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Linn K Kjær

Abstract

As the petroleum industry is in a constant move north for new exploration and production areas, both challenges and opportunities are many. The vast majority of the northern hemisphere are characterized by low temperatures, darkness, ice and great distances which makes any drilling operation more complicated and therefore precise measures and solutions need to be in place to prevent problems from arising. This is the case for the Norwegian part of the Barents Sea where petroleum activities has been ongoing for decades but is still relatively underdeveloped with only one field in production. The Barents Sea could be looked at as an extension of the harsh Norwegian Sea and additionally has the Arctic weather phenomena's such as polar lows and snow storms.

Well control is always of great concern in a drilling operation and it should be just as safe and secure in the Barents Sea as the rest of the Norwegian Continental Shelf (NCS). It is in this thesis tried to identify specific risks and precautions related to a drilling operation in the Barents Sea based on environmental conditions and recent findings, as it is expected to be the new phase of petroleum production in Norway in the years to come.

There is a general environmental concern with undertaking drilling in the Barents Sea areas as these locations are pristine and vulnerable to a potential oil spill. More specific challenges are related to the choice of an appropriate drilling unit and the limited number of winterized rigs available if a blow-out should occur and there is a need for relief well drilling. Hydrate formation in well control equipment both topside and subsea is a possible threat to create an unwanted situation. The main focus in this thesis is put towards recent findings of a karst reservoir at Gotha which is located in the Barents Sea. This is the first time there is proven economic viability of such a reservoir in Norway, a reservoir type which has a history of being complicated and costly to drill due to severe losses of circulation leading to non-productive time (NPT). A study of what karst are, how it is formed and the difficulty to both map and drill this geologic feature is included in this thesis. A possible solution to the drilling issues in karst is implementation of the managed pressure drilling (MPD) version pressurized mud cap drilling (PMCD), which is not yet a recognized drilling technique in Norway.

By looking at what is done up to date and comparing with the plans for the Barents Sea in the future it is clear that an accurately planning process is essential for successful operations. The planning process requires close cooperation between the industry and the authorities to enable PMCD on the NCS as well as regards to procedures, HSE, equipment and proper training of personnel.

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Abbreviations

ANN – Artificial Neural Network
BC – Black Carbon
BHP – Bottom hole Pressure
BOP – Blow out preventer
IADC – International Association of Drilling Contractors
LCM –Lost Circulation Material
LNG – Liquefied Natural Gas
MPD – Managed Pressure Drilling
MW – Mud weight
NCS – Norwegian continental shelf
NGH –Natural Gas Hydrates
NPT – Non-Productive time
NRV –Non-Return valve
PMCD – Pressurized mud-cap drilling
PPE – Personal protective equipment
RCD – Rotating Control Device
SAC – Sacrificial fluid

1 Introduction

Arctic exploration and development is the next step in hydrocarbon discoveries and new production areas. The area offers the industry a whole new set of challenges due to its rough environments including low temperatures, ice covered areas, icebergs, permafrost and periods of almost complete darkness. Another big challenge lies in the remoteness and lack of infrastructure in the Arctic Circle. The oil & gas industry is in a constant change where it needs to adapt and develop new technology to take on new challenges. Although, not new to the industry, it is estimated that the Arctic might hold up to 30% of the undiscovered gas left and 13% of undiscovered oil making it a present-day subject to ensure the future of the industry [1]. After BP's catastrophic incident in the Gulf of Mexico in 2010 the focus on well control has never been higher. Well control is always of great concern, but in the pristine and challenging areas of the Arctic a potential well control situation might provide serious challenges the industry has never seen before.

This thesis will focus on the Norwegian Arctic areas where the Southern Barents Sea seen in figure 1.1 will be discussed. The first exploration well in the Barents Sea was drilled back in 1980 already, but after 30 years of activity there is still only one field which is developed and in production [2]. This is due to, amongst other, lack of infrastructure and great distances which provide challenges in possible rescue scenarios which is an important requirement when operating offshore Norway. When drilling and operating in extreme environments it is important to be ready for all possible challenges along the way and it is in this thesis tried to recognize specific challenges regarding drilling in the Barents Sea.

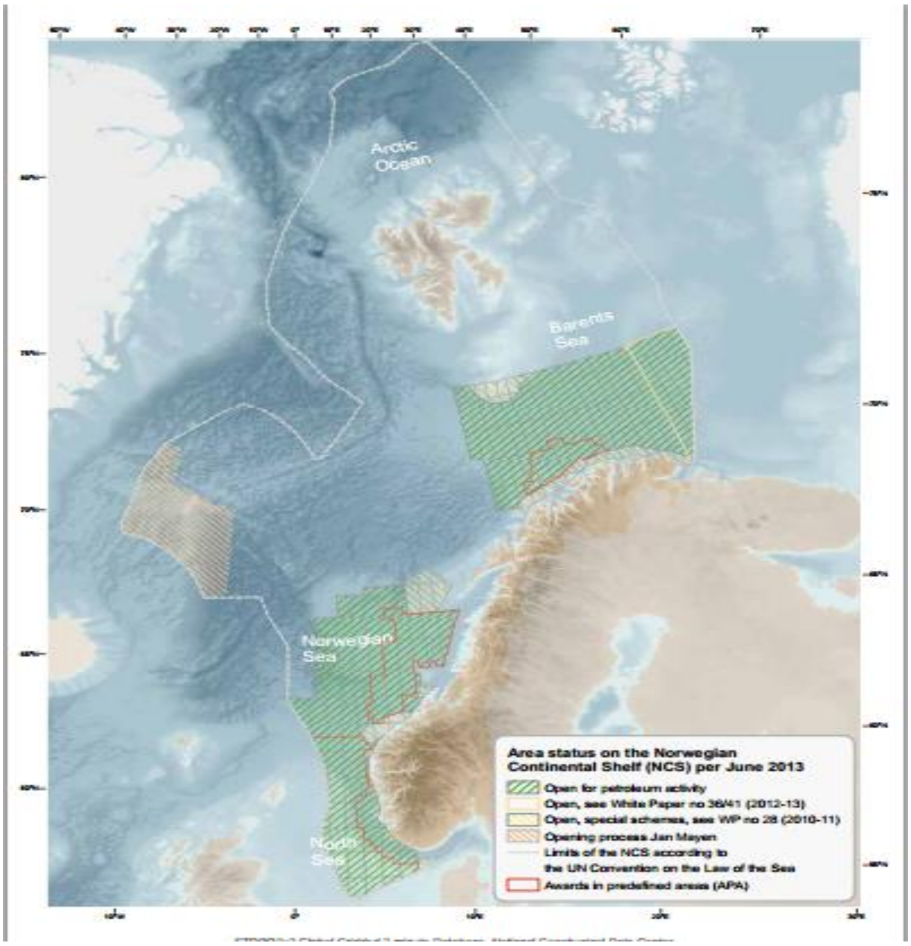


Figure 1.1 - Area status on the Norwegian Continental shelf [3]

Logistics are of main concern in the Barents Sea, as huge distances are present and there is a lack of existing infrastructure. There are tough restrictions for rigs to operate in the Barents Sea as winterization of rigs is important to operate safe in areas where darkness and cold prevails. If a blow-out should occur and the only remedy to kill the well is by drilling a relief well there is concern on available winterized rigs in the area able to perform the operation. Formation of hydrates is usually combined with deep water drilling but there is examples of hydrates in waters not too different from the Barents Sea, so hydrates in different well control equipment both topside and subsea should be of concern during operations.

Particular interest is taken on the Gotha field which was found by operator Lundin in 2013 and is the first successful drilling in karstified carbonate rocks on NCS. Karsts are geologic features which have caused challenges worldwide due to its difficulty to identify, map, understand and last but not least the related drilling challenges karst proposes. The main issue being lost circulation which have caused NPT, expensive mud losses and eventually abandoning of the well. Karst forms from the abundant carbonate rock, where the rock is exposed to acidic rainwater for a long period of time. This could lead to the creation of great caves beneath the earth's surface or just small cavitites and vugs within the rocks. Either way, these karstified rocks have a secondary porosity which will improve the reservoir quality and make excellent reservoir potentials.

The unconventional drilling technique, pressurized mud cap drilling, is looked upon as a solution to drill these sometimes "un-drillable" reservoirs. Pressurized mud cap drilling is a version of the managed pressure drilling technique, mostly practiced offshore in South-East Asia where the chances of drilling into severely fractured formations or even open cave systems are significant.

The first chapter contains a brief background on different drilling techniques as unconventional drilling methods are looked upon as a solution to drilling in formations that have experienced karsting in the end. Next there is a chapter including general information on different domains that needs to be taken into account when operating in the Barents Sea. Further on well control in general is discussed before challenges that might need special precautions in the Barents Sea is recognized and categorized as topside, subsea and subsurface challenges. A study of karst is included where its formation process, subsurface existence, detection problems and drilling issues is discussed. The following chapter contains information on the PMCD technique and the possibility for enabling it in Norway. In the end there is a discussion of the different challenges where possible solutions are included.

2 Basics of drilling

This chapter will include the basics of drilling operations with regards to drilling methods and drilling fluids whilst a broader understanding of the mud-cap drilling technique will be given in chapter 6.

2.1 Pressures while drilling

During drilling there are pressure regimes in the formation that is crucial to understand and know to be able to perform successful operations. There is a lower and an upper limit while drilling and the difference between them are recognized as the operating window or simply the drilling window [4]. Pore pressure normally represents the lower limit to avoid kicks and influx whilst the upper limit is normally represented by the fracture gradient or the lost circulation gradient [4].

Drilling operations can broadly be divided into three main categories based on their operating domain; conventional drilling, underbalanced drilling and MPD [5]. The different drilling categories and their operating windows can be seen in figure 2.1.

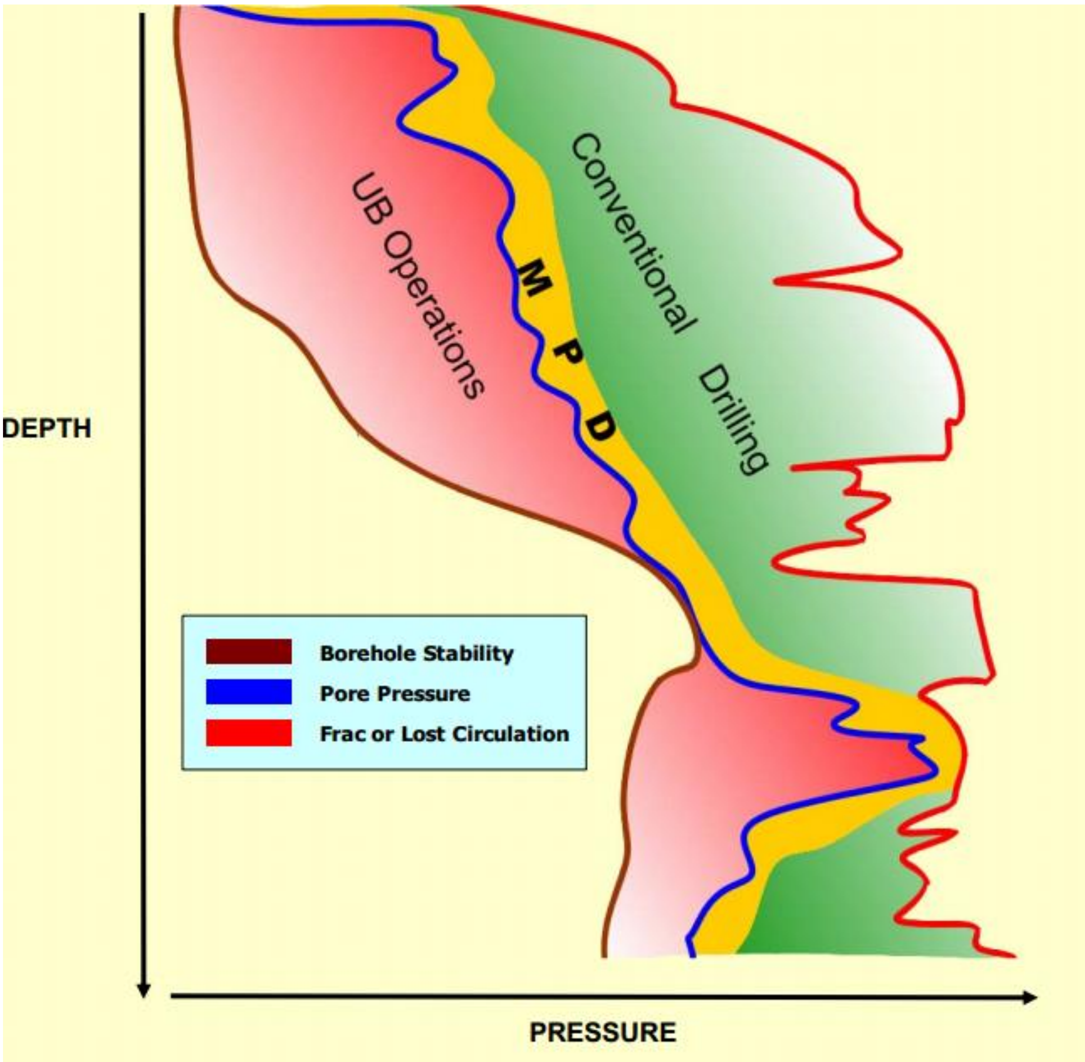


Figure 2.1 - Drilling windows for conventional drilling, underbalanced drilling and MPD [5]

2.1.1 Conventional drilling

Conventional drilling are in general performed in overbalance which is a condition where the bottom hole pressure (BHP) is kept in between the upper and lower limits [5].

Pore pressure < BHP < Fracture pressure

The whole circulation process starts with mud being pumped from the mud pit down hole through both drill- string and bit, the mud then flows up the annulus to exit via a bell nipple and enter a flow-line where it eventually ends up in a mud-gas separator system or directly in a shaker, where it after being processed will be lead back to the mud pit [4, 5]. The process is illustrated in figure 2.2.

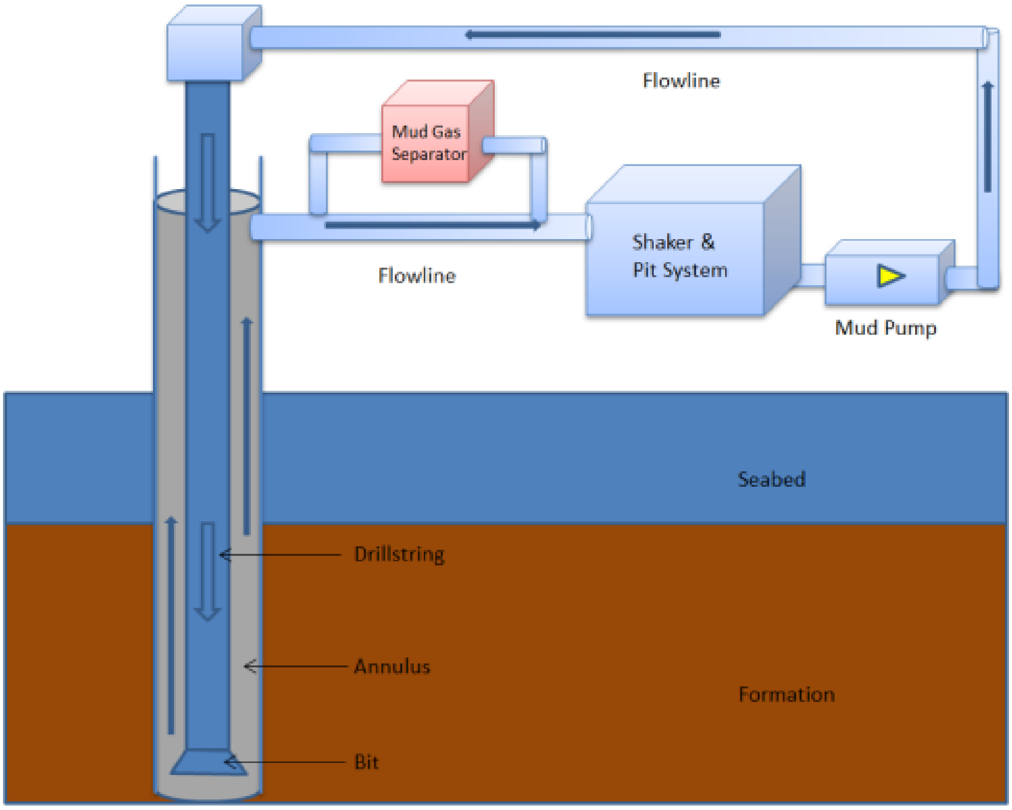


Figure 2.2 - Basic principle of circulation path in a conventional drilling operation [4]

Since both wellbore and mud pit is open to the atmosphere, pressure readings in the surface flow-lines will be equal to atmospheric, making it an open vessel system [5]. An open vessel system presents various challenges related to kick- and loss detection and pressure control down hole, often causing NPT fighting a well and added expenses.

2.1.2 Underbalanced drilling

During operations in underbalanced drilling the BHP are kept below the pore pressure which is the lower pressure limit and formation fluids are intentionally led to surface.

BHP < Pore pressure

The main reason for using this method is to reduce formation damage, resulting in higher productivity of the reservoir, this is achieved by using a very light fluid.

The Underbalanced Operations & Managed Pressure Drilling Committee of the International Association of Drilling Contractors (IADC) define underbalanced drilling as [6]:

"A drilling activity employing appropriate equipment and controls where the pressure exerted in the wellbore is intentionally less than the pore pressure in any part of the exposed formations with the intention of bringing formation fluids to the surface."

2.1.3 MPD

In an MPD operation one tries to keep the BHP constant and slightly above or balancing on the pore pressure curve, although there is MPD situations where the whole drilling window is used [4].

The Underbalanced Operations & Managed Pressure Drilling Committee of the IADC defines MPD as [6]:

"Managed Pressure Drilling is an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. It is the intention of MPD to avoid continuous influx of formation fluids to the surface. Any influx incidental to the operation will be safely contained using an appropriate process."

The principle behind the flow loop in MPD can be seen in figure 2.3 and differs from the conventional system by enclosing the loop with a rotating control device (RCD) and a MPD manifold. By closing the system and employing backpressure through chokes and a specific backpressure pump in the MPD manifold it is possible to achieve a pressurized system where the wellbore pressures are controlled at a greater extent.

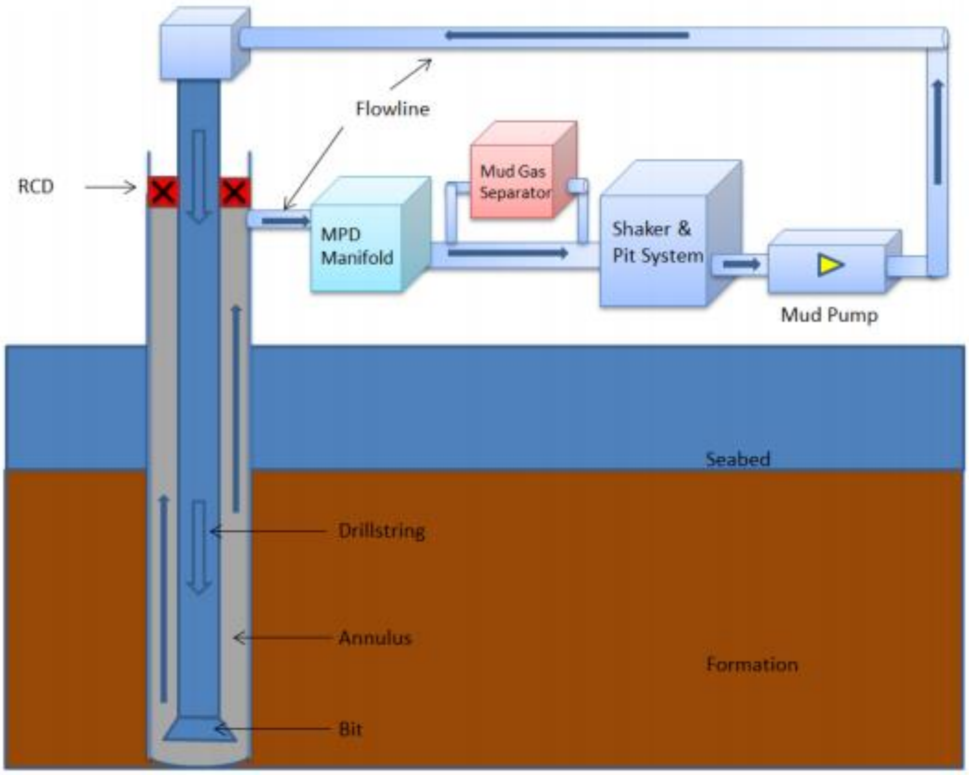


Figure 2.3 - Basic principle of the circulation path in a closed MPD drilling operation [4]

There are several versions of MPD techniques and the use of pressurized mud-cap drilling in naturally fractured reservoirs will be discussed in chapter 6.

2.2 Variations of MPD

MPD are in general divided into four branches; Constant Bottom Hole Pressure, Dual-Gradient drilling, Returns flow control (HSE) and pressurized mud cap drilling. A short introduction of the four will be given here whilst a more detailed description of PMCD is as mentioned given in chapter 6.

2.2.1 Constant bottom hole pressure

As one can understand from the name the main purpose of this method is to keep the BHP close to constant during all drilling operations. It is applicable for HPHT wells, depleted reservoirs and areas where frequent drilling problems are encountered due to the ability of navigating through prospects with narrow and/or almost unknown drilling windows [7]. It is the most recognized MPD technique and used worldwide both on- and offshore, it is for example implemented at the HPHT Kristin field located in the Norwegian Sea [7, 8].

2.2.2 Dual-Gradient drilling

The principle of dual gradient drilling is to inject a fluid which is lighter than the mud used in conventional drilling to be able to acquire a lower BHP. Different approaches to obtain dual gradient conditions exist but they all “trick” the well into “thinking” that the rig is placed closer to seabed than it actually is [7]. The method is applicable to deep sea environments where the mud column typically creates a considerable overbalance in the well [4].

2.2.3 Returns flow control (HSE)

This method use conventional drilling techniques whilst the return flow is closed under the drill floor where flow in and flow out of the well are measured. There is no pressure control of the annulus in this technique but since the flow is measured one is able to detect deviant flow situations and a MPD choke could close automatically if an influx should occur [4]. The technique could be useful when drilling exploration wells where the pressure situation is unknown [4].

2.2.4 Pressurized mud cap drilling

PMCD is a possible solution when drilling in highly fractured reservoirs. Conventional drilling methods can be performed and if severe losses occur one can switch to PMCD mode where an expendable fluid like seawater is pumped down the drill-string and a viscous mud down the annuli, this act as a pressurized barrier to prevent a potential kick [4]. This MPD technique is mostly used in South East Asia where cavernous reservoirs occur frequently [7].

2.3 Drilling fluids

Drilling fluid is often called drilling mud as the first drilling fluids consisted mainly of plain mud. Today though, the field of drilling fluids is another case as whole companies exist solely to develop compatible drilling fluids. All drilling operations require the use of drilling fluids which primary reason is to serve as a primary barrier in a well to maintain down-hole pressures. The fluids serves several purposes besides being a barrier such as a transport phase for cuttings, cools and lubricate the drill-bit and stabilize the wellbore walls.

Drilling fluid is generally injected down the well through the drill string and returns up the annulus transporting cuttings generated in the drilling process. To be able to re-deploy the drilling fluid separation techniques at surface are used whilst loss of fluid to for example fractured formations are simply adjusted for by adding new fluid. The main components used for this mud-cycle are mud-pits, mud-mixing equipment and mud pumps which can be seen in figure 2.4 [9].

As drilling reaches further into the subsurface the formation properties such as pressure and temperatures changes, meaning that the drilling fluid needs to be constantly balanced. There are two main types of drilling fluids, classified by which fluid is used as a base:

- Water-based mud (WBM)
- Oil-based mud (OBM)

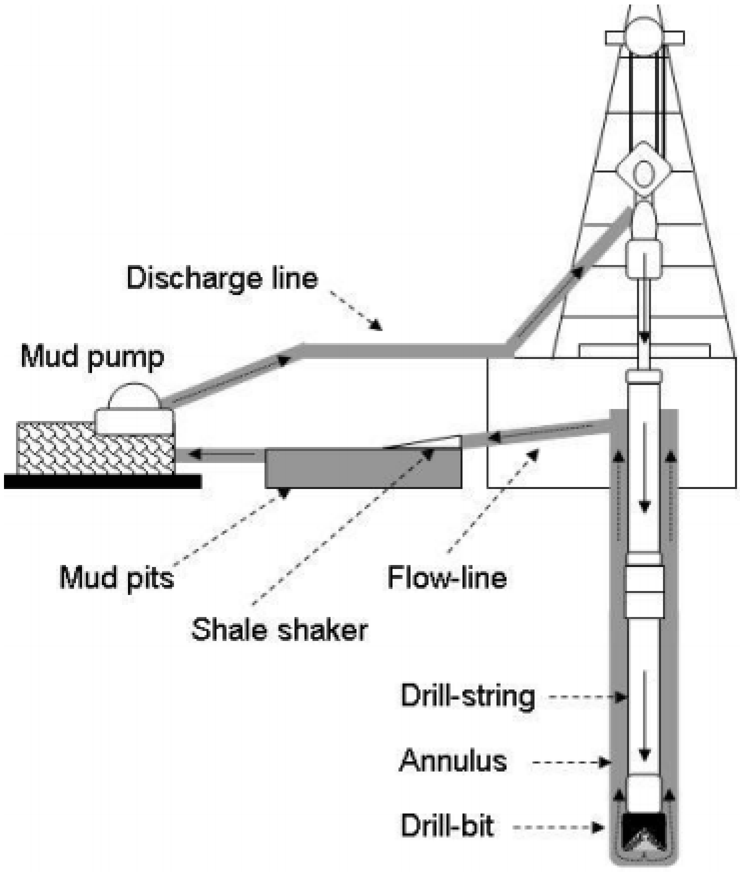


Figure 2.4 - The cycle of drilling fluids [9]

3 Operations in an Arctic environment

This chapter will give an introduction of the Arctic where definition, earlier activities, scope of work, vessels used and main challenges regarding safety and environment is discussed.

3.1 Definition of the Arctic

The Arctic is a polar region located at the most northern part of the Earth and consists of the ice-covered Arctic Ocean and includes territories in Russia, Canada, Alaska, Finland, Iceland and Scandinavia. The term “The Arctic” is quite a diffuse expression and has a lot of different definitions, the most common one being the area north of the Arctic Circle which is a fictional line around the globe at 66°33”N [10]. Other popular definitions of the Arctic is based on temperature and the most common one is set where the average summer temperature is below 10°C whilst other scientists use the area above the Arctic tree line [10]. A part of this polar region is in natural science called the subarctic and lies immediately south of the true Arctic [11]. This region generally falls between 50°N and 70°N latitude depending on local climates and is often ice-free or may have long seasonal open water periods [11]. These different definitions are illustrated in figure 3.1. The countries which hold land in this region may also have their own definitions of Arctic territory and these often include subarctic areas [10, 12]. The Arctic may be looked at as a single region but the conditions vary drastically from area to area concerning ice-conditions, temperatures, sensitive ecosystems and the presence of icebergs amongst other and each region requires different precautions regarding exploration, drilling and production.

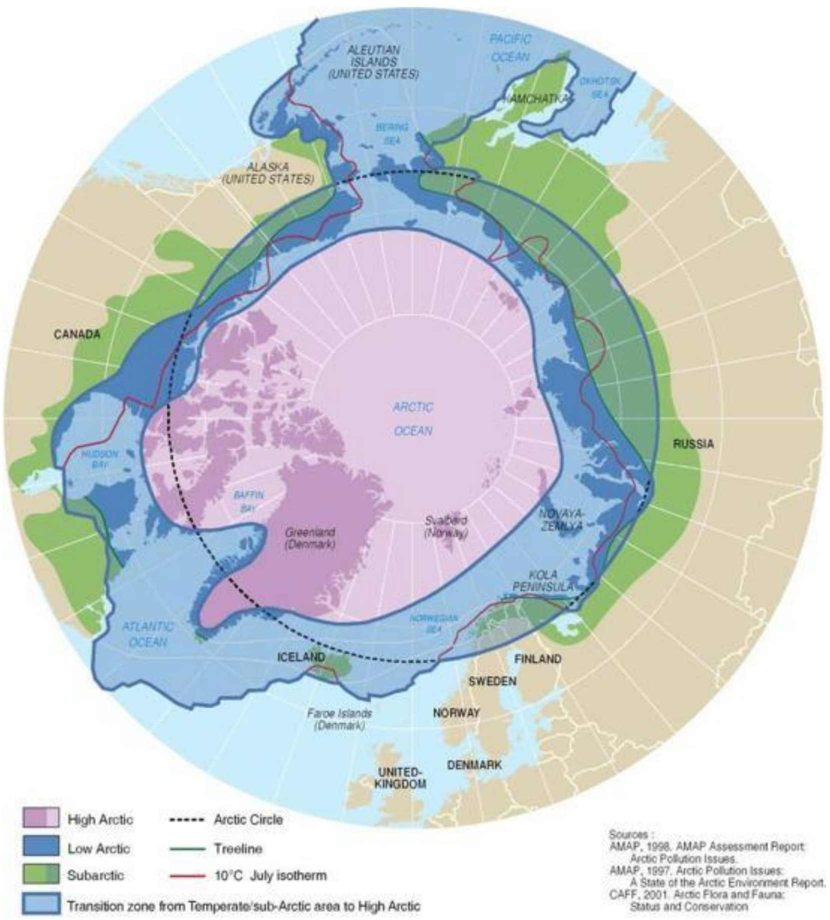


Figure 3.1 Definitions of the Arctic [10]

3.2 Arctic resources

One of the great uncertainties in the worlds future energy supply lies with the question of undiscovered resources in the northern part of the globe. According to research on "yet-to-find" technical recoverable resources in Arctic areas performed by the U.S Geological Survey (USGS) in 2008 the region might hold 30% of the undiscovered gas and 13% of the undiscovered oil left in the world today where unconventional resources such as coal bed methane and heavy oil have not been included [1]. This is estimated to be found mostly offshore on the continental shelf and with no more than 500m of water [1]. There are five areas of particular interest and those are the Barents Sea, north/east Greenland, north/east Canada, the north/north western parts of Alaska and the Kara Sea in Russia [1].

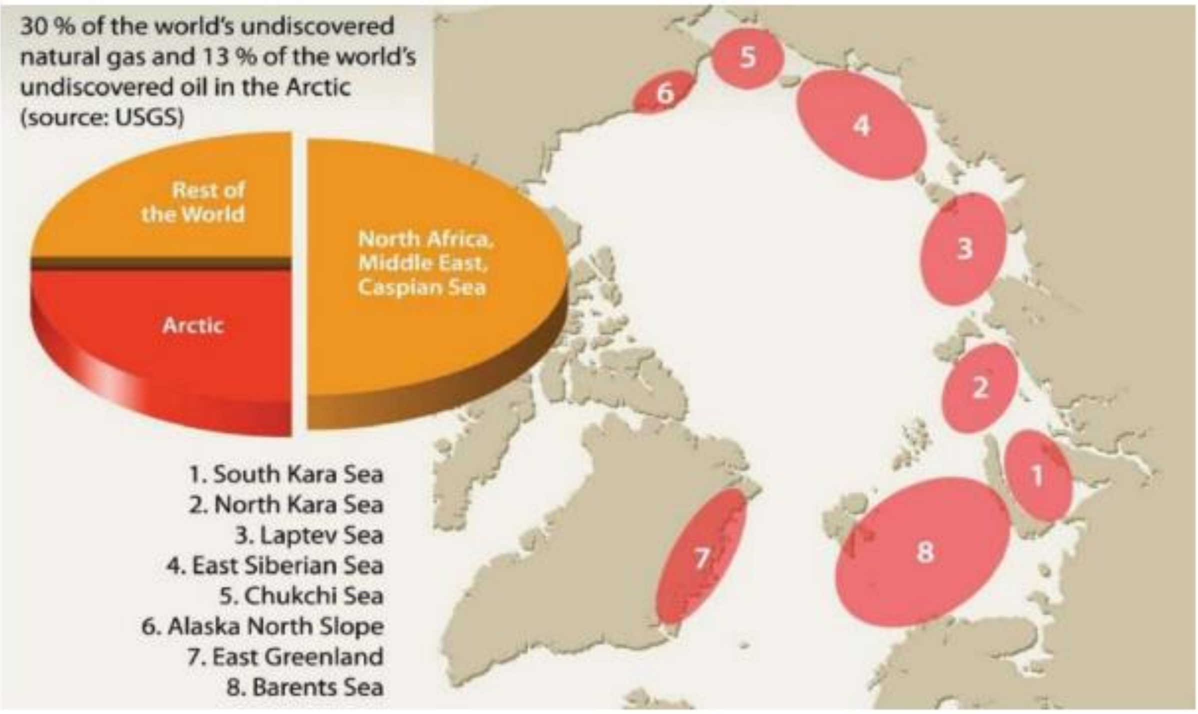


Figure 3.2 – Petroleum resources in the Arctic [13]

3.3 History of Arctic petroleum activities

Even though Arctic exploration and development is considered one of the main challenges left in today's petroleum industry activities in the region started decades ago. Onshore development started already around 1920 in Canada, in 1962 the land based Tazovskoye field in Russia was discovered and the Americans found the shallow water Prudhoe Bay field only five years later in 1967 [14]. In both Alaska (US), Canada and Russia there has been production in Arctic regions for years whilst in Norway the first discovery was made in the south Barents Sea in 1981 and is now a part of the shore connected subsea field Snøhvit which has been in production since 2007 [2].

Even though there was big interest in the Arctic some years ago the exploration activity declined in the 1990's due to incapability to develop the discovered resources in an economical viable way and there are still many discoveries in all of the Arctic countries that are waiting for the needed infrastructure and technology to be developed [10, 14]. The development of offshore activities in the region is more complicated due to areas affected by ice and harsh weather and has evolved at a much slower pace than the onshore development. Some offshore Arctic activity has been done via onshore directional drilling, man-made gravel islands or in subarctic areas where there is seasonal open water periods or ice-free conditions and conventional drilling methods may be used [15].

3.4 Scope of work

This thesis will focus on the Arctic and subarctic areas in Norway which in winter time are embossed by ice, cold, darkness, polar lows and year round changing weather conditions and huge distances to shore. Trough exploration drilling several discoveries has been made, but only one field, as mentioned in chapter 3.3, is in production. From Snøhvit the gas is transported in pipelines to shore where it is processed and cooled to LNG [2]. Goliat was discovered in year 2000 and is now under development with a circular FPSO solution, it was planned to start production in 2014 but is recently delayed to mid-2015 [2, 16]. In 2011 Johan Castberg was found by Statoil and it is the biggest discovery in the area since Goliat, a potential development of the field will be utterly important for the expansion of the needed infrastructure in the area [2].

Lundin published their discoveries at Gotha in 2013 and estimates that it is the same size as Goliat which contains 190 million barrels of oil, if both oil and gas reserves is included [17]. The discovery at Gotha is the first successful tests in Permian limestone at the Norwegian continental shelf and is considered a geologic breakthrough [17]. The findings at Gotha will be one of the main areas of study in this thesis.

At the Apollo and Atlantis prospects activities are planned to start this year, at more than 74°N this will be the most northern drilling ever done in Norway [2]. In 2013 the Parliament of Norway opened the Barents Sea south east, which borders Russian territory, for exploration drilling [2]. In figure 3.3 the most important discoveries are seen as well as the new area which borders to Russia. The coming years there will be numerous exploration wells in the area and it’s a crucial time for the operating companies and the industry to make this as safe and secure as possible for both workers and environment.

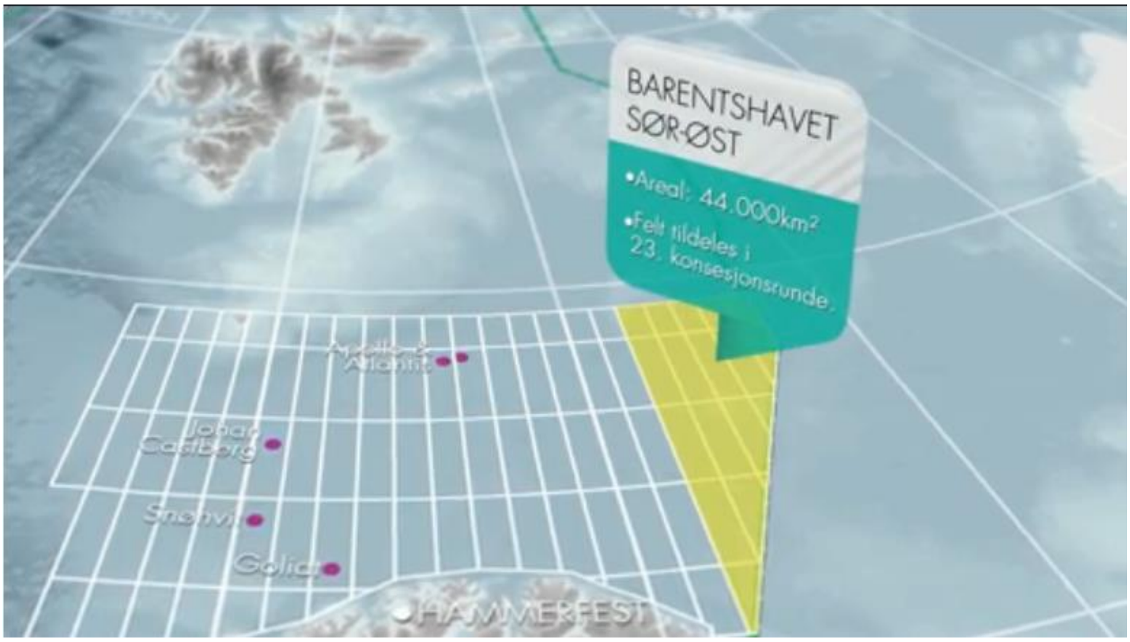


Figure 3.3 - Discoveries in Arctic Norway[2]

3.5 Vessels for Arctic drilling

The weather conditions in Arctic areas differ as mentioned from area to area. At specific latitudes in Norway it may be ice-free year-round whilst at the same latitudes in Canada there is only a small open water window every year. Therefore it is hard to make standard vessels as there is need for several options, each specialized for certain conditions. In recent years there have been huge developments in deep-water drilling around the world but the Arctic proposes quite different challenges for the industry. Shallow water is nothing new to the industry but combined with sea ice condition it to becomes challenging.

Water depth combined with location and adjoining environmental conditions will be crucial when deciding vessels for drilling in these areas. The Arctic is also usually divided into three major operating environments; the high Arctic, the sub-Arctic and harsh environment [18]. In the high Arctic one may encounter ice year round, the sub-Arctic there could be occasional ice-cover whilst the harsh environment might be ice-free but with extreme low temperatures and requires winterized equipment [18]. The southern part of the Barents Sea can be seen as an extension of the harsh Norwegian Sea, but with colder temperatures and the following Arctic weather phenomena such as polar lows and icing explained in chapter 3.7 [18].

After the peak of Arctic petroleum activity was reached in the 1990's there was a decrease in activity due to disappointing results and incapability of developing the fields discovered. It was later concluded that drilling in the Arctic would need dedicated solutions to meet the challenges properly. To prepare the units for operations in Arctic conditions several issues needs to be addressed. Optimally the unit should be able to perform in both ice condition and open water periods as acute operations are expected to happen in these periods of open water.

Usually units are made with water depth restrictions and as explained in this chapter gaps where there is no "best choice of unit" exist, flexible solutions which can comprehend wide ranges in depth are to be favored. The station keeping system needs high loading capacity to allow extended operation in difficult conditions whereas the design of the unit is crucial. Since the operation area often is remote there is need for a high variable load to reduce the need for re-supplies and the transit time for the unit to get there is also an important factor to make it economically feasible. Most importantly the unit must be able to protect the people working in extreme conditions and have high standards of environmental protection. The mobile offshore drilling units can generally be divided into three major types of units [18];

- Jack-ups
- Semi-submersibles
- Ship-shaped

3.5.1 The past

In early Arctic development large and solid structures designed to resist predicted ice forces and other loads such as man-made islands and caisson solutions where used. The first Arctic drilling system was man-made sand or gravel island, Imperial Oil built the first sand island in Canada in 1972/73 and standard Arctic land rigs where used [15]. The most valuable Arctic experience was gained from the Kulluk, which was a conical drilling unit used in combination with support icebreakers in shallow waters with ice (20-80m) from the mid 1970's to the early 1990's [19]. It was supposed to operate during summer and early fall but it soon developed to operate year round in difficult pack ice environments. The Kulluk was designed with a descending circular hull form which can be seen in figure 3.4, where the mooring was through the moonpool and reduced threats from ice on both equipment and mooring [19]. The mooring lines where all equipped with RAR's (Rig Anchor Release) to permit quick disconnects [19]. Lessons learned from the Kulluk is used when constructing new vessels, of great importance is the hull form that enhances icebreaking actions and reduces the damage of ice, the submerged mooring system and the quick disconnect system [19]. The opened area in Norway's Barents Sea is as mentioned ice-free and the wells at the only developed field, Snøhvit, were drilled by a semi-submersible drilling unit designed to operate in harsh environments [20].

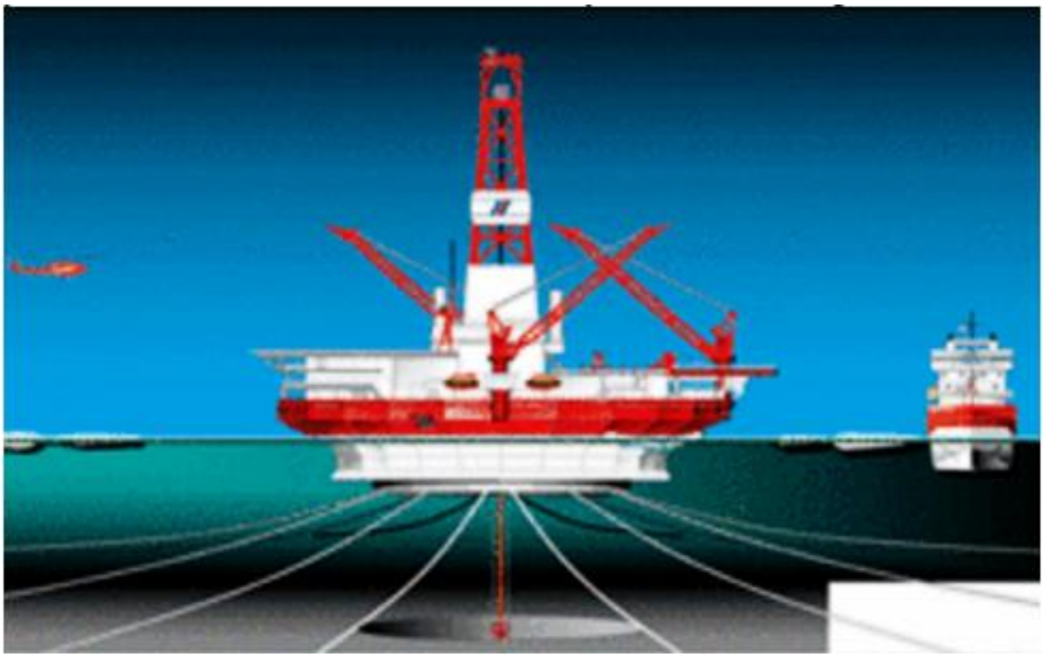


Figure 3.4 - The kulluk design [19]

3.5.2 Which mobile offshore drilling unit suits the Arctic best

In sea ice conditions the jack up faces substantial challenges, in particular the splash zone which is the transition from air to water when heavy equipment is lowered into the sea and could be exposed to ice [18]. Survival strategy for the workers should an uncontrolled event occur is also of big concern. However, the jack-ups offer a unique capability in shallow waters and are the specific issues correctly addressed they could operate in all the different environments. In general there is set an upper limit of 50 to 80 meters due to high ice sea loads [18]. Loads from sea ice are generally greater that wave loads hence the loads on the jack up legs are significantly higher in ice infested water. Figure 3.5 illustrates the loads exerted on the legs; an overturning moment on the overall unit and a horizontal load on the bottom legs which could cause sliding of the unit [18].

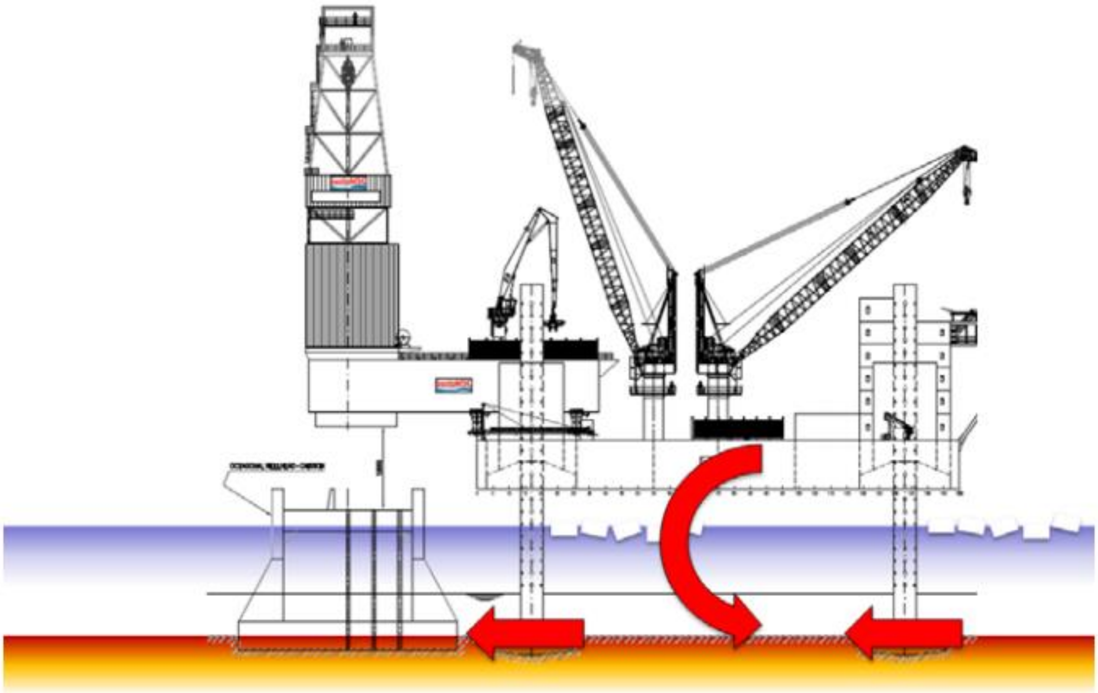


Figure 3.5 - Loads on a jack-up in sea ice conditions [18]

The semi-submersible drilling units faces the same problem as the jack ups, the equipment exposure in the splash zone [18]. Another factor is the “clogging” of sea ice that would present an ice load in between the legs [18]. The present semi-submersibles are considered superior in harsh environments because of their better motion characteristics. Areas in the high Arctic are generally in remote areas and due to the low transit speed of the semi-subs this also makes them less suitable [18].

A lot of experience from maritime ships operating in ice-infested water makes a huge advantage for the drill ships designed for the area. They offer good protection for the equipment compared to semi-subs and jack-ups as it pass through the moon pool and have in addition high transit speed making it easier reaching remote locations [18]. Almost all drill ships in use today depends on dynamic positioning for their station keeping system, which again leads to a lower limit of 300 to 400 meters water depth meaning they cannot be used in shallow waters [18].

Table 3.1 Favorable vessel options matrix for Arctic operations [18]

Area	*Jack-up*	*Semi-submersible*	*Ship-shaped*
High Arctic (Beaufort, Chuckci, Northern Greenland, Kara, East Siberian)	+*	-	++
Sub Arctic (Seasonal high arctic and periodic ice infested such as southern Greenland, Barents)	+*	+	++
Winterized / Harsh environment	+*	++	+

* Limitations in water depth apply

The compatibility for each of the units in the specific environments is seen in table 3.1.

3.5.3 Arctic Jack-up

Gusto MSC is a leading design and engineering company involved in the development of new solutions for the Arctic. One jack-up solution is the SEA-15000 ICE which is designed to operate year round in first year ice conditions [21]. The jack-up design consists of a square hull-form with an ice belt to resist ice loads and four circular legs designed to resist large ice loads [21]. It is equipped with a removable drilling caisson which protects the riser and drill string from ice during exploration, the caisson can be handled, installed and removed by the jack-up. This caisson has a foundation at the seabed for support which also serves as housing for the well isolation device. SEA-15000 ICE is meant to operate in managed ice conditions, meaning support vessels operate the surrounding area breaking ice and observes ice conditions. If there is excessive ice conditions the well is secured and the caisson removed whereas the rig is jacked down and moved off the site by the support vessels [21]. The work areas are all enclosed, heated and ventilated ensuring correct working conditions and access to both these and accommodation are in the hull minimizing the workers to the exposure of the harsh Arctic conditions [21]. Enclosed life boats and escape chutes to a support vessel or the level ice in the occurrence of an emergency are in place [18]. Figure 3.6 shows an image of the jack-up SEA-15000 ICE.

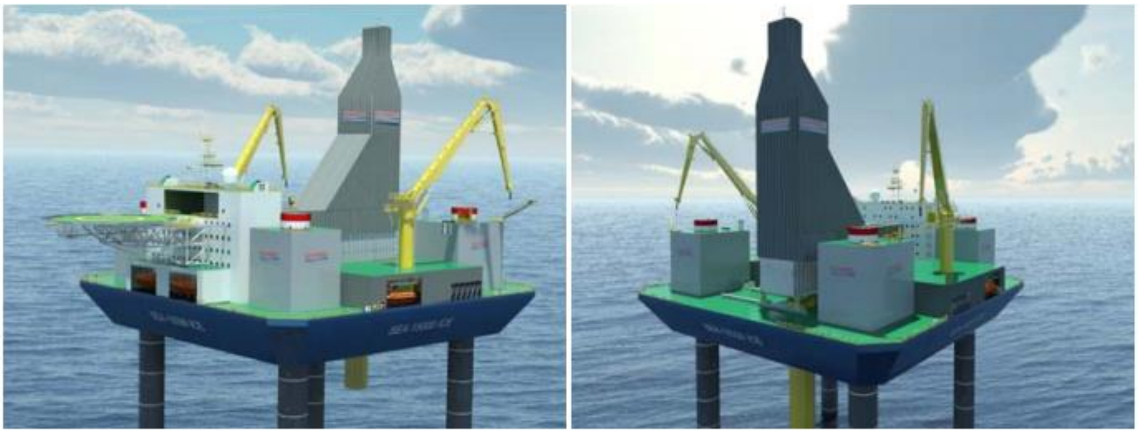


Figure 3.6 The SEA-15000 ICE from Gusto MSC [18]

3.5.4 Arctic drill ship

The NanuQ 5000 TM is a drillship designed by Gusto MSC to operate year round and meet rules and regulations in all arctic environments, offshore Alaska, Canada, Greenland, Iceland, Norway and Russia [22]. It is a turret moored drillship meaning it consists of a static part placed at seabed whilst there is a rotating part in the hull, these are connected allowing the vessel to weather vane around the mooring and find stable positions according to present wind, currents and waves [18]. A turret moored vessel principle can be seen in figure 3.7.

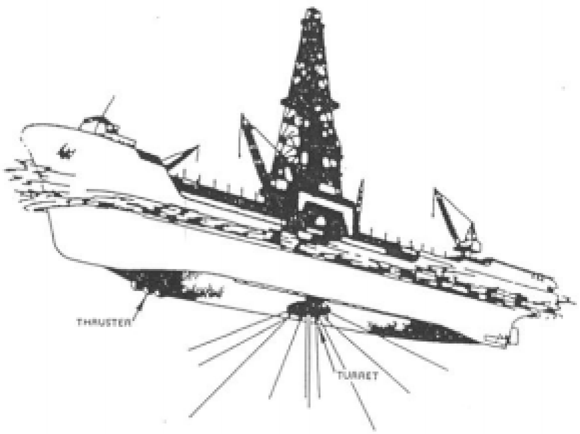


Figure 3.7 - Turret moored FPSO [19]

The vessel obtains the latest technologies in emission reduction and is based on the zero discharge philosophy for the sensitive environments in the Arctic [22]. It is based on a hull design where both conventional drilling with a subsea BOP and drilling with a surface BOP and seabed shut-off device are available [22]. All risers and tubulars are located within the superstructure deckhouse and the drilling and marine systems are winterized to comprehend the harsh environment. The superstructure deckhouses include work areas and access routes so personnel and equipment are protected from the arctic conditions. There is re-supply stations dedicated for re-supply in ice conditions on both sides of the vessel. This unit is turret moored but is equipped with a dynamic positioning system for station keeping during for example connect or disconnect [18]. NanuQ 5000 TM is seen in figure 3.8, it can operate in both sea ice and open water making it a very suitable unit for Arctic drilling.

Figure 3.8 - NanuQ 5000 TM from GustoMSC [22]

3.5.5 Arctic semi-submersible

Huisman is another company operating globally in the design and manufacturing of offshore drilling units among other. The Arctic S is a semi-submersible designed by Huisman to operate as a conventional semi-sub with low motion in waves as well as a heavily strengthened unit when ice is present [23]. There is also a third option where the unit acts as a gravity based structure and can be placed at seabed [23]. The different scenarios for the Arctic S semi-submersible can be seen in figure 3.9.

Arctic S consists of a round floater, eight legs and a round deck box [23]. The unit can operate as a conventional semi-sub in water depths ranging from 35 to 1000 meters and as for shallow water depths ranging from 12 to 30 meters [23]. It can be set on seabed therefore both columns and floater are ice resistant [23]. When operating in ice the unit protects the riser by ballast to level ice whilst the deck box is heavily strengthened to resist and break the ice. The complete drilling system is enclosed to ensure decent working conditions. Depending on how severe the ice conditions present are, ice management assisted by ice breakers might be required. To keep the unit stationed in ice infested waters there is a 16 point mooring system designed to resist forces from drifting ice [23]. Further, this unit is designed with the zero discharge philosophy which is an Arctic requirement.

Figure 3.9-The Arctic S from Huisman [23]

3.6 Environmental Issues

The Arctic environment as a whole has stronger sensitivity to development of any kind, including petroleum activities such as exploration and production, compared to other more known areas [10]. A situation with loss of control may differ and have more severe consequences than in other parts of the world where the environment is more understood and researched. A development of an oil or gas facility brings a whole set of new experiences and challenges to vast areas with sensitive ecosystems who have been in complete isolation from the rest of the world. To create a functioning facility it would involve, amongst other, transportation and infrastructure development and power generation combined with more people moving to these areas.

Along with the petroleum industry comes also the risk of contamination and effluent. The magnitude of such activities could give rise to a variety of impacts categorized as primary, secondary and indirect impacts, these vary with time and distance from the project site. In this kind of development there will be many factors to take into account where immediate, short-term and long-term effects are equally important and must be considered as they are all linked together in joint operation [10].
Several important issues are to be taken into account, these are the most important ones:

- Human population
- Flora and fauna
- Regulatory effluents to sea
- Regulatory effluents to air
- Acute contamination

3.6.1 Human population

The Arctic is known for extreme climates and is a challenging place to settle down, but for thousands of years people have found ways to adapt and live in these areas. Residents of Arctic areas include a number of different indigenous groups around the world but several people also lives in modern towns and cities [12]. The social effect of the petroleum industry moving north could be either adverse or beneficial, depending on how it is done. The Sami's are an indigenous group which has its traditionally living habitats in Norway, Sweden, Finland and Russia. Even though most Sami's today live like most other people, their tradition in for example reindeer activity is an important identity factor and Norway as a country are obliged to let the Sami's protect their culture [24]. Research shows that petroleum development is not considered to affect the Sami population more than other population other than that increased helicopter traffic may disturb reindeer troops [25]. In Norway the Snøhvit field is used as an example to show how it has affected Hammerfest and the surrounding area. After the start of production on Snøhvit there is seen an increase in population and more workplaces in Hammerfest [24]. Not only does the industry bring work to people directly connected to the industry, but one example is the need for more houses, which brings employment for construction workers [25].

3.6.2 Flora and fauna

The sensitive ecosystems of the Arctic are of high concern and conservation of the biological diversity is an important concern worldwide. The area opened for petroleum activity in the Barents Sea is populated by different fish species, whales, birds and the occasional polar bear [24]. The impact on these species from petroleum development is in varying degree and is not completely understood yet. Of special concern is marine uproar from offshore activity, these include sounds from drilling, seismic signal sampling and ship traffic [24]. These impacts are as mentioned not well understood, but could affect communication amongst animals or cause fish escaping from their normal routes which again affects the fishery industry. Seismic sampling is not done in periods of fish spawns or wanderings, the effects of ships is said to be of minimal concern as it will be over a big area and only the occasional boat whilst the sounds from drilling will be short termed [24]. Other concerns are the loss of habitat for animals and fish, the same goes for the fishery industry.

3.6.3 Regulatory effluents to sea

A regulatory effluent means planned effluents which are approved by the government and within regulatory frames. Regulatory effluents to sea mainly consist of cuttings, chemical leftovers from drilling fluid, produced water, hydraulic liquids and sanitary drainage [24]. It is mainly the effluent of cuttings during drilling and produced water that causes environmental concern. Knowledge of the consequences of these effluents is based on steady supervision and research done on the conditions around fields and installations since 1985 in Norway [24]. During the last years there has also been done research if organisms in the Arctic react differently than organism in more temperate areas. The results is not ambiguous; some claim higher sensitivity in temperate areas whereas some claim higher sensitivity in the Arctic [24]. There is done simulations on the effects of both cuttings and produced water in the actual area, the results indicates that only small areas around the wellbore will be affected by cuttings and may be neglected [24]. As for the produced water there is still uncertainty on long term effects but until further investigation is done it is considered negligible as well [24].

3.6.4 Regulatory effluents to air

Regulatory effluents to air from petroleum activities are mainly gases from the production of energy but it also includes diesel used for drilling, burning gas which could release CO2 and evaporation of oil from storing and loading [24]. Research shows that the whole Arctic has been exposed to long distance effluents, mainly with origin in the Eurasian continent, for years already [24]. In the Arctic there are different meteorological conditions; during winter there is a very stable atmosphere, almost blocking conditions, reduced chemical decomposition plus little precipitation and long degradation time [12]. The special meteorological conditions in the Arctic in combination with big seasonal changes are considered to be the main reason for high levels of airborne contamination [24].

Atmospheric particles have importance to climate, air quality and human health. Climate implications in Arctic areas are mainly related to sulfate and soot, also called black carbon (BC), because of their light absorbing and/or reflecting abilities [24]. BC- particles could affect the climate in three ways; BC in air absorbs sunlight and has a direct warming effect, it could also work as a condensate core leading to increased cloud formation which is an indirect cooling effect and at last the deposition of dark BC-particles on snow or ice would lead to reduced ground albedo hence an indirect warming [24]. Sulfate will on the other hand, reflect sunlight, hence have a direct cooling effect. It will in addition, as the BC-particles, increase cloud formation which again leads to an indirect cooling effect [24].

Today's models used to calculate the effects of these particles in the Arctic indicate that radiative forcing increases the further north the effluent is, thus increased petroleum activity in these areas could have a larger effect on the climate compared to similar activities further south [24]. The research done on these effects in Norway shows some increase in the mentioned particles, but is considered as a marginal addition in the overall load and will in general not bring any negative impacts on the environment [24].

3.6.5 Acute contamination

In the implication study performed by the Oil and Energy department in Norway they give the following definition of a blowout; *"A blowout is an event where formation fluid flows out of a well between formations to the surrounding environment after all defined technical well* *barriers or operations of these have failed. A blowout could arise at seabed or on a possible facility and can appear during drilling, completion, intervention or under normal production. This concerns both oil- and gas fields"*[24].

In the report it is used statistics from earlier blowouts which shows that most blowouts last for no longer than hours. The Barents Sea is still lacking infrastructure so the absolute worst case is set to 50 days for the most northern areas, but the most common is five days, which is still a conservative number [24]. There is done research on the different areas that are opened for activity which shows the potential impacts a blowout could cause. Consequences of a blowout for seabirds, marine mammals, fish and plankton are evaluated to affect only on an individual level and only on certain times of the year which makes the probability very low [24]. A way to avoid the chances of this happening at all, activities could be stopped at these certain times of the year. Potential coral reefs at the seabed will only be affected by oil spill very close to the source, as for now there are only detected reefs in places which will not be affected by blowouts in the opened area [24].

The Barents Sea is an important area for fishery, a potential blowout in the southern part of the area could affect coast near fishing. It is believed that a blowout would cause minimum effect on fish stocks and the fishery industry could change areas until the blowout is handled. An acute oil spill could have negative effects on society and business both locally and regionally, but based on the different scenarios in the report from the oil and energy department there is little foundation to believe a blowout would cause extended trouble for business in the area [24]. One important factor to decrease the damage of such an event lies in the handling of the event. There should be a correct and sufficient flow of information, political involvement and suitable actions done to protect the ones directly affected.

3.7 Safety

The main conditions that differ from the rest of the NCS to the Barents Sea are the cold, ice, darkness, difficulty to predict weather and great distances. To operate within the same safe limits as the rest of the NCS these conditions needs to be addressed properly by adequate planning of operations and training of personnel.

3.7.1 Cold

Despite of the northern altitude the south western part of the Barents Sea where there has been petroleum activity does not experience the extremely low temperatures one might find at similar altitudes around the world due to the Gulf Stream [2]. The eastern and more northern parts of the sea are however not affected by this and remain colder. In the south western parts of the Barents Sea, where Snøhvit is located, the temperatures can reach minus 20°C whereas the newly opened areas in the Barents Sea south east the thermometer can show down to minus 30°C [2]. At Svalbard and its surroundings you may experience as low as minus 40°C and below[2]. When looking at these temperatures it may not seem that extreme but one also need to take the wind into account which will make the cold experience much heavier.

Water temperature varies along with the air temperatures depending on where we are and season, but as a general from minus 2°C to plus 4°C [2]. These temperatures have a huge impact of the survival of a stay in the water, the deadly condition hypothermia occurs faster in colder waters. There is therefore developed new survival suits for northern areas [2].

The low temperatures in combination with strong wind will increase the occurrence of icing. Icing is when for example either seawater or wet snow freezes on ships or installation. This could lead to production equipment not working, PPE and safety equipment freezes and make ships unstable [2]. Icing is a well-known phenomenon in aviation and knowledge across industries may be used in integrated operations. The cold environment might introduce the workers to extreme working temperatures and research shows that sickness and injuries might arise from direct exposure to these low temperatures [2]. In addition, humans are affected both mentally and physically, and the working performance decrease in low temperature conditions

3.7.2 Ice

The ice conditions in the north are difficult to predict as they change from season to season and from year to year. As mentioned earlier they also differ drastically from one Arctic region to the next one. To talk about ice in general is not possible as it exists in several forms, each with its own properties.

Icebergs are chunks of ice that formed on land, breaks off and floats in the ocean. To be called an iceberg it has to be larger than 5m across [12]. In Norway the biggest occurrence of icebergs is around the island group, Kong Karls Land, which is located north east of Svalbard [2]. Here there are about 50 glaciers which calves or breaks off ice on a regular basis, the icebergs then floats with wind and currents south [2]. If an iceberg is on collision route with a facility it proposes a genuine risk as the ice does not contain salt it is very hard and could cause serious damage. In areas where an iceberg encounter could be possible it is important to have suitable measures to handle the situation properly. Such measures could be to design the facility to withstand a collision, towing of the iceberg or temporarily disconnect to remove a floating facility till the iceberg has passed among others [2].

Sea ice is divided into two main categories according to whether it is attached to land, land-fast ice, or if it occurs offshore, drift-ice [12]. Sea ice forms, grows and melts in the ocean, meaning it contains salt, making it softer than the icebergs and the impact of a collision will not be as severe [12]. There is also a difference between first year ice and multiyear ice. Multiyear ice has survived a melting season and grows thicker every year [12]. In the Barents Sea one year ice is the most common one whereas multiyear ice is almost secluded to the northern part of Kong Karls Land [2].

3.7.3 Weather and warning

In Norway both the North Sea and the Norwegian Sea offers harsh conditions during the winter months, but with its polar lows, fog and challenging and abrupt changing weather forecasts the Barents Sea proposes challenges for operating companies. Polar lows are a passing atmospheric low pressure system with a diameter ranging from 100-500 km, which forms when cold air from the Arctic flows over warmer open water [12]. The polar lows are often called Arctic hurricanes and are known for rapid weather changes where wind can reach storm conditions in minutes. A polar low often disappear as quickly as it appeared but can bring heavy snowfall and icing on the average one or two days it exists [2, 12]. The warm air from the Gulf Stream, which makes parts of the Barents Sea ice-free, also creates small snow storms because of the temperature differences in water and air [2].

Weather forecasting is one of the main challenges. To be able to give a detailed forecast meteorologists need more data and readings than are available in the area today. The weather phenomena in these areas are not easy to detect with existing equipment but satellites may present one solution. Even the summer months proposes challenges as the weather changes, now the water holds a colder temperature whilst the air gets milder. This easily leads to fog which decreases the visibility drastically. The area around Bjørnøya, where a possible future helicopter base could be located, poses a particular challenge as the temperature contrast is very high. During a year there is an average of 76 days with less than one km of visibility [2].

3.7.4 Darkness

North of the Arctic Circle there are phenomena called the polar night and polar day, also called midnight sun. During polar days the sun never sets for a period of time, as for the polar night the opposite happens, the sun never reaches the horizon. These phenomena increases in strength the further north of the Arctic Circle one is, at the North Pole there is complete darkness for six months during winter and following sunlight the next six months [12]. The durability of polar nights decreases when you move from the North Pole towards the Arctic Circle. This could cause operational hazards during both normal operations or during a possible oil spill or rescue scenario where the use of sight is important. The darkness also affects humans in a negative way and can trigger depression, this could be particular hard for foreign people not used to this phenomena [2].

3.7.5 Distance

Apart from Snøhvit there are no permanent facilities present in the Norwegian Arctic. The huge distances from shore to some of the fields are one of the main reasons for that, it is still hard to make it viable and maintaining the needed rescue and evacuation measurements. There is more than 450 km to the most northern part where petroleum activities now is allowed whilst the helicopters in use are limited to 340 km [2]. This helicopter limit is set so it can return to point of departure if landing is not possible. A new solution to reach the rest of the Barents Sea are refilling of tanks, this can be done in several ways, one being dedicated filling facilities serving various fields. Other options might be to land on existing facilities such as the planned Johan Castberg development which location is ideal for reaching big parts of the Barents Sea. In figure 3.10 one may see the area opened for activities and the helicopter reach from Hammerfest, Johan Castberg and a hypothetical installation is represented by the blue, green and dotted line respectively. To develop a helicopter base on Bjørnøya is also being evaluated but frequent fog in summer is a big concern [2].

The operating companies for both Snøhvit and Goliat have cooperated to place one "All weather search and rescue" helicopter in Hammerfest to cover the currently need for rescue and evacuation operations from the Barents Sea area [2]. The huge distances make medical evacuation a big challenge, and there are discussions if the new facilities should have increased medical staff and equipment onboard [2]. This far north the earth's curvature becomes an issue for satellite connection and communication with exploration rigs working in the area becomes a challenge, for permanent facility development this could be solved by fiber cables [2]. Electromagnetic storms are also a risk for communication equipment and do occur at these altitudes and could cause misleading signals or even complete loss of signals in a rescue situation [2]. It is expected that there will be specialized satellite signal designed for the high north to enhance the situation.

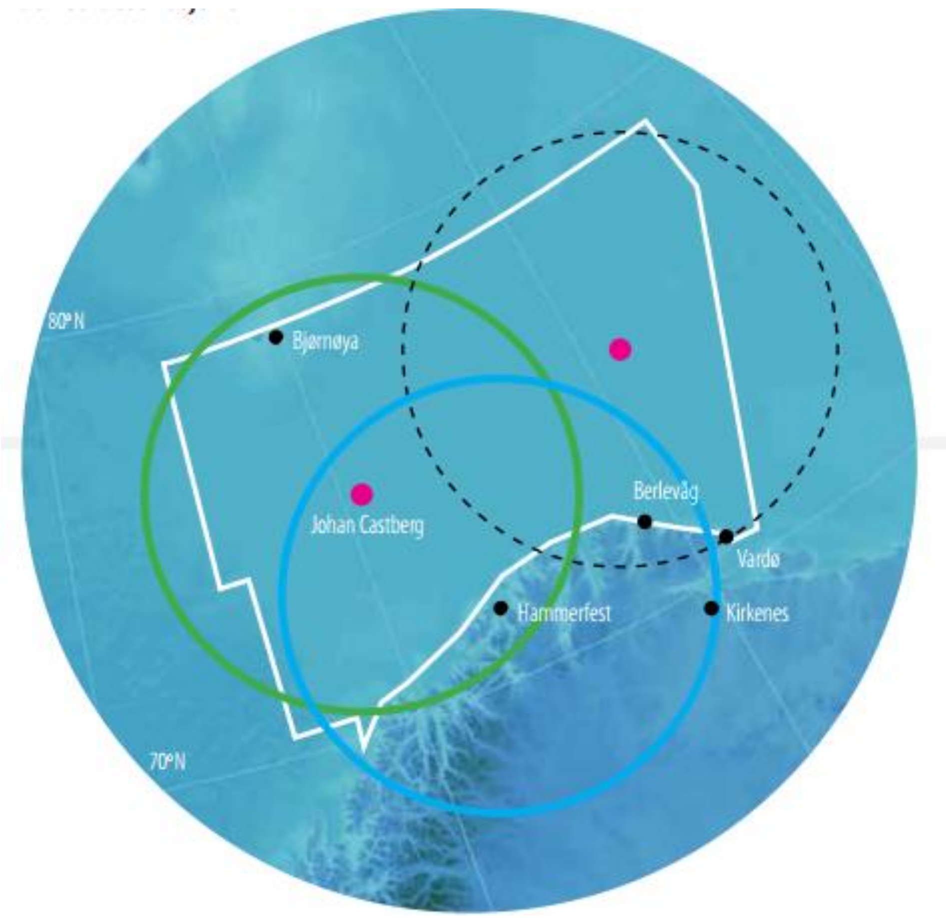


Figure 3.10 - Helicopter reach in the Barents Sea [2]

4 General about well control & blow out contingency

In NORSOK D-010 well control is defined as *"collective expression for all measures that can be applied to prevent uncontrolled release of well bore effluents to the external environment or uncontrolled underground flow"* [26].

Well control is one of the major concerns in any drilling procedure and the objective is to keep the well pressure stable and remain in control of the well. To explain well control very simply it is about keeping the formation fluids in the formation and the drilling fluids out of the formation. Any undesirable flow of formation fluids into the wellbore is called a kick and may be water, oil, gas or a mixture of any of these fluids. These kicks can cause unexpected high pressure on surface equipment which may exceed the equipment's pressure grading's and lead to very dangerous situations. To control the well during a kick, safety equipment such as the BOP is used; the BOP is recognized as a well barrier. If a kicking well is not detected and dealt with correctly it may lead to a full scale blow-out which is uncontrolled flow of formation fluids into the wellbore. In a worst case scenario this unwanted flow may reach the surface with catastrophic result. A blow-out can cause pollution and release poisonous gases, cause an oil spill, create fire hazards, damage equipment and environment or even more severe, injure and even kill personnel.

Figure 4.1- The Macondo incident [27]

4.1 Well barriers

The purpose of a well barrier is to reduce, avoid or stop unwanted and accidental events in a well. It can be looked upon as a defense system and includes human, technical and organizational barriers. This defense system shall protect from unwanted fluid flow at any time and guarantee the overall safety for the workers, platform and environment. Barrier systems consist of one or more barrier elements, these systems are often called barrier envelopes, and are in place to define their function and make the systems fail-safe. If a barrier or barrier element fails, all actions should be temporarily stopped until the failure is fixed and the barrier regains its function [28].

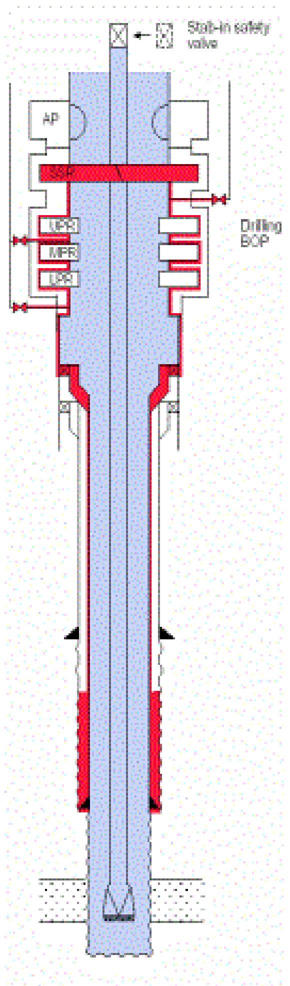
The barrier philosophy differs around the world and the government's involvement in petroleum activities varies drastically. There is no standard that is in use worldwide, but in Norway the NORSOK Standard is a guideline and defines minimum requirements that companies must follow to operate within Norwegian law.

In NORSOK D-010 it is stated *"There shall be two well barriers available during all well activities and operations, including suspended or abandoned wells, where a pressure differential exists that may cause uncontrolled outflow from the borehole/well to the external environment"* [26].

4.1.1 Well barrier schematics

In NORSOK D-010 there are well barrier schematics illustrated for the different phases of operation such as drilling, production and intervention.
Figure 4.2 shows the well barrier elements required according to the NORSOK-D010 regulations for conventional drilling, as seen in the figure it is distinguished between primary and secondary well barrier.

5) Drilling, coring or tripping – Shearable drill string



1) Well barrier elements	See Table 2)	3) Comments
Primary well barrier		
1. Fluid column	1	
Secondary wellbarrier		
1. Casing cement	22	
2. Casing	2	Last casing set
3. Wellhead	5	
4. High pressure riser	26	If installed
5. Drilling BOP	4	

4) Note

Legend:

1. *This describes the name of the WBE(s)*
2. *A complete description of general acceptance criteria for this WBE is found in Clause 15 which contains a library of WBE acceptance criteria tables.*
3. *This table column is used to describe comments.*
4. *The place can be used for describing additional requirements and guidelines. For example a description of compensative measures if there exist common WBEs.*
5. *The illustration shows the primary well barrier in its normal working stage, while the secondary well barrier is shown in its ultimate stage. This stage often described with a closed shearing device.*

Figure 4.2- Well barrier schematic [26].

4.1.2 Well barrier element

A well barrier element is defined as an *"object that alone can not prevent flow from one side to the other side of itself"* [26]. To avoid unwanted fluid flow to reach the surface several well barrier elements are needed to fulfill the barrier envelope. The different well barrier elements in a conventional drilling operation are seen in figure 4.2.

4.1.3 Primary well barrier

The primary well barrier is, as the term indicates, the first defense for unintentional fluid flow. During normal operations the mud column is defined as the primary well barrier, it closes around the entire wellbore and is used to keep the well pressure above the pore pressure and below the fracture pressure. In this way it ensures no inflow of formation fluids and should not fracture the formation to cause lost circulation. In addition to being a primary well barrier the drilling fluid has numerous other functions and its properties are under constant monitoring during operations [28, 29]. In figure 4.2 the primary barrier is outlined in blue.

4.1.4 Secondary well barrier

As mentioned the NORSOK D-010 requires two functioning barriers in most operations and the intention of the secondary well barrier is to work as a backup system for the primary well barrier. This secondary independent barrier or barrier elements are outlined in red in figure 4.2 and includes the casing, casing cement, high pressure riser, wellhead and the BOP stack [26]. If the primary barrier fails and unwanted fluid flow occurs the casing and casing cement (primarily) shall prevent underground blowouts and subsurface cross-flow whilst the BOP should shut in the well before the influx reaches surface [28, 29].

4.2 Reasons for kick

A kick is as mentioned a well control problem occurring when the pressure exerted by the drilling mud is less than the pressure in the formation that the drill string is penetrating. This could cause the formation fluid to flow from the formation into the wellbore which is what is called a kick situation and if not detected and dealt with correctly could lead to a full scale blowout. There are several factors that decide the severity of kick including the formations permeability and porosity.

There are several reason that may lead to a kick situation, these are retrieved from [28]:

- Insufficient mud weight
- Improper hole fill-up on trips
- Swabbing
- Gas cut mud
- Lost circulation

4.2.1 Insufficient mud weight

Wrong mud weight is the most frequent cause of kicks. When drilling it is important that the mud column exerts higher pressure than the formation and at the same time stays within the drilling window which is lower than the fracture pressure and higher than the pore pressure. If the formation pressure exceeds the well pressure fluids begin to flow into the wellbore and a kick occurs. Insufficient mud weight is often related to abnormal pressures zones, where the pressure exerted by the formation is higher than expected.

4.2.2 Improper hole fill-ups on trips

Tripping is when the drill pipe is either pulled out or placed in a well. When tripping out of a well the level of mud decreases as the pipe no longer displaces the mud, as this happens the well bore must be filled up with mud to avoid reducing the overall hydrostatic pressure hence preventing a kick situation [28]. This can be done in several ways but it is important that the volume of mud required is accurately measured.

4.2.3 Swabbing

Swab pressures are temporary, pressure reducing and occur when pulling the drill string from the bore hole. This pressure reduction will reduce the effective hydrostatic pressure over the well bore and if it reduces below the formation pressure a kick situation might occur. To avoid the swab effect certain parameters such as tripping speed, hole configurations, mud properties and the effect of "balled" equipment needs to be monitored [28]. Balled equipment is when the outer diameter of the equipment is enlarged because for example sandstone or clay sticks to the pipe [28].

4.2.4 Gas cut mud

A kick caused by gas-cut mud is rare but will occasionally cause a kick situation. When drilling a hydrocarbon bearing formation small amounts of gas will be present in the well as well as in the cuttings. This gas will on its way up to the surface expand and reduce the hydrostatic pressure. Most expansion occurs near the surface thus not reducing the overall mud weight sufficient enough to cause a kick.

4.2.5 Lost circulation

There are several scenarios leading to a lost circulation situation. A lost circulation problem is graded in order of its severity, i.e. how much mud is lost, taken from [30]:

- Seepage losses – refers to continuous loss of mud up to $3m^3/hr$ during conventional drilling
- Partial loss of circulation – refers to continuous loss of mud over $3m^3/hr$ during conventional drilling
- Total loss of circulation – the pressure of the mud exceeds formation pressure

The two first conditions is often an indication of a total loss of circulation, and it can be looked at as a development scale which could lead to both well control problems or a stuck pipe situation [30]. There are two main reasons for a lost circulation situation [30]:

- Pressure induced fracturing – the fluid pressure exceeds the formations fracture pressure
- Natural fractures/high permeability – formations or zones with natural fractures or high permeability which are exposed to fluid pressures exceeding what they can bear

Lost circulation is a major drilling issue when dealing with karst reservoirs which are the main study in this thesis and there is therefore a more detailed description of what lost circulation and how it occurs. Karst reservoirs are discussed in details in chapter 5.3.

When drilling into a zone with high permeability or natural fractures the formation could be unable to prevent the drilling fluid from entering this zone. These zones are recognized as weak zones because the initial fracturing is already done and fracture pressure is lower than normal.

In this case the mud level will drop resulting in reduced bottom hole pressure, should the pressure drop below the formation pressure influx of formation fluids will occur and the outcome will be a kick. The magnitude of the kick will greatly depend on how much mud is lost and how big the differential pressure gets. Should the formation fluid enter the well it will mix with the well bore fluids and further reduce the mud density making even more formation fluid influx, hence the outcome of a kick caused by lost circulation could get severe [28].

Next follows an example were the mud weight to control the subsurface pressure, after loss of circulation has occurred, is determined.

The well data is as follows and the situation is illustrated in figure 4.3:

- Well depth: 15 000ft
- Mud weight (MW): 17.0ppg
- Drill pipe: 4, 5"
- Hole size: 8, 5"
- Water required to fill the hole: 20bbl

First the annulus volume is calculated where 1029,4 is a conversion factor to obtain an answer in bbl/ft:

$$Annular\ capacity\ \left(\frac{bbl}{ft}\right) = \frac{(Dhole^2 - \ Dpipe^2)}{1029{,}4}$$

$$Annular\ capacity\ \left(\frac{bbl}{ft}\right) = \frac{(8{,}5^2 - \ 4{,}5^2)}{1029{,}4} = 0{,}05\ bbl/ft$$

Next step is to calculate the amount of water that is displaced in the annulus after mud is lost to fill up the well:

$$Number\ of\ feet\ of\ water\ in\ annulus = \frac{Water\ added\ (bbl)}{Annular\ capacity\ (\frac{bbl}{ft})}$$

$$Number\ of\ feet\ of\ water\ in\ annulus = \frac{20}{0{,}05} = 400ft$$

The BHP pressure reduction can then be determined:

$$BHP\ decrease\ (psi) = (MW - Weight\ of\ water) * 0{,}052 * Water\ added$$

$$BHP\ decrease\ (psi) = (17 - 8{,}33)(ppg) * 0{,}052 * 400 = 180\ psi$$

When the pressure drop below the formation pressure an influx is taken and the next step is to calculate the mud weight required to force the influx back into the formation and control the subsurface pressure:

$$Equivalent\ MW = MW - \frac{BHPdecrease}{0{,}052 * Depth}$$

$$Equivalent\ MW = 17 - \frac{180}{0{,}052 * 15\ 000} = 16{,}78ppg$$

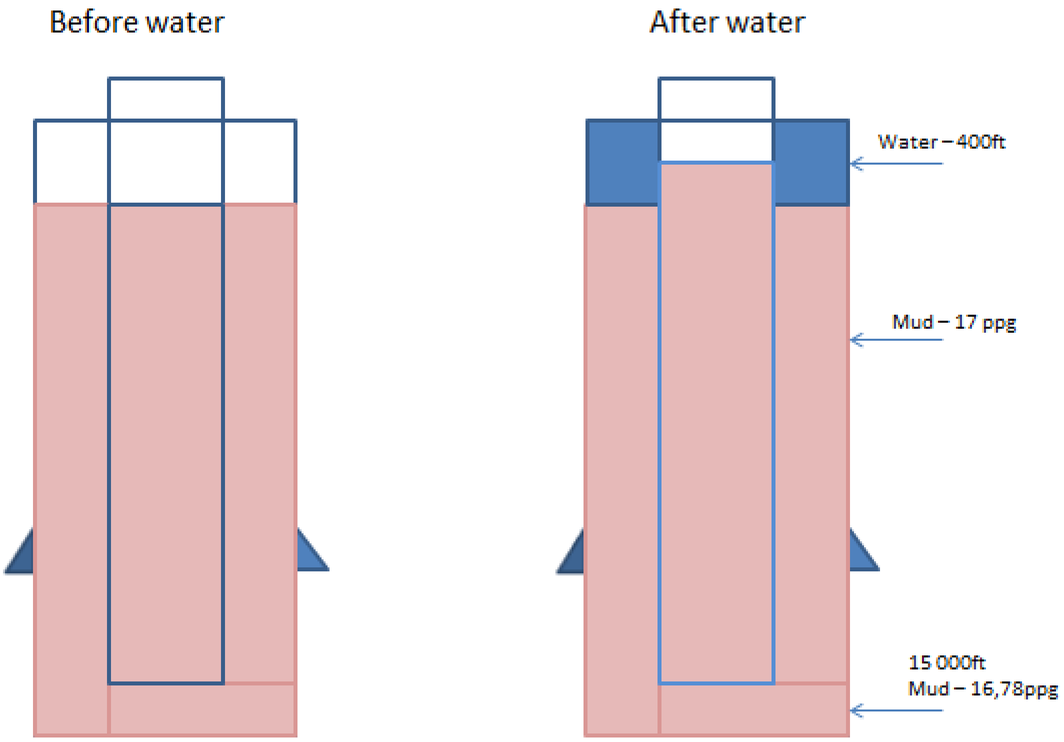


Figure 4.3 - Determination of MW after loss of mud

By adjusting the mud weight one can control the influx and avoid a kick.

4.3 Kick detection

During well operations it is important to monitor the well at all times because warning signs of a kick could be observed at surface and it is each crew members responsibility to detect and identify these signs and take the correct action. There are some key warning signs that a kick is under development, these are retrieved from [28]:

- Flow rate increase
- Pit volume increase
- Flowing well with pump offs
- Decreasing pump pressure and increasing pump strokes
- Improper hole-fill ups on trips
- String weight change
- Drilling break – e.g when drilling into an open hole which increase the ROP significantly

4.4 Well control procedures

Below there is shown an illustration of a well with its different components during a drilling operation [28]. Figure 4.4 is missing a kill line which should be equal in length and size as the choke line.

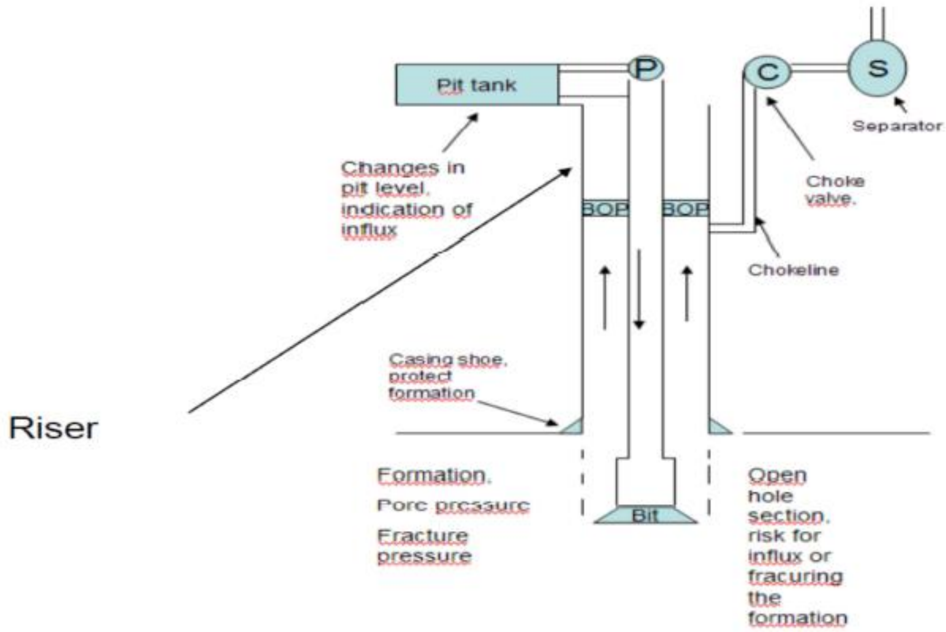


Figure 4.4 - An illustration of the different components in a drilling operation [28]

If a kick occurs and the well is shut-in, appropriate action needs to be taken. To kill a well means removal of the influx fluids from the borehole and re-establish the mud column as the primary barrier. There are several actions that can be performed, which one to choose highly depends on the particular situation – the drill pipe location is one important factor. It is important that the situation is handled in the most safe and efficient way possible. A discussion of the following killing methods will be performed:

- Driller's method
- Wait and weight
- Bullheading
- Volumetric method

4.4.1 Driller's method

This well killing method requires the bit to be located at the bottom, if not stripping to bottom will be required. It is known as a two circulation method meaning there will be two complete and separate rounds of circulation of the drilling fluid in the well. The first circulation will be performed with the original drilling mud to remove the influx fluids. Since the well is shut-in and the BOP is closed the return flow needs to go through the choke line, a line located outside of the riser and up to surface [28]. During performance of the driller's method the BHP needs to be held constant and slightly higher than formation pressure to avoid further influx of formation fluids. This is completed by a valve at the end of the choke line which enables regulation to keep a constant BHP. The second round of circulation is done with kill mud which should balance the formation pressure after the kick has been circulated out of the well in round one [28]. The new kill mud is circulated down the drill pipe and up annulus, after this is completed the new mud should balance the formation pressure and drilling operation can continue.

4.4.2 Wait and weight

Wait and weight is another circulation method to kill a well, similar to the driller's method but this involves only one round of circulation. In a wait and weight operation removal of influx fluids and displace the well to kill mud is done in only one round of circulation [29]. As for the driller's method it is important to keep the BHP constant, thus this method is more difficult to perform as the columns in both annulus and drill pipe will change simultaneously as the kill process takes place [28].

4.4.3 Bullheading

When using the bullheading technique to kill a well, the influx is pumped with a constant rate back into the formation without returns to the surface [29]. This technique is used when the margin against the formation pressure is too low for driller's method or wait and weight, when hydrogen sulfide is expected in the influx fluid or when the drill string is out of the well bore [29].

4.4.4 Volumetric method

The volumetric method is used in scenarios where there is no possibility to circulate the well through the drill string meaning it can only be initiated when there is a gas kick which migrates upwards in the well bore [28]. As the gas kick moves up and the pressure increases the choke valve is opened to bleed off the mud hence the pressure is reduced, it is then closed again when the pressure reduction is sufficient [28]. This is done stepwise to maintain in control and keep the BHP constant keeping more influx from occurring.

5 Special precautions regarding well control in Arctic environments

It is in this chapter tried to identify specific well control considerations in the southern Barents Sea, the different risks are divided into three sections being topside, subsea and subsurface related risks.

5.1 Topside

With the term topside, the upper half of the structure which is above sea level and out of the splash zone where equipment is installed and stored is meant. At the topside we find the platform structure, equipment and the personnel.

5.1.1 Equipment preparation

A main topside concern is to make the drilling unit and its equipment ready for the harsh environment by winterizing them and enabling it for year round operations. Everything that is to be used in the northern areas needs to comprehend low temperatures. Installations needs to be designed in a way that cold, drift ice, icing and Arctic weather phenomena do not affect safe operations [31]. By winterizing an installation it often means that work areas are more secluded which will prevent workers and equipment from harsh weather exposure but will also introduce challenges related to risk for fires and explosions [2]. By building work areas which normally are in a fresh air environment to an inside environment brings new fire risks and increased fire intensity which is a consequence that needs to be taken account for [2]. Winterizing installations also introduces challenges relating to increased weight and complexity. The ultimate goal of winterization is to make it comfortable for humans to perform operations on the platform over a long period of time.

To be able to operate safely in the Barents Sea accurate research on the conditions in the exact area needs to be done. When all information on weather phenomena, temperatures, water depths and ice conditions is done the appropriate drilling unit can be chosen.

Eni Norge is the operator of the field Goliat which is thought to be the first oil field to come on stream in the Barents Sea [32]. Together with their partner Statoil they have chosen the Sevan FPSO 1000 which can be seen in figure 5.1, this is a cylindrical FPSO solution for the field development [33].

Figure 5.1- Sevan 1000 FPSO [32]

Sevan 1000 FPSO is designed to comprehend the challenging environment it will encounter in the Barents Sea, for example to withstand icing and ensures that snow and rain drains naturally from walls and roofs [32]. It was also considered the best solution based on the environment, technology, economic considerations and area development [33]. As a floating production facility it is flexible and offers the opportunity of tie-ins to new discoveries and the possibility for integrated operations [33].

5.1.2 Relief well

In NORSOK D-010 it is stated that *"For offshore wells, the well design should enable killing a blowout with one (1) relief well. If two (2) relief wells are required, it shall be documented that such an operation is feasible with respect to logistics, weather criteria and availability of rigs"* [26].

A relief well is the last option in a blowout contingency plan and is to be drilled if surface intervention or other attempts such as capping has failed to stop the uncontrolled flow [34]. It is drilled next to well that has suffered an uncontrolled release of fluid, a basic design concept of a relief well can be seen in figure 5.2 [34]. The goal of a relief well is to regain control of the fluid flowing in the well by either leading the hydrocarbons up the new wellbore or to kill the blowout with mud and secure it with cement [34]. For either of the operations to be a success accurate interception of the flowing wellbore is crucial.

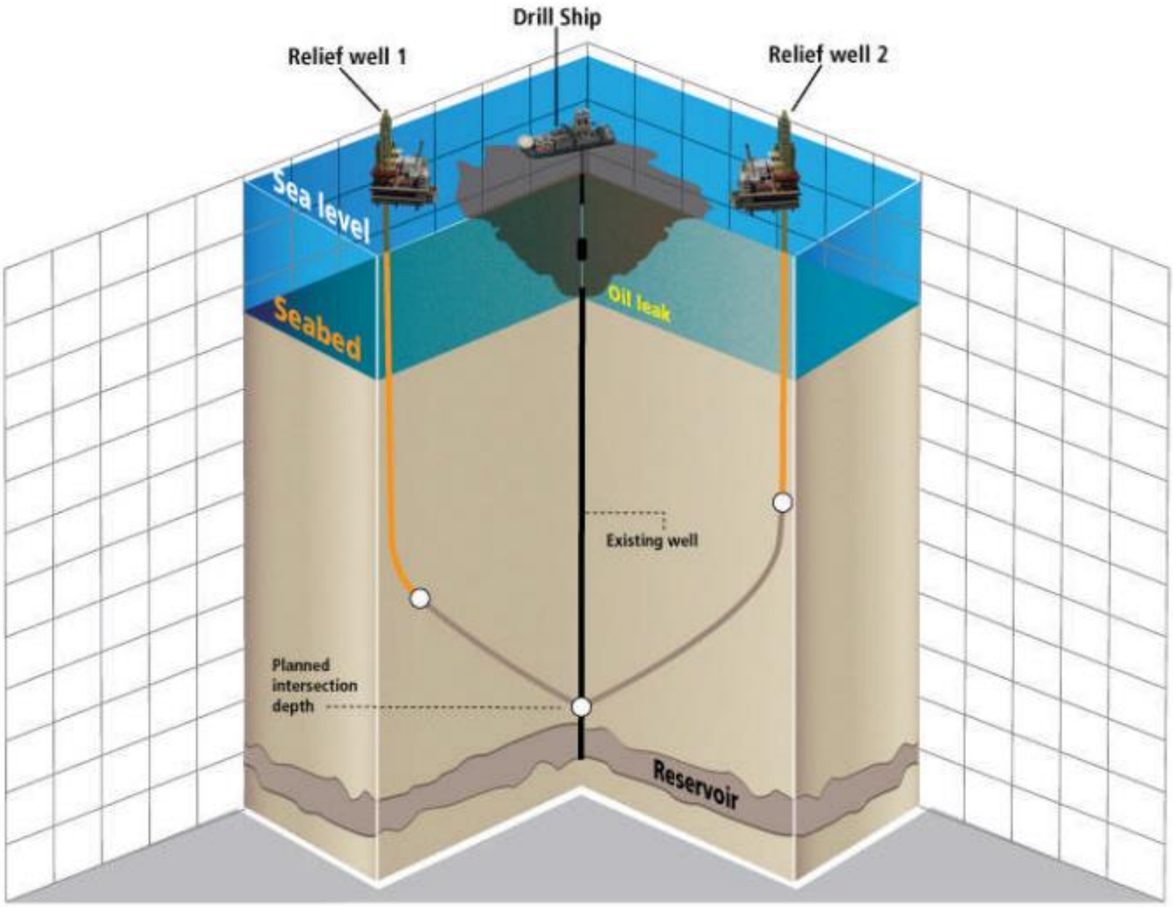


Figure 5.2 - Relief well design [34]

In the implication study performed by the Oil and Energy department it is raised concern towards areas which are covered in ice wintertime and if it is possible to mobilize a rig for relief well drilling at all [24]. Responses to the study raise concern on relief well drilling and whether there is access to rigs that are prepared to operate the harsh environment in the Barents Sea [24].

There is also a concern regarding existing directional measuring equipment and if it has to high uncertainties for wells in these areas. This is because of the critical angle to the magnetic field and magnetic waves from sun storms could present a source which is way off compared to measurements further south on the shelf [24]. Accurate data for directional measurements in wells are critical to be able to drill a relief well safely.

NORSOK D-010 also states that *"The time for mobilizing relief well rig(s) shall be evaluated in the planning phase. Initiation of relief well drilling should start no longer than twelve (12) days after the decision to drill the relief well(s) has been taken"* [26].

It is raised questions to if this will be possible in all areas in the Barents Sea, or if extension of this time period is needed. In the northernmost part of the opened area there are vast distances and higher uncertainties regarding weather and ice relations and could make it impossible to mobilize a rig within the given time frame [24].

They also mention capping and containment as another possible solution to an oil spill for future accidents [24].

5.1.3 Hydrates formation

The risk of hydrates creating operational hazards is usually related to deep water drilling where the water is colder and the hydrostatic pressure is higher [13]. However, hydrates have been detected at depths of 350 m with a temperature of 7°C [35], whereas the depths in the opened area in the Barents Sea is up to 400 m [24]. In the same area during winter and spring the water temperature at 20 m depth is said to be 4-5°C in the southern part whilst it can drop to 1°C in the northern part [24]. During summer and autumn the temperatures at 20 m below surface will increase to 7°C in the south and around 4-5°C in the north [24]. These conditions make hydrate formation possible, as the seabed temperature will be even lower, and should be of high concern when operating in the Barents Sea. Hydrates formed in equipment such as choke lines, kill lines, BOP and risers during drilling operations can plug these and cause difficulties in subsequent operations [35].

These gas hydrates can form in any location where there is free gas, water and where the appropriate pressure and temperature exists, this could happen on surface, subsurface and in technical systems used to retrieve hydrocarbons in a safe manner [13]. Hydrates belong to a group of substances known as clathrates because they consists of a “host” molecule which acts like a trap for the “guest” molecule [35]. As mentioned, hydrate formation can form in any location where there is gas, water and the right temperature and pressure regimes. In an offshore operation there is obviously a tremendous access to water, which acts like the “host” molecules whereas gas comes from the formations acting like the “guest” molecules [35]. An interesting property of hydrates is the amount of gas it can hold in a given volume, 0,028 m^3 of hydrate could contain as much as 4,8 std m^3 of gas [35]. When hydrates decompose, or break down, because of remediating actions or natural occurring pressure reduction and/or increased temperature, the result could be a large volume of gas released. If this should occur in a limited-volume, sealed container as for example a core barrel, it could bring forth high pressures that could lead to breaching of the container [35]. Research has obtained pressure and temperature combinations which will allow the gas and water to form stable hydrates and can be seen in figure 5.3 [35].

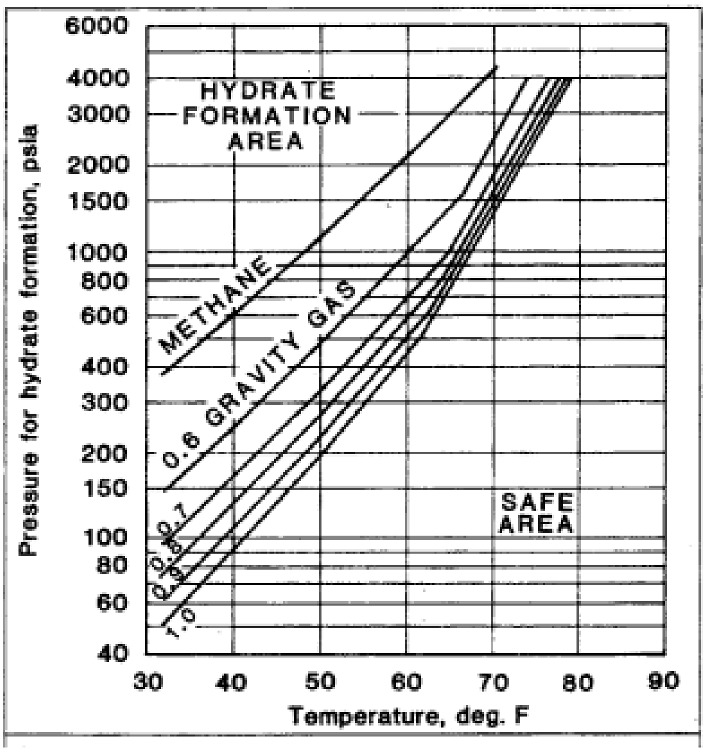


Figure 5.3 - Favorable conditions for hydrate formation of natural gas/freshwater hydrates [35].

This elaboration on hydrates will be the basis for hydrate occurrence in the subsea chapters 5.2.1 and 5.2.2 as well.

Case studies from two very different offshore locations show that hydrates can form in varying conditions. One well off the U.S west coast with a sea water temperature of 7°C at seabed and a water depth of 350 m which is not very deep, the other in the Gulf of Mexico with a seabed temperature of 4°C and water depth at 945 m [35]. Both wells experienced operational trouble which led to costly delays and special procedures to remain in control of the wells.

In the well off the U.S west coast a gas influx was detected, the kill operation experienced a lot of trouble, and seven days after the gas was discovered both the choke and kill lines were found plugged [35]. Actions to unplug the lines where taken but pressure surges applied from surface failed numerous times. When the wellbore was secured by cementing operations, the BOP was recovered and hydrates and trapped gas was found in both choke and kill lines [35].

Choke and kill lines are exposed to seawater and in the cold environments in the Barents Sea there could be hydrate formation in these. Hydrate formation could plug either choke or kill line which will prevent their use in well circulation thus making it a well control issue [35]. To address hydrate formation likelihood assessment of the existing pressures and temperatures along with fluid compositions should be done prior to drilling. As seen in the two case studies, hydrates tend to form in periods of shut in where the well is not circulated thus temperatures in the wellbore decrease [35]. Periods of shut in could occur for example due to severe weather conditions which is not uncommon in the Barents Sea. Greater insulation of choke and kill lines could help to at least decrease the rate of heat transfer in these periods [35].

5.2 Subsea

Subsea is a general term frequently used to describe the position of equipment, technology and methods used in the offshore industry thus subsea means underwater, and most common at the seabed.

5.2.1 BOP

The BOP, or blow out preventer, is a secondary barrier element which consists of various BOP rams, each with specific closing purposes.

In chapter 5.1.3 hydrate formation and properties is discussed and a case study of two wells in different locations is introduced. The case study will be used here as well.

The well located in the Gulf of Mexico experienced hydrate occurrence while drilling, its detailed BOP arrangement can be seen in figure 5.4. After some time of drilling the well was found flowing, it was then shut in to measure well bore pressures. Several attempts to open the BOP’s, diverting the gas influx and establish circulation was done but 48 hours after the first kick was detected the well flowed a third time [35]. During operations they experienced trouble with opening and closing of the different BOP rams and both choke and kill lines where found plugged. After the well was secured and the riser and BOP was pulled, hydrates where found in both kill- and choke lines and surface testing of the BOP’s showed no mechanical failure or issues in the BOP control system [35]. In addition to this there was observed great amounts of gas in the return mud which is an indication of decomposing hydrates. Hydrate formation in or around the BOP could cause severe situations during well control operations.

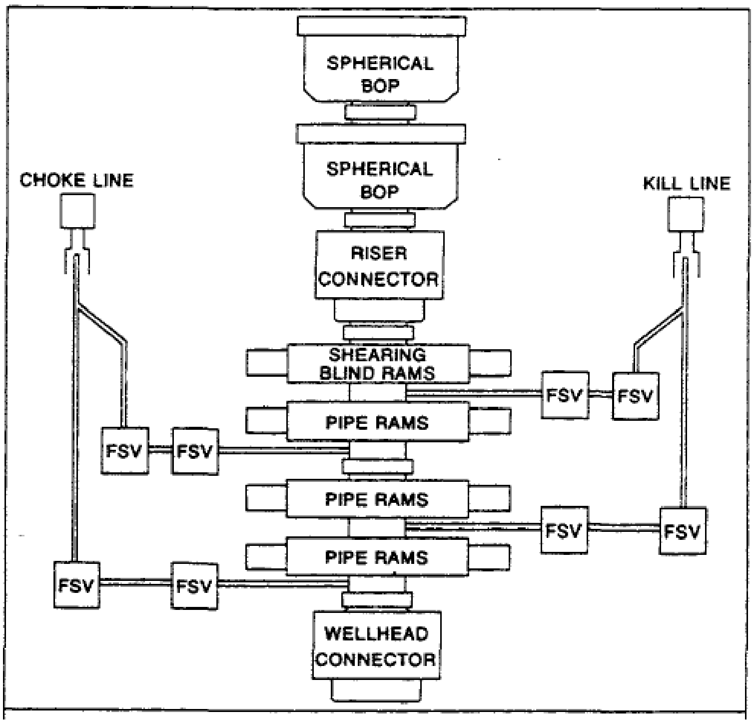


Figure 5.4 - Subsea BOP arrangement - Gulf of Mexico well, case study [35]

5.2.2 Pipelines

Development of offshore oil and gas fields in Arctic and sub-Arctic regions introduce the need for safe and secure transportation systems which needs to operate within the extreme environment encountered in these areas. Transportation system of oil and gas, respectively, are characterized by shipping or subsea pipelines [13]. A lot of the undeveloped areas in Arctic offshore are being evaluated for tie-back solutions without host facilities. This can lead to extreme lengths of pipeline systems which again will lead to an increased temperature drop along the system. In addition the cold seawater surrounding the pipes can cause arrival temperature of the hydrocarbons to be very low. As the temperature in the flow of produced fluids drops, the hydrocarbons could leave the safe area seen in figure 5.3 to form hydrates and result in critical blockages in the pipes [13]. A hydrate plug from a subsea pipeline can be seen in figure 5.5.

Figure 5.5 - Hydrate plug formed in subsea pipe offshore Brazil [13].

5.3 Subsurface

Subsurface refers to everything below the seabed, thus under the level of the ground. The subsurface consists of layers of rock and sediments. Recent findings in the Barents Sea has shown exciting results in carbonates from Permian time and this section will include information about carbonates, karst formation and its relating properties, challenges and possible solutions to these.

5.3.1 Motivation

One of the newest discoveries in the Barents Sea is the Gotha field which is located at the Loppa high (figure 5.6) 35 km northwest for Snøhvit and has proven oil and gas condensates [36, 37]. When drilling started, the operator Lundin, was well aware that there had never been found economical feasible reservoirs with carbonates from Permian time on the NCS. There have been drilled wells in the same license area earlier but these showed poor production properties of hydrocarbons [37].

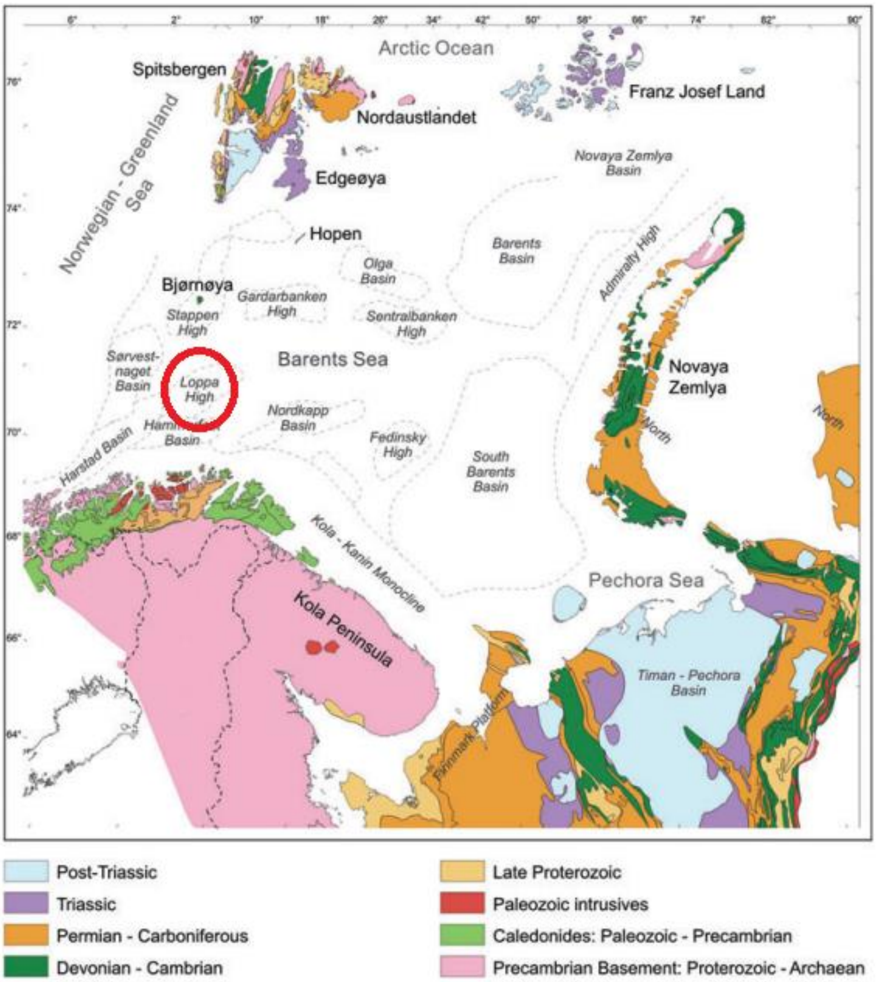


Figure 5.6 - Surrounding geology of the Barents Sea [38]

The reservoir at Gotha is made of carbonates and these are often complicated with unpredictable porosity and permeability values. In addition, Lundin confirms that the discovery is made in so called karstified rocks, meaning the rocks have been exposed to a chemical process which makes caves leading to a network of cavities [36]. The geology at Gotha is believed to have similarities to exposed layers at Svalbard and Bjørnøya and a karst hole or a doline in the mountain Fortet in Billefjorden on Svalbard is seen in figure 5.7 [36].

Figure 5.7 - Karsthole at Fortet, Billefjorden, Spitsbergen [36]

Even though this type of reservoir is new to Norway there has been successful experience with karstified reservoirs in other parts of the world such as Russia and Malaysia [36, 39]. The F6 field offshore Malaysia was discovered in 1987 and when half of the carbonate reserves were produced a re-development plan of the field was initiated [40]. The area had dealt with drilling problems such as severe mud losses and drop of drill string which is often linked to Karst networks but it was first after old 2D seismic was updated to 3D seismic and tested against drilling operational data that large Karst networks were proven [40]. After more and better subsurface data the operator was able to define strategies to decrease the risk of Karst induced issues during operations [40].

Karstification is quite frequent in hydrocarbon reserves but is often underestimated, misunderstood and poorly modeled in carbonate petroleum reservoirs.

5.3.2 Formation of carbonates

Carbonate rocks are classified as sedimentary rocks, meaning they are produced from processes on the Earth's surface. Sedimentation can be looked at as a downhill process, as transportation of sediments follows a downhill trend in response to gravity and sedimentation starts where the transportation ends. The term sediment include solid materials physically deposited by water, ice and wind, as well as substances precipitated chemically from oceans, rivers or lakes [41].

Carbonate sediments are formed in two different ways; they could either precipitate from seawater directly which is a chemical process or accumulate from skeletal debris from organisms which is a biological process [42]. The equation to form carbonate sediment is taken from [41]:

Calcium ion + bicarbonate ion → calcium carbonate + hydrogen ion

The major part of carbonate rocks are formed by the lithification and accretion of carbonate minerals that are precipitated from organisms, directly or indirectly [43]. Different organisms precipitate different minerals, some will precipitate calcite whilst other will precipitate aragonite or in some cases both [43]. Carbonate sediments are deposited in both shallow marine environments and deep sea environments by organisms living near surface or at the bottom. When these organisms die their shells fall to the seabed and accumulate there as sediments, foraminifera is an example of calcite shells forming carbonate sediments and can be seen in figure 5.8 [43, 44].

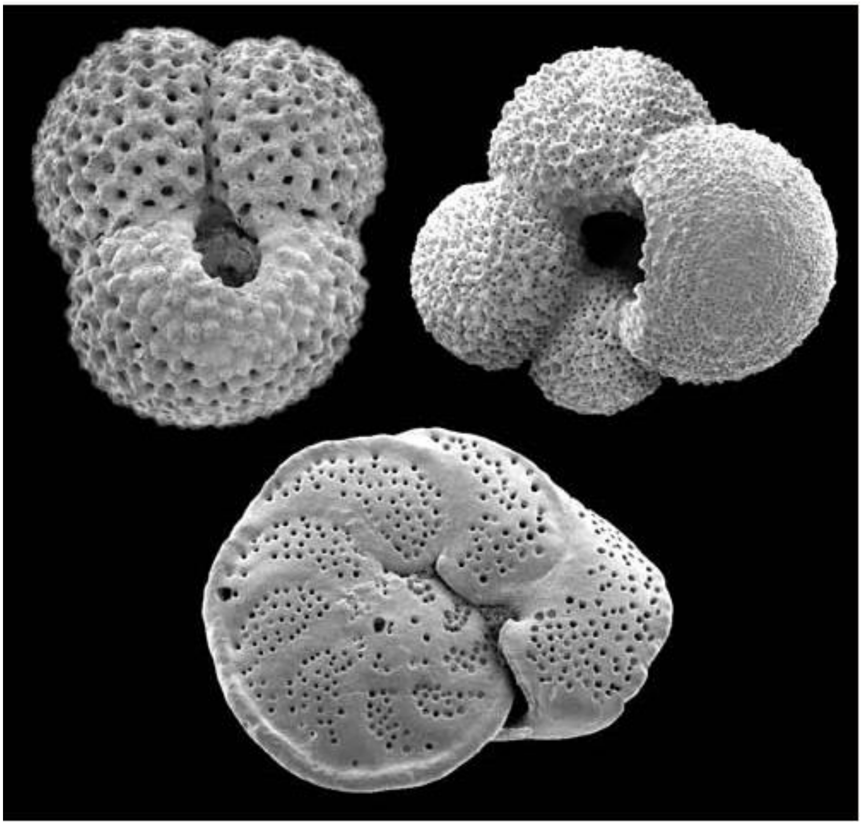


Figure 5.8 - Foraminifera seen from electron microscope [44]

The most abundant carbonate rock formed by lithification of carbonate sediments is limestone which is formed from carbonate muds and sands or in some cases ancient reefs [43]. Dolostone is another widely found carbonate rock which does not form as a direct precipitate from seawater, it is rather an altered limestone where the calcium ions have been replaced by magnesium ions from seawater slowly passing through the pores of the rock [43].

Reefs are probably the carbonate structure which has captured most attention of scientists the last decades and could lead to the formation of a carbonate platform such as the Loppa high where Gotha is located [37, 43]. A carbonate platform formation process starts with a reef enclosing and sheltering an area of shallow water often called a lagoon [43]. In and around this lagoon carbonate sediments will accumulate at a high rate whilst sedimentation is much slower in the surrounding open ocean, this will lead to a high point with gentle slopes towards deeper water [43]. As this process continues the result will be a rimmed shelf morphology with steep sides covered with carbonate sediments to the open ocean [43].

Large amounts of calcium and carbonate minerals dissolved in seawater makes carbonate rocks very abundant around the world.

However, not all carbonates are formed in the sea, some are formed around hot springs where calcium carbonate may deposit by algae in the water or by non-biological precipitation [41]. Caves which are generally formed by the dissolution of limestone by acidic ground water will also contain carbonate sediments. In these, now air filled caves, water containing calcium carbonate may ooze through the cave ceiling where each drop will precipitate a small amount of calcium carbonate on the ceiling [45]. These precipitations will accumulate and form a long narrow spike of carbonate from the ceiling, called a stalactite [41]. As this water drop hits the floor more calcium carbonate will precipitate and accumulate just beneath the stalactite. This is called a stalagmite and by growing together with the stalactite they can form a column which can be seen in figure 5.9 [45].

Figure 5.9 - Stalactites and stalagnites have formed a column. Carlsbad Caverns, New Mexico [45]

In some of the limestone caves around the world, dissolution may thin the roof sufficiently enough for it to collapse and create a sinkhole. Sinkholes are one of the main characteristics of the type of topography called karst [45].

5.3.3 Karst development

Karst is a topography found in many areas around the world where acidic groundwater to a great extent have formed the landscape. These regions will typically have an asymmetrical terrain with depressions called sinkholes and in addition there will be a lack of surface streams,- the streams will still be there, just located beneath the ground [46]. In figure 5.10 an illustration of a typical development of a karst landscape is divided into three stages. During early stages of the development groundwater will penetrate through limestone to dissolve the limestone rocks leading to the creation and enlarging of cavities at and below the water table

[46]. Next step in the illustration shows more developed sinkholes and as mentioned surface streams is now ducted below ground [46]. The last stage in figure 5.10 shows the area with the passage of time. Here the cavities is larger and the sinkholes increase in both size and numbers [46].

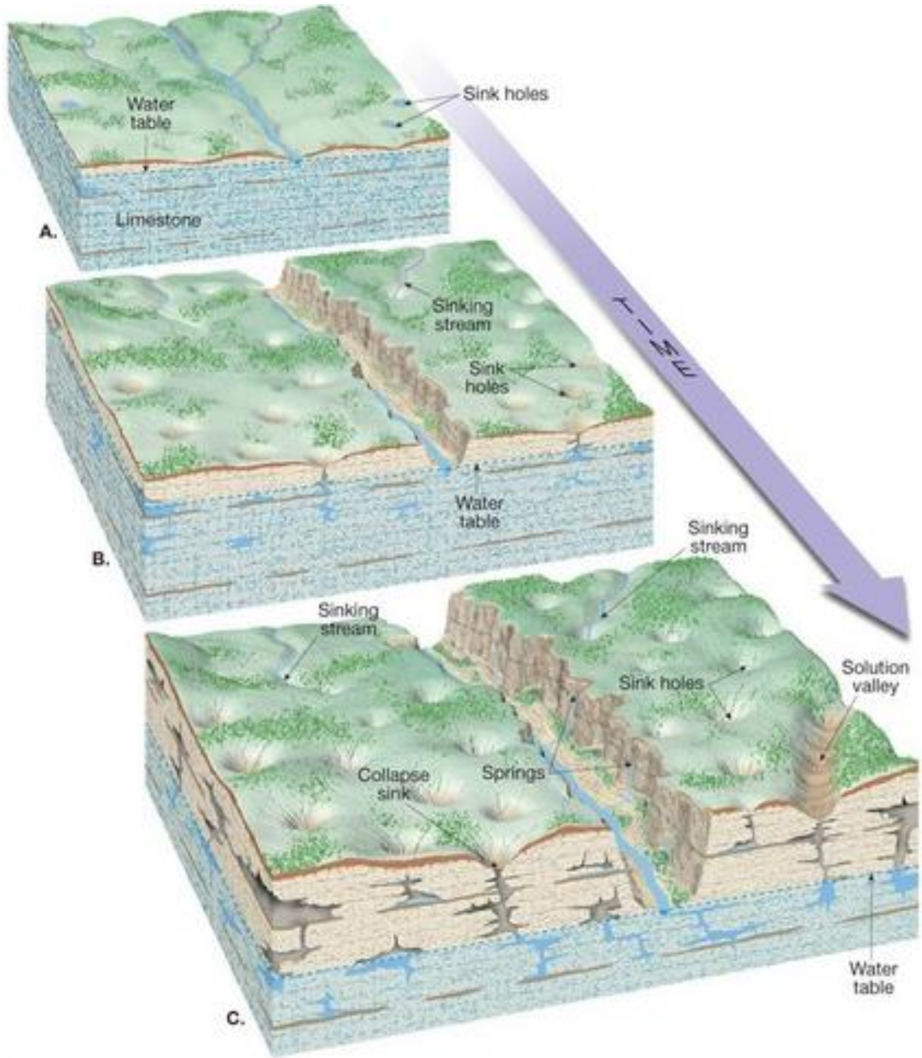


Figure 5.10 - Development of a Karst landscape [46]

The caves created could eventually collapse or the sinkholes could merge to form larger plane depressions in the ground. In time, the solution activity may clear most of the limestone leaving only remnants often isolated and known as tower karst development; in figure 5.11 a characteristic karst landscape in the Guilin District in China is shown.

Figure 5.11 - Karst towers in the Guilin district in China [46]

In general Karst topography will not develop in dry areas because there is not enough groundwater, however, if Karst features is seen in arid regions they are likely to be remnants of a more humid time. Thus Karst development is more rapid in humid areas where heavy rainfall is normal and the availability of carbon dioxide from rich tropical vegetation is greater [46].

As the geology of the earth is in constant change, some of these caves that formed millions of years ago in a humid area near surface may have been exposed to burial processes and could now be located in a subsurface environment such as the newly discovered reservoir at the Loppa high in the Barents Sea. The next subchapter will give an explanation to why and how this occurs.

5.3.4 Karst occurrence offshore

Over time, in a geologically sense, Karst environments could get buried by other rocks and become inactive. They are often a victim to tectonic subsidence and lies unconformably beneath cover rocks, and are referred to as paleokarst or paleocave systems and are most commonly ancient rocks [47, 48].

Gotha is as mentioned located at the Loppa high where the reservoir rocks have been exposed to a process of Karstification. The Loppa high developed as a result of the rifting between Norway and Greenland during the late Paleozoic and from the Late Jurrasic-Early Cretaceous rifting [49, 50]. It is proposed three main reasons for the Karst processes at the Loppa high [50]:

- High frequency subaerial exposures related to glacioeustatic sea level changes
- Subaerial exposure and karstification associated with third- and second order sequence boundaries

- Protracted exposure to and the formation of a major unconformity between the late Permian and the Anisian, lasting for approximately 25 m.y

The Loppa high with its surrounding basins and platforms are seen in figure 5.12.

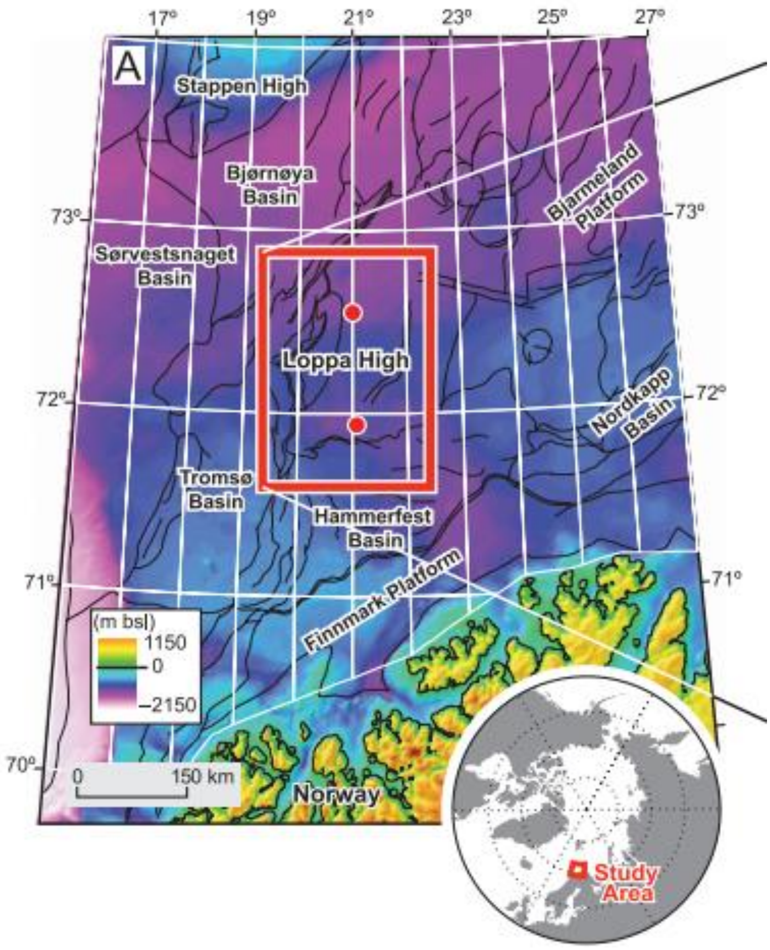


Figure 5.12 - Map of the Barents Sea showing the basins [49]

Karsting in a subsurface environment will create a range of different structures such as greater cracks and varying cavities at different scales. When these systems are buried the stress will increase as the overlying strata gets heavier and over time the ceiling will collapse [48]. A collapse of the roof will produce chaotic breakdown breccia on the floor, whilst the adjacent walls will produce crackle- and mosaic breccias due to the associated stress release around the cavity that collapsed [48]. The sequence of a cave formation in a Karst environment near surface, to the collapse and mechanical compaction of it is seen in figure 5.13.

Breccias are rocks which are a result of these cave collapses and their classification together with cave sediment fill can be seen in figure 5.14. They are as mentioned divided into three main types which is crackle breccia, mosaic breccia and chaotic breccia. Crackle breccias are fractured rocks but the individual clasts show no great displacement, whilst similar fractured rocks which show more displacement are called mosaic breccias, in both rocks it is possible to visually put the original clasts together [51]. The chaotic breccias are the rocks that falls to the floor and as the name settles there are no obvious connection in the clasts [51]. As these burial processes goes on smaller cavities may collapse again generating further brecciation of already existing breccias [49]. Figure 5.15 shows a picture from a modern cave where the chaotic breccias forms the cave floor whilst large crackle breccias occurs in the cave ceiling, also note the person for size proportion.

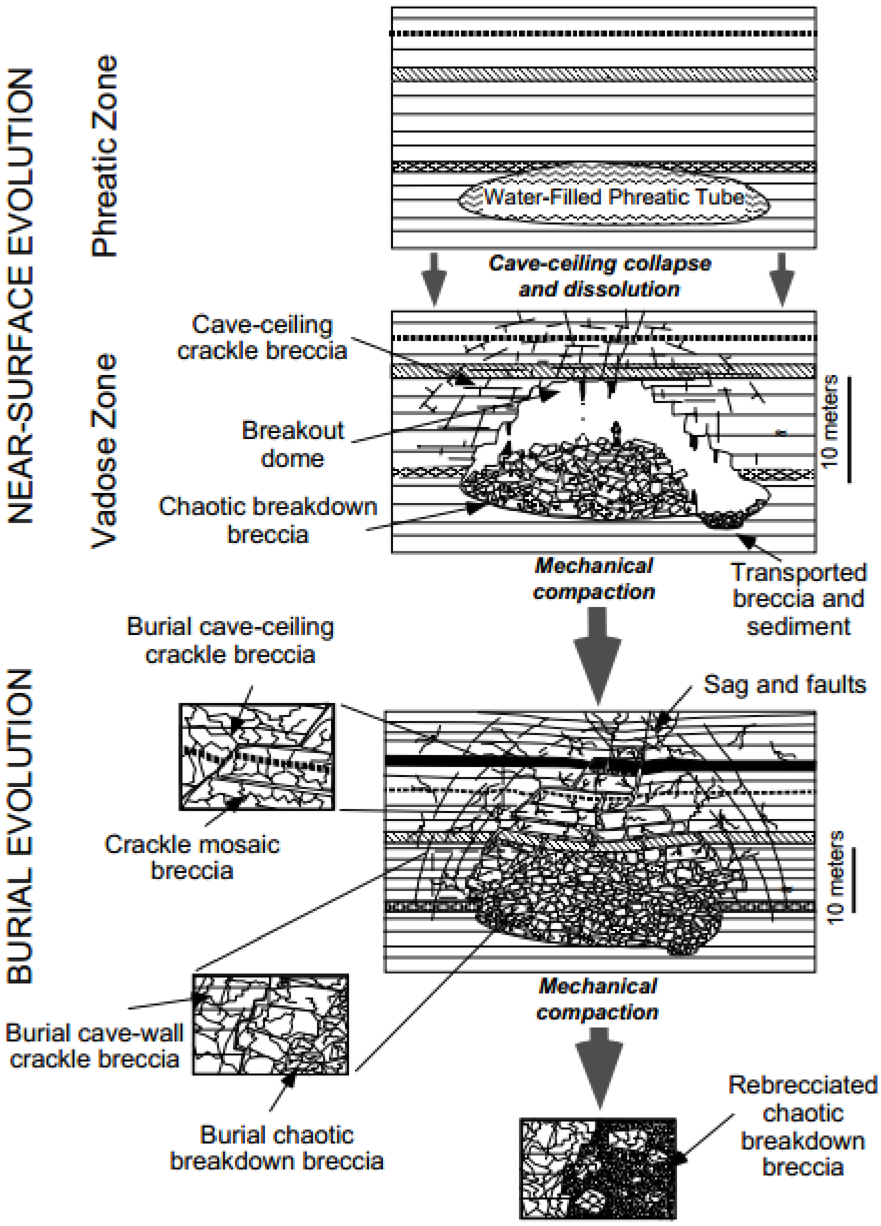


Figure 5.13 - Evolution of a single cave passage from formation in near surface Karst environment to burial in the subsurface where collapse and brecciation occurs [48]

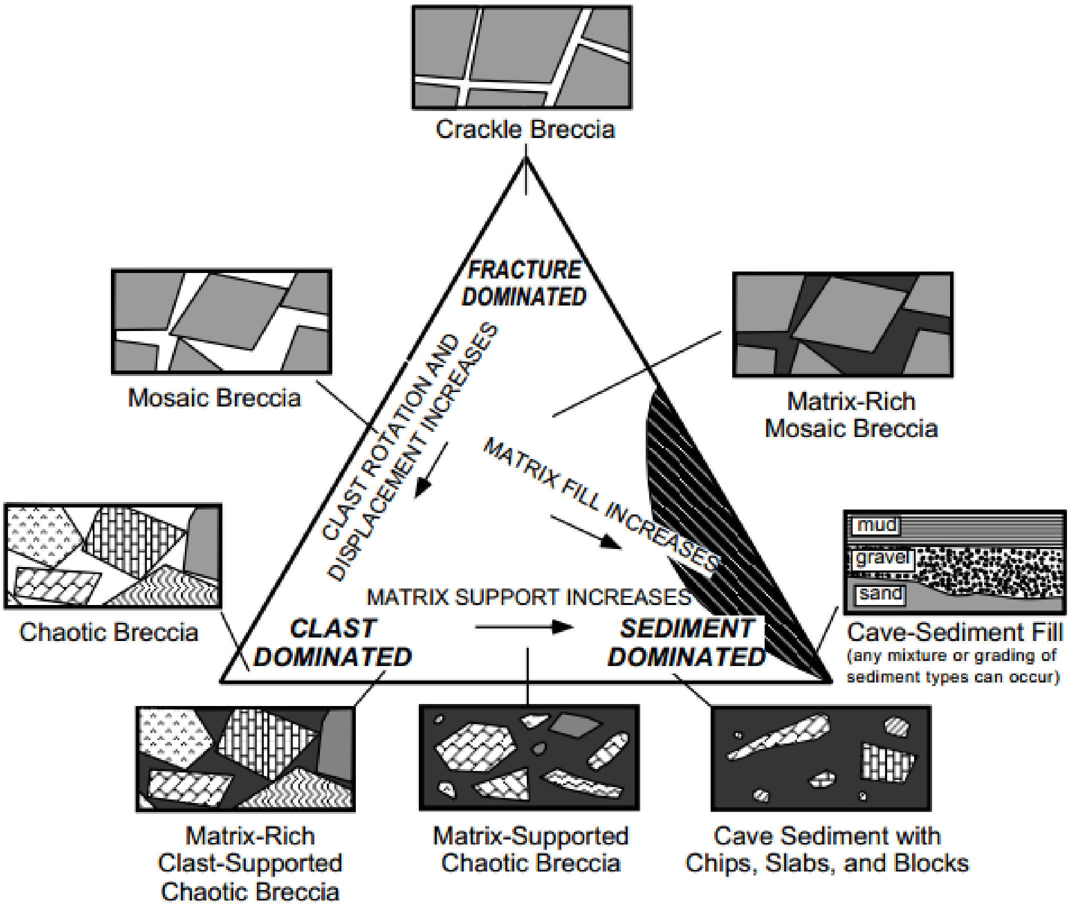


Figure 5.14 - Classification of Breccias, the three end members are; clast dominated, fracture dominated and clast dominated [48]

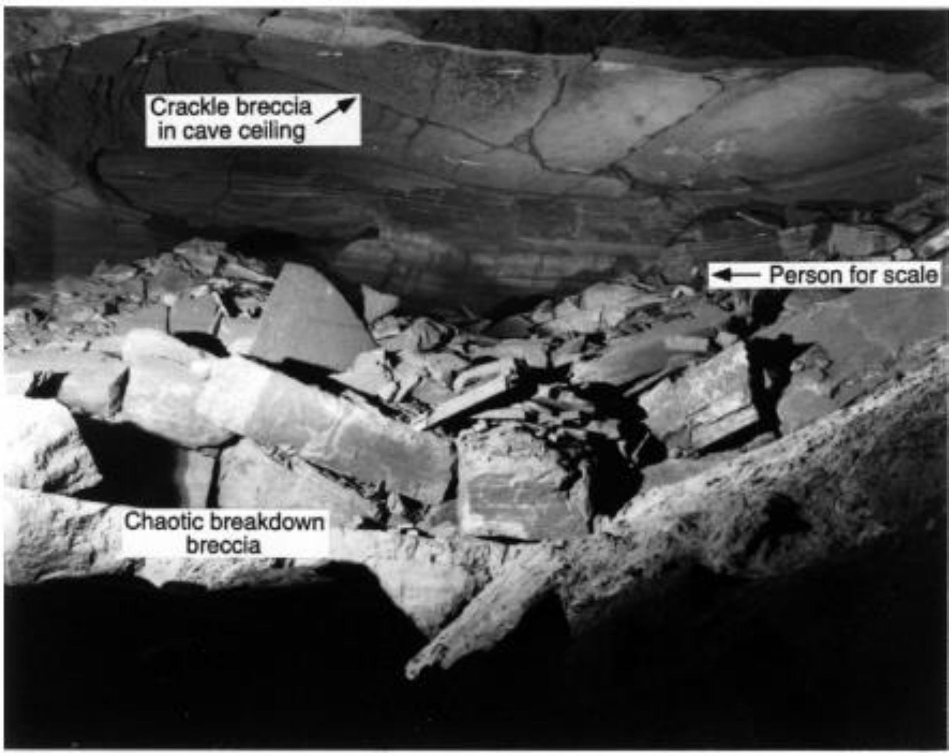


Figure 5.15 - Modern cave breccias from Ennis Cave in Arkansas, USA [48]

Several different phases of collapse may occur in the same areas over a long period of time. Cavities which are still open may however be found at great depths, bit drops of meter-scale have been reported up to depths of 3000m [48]. This says that one may encounter open cave systems as well as filled and collapsed ones at great depths in karstified subsurface reservoirs which again emphasize the importance of understanding the properties and distribution of karst and paleokarst.

Karst processes could lead to increased porosity and permeability in rocks by erosion which will remove parts of the rock volume. Karstification of rocks will produce a secondary porosity in carbonate rocks thus karstificiation could improve reservoir quality [51]. It is also known that the carbonate deposits in which contain recoverable hydrocarbons, 40% or more are of karst origin [49]. Earlier research suggest that most karst related reservoirs due to their great extent, they could cover hundreds to several thousand meters across, are the result of numerous collapsed cave systems [48, 49]. Reservoirs made of the combination of karstification and burial processes often introduce very complex architecture with great spatial heterogeneities [49]. This only adds to the importance of being able to map and predict karst features in subsurface environments.

5.3.5 How to identify Karst

As stated in the previous chapter it is important that good value methods to interpret and recognize karst features in the subsurface are developed. This is to evaluate the reservoir potential and foresee potential thief zones which could cause drilling issues amongst other. However, karst has proved itself difficult to recognize due to a number of reasons, these are taken from [51]:

- Karsting is not uniformly distributed but exhibits an extreme spatial variability
- Most karst features are close to or below seismic resolution making them difficult to map
- Karst features exhibits a multitude of shapes and characteristics which affect the host rocks in different ways
- Features resulting from karst processes may be overprinted by later cementation and diagenesis which further changes petrophysical properties

Conventional seismic methods are in general not sufficient enough to differentiate karstified areas from their surrounding environments, therefore it might be useful to combine studies of paleokarst with data from areas with ongoing karst processes.

As mentioned earlier the F6 field offshore Malaysia experienced water breakthrough after 15 years of production and 3D seismic was shot to re-evaluate the field [40]. The field had experienced moderate to more severe mud losses which is an indication of a karstified subsurface [40]. To identify the Karst network a technique called history matching was used. A history matching process consists of the building of one or more sets of reservoir models based on observed and measured data, used to help in the decision making process of what to do with the field in the future [52]. It is a prolonged process for numerous reasons, firstly multiple attributes are found to influence a match, such as amplitude, porosity or permeability [52]. A second reason for its complexity is to define “a match” as it is multi-dimensional [52]. In the majority of these cases there will be an infinite number of solutions to a history match, it is therefore important to remember what the purpose of the process is.

History matching is as explained very complex and time consuming but at the F6 field experimental design where used to enhance the process. The following steps were followed to ease the process [52]:

- Select key parameters with variance analysis
- Reduction of dimension by creation of hybrid parameters
- Predicting matching domains

The resulting models are then tested against operational data to confirm presence of karst features where wells have experienced mud losses [40].

Another mapping of karst features in the subsurface, more exactly at the Loppa high, has been performed. This was done by an integrated approach where core analysis was combined with 3D seismic mapping and multi-attribute seismic facies (SF) classification was used [49]. A facies is, ideally, a body of rock which distinct shows where it was deposited or a certain development process. Observations of Loppa high seismic, both 2D and 3D made prior to this study showed the presence of karst plains in the form of sinkholes, caves and other phenomena associated with a paleokarst terrain [50]. Figure 5.16, 5.17 and 5.18 shows examples of seismic indications of karst features. This research was used as a base for the new method.

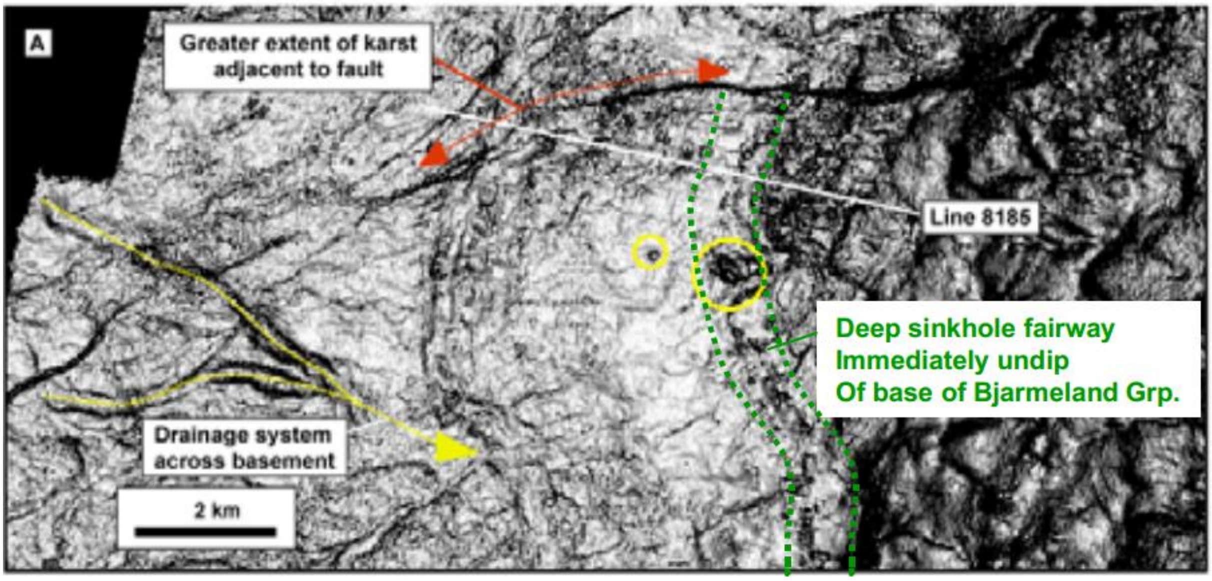


Figure 5.16 - Seismic example of large-scale karst features including sinkholes and drainage system [50]

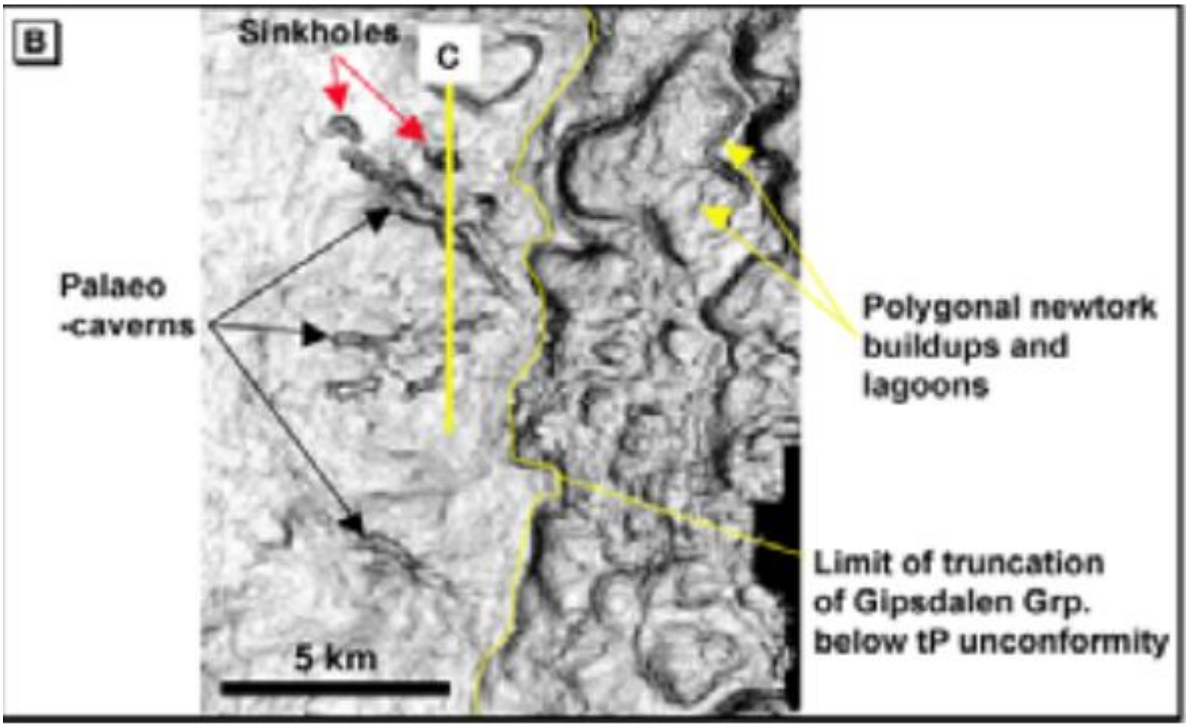


Figure 5.17 - Seismic example of excavated paleocaverns along linear faults [50]

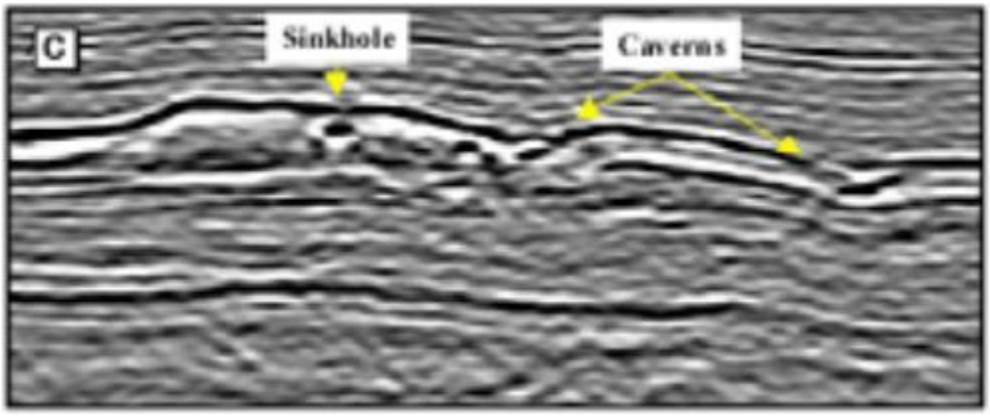


Figure 5.18 - Seismic lines indicating palaeocaverns [50]

From the Statoil drilled 7220/6-1 well and the Esso Exploration and Production Norway drilled 7121/1-1R, core samples were logged and described and the data was used for calibrating stratigraphic markers along with the 3D survey SG9810 [49]. Both well locations and SG9810’s coverage can be seen in figure 5.19.

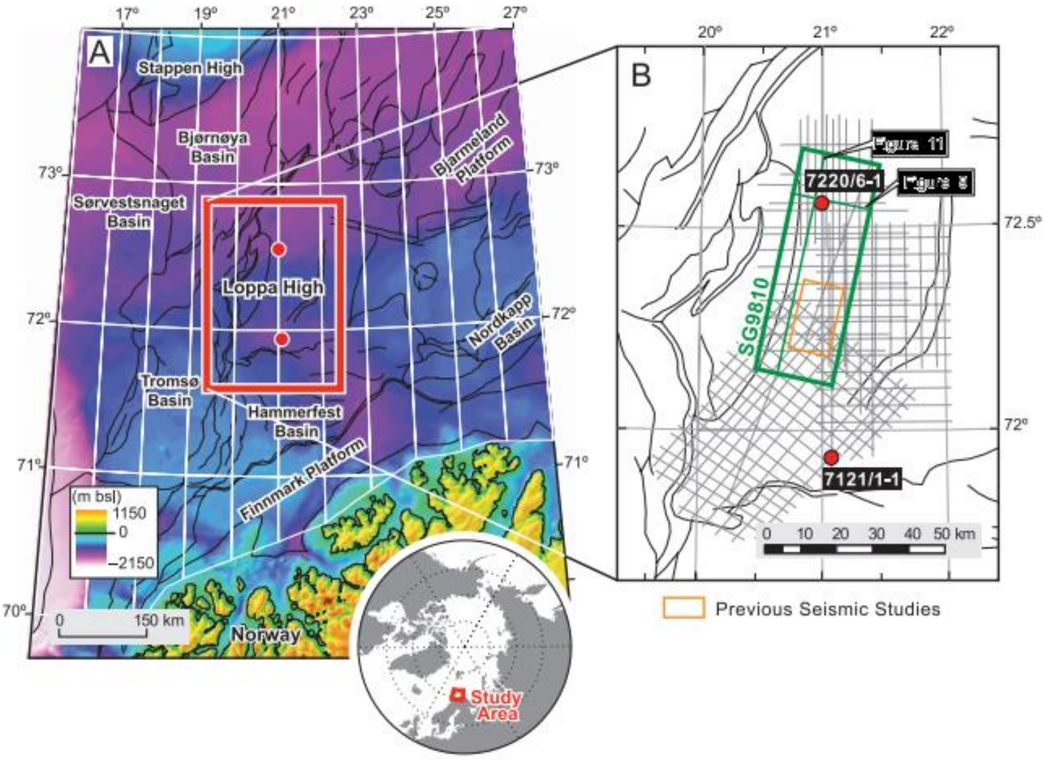


Figure 5.19 - Loppa high - well locations [49]

To perform the seismic well calibration data from the available wells and from the 3D survey was combined, resulting in the construction of a 3D seismic stratigraphic model of reference [49]. The model showed the lateral magnitude as well as the main stratigraphic units within the 3D survey, it can be seen in figure 5.20.

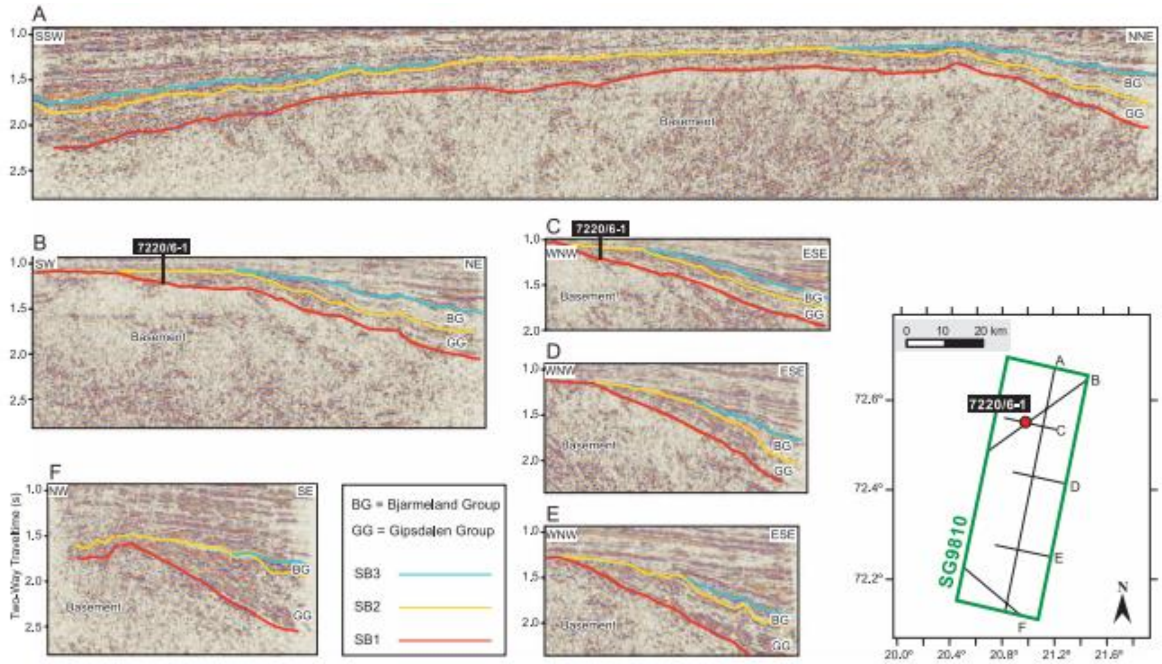


Figure 5.20 - Seismic lines showing an interpretation of the SG9810 3D survey, the inset map shows the location of the lines A-E [49]

The next step was the 3D SF classification and first the number of seismic attributes where decided. In this case 18 seismic attributes where calculated and they were all visually evaluated and studied against the reference model to find corresponding geologic correlations and trends [49]. The attributes chosen have geologic or geophysical significance rather than mathematical meaning and can be seen in table 5.1 [49].

Table 5.1 - 18 computed attributes chosen for the study of Loppa High [49]

Seismic Attribute	Basic Seismic Information	Event Continuity	Lithology	Structures	Fluid Content	Sequence Boundaries	Rock Properties	Stratigraphic Features
Apparent polarity	Sign of seismic trace	✓✓				✓✓		
Gradient magnitude	Amplitude	✓✓		✓✓		✓		
Reflection intensity	Amplitude	✓✓	✓✓			✓✓		
RMS** amplitude	Amplitude			✓	✓✓			
First derivative	Amplitude							✓
Instantaneous quality	Amplitude				✓			
Envelope	Total energy of the seismic trace		✓			✓✓		
Cosine of instantaneous phase	Phase	✓✓		✓✓		✓✓		✓✓
Instantaneous bandwidth	Frequency						✓✓	✓
Instantaneous frequency	Frequency		✓✓				✓✓	
Dominant frequency	Frequency						✓✓	
Instantaneous phase	Phase	✓✓		✓✓		✓✓		
Chaos	Chaoticness of seismic signal	✓✓		✓✓				
Variance	Structural information	✓✓		✓✓		✓✓		
Relative acoustic impedance	Apparent acoustic contrast		✓		✓✓	✓✓		
Local structural dip	Dip of seismic events	✓		✓✓				
Local structural azimuth	Azimuth of seismic events			✓✓				
Attenuation	Frequency	✓		✓	✓✓		✓✓	

*The table shows the geophysical and geologic significance of each seismic attribute.
**RMS = root mean square.
†✓✓ = good indicator; ✓ = medium indicator.

In this kind of matching it is important to avoid redundancy of data, so further evaluation of the attributes are performed by a cross-plot technique to analyze the independence of each attribute [49]. In figure 5.21 parts of such a cross plot can be seen, images A and B shows spread correlation whilst images C and D shows linear correlation. This means images A and B represents unlike seismic properties and may be chosen for the classification process, whilst images C and D are identical and unfit for further classification [49].

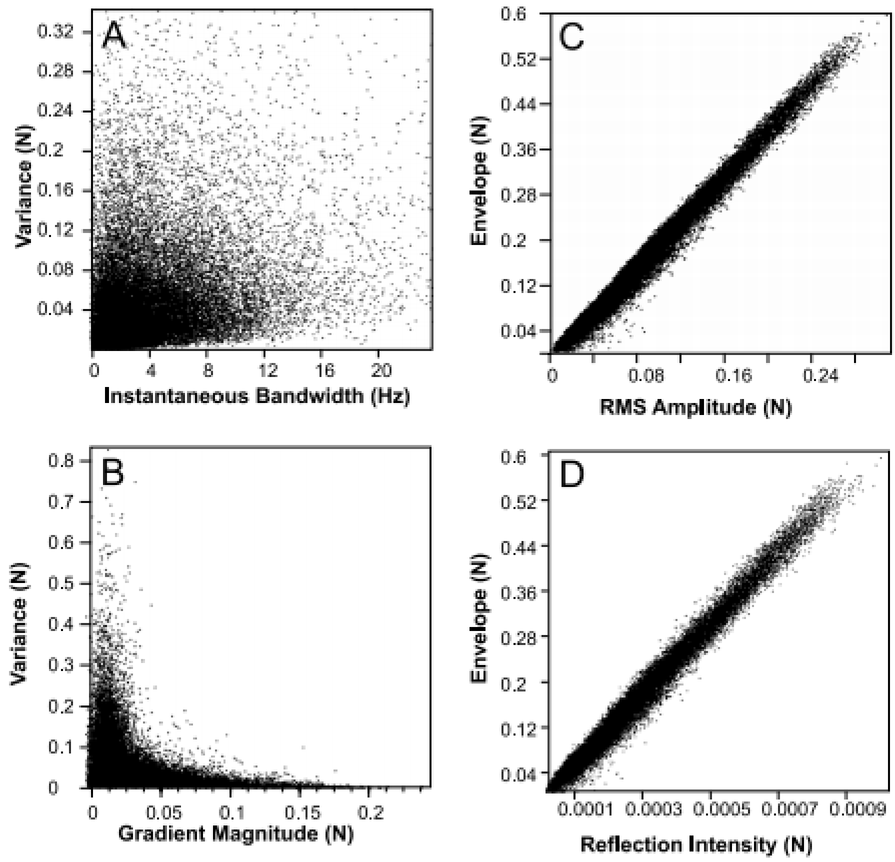


Figure 5.21- Crossplots of seismic attributes performed in the study [49]

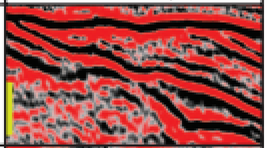
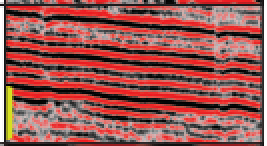
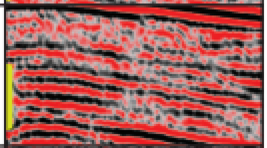
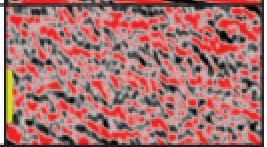
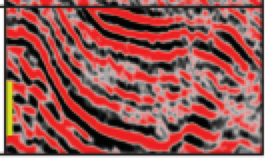
This technique gave six attributes which were dominant frequency, chaos, gradient magnitude, instantaneous bandwidth, variance and envelope, they are listed with their seismic information and function for this study in table 5.2 [49].

Table 5.2 - Chosen attributes from the cross-plot analysis, showing basic seismic information, type of seismic attribute, application of attribute

Seismic Attribute	Basic Seismic Information	Type of Seismic Attribute	Application in This Study
Envelope	Energy of the seismic trace	Complex trace attribute	Acoustic impedance contrast and detection of major lithologic changes and sequence boundaries
Dominant frequency	Frequency	Complex trace attribute	Time-varying spectral properties of seismic data
Chaos	Chaoticness of seismic signal	Stratigraphic attribute	Recognition of chaotic texture in seismic data
Gradient magnitude	Amplitude sensitive	Structural attribute	Determination regions of weak coherent signal from the ones with significant reflectivity and signal strength
Instantaneous bandwidth	Frequency	Complex trace attribute	Time-varying spectral properties of seismic data; good indicator of lower frequency areas
Variance	Structural information	Structural and/or stratigraphic attribute	Isolation of edges from the input data set

The next step is to classify the seismic facies, which can be done in supervised- or unsupervised mode [49]. In an unsupervised mode a natural selection of the data is acquired by different combinations of the seismic attributes into an artificial neural network [49]. An artificial neural network (ANN) is a computational model which is able to recognize patterns. In the supervised mode on the other hand, sets of various SF were selected from the 3D survey and used to develop the ANN as seen in table 5.3 [49]. Both the unsupervised mode and the supervised mode resulted in similar patterns as shown in figure 5.22. A schematic workflow is shown step by step in figure 5.23, this is repeated until a satisfying result is obtained [49].

Table 5.3 - Seismic Facies (training data) to train the Artificial Neural Network [49]

Seismic Facies	Reflection geometry	Amplitude characteristic	Spatial distribution	Example (Vertical bars represent 100 ms)
SF1	Parallel continuous	High amplitude	Occurs mainly at the crest of the structural high and at the top of basement	
SF2	Parallel continuous	Medium to low amplitude	Occurs mostly towards the flanks of the Loppa High	
SF3	Parallel discontinuous	Medium to low amplitude	In overlying Triassic clastics and some areas of the carbonate intervals	
SF4	Chaotic	Low amplitude	Present at the core of the buildups and in the basement	
SF5	Semiparallel dipping discontinuous	Medium amplitude	Occurs mostly in the slopes of buildups	

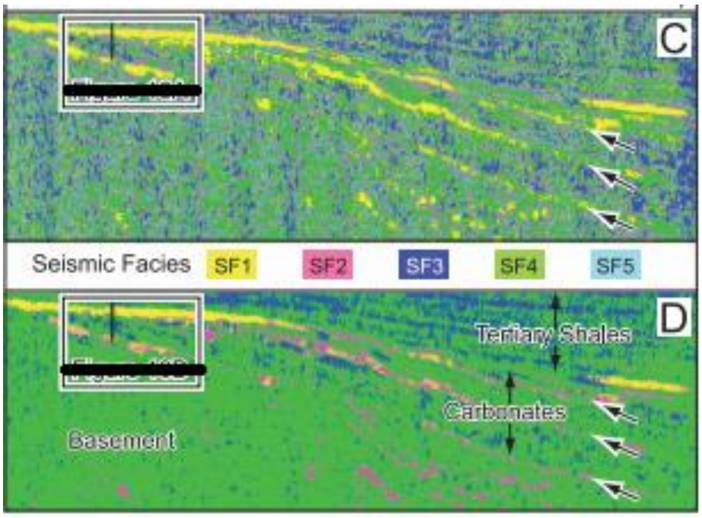


Figure 5.22 – Unsupervised classification in upper part vs supervised classification in lower part [49]

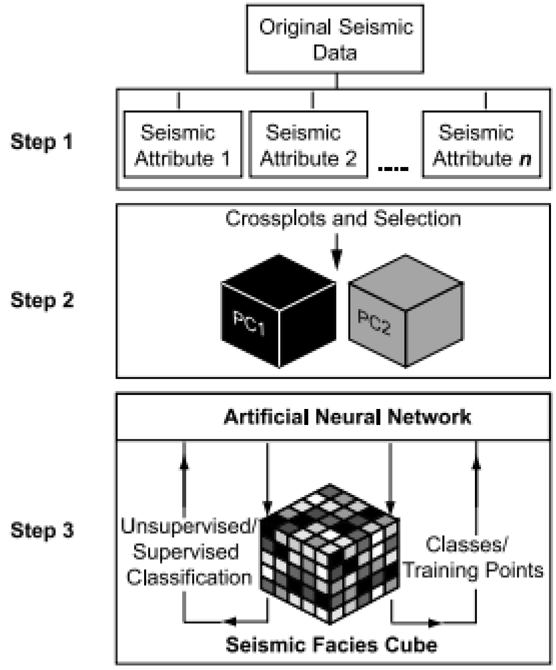


Figure 5.23- Schematic workflow of a seismic classification process using an artificial neural network [49]

This integrated approach of various techniques combined helped to map and characterize a buried paleokarst terrain. The core analysis suggest that 50 m thick breccia deposits cover large parts of Loppa High and facies analysis indicate that these deposits formed during times of cave development and the following cave collapse connected with karst networks [49]. Together with the 3D SF classification it was proposed that the breccias occupies and area which is 40 – 50 km long and 10 to 12 km wide whilst the thickness was estimated to be 10 – 150 m [49]. This approach may be applicable in other areas where 3D seismic as well as core data is available to map and predict karst features [49].

Conventional seismic methods are in general not sufficient enough to differentiate karstified areas from their surrounding environments, therefore it might also be useful to combine studies of paleokarst with data from areas with ongoing karst processes to understand the subsurface features.

5.3.6 Drilling issues in Karst

Karst features in the subsurface give rise to different risks regarding drilling, some of the main risks are [40, 48, 53]:

- Mud losses while drilling – lost circulation
- Drop of drill bit

Lost circulation is discussed in chapter 4.2.5 and is a real threat in karstified carbonate reservoirs because of the high permeability/porosity and possible cavities in the subsurface. A mature gas field located offshore Sarawak, Malaysia experienced severe mud losses during drilling through karstified zones which led to costly delays and abandoning and sidetracking of several wells [53]. At the same field the subsurface karst was demonstrated by drill bit drops of up to 6m while drilling [53]. F6 is a field in the same area which also experienced mud losses of all degrees, the wells which was exposed to total losses were abandoned and sidetracked [40]. At the Yates field in west Texas there have been reported 6m large open cavities at depths up to 550m, whilst bit drops of as much as 5m at depths as great as 2600m has been reported from the Dollarhide field also located in west Texas [48].

All these examples are scenarios where well control is lost which is a safety risk, in addition valuable time and money is spent to regain control instead of continuing operations.

Karst existence is as mentioned not easy to map and foresee which could cause unpredicted risks when drilling carbonate reservoirs. However, if one should encounter karst features during drilling, a possible solution to reduce the time and cost related to continuous well control issues and loss of fluid is a MPD technique called pressurized mud-cap drilling.

6 Mud-cap drilling

Mud cap drilling is the general version of PMCD which is one of the MPD techniques that was looked at in chapter 2.2, developed to handle reservoirs where it is difficult or impossible to maintain circulation. This is a drilling technique able to handle reservoirs with karst features in a secure manner.

6.1 Development of mud-cap drilling

The mud cap drilling application was first used in the Austin Chalk fields of Texas and Louisiana where the reservoirs are highly fractured carbonates [54]. The field was explored using horizontal wells and because of that reservoir pressure was the same throughout the lateral. When drilling was in progress, casing was commonly set at the top of the chalk hence chalk was the only exposed formation and when they hit the first fracture either a kick was taken or circulation was lost [54]. An effort to plug the fracture with lost circulation material (LCM) was performed with various results, often impossible to accomplish [54]. This was solved by balancing the fracture with adjusting mud weight, choke pressure or a combination of the two to keep circulation and control the influx to a manageable level for the existing surface equipment [54].

However, as development progressed, the targets got deeper and several fractures were encountered along the horizontal wellbore and it became unachievable to balance them all at the same time [54]. As targets got deeper the formation pressure increased resulting in circulation surface pressure and production rates which surpassed the available RCD's capacity as well as the mud-gas separators [54]. This lead to NPT whereas drilling was stopped whenever surface pressure reached values which were too high for the RCD, BOP's were closed and circulation of the well continued until surface pressure was reduced to a satisfactory level [54]. The result was often down-hole cross-flow and loss of weighted mud which became very time devouring and costly, whereas mud cap drilling was developed as a possible solution to this.

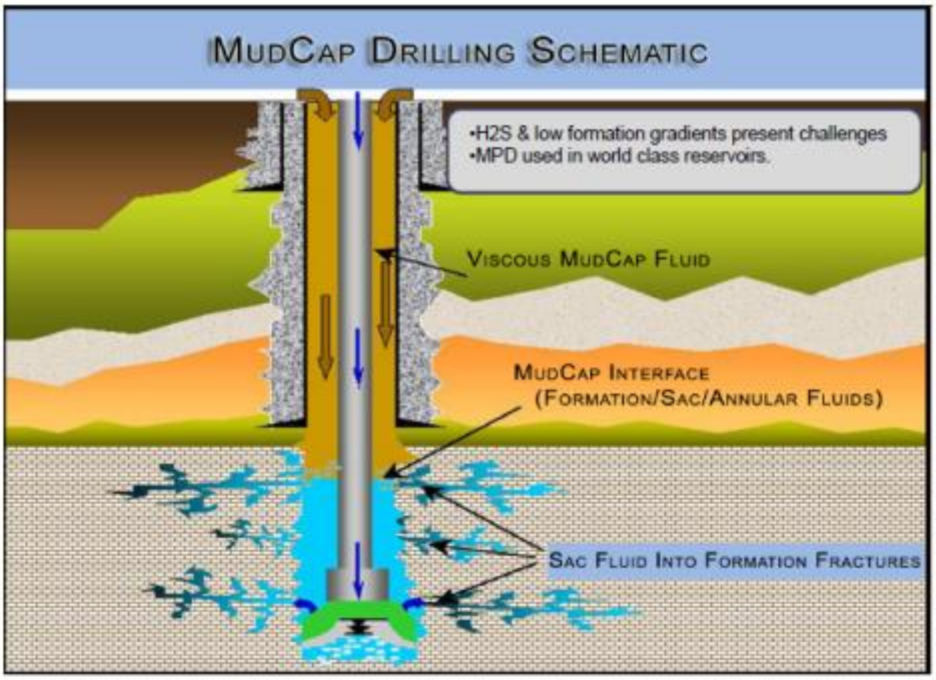


Figure 6.1 - Mud cap drilling principle [55]

Figure 6.1 shows a plain illustration of the mud-cap principle. A sacrificial fluid (SAC), often abundant seawater, is pumped down the drillstring to drive the motor and MWD and to clean and cool the bit [54]. This fluid also carries the cuttings generated from drilling into the vugs or fractures in the formation so there is no return to surface [55]. A mud-cap fluid is pumped down the annulus to keep the formation fluid from migrating to surface where a RCD is placed to seal the annulus. The technique was further developed to comprehend thick fractured reservoirs which require very heavy cap-mud to balance formation pressure whilst the unknown fluid level and sudden and severe kicks presented a source of concern [54, 56]. The new application of mud cap drilling was called PMCD and allows continuous monitoring of pressure readings at surface [54].

6.2 Pressurized mud-cap drilling

The Underbalanced Operations & MPD committee defines PMCD as [6]:

"Variation of MPD, drilling with no returns to surface where an annulus fluid column, assisted by surface pressure, is maintained above a formation that is capable of accepting fluid and cuttings. A sacrificial fluid with cuttings is accepted by the loss circulation zone. Useful for cases of severe loss circulation that preclude the use of conventional wellbore construction techniques."

This method differs from normal mud cap drilling in that a weighted mud, lighter than what is required to balance reservoir pressure, is placed in the annulus. The well is shut in at surface by a RCD which allows drill pipe to enter and exit the wellbore, while maintaining annulus pressure at the same time [4]. This allows for annular surface pressure readings to monitor the wellbore more precisely throughout operation. In addition, the RCD allows for rotation, hence pressure can be exerted while drilling. An RCD is illustrated in figure 6.2 where annular pressure, in red, applies force towards sealing components during operations [4].

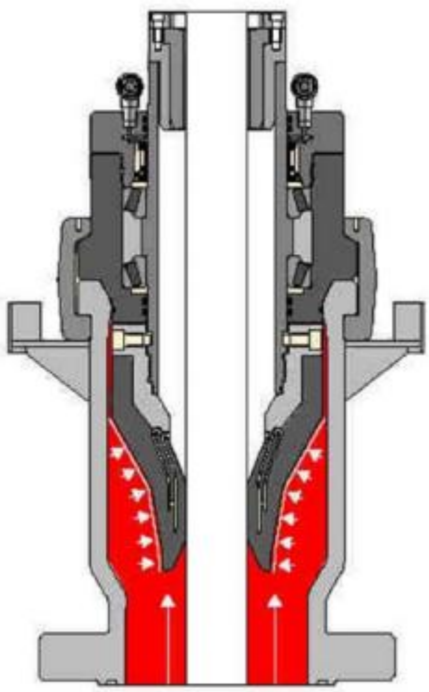


Figure 6.2 - RCD with annular pressure in red [4]

By recording this surface annular pressure before drilling is conducted a guideline is established to recognize plugging of fractures or if new fractures are encountered, hence control of down hole changes is established [54]. As seen in figure 6.3 a SAC fluid is pumped down the drill string and is together with generated cuttings led back into the fractured formation. The hole is kept full to reduce mud loss and continuous contact with the reservoir is achieved [54]. If migration of formation fluids through the mud-cap should occur, because it is less dense than the mud, an increase in the surface pressure is observed as the annular fluid is being displaced by the kicking formation fluid making it possible to detect influx at an early stage. If this is to happen, additional mud-cap fluid is bullheaded into the annulus pushing the formation fluid and some contaminated mud-cap fluid back into the fractured zone until accepted annular pressure is regained [54, 57].

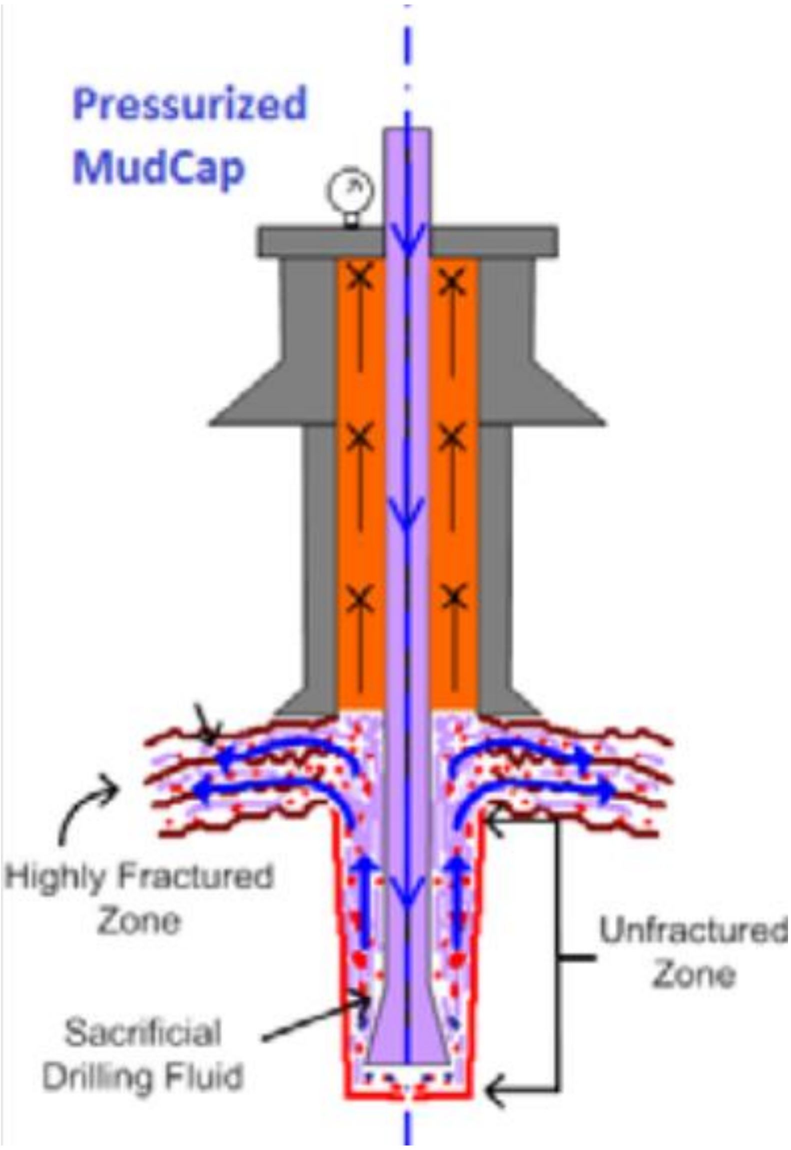


Figure 6.3 - Principle of PMCD operations [57]

A simplified illustration of the principle of a PMCD operation is seen in figure 6.3. PMCD allows actively monitoring of the pressures in a wellbore and can be considered as a low risk option of certain conditions in drilling fractured carbonates. It is also possible to use conventional drilling with LCM and cement plugs until losses becomes unmanageable, then switch to PMCD mode [58, 59].

6.2.1 Pressurized mud cap tripping

When tripping out the pipe, a volume of annular mud equal to the pipe being removed, is pumped down the kill line [54]. The mud volume is adjusted as essential to keep a constant casing pressure, if mud is pumped faster than pipe is pulled redundant mud is lost whilst if inadequate mud is pumped there will be influx causing the casing pressure to increase [54]. To maintain the correct casing pressure additional mud is pumped down to force the influx back into the formation.

6.3 PMCD calculation

To illustrate when PMCD could be used and the PMCD principle a candidate well is illustrated in figure 6.4 where a vertical hole is to be drilled in a carbonate reservoir and the properties of the well are as follows and are inspired by an example in [54]:

- Casing: 7 5/8” set at 10 010ft
- Hole size: 6 ½”
- Drill-pipe 4 ½”
- Drilling fluid rate: 225gpm
- Top of reservoir: 10 000ft
- Reservoir pressure: 6250 psi at 10 000ft
- Reservoir fluid: Gas, assuming 0,1 psi/ft hydrostatic gradient
- First fracture: 10 100ft
- Second fracture: 10 300ft
- Third fracture: 11 000ft

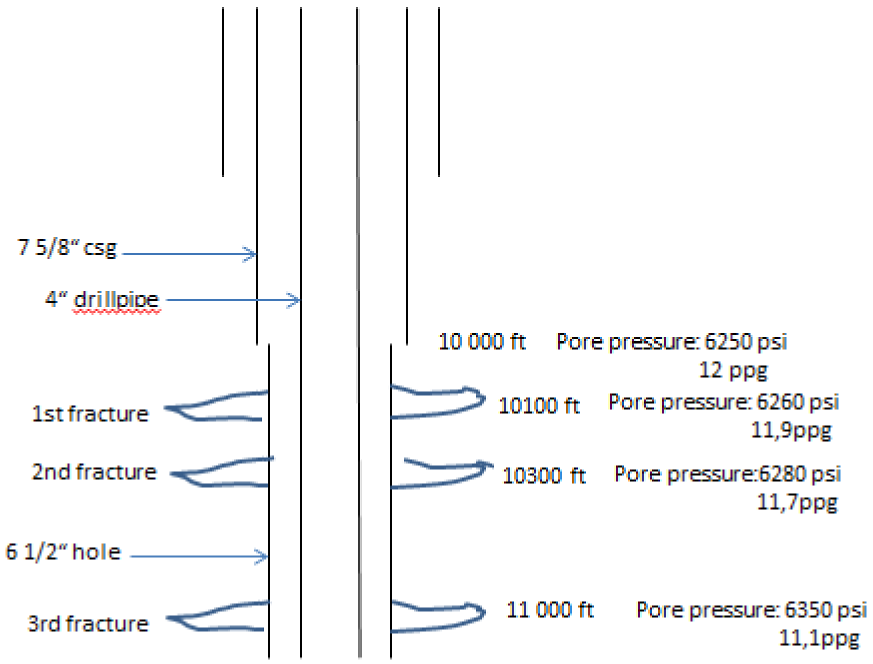


Figure 6.4 - A PMCD candidate well

The reservoir pressure is estimated to be 6250 psi at 10 000ft meaning that required weight of mud to balance the formation at this point is:

$$Mud\ weight = \frac{P}{0{,}052 * Depth} \qquad \text{(Equation 1)}$$

$$Mud\ weight = \frac{6250}{0{,}052 * 10\ 000} = 12{,}0\ ppg$$

Where P stands for pressure and 0,052 is a conversion factor such that mud weight results in ppg (lbm/gal). When the first fracture is met at 10 100ft the formation pressure is:

$$Formation\ pressure_{at\ 10100\ ft} = P_{at\ 10\ 000ft} + (\Delta Depth) * P_{Gradient}$$

$$Formation\ pressure_{at\ 10100\ ft} = 6250 + (10100 - 10\ 000) * 0{,}1 = 6260\ psi$$

At this depth the static conditions are obtained by equation 1 and are:

$$\frac{6260}{0{,}052 * 10100} = 11{,}9\ ppg\ formation\ fluid\ pressure$$

The static wellbore pressure at the same depth is obtained by rearranging equation 1 and is:

$$12 * 0{,}052 * 10100 = 6302\ psi$$

It is observed that the well is slightly overbalanced and as the fracture is encountered the pumps are running at 225gpm. These conditions will result in an equivalent circulating density (ECD) value on top of the static mud weight calculated by:

$$ECD\ (ppg) = \frac{Annular\ pressure\ loss}{0{,}052 * Depth} + Mud\ weight$$

$$Annular\ pressure\ loss\ (psi) = \frac{[(1{,}4327 * 10^{-7}) * Mud\ weight * Depth * V^2]}{Dhole - Dpipe}$$

Where V is annular velocity:

$$V = Annular\ velocity(\frac{ft}{min}) = \frac{24{,}5 * Drilling\ fluid\ rate}{Dhole^2 - Dpipe^2}$$

$$V = \frac{24{,}5 * 225}{6{,}5^2 - 4{,}5^2} = 210\ ft/min$$

$$Annular\ pressure\ loss = \frac{[(1{,}4327 * 10^{-7}) * 12 * 10100 * 210^2]}{6{,}5 - 4} = 306 psi$$

$$ECD\ (ppg) = \frac{306}{0{,}052 * 10100} + 12 = 12{,}5\ ppg$$

The ECD is equivalent to:

$$12{,}5 * 0{,}052 * 10100 = 6607\ psi$$

This means that returns are lost and no matter how the drilling operation continues the situation becomes more complicated when the second fracture is encountered at 10300ft where the pore pressure will be:

$$Formation\ pressure_{at\ 10300\ ft} = P_{at\ 10\ 000ft} + (\Delta Depth) * P_{Gradient}$$

$$Formation\ pressure_{at\ 10300\ ft} = 6250 + (10300 - 10000) * 0{,}1 = 6280\ psi$$

Whereas the required mud weight will be calculated by equation 1:

$$Mud\ weight = \frac{6280}{0{,}052 * 10\ 300} = 11{,}7\ ppg$$

The problem in this situation is if the second fracture is balanced by reducing the mud weight the first fracture will flow. On the other hand, if drilling is to continue with the 11,9ppg mud the returns will be lost in the second fracture resulting in a drop of fluid level leaving the first fracture underbalanced and flowing. The problem becomes even worse if there is a third fracture which will be encountered as seen in figure 6.4. The properties at this depth are:

$$Formation\ pressure_{at\ 11000\ ft} = P_{at\ 10\ 000ft} + (\Delta Depth) * P_{Gradient}$$

$$Formation\ pressure_{at\ 11000\ ft} = 6250 + (11\ 000 - 10\ 000) * 0{,}1 = 6350 psi$$

$$Mud\ weight = \frac{6350}{0{,}052 * 11\ 000} = 11{,}1\ ppg$$

This situation will be impossible to handle with conventional drilling techniques without losing the returns or taking a kick. PMCD is an option to drill this well and if it is chosen as suitable a positive surface pressure is needed meaning a lower mud weight is used. It is assumed that a surface pressure is decided to be 165psi which results in a new mud weight at the first fracture:

$$11{,}9 - \frac{165}{0{,}052 * 10100} = 11{,}58 ppg$$

Based on this an 11,6ppg mud is used to drill the well and the actual annular surface pressure will be lower. Obtaining these conditions is done by bullheading the 11,6ppg mud down the annulus until displacement of the original fluid is final. Whilst water is pumped down the drill string operation can continue and the annular pressure is recorded. Recording of this pressure prior to drilling will enabling early detection of fracture behavior or possible new fracture encounters by changes in pressure readings. If migration of formation fluids occurs, additional mud is simply bullheaded down the annulus whereas the fluid will be pushed back into the formation hence minimizing surface pressure and mud losses and drilling can continue.

6.4 PMCD equipment

For a vessel to be able to perform a PMCD operation certain surface equipment must be installed. This is a very general overview over PMCD equipment, as almost all PMCD operations are practiced using a RCD, a non-return valve and a choke manifold system of some sort, depending on the situation and complexity more advanced equipment could be necessary but almost all operations include these components [60]:

- Rotating control device
- Slip-joint
- Active choke manifold systems
- Non-return valve

The different components can be seen in figure 6.5.

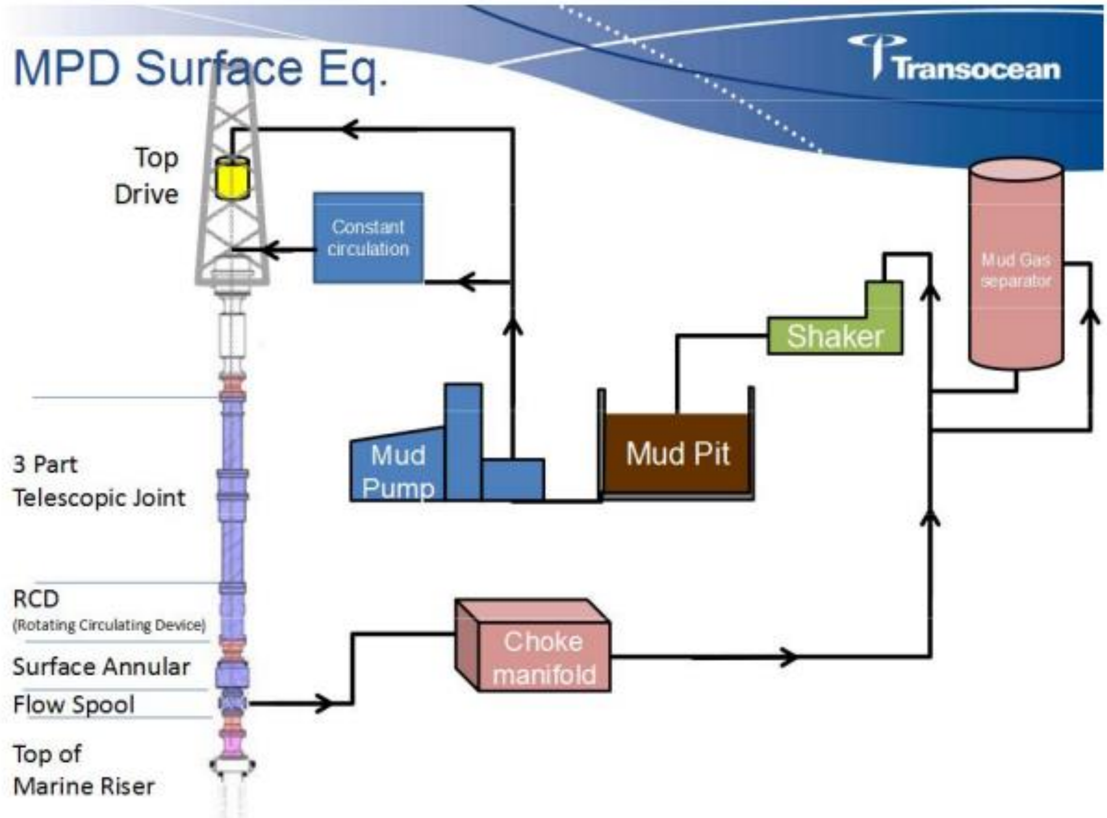


Figure 6.5 - A MPD system setup used on Transocean rigs in Africa [61]

6.4.1 RCD

The RCD is placed in MPD operations to seal the wellbore and to divert well flow to the choke manifold via a flow spool which is located just beneath the RCD [4]. It also allows for rotation of the drill pipe and to maintain pressure while the drill pipe enters and exit the wellbore.

To conduct MPD from a floater the positioning of the RCD is important, whereas it could be placed above or below the tension ring. The tension ring is normally just above the water line, where the top of the riser is.

6.4.2 Slip joint

As seen in figure 6.4 the slip joint is a telescopic joint between the rig and the top of the marine riser. This joint allows the marine riser to be almost unaffected by the heave motions, because in heave this joint moves the same amount as the heave motion [4]. The slip joint is needed to allow for switching between drilling techniques as conventional drilling can be conducted by removal of the RCD assembly, to provide an alignment and to contain oil spills in case of leaks in the RCD.

6.4.3 Active choke manifold system

In a PMCD operation an active choke manifold system is one of the main tools necessary to perform safely and to control the BHP. The systems varies in complexity from vendor to vendor but often consist of a choke, pressure gauges, flow meter, backpressure pump and an advanced control system [4]. An active choke manifold system is seen in figure 6.6.

Figure 6.6 - A control system. Courtesy of Weatherford

6.4.4 Non-return valve

The non-return valves (NRV) are also known as “drill string float valves” and is crucial in PMCD operations [60]. In PMCD mode annulus backpressure is applied which could induce U-tubing in between the annulus and the drill string during connections, this will push drilling fluid up the drill string and in a worst case scenario blow out the drill pipe [4]. To avoid this, a NRV is installed in the BHA or close to it and will prevent drilling fluid to return up the drill string as backpressure is applied in the annulus. Since this backpressure is applied most of the time it is crucial that the NRV is functioning and there is usually installed two or more NRV’s for redundancy [4].

6.5 Cases of PMCD in fractured carbonate reservoirs

The application of PMCD in fractured carbonate reservoirs, often with features of karst, is well-documented especially offshore in South-East Asia. PMCD is often initiated after conventional drilling techniques have proved insufficient when severe mud losses are encountered.

6.5.1 PMCD from a semi-submersible

The KUN2 well was drilled by a semi-submersible drilling rig in 2012, it is located offshore Sarawak, Malaysia as seen in figure 6.7, in 311 m water depth [62].

Figure 6.7 - KUN2 well location offshore Sarawak, Malaysia [62]

Shortly after drilling into the carbonate formation, the well experienced a total loss of drilling fluids [62]. It was decided that drilling should be continued in PMCD mode, so the well was filled with seawater to be able to estimate the pore pressure at the first fracture to properly weigh the LAM. After successful injectivity tests were performed drilling continued in PMCD mode until target depth were reached [62].

6.5.2 PMCD from a dynamically positioned drillship

PMCD from a drillship is not a well-established procedure yet, but one case history from deep-water Makassar Strait, Indonesia exists. It is the first documented operation of a well drilled with a below tension ring RCD and in addition an annular preventer for riser gas handling [63]. Due to the drillship rotation and to avoid the risk of disconnecting umbilicals and hoses the RCD was installed below the telescopic joint [63].

The well was an exploration well, and the carbonate structure was estimated to be approximately 400 meters thick [63]. After the detection of the top of carbonate started a kick was soon taken, bullheaded back into the formation and after an injectivity test it was decided to switch to PMCD mode. Drilling continued by pumping seawater as the SAC down the drill pipe whilst a proper mud was selected for maintaining annulus pressure. Drilling in this mode continued throughout the well and after 12 days after the kick was taken the well was finished successfully [63].

6.6 Challenges of PMCD

As an unconventional drilling technique PMCD faces challenges regarding planning, operational experience, drilling strategies, fluid requirements, equipment and trained personnel. In addition, these fractured reservoirs, vary considerably even in the same area, so a standardized solution is not possible and every well needs careful planning.

6.6.1 Geology & Geophysics

A known challenge when drilling carbonate wells is to recognize the top of the carbonate formation to set the production casing, because carbonate stringers could exist and be interpreted as the top, hence the casing is set too high [64]. This is to isolate the reservoir from the overlying formations.

Another great challenge is to predict the pore pressure gradient in a carbonate formation [64].

6.6.2 Well design

Several considerations regarding well design needs to be addressed when drilling carbonate reservoirs. An important factor is to set the production casing just inside the carbonate structure to ensure total isolation from overlying formations [64]. This is also to make sure there is an annular capacity which enables an applicable loss management for the reservoir section. An ideal design of a well in a carbonate formation is seen in figure 6.8.

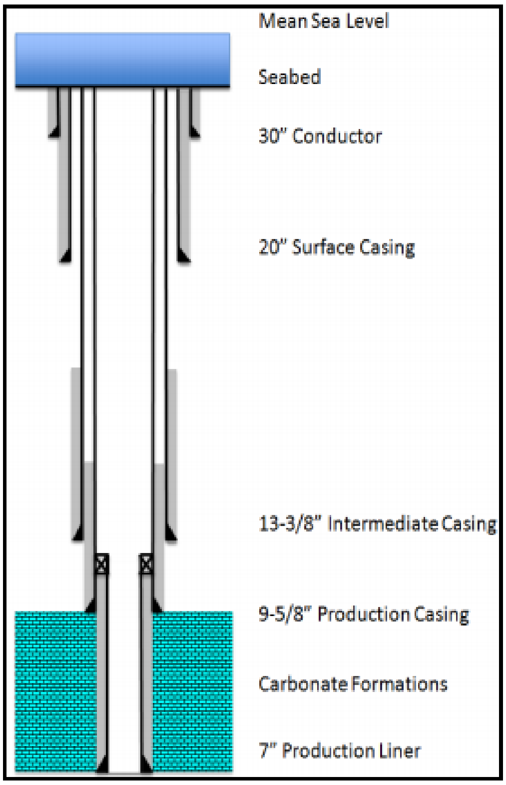


Figure 6.8 - Typical carbonate well design [62]

6.6.3 Personnel

As a relatively new technique PMCD proposes challenges for all involved personnel as limited experience and no standard “way of doing things” exists.

To adjust for this, proper training of personnel prior to operations is necessary and the presence of a PMCD expert during operations could be essential for successful operation [64].

6.6.4 Logistics

To perform a successful PMCD operation several different fluids needs to be available for injection as required [64]. The limited pit volumes and mixing capacities on rigs could result in logistical complications, especially if the rig site is far from a supply base [64]. A carefully constructed pit & fluids management plan is necessary to ensure safe operations.

6.6.5 Operation

Various challenges could occur during drilling of carbonates with PMCD. One of them is to switch to the PMCD mode if the injectivity pressure is too high when losses are encountered [64]. Another challenge is to ensure efficient PMCD mode with vibrations and stuck pipe events during operations [64].

7 Discussion

In this section the theoretical content of this thesis will be discussed and tried to address, the section is divided into:

1. General considerations
2. Topside considerations
3. Subsea considerations
4. Subsurface considerations

7.1 General considerations

Although the Barents Sea is affected by the Gulf Stream the temperatures during winter time could get considerably low and in combination with strong wind, severely low. These temperatures could affect humans working in this environment both physically and mentally. For the physical point of view, proper PPE equipment needs to be in place to ensure both warmth and mobility. The Barents Sea also experiences the phenomena of polar nights, which could be critical in a possible oil spill or a rescue scenario where visibility is important. The installations operating these areas should be equipped with lighting reaching a certain circle of criticality. Both cold and darkness affect humans in a negative way, depression could be triggered and working performance could decrease. Therefore both physical and mental related issues would need to be addressed adequately.

The cold temperatures would propose that ice is present, but the Barents Sea is not affected by multiyear ice and icebergs so there is no immediate threat due to ice until the industry makes its way even further north to the latitudes of Svalbard.

Weather forecasting is a major concern as the weather can change abruptly in this area. The following weather phenomena's such as polar lows, snow storms or fog could cause a hazardous situation. Existing equipment is limited and has been proven to be insufficient when the Earth's curvature increases whereas satellites could be a possible solution.

One of the main reasons the Barents Sea is still underdeveloped is the lack of functioning infrastructure. The existing helicopters are unsuitable for long distance travel and cannot reach all parts of the opened up area. To be able to operate in the north the oil companies must work together with the authorities to make up a proper implementation plan. The most likely solution will be refilling at existing installations such as the planned Johan Castberg prospect and a dedicated filling facility, making it possible to reach the whole area. Even if this is implemented it will still take some time to reach the most northern prospects by helicopter. It is therefore suggested that the installations which needs a filling stop have extended medical equipment and personnel available on the rig in case of an emergency situation.

7.2 Topside considerations

Rig choice is always important and is affected by cost, availability, target/water depth and weather conditions in the area. Since the environment in the Barents Sea is quite harsh a proper installation needs to be able to handle the cold, snow, icing and Arctic weather phenomena as well as fulfilling the requirements laid down by Norwegian authorities.
This is not always easy as the circular FPSO especially designed to operate Eni's oilfield in the Barents Sea, Goliat, was meant to start production late 2013 but is still located in Asia, not

ready and production start of the field is once again postponed, now till mid-2015 [16]. This just emphasizes how much time is spent on planning and implementing and may give a hint on what type of time frame the development of the Barents Sea is facing.

Logistics if a possible blow out should occur is of high concern as available rigs for relief well drilling which serves the requirements laid down by the government may be limited. Drilling in these areas require careful and adequate planning due to great distances and the availability of certified rigs.

Another consideration to the topside environment is formation of hydrates in well control equipment as hydrates have been detected in wells with similar environment and caused operational hazards. This typically occurs if the well is shut in which is not uncommon in harsh weather environments such as the Barents Sea. A possible solution to this is greater insulation of choke- and kill- lines.

7.3 Subsea considerations

As for subsea considerations only hydrates formation in BOP and pipelines is discussed in this thesis. Hydrates in the BOP could prevent the BOP from opening and closing which could be crucial in a well control situation where a functioning BOP is essential.

The likelihood of hydrates should be assessed prior to drilling a well where parameters such as temperature, pressure and gas/fluid phase compositions should be included. If there is a potential for hydrates pre-well analysis and contingency plans including shut in periods is needed.

Heat maintenance of well control equipment at the seabed could be a possible solution.

7.4 Subsurface considerations

The main focus in this thesis has been on the Gotha field which is the first reservoir with karst origin found in Norway. Karsts are geologic features which are characterized by voids, fractures and open cave systems which could be encountered at great depths. Reservoirs with karst features are often combined with drilling issues such as severe losses of circulation and drop of drill-string which could cause a well control situation and costly delays. In addition to this subsurface karst has proved to be difficult to identify but techniques such as history matching and 3D seismic has helped to improve the detection of karst significantly.

Karst reservoirs is frequent in South East Asia and operators have been developing methods to drill these in a safe and secure manner avoiding increased costs related to NPT and severe losses. A method commonly used to handle karst in South East Asia is a MPD version called PMCD technique.

This drilling technique could be a possible solution for the development of Gotha, although PMCD has never been used in Europe. PMCD is not yet a recognized drilling technique in Norway and needs to go through substantial research and verifications before it is applicable to the NCS. Such a process is time consuming, as the process to implement the first underbalanced operation (UBO) well in Norway took 3 years [65]. In 2004 Statoil introduced underbalanced drilling technology to the Gullfaks field offshore Norway were the main drive was to overcome the pressure control problems experienced by conventional drilling [66].

Most of the existing requirements and guidelines in Norway at the time were developed for conventional drilling only. Meaning the UBO equipment had to go through a detailed review and modifications to satisfy both Statoil's internal requirements and the Norwegian demands and standards, risks defined for UBO compared to conventional methods were developed and proper planning of procedures and possible emergency scenarios were made to ensure the safety of personnel at all times [66]. The project was met by a positive attitude by the authorities as they recognized the necessity of implementing the technology in Norway [66]. The process of initiating UBO at Gullfaks was divided into 3 phases [66]:

- Feasibility phase
- Initial planning, process design, contracting and purchasing
- Execution and field implementation

The feasibility phase consisted mainly of learning about UBO technology by literature research and contacting IADC to get the most updated information surrounding UBO [66]. In the second phase personnel from all involved disciplines as well as the authorities gathered to perform a preliminary hazard identification and a common goal to work towards [66]. The third and last phase included proper training of the UBO technology for the people involved before execution and implementation were finalized.

The UBO spanned for 200m were the problem zone was 40m and it was a success without operational trouble or injuries to personnel, environment or equipment [65, 66]. After the operation Statoil's UBO manager, Johan Eck-Olsen, said "Forty meters – that's 4 hours of work. We planned 3 years for 4 hours of work. But it was worth it" [65].

To be able to perform PMCD on the NCS a similar approach to the authorities where one explains why the technique should be implemented and information regarding PMCD needs to take place. As explained evaluation of equipment, rig specifications, HSE procedures, training of personnel and development procedures is necessary.

To ensure safe operations the technique could be tried out in a well-known area during summer time when the weather conditions usually are easier to operate in compared to harsh conditions during winter time in the Barents Sea.

An implication process is as explained both time consuming and costly and a big operator with a lot of resources such as Statoil might need to take the first step for the implementation to be possible.

8 Conclusion

The challenges of petroleum activities in the Barents Sea are substantial and well control is of major concern for both authorities and the industry. Although the development started years ago and is slowly growing there is still a long way to go in both emergency preparedness and technology developments. Several issues related to drilling in this harsh environment are recognized in this thesis.

The Barents Sea environment is characterized by cold, darkness and great distances which require winterized rigs and specialized equipment for the personnel working. Formation of hydrates in well control equipment is a possibility and needs to be assessed prior to drilling. Prudent planning of logistics regarding rigs, operational procedures, training of personnel and emergency preparedness is recognized as crucial. With the Macondo incident in mind where hundreds of boats and thousands of volunteers in addition to the coastguard and several organizations assisted the cleanup job one should wonder if such a response would be possible in the Barents Sea.

The karst reservoir found at Gotha can propose challenges due to severe losses of circulation. It is in addition difficult to map and predict which could cause unwanted surprises during operations. A possible solution is to use the PMCD technique which is frequently used to handle such reservoirs in South East Asia but needs to go through a verification process with the authorities before it can be implemented in Norway.

The Barents Sea is looked upon as the next big step in exploration and production on the NCS and for the development plans to be successful tight cooperation between the authorities and the industry is essential. The recent extended delay of the Goliat development and the findings at Gotha which may need drilling techniques which are not yet approved in Norway only illustrates the amount of time and money needed for development of the Barents Sea.

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