during pull	Ergonomics /HMI		Swabbing in a kick	
	1.6.6		Set slips below top tool joint	o4	A9 Operation omitted	Fail to set slips before breaking connection			Drillstring dropped; fishing job to retrieve it	
	1.6.7		Break connection [iron roughneck]	o4					Automated, no potential for human error	

Task ID.			Description	OP	Guideword	Potential human failures	PSFs	Potential to recover from the failure before consequences occur	Potential consequences if the failure is not recovered	Comments
1st level	2nd level	3rd level								
	1.6.8		Close mud bucket around DP	o4	A11 Operation too late	Fail to close mud bucket properly before driller starts pulling pipe		Communication and visual contact between o4 and o7	Mud released on drill floor	Action performed at drillers command
					A9 Operation omitted	Forget to use mud bucket during pull			Mud, at potentially high pressures, released on drill floor.	
	1.6.9		Place stand in fingerboard	o5, o7						
	1.6.10		Check that hole is taking calc. amount of mud	o4, s1	C1 Check omitted	Fail to compare volume drop in trip tank to trip sheet			Unable to detect improper hole fill-up; will not stop pull to conduct flow check	
	1.6.11		Conduct flowcheck	o4	C1 Check omitted	Fail to conduct flowcheck	Procedures, Experience/ training		Unable to detect kick	
					C2 Check incomplete	Complete flowcheck in less than 15 mins	Procedures		Unable to detect kick; well deemed static even though it is not	
1.7			Prepare and pump a slug		A10 Operation incomplete	Slug displacement inadequate			Next stand will be pulled wet; release of mud to drill floor	
2.1			Set slips below top tool joint	o4	A9 Operation omitted	Fail to set slips before TD disconnect			Drillstring dropped; fishing job to retrieve it	
2.2			Disconnect TD	o4	A11 Operation too early	Fail to set slips before TD disconnect			Drillstring dropped; fishing job to retrieve it	Same failure as 1.6.1
2.3			Connect elevator	o4						
2.4			Open slips	o4	A9 Operation omitted	Fail to open slips before elevating TD			Damage to slips and DP when elevating TD	
2.5			Pull one stand	o4						
	2.5.1		Elevate TD	o4	A5 Operation too fast	Pull pipe too fast	Stress/stressors, Available time, Experience/ training		Swabbing in a kick	
					V2 Deliberate action	Deliberately pull pipe too fast			Swabbing in a kick	
					A3 Operation in wrong direction	Inadvertently lower TD			Surge pressure leading to lost circulation, which again can cause a kick	
	2.5.2		Check that pulling speed is within limits from 1.2	o4	C1 Check omitted	Fail to continously monitor pulling speed during pull	Ergonomics /HMI		Swabbing in a kick	
2.6			Set slips below top tool joint	o4	A9 Operation omitted	Fail to set slips before breaking connection			Drillstring dropped; fishing job to retrieve it	
2.7			Break connection [iron roughneck]	o4					Automated, no potential for human error	
2.8			Place stand in fingerboard	o5, o7						

Task ID. 1st level	2nd level	3rd level	Description	OP	Guideword	Potential human failures	PSFs	Potential to recover from the failure before consequences occur	Potential consequences if the failure is not recovered	Comments
2.9			Check that hole is taking calc. amount of mud	o4, s1	C1 Check omitted	Fail to compare volume drop in trip tank to trip sheet			Unable to detect improper hole fill-up; will not stop pull to conduct flow check	
2.10			Conduct flowcheck	o4	C1 Check omitted	Fail to conduct flowcheck	Procedures, Experience/ training		Unable to detect kick	
					C1 Check omitted	Fail to conduct flowcheck prior to pulling BHA and bit through BOP	Procedures, Experience/ training		Unable to detect kick; well deemed stativ eventhough it is not.	An undetected kick at this stage will make well control more difficult; one has to strip back into a closed well.
					C2 Check incomplete	Complete flowcheck in less than 15 mins	Procedures		Unable to detect kick; well deemed static even though it is not	
	1.3.2 (2)		Fill tank with mud from active volume		A9 Operation omitted	Fail to re-fill TT during POOH		Danger-low alarm goes off on TT and on drillers panel	Improper hole fill-up	Any of the HFEs identified previously (in 1.3.2) still apply for this failure.

Appendix I

Fault Tree Model

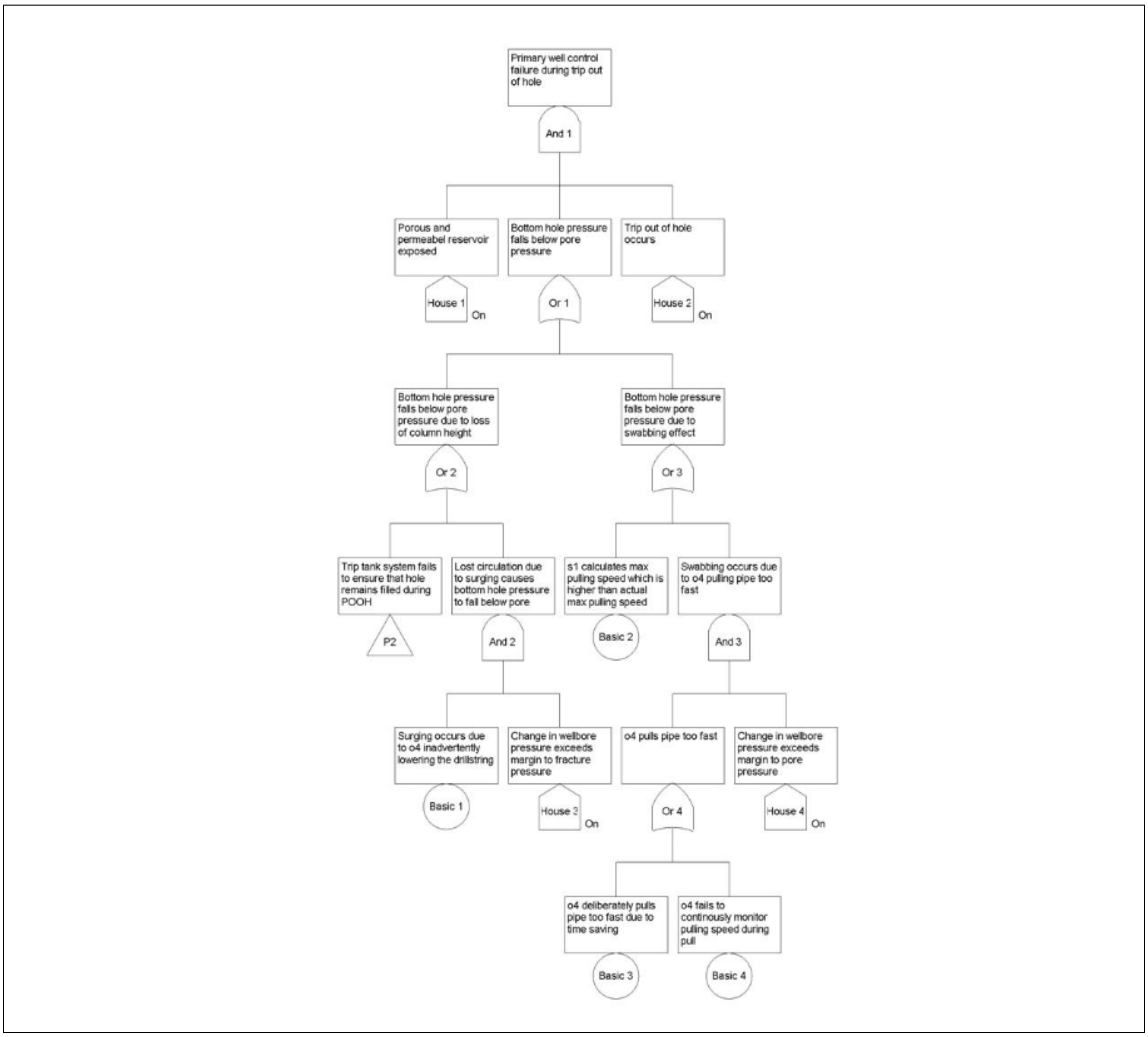

Figure I.1: Fault tree analysis. Pagename: P1.

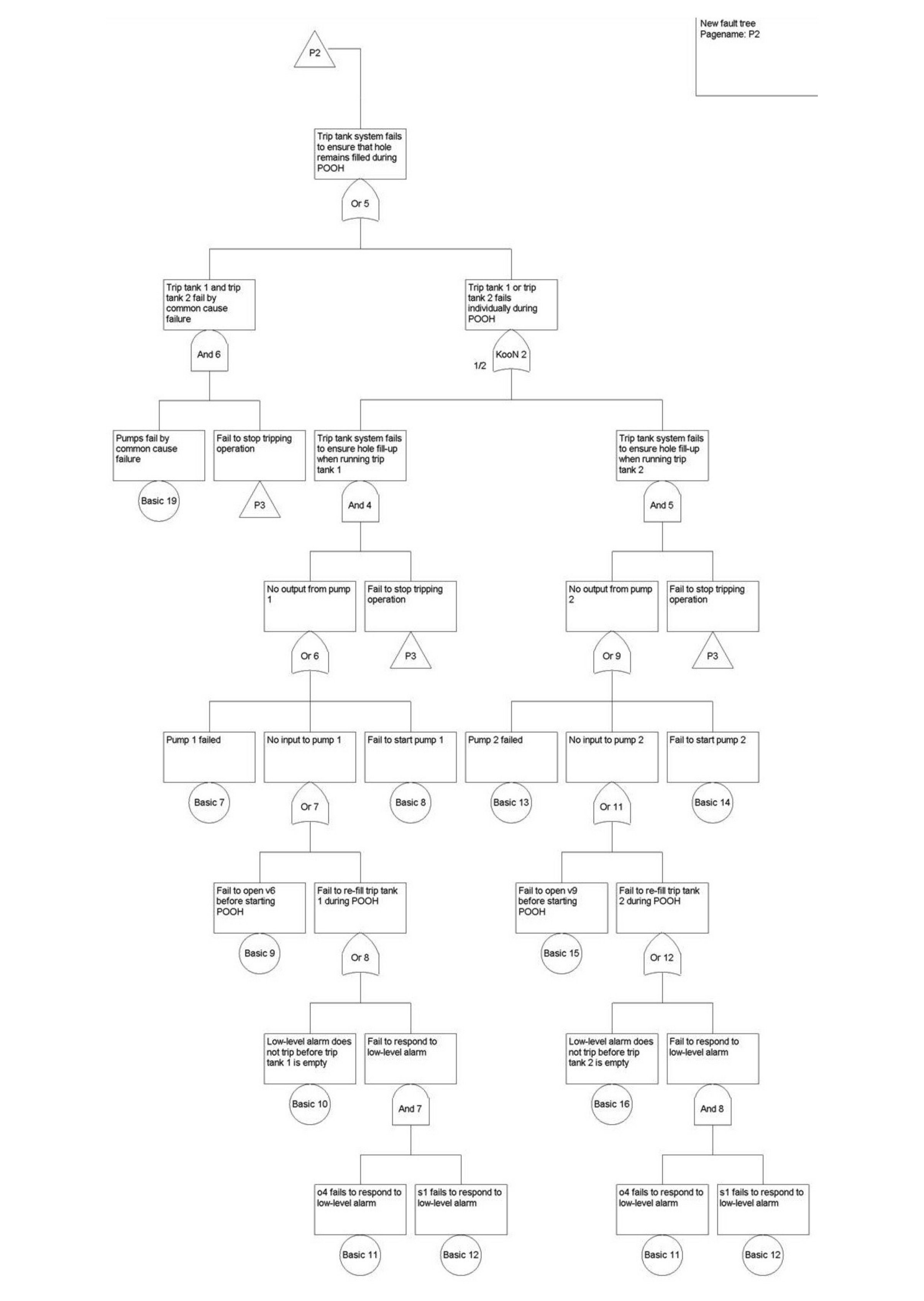

Figure I.2: Fault tree analysis. Pagename: P2.

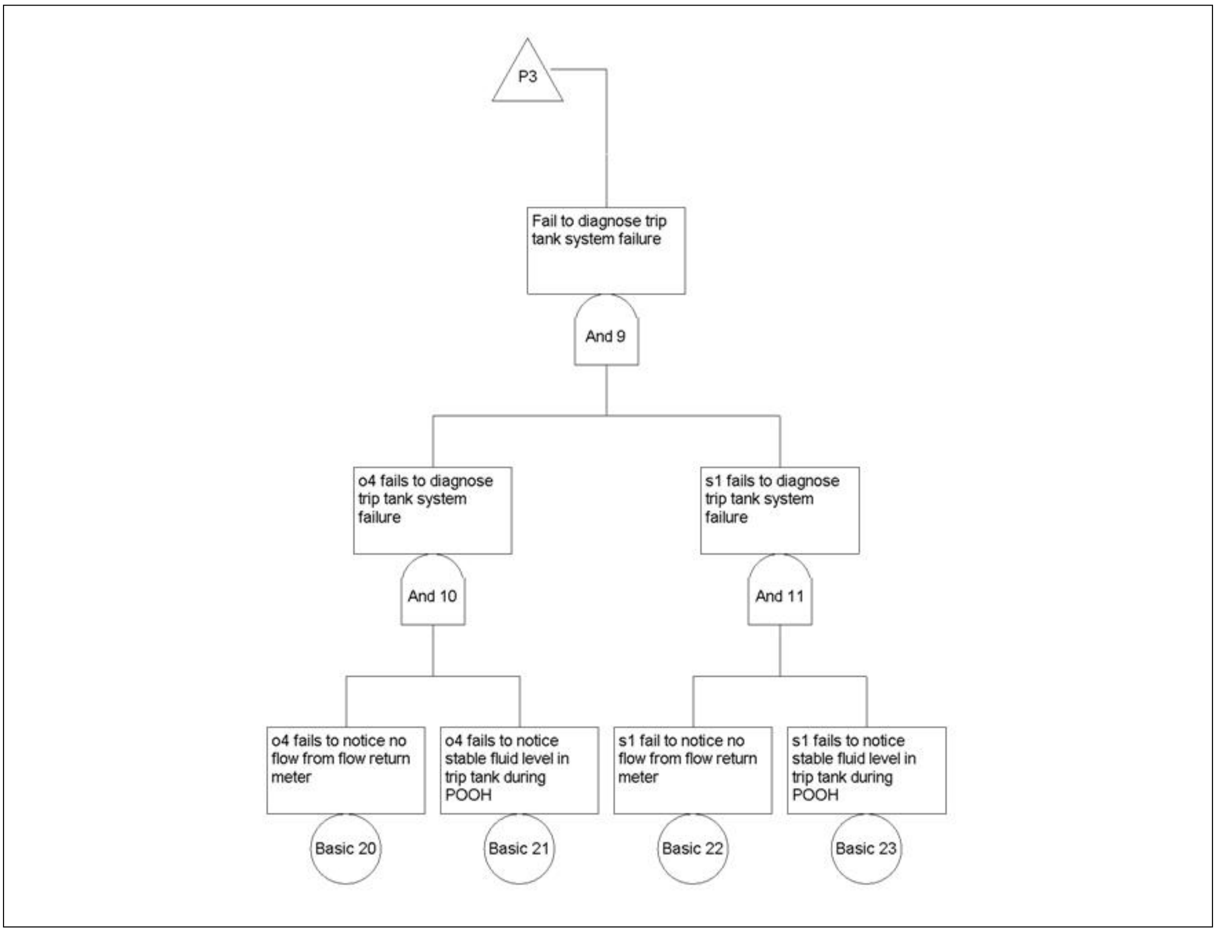

Figure I.3: Fault tree analysis. Pagename: P3.