UiT THE ARCTIC UNIVERSITY OF NORWAY

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Risk Analysis of Well Control Operations Considering Arctic Environmental Conditions

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Abstract

Oil and gas development in the Arctic is becoming a major focus in the industry today. However, compared to other regions, there is less experience regarding drilling operations in the Arctic environment. This fact raises concerns about high-risk scenarios, which might take place because of the harsh environmental conditions and the effects they have on various phases of operations, equipment and human performance. The operating conditions depend on the location in the Arctic, but sea ice, spray and atmospheric icing, low temperatures, seasonal darkness, winds, and polar lows, are considered as important Arctic environmental factors.

In any offshore drilling setting, well control operations are among the most crucial activities taking place, from risk perspective. A failure to control the wellbore can lead to devastating scenarios such as oil spills, explosions and major fatalities. There are mainly two safety barriers in place to prevent the loss of well control: primary and secondary well control barriers. The former refers to maintaining the wellbore pressure greater than formation pore pressure and less than formation fracture pressure, using the mud column pressure. The latter refers to mechanically securing the wellbore utilizing the blowout preventer (BOP) stack.

This study aims to develop a risk model for a well control operation, based on which the effects of the operating conditions in the Arctic offshore can be assessed. This aim is achieved through a stepwise procedure. By identifying the causes and consequences of failures in different phases of a well control operation, the risk model is built. Furthermore, the potential impacts of Arctic operating environment are investigated. Finally, how such impacts can be quantified and applied to the model is discussed.

The analyses performed in this study indicate that Arctic operating conditions can negatively affect human performance and reliability performances of well control procedures. The potential impacts are accounted for in the developed risk model through an expert-based approach, based on linear aggregation of expert opinions, through which the decision-maker's distribution is estimated using a Monte Carlo simulation method. A sensitivity analysis of well control safety barriers is performed, using Birnbaum's importance measure, to prioritize such barriers from reliability performance perspective. Moreover, a Monte Carlo simulation technique is used for the propagation of parameter uncertainties, to evaluate the resulting probabilities of near miss and blowout.

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Chapter 1

Introduction

1.1 Background

The Arctic is believed to hold approximately 25% of the world's undiscovered oil and gas resources, mainly offshore under less than 500 meters of water [Brekke, 2014]. This fact draws the attention of the petroleum industry towards these hydrocarbon resources and the Arctic region, especially since the present resources are reaching their maturity. At the same time, technological advances are made and the Arctic sea ice is retreating further north. The oil and gas resources in the Arctic are thus becoming a major focus in the industry today.

Although drilling operations in cold climates are not a new phenomenon, there exist challenges in the Arctic environment that remain to be addressed. The Arctic offshore is characterized by harsh environmental conditions such as freezing temperatures, atmospheric icing and marine icing, sea ice and icebergs, polar low pressures, etc. [Gudmestad and Karunakaran, 2012; Løset et al., 1999; Barabadi et al., 2013; NORSOK, 2007]. The severe weather conditions can affect the operations, and thus influence the safety and risks associated with activities involved in drilling operations. Potential scenarios are failures in oil spill recovery attempts, challenges with regards to search and rescue operations, increase in the failure rates of mechanical equipment, and an increase in human error probability.

Performing risk analyses is of great importance to evaluate operational reliability and safety. Such analyses can, if accounted for the potential effects of operating conditions on drilling operations, provide decisive information for the analysts to reduce both the probability of accidents and failures to occur and the severity of their consequences. Risk analyses, qualitative or quantitative, can be referred to as "*a process to comprehend the nature of risk and to determine the level of risk*" [ISO, 2002].

The well control operation is one of the important activities taking place in every drilling activity. In overbalanced drilling, two barriers are in place to prevent the loss of well control and ensure a safe drilling operation from the well control perspective. The primary well control barrier makes sure that the wellbore pressure is greater than the formation pressure and less than the formation fracture pressure, so that formation fluid does not enter the well. If the primary barrier fails, the secondary well control barrier is activated. In that case, the wellbore is shut in and secured by utilizing the valves that altogether form the blowout preventer (BOP) stack. By the time the well is shut in, the drilling mud is modified to regain sufficient wellbore pressure so that the well can be brought back to its original state where the primary well control barrier is active [Grace et al., 2003]. If the wellbore is not secured in time, a blowout might occur that can result in explosion, several fatalities and a major oil spill.

Several studies [Xue et al., 2013; Abimbola et al., 2014; Khakzad et al., 2013; Cai et al., 2012] have been performed on the risks associated with well control operations by analyzing the causes and consequences of the different phases of well control. For instance, accident models based on three-level well control theory with an extra well monitoring barrier have been proposed [Xue et al., 2013] and dynamic safety risk analyses have been performed [Abimbola et al., 2014]. However, in Arctic offshore drilling activities, the harsh operating environment can influence various phases of the drilling operation and the performance of potential well control scenarios. Such effects of operating conditions have not been considered in previous well control studies. If these effects are not evaluated, the potential increase in the risk of a blowout will not be accounted for in the risk analyses. In the worst-case scenario, as a result, a major blowout occurs during a drilling operation in the Arctic, with severe consequences that are very challenging to deal with. In a cold environment, in the dark and with long distances to shore, a rescue operation must be initiated as well as an oil spill recovery operation. There will be severe damages to the sensitive environment in the Arctic, ecosystems will be ruined, etc.

In this regard, it is required that the risk analyses are performed according to the operating conditions in the Arctic, and that the impact on system failure rate and human performance are considered in the assessments. In order to do so, there is a need of risk models to be developed, where these effects can be accounted for. The failure causes and consequences can be identified using fault tree analysis (FTA) and event tree analysis (ETA). Combining these logic diagrams, one for each phase of an operation, the structure of a risk model for the whole operation can be formed. Before an assessment can be performed, the effects of Arctic operating environment on phases and elements of an operation must be investigated. In order to quantify the impact, there is a need of historical data from previous operations. As the data from previous drilling operations in the Arctic is sparse, the risk analysis must be based on operational data from baseline regions, e.g. the North Sea. However, the available data can be modified by using expert opinions to include the effects of Arctic operating environment. These modifications can then be applied to the developed risk model.

To evaluate how the performance of the well control operation can be improved, the factors that have the biggest influence on the probability of different consequence categories should be identified. On that basis, the focus and efforts to enhance the reliability performance of well control procedures can be prioritized. Through sensitivity analyses, such importance measures can be determined. Moreover, the uncertainty element should also be included in risk analyses of well control operations. By understanding and analyzing the propagation of parameter uncertainties, adequate adjustments to tackle the potential negative effects on the reliability performance of well control barriers can be made.

1.2 Aim of the thesis and objectives

The aim of this thesis is to evaluate the performance of well control procedures during drilling operations in the Arctic offshore. For this purpose, the Arctic environment is reviewed and different phases of a well control operation are discussed. On this basis, the main objective in the thesis is to develop a risk model, based on which the potential impacts of the operating environment in the Arctic can be discussed and quantitatively assessed. Sub-objectives in the thesis are to demonstrate risk analysis techniques, study the reliability performance of each phase of the well control operation, illustrate the use of expert judgement-methods, and show how to apply modifications to a developed model.

1.3 Limitations

As the amount of experience, literature and historical data from operations in the Arctic environment are limited, common practices and standards for this region are not fully and thoroughly defined. In that regard, the risk analysis and assessments to be performed need to be based on adjustments of operational data from baseline locations, where the operating conditions are considered as normal and required data are available. In addition, the details and accuracy of the presented results must be handled with care, due to shortages in source data utilized for reliability calculations. The estimations of failure probability, barrier reliability and level of risk, therefore needs to be considered as general guidance.

1.4 Research methodology

In this thesis the methodology used is principally theoretical. The existing experience, literature and data are discussed and analyzed and then evaluated when the operating parameters exceed their original field of application. The thesis is based on both primary and secondary data. The primary data are subjective opinions from experts, which have been collected in order to perform quantitative analyses. The secondary data are collected from relevant books, scientific reports, standards, published papers and databases. The evaluations and considerations in this work will be based on a review of the Arctic environment and a study of the procedures and elements of well control. Different risk analysis tools, methods and techniques will be utilized, as well as spreadsheet applications and technical computing softwares.

1.5 Structure of thesis

The thesis has been divided into different sections based on the introduced topic. Chapter 1 contains the introduction, with the background, objectives and limitations of the thesis. In Chapter 2, the Arctic environment and its distinctive features are reviewed. The operating environment that will be experienced during drilling operations is introduced, in order to gain knowledge about the harsh physical conditions, and thus to be able to analyze their impacts on well control procedures.

Chapter 3 discusses the elements of the well control procedure, and identifies well control barriers, equipment, systems, and the fundamentals of the overall operation. The causes of loss of control and the consequences of failure of the well control operation are reviewed and discussed. In Chapter 4, the risk model is developed by using the risk picture-approach. Different well control procedures are analyzed step-by-step, by utilizing the concepts of fault tree analysis (FTA) and event tree analysis (ETA). Finally, the FTA and ETA models are combined to form the overall risk picture, and establish different well control scenarios. In Chapter 5, the potential impacts of the Arctic operating environment on well control procedures are discussed, based on which the reliability performance of a well control operation is analyzed.

The discussions and the obtained results from sections up to and including Chapter 5, are published in the 23rd International Conference on Port and Ocean Engineering under Arctic Conditions (POAC). The conference paper is given in Appendix D.

Furthermore, Chapter 6 presents a quantitative well control risk analysis and an expert-based approach on how the effects of Arctic operating environment can be quantified and applied to the developed risk model. Chapter 7 contains the results and discussion part, and recommendations on how the results can be further improved. Finally, the conclusion is given in Chapter 8.

1.6 Abbreviations

BOP	Blowout preventer
CCF	Common cause failures
CDF	Cumulative density function
ETA	Event tree analysis
FTA	Fault tree analysis
PDF	Probability density function
PFD	Probability of failure on demand
PVTs	Pit volume totalizer-sensors

Chapter 2

The Arctic region and its physical environment

In order to gain a better understanding about the Arctic, it is beneficial to investigate the distinctive features of this environment and the challenges they introduce to the drilling operations. Before that, it is important to clarify what is defined as the Arctic and specify the regions that can be included in this area. One definition is based on temperature, implying that the areas in the north where the average temperature in the July does not exceed 10°C are considered as Arctic areas [FNI, 2012]. In some occasions, the area north of the tree line is defined as Arctic regions [AMAP, 2010]. In this paper the Arctic is defined as the area north of the Arctic circle, in other words the lands and waters north of approximately 66°N latitude. An overview of the region is presented in Figure 2.1.

2.1 Environment and distinctive features

The Arctic region is characterized by remoteness and harsh environmental conditions. There is a general lack of infrastructure in these areas and offshore operations normally take place at locations with long distances to shore. Additionally, the Arctic regions are associated with lack of complete satellite coverage. Distinctive features of the Arctic environment are [Gudmestad and Karunakaran, 2012; Løset et al., 1999; Barabadi et al., 2013; NORSOK, 2007]:

- Seasonal darkness
- Snow precipitation
- Freezing temperatures and atmospheric icing
- Marine icing

- Different forms of sea ice and icebergs
- Dense fog
- Strong winds, waves and currents
- Polar low pressures

Figure 2.1: Illustration of the Arctic region with its lands and waters [Bishop et al., 2011]

In the Arctic there are periods where the sun does not rise above the horizon. This is called the "darkness period" or the "polar night" and begins at winter solstice. The length of the polar night increase towards the north, and for instance at Bear Island the polar night lasts from 8th of November to February 3rd [met.no].

The environment in the Arctic is characterized by freezing temperatures. In, for instance, the northern parts of the Barents Sea, an annual minimum temperature of - 39°C to - 20°C can be experienced [ISO, 2010]. In such temperature conditions, atmospheric and marine icing definitely come into play. The former is a result of high air humidity, cold rain and accumulation of dense fog, while the latter is a combination of sea spray and cold temperatures [Larsen and Markeset, 2007; NORSOK, 2007]. Both can cause severe ice growth on surfaces and structures.

With regards to sea ice, the Arctic holds different forms of sea ice with varying characteristics and extent. In this regard, the region can be divided into three zones; 1) a non-sea ice zone, 2) a seasonal ice zone and 3) a perennial ice zone where ice is present throughout the year [Polyak et al., 2010]. Modeling the failure of sea ice is quite a challenging task, as it depends on, among others, the size of the floe, lateral confinement and ice-structure contact conditions [Lu et al., 2015].

As introduced above, the Arctic environment is also characterized by large variations in its physical conditions. It is not unusual that the variations within the Arctic region are larger than those between this region and bordering regions. For instance, the sea surface and air temperatures considerably vary over the Barents Sea due to a number of factors. These factors include, but are not limited to, flow of various water masses with different temperatures, diverse wind direction, latitudinal changes in solar radiation rates, and presence of sea ice in the northern areas and usually open waters in the west and southwest regions. At some Arctic locations, the year-round air temperature variations can be up to 50°C [FNI, 2012].

Polar low pressures are common meteorological phenomena in the Arctic, especially in the Barents Sea. The polar lows mainly form from September to early summer when a system of cold polar air moves over relatively warmer, ice-free waters of the Barents Sea [Hamilton, 2004]. The phenomena can be defined as intense meso-scale cyclones with a horizontal extensiveness of less than 1000km [Guo et al., 2007]. Polar low pressures can cause sudden dramatic changes in weather conditions, and specific characteristics are considerable snowfalls and sudden increases in wind speed, creating high waves, causing snow and icing storms. They develop quite rapid and are difficult to predict [Carstens, 1985; Gudmestad and Karunakaran, 2012; Hamilton, 2004; Barabadi and Markeset, 2011].

In the northernmost parts of the Arctic region, satellite communications and satellite systems will face difficulties and operate with reduced performance. This is due to the fact that geostationary satellites are visible only at low angles. In addition, there will be ionospheric effects on satellite signals, as a result of an increased electron precipitation in the Arctic causing a higher variability in the ionosphere [Jensen and Sicard, 2010].

2.2 Planning approach for the Arctic operations

The environmental characteristics of the Arctic region introduce challenging operating conditions. Furthermore, in comparison with other regions, the amount of experience from drilling rig operations executed in the Arctic is limited. Therefore, the planning of future drilling activities and the management of Arctic risks are complicated processes. Besides, bearing in mind the large variations of the environmental factors, obviously there can be no "one-size fits all" approach for drilling operations in the Arctic region [PAME, 2014].

For the Arctic region a stepwise approach is proposed [Dahlsett et al., 2014]. This means that locations where the operating conditions are most similar to baseline conditions, for instance, the North Sea conditions, should be entered first. Only when acceptable risk levels for drilling operations in these areas have been demonstrated, the heavier ice-environments can be approached [Dahlsett et al., 2014]. Along with this process, it is of great importance to share data from previous drilling operations and report the lessons learned from incidents or accidents that have occurred in the Arctic. The sharing of near miss incidents will also be of relevance, as they can turn out to be more critical incidents with a higher risk at another location [PAME, 2014].

2.3 Illustrations of the physical environment

By utilizing statistical weather reports and databases, the distributional of different environmental features of the Arctic can be described over time and location. Such distributions can aid the companies to better map the operating conditions, and thus to gain more knowledge on the risks associated with different oil and gas activities at different Arctic locations. In the following, the extent of the Arctic sea ice (see Figure 2.2), temperature contours over most of the region, and monthly weather extremes at a given location are outlined.

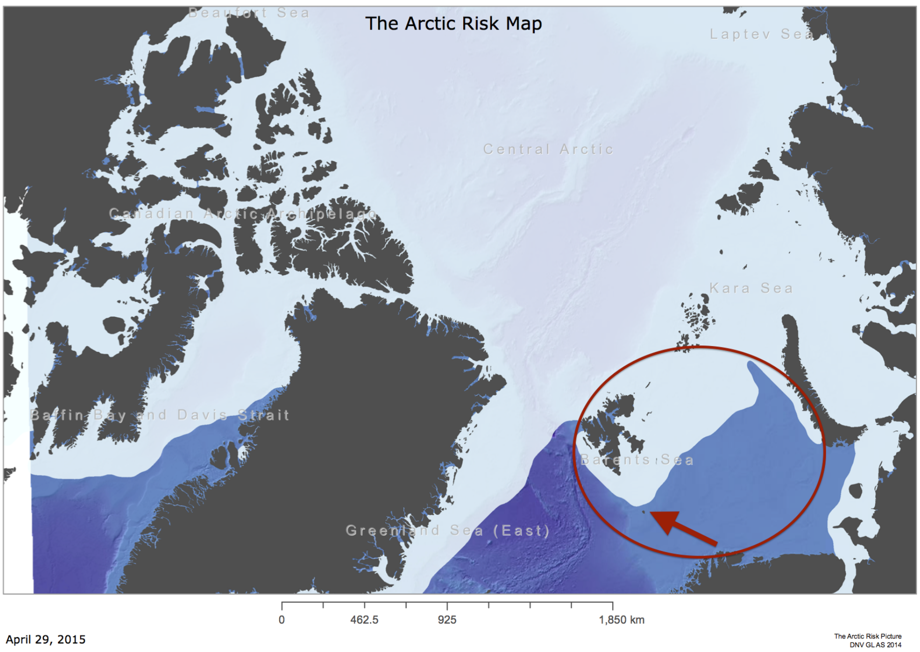

Figure 2.2: Illustration of the Arctic sea ice cover, January 2011. The outline of the Barents Sea is given by the circle and Bear Island is indicated by the arrow [DNV, 2014]

In Figure 2.2, the Arctic sea ice cover in January 2011 is presented. In the Barents Sea for instance, the ice edge runs just north of Bear Island at one point, approximately at 75°N latitude. Since year 2011 the ice has retreated further north, allowing new oil concessions to be offered to the petroleum industry. In Figure 2.3, temperature contours for the Arctic region are illustrated. The contours represent the 100 years minimum temperature in different Arctic waters.

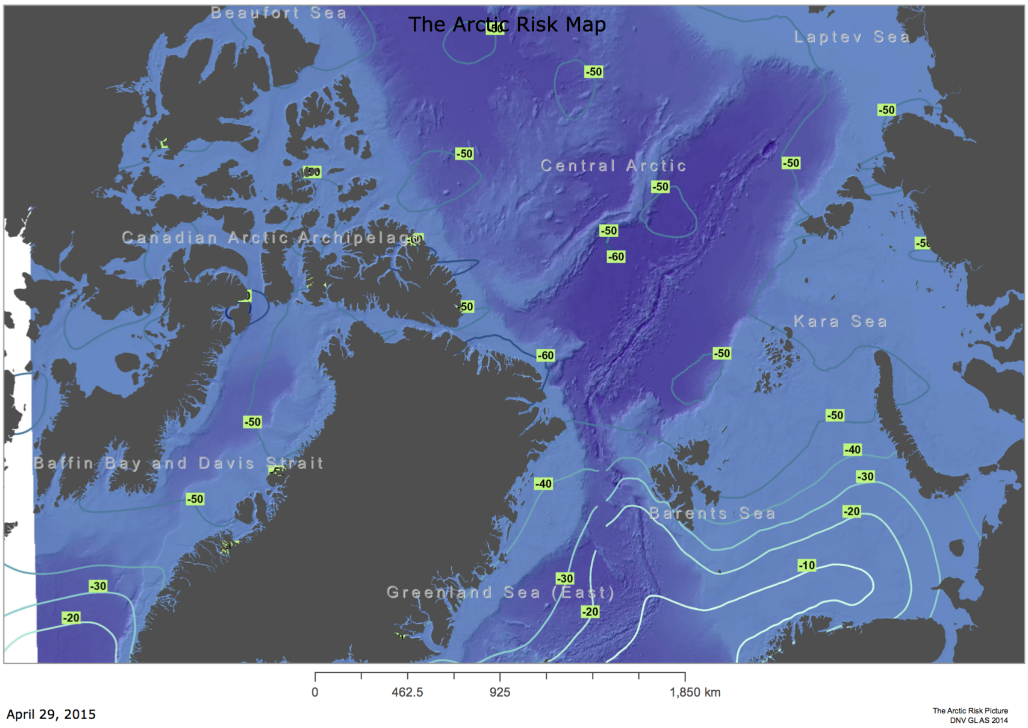

Figure 2.3: 100 years minimum temperature contours for the Arctic region [DNV, 2014]

In the Western Barents Sea, the oil and gas companies are currently approaching the latitudes equivalent to the location of Bear Island. For this reason, weather data and monthly extremes from approximately these areas are presented to illustrate the physical environment about to be entered, given in Table 2.1.

Table 2.1: Monthly extremes during the period from 2009 to 2014, Bear Island [met.no]

	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Des**
Max. wind speed (m/s)	**20.1**	**20.6**	**25.8**	**19.2**	**18.3**	**16.1**	**16.0**	**17.2**	**18.8**	**21.5**	**21.7**	**22.8**
Year	2010	2013	2013	2014	2011	2010	2012	2013	2014	2012	2013	2013
Precipitation (mm)	**62.4**	**60.0**	**68.2**	**49.8**	**38.6**	**35.5**	**64.0**	**52.1**	**94.4**	**51.8**	**65.4**	**81.3**
Year	2010	2012	2011	2013	2012	2009	2012	2009	2009	2011	2013	2014
Min. temperature (°C)	**-21.0**	**-16.8**	**-19.6**	**-19.9**	**-8.2**	**-2.3**	**-0.1**	**0.2**	**-2.5**	**-10.8**	**-14.0**	**-14.3**
Year	2009	2011	2009	2013	2014	2011	2009	2009	2012	2013	2010	2012

In Table 2.1, monthly weather extremes with regards to wind, precipitation (during one day) and temperature are given. The duration of the weather record is six years, in the period from 2009 to 2014. The most extreme measures are listed along with the year of occurrence. Finally, the significant wave heights in the Western Barents Sea are presented in Figure 2.4.

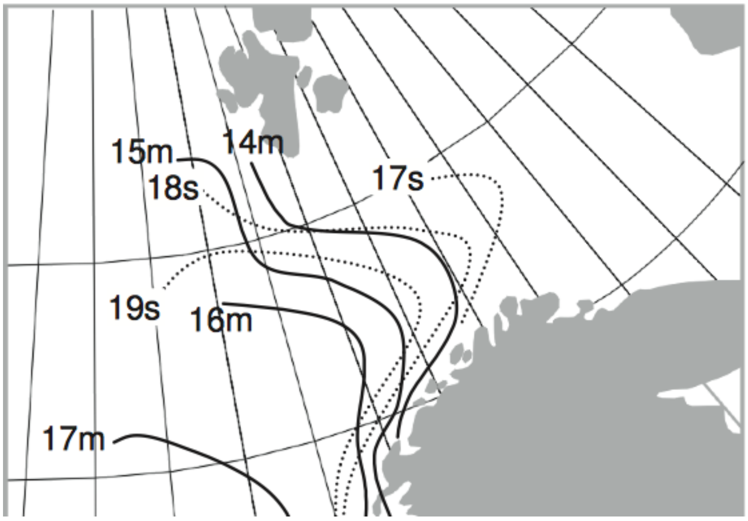

Figure 2.4: Significant wave height (m), solid lines, and related wave period (s), dotted lines, in the Western Barents Sea [NORSOK, 2007]

For the case of this study, the evaluations on how the Arctic operating environment can affect well control barriers and procedures will not be attributed to a specific Arctic location. However, later discussions of such impacts will be of most relevance for the areas where adverse effects of freezing temperatures and icing will be experienced and where drilling rigs are operating in ice-infested waters.

The Arctic environment and the harsh physical conditions that will be experienced during drilling operations have now been introduced. The operating conditions can influence various phases of the drilling operation, one of them is the well control operation. In order to evaluate the performance of the well control operation, firstly its elements and procedures need to be discussed.

Chapter 3

The well control operation

In every drilling activity, the well control operation is among the most important activities taking place from the risk perspective. A well control operation is defined as a:

Collective expression for all measures that can be applied to prevent uncontrolled release of wellbore effluents to the external environment or uncontrolled underground flow [NORSOK, 2010a]

Within the concept of well control, there exist different types of operations. Basically these are drilling, completion, workover, production and wireline operations [Holand, 1997]. In this study, well control during the overbalanced drilling operation is considered, referring to the process of controlling exploration wells.

The effort of maintaining a well under control can be divided into primary and secondary control, utilizing the functions of primary and secondary well control barriers. The primary well barrier refers to the mud column in the wellbore providing a hydrostatic pressure greater than formation pore pressure and less than formation fracture pressure. If this barrier fails to fulfill its function, an unwanted influx of formation fluid into the wellbore is experienced, defined as a kick [Fraser et al., 2014]. Secondary well control must then be initiated, involving the discovery of the influx, the containment of it and the issue of circulating the influx out of the well. This includes the utilization of the secondary well barrier that is referred to activating the blowout preventer(BOP) stack [Grace et al., 2003]. A BOP stack is a combination valves, typically consisting of four ram-type preventers and two annular-type preventers [Cai et al., 2012].

3.1 Well control procedures

A well control operation can be divided into four phases as illustrated in Figure 3.1. These are kick prevention, kick detection, blowout prevention and killing operations.

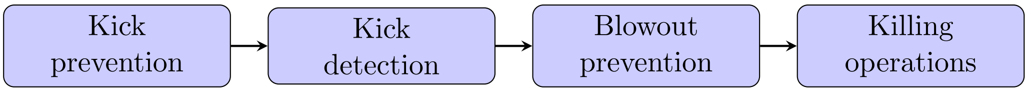

Figure 3.1: Well control operation phases [Khakzad et al., 2013]

3.1.1 Kick prevention

During an overbalanced drilling operation, kick prevention refers to the process of maintaining the pressure in the wellbore at a higher level than the pressure in the surrounding formation. If the pore pressure of the formation drilled into exceeds the pressure at the bottom of the wellbore, formation fluids will enter the well. It is, however, important that the pressure in the well does not exceed the formation fracture pressure. In case of a fracture, drilling mud will be lost to the formation, the hydrostatic pressure in the well will decrease and there is an increase in the possibility of a kick occurrence [Khakzad et al., 2013]. The wellbore pressure requirement is illustrated in Figure 3.2.

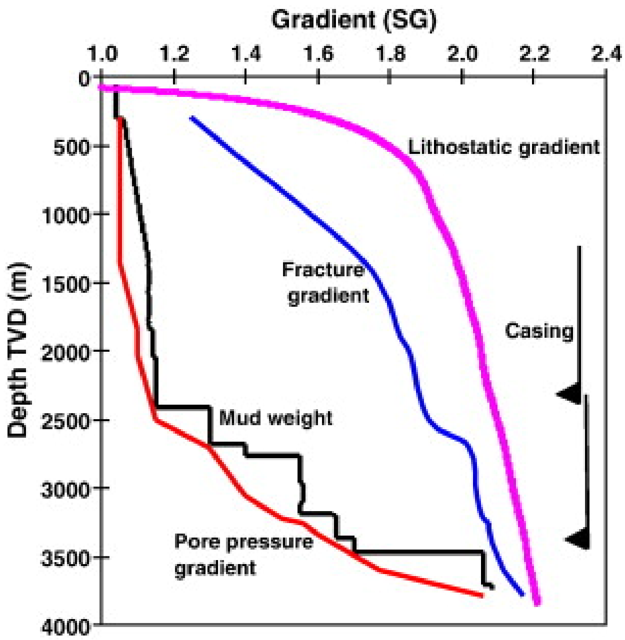

Figure 3.2: The wellbore pressure supported by the weight of mud column should be less than fracture pressure and more than pore pressure to maintain the primary well control barrier in an overbalanced drilling operation [Zhang, 2011]

In general, a well kick may result from one of the following causes [Grace et al., 2003]:

- Formation pore pressure greater than the mud weight
- Hole not kept full of mud while tripping

- Swabbing during tripping
- Loss of circulation
- Mud cut

The term tripping refers to the procedure of inserting the drill string into the well, i.e., tripping in, or removing it from the well, i.e., tripping out. Tripping in rarely leads to a kick, because of the increase in wellbore pressure as pipes are put into the well [Fraser et al., 2014]. However, a kick is more likely to occur while tripping out, as the drilling mud has to replace the volume occupied by the drill string that is removed from the hole. If such difference in the mud volume is not replaced by adding more drilling mud, the hydrostatic head of the mud column drops, leading to a wellbore pressure lower than formation pressure. During the tripping process, swab and surge pressures are created, as the drill string behaves like a piston inside a cylinder. This movement causes friction losses between the string and the drilling mud, resulting in swab pressures when the string is pulled out of the hole and surge pressures when it is run in[Mme and Skalle, 2012]. The former can reduce the hydrostatic pressure in the well below the formation pore pressure and the latter can cause fractures leading to the loss of circulation[Mme and Skalle, 2012]. If circulation of drilling mud is no longer achieved, returns are lost, the hydrostatic pressure drops, and thus the fluid of a formation with a permeable character and of higher pressure will start flowing into the well[Grace et al., 2003]. A decrease in pressure at the bottom of the wellbore can also be a result of gas-cut mud, reducing the density of the drilling fluid due to the presence of gas bubbles in the mud.

3.1.2 Kick detection

In case of the occurrence of a well kick, it is crucial that the kick is detected at an early stage. If not, formation fluids will continue to displace the heavier fluids in the wellbore and the pressure in the well will further decrease, allowing the cycle to feed on itself and the kick to escalate [Fraser et al., 2014]. The later the kick is detected the more influx will enter the wellbore, going past the BOP and up in the riser, and in the worst case escalating into a blowout. The indications of a well kick are therefore important to understand. Common indications are immediate increase in the penetration rate, increased volume in the pit tank or increased flow rate, changed pump pressure and reduced drillpipe weight or weight-on-bit [Grace et al., 2003]. An increase in drilling rate suggests that a porous or fractured formation has been entered [Khakzad et al., 2013], and drilling fluid in the wellbore will enter the formation unless the weight of the mud column is decreased. In addition, an increase in the penetration rate is an indication of a decreasing margin between the bottom hole pressure and the formation pore pressure [Khakzad et al., 2013]. A rise in pit level in the mud or trip tank is likely to be a result of influx of formation fluid. This same influx will also cause a decrease in pump pressure, as the hydrostatic pressure in the annulus will be lowered [Grace et al., 2003]. Finally, as formation fluids are less dense than the heavy drilling mud used, an increased weight-on-bit will be experienced in case of a kick, because of the reduction in the buoyancy force.

To be able to detect the kick at an early stage, a number of indicators must be in place to detect one or more of the above-mentioned signs of kick occurrence. The primary kick indicators are principally the flow-out sensors and the pit volume totalizer-sensors (PVTs). The flow-out sensors are installed to detect an increasing flow rate and the PVTs are continuously measuring the present fluid level in the mud tanks [Fraser et al., 2014]. Furthermore, during tripping, and when no circulation in the well takes place, the trip tanks serve as accurate volume detectors. To discover an increasing drilling rate, changes in the weight-on-bit, and deviations in standpipe pressure, some topside gauges are installed. Gauges are also installed on the mud pumps to register changes and variations in the pump pressure. Among the downhole equipment tools, the pressure while drilling-equipment is an important one, sending signals to the surface with wellbore- and formation pore pressure-readings.

3.1.3 Blowout prevention

Once a kick has been detected, the next step is to shut in the wellbore by actuating the BOP stack to prevent a blowout. The BOP stack has a collection of at least four rams and typically one or two annular preventers [Cai et al., 2012]. The annular preventers are spherical shaped seals located at the top of the stack, which can close around the outside of the drill string (can also seal an open hole) and thus seal the annulus [Skalle, 2011]. The pipe rams are in place for the same purpose as their circular ends can clamp around the drillpipe [DeepwaterHorizonStudyGroup, 2011]. In addition, shear rams are part of the BOP stack, with the ability to seal the well even if the drill string is present, as they can cut through the pipes occupying the bore. However, the shear rams cannot cut through tool joints, so the operators must pay close attention to the location of the joints [DeepwaterHorizonStudyGroup, 2011]. A typical BOP stack is illustrated in Figure 3.3.

To manage the BOP stack and the killing operation, there is a need for a BOP control system. The control system consists of electric control system and fluid control system. For comprehensive information and schematics of electric control systems, see the article by Cai et al. [2012]. The fluid control system includes accumulators, pumps, valves, fluid storage and mixing equipment, manifold, piping, hoses, control panels and other items necessary to actuate the BOP stack hydraulically. The electronic control system includes topside components that form the central control unit, subsea components, and umbilical cables responsible for transmitting initiated commands to the subsea control pods [Cai et al., 2012]. In subsea control pods, the yellow or the blue pod (see Figure 3.3), the signal is received an decoded by subsea electronic modules. Furthermore, the signal is sent to a solenoid, that opens electrically and initiates a hydraulic pilot signal to a specific hydraulic valve [Shanks et al., 2003]. On this basis, the hydraulic valve will shift and generate pressurized hydraulic fluid required to close BOP valves[Shanks et al., 2003].

At this point, when the well has been shut in, formation fluids will enter the wellbore until the bottom hole pressure becomes equal to the formation pressure.

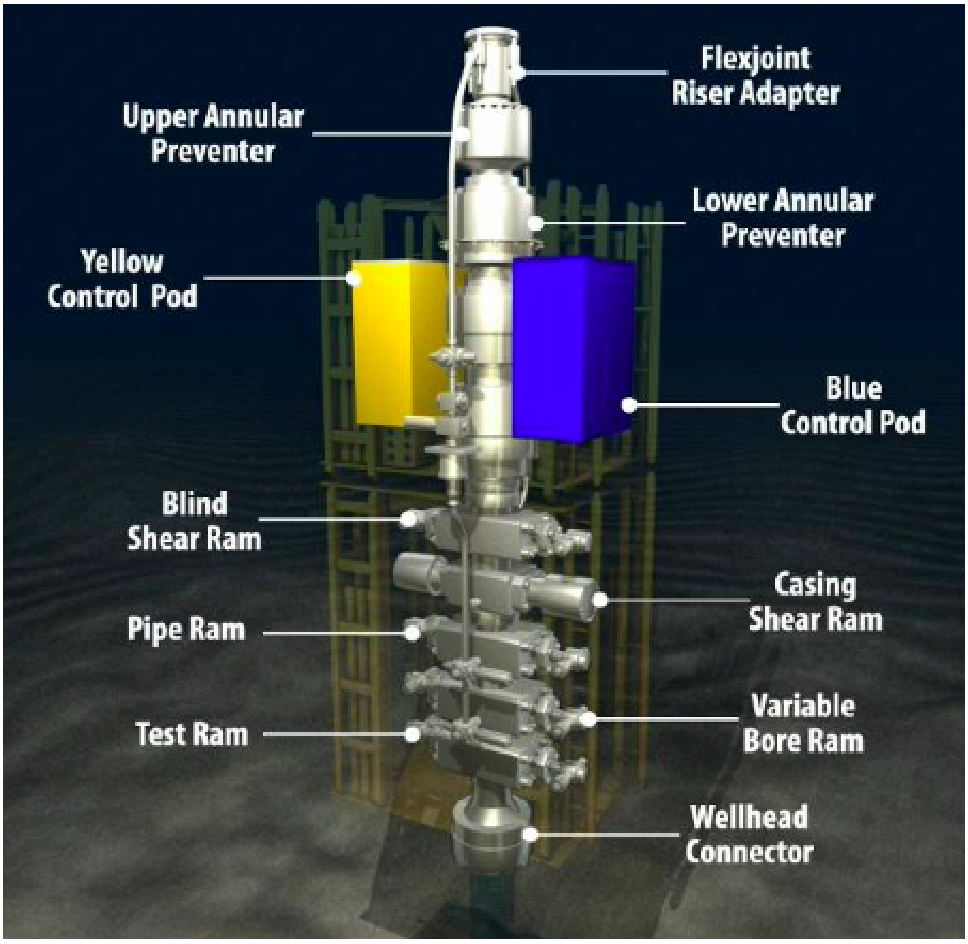

Figure 3.3: Elements of the BOP stack [DeepwaterHorizonStudyGroup, 2011]

3.1.4 Killing operation

While the wellbore is shut in, the killing operation can be initiated. In order to regain control of the wellbore by means of the primary well control barrier, the formation influx should be circulated out. The unwanted influx, i.e., the kick, can be circulated out through the choke line. The Driller's Method and the Wait and Weight Method are two common ways to carry out such a procedure [Grace et al., 2003]. What separates these methods is the kind of mud that is utilized to circulate out the kick. If the Driller's Method is applied, the formation fluids are circulated out by continuing to pump the present drilling mud that was in use while drilling. The downhole pressure is maintained constant during this process, by utilizing the choke valve at the end of the choke line.

While the formation fluids are being circulated out, heavier mud, i.e., kill mud, is made to kill the well. The weight of the kill mud is calculated according to the original mud weight and shut-in drillpipe pressure [Grace et al., 2003]. By the time all the influx is removed, the kill mud is pumped in to circulate out the initial mud used and thus to regain the overbalanced conditions, after which the BOP stack opens the wellbore again.

Until the operators are able to start the killing operation, it is decisive that the BOP stack keeps the wellbore closed. Furthermore, the stack should be able to allow the operators to inject the kill mud at a specified injection pressure and rate, while the kick is being circulated out. In order for them to do so, the BOP control system must also perform its desired function satisfactorily. In addition, surface facilities such as mud pumps, hoses, mixing tanks, injection pressure and rate gauges, and all other equipment units involved in a routine drilling operation, should be available as well. A system sketch and some of the equipment used in well control procedures can be seen in Figure 3.4.

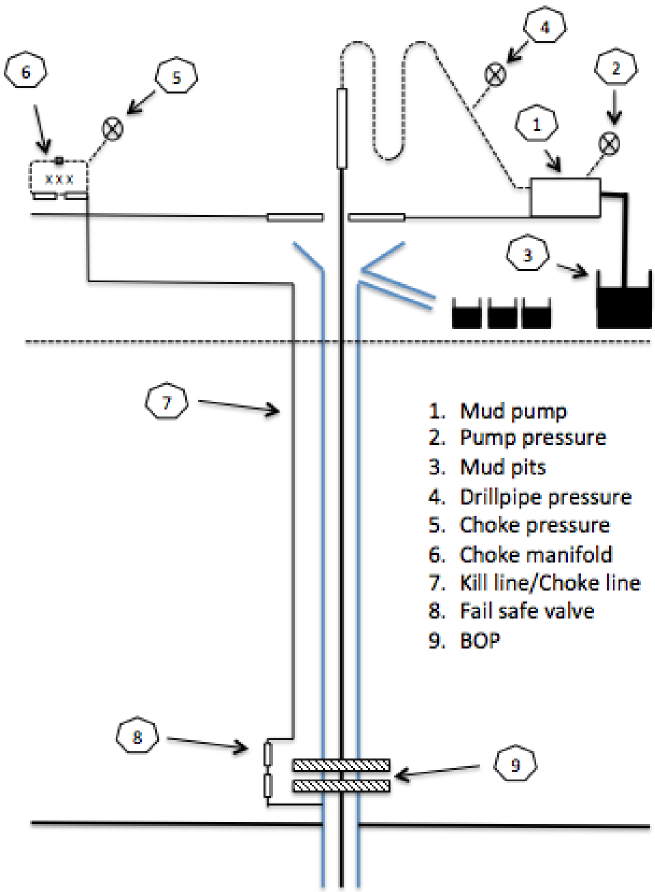

Figure 3.4: Overview of some of the well control equipment, modified from Skalle [2011]

3.2 Consequences of well control failure

If a kick is not discovered or the secondary well control barrier fails to fulfill its function, a blowout will occur. Moreover, there might be situations where a kick is detected, the wellbore is shut in, but the killing operation is unsuccessful. Such a situation may escalate to a loss of the well, if the BOP stack is no longer capable of keeping the wellbore closed. The severity of a blowout depends on whether it is a partial blowout or a full blowout. In that case, the outcomes of losing control of the wellbore can be grouped in different consequence categories. Such detailed analyses of the severity of a blowout will not be performed in this study, where two general consequence categories, being either a near miss or a blowout, are developed. In terms of a major blowout, oil spills, gas ignition and explosion, and major fatalities is a worst-case scenario. The Macondo accident in the Gulf of Mexico is an example of such a scenario, where a blowout occurred after completing the well. The result of the blowout was that the Deepwater horizon drilling rig sank, eleven people lost their lives and a massive amount of oil was spilt [DeepwaterHorizonStudyGroup, 2011].

In order to reduce such severe consequences, one can, from risk point of view, focus on decreasing the probability of having blowouts. As a blowout starts with kick occurrence, it is of crucial importance to identify the factors that can lead to a kick. Moreover, by performing a risk analysis it is possible to categorize the consequences of a kick and then to implement adequate passive barriers. The aim of the process is to make sure that the risks are controlled and reduced to an acceptable level.

Chapter 4

Developing a well control risk model

4.1 Risk picture approach

To analyze the risks associated with well control operations, a risk model needs to be developed. In this study, the risk picture approach has been selected to create such a model. First of all, one important term to clarify is the term risk. In the context of risk analysis in engineering, risk is defined as the combination of the probability of an event and its consequence [ISO, 2002], meaning both the probability and consequence need to be evaluated in the determination of the level of risk. A general illustration of a risk picture is given in Figure 4.1.

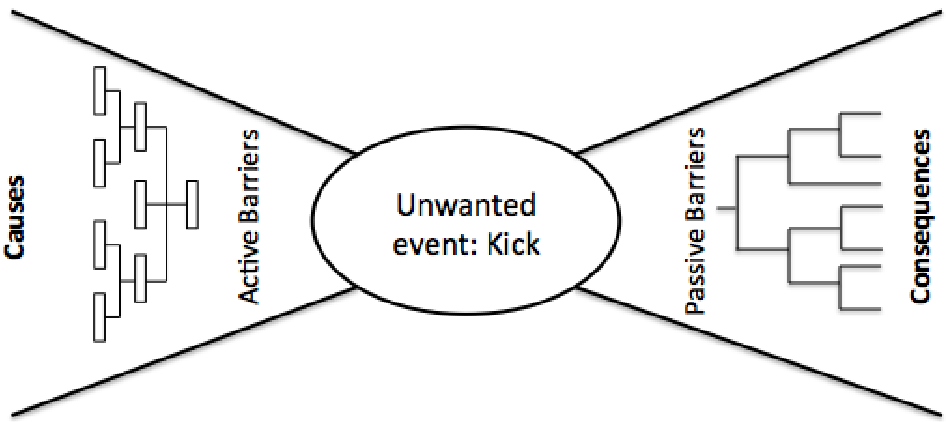

Figure 4.1: Outline of the risk picture with its active and passive barriers

The risk picture gives a clear overview of potential undesired scenarios, and is commonly used for process accident risk analysis [Khakzad et al., 2013]. On the basis of an unwanted event, the model basically includes a fault tree to determine the potential causes and an event tree to determine the potential consequences of the unwanted event. In addition, the risk picture consists of active and passive barriers, to either prevent the unwanted event from occurring or mitigate the impact from it if it occurs. Another classification defines the active barriers as the ones that are active and thus prevent an event to occur, while passive ones are those designed for the situation where the unwanted event occurs [Øie et al., 2014].

4.1.1 Fault tree analysis (FTA)

A fault tree model can be used to gain a better understanding of the causes of the unwanted event and in what ways it can arise. The fault tree is a graphic model that consists of the combination of faults that will lead to the occurrence of the specified undesired event [Stamatelatos et al., 2002]. The unwanted event is then set as the top event in a fault tree diagram, representing an overview of the system under investigation [Vesely and Roberts, 1981]. The faults can be considered as basic events that will result in the top event. In this regard, the fault tree represents the logical interrelationship between these events. A fault tree analysis is a deductive technique focusing on a specified unwanted event that is analyzed to find all the possible ways it can occur [Vesely and Roberts, 1981].

To build the fault tree and express the logic of the model, different symbols are used. There are mainly three types of symbols: events, gates, and transfers [Modarres, 2006]. In this study, the event symbols and gate symbols are utilized to develop the fault trees. The introduced symbols and what they represent are shown in Figure 4.2.

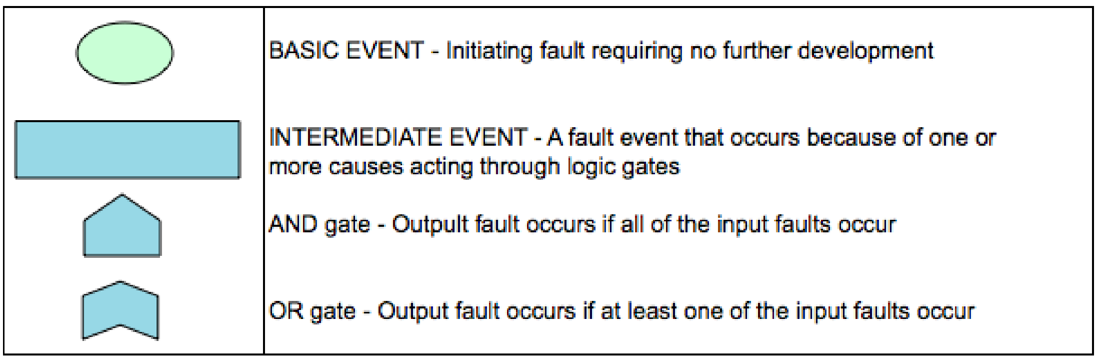

Figure 4.2: Event and gate symbols used to build fault trees, modified from Vesely and Roberts [1981]

4.1.2 Event tree analysis (ETA)

In an event tree analysis, scenarios of successive events leading to hazard exposure and undesirable consequences are modeled [Modarres, 2006]. The analysis utilizes event trees based on forward logic. The trees propagate from an unwanted event through a chosen system, and consider all the potential ways this event can effect the system's behavior [Bedford and Cooke, 2001]. The system consists of subsystems or safety barriers, presented as event headings, which the tree proceeds chronologically through [Modarres, 2006]. The outcomes of the event tree are dependent upon whether these barriers perform their intended function or not.

4.2 Risk picture for the kick event

The schematic of the well control operation in Chapter 3 (see Figure 3.1), presents the elements to be investigated to form the overall risk model. The unwanted event is the kick event, for which its causal picture and phases towards a potential blowout will be analyzed.

4.2.1 Fault tree for kick occurrence

According to the discussion presented for the causes of a kick, the fault tree model, shown in Figure 4.3, is made. When a kick takes place, the primary well control barrier fails. As illustrated in the figure, this can happen in different ways originating from various basic events listed in Table 4.1, part A. It is most common that a kick occurs when making a connection to be able to continue the drilling process, based on an estimation that approximately 70% of the kicks are caused in this operating mode [Fraser et al., 2014].

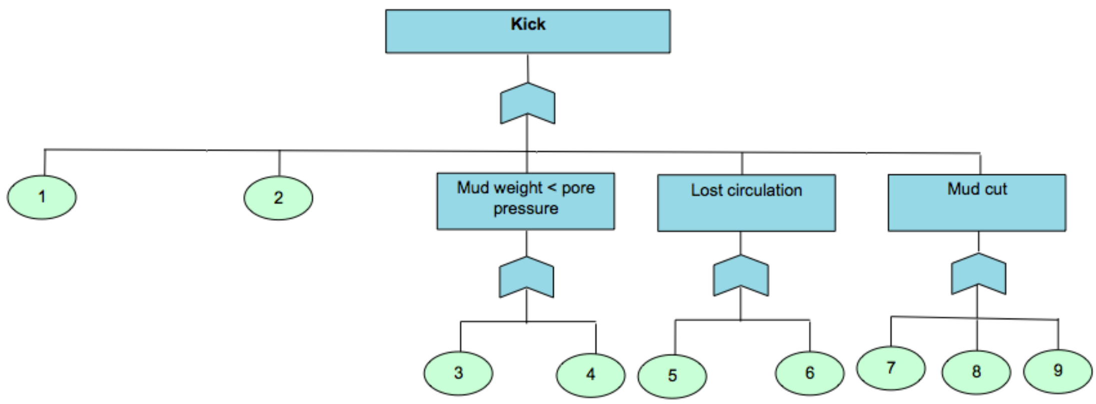

Figure 4.3: Fault tree for the kick event

Table 4.1: Basic events of the kick FT (A) and BOP system FT (B)

A		B	
Index	Description	Index	Description
1	Failure to keep the hole full while tripping	1	Upper annular preventer fails
2	Swabbing while tripping	2	Lower annular preventer fails
3	Too low volume	3	Upper pipe ram fails
4	Too low density	4	Middle pipe ram fails
5	Loss of returns to formation	5	Lower pipe ram fails
6	Plugged annulus	6	Blind shear ram fails
7	Water cut	7	Choke valve fails
8	Oil cut	8	Kill valve fails
9	Gas cut	9	Choke line fails
		10	Kill line fails
		11	BOP control system fails

4.2.2 Event tree for kick detection

The discovery of a kicking well can be considered as the first passive safety barrier to prevent a blowout from occurring. The performance of this barrier can be readily analyzed through an event tree model. The primary kick indicators that most probably will be a part of the early kick detection picture are selected for the development of the event tree. Figure 4.4 illustrates one set of successive events taking place in the first time after the unwanted kick is experienced, involving the flow-out sensor and the PVTs.

In general, for the case of the event tree in Figure 4.4, both the flow-out sensor and PVTs must indicate the possible presence of a kick for actions to be taken. However, if the unwanted influx is larger than 10bbl and detected by the PVTs, this will be a standalone indicator and the well will be shut in [Fraser et al., 2014]. The potential outcomes of the event tree are grouped into three consequence categories: early detection, detection with some major influx and no detection.

The incidents where the kick has been detected in time and no major influx has entered the wellbore, fall within the early detection category. Detection of the kick during the later stages with some major influx in the well, occurs when the operator does not notice indications from the PVTs or that the PVTs fail to indicate the volume changes. In other words, additional time and additional indications are required for the kick to be identified. The last category involves the potential outcomes where the kick is temporary undetected. In this case, both indicators fail to fulfill their function or the operator fails to notice their indications. If the well is not shut in, the kick will escalate into a blowout.

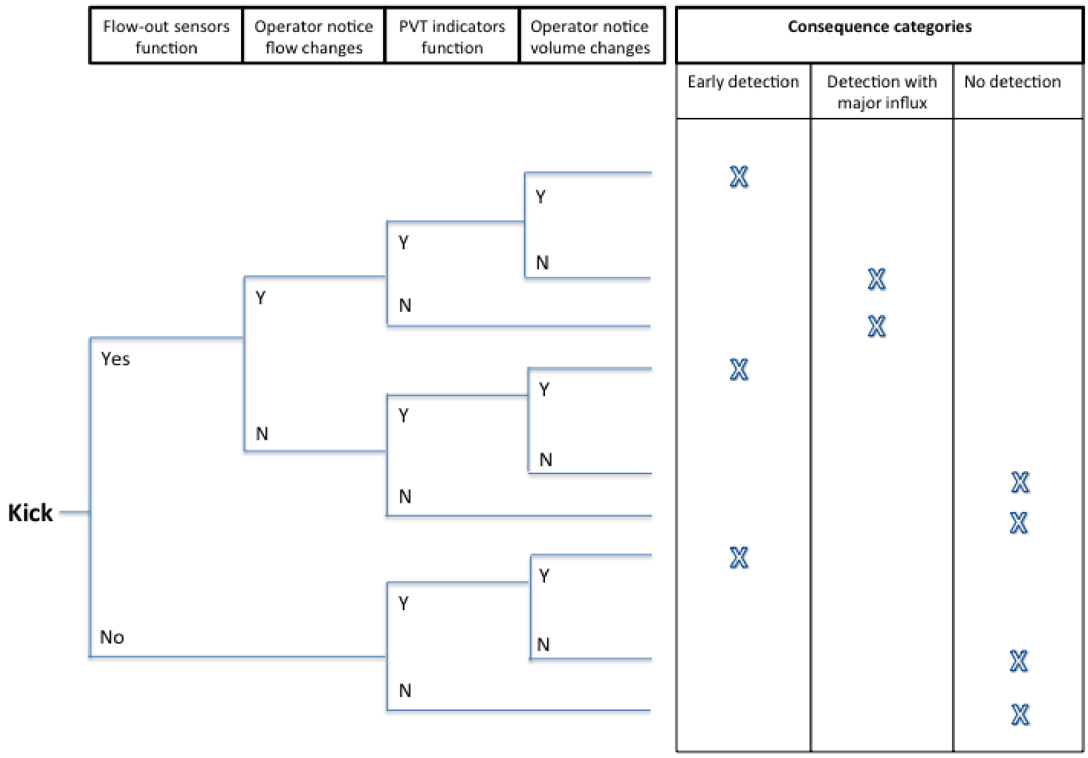

Figure 4.4: Event tree diagram showing the different initial consequence categories of kick occurrence

4.2.3 Fault tree for BOP system

If the kick has been detected, the next step in the well control procedure involves the activation and use of the BOP system. The BOP stack and its associated elements, discussed in previous sections, form the next safety barrier to prevent a well blowout. A fault tree model can be developed, based on which one can assess the reliability of the BOP system, and identify the causes and their interactions that can lead to the failure of the system. Such a fault tree is depicted in Figure 4.5. The model is based on a typical BOP configuration having two annular preventers, three pipe rams, a blind shear ram, choke and kill lines, choke and kill valves, and an overall BOP control system. As illustrated in the model, a failure of choke and kill lines or a failure of choke and kill valves can lead to a BOP system failure. With regards to the BOP stack, it is assumed that both the annular preventers and the ram preventers must fail in order to cause a failure of the stack. The basic events of the fault tree and their descriptions are given in Table 4.1, part B.

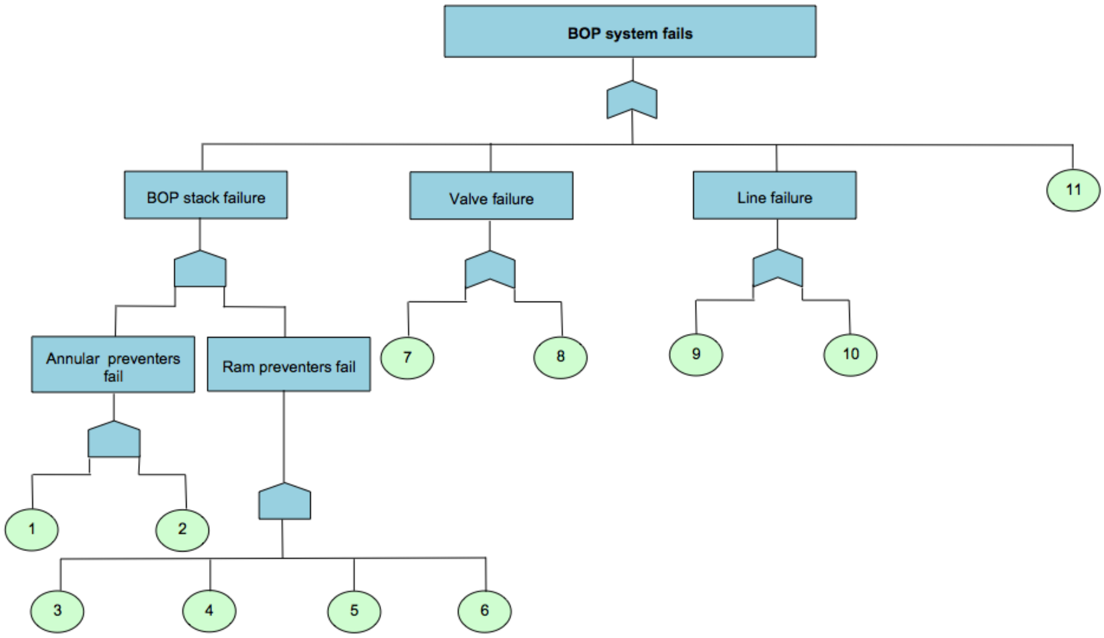

Figure 4.5: Fault tree for the failure of the BOP system

4.2.4 Killing operation

The last step in the well control procedure is killing operation. If the BOP system works and other required facilities are available for use, the killing operation can be initiated. The killing operation forms the last safety barrier to prevent a blowout, and is included as the final barrier in the overall risk picture. In this paper, for simplicity reasons, the early and late kick-detection categories from Figure 4.4 are treated identically. That means, a killing operation can be considered for both the early and late kick detection, on the condition that the wellbore has been already shut in using the BOP stack.

4.2.5 Overall risk model

Using the developed fault- and event tree models, the final risk picture for the kick event can be constructed. The fault tree of Figure 4.3 defines the causal picture. Furthermore, the kick detection barrier modeled in the event tree in Figure 4.4, the BOP system barrier modeled in Figure 4.5, and the killing operation barrier, form the safety barriers to prevent a kick from escalating into a blowout. These barriers, acting as passive barriers once a kick occurs, form an overall event tree. The overall risk model, given in Figure 4.6 illustrates the whole scenario from the part where a kick is experienced to the stages where a blowout is prevented or not. Therefore, two consequence categories, being either near miss or a blowout, are developed.

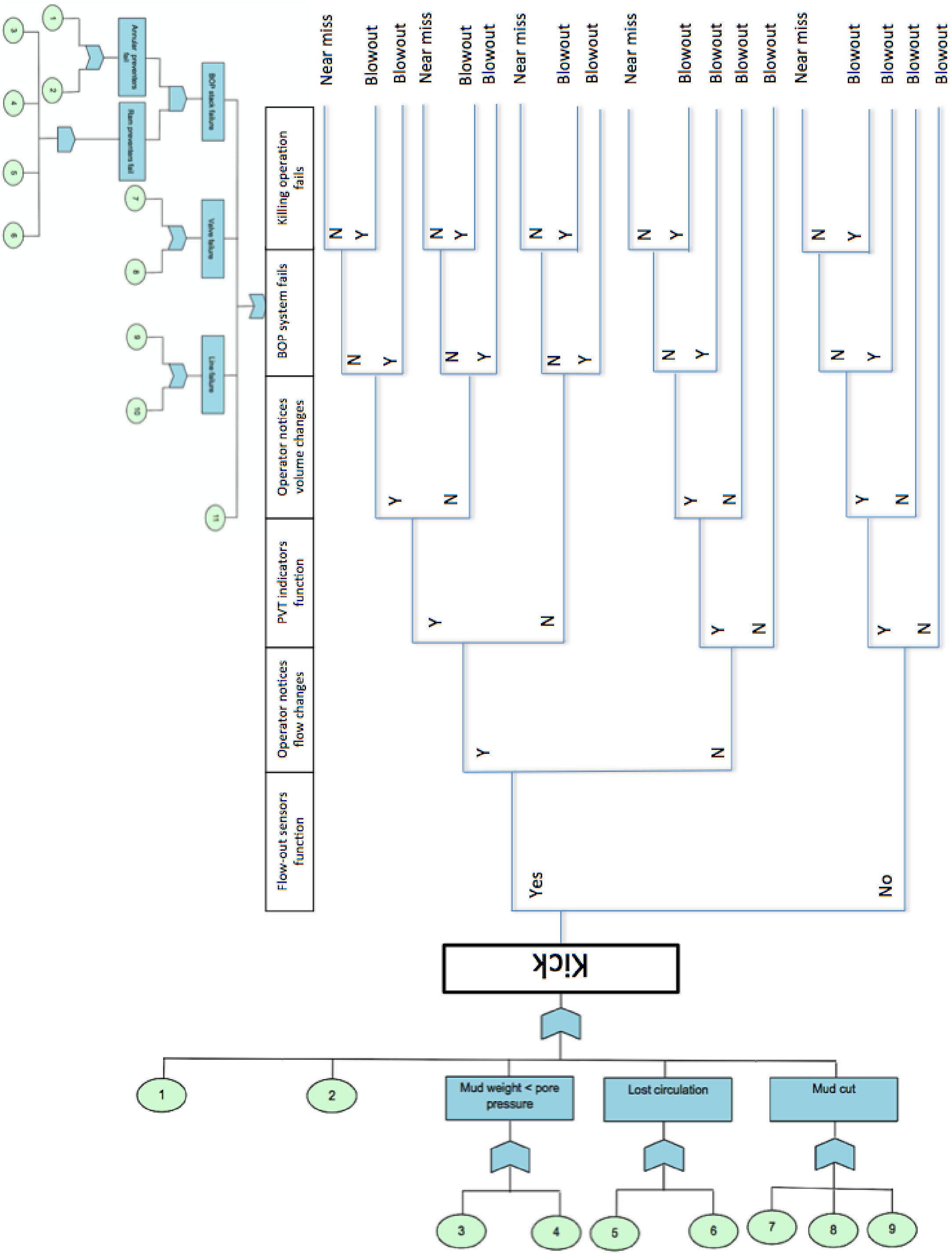

Figure 4.6: Risk picture for the kick event

Chapter 5

Impacts of Arctic operating environment on well control operations

In order to be able to evaluate the reliability performance of well control barriers during drilling operations in the Arctic, it is necessary to identify and assess the potential impact from environmental conditions. In the following, the effects of Arctic operating environment on well control procedures and equipment are reviewed and discussed.

5.1 Kick prevention

The causes of a kick event have been modeled in the fault tree in Chapter 4 (See Figure 4.3). With regards to the failure of the primary well control barrier, the factors involved are related to properties of the formation fluid, drilling fluid characteristics, failure of topside devices and errors made by the drilling crew. In general, the operating environment in the Arctic has the potential to affect well control elements and equipment located topside on the rig. The subsurface formation characteristics are in this paper therefore set to be independent of such conditions, but the remaining factors that can cause the occurrence of a kick can be affected.

In very cold temperatures, the rheological properties of drilling mud and lubricants as well as the mechanical properties of hoses and sealants can be adversely affected [Caenn et al., 2011; Fink, 2012]. The failure probability of pumps, connections, gauges and devices mounted on trip tanks, based on which the operator keeps the well full while tripping, can be increased by such effects.

The harsh weather conditions in the Arctic can adversely influence the performance of the drilling crew [Bercha et al., 2003]. As a consequence, for instance, miscalculations of realtime swab pressure and errors during the tripping procedure are more likely to occur.

5.2 Kick detection

The kick detection barrier includes elements and equipment that will be exposed to harsh weather conditions. The freezing temperatures that will be experienced during a drilling operation in the Arctic, can change material properties. Among others, high-strength steels, plastics and polymers become brittle when exposed to low temperatures [Singh, 2013; Barabadi and Markeset, 2011]. If kick indicators and gauges are composed of such elements, fractures and structural cracks may occur. As transmitters and electronic devices might be sensitive to cold temperatures [Keane et al., 2013], the output signals from the gauges or detectors can be distorted. Furthermore, because of the large temperature variation in the Arctic, topside equipment can experience an additional strain [Larsen and Markeset, 2007]. In addition, in cold temperatures, fluids will freeze and properties of hydraulic oils may change [Barabadi and Markeset, 2011].

The icing feature can potentially threaten the early kick detection, as accretion of ice can reduce equipment accessibility. If, for instance, a pressure indicator has been exposed to severe atmospheric icing and the operator has to do a manual reading, the reduced accessibility may cause difficulties and lead to late kick-detection.

As illustrated in the event tree in Chapter 4 (See Figure 4.4), the performance of the kick detection procedure also depends on the ability of the operators to notice changes in drilling parameters. During severe weather conditions, an operator's cognitive and reasoning abilities might be negatively affected [Larsen and Markeset, 2007]. This may lead to situations where the operator misses to read or notice the changes in drilling parameters or kick occurrence signs. To summarize, all the elements that form the kick detection barrier can be affected by the Arctic operating environment.

5.3 Blowout prevention

The BOP stack is expected to be unaffected by the Arctic operating environment, because of its location on the seabed. Some elements of the control unit system, however, are exposed to severe weather conditions and their reliability performance may be unfavorably affected. Elements of the control unit system include driller's control panel, toolpusher's control panel, work-station, triple modular redundancy controllers, and connecting cables [Cai et al., 2012]. The accessibility to redundant control panels may be limited, because of accreted ice on the floor and accumulated snow, and thus reduce the reliability of BOP control systems. Ice growth on the connecting cables can exert additional and asymmetric loads, which can increase stress and fatigue rate, finally resulting in a shortened lifetime [Ryerson, 2011; NORSOK, 2007]. Besides, the impact of the operating environment on human performance can have adverse effects on the shut in procedure, as the actuation of the BOP preventers are carried out by the operators. The distortion of electric signals in very cold temperatures [Keane et al., 2013] can also reduce the performance of the BOP control system, as it can affect the commands that are to be transmitted from the central control unit to the subsea control pods.

5.4 Killing operation

From a killing operation perspective, equipment units such as mechanical equipment, sensors and gauges, can experience a reduced reliability performance. This is a result of the brittleness of plastics, polymers and metals and the changes in their mechanical behavior under the influence of freezing temperatures. Furthermore, the temperature-dependent rheological properties of drilling mud and lubricants may be altered, which can cause damages to pumps, connections, hoses, lines, etc. During low temperatures and high pressures, natural gas hydrates can form when gas molecules become entrapped in the cages of host clathrate lattices made of hydrogen-bonded water molecules [Gasson et al., 2013; Jamaluddin et al., 1991]. This process can occur in gas cut mud that is being circulated out from the wellbore, finally resulting in operational failures, corrosion and safety hazards in solid control systems.

Loads imposed by accreted ice can damage shelter ceilings and result in equipment malfunction [Ryerson, 2011]. In addition, accumulation of snow and accreted ice will reduce equipment accessibility, which can lead to delays in operation tasks such as the preparation of kill mud and kill mud injection.

The reliability of the killing operation can also be reduced by the increase in human error probability, caused by the effects of being exposed to low temperatures, risks of falling ice and slippery surfaces. Besides, the combination of low temperatures and wind can make breathing difficult, lead to muscular stiffness, and cause frostbites and hypothermia [Bercha et al., 2003], which will negatively affect human performance. Additionally, cognitive errors are more likely to occur during severe weather conditions, along with decreased work effectiveness and accuracy [Larsen and Markeset, 2007].

The presence of sea ice and icebergs in the Arctic will be of concern during drilling operations or well control procedures, as there exist uncertainties regarding the calculation of ice-loads and load effects [Eik, 2010]. If the drilling platform fails to withstand the forces exerted by sea ice, an ongoing well control operation can be interrupted, leading to devastating scenarios. Furthermore, platform vibration induced by crushing ice sheets can be harmful for rig structures, aboard equipment and crew performance [Hou and Shao, 2014]. Ongoing well control procedures, e.g. killing operation, can also be considerably threatened by the occurrence of polar low pressures. The sudden increases in wind speed, icing storms, heavy snowfalls, high waves and the dramatic decrease in temperature associated with these phenomena [Gudmestad and Karunakaran, 2012], can, at the worst, cause the termination of procedures in progress.

For a detailed discussion of the process of establishing a model that can base a foundation for identifying the elements involved in well control procedures that can be affected by the operating conditions in the Arctic, see the appended paper (Appendix D).

5.5 Suggested risk reducing measures

The introduced effects of Arctic operating environment will, if not mitigated, cause a reduction in barrier reliability, resulting in an increase in the probability of well control failure, and thus the risk of a blowout will be enhanced. To cope with such undesired circumstances, a number of risk reducing measures can be implemented.

Some of the issues contributing to an elevated risk can be overcome by winterizing the equipment units and elements, which are likely to be affected by the Arctic weather conditions. Winterization refers to the measures taken for the facilities to be prepared for cold climate conditions in order to achieve an acceptable level of risk. If facilities are exposed to harsh weather conditions, these measures can control the effects of icing, snow precipitation, low temperatures, and other features of the Arctic environment [DNV, 2013]. With regards to topside components, winterization may involve the use of an enclosure probably accompanied by internal heating elements [Gudmestad, 2010]. However, lack of complete enclosure or/and failure of heating elements can occur, presenting potential scenarios of higher risk.

The use of indicators, gauges and alarms, which their function is independent of cold climate conditions, is of great interest in the Arctic. In a successful well control operation, the procedure of detecting a kick at an early stage plays a crucial role. In that case, special consideration must be paid to kick detectors with high reliability performance. Recent studies have proposed adding flow meters to the outflow side of the riser [Fraser et al., 2014]. Not only will this improve the overall performance of the kick-detection safety barrier, it will also move some of the kick indicators away from the harsh surface conditions to more pleasant subsea conditions. Flow meters in the riser have the ability to detect the kick earlier than today's primary topside indicators can. In this case, topside flow meters will serve as redundant indicators that can confirm the deviations in flow rate measured in the riser [Fraser et al., 2014].

In general, adding redundancy can improve the reliability of the whole well control operation. It can be applied, not only to kick indicators, but also to control unit panels, BOP preventers and rams, transmitters, and cables. During a drilling operation, it should be ensured that in emergency cases, all the required facilities and equipment are accessible.

The introduced winterization measures may provide the drilling operators with more convenient working conditions, but there are still remaining stress factors affecting the operator's skill and reasoning capabilities. This will consequently result in an increased risk of human errors to occur. However, optimizing working shifts, providing adequate clothing, and additional training, can, to some extent, improve the operator's performance.

Chapter 6

Quantitative well control risk analysis

On the basis of the developed risk model for the well control operation given in Chapter 4 (see Figure 4.6), the different consequence categories following the kick occurrence can be quantified. In the beginning of this chapter, a quantitive well control risk analysis under normal operating conditions will be performed, for which the required risk and reliability data are available. Furthermore, the relative importance of the well control safety barriers will be identified and a methodology on the propagation of possible uncertainties through the developed risk model will be demonstrated. As discussed in Chapter 5, the performance of well control barriers, active and passive, can be negatively affected by the harsh operating environment in the Arctic. An expert-based approach on how these effects can be quantified and applied to the risk model will finalize this chapter. For this purpose, experts have been questioned regarding the performance of well control procedures, based on which the probability of well control failure and the risk of a blowout and near miss can be assessed.

6.1 Quantitative analysis under normal operating conditions

6.1.1 Reliability data and failure statistics

In order to quantify the possible outcomes of the developed risk model, several databases and reports have been studied and reviewed. These sources of information document and discuss data on risk and reliability of different BOP elements, and provide statistics of previous kick occurrences and blowouts.

Kick occurrence failure probability data

Due to the lack of data on some of the basic events resulting in kick occurrence (see Table 4.1), the overall kick occurrence frequency has been used instead, based on which the probability of kick occurrence can be estimated. The kick occurrence frequency data are from Holand and Awan [2012].

Kick detection failure probability data

With regards to the kick detection procedure, failure probabilities of kick indicators and operators given in a similar well control study have been used [Khakzad et al., 2013]. Based on these data, the probability that a kick is detected can be estimated by using the developed event tree model given in Chapter 4 (see Figure 4.4). The failure data on kick detection barriers, along with the data on kick occurrence probability, are given in Table 6.1.

Table 6.1: Occurrence probabilities for the kick and the kick detection elements [Holand and Awan, 2012; Khakzad et al., 2013]

Index	Events	Probability
1	Kick occurrence	0.00538
2	Flow-out sensor functions	0.99989
3	Operator notices flow changes	0.99500
4	PVT indicators function	0.99986
5	Operator notices volume changes	0.90000

BOP system - Probability of failure on demand

For the BOP system, detailed reliability data for its elements were available. Based on the developed fault tree model given in Chapter 4 (see Figure 4.5), the probability of BOP system failure is estimated in terms of the probability of failure on demand (PFD), as the BOP system serves as a safety instrumented system. The BOP system is a passive safety barrier for drilling operations, and in order to reveal eventual defects, its function needs to be tested on a regular basis. In other words, the system's ability to function when demanded is investigated. The testing frequency should be in accordance with regulations, and a common requirement is that the functional testing should be performed once a week and pressure testing (maximum section design pressure) every 14 days [NORSOK, 2010a]. In this study it is assumed that general tests of the BOP stack, choke/kill valves and choke/kill lines are performed every 14 days, whereas the BOP control system is tested once a week.

The failure statistics of the elements of the BOP system have been collected from Holand and Awan [2012]. On the basis of a discussion in the report, only the number of failures that are regarded as critical in terms of well control have been considered. Assuming a one-parameter exponential distribution to fit the data, corresponding constant failure rates, λ, have been calculated and are reported in the right-most column of Table 6.2.

Table 6.2: Failure rates of BOP system elements

Safety critical failures - BOP system				
BOP elements	**Element ID**	**No. of failures**	**Item days in service**	**λ (per hour)**
Annular preventer	ANNP	6	28150	0.0000089
Ram preventer	RAM	9	77264	0.0000049
Choke/kill valve	C/K V	1	160310	0.0000003
Choke/kill line	C/K L	6	15056	0.0000166
Control system	CSY	8	15056	0.0000221

The configuration of the BOP system can be presented through the reliability block diagram by identifying the minimal cut sets of the fault tree developed in Chapter 4 (see Figure 4.5). Such a block diagram is depicted in Figure 6.1. In the block diagram, the BOP preventers (ANNP and RAM) are presented through the parallel configuration. For simplicity, only one set of choke and kill valves (C/K V) is assumed in this study, and the valves are arranged in series. The same assumptions stand for the choke and kill lines (C/K L), and then finally the BOP control system (CSY) is arranged as a series block.

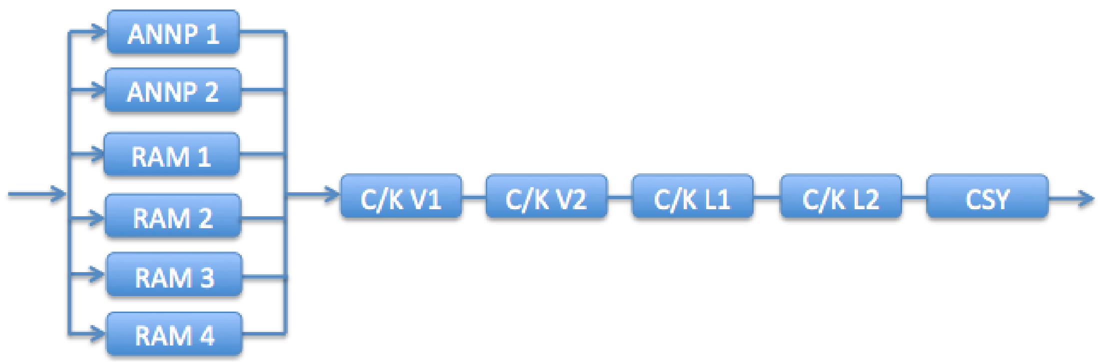

Figure 6.1: Block diagram for the BOP system

On this basis, the PFD for the overall BOP system can be estimated step-by-step. First of all, the PFD for a single item, tested regularly at an interval of length τ and with constant failure rate λ, is given by [Rausand and Høyland, 2004]

$$PFD = 1 - \frac{1}{\tau}\int_0^{\tau} \mathrm{R}(t)\,\mathrm{d}t = 1 - \frac{1}{\tau}\int_0^{\tau} \mathrm{e}^{-\lambda t}\,\mathrm{d}t \approx \frac{\lambda\tau}{2} \tag{6.1}$$

The survivor function in the expression, $R(t)$, depends on system configuration, number of items, parallel or series system, etc. In order to simplify the PFD formulas, some assumptions and approximations can be performed. Before that, one more thing that is common to take into account when evaluating the failure probabilities of, e.g. the redundant preventers of the BOP system, is common cause failures (CCF). With that said, the PFD can be expressed as

$$PFD = PFD_{no\ CCF} + PFD_{CCF} = (1-\beta)X + \beta Y \tag{6.2}$$

In Equation (6.2), X is the contribution from the independent failures of the items in a system, which can be found when inserting $R(t)$ for that particular system in Equation (6.1). Y is the contribution from the common cause failures, causing all the items to fail at the same time [Rausand and Høyland, 2004]. The β factor is the fraction of failures that are due to common causes, which in this case is assumed to be 0.1 or 10%. It can be proved that the βY factor in Equation (6.2) will be the greatest by many magnitudes of order, and the contribution from independent failures can therefore be neglected [Rausand and Høyland, 2004].

Using the introduced theory and approximations from relevant literature, rough PFD estimations for the different elements of the block diagram can be presented. A PFD considering two similar components in series, which can be applied for choke/kill valves and choke/kill lines, is

$$PFD \approx \beta(\frac{\lambda\tau}{2} + \frac{\lambda\tau}{2}) = \beta(\lambda\tau) \tag{6.3}$$

The BOP control system is considered a single item, and the PFD is given by

$$PFD \approx \frac{\lambda\tau}{2} \tag{6.4}$$

For the parallel part of the block diagram in Figure 6.1, a PFD approximation as proposed by Hauge et al. [2010] is used . By assuming six redundant preventers, the PFD is roughly given by

$$PFD \approx \beta(\frac{\sqrt[6]{\lambda_1 \times \lambda_2 \times \ldots \times \lambda_6} \times \tau}{2}) \tag{6.5}$$

Finally, by adding up the given equations, the PFD for the overall BOP system can be written as

$$PFD = PFD_{BOP\ stack} + PFD_{Valves} + PFD_{Lines} + PFD_{Control\ system} \tag{6.6}$$

Using Equation (6.6) and the data given in Table 6.2, the PFD for the BOP system is 0.00253.

Killing operation failure probability data

In this study, it is assumed that the killing operations are more or less always successful. This assumption was made in accordance with the insights given by some offshore drilling engineers. The reason for making an assumption, is due to the lack of historical data on the killing operation when collecting failure probabilities for well control safety barriers. In terms of the definition of a blowout, which in this case refers to major oil spills, explosions, and fatalities, the probability of failure to kill the well is set to be 0.002. In other words, only two killing operations were unsuccessful out one of thousand attempts.

6.1.2 Quantification - normal operating conditions

On the basis of the data given in Table 6.1 and the failure rates of the BOP system and killing operation, the probabilities related to the possible outcomes of kick occurrence can be calculated by applying the standard quantification approach for an ETA (see Figure 6.2). Considering the kick as initiating event and kick detection, BOP system, and killing operation as passive safety barriers, blowout and near miss probabilities are estimated as 2.71E-05 and 5.35E-03. Based on these numbers, it can stated that it is a 0.5% chance for having a kick that will escalate into a blowout. A near miss will be the result 99.5% of the time.

The occurrence probabilities used in the calculations are initially intended for offshore locations where the operating conditions are considered normal, and may not be valid for Arctic locations. In that regard, the potential impact of the Arctic operating environment needs to be accounted for in the developed risk model.

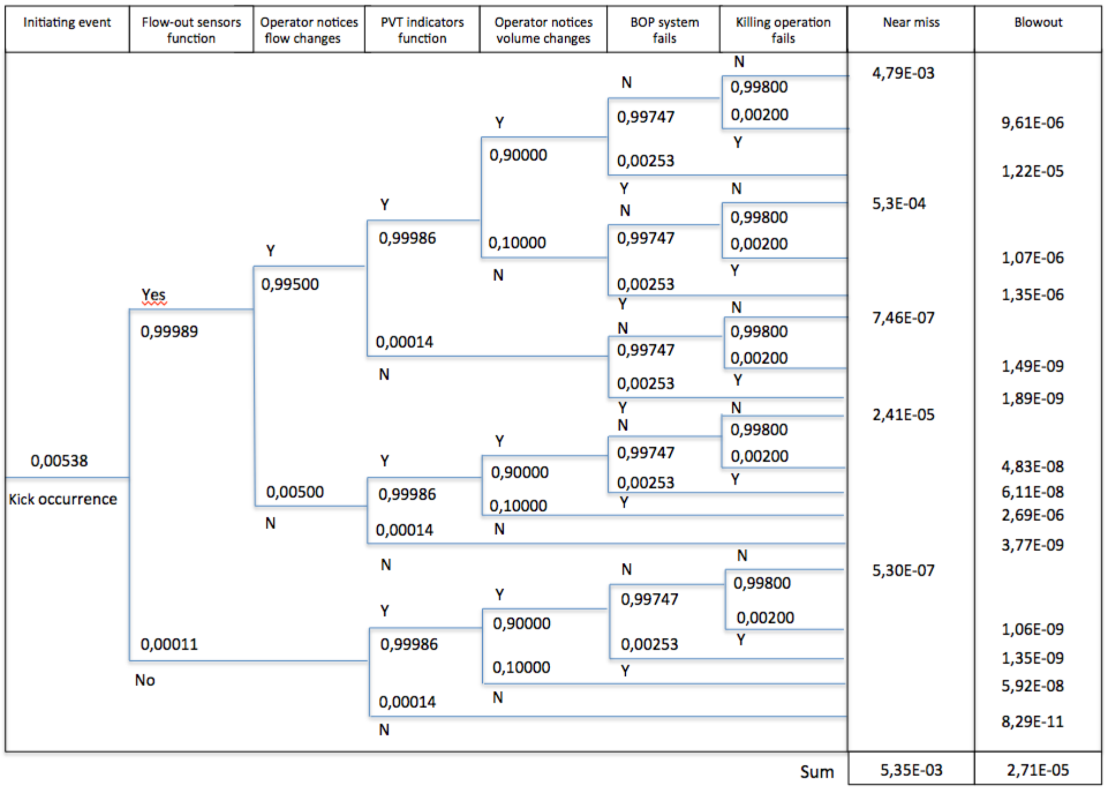

Figure 6.2: Probabilities related to possible outcomes of the kick event

6.2 Sensitivity analysis

In terms of the different consequence categories of the risk model, it is important to identify which of the well control safety barriers have the largest influence on their probabilities. By performing a sensitivity analysis, the relative importance of the input parameters in a model is determined. The importance measures can be obtained by changing the value of an input parameter, such as the failure rate of a component in a fault tree, and then observe the resulting change in the probability of the top event [Modarres, 2006]. In order to investigate which input variable contributes the most to the overall probability change, the process is repeated for different variables. The parameter that contributes the most is considered as "sensitive" and is given the highest priority in the efforts to improve the performance of the system [Modarres, 2006].

For the case of this analysis, the aim is to find the relative importance of well control safety barriers in terms of the resulting near miss probability. This can be demonstrated by using Birnbaum's importance measure. According to Birnbaum, the measure of importance of component i at time t is

$$I^B(i \mid t) = \frac{\delta h(p(t))}{\delta p_i(t)} \quad \text{for i =1,2,..., n.} \tag{6.7}$$

where $h(p(t))$ is the system reliability and p_i(t) is the reliability of component i. By doing some intermediate modifications [Rausand and Høyland, 2004], Equation (6.7) can be written as

$$I^B(i \mid t) = \frac{\delta h(p(t))}{\delta p_i(t)} = h(1_i, p(t)) - h(0_i, p(t)) \tag{6.8}$$

where $h(1_i, p(t))$ is the system reliability given that component i functions at time t, and $h(0_i, p(t))$ the system reliability when component i has failed at time t.

Considering the safety barriers of the event tree in Figure 6.2, and that p_i is not a function of time, Birnbaum's measure of barrier i becomes

$$I^B(i) = h(1_i, p) - h(0_i, p) \tag{6.9}$$

If $I^B(i)$ is large, it means that a minor change in the reliability of barrier i will give a comparatively large change in the resulting consequence probability for near miss.

The importance measures have been identified by using the MATLAB software. By creating a function that returns the probability of near miss based on the reliability of the different barriers in Figure 6.2, the deviation when barrier i is functioning and not can be calculated. This way the importance of barrier i can be determined. The MATLAB code developed for this assignment is given in Appendix A.

The importance measures of well control safety barriers are given in Table 6.3. As presented in this table, the BOP system and the killing operation are considered as sensitive barriers - the former the most sensitive.

Table 6.3: Birnbaum's importance measures for different barrier elements

Index	Barrier element	$I^B(i)$
1	Flow-out sensors	5.34E-04
2	Operator to notice flow changes	5.36E-04
3	PVT indicators	2.46E-05
4	Operator to notice volume changes	2.74E-05
5	BOP system	5.37E-03
6	Killing operation	5.36E-03

In other words, the most significant increase in the probability of near miss will occur if the reliability of the BOP system is increased. At the same time, this increase in the probability of near miss results in a decrease in the probability of a blowout, which is desirable. Therefore, the efforts to improve the reliability performance of well control safety barriers should focus on the BOP system, and also on the killing operation.

6.3 Uncertainty analysis

Uncertainty can be defined as the measure of the "goodness" of an estimate, and can arise as a result of missing knowledge about events or system states [Modarres, 2006]. In this case, uncertainties that can be associated with the parameters representing occurrence probabilities for the barriers and events in Figure 6.2 are studied. Due to a limited amount of data, the given uncertainties are based on assumptions and not real data. The aim of this section is to highlight the concept of uncertainty though, and to show the methodology for uncertainty propagation. Similar methodologies can then be applied when real data are obtained.

By propagating uncertainties related to barrier reliabilities through the event tree in Figure 6.2, the resulting uncertainty in the possible outcomes, near miss or blowout, can be measured. A common method applied for the propagation of uncertainty is the Monte Carlo method. This is a simulation technique where random numbers are used for random sampling of a parameter's uncertainty space [Basil et al., 2001]. In this analysis, the technique is used to sample parameter values from predefined normal distributions with specified mean and standard deviation. This procedure is repeated 1E5 times, while the parameters are part of their respective equations, to obtain a distribution of the resulting near miss and blowout outcomes. The distribution characteristics can then be determined, based on which the properties of the uncertainty associated with the outcomes can be discussed.

The introduced procedure has been carried out by using the MATLAB software. Only the results will be provided here, while the developed script and details of the approach are outlined in Appendix B. From the propagation of parameter uncertainties through the system structure in Figure 6.2, the probability density function (PDF) as shown in Figure 6.3 was obtained for the near miss consequence category. The PDF is a function, $f(x)$, such that for a continuos random variable X, the probability that X takes on a value between a and b is the area under $f(x)$ from a to b, given by [Walpole et al., 2012]

$$P(a < X < b) = \int_a^b f(x)dx \tag{6.10}$$

In the plot of the PDF for the near miss variable, X, in Figure 6.3, the densities of possible near miss values are illustrated. Along with the PDF, the 10 %, 50% and 90% quantiles are given. The quantiles describe the probability that the near miss variable is less than or equal to a particular value.

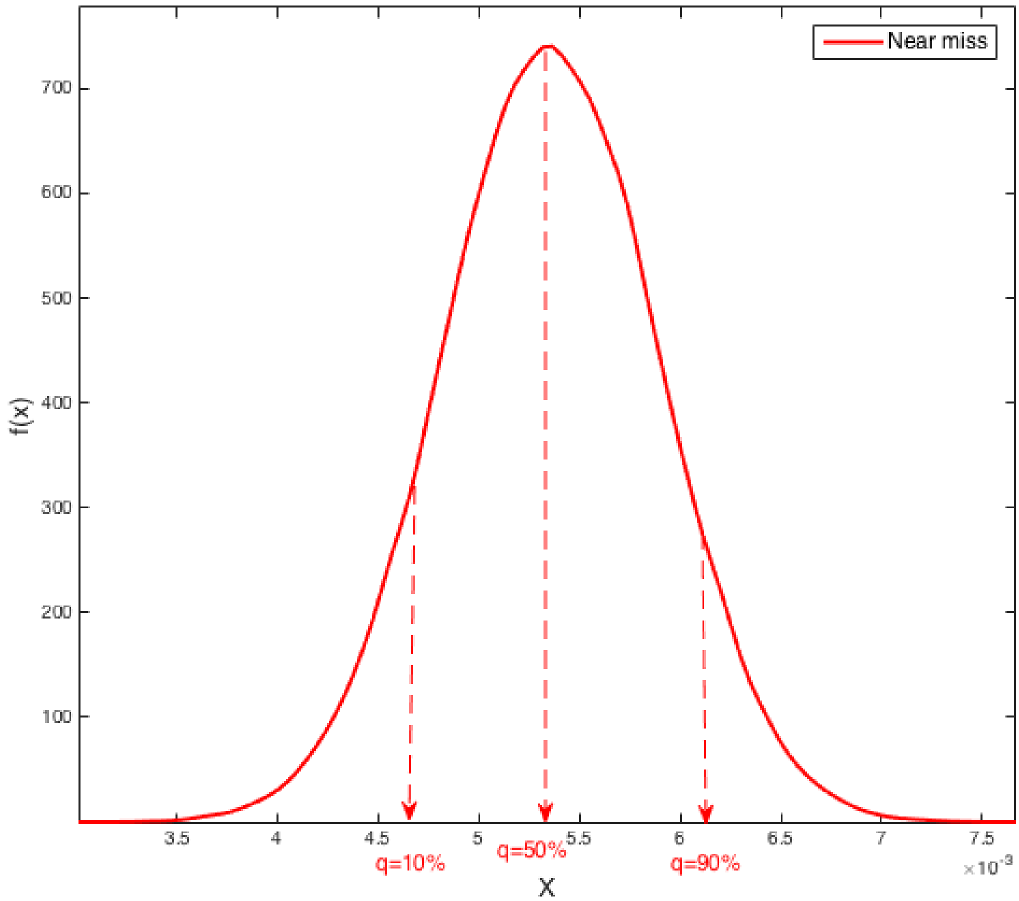

Figure 6.3: PDF plot for near miss with 10, 50 and 90% quantiles

On this basis, the uncertainty related to a potential near miss can be summarized. In five out of ten times, the probability of a near miss will be less than or approximately equal to 5.35E-03, which was the value calculated for normal operating conditions. In nine out of ten times, the probability of a near miss will be less than or approximately equal to 6.04E-03. The overall span of the near miss uncertainty is from approximately 3.0E-03 to 7.5E-03.

6.4 Quantification of the effects of Arctic operating environment

To evaluate the performance of well control operations in the Arctic, the potential environmental effects on well control barriers and procedures should be accounted for in the risk model. By estimating the possible reduction in the reliability performance of well control procedures due to the adverse effects of Arctic operating environment, the resulting change in near miss and blowout probability can be quantified. These numbers can then be compared with the situation under normal operating conditions. In this study, a methodology using expert opinions is presented.

6.4.1 Quantitative analysis using expert judgements

The use of expert judgement methods can be applied in quantitative analyses of risk and reliability. Expert opinions are useful when quantifying models in unique situations and are often used when considering parameter uncertainties [Bedford and Cooke, 2001]. In the process of assessing the impact of Arctic operating conditions on the performance of well control procedures, it is quite relevant to involve experts due to the scarcity of historical data from operations under such conditions.

The expert judgement process

The use of expert judgement in an assessment can be considered a three-phase process. Two of these phases concerns decision-making, known as elicitation of expert opinions and analysis of expert opinions [Modarres, 2006]. In advance comes the expert selection-phase, where experts qualified to give reasonable opinions on the specific subject are chosen. An expert should be familiar with the system, hold knowledge about its working environment and have practice in the system operation [Rajakarunakaran et al., 2015]. When the experts have been selected, elicitation of their opinions is the next step. In this process, an expert's subjective judgement is obtained, in the form of, i.e., single probability values, probability distributions, quantiles of a distribution or a range of values [Bedford and Cooke, 2001]. The received opinions must be handled with care, as there might be motivational biases behind them. Such biases can occur, i.e., if an expert has a stake in the result of the study [Bedford and Cooke, 2001]. In the attempt of accounting for the biases, weighing factors can be used to reflect the relative quality among the experts [Clemen and Winkler, 1999].

Once the opinions from the experts are elicited, a method needs to be developed to aggregate the obtained data. There exists different approaches on how to do this, which can be divided into mathematical approaches and behavior approaches [Clemen and Winkler, 1999]. Among the mathematical approaches, linear and logarithmic pooling methods can be used to aggregate the opinions [Bedford and Cooke, 2001]. On the basis of the combined opinions, the uncertainty of interest of the system under investigation can be assessed.

Analyzing the performance of well control procedures

In this occasion, expert opinions are used to analyze the reliability performance of well control procedures in the Arctic, with the intention to assess the resulting blowout probability. The purpose is illustrated in Figure 6.4, showing how the input from experts will be accounted for in the consequence categories. Their opinions will be combined to form percentages of increase in the failure probabilities of well control procedures, which are added to the parameters from baseline areas.

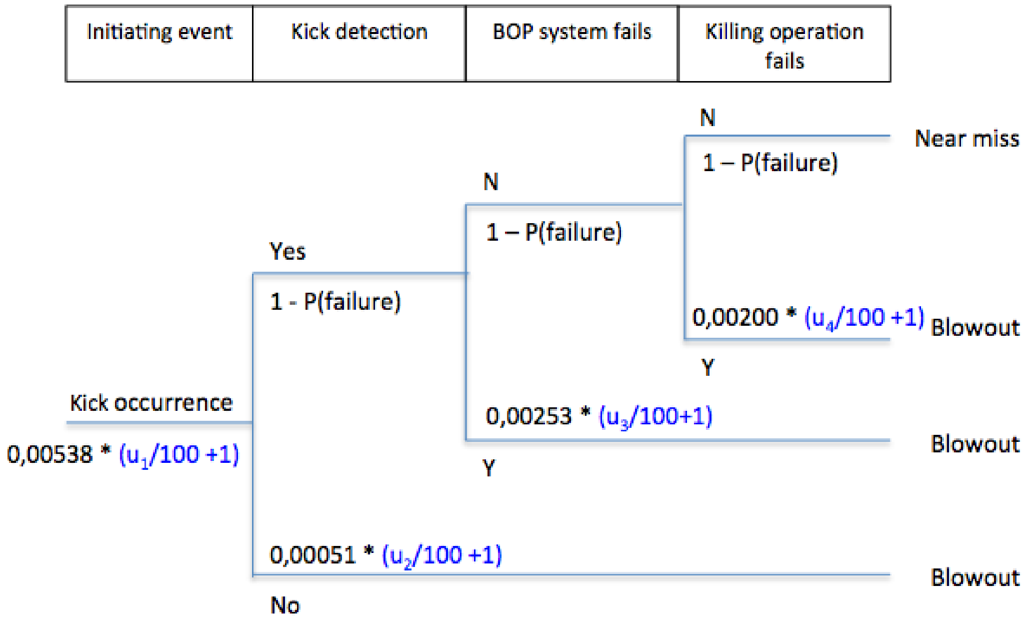

Figure 6.4: Input from experts is combined to form percentages of increase, u_n, which will be added to baseline failure probabilities

A questionnaire has been developed, where the experts are informed about the objective, the environmental conditions and the operation that is investigated. The experts are asked to give their opinion on the failure probability of well control procedures during a drilling operation in the Arctic. Their estimates are in the form of percentage intervals, which can be used to modify the historical data on barrier reliability from baseline areas. As the author was unable to get a response from experts, this analysis is based on assumptions with the purpose of illustrating the methodology. Thus, the results obtained from expert judgements cannot represent any practical use.

Aggregation of expert data

In Table 6.4, an example of data that can be received from an expert is presented. A total of four opinions, based on four questions, on the failure probability of well control procedures in the Arctic are given by the expert.

Table 6.4: Example of data given by expert i

Well control procedures	**Percentage of increase in failure probability**
Kick prevention	5-10%
Kick detection	15-20%
Blowout prevention	5-10%
Killing operation	10-20%

The obtained opinion, on each question, can be regarded as a uniform distribution over a specified interval from a to b, where a is the lowest percentage of increase in the failure probability and b is the highest. A generalized expression on the range given by expert i on question m can be written as

$$[a_{im}, b_{im}], \quad \text{for i=1,2,..,N and m=1,2,..,M} \tag{6.11}$$

where N and M stand for the number of experts and questions, respectively. For the process of combining expert data to form an aggregated opinion on the percentage of increase in the failure probability of each well control procedure, the MATLAB software is used. The developed script is given in Appendix C. At first, a random expert i is selected, among equally weighted experts, and a sample from his distribution provided for question $m = 1$ is captured, through a Monte Carlo simulation. This sequence is repeated for each question, and run 5E3 times, based on which a PDF of possible percentages of increase in failure probabilities for each of the four procedures in Table 6.4 can be generated. The PDF of the percentage of increase in kick prevention failure probability, from question 1, is given in Figure 6.5.

On the basis of each PDF, empirical cumulative distribution functions (CDF) can be made, evaluating the probability that the percentage of increase takes a value less than or equal to ϵ. If E is the percentage of increase, the CDF is [Zio, 2013]

$$F_E(\epsilon) = \int_{-\infty}^{\epsilon} f_E(\epsilon')d\epsilon' = P(E \leq \epsilon) \tag{6.12}$$

The decision-maker's CDFs are given in Figure 6.6., where x_1 evaluates the percentage of increase in the failure probability of the kick prevention procedure, x_2 the kick detection procedure, x_3 the blowout prevention procedure and x_4 the killing operation procedure.

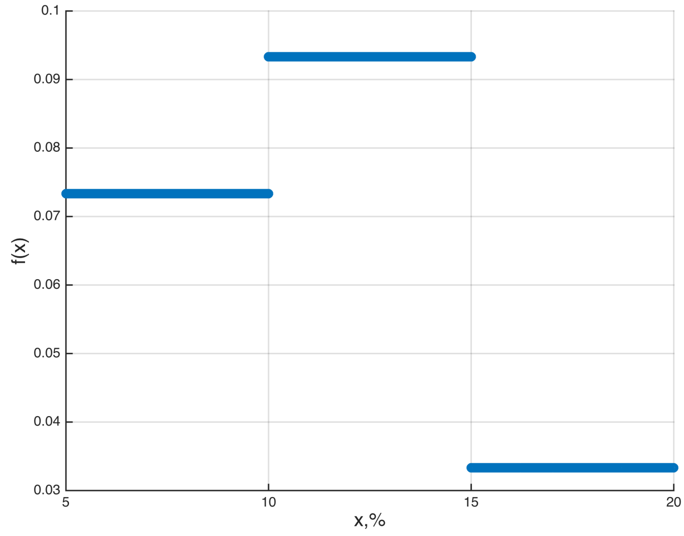

Figure 6.5: PDF of expert opinions, describing the percentage of increase in the failure probability of the kick prevention procedure

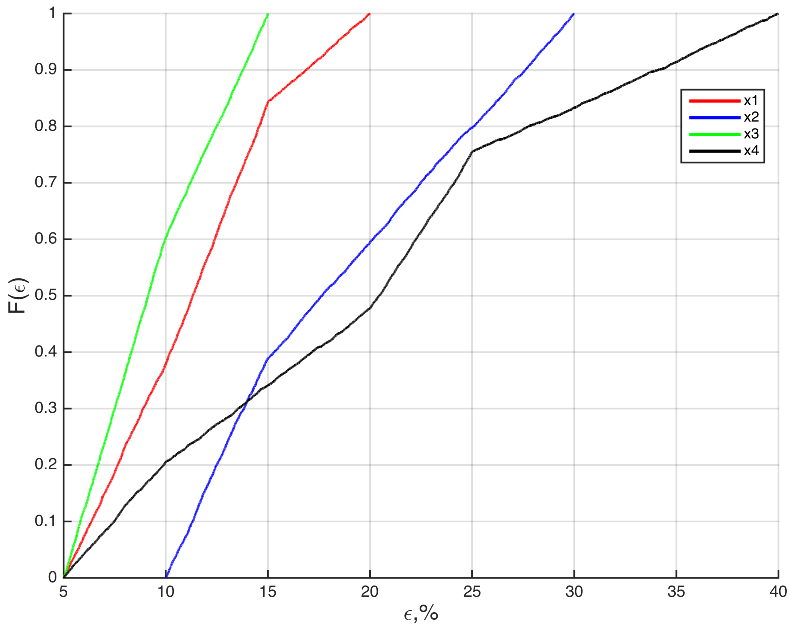

Figure 6.6: 4 CDFs that the decision-maker can use for the analyses, describing the percentage of increase in the failure probabilities of well control procedures through x1, x2, x3 and x4

Furthermore, to find the actual percentage of increase in each of the four cases, samples following an inverse transform method are taken from the empirical CDFs. Based on a value R sampled from the uniform distribution over [0,1], it can be proved that, in the case with discrete values ϵ_k, the probability that R lies within the interval $(F_{k-1}, F_k]$ is [Zio, 2013]

$$P(F_{k-1} < R \leq F_k) = \int_{F_{k-1}}^{F_k} dr = F_k - F_{k-1} = f_k = P(E = \epsilon_k) \tag{6.13}$$

where $k = 0, 1, ...,$ and, by definition, $F_{-1} = 0$. From this, the realization $E = \epsilon_k$ is obtained, where k is the index of $F_{k-1} < R \leq F_k$.

The samples of the percentage of increase in the failure probabilities of well control procedures can then be added to the failure probabilities from base area, and updated near miss and blowout probabilities can be calculated. A Monte Carlo simulation approach is used to estimate the consequence probabilities for different values of increased failure probabilities. The PDF of the blowout consequence category is given in Figure 6.7.

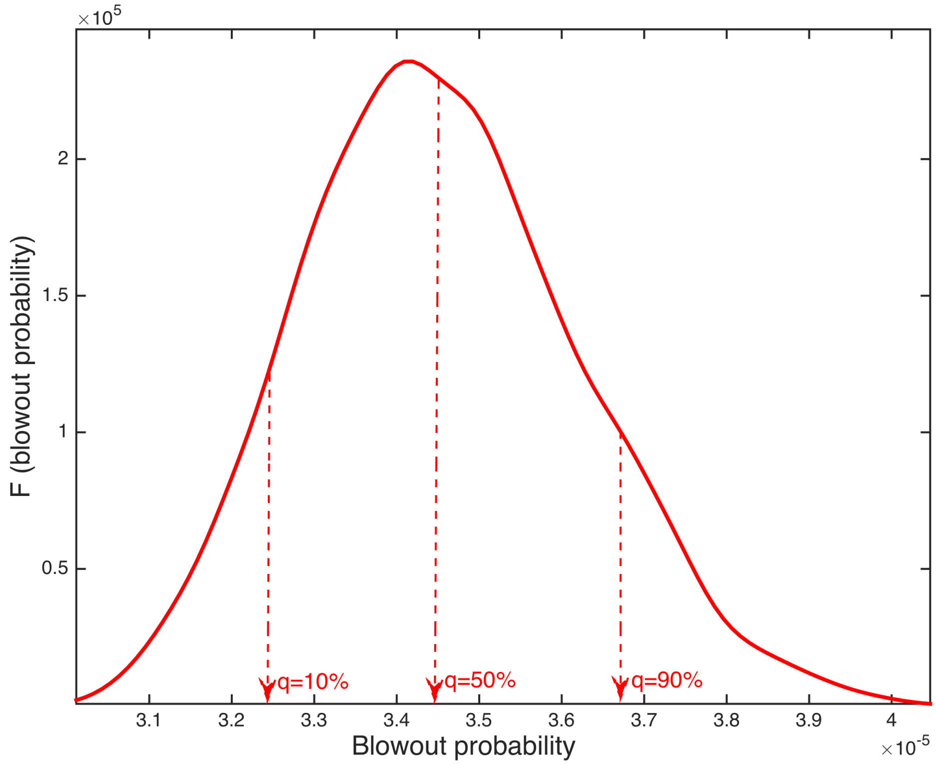

Figure 6.7: PDF plot for blowout with 10, 50 and 90% quantiles

Analyzing the results

Based on the PDF plot for blowout in Figure 6.7, the potential increase in blowout probability as a result of the effects of Arctic operating conditions can be discussed. As illustrated in the plot, on an average basis, the probability of a blowout is approximately 3.45E-05 (50% quantile). In comparison, the blowout probability at a baseline location was estimated to be 2.71E-05. The decrease in the reliability performance of well control procedures, thus result in approximately a 27 % increase in the probability of having a blowout. In this case, the opinions from experts were based on assumptions with the purpose of illustrating the methodology. Such a methodology can be applied when true estimates are obtained from experts, and thus the introduced approach can be used in real practices.

Chapter 7

Results and discussion

In this chapter, the findings of the current research are presented and discussed. The focus of the discussion is on the stated thesis objectives.

In order to evaluate the performance of well control operations during different operating conditions, a risk model was developed. Based on the review and discussion of primary and secondary well control barriers, their failure causes and consequences could be determined through FTA and ETA. By using the risk picture approach, resulting consequence categories of kick occurrence were identified, for which potential negative effects of Arctic operating conditions could be accounted for in their probabilities of occurrence.

Through the review of the Arctic environment and its distinctive features, the harsh physical conditions that will be experienced during drilling operations in the Arctic were documented. On this basis, it was found that the environmental conditions may not influence the characteristics of the subsurface formations, but can adversely affect the remaining elements involved in the procedures of a well control operation. As a result, the reliability performance of the kick prevention phase, kick detection phase, and blowout prevention and killing operation phases, can be reduced. Some of the factors contributing to such an elevated risk can be overcome through the use of winterization measures. Furthermore, additional risk reducing measures are suggested, which can be implemented to improve reliability performance. It can be stated that it will be a demanding task to maintain a risk level equal to that associated with baseline locations, especially considering the negative effects of Arctic operating environment on human performance.

Based on the developed risk model, the probability of a blowout being a result of well control failure could be quantified under normal operating conditions. With kick occurrence as initiating event and kick detection, BOP system, and killing operation as passive safety barriers, the blowout probability was estimated to be 2.71E-05. Detailed reliability data were not available for all elements, which can be reflected in the accuracy of the result. However, the purpose with the quantitative analysis under normal conditions was to form a basis, which the result from the analysis under Arctic operating conditions can be compared with.

In decision-making processes, it is important that the uncertainties that can be associated with the obtained estimates are considered. In the uncertainty analysis performed in Chapter 6, a methodology on the propagation of parameter uncertainty through the risk model was presented. By applying the introduced methodology, measures of the uncertainties related to the possible outcomes of kick occurrence are obtained, which can be included in the decision-maker's analysis.

To evaluate the relative importance of well control safety barriers in terms of blowout probability, a sensitivity analysis was performed. It was found that the BOP system and the killing operation can be considered the most sensitive barriers. The efforts to improve the performance of the well control operation should thus be focused on these elements. Possible efforts to achieve an improved performance can be, for instance, increasing the number of BOP ram preventers, adding redundancy to the BOP control system, and special training for the crew on well control under severe weather conditions.

A methodology using expert opinions was demonstrated for the process of quantifying the effects of Arctic operating environment. Expert judgements on the reliability performance of well control procedures were requested, based on which an aggregated opinion could be formed for decision-makers to evaluate the probability of a blowout under Arctic operating conditions. As the author was unable to get a response from experts in an appropriate time, the analysis had to be based on assumptions. However, the introduced methodology can be applied by the time real expert data are obtained. Then, the probability of well control failure resulting in a blowout, where Arctic environmental effects are accounted for, can be estimated.

Based on the qualitative analyses of the impact of Arctic operating conditions and indications of reduced reliability performances of well control procedures, generally, there will be an elevated probability of losing well control barriers during Arctic drilling operations and severe weather conditions. The level of risk will vary depending on the drilling rig location in the Arctic and time of year. During periods of increased strain due to extreme temperatures, icing and negative effects on human performance, the risk of a blowout will be increased.

With more resources and data available, further work can be done to improve the results of the performed analyses. In order to obtain more accurate estimates of probability and risk, there is a need of detailed historical data on the reliability of every well control barrier and procedure. Furthermore, a study on crew performance under severe weather conditions must be established. To quantify the effects of Arctic operating conditions on the failure probability of well control equipment, reliability testing should be performed in harsh physical environments. If expert judgement methods are used, different weighting approaches should be tried, to observe how it affects the analysis result.

Chapter 8

Conclusion

As the petroleum industry moves further north in the Arctic region, there is a need of updated analyses assessing how the harsh physical environment in the region can affect operational reliability and safety. From risk perspective, the well control operation is among the most important operations in every drilling activity, as a failure to control the wellbore can result in oil spills, explosions and major fatalities. Potential effects of Arctic operating environment on the reliability of well control barriers must therefore be investigated, to assess the risk of well control failure and the probability of a blowout under these circumstances.

In this thesis, a risk model was developed for a well control operation, based on which potential impacts of Arctic operating conditions can be evaluated. An approach on how to quantify such impacts using an expert judgement method has been proposed. By implementing this method, the potential increase in the probability and risk of losing well control barriers can be identified and applied to the developed model. The risk of a blowout in the Arctic can thus be estimated.

In order to improve the performance of the well control operation, the efforts should focus on the BOP system and the killing operation, as it has been found that these elements are the most sensitive well control barriers.

Most of the issues imposed by the severe weather conditions on topside well control elements, can be overcome by implementing adequate winterization measures. However, the role of human performance in well control procedures must also be considered. In general, the human performance is considered poorer in Arctic drilling operations. As a result, and on the basis of qualitative analyses of reliability performance, it is concluded that the risk of a blowout in Arctic offshore drilling operations will be higher than the risk associated with drilling operations under normal-climate conditions.

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Appendix A

MATLAB script used in sensitivity analysis

To do the sensitivity analysis and determine the importance measures, the MATLAB software was used. The function that was created for this purpose is given below. To obtain the importance measure of barrier i, the function was run twice. At first the value of r_i was set to 1, afterwards it was shifted to zero, and then $I^B(i)$ was identified by measuring the deviation in the output(near miss) probability.

MATLAB code

```
function [ nm ] = nm( r )
%Near miss function, nm(r), returning the probability of
%a near miss by adding up the five branches(k=1:5) in the
%event tree leading to this outcome.

%Function nm accepts an input vector r, representing
%the occurrence probabilities(reliability) for the
%top headings in the event tree.

%By changing the input vector r, the corresponding change
%in nm(r) can be measured.

%
nm=0;

for k=1:5                %Near miss, uppermost branch
    if k==1
        for l=1:7
            s(l)=r(l);
        end

        a(k)=1;
```

```
        for j=1:7
            a(k)=a(k)*s(j);
        end
        nm=nm + a(k); %Near miss

    elseif k==2          %Near miss, branch nr 4
        for l=1:4
            s(l)=r(l);
        end
            s(5)=1-r(5);
            s(6)=r(6);
            s(7)=r(7);

        a(k)=1;

        for j=1:7
            a(k)=a(k)*s(j);
        end
        nm=nm + a(k);       %Updated Near miss

    elseif k==3     %Near miss, branch nr 7
        for l=1:3
            s(l)=r(l);
        end
            s(4)=1-r(4);
            s(5)=1;
            s(6)=r(6);
            s(7)=r(7);

        a(k)=1;

        for j=1:7
            a(k)=a(k)*s(j);
        end
        nm=nm + a(k); %Updated Near miss

    elseif k==4     %Near miss, branch nr 10
        s(1)=r(1);
        s(2)=r(2);
        s(3)=1-r(3);
        for l=4:7
            s(l)=r(l);
        end

        a(k)=1;

        for j=1:7
            a(k)=a(k)*s(j);
        end
        nm=nm + a(k); %Updated Near miss

    elseif k==5     %Near miss, branch nr 15
```

```
        s(1)=r(1);
        s(2)=1-r(2);
        s(3)=1;
        for l=4:7
            s(l)=r(l);
        end

        a(k)=1;

        for j=1:7
            a(k)=a(k)*s(j);
        end
        nm=nm + a(k); % Total Near miss
    end


end
```

Appendix B

MATLAB script used in uncertainty analysis

The sampling of a parameter's uncertainty space and the propagation of uncertainty through the system were carried out using MATLAB. Firstly, it was assumed that the parameters were normally distributed with a predefined mean and standard deviation. Then, random numbers were sampled from these distributions by using Monte Carlo simulation. Furthermore, the parameters, representing barrier reliabilities, were put into their respective equations based on the structure of the event tree in Figure 6.2, so the resulting blowout and near miss probabilities were obtained. By repeating the sampling procedure for the parameters, to the total of i=1E5 times, matrices for the near miss and blowout categories were obtained, containing all the possible outputs.

On the basis of the matrix of possible outputs for the near miss probability, a distribution can be developed to fit the results, based on which a probability density function (PDF) can be plotted. The PDF plot and evaluations of the results are provided in the thesis.

MATLAB code

```
% Script for the determination of parameter uncertainty
% space, and the propagation of uncertainties
% through the Event tree

% Random numbers are sampled from normal distributions,
% normrnd, with a mean and st.dev (mean, st.dev)
% with specifications to avoid non-positive values

for i=1:100000
                    % mean   %st.dev
    r1=max(normrnd(0.00538,5.38e-04),0);  %Kick_occurrence
    r2=max(normrnd(0.99989,1.1e-05),0);  %Flow_out_sensors
```

```
    r3=max(normrnd(0.99500,5.0e-04),0);  %Operator_to_notice_1
    r4=max(normrnd(0.99986,1.4e-05),0);  %PVT_indicators
    r5=max(normrnd(0.90000,1.0e-02),0);  %Operator_to_notice_2
    r6=max(normrnd(0.99747,2.53e-04),0);  %BOP_system
    r7=max(normrnd(0.99800,2.0e-04),0);  %Killing_operation

% Formulas to determine the probability of ET outcomes

A(i)=r1*r2*r3*r4*r5*r6*r7; %First branch of event tree
B(i)=r1*r2*r3*r4*r5*r6*(1-r7); %Second branch and so on
C(i)=r1*r2*r3*r4*r5*(1-r6);
D(i)=r1*r2*r3*r4*(1-r5)*r6*r7;
E(i)=r1*r2*r3*r4*(1-r5)*r6*(1-r7);
F(i)=r1*r2*r3*r4*(1-r5)*(1-r6);
G(i)=r1*r2*r3*(1-r4)*r6*r7;
H(i)=r1*r2*r3*(1-r4)*r6*(1-r7);
I(i)=r1*r2*r3*(1-r4)*(1-r6);
J(i)=r1*r2*(1-r3)*r4*r5*r6*r7;
K(i)=r1*r2*(1-r3)*r4*r5*r6*(1-r7);
L(i)=r1*r2*(1-r3)*r4*r5*(1-r6);
M(i)=r1*r2*(1-r3)*r4*(1-r5);
N(i)=r1*r2*(1-r3)*(1-r4);
O(i)=r1*(1-r2)*r4*r5*r6*r7;
P(i)=r1*(1-r2)*r4*r5*r6*(1-r7);
Q(i)=r1*(1-r2)*r4*r5*(1-r6);
R(i)=r1*(1-r2)*r4*(1-r5);
S(i)=r1*(1-r2)*(1-r4);

end

%Results

Near_miss=A+D+G+J+O;
Blow_out=B+C+E+F+H+I+K+L+M+N+P+Q+R+S;
```

Appendix C

MATLAB script used in expert judgement method

For the process of combing expert data to form aggregated opinions and evaluate the resulting consequence probabilities, the MATLAB software was used. The developed script with explanations is given here, while the overall procedure is explained in the thesis. With regards to the failure probability of kick detection, the given number, 0.00051, represents the overall probability of a kick non-detection, in other words the *no detection* category in Figure 4.4.

MATLAB code

```
% Script for the combination and aggregation of expert data
clear all
close all

N_exp=5;     % N number of Experts
M_ques=4;    % M number of questions

% Failure probabilities of well control procedures, base area
Q_base=[0.00538; 0.00051; 0.00253; 0.00200];

% Percentage intervals [a,b] provided by experts
a=[5 15 5 10
   5 10 10 20
   10 10 5 5
   10 20 10 20
   5 20 5 10];

b=[10 20 10 20
   15 15 15 25
   15 15 10 10
   20 30 15 40
   20 30 10 40];
```

```
%Experts are equally weighed
w=[0.2; 0.2; 0.2; 0.2; 0.2];

N_sim=5000;
for m=1:M_ques

    for j=1:N_sim

        Sel_exp=randi(N_exp);    %Random expert is selected along with his
                                 %idea
        r(j,m)=(b(Sel_exp,m)-a(Sel_exp,m))*rand+a(Sel_exp,m);

        s=0;
        for k=1:N_exp
           s=s+ w(k,1)*unifpdf(r(j,m),a(k,m),b(k,m));
        end

        DM(j,m)=s;             % Uniform pdfs generated, DM holds the
                               % obtained densities
    end
end

figure(1)
scatter(r(:,1),DM(:,1));grid on;
xlabel('x,%','fontsize',14)
ylabel('f(x)','fontsize',14) ; % See plot in thesis
colourcode={'-r';'-b';'-g';'-k'};
for m=1:M_ques

    [F(:,m),x(:,m)] = ecdf(r(:,m)); %Empirical cdfs generated
figure(2)
xlabel('\epsilon,%','fontsize',14)
ylabel('F(\epsilon)','fontsize',14);hold on
h(m)=plot(x(:,m),F(:,m),colourcode{m},'linewidth',2);grid on; %See plot in thesis

end
legend([h(1),h(2),h(3),h(4)],'x1','x2','x3','x4')

for k=1:N_sim
    for m=1:M_ques
        Row_number=find(F(:,m)>=rand,1,'first'); %Samples from the cdfs
        sample(m,1)=x(Row_number,m);

    Q(k,m)=Q_base(m,1)*(sample(m,1)/100+1); % Percentage of increase added
                                            % to base values
    end
    %Event tree consequence quantifications
    NM(k,1)=Q(k,1)*(1-Q(k,2))*(1-Q(k,3))*(1-Q(k,4)); % Near miss
    BO(k,1)= Q(k,1)-NM(k,1); % Blowout
end
```

Appendix D

Conference paper

Bergan, H. and Naseri, M. (in press). Well control operation in the Arctic offshore: A qualitative risk model. *Proceedings of the 23rd International Conference on Port and Ocean Engineering under Arctic Conditions* (POAC). June 14-18, Trondheim, Norway.

WELL CONTROL OPERATION IN THE ARCTIC OFFSHORE: A QUALITATIVE RISK MODEL

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ABSTRACT
Oil and gas development in the Arctic is becoming a major focus in the industry today. However, compared to other regions, the less experience of drilling operations in the Arctic raises concerns about high-risk scenarios that might take place because of the harsh environmental conditions and their effects on operations, equipment, and human performance. In any offshore drilling setting, well control operations are among the most crucial activities taking place as failure to control the wellbore can lead to devastating scenarios such as oil spills, explosions, and major fatalities. There are mainly two safety barriers in place to prevent the loss of well control: primary and secondary well control barrier. The aim of this paper is to develop a qualitative risk model for a well control operation in the Arctic offshore. This aim is achieved by analysing the adverse effects of Arctic operating conditions on the causes and consequences of losing the primary and secondary well control barrier. Some risk reducing measures are then proposed based on such analysis.

INTRODUCTION
Despite the increasing trend of oil and gas activities in the Arctic offshore, there exist some major issues and challenges posed by the severe weather conditions and distinctive environmental features of the Arctic offshore, which need to be dealt accordingly. The Arctic offshore is characterized by harsh environmental conditions such as seasonal darkness, snowstorms, freezing temperatures, atmospheric and marine icing, different forms of sea ice and icebergs, dense fog, polar low pressures, etc. (Gudmestad and Karunakaran, 2012, Løset et al., 1999, Barabadi et al., 2013, NORSOK, 2007). Additionally, one should also consider the large variations in Arctic physical conditions. For instance, while the annual minimum air temperature in the southern Barents Sea varies from -9°C to -6°C, the northern parts experience an annual minimum temperature of -39°C to -20°C (ISO, 2010). Besides, there is a general lack of infrastructure in Arctic areas, where offshore operations normally take place at locations with long distances to shore. Such harsh operating conditions can result in reduced operational reliability and elevated risks associated with drilling activities (Naseri and Barabady, 2013, Barabadi and Markeset, 2011).

Qualitative and quantitative risk assessments are defined as "analyses that will assess causes for and consequences of accidental events, with respect to risk to personnel, environment and assets" (NORSOK, 2010b). Such assessments, if accounted for the adverse effects of Arctic operating conditions on drilling operations, can provide crucial information for the analysts to improve the operational reliability and safety by reducing the occurrence probability of the failures and severity of their consequences.

In terms of safety, well control operations are among the most important activities taking place in every drilling activity, as a complete loss of well control can result in a blowout leading to explosion, several fatalities, and major oil spills. In an overbalanced drilling, two barriers, known as primary and secondary well control barriers, are in place to prevent loss of well control. The primary well control barrier is referred to the mud column in the wellbore providing a hydrostatic pressure greater than formation pressure and smaller than formation fracture pressure, that prevents the influx of formation fluid into the wellbore. The secondary well control barrier is referred to securing the wellbore, using several valves that altogether form the blowout preventer (BOP) stack. The BOP stack acts as a redundant barrier if the primary barrier fails (Grace et al., 2003). If the wellbore is not secured within an appropriate time, a blowout may occur.

Several researchers (Xue et al., 2013, Abimbola et al., 2014, Khakzad et al., 2013, Abimbola et al., 2015, Cai et al., 2012) have analysed the risks associated with well control operations by analysing the causes and consequences of its different phases, including kick occurrence, BOP actuation, killing operation, etc. These studies, however, do not take into account the effects of operating environment. In the Arctic offshore drilling activities, the harsh operating environment can influence various phases of drilling activities, efficiency of well control barriers, and performance of drilling crew during killing operations, etc. In this regard, a risk model should be developed to account for such adverse effects on different elements and phases of well control operations.

The aim of this study is to present a qualitative risk model for the performance of the primary and secondary well control barriers considering the negative effects of Arctic operating conditions. For this purpose, different phases of a well control operation are discussed. The failure causes and consequences are identified using fault tree analysis (FTA) and event tree analysis (ETA), based on which a risk model is developed for the whole operation. The rest of the paper is organised as follows. The procedures and elements of the well control operation are reviewed and discussed, based on which a bowtie approach is selected to analyse various causes and consequences of unwanted events. The effects of Arctic operating conditions are discussed on different phases of the developed risk model. Concluding remarks are presented after discussing a number of risk reducing measures.

WELL CONTROL OPERATION PHASES

A well control operation is defined as a "collective expression for all measures that can be applied to prevent uncontrolled release of wellbore effluents to the external environment or uncontrolled underground flow" (NORSOK, 2010a). Well control operation can be discussed within different types of activities including drilling, completion, workover, production, and wireline operations, of which well control during overbalanced drilling of exploration wells is the focus of this study.

Maintaining a well under control can be achieved utilizing the functions of primary (i.e., mud column) and secondary (i.e., BOP stack) well control barriers. If the primary barrier fails to fulfil its function, an unwanted influx of formation fluid enters to the wellbore. This process is known as kick occurrence (Fraser et al., 2014). Secondary well control barrier must then be initiated that includes the discovery of the influx, containment, and circulation of the influx out of the wellbore using BOP stack (Grace et al., 2003, Khakzad et al., 2013). Thus, well control operations can be divided into four phases: kick prevention, kick detection, blowout prevention and killing operations, illustrated in Figure 1.

Figure 1. Well control operation phases (Khakzad et al., 2013)

DEVELOPING RISK MODEL FOR A WELL CONTROL OPERATION

A bowtie approach is selected to analyse the risks associated with well control operations. A bowtie diagram (see Figure 2) gives a clear overview of potential undesired scenarios, and is commonly used for process accident risk analysis (Khakzad et al., 2013). It consists of an unwanted event and a set of barriers for either preventing the unwanted event from occurring (i.e., active barriers) or mitigating the impacts if it occurs (i.e., passive barriers). Depending on the focus of the risk assessment, the unwanted event can be defined as a blowout or different phases of a well control operation. In this study, the bowtie diagram is adopted to analyse the performance of primary and secondary well control barrier, by taking each phase of a well control operation as an unwanted event. Thus, for each phase, a FTA and ETA are required to identify the causes and consequences of the failures of well control barriers in order, and thus to develop the overall risk model.

A fault tree is a graphic model that consists of logical interrelationships between different faults that can lead to the occurrence of the specified undesired event. Thus, by performing an FTA, one can identify the causes of an unwanted event and determine all the possible ways the unwanted event may occur (Stamatelatos et al., 2002, Vesely and Roberts, 1981). In an ETA, scenarios of successive events leading to hazard exposure and to undesirable consequences are modelled. The analysis utilizes event trees based on forward logic that propagate from an unwanted event through a chosen system, and consider all the potential ways the unwanted event can affect the system's behaviour. The system consists of subsystems or safety barriers, presented as event headings, which the tree proceeds chronologically through (Modarres, 2006). The outcomes of the event tree are dependent upon whether these barriers perform their intended functions.

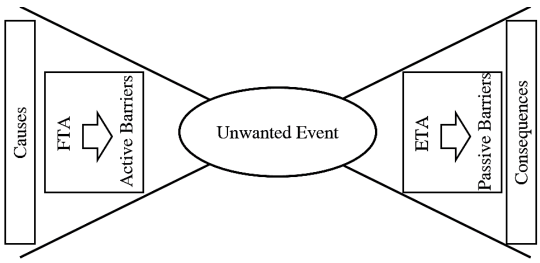

Figure 2. Illustration of a bowtie diagram, whose active and passive barriers are developed using FTA and ETA, respectively

Kick prevention

During an overbalanced drilling operation, kick prevention refers to the process of maintaining the wellbore pressure, which is supported by the weight of mud column, at a level higher than the surrounding formation pore and smaller than formation fracture pressure. If the formation pore pressure exceeds the wellbore pressure, formation fluid flows into the wellbore resulting in kick. Alternatively, if wellbore pressure is greater formation fracture pressure, drilling mud will be lost into the formation. This results in a reduced hydrostatic mud pressure below the formation pore pressure that consequently causes a formation influx into the wellbore. In general, the causes of a well kick can be categorized as: formation pore pressure greater than the mud weight; wellbore not kept full of mud while tripping; swabbing during tripping; loss of circulation; and presence of mud cut (Khakzad et al., 2013, Grace et al., 2003). Taking into account the causes of a kick occurrence, the corresponding fault tree model can be developed, as depicted in Figure 3.

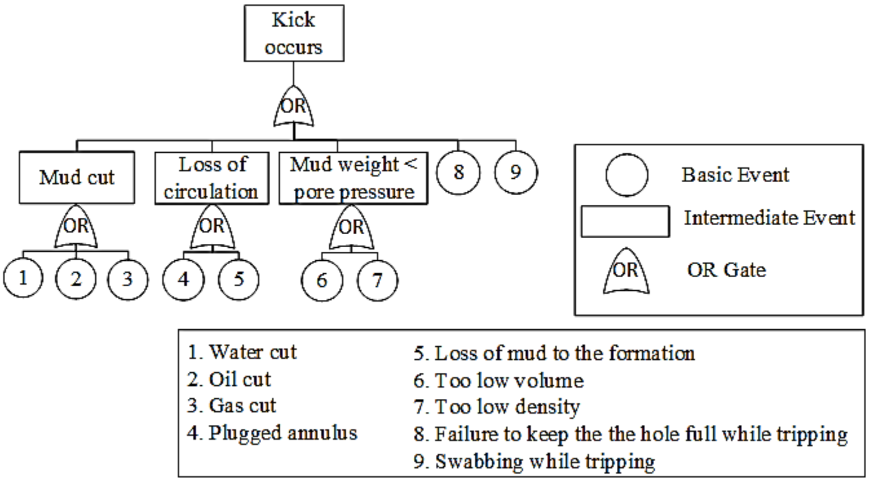

Figure 3. Fault tree for the kick event

Effects of Arctic operating environment on kick occurrence probability: In order to estimate kick occurrence probability in Arctic offshore drilling operations, one needs to account for the negative impacts of harsh environmental conditions on different causes of kick. As illustrated in Figure 3, causes of kicks can be related to either formation fluid properties, drilling fluid characteristics, failures in topside devices and facilities, and errors made by drilling crew. Although the Arctic environmental conditions may not influence the subsurface formation characteristics, they might have adverse effects of the remaining categories.

Low temperatures can adversely affect the rheological properties of drilling mud and lubricants (e.g., mud viscosity and gel strength), and mechanical properties of hoses and sealants (Caenn et al., 2011, Fink, 2012). Such adverse effects can increase the failure probability of pumps, gauges and devices mounted on trip tanks, based on which the operator keeps the well full while tripping, as well as hoses and connections.

The severe weather conditions can adversely influence the performance of drilling crew (Bercha et al., 2003). This may consequently result in, for instance, miscalculations of real-time swab pressure, failure of pumping drilling fluid into the wellbore while tripping, tripping in or out with a speed beyond the specified limit, etc.

Kick detection

If a kick occurs, it is of crucial importance that the kick is detected at an early stage to prevent its escalation. There are a number of common indications that a kick has occurred, including immediate increase in drilling rate, increased volume in the pit tank or increased flow rate, changes in pump pressure, and reduced drillpipe weight or weight-on-bit (Grace et al., 2003). An increase in drilling rate is an indication that a porous or fractured formation may have been entered, and thus there is a risk of underbalanced pressure (Khakzad et al., 2013). A rise in pit level in the mud or trip tank is likely to be a result of influx of formation fluid. This can also cause a decrease in pump pressure, as the hydrostatic pressure in the annulus will be lowered. Finally, as drilling mud is denser than formation fluid, an increased weight-on-bit will be experienced in case of a kick, due to the reduction in the buoyancy force (Grace et al., 2003).

A kick can be detected in its early stages by the use of several kick indicators. The primary kick indicators are principally flow-out sensors, installed to detect an increasing flow rate, and pit volume totalizer-sensors (PVTs), installed to continuously measure the present fluid level in the mud tanks (Fraser et al., 2014). Furthermore, while tripping, and when no circulation in the well takes place, trip tanks serve as accurate volume detectors. The increase in drilling rate, changes in the weight-on-bit, and deviations in standpipe pressure are detected by a number of topside gauges. Additional topside gauges are installed on the mud pumps to register the variations in pump pressure. Besides, some downhole tools, such as measurement-while-drilling (MWD) tools, can register the wellbore- and formation pore pressures and transfer the real-time information to the surface aiding the operators to maintain the overbalanced situation.

Such indicators can be considered as passive barriers to a well kick. Hence, an event tree model can provide essential information to analyse the performance of kick detection procedure. Figure 4 shows an event tree model developed for kick detection. To shut in the well, both the flow-out sensor and PVTs must indicate the possible presence of a kick. However, if the unwanted influx is larger than 10 barrel and detected by the PVTs, this will be a standalone indicator and the well should be shut in (Fraser et al., 2014).

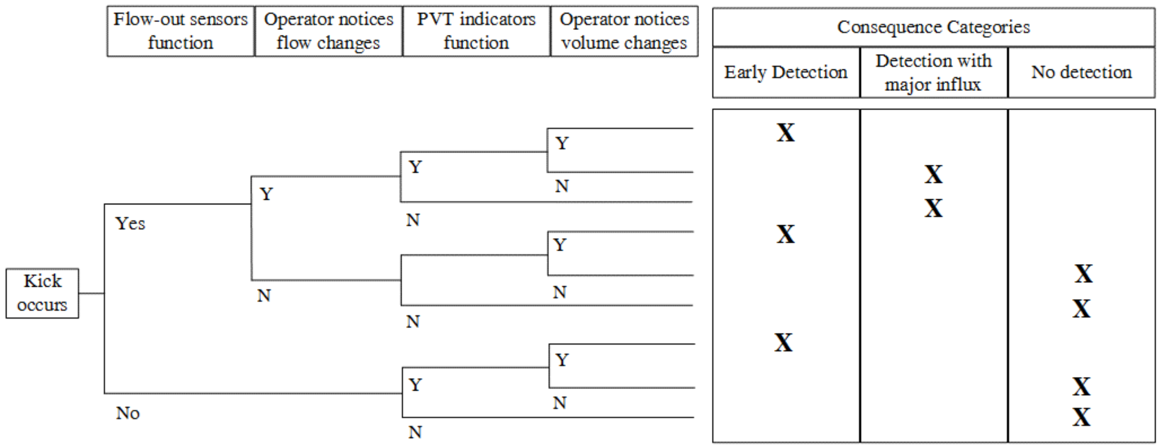

Figure 4. Event tree diagram showing the different consequence categories of kick occurrence

The potential outcomes of the developed event tree model are categorized into three groups: early detection, detection with some major influx and no detection. The early-detection category is when the kick has been detected in time and no major influx has entered the wellbore. Detection of the kick during the later stages with some major influx in the well occurs when the operator does not notice indications from the PVTs or that the PVTs fail to indicate the volume changes. In other words, additional time and additional indications are required for the kick to be identified. The last category involves the potential outcomes where the kick is temporary undetected. In this case, both indicators fail to fulfil their function or the operator fails to notice their indications. While a kick escalates without being detected, it migrates towards the surface due to its lower density. In lower depths, the reduction in hydrostatic pressure expands the kick and thus the mud hydrostatic head will be further dropped. This consequently results in the flow of more influx into the wellbore until it creates critical situations that might result in a blowout.

Effects of Arctic operating environment on kick detection probability: The elements and equipment that are located topside on the rig will be exposed to harsh weather conditions. Freezing temperatures that will be experienced during a drilling operation may alter material properties. Among others, high-strength steels, plastics and polymers become brittle when exposed to low temperatures (Singh, 2013, Barabadi and Markeset, 2011). If kick indicators and gauges are composed of such elements, fractures and structural cracks may occur. As transmitters might be sensitive to cold temperatures (Keane et al., 2013), the output signals from the gauges or detectors can be distorted. In addition, because of the large temperature variation in the Arctic, topside equipment can experience an additional strain (Larsen and Markeset, 2007). In cold temperatures, fluids will freeze and properties of hydraulic oils may change (Barabadi and Markeset, 2011).

Accretion of ice can reduce equipment accessibility, and potentially threaten the early kick detection. If, for instance, a pressure indicator has been exposed to severe atmospheric icing and the operator has to do a manual reading, some difficulties may arise due to reduced accessibility leading to late kick-detection.

As shown in Figure 4, early kick detection depends not only on the performance of flow-out sensors and PVT indicators, but also on the ability of the operators to notice changes in drilling parameters. Severe weather conditions can adversely affect the operator's cognitive and reasoning abilities (Larsen and Markeset, 2007). This may consequently lead to situations where the operator misses to read or notice the changes in drilling parameters or kick occurrence signs. In summary, all the passive barriers to kick detection can be affected by the Arctic operating environment.

Blowout prevention

Once a kick has been detected, the wellbore is shut in by actuating the BOP stack to prevent a blowout and to make a secure conduit for further killing operation. The BOP stack has a collection of at least four rams and typically one or two annular preventers (Cai et al., 2012). A BOP system also includes a control system required to manage the BOP stack and killing operation. The BOP control system consists of electric control system and fluid control system. The fluid control system includes pumps, valves, accumulators, fluid storage and mixing equipment, manifold, piping, hoses, control panels and other items necessary to hydraulically actuate the BOP stack. The electronic control system includes topside components that form the central control unit, subsea components, and umbilical cables responsible for transmitting the commands, initiated at the surface components, to the subsea control pods (Cai et al., 2012). In subsea control pods, the received signals are converted to hydraulic pilot signals and forwarded to specific hydraulic valves, which generate pressurized fluid required to close BOP valves (Shanks et al., 2003). At this step, when the well is shut in, formation fluids will enter the wellbore until the pressure in the well finally overcomes the formation pressure, i.e. regaining the overbalanced conditions while the well is kept shut in.

A reliable BOP system plays a crucial role in a successful well control operation. A fault tree model can be developed (see Figure 5), based on which one can assess the reliability performance of a BOP system, and identify the causes and their interactions that can lead to BOP system failure. The fault tree model, depicted in Figure 5, is developed for a typical BOP configuration that consists of two annular preventers, four ram-type preventers, choke and kill lines, choke and kill valves, and overall BOP control system.

As illustrated by the developed fault tree, a failure of choke and kill lines, as well as choke and kill valves can lead to a BOP system failure. In terms of annular and ram preventers, the BOP system may function if at least one annular preventer or ram functions properly. By connecting the annular and ram preventers by an OR-gate to the top event, this can be modelled. However, depending on the amount of escalated kick and its pressure, it might not be possible to shut in the wellbore safely, although an annular preventer functions. Thus, in emergency cases, one should actuate pipe or blind shear rams (Cai et al., 2012). In such scenarios, one may follow a conservative approach and, for instance, connect the failure in all the preventers by an AND-gate to the top event.

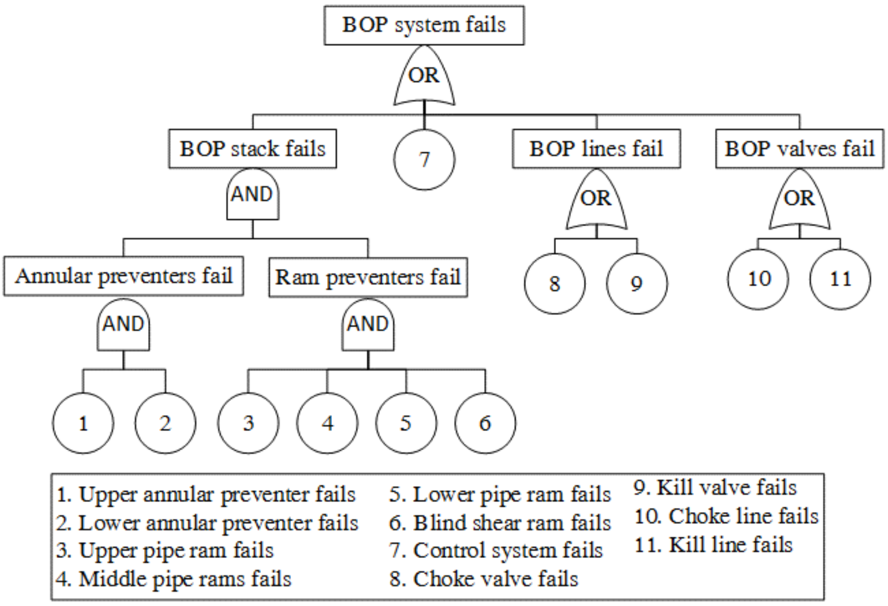

Figure 5. Fault tree for the failure of the BOP system

Effects of Arctic operating environment on blowout prevention: BOP stack is located on the seabed, and thus it is expected to be unaffected by the severe weather conditions experienced on the surface. Some elements of control unit system, such as driller's control panel, toolpusher's control panel, work-station, triple modular redundancy controllers, and connecting cables (Cai et al., 2012), however, are exposed to harsh Arctic operating environment, and thus their reliability performance may be adversely affected. Accreted ice on the floor and accumulated snow may limit accessibility to redundant control panels and thus reduce the reliability of BOP control systems. Atmospheric icing accreted on the connecting cables can exert additional loads, which may be asymmetric, that consequently can increase stress and fatigue rate, finally resulting in a shortened lifetime (Ryerson, 2011, NORSOK, 2007). Besides, as the actuation of the BOP preventers are performed by the operators, reduced human reliability under severe weather conditions can adversely affect the shut in procedure. Signal distortion in low temperatures (Keane et al., 2013) can also reduce the performance of the BOP control system, as it can affect the commands that are to be transmitted from the central control unit to the subsea control pods.

Killing operation

While the wellbore is shut in, the formation influx should be circulated out in order to regain the control of the wellbore by means of the primary well control barrier. The unwanted influx can then be circulated out through the choke line. The Driller's and the Wait and Weight methods are two common procedures for circulating the kick out of the well (Carlsen et al., 2013, Grace et al., 2003). The difference between these methods is about circulating out the kick using the mud that was in use or using the weighted mud. In Driller's method the formation fluids are circulated out by continuing to pump the drilling mud that was in use, while in Wait and Weight method, the wellbore is kept shut in until a weighted mud is prepared to start the killing operation (Grace et al., 2003).

A failure in killing operation can result in uncontrolled scenarios leading to devastating consequences. To have a reliable killing operation, one needs to identify all the contributing elements. First, BOP stack should be able to keep the wellbore closed until the operators start the killing operation. Once the kill mud is prepared and operators start the killing operation, BOP stack should be able to allow the operators to inject the kill mud at a specified injection pressure and rate, while the kick is being circulated out. For this purpose, in addition to BOP stack, the BOP control system must perform its desired function. Surface facilities, such as mud pump, hoses, mixing tanks, injection pressure and rate gauges, and all other equipment involved in a routine drilling operation, should be reliable, as well. Finally, killing operation is considered as an integrated task, which involves several members of drilling crew and requires their utmost attention on their specified tasks to prevent any operational mistake.

Effects of Arctic operating environment on killing operation: Brittleness of plastics, polymers, and metals, and changes in their mechanical behaviour can reduce the reliability performance of the equipment units, such as mechanical equipment, gauges, sensors, etc. Changes in temperature-dependent rheological properties of drilling mud and lubricants can damage the pumps, connections, hoses, lines, etc. Natural gas hydrates can form in low temperatures and high pressures when small gas molecules become entrapped in the cages of host clathrate lattices made of hydrogen-bonded water molecules (Gasson et al., 2013, Jamaluddin et al., 1991). This process may occur in gas cut mud, which is being circulated out from the wellbore and consequently lead to operational failures, corrosion, and safety hazards in solid control system.

Effects of being exposed to low temperatures, risks of falling ice, and slippery surfaces can increase human error probability and thus reduce the reliability of killing operation. Additionally, human performance can be negatively affected in cold temperatures combined with winds. For instance, low temperatures can make breathing difficult and thus lead to muscular stiffness. They can cause frostbites and hypothermia (Bercha et al., 2003). An operator's cognitive and reasoning abilities may be affected under these conditions, and cognitive errors are more likely to occur along with decreased work effectiveness and accuracy (Larsen and Markeset, 2007).

Loads imposed by accreted ice can damage shelter ceilings and result in equipment malfunction (Ryerson, 2011). Besides, the accumulated snow and accreted ice can reduce equipment accessibility leading to delays in operation tasks such as kill mud preparation.

The occurrence of polar low pressures can cause high waves, heavy snowfalls, icing storms, dramatic decrease in temperature, and sudden increases in wind speed (Gudmestad and Karunakaran, 2012). Such scenarios can considerably threaten the ongoing well control or killing operations.

The presence of sea ice and icebergs in the Arctic will be of concern during drilling operations, as there exist uncertainties regarding the calculation of ice-loads and load effects (Eik, 2011). If the drilling platform does not withstand the forces exerted by sea ice, an ongoing well control operation can be interrupted, leading to devastating scenarios. Furthermore, crushing ice sheets can induce platform vibration that can be harmful for rig structures, aboard equipment, and crew performance (Hou and Shao, 2014).

SUGGESTED RISK REDUCING MEASURES

The overall risk model for a well control operation can be obtained by combining its four phases using a bowtie diagram. Such model is illustrated in Figure 6 by considering the well kick as the unwanted event. Once a kick occurs, kick detection, blowout prevention and killing operation play as passive barriers to a blowout. However, as discussed the performance of such active and passive barriers can be negatively affected by harsh Arctic operating conditions. To cope for such effects, a number of risk reducing measures should be implemented.

Some of the factors contributing to an elevated risk can be overcome by winterizing the equipment units, which are likely to be affected by severe weather conditions. Winterization refers to the measures taken for the facilities to ensure an acceptable level of risk is achieved if such facilities are exposed to harsh weather conditions. This preparedness for cold climate conditions includes controlling the effects of icing, snow precipitation, low temperatures, and other Arctic meteorological characteristics (DNV, 2013).

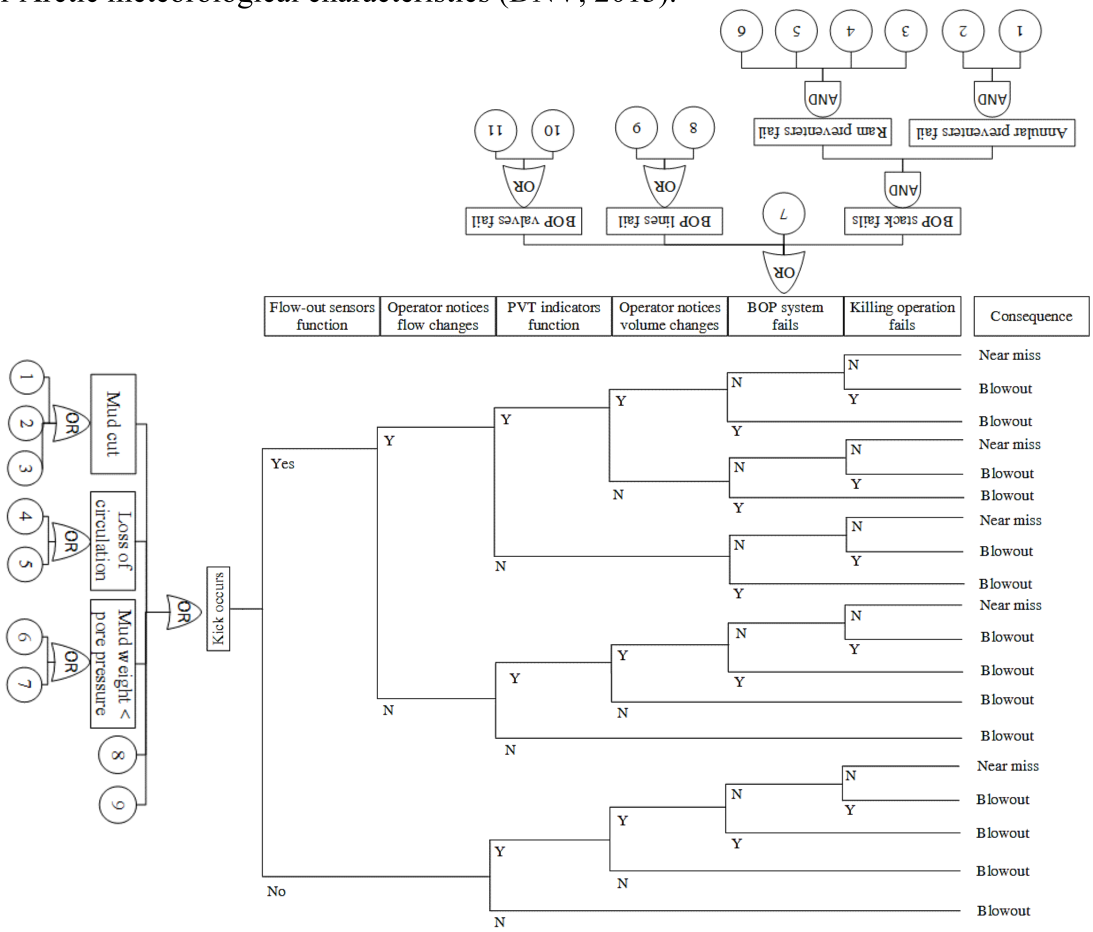

Figure 6. Overall risk model for a well control operation

For topside components, winterization may involve the use of an enclosure probably accompanied by installing internal heating elements (Gudmestad, 2010). Lack of complete enclosure or/and failure of heating elements can occur though, presenting potential scenarios of higher risks. Alternatively, using indicators, gauges, and alarms, which their function is independent of the cold climate conditions, is of great interest. In addition to winterization, adding redundancy can improve the reliability of the well control operations considerably. This can be implemented to kick indicators, control unit panels, BOP preventer and rams, transmitters, and cables. It should be ensured that in emergency cases all the required facilities and equipment are accessible.

Since early kick detection plays a crucial role in a successful well control operation, special considerations must be paid to the kick detectors with high reliability performance. Recent studies have proposed adding flow meters to the outflow side of the riser (Fraser et al., 2014). Not only will this improve the overall performance of the kick-detection safety barrier, but also it keeps some of the kick indicators away from the harsh surface conditions. Flow meters in the riser will detect the kick earlier than today's primary topside indicators can. In this case, flow meters will serve as redundant indicators that can confirm the flow rate deviations measured in the riser (Fraser et al., 2014).

Although some winterization measures may provide the operators with more convenient working conditions, there are still remaining stress factors affecting the operator's skill and reasoning capabilities. Training, optimising working shifts, and providing adequate clothing that can withstand the severe weather conditions and at the same time allow the crew to perform their required tasks conveniently, can be considered as measures to improve drilling crew performance.

DISCUSSION AND CONCLUSIONS

In this paper, a qualitative risk model was developed for a well control operation, by which different scenarios that can escalate a kick into a blowout were addressed. For this purpose, four main phases of a well control operation were identified and described by analysing the causes and consequences of primary and secondary well control barriers. Causes of a kick occurrence and BOP system failure were identified using fault tree models, while kick detection and killing operation scenarios were investigated using event tree models. The effects of Arctic operating conditions on different phases of a well control operation were discussed. Based on the qualitative analyses, it is concluded that the risk of a blowout in Arctic offshore drilling operations can be higher than the ones in the normal-climate conditions. The proposed model can base a foundation for identifying the elements of a well control operation that can be affected by the harsh Arctic operating environment. Based on such assessments, appropriate risk reducing measures can be introduced and applied. By implementing adequate winterization measures, the issues imposed by severe weather conditions on topside elements can be overcome. However, one must also consider the role of the human performance in well control procedures. On an overall basis, the human performance is considered poorer in the Arctic, resulting in an elevated probability of losing well control barriers.

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