DRILLING THROUGH GAS HYDRATE FORMATIONS: POSSIBLE PROBLEMS AND SUGGESTED SOLUTIONS

A Thesis

by

AFOLABI AYOOLA AMODU

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

August 2008

Major Subject: Petroleum Engineering

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ABSTRACT

Drilling through Gas Hydrate Formations: Possible Problems and Suggested Solutions.

(August 2008)

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Gas hydrate research in the last two decades has taken various directions ranging from ways to understand the safe and economical production of this enormous resource to drilling problems. as more rigs and production platforms move into deeper waters to its environmental impact on global warming and cooling. Gas hydrates are ice-like structures of a water lattice with cavities, which contain guest gases. Gas hydrates are stable at low temperatures and high pressures. The amount of energy trapped in gas hydrates all over the world is about twice the amount found in all recoverable fossil fuels today.

This research identifies the problems facing the oil and gas industry as it drills in deeper waters where gas hydrates are present and suggests solutions to some of the problems. The problems considered in this research have been approached from a drilling point of view. Hence, the parameters investigated and discussed are drilling controlled parameters. They include rate of penetration, circulation rate and drilling fluid density. The rate of penetration in offshore wells contributes largely to the final cost of the drilling process. These 3 parameters have been linked in the course of this research in order to suggest an optimum rate of penetration.

The results show the rate of penetration is directly proportional to the amount of gas released when drilling through gas hydrate. As the volume of gas released increases, the problems facing the drilling rigs, drilling crew and environment is seen to increase. The results also show the extent of risk to be expected while drilling through gas hydrate formations. A chart relating the rate of penetration, circulation rate and effective mud weight was used to select the optimum drilling rate within the drilling safety window.

Finally, future considerations and recommendations in order to improve the analyses presented in this work are presented. Other drilling parameters proposed for future analysis include drill bit analysis with respect to heat transfer and the impact of dissociation of gas hydrate around the wellbore and seafloor stability.

DEDICATION

I would like to dedicate this work to God, for giving me the strength and guidance. To my late mum, for the awesome training she gave and the ever fighting spirit she bestowed upon me. To my dad, first for being my friend and secondly for his support both mentally and financially and to my siblings for always being a shoulder to rest on.

ACKNOWLEDGEMENTS

I would like to express my sincere gratitude to Dr. Catalin Teodoriu, chair of my graduate committee, for his continuous support and drive through out this work. His contribution in guiding me and constantly being available to discuss my problems cannot be overemphasized in the success of this work.

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To Damola, Nyasha, Shelly, Kelly, Yomi, Faith, Olayide, Mowunmi and Wola, you guys have been great friends. Your support out of class has been the driving force to return to class every other day.

To Seun, Olisa, Jide and Bimbo, my brothers, I've come a long way with you guys, thanks.

To my fellow students at Texas A&M University, it has been a lovely two years studying with all of you. I would not have enjoyed going to school in Aggieland without the likes of you guys. Finally, I would like to thank Texas A&M University for the wonderful education I have received. Thank you all.

TABLE OF CONTENTS

LIST OF FIGURES

FIGURE Page

LIST OF TABLES

CHAPTER I

INTRODUCTION TO GAS HYDRATES

Gas hydrates are believed to have first been discovered in 1810 in the laboratory of Sir Humphrey Davy, who cooled an aqueous solution saturated with chlorine gas below $9^{o}C$ to yield a crystal/ice like material.[1] General research in gas hydrates started in the early 19^{th} century when chemists generally made different hydrates in the laboratory from combinations of water with different gases. In the 1930s, it was suggested that the blockage observed in some gas pipelines was due to formation of gas hydrate and not ice as initially thought. This led to the extensive research in the use of thermodynamic and kinetic inhibitors for delaying or avoiding the formation of gas hydrate during drilling and production activities. It is believed that most of the gas reservoirs such as the Mackenzie delta of Canada and Messoyakha field in Siberia, have an increased production life due to the contribution of top hydrates layers around the producing zones.[2] Studies have shown that the estimate of carbon mass in hydrates is approximately 10 teratonnes (2.2×10^{16} pounds), this amount is twice the total of all recoverable and unrecoverable fossil fuels.[2] Gas hydrates have been recovered from the seafloor as mounds as shown in fig 1.1. Apart from the amount of fossil fuel being held in gas hydrate formations all over the world, the knowledge and understanding of gas

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This thesis follows the style and format of *SPE Drilling and Completion*.

hydrate formation and dissociation is very important in making use of their essential properties.

A unique property of hydrates is the change in specific volume during their transition from the free state to the hydrate form and vice versa. This property could be explored in the storage and transportation of large volumes of gases in hydrate form at low pressures. It is also useful is designing a machineless thermal gas compression system, generation of cold energy production during the use of low potential heat.

Fig. 1.1- Gas hydrate mounds seen on the seafloor of the Gulf of Mexico.[1]

1.1 Properties and Characteristics of Gas Hydrates

Gas hydrates are ice-like structures of a water lattice with cavities, which contain guest gases. These crystalline structures are part of a group of solids known as clathrate[3] and are formed from the mixture of water and low molecular gases at high pressures and low temperatures. Gases likely to combine with water to form hydrates include light alkanes (methane and iso-butane), carbon dioxide, hydrogen sulfide, nitrogen, oxygen and argon.

A very important property of hydrate is the amount of natural gas that can be held in the lattice structure. 1cf of gas hydrates could hold as much as 170 ft^3 of gas[3]. Three different structures of hydrates have been identified namely structure I, II and H. Fig 1.2 shows the three structures of hydrates[4]. Structure II is mainly expected to form with natural gas under production conditions[4].

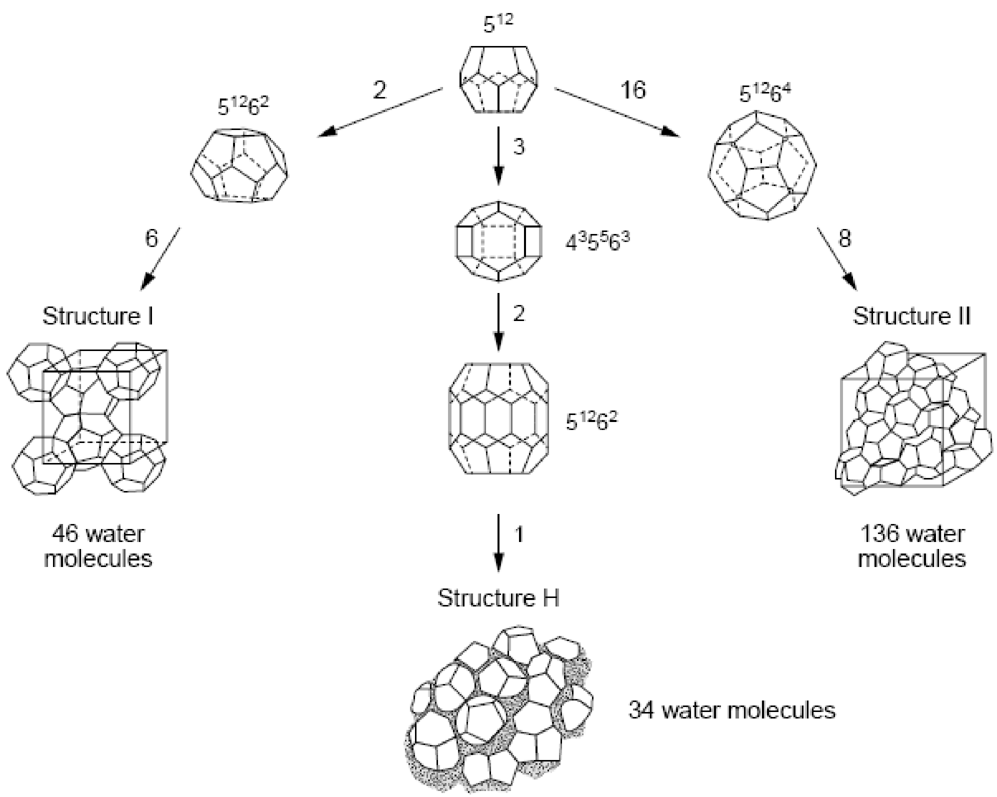


Fig. 1.2- Physical structure/composition of hydrates.[4]

1.2 Stability of Gas Hydrates

The conditions necessary for the stability of gas hydrates are moderately low temperatures and moderately high pressures. These conditions could exist offshore in shallow depths below the ocean floor and onshore beneath the permafrost. The geothermal gradient of the earth increases the pressure requirement for the stability of the hydrates at a much greater rate than that provided by the available increased pressure from the hydrostatic gradient. In oceanic conditions, temperatures are too warm and pressures are too low for hydrates to form, but as we move down the water column, temperature drops and an inflection in the temperature curve is reached (Fig 1.3). This inflection is known as the main thermocline, which separates the warm surface waters from the deeper cold waters. From the point where the temperature curve crosses the phase boundary curve, downward temperatures are cool enough and pressures are high enough to allow the methane hydrate to be stable in the ocean. There are certain depths at which gas hydrates would be stable.

In permafrost regions, where surface temperatures are well below freezing points, gas hydrates are present and stable at depths ranging from 1640 ft to 6560 ft, while under offshore conditions, gas hydrates stability zones usually extend 328 ft to 1640 ft below the ocean floor[4]. The stability of gas hydrate offshore in specific places has been seen to extend up to 6560 ft (Makogun, 1974) below the seafloor. These hydrates are known as high temperature gas hydrate deposits. The gas hydrate stability zone (GHSZ) is defined by the hydrate forming gas and by the temperature. The gas pressure is usually equal to the external pressure which is equal to the sum of the hydrostatic and lithostatic pressure[5]. The gas hydrate stability zone is known to have a lower base, a point beyond which gas hydrates become unstable as the depth increases. The precise location of this point under known pressure and temperature conditions vary with a number of factors, the most important factor being gas chemistry. The various temperature and pressure profile for the 3 known hydrate structure is shown in fig 1.4. In places such as the Gulf of Mexico, at a pressure equivalent of 8200ft, the base GHSZ will occur at about 21^{o}C for pure methane hydrates, about 23^{o}C for a typical mixture (methane 93%, ethane 4%, propane 1% and other higher hydrocarbon) and 28^{o}C for a possible mixture of methane 62%, ethane 9%, propane 23% and other hydrocarbons[5]. These differences in the temperature cause major shifts in the depths to the base of the GHSZ. Below the GHSZ, methane and water would exist independently and gas hydrates would not be formed. This is shown in fig 1.3.

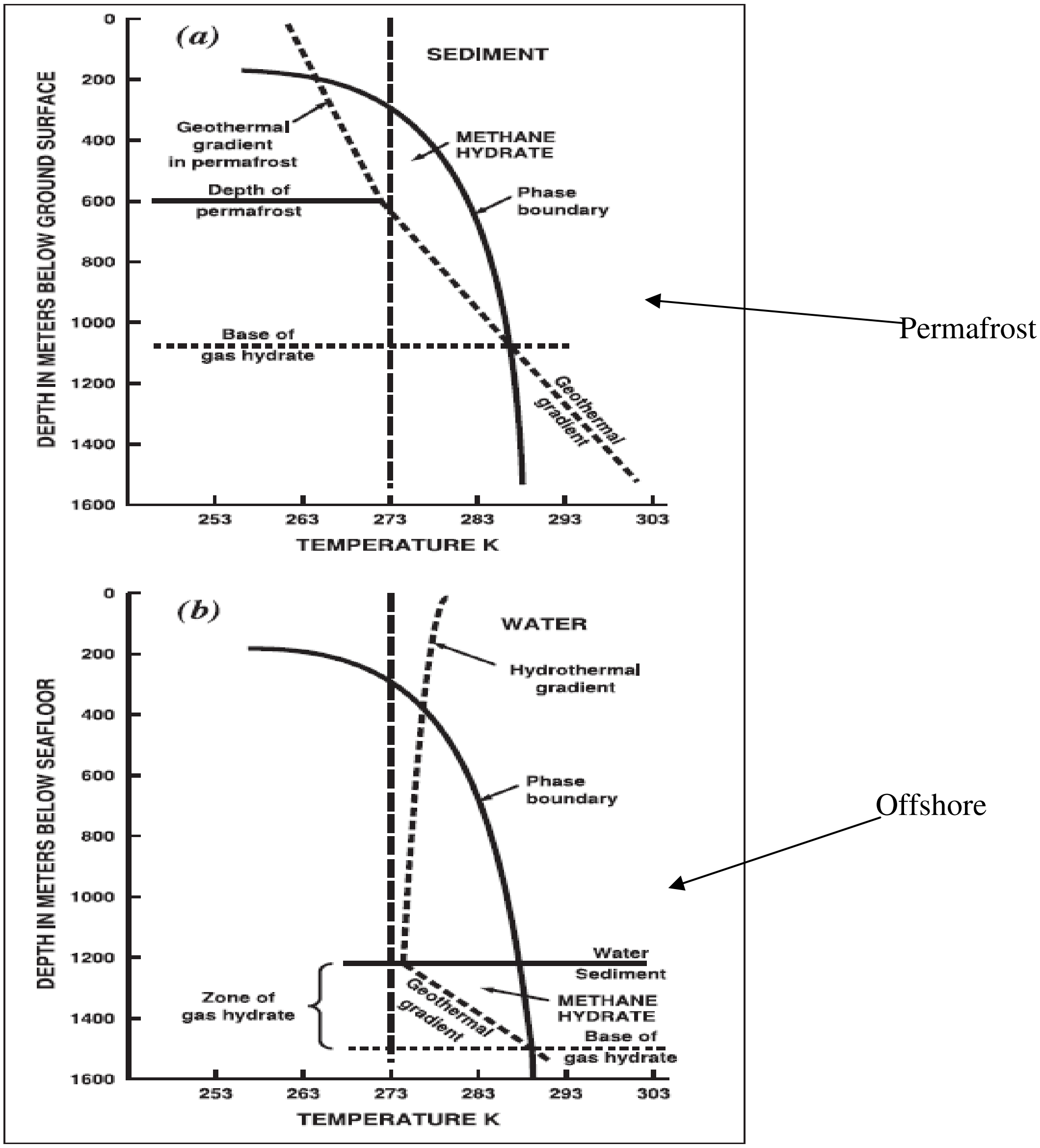
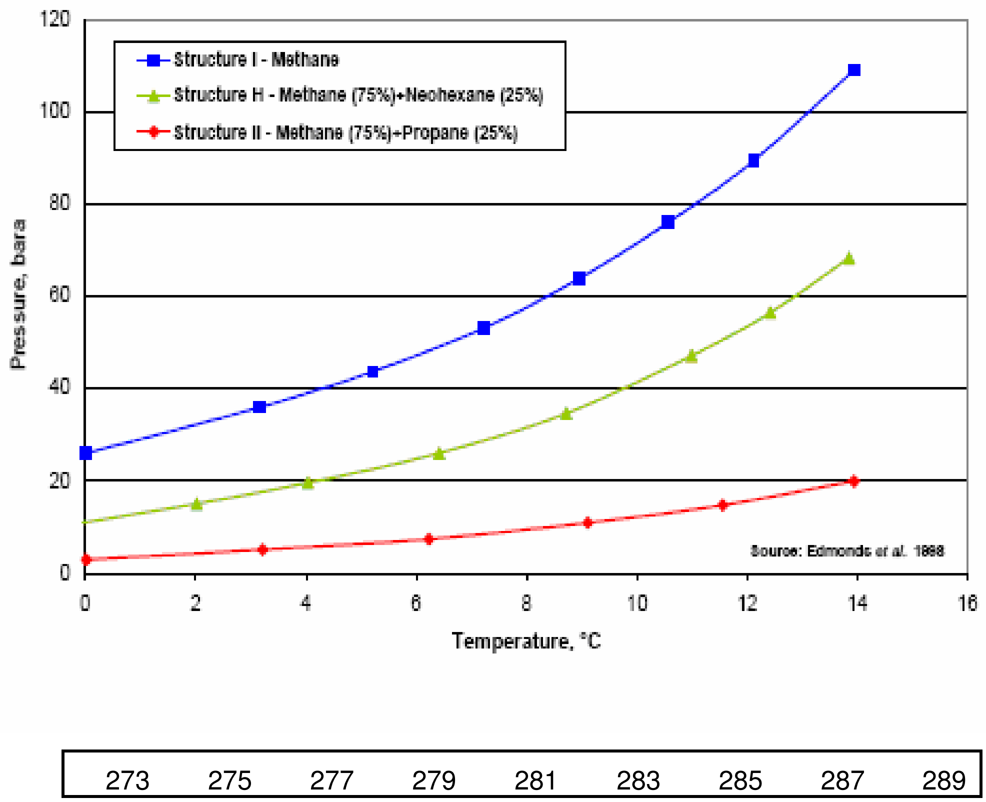


Fig. 1.3**-** Graph showing the depth-temperature zone in which methane hydrates are stable in both permafrost region and outer continental margin marine setting.[6]



Temperature, °K

Fig. 1.4- Graph showing the relative stability of S1, SII and SH structures of hydrates with respect to pressure and temperature.[7]

1.3 Formation and Production of Gas Hydrates

In addition to the required temperatures and pressures, certain hydrate forming gases must also be present in order for gas hydrates to be formed. These gases may be present as a result of the breakdown of organic matter by bacteria under the seafloor or from thermogenic sources such as hydrocarbon generated from much deeper sources and have flowed upwards through fractures or cracks. Also during drilling, as the water depth increases, the potential for gas hydrate to form increases. Many sources have suggested that the main source of naturally occurring hydrate is biogenic[2]. Methane hydrate, which makes up most of the naturally occurring hydrates, is composed of roughly 6 molecules of water for each molecule of methane. The decomposition reaction can be given as follows:

$$(CH_4.6H_20)_{\text{solid}} \longrightarrow (CH_4)_{\text{gas}} + 6(H_20)_{\text{liquid}}$$

The energy generated from the hydrate gas dissociation is about 10 times the energy required to dissociate the hydrate in typical reservoirs. The excess energy is what is required in commercial quantity in the industry. In order to produce the gas from hydrates sources, the following conditions must be met:

- The pressure and temperature of the hydrate must be brought outside the stability zones
- The energy required for the endothermic reaction must be sustained
- A special means of transfer of the products of decomposition (gas) to the production wells must be designed (to ensure gas hydrates are not formed within the lines).
- There dissociation needs to be monitored in order to avoid seafloor collapse.

For gas hydrates to accumulate in the region of fluid discharge, two basic mechanisms are known, firstly, hydrate can form from precipitation of water where a saturated solution moves to a zone of lower temperature and secondly, hydrate can form in static pore water in the hydrate formation zone by reaction with percolating free gas that has migrated into its presence from hydraulically subjacent zones. Overcooling and oversaturation of water by gas, relative to equilibrium values is required to initiate hydrate formation and hydrate accumulation. The kinetically most favorable conditions for hydrate formation and accumulation (i.e. the greatest possible oversaturation and overcooling) occur in the uppermost part of the sedimentary cover and on the sea floor[5]. Figure 1.5 is an illustration of the possible configurations of hydrates[8]. In coarse grained sediments, methane hydrates are formed as disseminated grains and pore fillings but in finer silt/clay deposits, it commonly appears as nodules and veins[8].

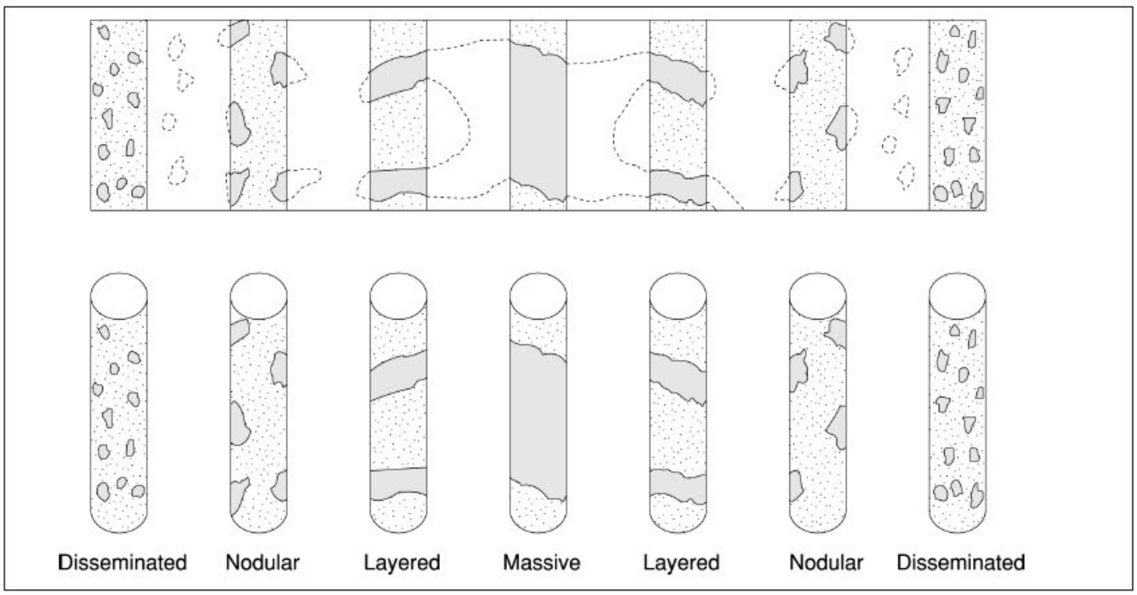


Fig. 1.5- Various morphological forms of natural gas hydrate occurrence.[8]

1.4 Location of Gas Hydrates

Most of the discovered hydrates have been with the aid of geophysical models. A seismic signature known as the bottom simulating reflector (BSR) is often used to determine the hydrate bearing location in marine environments. This technique relies primarily on the contrast between sound velocity in the hydrate bearing zone and the free gas bearing formations below. The BSR is a sure sign that gas exists trapped below the base of the GHSZ and therefore the existence of gas hydrate since free gas would normally travel upwards but it exists in a zone where gas would normally be converted to hydrates. As shown in figure 1.6, most of the hydrates recovered in nature are offshore although there are a few hydrates deposits found on land (permafrost).

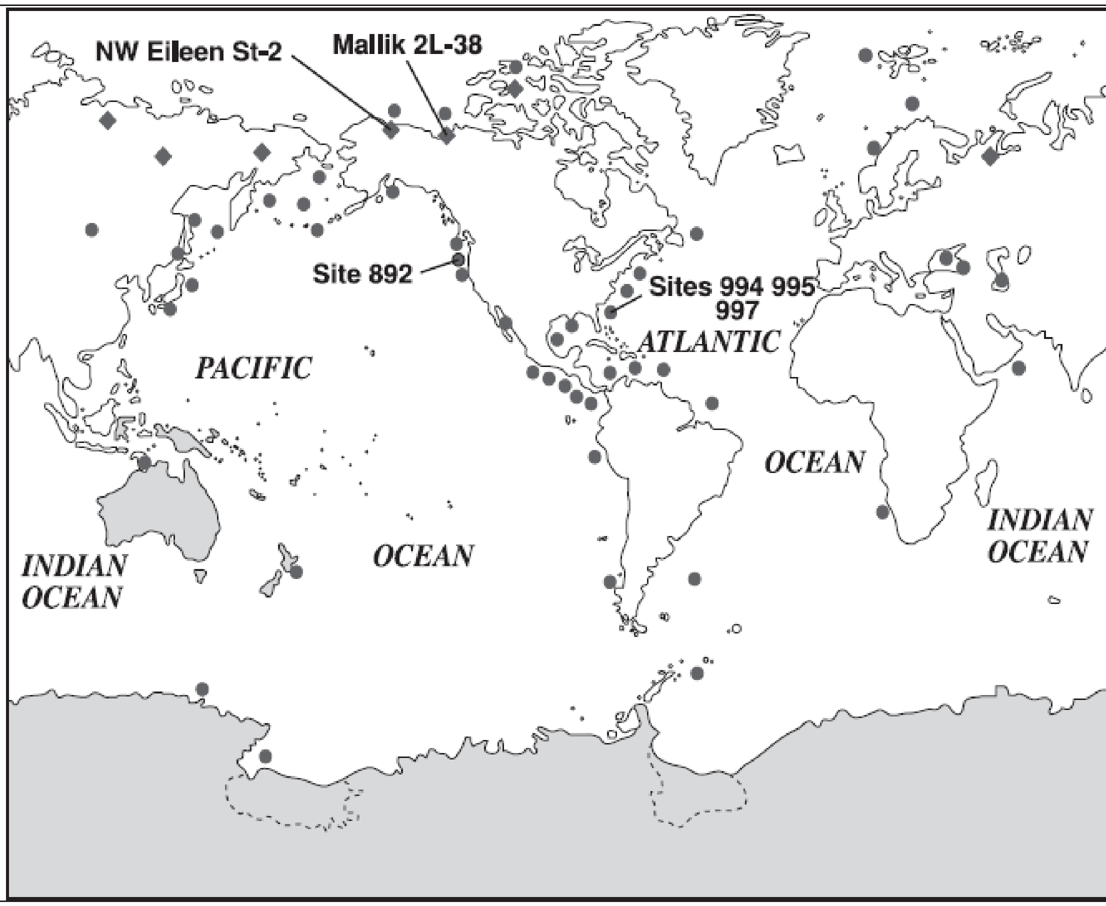


Fig. 1.6- Location of known and inferred gas hydrate occurrences.[6]

CHAPTER II

DRILLING THROUGH GAS HYDRATES

2.1 Gas Hydrate Problems in the Industry

Drilling of deeper wells has increased greatly in the last 20 years. The potential of gas hydrate formation has been recognized in a few of these wells. Drilling of an oil or gas well can be described as a series of operations or drilling activities, each performed to achieve a particular task. There are various problems encountered in the course of a drilling operation through gas hydrate formation especially in deepwater or offshore. Some of the notable/possible problems encountered during drilling through gas hydrate formation are shown pictorially in Fig 2.1 and explained below:

- Choke and Kill-line plugging: This causes difficulty in the use of the lines during well circulation
- Plug formation at or below the blow out preventers (BOP): Well-pressure monitoring below the BOPs becomes impossible or difficult
- Plug formation around the drillstring in the riser, BOPs or casing: Makes the drillstring movement a problem
- Plug formation between the drillstring and BOPs: This causes problems in the full closure of the BOPs when necessary
- Plug formation in the ram cavity of the BOPs: Causes difficulty in opening the BOPs fully.

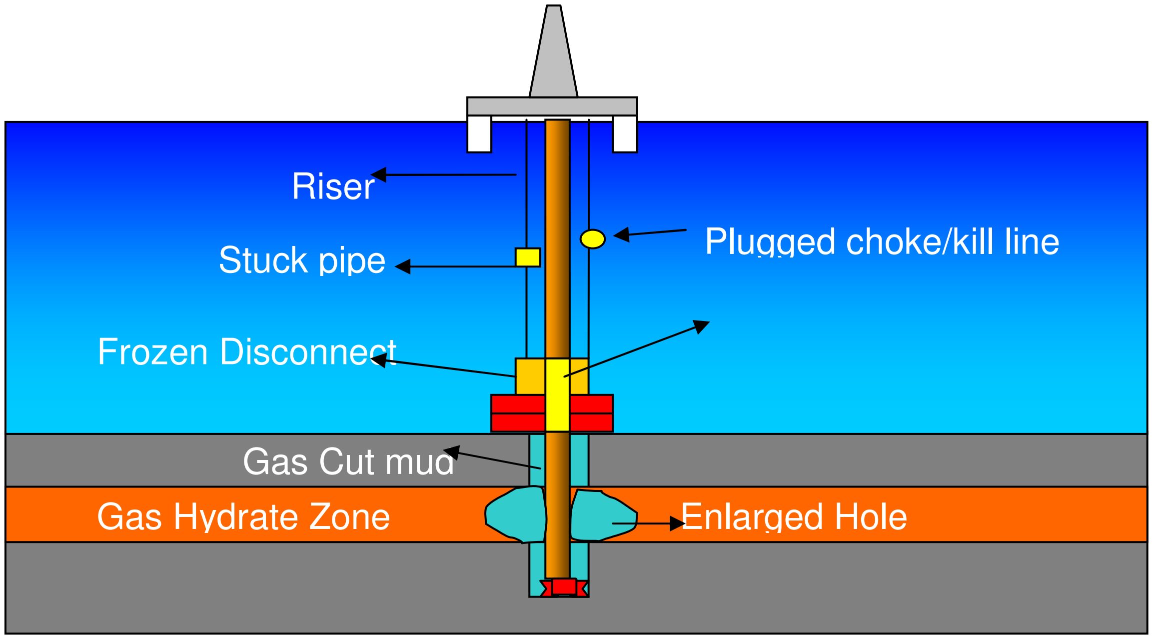


Fig. 2.1- Pictorial representation of some notable problems encountered while drilling through gas hydrate formation.

2.2 Case Studies: Notable Hydrate Problems in Deepwater Drilling[9, 10]

2.2.1 Case 1

An occurrence of hydrates in a well located at 1150ft water depth, off the US west coast. The temperature is noted at 45^{o}C at the mudline. Figure 2.2 shows the casing strings in the wellbore. After the casing was run and cemented, the casing hanger was set and pressure tested. The BOPs were round-tripped from the ocean floor to change the BOP ram sizes. While cement was drilled at the casing shoe, low gas units were detected. This increased sporadically. The BOPs were closed and casing pressure was increased to 1300psi. A through-drillstring noise indicated that a gas influx was occurring from a sand at 7750ft. Gas was entering from the formation, channeling through the primary cement column and migrating up the casing annulus. The wellhead hanger was leaking (even though it had been pressure tested) allowing the migrating gas to enter the fresh water mud at subsea wellhead. An unsuccessful attempt to recover the BOP wear bushing while holding the pressure was made. Hydrates may have prevented the retrieval of the wear bushing. The recovery of the wear bushing would have allowed access to the leaking casing hanger packoff. Attempts to pump mud into the casing annulus with pressures as high as 3000 psi proved unsuccessful.

To stop the gas influx, the casing was perforated just above the gas sand. This also helped to pump heavyweight mud into the formation. To ensure a successful casing perforating job, the drill string was severed and stripped up through the BOPs until the severed drillstring end was above the gas sand. A through drill string perforating gun was then run to shoot the 7in casing just above the gas sand. The gas influx was killed by pumping 14.2 Ibm/gal mud down the drillstring and into the formation at surface pressures up to 3100 psi. At the conclusion of the kill operation, approximately 7 days after the gas was first discovered, both the chokeline and the kill line were found plugged. Either line became unusable. After cementing operations,which secured the wellbore, the BOPs were recovered. Hydrates and trapped gas were found in the chokeline and the kill line of the bottom eight riser joints.

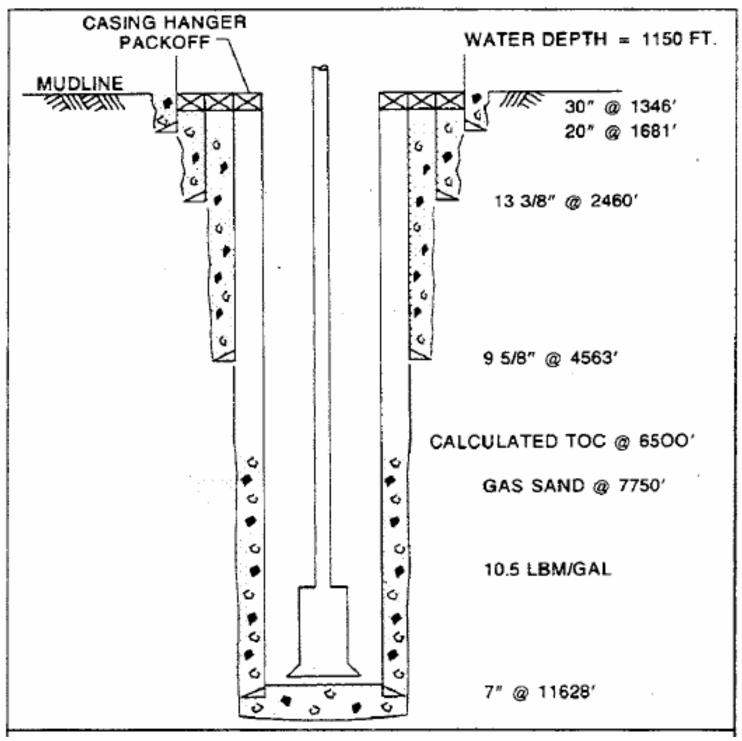


Fig. 2.2- Wellbore sketch for Case 1.[9]

2.2.2 Case 2

This addresses an example of a hydrate occurrence while drilling a Gulf of Mexico well located in 3100 ft of water with a mudline temperature of 40°C. Figure 2.3 detail the status of the wellbore and the BOP arrangement. After drilling to about 7679 ft, the well was found to be flowing during a flow check. The well was then shut in to determine the wellbore pressures. During the attempt to establish circulation after shut in, returns could not be established and casing pressure fell to zero. Fourteen hours after the kick was first detected, all BOPs were opened to observe the well, which appeared static. During the next fourteen hours, several unsuccessful attempts were made to establish circulation by pumping lost circulation pills. Both a choke line and a kill line were circulated during this time. Almost 30 hrs after initial shut-in, the well flowed again and the BOPs were closed as shown in fig 2.3. Part of the gas influx above the BOPs continued to migrate up the riser and was successfully diverted. The choke line was determined to be plugged during subsequent attempts to circulate mud up the riser and above a closed ram-type BOP. The kill line also may have been plugged because it was not checked at the time. With no apparent well pressure, the BOPs were opened again to monitor the well.

Almost 48 hrs after the initial well kick, the well flowed a third time. After an annular BOP was closed, the lower middle ram-type BOP was actuated to prepare for drillstring hangoff; however, it did not take the proper amount of closing fluid. The lowermost ram-type BOP was then closed. The riser continued to flow mud and gas that was successfully diverted overboard. During subsequent attempts to fill the riser, the kill line was determined to be plugged.

The well remained shut-in on the lowermost ram-type BOP while the drillstring was cemented in the open hole. Numerous attempts to unplug the choke line and kill line by applying pressure surges at the surface were unsuccessful. Neutron decay and unfocused density logging indicated gas in the drillstring below and above the BOPs in the casing annulus. Sources of the gas in the annulus were from either gas migrating up the annuli and accumulating or a slight leak in the wellhead casing hanger packoff. Although neutron decay logging detected free gas in the wellbore, these logs can not differentiate between hydrates and mud.

The method used to remove gas in the drillstring casing annulus was to perforate the drillstring about 400 ft above the annulus gas/liquid contact. After coiled tubing was run inside the drillstring, hot mud was circulated and the gas was allowed to migrate into the coiled tubing annulus and was then circulated out of the well. Three sets of successfully shallower perforations were required to remove the gas completely from the annulus. After all ram-type BOPs were opened (some still did not open fully), the drillstring was backed off at 5000 ft and recovered. After washing back to 5000 ft with the drillstring, a cement plug was set in the casing. After a successful pressure test, the well was secure and preparations were made to pull the BOP stack. During pulling of the riser and BOPs, hydrates were recovered from the choke line and kill line of the bottom riser joints. Testing of the BOP at the surface indicated that failure to open and close completely was not due to mechanical problems in the BOP system.

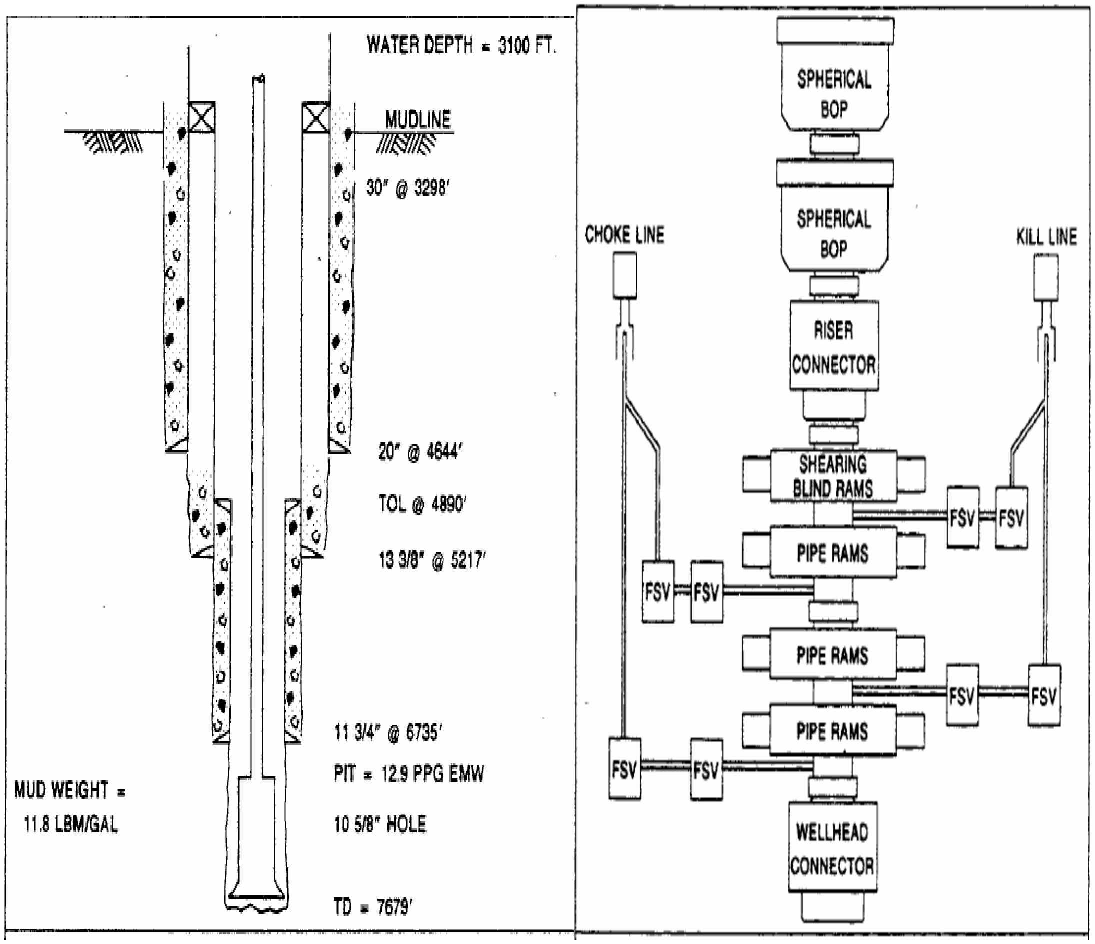


Fig. 2.3- Wellbore sketch for Case 2.[9]

2.2.3 Case 3[10]

This is the case of a gas hydrate buildup problem in a subsea christmas tree. The problem was that of a typical Campos Basin subsea well (1971.78ft water depth, 8°C at seabed) producing to a submarine production manifold on the seabed, at around 1049.87ft water depth, which was scheduled for an ordinary workover job. The goal of this routine job was to retrieve a bad sub surface safety valve (SSSV) for ordinary maintenance or replacement. It became impossible to retrieve the tree-cap by means of a regular Tree Cap Return Tool (TCRT). A schematic diagram of the tree cap showing the location of the gas hydrate blockage in shown in fig 2.4. Along the operation and with the aid of a remote operated vehicle (ROV), they noticed the external "lock-unlock" pin was stationary despite all efforts to activate the TCRT. Therefore the workover job had to be postponed while they tried to determine a solution.

The solution was a patented thermochemical method –Self Generated Nitrogen (SGN) which was applied to the heat to dissociate the crystallized hydrate, which was clogging the tree-cap-locking pin's chamber. Heat application around the body of the Christmas tree enabled them to dissociate and release the tree cap by means of its regular retrieving tool. The following steps were taken to achieve the desired results: The first step taken to address the problem comprised running heat exchange simulations. That was accomplished with the aid of a thermodynamic simulator. Nevertheless, those who are familiar with such simulators are aware how cumbersome it can be to define reliable boundary conditions and sound input parameters to get reliable results. Some of the input data used include:

- Christmas-tree's mass and geometry
- Seabed temperature
- Where and how to release the heat given off by the red-ox SGN reaction
- Global heat transfer coefficients
- Current speed at the bottom of the sea
- SGN(Self Generated Nitrogen) flow profile around the body of the Christmas tree

After pumping of the SGN solution based on the design obtained from the simulations, the tree cap was released after circa 80% of the SGN batch had been pumped. The gas hydrates had gradually dissociated and the TCRT was free to move. Figures 2.5a and 2.5b show the Christmas tree before and after pumping the SGN.

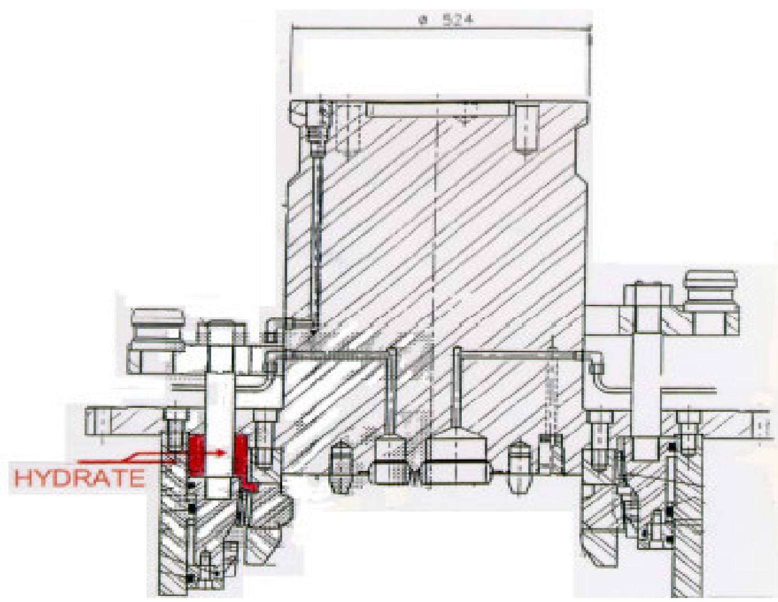


Fig. 2.4- Localization of gas hydrate in tree cap.[10]

Fig. 2.5a- ROV photo of the TCRT on the Christmas tree prior to pumping the SGN fluids.[10]

Fig. 2.5b- ROV photo of the TCRT on the Christmas tree surrounded by nitrogen gas bubbles from the SGN reactions.[10]

2.3 New Drilling Solutions through Gas Hydrate Formations

There is a very good possibility of hydrates forming in the wellhead, BOPs, choke line and kill line during a drilling operation, hence the importance of proper assessment of the drilling conditions and environment before proceeding to deepwater or offshore drilling. The important parameters needed for this assessment include temperature, pressure conditions, gas compositions, drilling mud properties and fluid phase compositions.

The temperature and pressure conditions for most drilling operations can be predicted with respect to the depth. Many hours or days may elapse during which the well will not be circulated, allowing the wellbore temperatures to approach static gradients.

Some new technologies to consider in deepwater or offshore drilling may include[11]:

- Managed Pressure Drilling (MPD): A process used to control the annular pressure profile through out the wellbore. The objectives include ascertaining the downhole pressure environment limits and to manage the annular hydraulic pressure profile.
- Slim and Insulated Marine Riser: Deep sea currents and the need to insulate the riser, especially in temperate waters, indicate the applicability of the slim riser deep-water drilling technology with a surface BOP. The increased velocity of returns will allow the returns chilled by drilling into hydrates less time for heat transfer to warm the returns, thus reducing dissociation within the riser itself. Further, it is believe a 13-3/8 in marine riser may be less adversely affected by

underwater currents. Drilling with a chilled mud system to maintain bottom-hole temperature (BHT) below 11^{o}C should be sufficient to avoid any dissociation of the hydrate or associated gas in the return riser.

- Drilling the Top Hole in Deep Water: A riserless top drilling package is applied to a batch drill process. Such a system incorporates a subsea rotating control device and a subsea choke that enables mud returns to be pressurized with pipe rotation. A subsea pump returns annulus fluids to the floating rig via a mud returns riser or flowline. Such a system is a “riserless” closed loop circulation system and offers precise wellbore pressure management in the top hole by adjusting the surface mud pump rate, applying backpressure to the annulus at the seafloor and adjusting subsea mud return pumping rate.
- Underbalanced Drilling: It is applicable to fixed rigs with surface BOPs and floating rigs with subsea or surface BOPs. The real time temperature and pressure monitoring used in the underbalanced drilling could be particularly useful in drilling through hydrates.
- Drilling With Casing (DWC): It is a one-trip casing drilling technology that tries to avoid pulsating the fragile and frozen wellbore unnecessarily. A robust casing could be one-trip set and cemented to a sufficiently deep depth to minimize the risk of seafloor collapse from the temperature, pressure and chemical quasi-mining process of producing the methane hydrates over time. The circulation f cold drilling mud could assist in absorbing the heat released by the setting of the cement.

The presence of water is a necessary factor for the formation of hydrates. The source of this water could be from two sources, drilling fluid or formation water produced with gas influx. Produced formation water usually contains salt, which provides some inhibition to hydrate formation. The degree of hydrate temperature depression caused by the addition of salt to fresh water can be calculated with the Hammerschidt equation.[12]

$$dT = 2335W/(100M - MW)$$

Where dT = temperature depression, Fahrenheit

M= Molar mass (g/mol)

W= weight percent inhibitor

Based on discussion with personnel in the oil and gas industry, gas hydrate bearing formations are usually avoided during drilling as much as possible. The general ideology would be to relocate or design the field development in such a way as to avoid drilling through these hydrates formations. This is shown in figure 2.6a and 2.6b. The white patches seen in the figures are hydrates located with the aid of seismic analyses and bottom stimulating reflectors (BSR). The red dots are the locations of where the well is spuded or would be drilled on the seafloor. The movement of the rig or drilling unit and design of the field development to avoid these hydrates zones could lead to an increase in drilling cost. The relocation in a bid to avoid these hydrates zone might not completely solve the problem as the length and breadth of the hydrates is not totally known. Hence the need to understand and be prepared to deal with the problems that arise in the course of drilling through and around these hydrates zones.

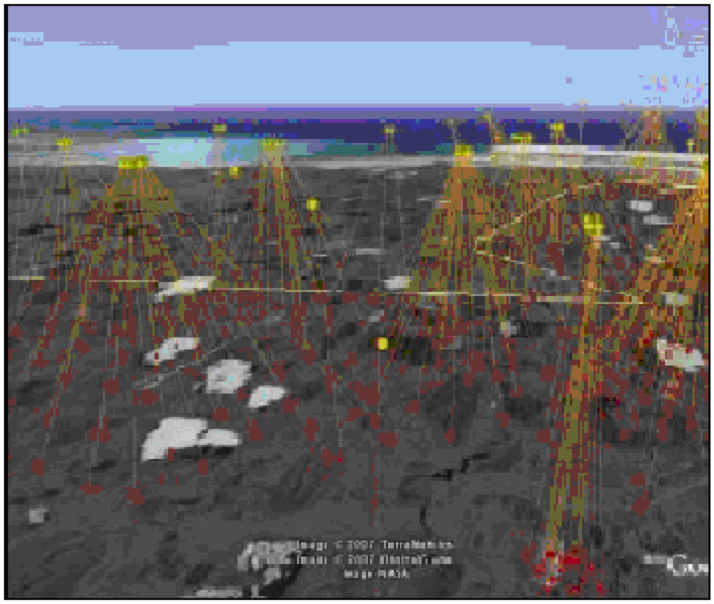


Fig. 2.6a- Various field developments to avoid drilling through gas hydrate formations.[13] 3D Placemarks with wellhead set to 3000m, yellow dot represents well head, red dot represents end of tubing and brown line represents simulation of tubing.

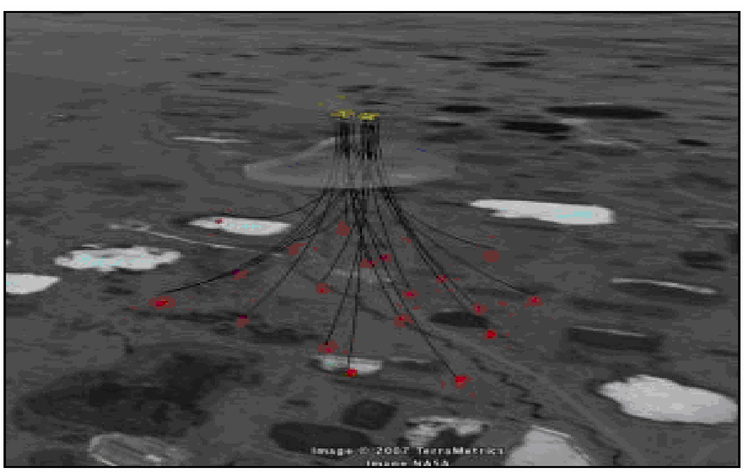


Fig. 2.6b- Various field developments to avoid drilling through gas hydrate formations.[13] Kuparuk River Unit 3D with 300ft thick hydrate at 2000ft below wellhead pad.

2.4 Research Objectives

Based on the extensive literature review, we have decided to focus on the problems associated with wellbore stability with respect to drilling fluids, improving or optimizing the rate of penetration (a very important cost determining factor in offshore rigs), effect of various circulation rates on the 2 earlier mentioned parameters; drilling fluid properties and rate of penetration. The thought process for this research and thesis work is presented in figure 2.7 in the form of a flow chart. This work assumes we are dealing with a worst case scenario which is when the gas hydrate formation or zone is made up of "massive" hydrate type (shown in figure 1.3). The hydrates are treated as pure methane hydrates hence the gas properties applied are those for methane gas. Saturation and porosity are also considered at the maximum possible level in order to clearly show the worst case or the extreme safety effect. Most of the equations employed in this analysis are from basic drilling engineering text. The equations and their applications are presented later in the text.

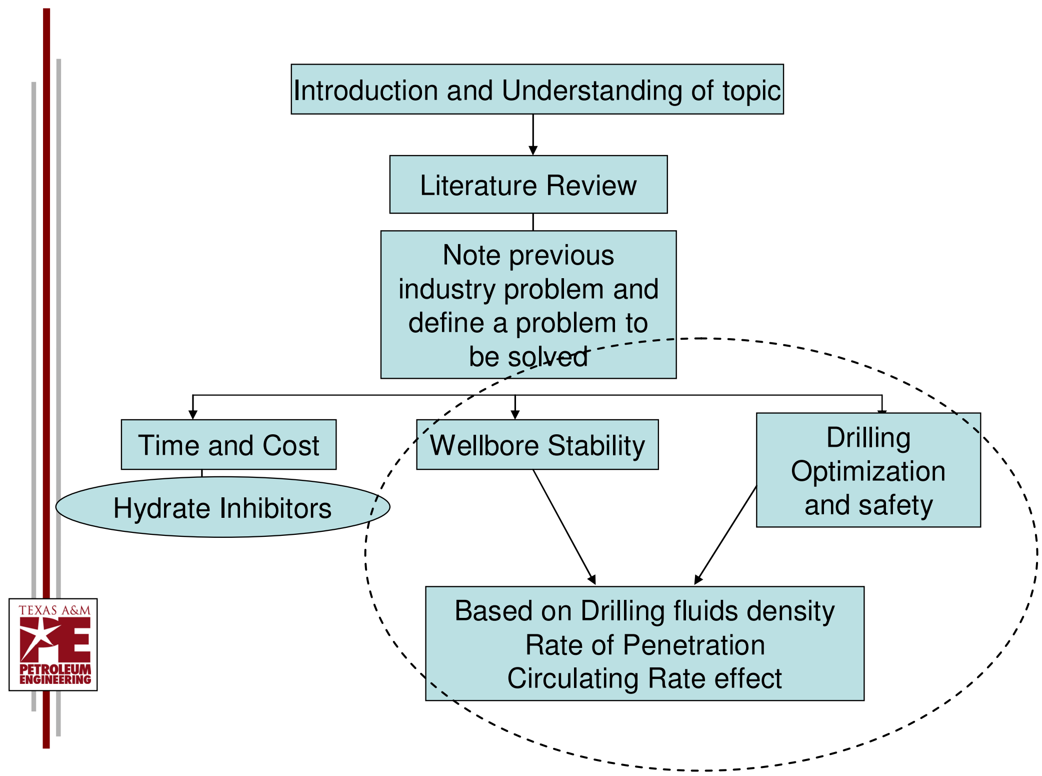


Fig. 2.7- Flowchart showing the thought process of this thesis work. The dotted ellipse highlights the main focus of the research.

2.5 Research Significance

This research would actually focus on addressing the problems listed below:

- When gas hydrate bearing sediments are penetrated, the change in temperature and pressure of the sediments may cause the gas hydrates to dissociate into gas and fresh water. The drilling fluid can become highly gasified (gas cut mud). The gas hydrate adjacent to the wellbore wall will continue to dissociate and gasify the drilling fluid as long as the drilling fluid pressure and heat introduced into the formation by the drilling operation results in the gas hydrates remaining outside the stability zone. The gasification leads to lowering of the mud density i.e. reduction of the drilling fluid pressure which may cause wellbore instability and lead to hole enlargement and finally, wellbore collapse.

- When gas hydrates dissociate, the mechanical and physical properties of the sediments/formation will change. The change in material properties associated with dissociation includes increase in permeability, reduction in modulus and weakening of the cementation provided by the hydrates. This strength reduction in formation will also lead to wellbore instability.
- The initially mentioned changes in mud properties would also reduce the cleaning property of the mud and hence may result in a tight hole due to the weakness of the formation (as mentioned above). This could lead to packing off and stuck pipe.

CHAPTER III

DRILLING FLUIDS ADDITIVES AND CHARACTERISTICS FOR GAS HYDRATE APPLICATIONS

The most common method of combating gas hydrate formation is to design fluids which avoid the pressure and temperature conditions required for hydrate formation. This can be done by adding specially designed additives to drilling fluids with known characteristics in order to provide thermodynamic inhibition. As long as the fluid is used under the specified conditions of pressure and temperature, formation of gas hydrates should remain thermodynamically impossible or unlikely.

3.1 Selection Criteria for Drilling Fluids

The selection of a drilling fluid to suppress the formation of gas hydrates is specifically useful in areas where gas hydrates are likely to be formed. Most of the other requirements are more general and apply to various drilling operations. Here are some of the primary factors to be considered in the selection of a high performance fluid for ultimate performance during drilling:

- Wellbore stability
- Stuck pipe prevention
- Lost circulation mitigation and prevention
- Fluid and solids control management
- Environmental compliance
- Cost containment
- Waste management disposal
- Logging objectives
- Formation damage
- Gas hydrate suppression

Once a well is determined to be within the hydrate forming window, it is advisable to apply hydrate inhibitors/suppressors into the drilling fluid. It is also possible to drill to water depths of about 7500 ft without encountering gas hydrates or its problems. This can be attributed to any of the following reasons; small or no gas kicks, very short shut down periods, gas kick is of very low gravity gas (methane), effect of metastability, presence of inhibitor that have been unaccounted for and finally good well control procedures.

3.2 State of the Art Drilling Fluid Design

More deepwater wells are being drilling continuously in the industry and hence the need for more improved drilling fluids to handle the various conditions. Newly improved drilling fluids are designed to deal with the changing mud line temperatures being experienced in the various deepwater regions. For example the Norwegian deepwater has a mudline temperature of -2°C to -1°C[14] which requires drilling fluid that would prevent hydrate formation at this temperature and at the same time maintain most drilling fluid properties (density, cleaning ability). The current practice in the deepwater drilling industry to suppress hydrate formation temperature is by using saline drilling fluids which is made by addition of salts or NaCl. About 20-23 wt% NaCl/polymer drilling fluid systems are the most commonly used drilling fluids in deep water drilling[14]. Drilling with these systems has been successful in water depths up to 7500 ft (7503.28 ft), such wells have been drilled in the Gulf of Mexico. The depths for these wells range from 2000 ft – 7500 ft using mainly 20wt% NaCl and Partially Hydrolyzed polyacrylamide (PHPA) based drilling fluid. This has been found very useful in the Gulf of Mexico, but has not been too successful in the Norwegian deepwater due to the low temperature mudline. At extreme low mudline temperatures, thermodynamic inhibitors alone may be insufficient to deal with hydrate formation but the addition of both kinetic inhibitors and thermodynamic inhibitors in deepwater drilling fluid design may win the prize. Kinetic inhibitors are based on the effect of chemicals on the nucleation and growth of natural gas hydrates which are time dependent and stochastic processes.

The use of high performance drilling mud could be a very good way to avoid the formation of gas hydrates during drilling. As discussed earlier, the two documented problems encountered while drilling, through gas hydrates i.e. blocking of BOP stacks and choke and kill lines, could be avoided by using specially designed drilling fluids (e.g. synthetic based mud SBM or High Performance Water Based Mud, HPWBM). Gas migration in SBM is negligible, once the gas is absorbed or goes into solution, there would be effectively little or no migration. This reduces the effect of gas migrating to the BOPs or choke lines. The higher the drilling mud pressure, the more gas it would absorb. Hydrates suppression could be achieved by addition of certain salts such as calcium chloride or sodium chloride. Gas hydrate formation could also be suppressed by addition of specifically built glycol for hydrate suppression purposes.

3.2.1 Effect of Polar and Surface Active Additives on Hydrate Formation[14]

Alcohols and glycols are well known hydrate thermodynamic inhibitors. Surfactants and alcohol are known to decrease the surface tension of water. Lowering the surface tension of water, increased the rate of gas diffusion in the bulk water and hence and increase in hydrate formation. By dissolving the alcohols and glycols in aqueous solution, hydrogen bonds are formed with the water molecules making it difficult for the water molecules to migrate and bond with gas to form hydrates. On the contrary, the effect of addition of glycols and alcohols on the kinetics of hydrate formation is different. Results actually show that alcohols and glycols enhance the rate of hydrate formation.[14] One explanation for this result is that polar molecules act as templates for nucleation when they exist at low concentration. The presence of drilling fluid additives such as bentonite, barite, and lignite with their tremendous surface area could provide a surface by which gas molecules could be adsorbed. This behavior could cause the physical entrapment of gas in quantities larger than the amount of gas dissolved in water. The adsorbed gas which is dispersed within the bulk water with the solid particles is readily available for encapsulation in the hydrate structure.

3.2.2 Kinetic Inhibitors and Crystal Modifiers[14]

Kinetic inhibition of gas hydrates refers to the process by which the nucleation and growth of hydrate crystals are altered by using a low concentration of mostly polymeric and surfactant-based chemicals. The inhibitors may cause any of the following effects:

- delay the appearance of the critical nuclei (kinetic inhibitor)
- slow the rate of hydrate formation (crystal modifier)
- prevent the agglomeration process (crystal modifier)

These chemicals do not disrupt the thermodynamic equilibrium of the hydrates. The proposed mechanisms for the processes are surface adsorption on the face of the growing crystals and steric stabilization. Generally, these chemicals have hydrophilic groups in their structure which hydrogen bond to water molecules in the liquid water and/or the hydrate crystal. Working with a high salinity drilling fluid, as in deepwater, reduces the options in selecting a good kinetic inhibitor or crystal modifier. Another challenge with working with the kinetic inhibitor is their surface activity.

3.2.3 New Design for Hydrate Fluid Inhibition

In the search for an improved gas hydrate inhibitor for drilling fluid applications, characteristics that should be included are[15]

- Lowest possible density with maximum hydrate suppression
- Compatibility with most common drilling fluid components
- Compatibility with most salts to balance hydrates suppression and fluid density
- Provide shale inhibition for adequate borehole and drill cuttings stability

There have been two approaches to selection of additives for thermodynamic gas hydrate control in water based muds – salts such as sodium chloride, sodium bromide and calcium chloride or the addition of water soluble organics. Organic compounds such as alcohol and glycol have also been used for many years to control gas hydrate formation. However the use of organic compounds is not usually encouraged due to undesirable health hazards and unacceptable physical properties. Although glycol and polyglycol both possess good physical and environmental properties, their high density makes it difficult to achieve the low density design required for formation fracture gradients.[15] The introduction of the gas hydrate pill formation can also be considered a good way of reducing hydrate formation during drilling.[15] These gas hydrate “pills” are concentrated, highly-inhibitive formulations and can be placed in the BOP stack and choke and kill lines. The pills are utilized when a gas kick is encountered during a drilling operation or when the drilling location is abandoned during several hours due to adverse weather or technical faults. By placing the pills in the choke or kill lines or the BOP stack, the potential for gas hydrate formation is reduced. These fluid are usually formulated to be much more hydrate suppressive than drilling fluids.

3.3 Dissociation of Gas Hydrates and Entry of Gas into Drilling Fluids

The dissociation of gas hydrates during drilling could be as a result of either change in temperature or change in pressure. Two of the ways in which gas hydrates dissociate are explained below:

- When a well is drilled through a gas hydrate bearing formation, the hydrates are broken into pieces and carried up by drilling fluid. In the drilling fluid, the hydrates are likely to dissociate into gas and water because the temperature and pressure of the drilling fluid is outside the gas hydrate stability zone. The gas enters the drilling fluid and alters its rheology (viscosity, density, cleaning power and modulus). This could be very dangerous if not taken into consideration in the mud design phase.

- After drilling through a gas hydrate bearing zone, the hydrate at the front or at the edge of the hole are likely to start dissociating. This releases gas into the drilling mud flowing through the annulus. The rate of dissociation of the gas at the front of the hole is very important as it helps in calculating the amount of gas released into the mud. This can be used in designing the mud weight to keep the gas locked back in place until the casing is set.

Based on the depth of the hydrate bearing zone, the amount of hydrates drilled and carried up the annulus can be analyzed. The volume of gas and water that would be produced could be obtained from correlations[1]. The next part of this report would look at the dissociation at the drilling front in order to determine the rate of dissociation of hydrates at the drilling front and amount of gas released into the drilling fluid.

CHAPTER IV

DRILLING HYDRAULICS PROPERTIES/PARAMETERS

The process followed for this work is given below:

1. Study of gas hydrate properties and locations: This includes a literature survey of the various types of hydrates, possible resource potential and volume, places where cores have been recovered in order to determine the necessary in-situ properties of the hydrates and places where hydrates are possible to exist (this would assist in design or development of newer fields).
2. Understanding the dangers of gas hydrates with respect to drilling and environmental issues: This includes the various drilling problems possible offshore, most especially deep water drilling. Special focus is placed on problems caused by gas hydrate bearing formations both during drilling through such formations and drilling deeper below hydrates zone.
3. Selection of specific problems to be investigated based on industry problems and presently available solutions: The problems being faced by the industry while drilling in deep waters was analyzed and those specific to gas hydrates were singled out. Present solutions being implemented by the industry were noted and a look at a new solution to address some of the problems noted above.
4. Selection of drilling parameters to be analyzed: Although a number of drilling parameters affect the final outcome of a drilling job, 3 very important parameters

were selected and investigated in the course of this work. The 3 parameters include Rate of Penetration, Circulation Rate and Drilling fluid Weight.

5. Understanding and Discussion of results: A number of plots were generated based on the parameters investigated for selected gas hydrate zone properties. Although these properties are not universal, the process and relationship obtained in this work could be applied to various gas hydrate fields all over the world. Interpretation of the results in order to help solve part of the problems in the industry is finally presented.

4.1 Drilling Fluids

Drilling fluids are primarily used to keep the hole-open while drilling. They assist in transport of the cuttings from the drill bits to the surface. On a well control basis, the drilling fluid assists in maintaining hydrostatic pressure exerted by the earth on the bore hole. Some other notable functions of drilling fluids include cooling and lubrication of the drill string and bit, provide a wall cake (this could be both advantageous and disadvantageous), provide information about the well, prevent corrosion (instantaneous) and provide data transmission for MWD tools. There are 3 major types drilling fluids:

1. Gaseous Fluids such as compressed air, foam and nitrogen
2. Water Based Fluids, either fresh water based or salt water based
3. Oil Based Fluids such as oil based, diesel based, refined diesel oils or synthetic oil

4.1.1 Drilling Fluid Properties

There are some basic characteristics necessary for the design of a drilling fluid. Some of them include:

1. Density: The density of a drilling fluid is a measure of weight of the fluid with respect to a known volume. The weight of a drilling fluid is usually measured with the use of a mud balance. The unit of measurement for a drilling fluid is usually pounds per gallon (ppg).
2. Viscosity: This is a measure of the tendency of a fluid to flow. It can also be described as the measure of the thickness of a fluid. The dynamic property is due to the addition of inert solids (not reacting with water) to the drilling fluids compositions. Viscosity could be measured in two ways. Funnel viscosity is checked by using a Marsh Funnel and recording the time required for a quart of the fluid to flow through the funnel. It is only a relative measure of viscosity. The second means is by using a Rotational Viscometer and is normally performed by the mud engineer. This unit of measure for this “plastic viscosity” is centipoise.
3. Yield point: This is another dynamic property of drilling fluids. Usually performed by the mud engineer and its regarded as a measure of the dynamic surface tension of the mud. Unit of measurement is pounds per 100 square feet. Gel strength is relatively compared to the yield point but it measures the static surface tension of the mud or how well it can suspend solids when not in motion.
4. Gas Solubility in Oil Based Muds: Drilling muds/fluids use either water or oil as the primary liquid phase. When oil is used, special caution should be taken by the

crew members. There is always a possibility of gas solubility in oil based muds. Natural gas would mostly go into solution in oil based muds at the drilling depths where a gas zone is encountered. The inherent problem in this situation is noticed when the mud is being circulated to the surface. Very near to the surface, the gas is likely to reach the bubble point and there is a sudden release of gas from the mud. This gas flash would cause a drastic increase in the outflow of mud to the facility. In the case of specially designed mud, this could lead to a loss of huge volumes of muds and possible destruction of wellhead/surface equipments. A substantial loss of hydrostatic is also possible. This could enhance shallow water flows or shallow gas kick.

Some of the functions of the drilling fluid in a drilling job include removal of cuttings from the well, control formation pressures, maintaining wellbore stability and cooling, lubricating and supporting the drill bit during assembly. Some other notable functions include transmitting hydraulic energy to bit and tools, control corrosion (in some cases), facilitate cementing and completions and minimize the impact on the environment.

4.2 Rate of Penetration

The rate of penetration is the speed at which the drill bit can break the rock under it and thereby producing an increase in depth in the desired direction. It is usually recorded in feet per hour (ft/hr). The rate of penetration has a very profound effect on cost per foot drilled. Some of the most notable variables that affect the rate of penetration and presently being studied include

1. Bit type
2. Formation characteristics
3. Drilling fluid properties (circulation rate and density)
4. Bit operating conditions (bit weight and rotary speed)
5. Bit hydraulics (bit balling)

The rate of penetration can be expressed as a function of a number of parameters and has been defined by various equations.

The first of such equations is the Maurer equation[16] developed for rolling cutter bits rate of penetration with respect to bit weight, rotary size, bit size and rock strength. The assumptions made in this equation are:

- The crater volume is proportional to the square of the depth of cutter penetration.
- The depth of cutter penetration is inversely proportional to the rock strength.

$$R = \frac{k}{S^2}\left[\frac{w}{d_b} - \left(\frac{w}{d_b}\right)_t\right]^2 N \qquad 4.1$$

Where: k = Constant of proportionality

S = compressive strength of the rock(psi)

W = Bit weight(Ibf)

W= Threshold bit weight (Ibf)

d_b = Bit diameter(inches)

N = Rotary speed (rev/min)

The above relationship assumes perfect hole cleaning and incomplete bit tooth penetration. With respect to well control issues, the rate of drilled gas to volume of mud can also be calculated or correlated from the rate of penetration and other parameters. The equation below (4.2) is used to compute the amount of gas released in the case of drilled gas. The gas trapped in the formation that is actually drilled out and not the gas entering the mud from the surrounding formation. We would try to relate this with gas hydrate formation. The equation below[17] expresses the rate of penetration while drilling as a function of some other drilling parameters:

$$R = \frac{310 \quad r_m \, zT_d \, q_m}{d_b^2 \phi S_g \, P_d} \qquad 4.2$$

Where: R = Rate of penetration (ft/hr)

z = Compressibility factor

T_d = Temperature at hydrate depth (kelvin)

q_m = Circulation rate (gal/min)

φ = Porosity

S_g = Formation saturation

P_d = Pressure at hydrate depth (psi)

From the above equation, a direct relationship could be established between rate of penetration and circulation rate. The equation can be expressed in terms of gas/mud ratio (r_m).

$$r_m = \frac{R d_b^2 \phi S_g \, P_d}{310 \quad zT_d \, q_m} \qquad 4.3$$

At a fixed depth, the following properties can be regarded as a constant, the temperature of the formation, the pressure at that depth, the drill bit diameter, porosity and gas saturation. All these parameters are not controlled by the driller. In the above equation, the rate of penetration (R) and circulation rate (q_m) are the only 2 parameters that could be altered in order to adjust or control the amount of gas dissolved in the mud.

$$r_m \propto \frac{R}{q_m} \qquad 4.4$$

$$r_m = K' \frac{R}{q_m} \qquad 4.5$$

Where K' is a constant dependent on the depth of the formation.

4.3 Circulation Rate

The importance of the circulation rate can be related to the frictional pressure drop along the drill pipe. The circulation rate can also be seen to affect the formation fracture conditions. A very high circulation rate could be seen to cause fracture of the formation. On the contrary, if the circulation rate is too low, the cleaning effect of the drilling mud becomes an issue. A very low circulation rate with respect to the rate of penetration could finally lead to stuck pipe in the hole.

4.4 Depth of Gas Hydrate Sediments

Some of the dangers of drilling through gas hydrates to the drilling crew and facility can be directly related to the depth at which these hydrates are found. The installation of drilling and completion equipments is dependent on the present depth of the drilling process. The most commonly encountered gas hydrates are found at about 800 ft to 2000 ft below mudline. At this depth, usually most well control equipment such as blow out preventers, risers, choke and kill lines have not been installed. Hence the danger facing the drill rig is usually restricted to the well bore stability in the region that has been drilled and yet to be cased. These dangers could be as a result of gasification of the drilling mud, shallow gas or water flows, stuck pipe and dissociation of the surrounding formation gas hydrate. When the drill bits drill into the hydrates zone, hydrates are broken up and based on the temperature of the drilling mud, a dissociation of the hydrates is noticed. This dissociation produces water and gas which could be either dissolved in the drilling fluid or carried to the surface as gas pockets when using water based drilling fluids. In either case, the gas reduces the effective weight of the mud in maintaining the hydrostatic of the drilled zone.

When gas hydrates are encountered at much deeper depths as shown in figure 4.1 and table 4.1, the dangers are more pronounce. At depths of 3000ft, the blow out preventers (BOP) would likely have been installed. The choke and kill lines, risers and surface control equipments become more prone to destruction. The volume of hydrates drilled is proportional to the volume of gas produced and returned to the seafloor and surface. The gas volume impacts a huge strain on the well control equipments and should be minimized as much as possible.

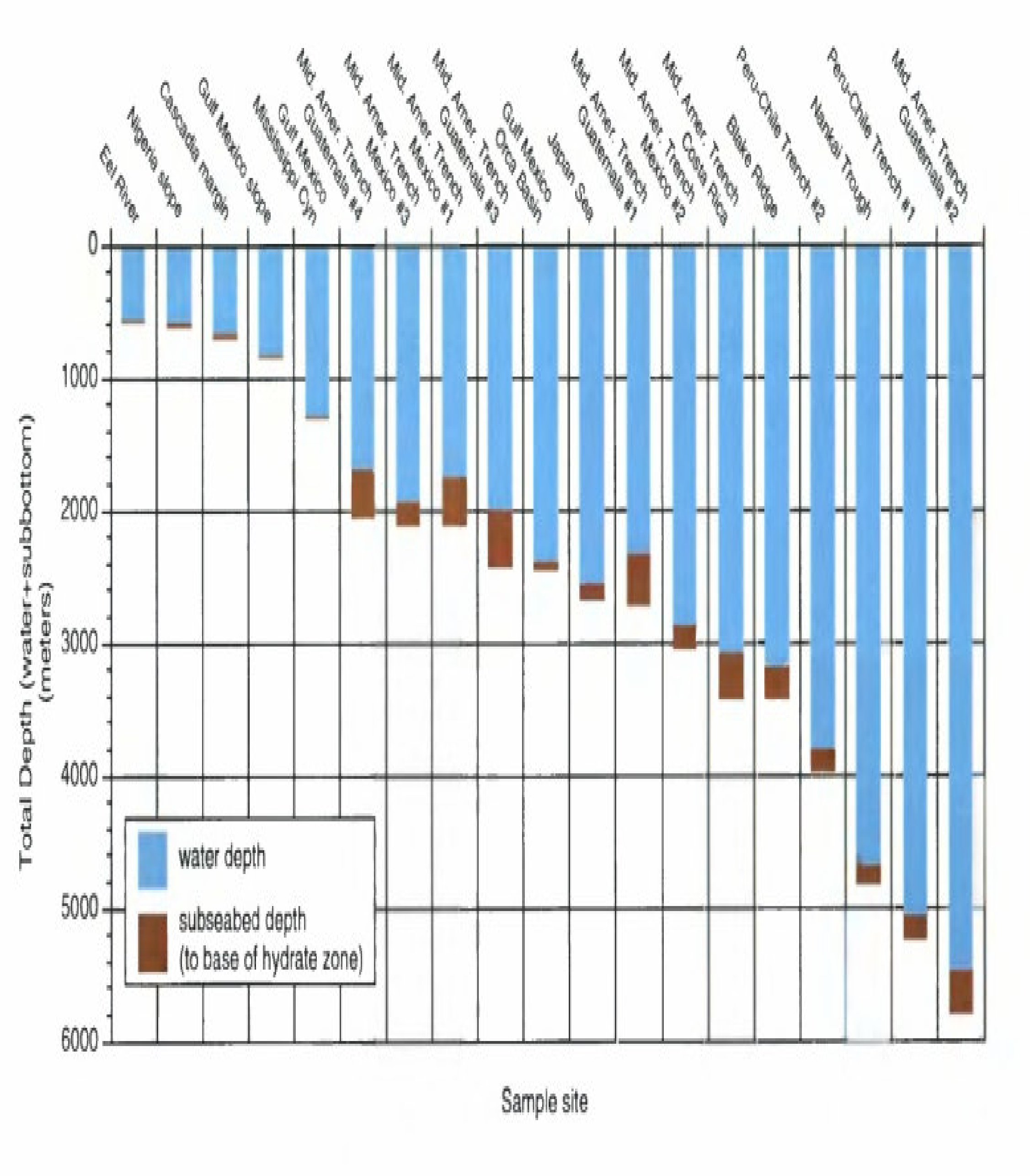


Fig. 4.1- Shows various locations of gas hydrate sediments around the world with the depth of gas hydrate zone with respect to water depth.[18]

The present drilling depth also influences the type of drilling fluid being used. At much shallower depth, water based drilling fluid is usually being used. This is because the returns are usually returned to the sea floor and for environmental reasons; they have to be marine life friendly. It is also important to mention that since the drilling fluid is not being reused, it is economically advantageous to use the relatively cheaper water based drilling fluids (sea water). Once the blow out preventers have been installed and the cuttings and mud are being returned to the surface via the riser, a much wider range and flexibility for the selection of drilling fluid is possible. Although more specially designed drilling fluids can be used, the Minerals Management Service (MMS) makes it mandatory that oil based drilling fluid should not be used while drilling offshore. This is mainly for environmental safety reasons. Due to the hazards of gas hydrates being formed along the various equipments, specially designed drilling fluids are being investigated. Presently, synthetic based drilling fluids are mostly used in offshore operations. According to the MMS, synthetic based drilling fluids are a relatively new class of drilling fluids that are particularly used for deepwater and deviated wells where there is a possibility of drilling through hydratable shales or temperature and pressure conditions of hydrates formations. Synthetic based drilling fluids were actually developed to combine the technical advantages of oil based drilling fluids with the low persistence and low toxicity of water based drilling fluids. It is produced by the dispersing salt brine in a synthetic phase to form an emulsion. The other additives include emulsifiers, barite, clay, lignite and lime. The type of emulsifiers usually distinguishes types of SBF from each other. The solubility of gases in SBF could also serve as a drilling danger. This could mask one of the most important kick detection process, increase in drilling mud return at the surface.

Table 4.1: Gas hydrate sample data from the GOM (characterizing natural gas hydrates in deep water Gulf of Mexico.[19]

CASE: Fresh Water in Pores, No Salt, Pure Methane Hydrate Assumed

Geothermal gradient (°C/100 meters)	Variable
Pore water salinity (wt %)	0

	Water Depth (feet)				
Hydrate Stability Zone Characteristics	**2000'**	**3000'**	**4000'**	**6000'**	**8000'**
Thickness (mbsf)	154	452.5	693	1140	1602
Thickness (ft below seafloor)	505	1485	2274	3740	5256
Hydrostatic pressure @ seafloor					
$P_{seafloor}$ (psi)	907	1353	1800	2691	3584
$T_{seafloor}$ (°C)	6.3	4.9	4.2	3.3	2.7
Hydrostatic pressure @ BHSZ					
P_{BHSZ} (psi)	1123	2009	2810	4363	5938
T_{BHSZ} (°C)	10.4	15.3	18.1	21.8	24.4
Average hydrostatic HSZ Pressure (psi)	1015	1681	2305	3527	4761
Average HSZ Temperature (°C)	8.4	10.1	11.2	12.6	13.6

For 2000 feet WD	2.68	°C/100 meters
For 3000 feet WD	2.29	°C/100 meters
For 4000 feet WD	2.02	°C/100 meters
For 6000 feet WD	1.63	°C/100 meters
For 8000 feet WD	1.35	°C/100 meters

4.5 Drilling Hydraulics

In many drilling and completion operations, gas is usually introduced into the wellbore either as a form of drilled gas, formation gas (kick) or from the surface. The variation of pressure with depth in a static gas column is more complicated than in a static liquid column. This is because the density of gas changes with pressure. The gas behavior in a well can be explained using the real gas equation:

$$pV = znRT \tag{4.6}$$

Where: P = absolute pressure

V= gas volume

n= moles of gas

R= Universal gas constant

T= absolute temperature

z= gas deviation factor

The gas deviation factor is a measure how much the gas behavior deviates from ideal gas. The equation 4.6 above could be rearranged in order to obtain the density of the gas at various pressures and temperature conditions. This is given by:

$$\rho = \frac{pM}{zRT} \tag{4.7}$$

Changing consistent units to field units gives:

$$\rho = \frac{pM}{80.3zT} \qquad 4.8$$

Where: ρ = density (ppg)

p = pressure (psi)

M = gas molecular weight

T = temperature (Rankine)

When the gas column is much larger or not highly pressured, then the depth of the column should be taken into consideration when computing the density. The following equation relates the change in depth with change in pressure.

$$dp = \frac{0.052\ pM}{80.3zT}dD \qquad 4.9$$

Where dD and dp are changes in depth and pressure respectively.

Assuming the variation of z is not too great, we can treat z as a constant. Separating variables and solving yields the following equation:

$$p = p_o e^{\frac{M(D-D_o)}{1544\ zT}} \qquad 4.10$$

During drilling operations, the mud density could be altered due to the mixing of drilled cuttings, formation fluids and drilled gas. The average density of an ideal mixture of several components is given by:

$$\rho = \frac{\sum_{i=1}^{n} m_i}{\sum_{i=1}^{n} V_i} = \frac{\sum_{i=1}^{n} \rho_i V_i}{\sum_{i=1}^{n} V_i} = \sum_{i=1}^{n} \rho_i f_i \qquad 4.11$$

The above equation is used only if one gas is present in the mixture

Where: m_i = mass of component

V_i = volume of component

ρ_i= density of component

f_i = volume fraction of component

$$f_i = \frac{\frac{zN_v RT}{p}}{1 + \frac{zN_v RT}{p}} \qquad 4.12$$

The volume fraction becomes important when a gas phase is involved. For solids and liquids, the volume component is constant throughout the mixture. When a gas phase is involved, the depth affects the density which affects the volumes of gas present. The impact becomes very huge at depth very close to the surface, where the pressure is very low and so the gas volume is much higher based on equation 4.4. The impact of the gas on the mud is quite significant at depths closer to the surface. The density of the mud is greatly reduced as the depths get closer to the surface. The density of the mud returned to the surface cannot be used to compute the necessary equivalent mud needed to stop or address a kick. This could easily lead to fracture of the formation downhole.

For the above equations, the z factor was computed using the Dranchuk and Abou-Kassem numerical model with various coefficients to fit the Standing and Katz data. The equation is given by:

$$z = 1 + C_1(T_{pr})\rho_r + C_2(T_{pr})\rho_r^2 - C_3(T_{pr})\rho_r^5 + C_4(\rho_r, T_{pr}) \qquad 4.13$$

The "reduced" density term ρ_r is obtained from the expression:

$$\rho_r = \frac{0.27\, p_{pr}}{zT_{pr}} \qquad 4.14$$

The other coefficients of C(T,P) in the equation 4.13 are given by:

$$\begin{aligned}
C_1(T_{pr}) &= 0.3265 - 1.07/T_{pr} - 0.5339/T_{pr}^3 \\
&+ 0.01569/T_{pr}^4 - 0.05165/T_{pr}^5 \\
C_2(T_{pr}) &= 0.5475 - 0.7361/T_{pr} + 0.1844/T_{pr}^2 \\
C_3(T_{pr}) &= 0.1056(-0.7361/T_{pr} + 0.1844/T_{pr}^2) \\
C_4(T_{pr}, \rho_r) &= 0.6134(1 + 0.721\rho_r^2)(\rho_r^2/T_{pr}^3) \\
&\exp(-0.721\rho_r^2)
\end{aligned} \qquad 4.15$$

Solving the Dranchuk and Abou-Kassem relation is an iterative process since the z-factor depends on functions that contain the term. The Newton-Raphson iteration technique has the form:

$$z_{i+1} = z_i - f(z)/f'(z) \qquad 4.16$$

Where f(z) is a function of z and f'(z) is the first derivative of that function. The function for the z factor is obtained from the following equation:

$$f(z) = z - \begin{bmatrix} 1 + C_1(T_{pr})\rho_r + C_2(T_{pr})\rho_r^2 \\ - C_3(T_{pr})\rho_r^5 + C_4(\rho_r, T_{pr}) \end{bmatrix} = 0 \qquad 4.17$$

And the derivative f'(z) is given by:

$$f'(z) = \frac{\partial f(z)}{\partial z} = 1 + C_1(T_{pr})\rho_r / z + 2C_2(T_{pr})\rho_r^2 / z$$
$$- 5C_3(T_{pr})\rho_r^5 / z + \frac{1.2268\ \rho_r^2}{T_{pr}^3 z}\left[1 + 0.721\ \rho_r^2 - (0.721\ \rho_r^2)\right] \qquad 4.18$$
$$\exp(-0.721\ \rho_r^3)$$

CHAPTER V

RESULTS AND DISCUSSION

In order to suggest a solution to the problems or dangers encountered while drilling through gas hydrates, a graphical representation and analysis of the various parameters mentioned earlier have been presented. When engineers drill through gas bearing formations, the gas enters into the mud. This gas is known as drilled gas. In the same way, the gas dissociated from hydrates zone was treated as drilled gas for the purpose of this work. This assumption neglects the continuous dissociation of the surrounding gas hydrates due to change in stability conditions of the hydrate zone in the calculations done. Figure 5.1 shows a direct relationship between rate of penetration and volume of gas dissociated at the drill bits. The graph is linear for the selected data from appendix A. It can also be assumed that if the dissociation occurs at the fronts of the hydrate zone downhole, then the relationship would still remain linear with an increase in the volume of gas produced downhole.

Based on the drilling fluid employed or rather based on the depth at which the gas hydrates are encountered, the effect of the gas expansion is analyzed. Fig 5.2 shows the expansion of the gas from downhole (at the drill bits) to the seafloor. The impact at the seafloor could be more significant when drilling in deeper water or through much deeper hydrates zones. In the case where BOPs have been installed, then the impact on the BOPs could be worth noting. The expansion noted in Fig 5.2 is relatively uniform for each rate of penetration. This gives an idea of how much gas volume is released based on the rate of penetration selected. Although selecting a much smaller rate of penetration would apparently results in lesser gas volumes and impact at the seafloor, the cost of drilling at a much slower rate might ruin the idea. This led to the idea of selecting an optimum drilling rate or rate of penetration based on a couple of other important factors that would be discussed later. The values used in the calculation to generate the graph below are given in appendix B. The gas volume is based on a specific height of formation specified in the appendix.

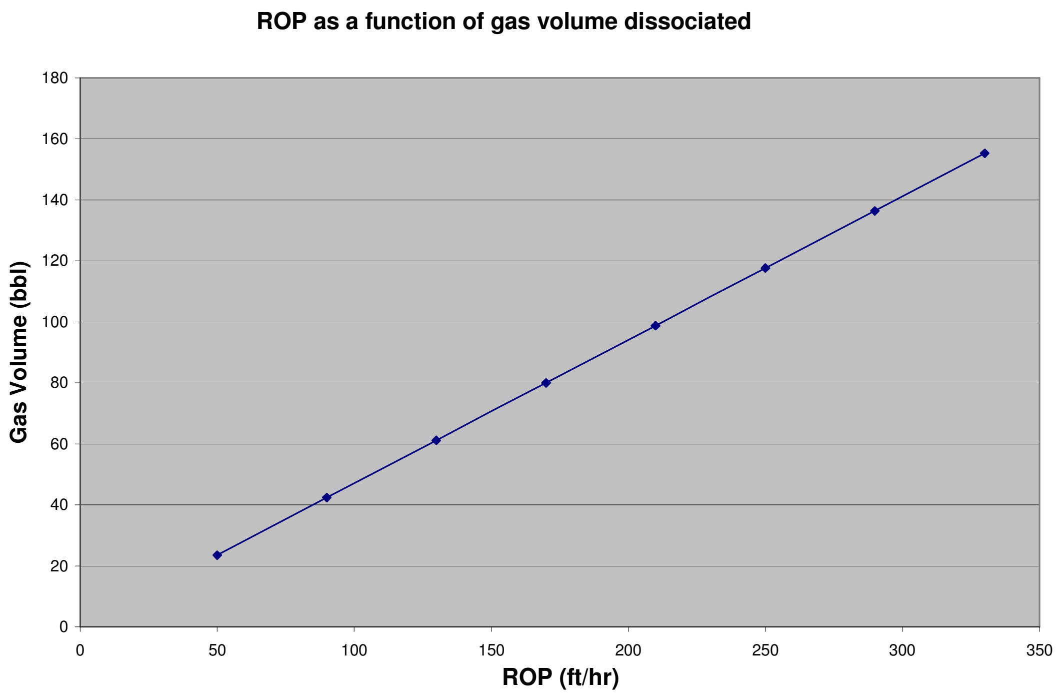


Fig. 5.1- Prediction of hydrate gas volume shows a linear relationship with rate of penetration.

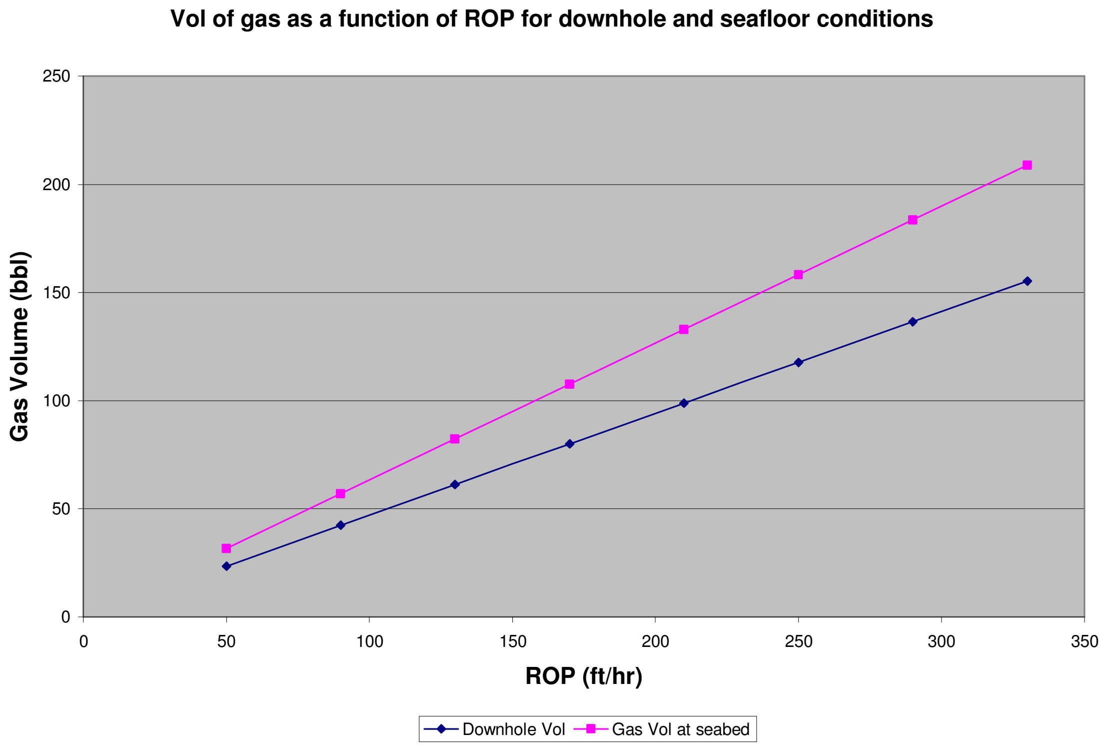


Fig. 5.2- Prediction of gas volume as a function of ROP for both downhole and seabed conditions.

It is general knowledge that the volume of gas being held in gas hydrates is enormous. This gas is compressed at high pressure and low temperatures to form hydrates. In the form of hydrates, huge volumes of gas occupy relatively very small space. Once drilled, the change in temperature and pressure are kept or maintained outside the hydrates forming zone, the expansion is continuous from downhole to surface or standard temperature and pressure conditions. As discussed earlier, while drilling with a synthetic based mud, there is a very good possibility of gas dissolving in the mud. The dissolved gas reduces the ability of the drilling engineer to recognize the event of a "kick" (entry of gas into the well in this case). This gas travels with the mud and based on the composition and conditions of the mud, could be released at bubble point close to the surface.

Fig 5.3 shows a relationship between the gas volume at downhole, at seafloor (or BOPs) and at the surface. The volume is given in barrels in order to show how much drilling fluid could be suddenly or unexpectedly ejected to the seafloor due to expansion of the gas.

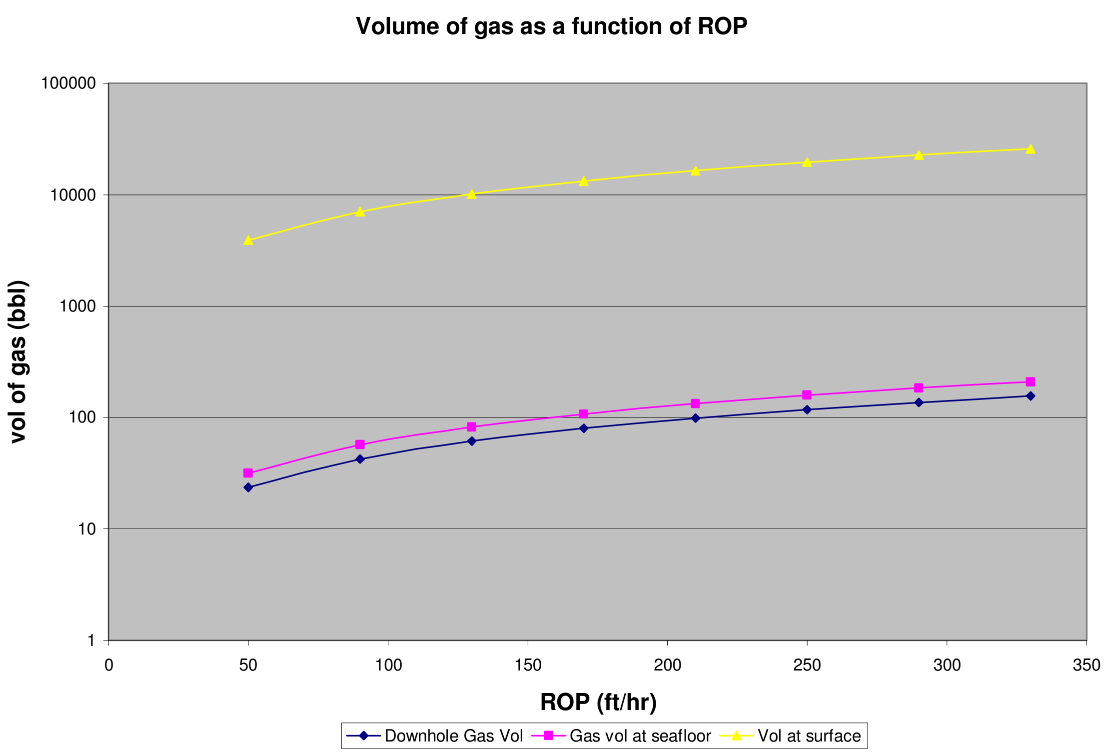


Fig. 5.3- Prediction of variation of volume of gas with ROP for downhole, seafloor and surface conditions.

The volume of gas evolved at the surface is about a 100 times or actually 170 times the volume of gas at downhole conditions. This produces a more hazardous situation at the surface if proper care is not taken when drilling into gas hydrate formations. Figure 5.3 is plotted on a semi log axis. This was the only way to show the volumes on the same graph without having the volume of gas downhole and at seafloor appear completely negligible on the same graph. Since the problem of uncontrolled drilling has been apparent in fig 5.1-5.3, the next step would be to embark on a way to avoid or alleviate these problems. The factor being considered in order to assist in selecting an optimum rate of penetration would be the drilling fluid circulating rate with the mud density serving as a control for the research. The mud density serves a very important role in the stability of the wellbore. Hence the mud density would be used as a check in order to ensure safety while trying to design an optimum drilling design.

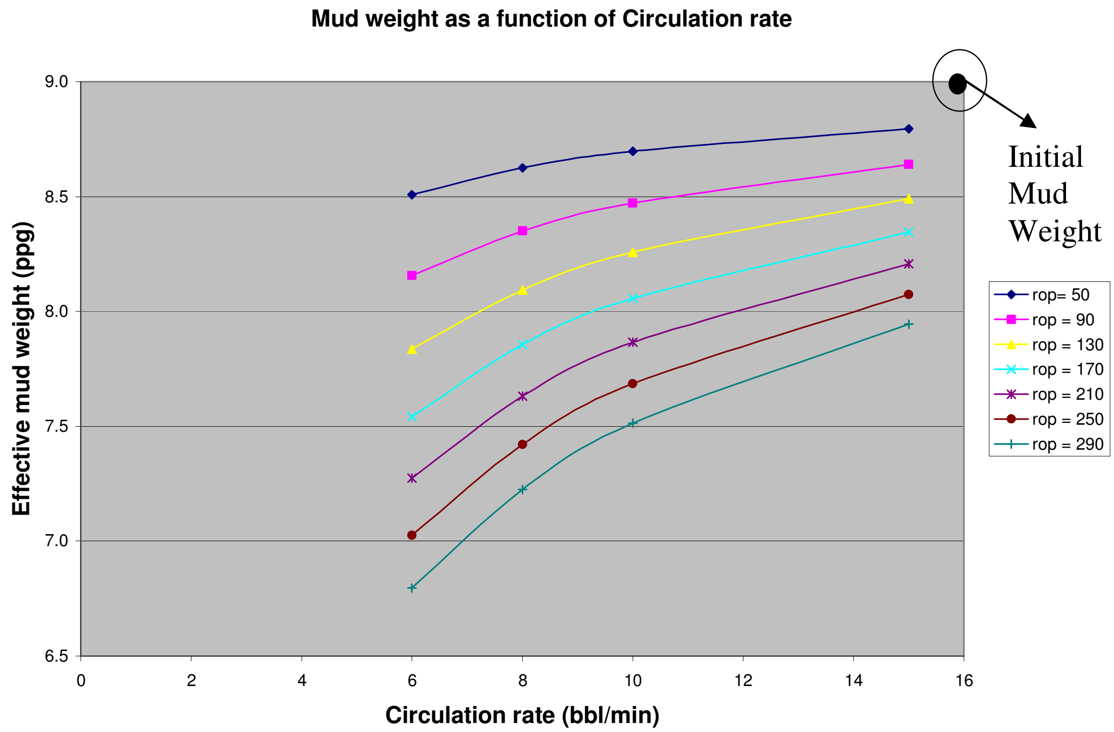


Fig. 5.4- Prediction of mud weight as a function of circulation rate for various ROP.

Fig 5.4 shows the mud weight as a function of circulation rate for various rate of penetration. The circulation rate is seen to affect the mud weight for various rate of penetration selected. The black dot on fig 5.4 shows the initial mud density before the hydrate zone is drilling into. Once the hydrate zone is drilled, the mud density changes as expected due to gasification of the mud. It can be seen from fig 5.4 that the closest point to the black dot would be at very low rate of penetrations and at very high circulation rate. The unit for circulation rates used in this work is barrels per min. Special care should be taken while selecting the circulation rate in order to ensure proper and efficient transport of cuttings to the surface avoid fracturing of the surrounding formation and minimize pressure loss due to frictional pressure drop within the drill string. The worst case scenario would be drilling at a very high rate of penetration and circulating at the minimal rate of 6 barrels per minute. Since the goal of this work is to select or suggest an optimal drilling rate of penetration and circulation rate in order to minimize the hazards of drilling through gas hydrates, then we need to analyze or understand how the 2 parameters could be linked properly.

Based on the assumed values from appendix A, a random selection was made from the ranges presented. This serves as a control to compare the danger if the extreme condition is not taken into account. Table 5.1 shows the effect of various circulation rates and rate of penetration on the effective mud density for the random (not extreme case) selection of values.

Table 5.1: Change in effective mud weight as a function of rate of penetration and circulation rate for randomly selected hydrates properties.

	ROP (ft/hr)	**50**	**90**	**130**	**170**	**210**	**250**	**290**	**330**
Cir Rate (bbl/min)	Mud weight	ppg							
15	9	8.92	8.85	8.79	8.73	8.66	8.60	8.54	8.48
10	9	8.88	8.78	8.69	8.60	8.51	8.42	8.33	8.25
8	9	8.85	8.73	8.61	8.50	8.39	8.29	8.19	8.09
6	9	8.80	8.64	8.49	8.35	8.21	8.08	7.95	7.83

The yellow part of the table represents the region where the density of the mud is acceptable. The grey part represents the area where the density of mud could lead to a possibility of formation fluid flowing back in the well. The red zone actually shows the region where the mud weight has dropped well below the equivalent mud weight required to keep the well from flowing. Table 5.1 shows the extreme conditions. This table shows the variation of mud weight with rate of penetration and circulation rates. It assumes we are dealing with a massive gas hydrate sediments with porosity and saturation of the gas hydrates being equal to 1(maximum). The difference in the two is the number of possible rate of penetration at specific circulation rates that could cause the well to flow or collapse. For table 5.1, at 15bbl/min, it is possible to drill at any of the rate of penetration investigated and still be within the accepted range. At the extreme case in table 5.2, at 15bbl/min, it is not wise to drill at rate of penetration higher that 210ft/hr. These two tables show the effect of adequately understanding the properties and composition of an hydrate formation before embarking on a drilling process or even a design process. Since the well is usually still about a few hundred feet below the mudline, the effect of these alteration in mud density might not be too severe. At deeper water depths and high temperature hydrates, the alteration in mud density could be very disastrous both to the rig personal and environmentally.

Table 5.2: Change in effective mud weight as a function of rate of penetration and circulation rate for extreme case of selected hydrate properties.

	ROP (ft/hr)	**50**	**90**	**130**	**170**	**210**	**250**	**290**	**330**
Cir Rate (bbl/min)	**Mud Weight**	**ppg**							
15	9	8.80	8.64	8.49	8.35	8.21	8.07	7.94	7.82
10	9	8.70	8.47	8.26	8.06	7.87	7.69	7.51	7.35
8	9	8.63	8.35	8.09	7.85	7.63	7.42	7.23	7.04
6	9	8.51	8.16	7.84	7.54	7.27	7.03	6.80	6.58

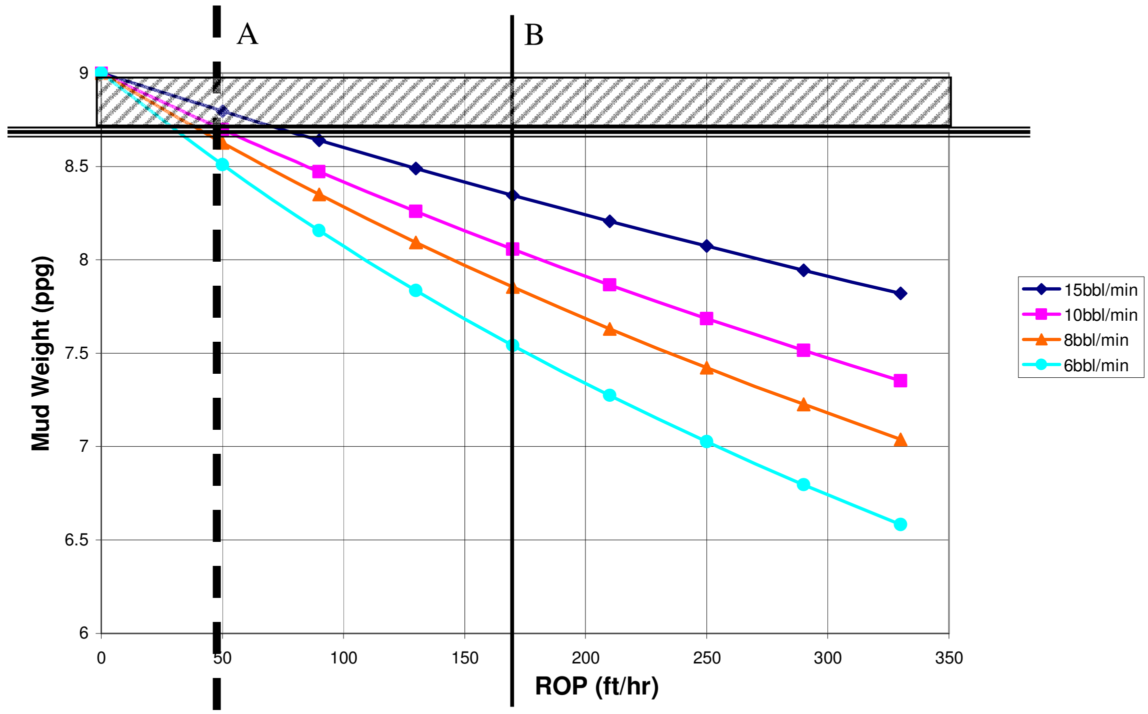


Fig. 5.5- Prediction of variation of mud weight with rate of penetration and circulation rate.

Fig 5.5 shows the variation of mud weight with ROP at various circulation rates. The graph would not make much sense without a basis for judgment. The basis for judgment in the above graph would be the fracture gradient and the formation pressure. One of the most important goals in a normal drilling operation is to keep the mud weight between the fracture pressure and formation pressure. The exception to this rule would be in the case where it is desired to drill underbalanced depending on the knowledge, history and goals of the formation. In order to relate the 3 parameters, a suitable hydrostatic gradient is selected based on history, cores or knowledge of formation. This hydrostatic gradient is used in computing the required mud weight in order to keep the formation safe. The required mud weight is shown on fig 5.5 with the horizontal dark colored double line. In this case 8.72ppg is selected. The goal of the drilling team is to drill and make sure the mud weight is always above 8.72ppg knowing very well it would never exceed 9ppg due to the dissolution of the gas in the drill mud. According the graph, only the shaded part of fig 5.5 matches this criterion hence the other 2 parameters must be selected to match or fall within this area. This leaves us with only very few possible rates of penetration and circulation rates for this particular example. The maximum possible ROP would be about 70 ft/hr for the circulation rates investigated in this work or in order to circulate at 15bbl/min. Since the ROP of penetration is directly related to drilling time which constitutes a major cost of an offshore well, it is important to try to maximize the ROP while keeping all other parameters within the safety limit of the rig, its personnel and the environment in general.

Line A in fig 5.5 shows the maximum possible circulation rate and rate of penetration for the equivalent mud weight selected (8.72ppg). At a rate of penetration of 60 ft/hr and circulation rate of 15bbl/min, the required mud weight could be achieved. Line B shows the expected equivalent mud weight based on a randomly selected rate of penetration. It can be seen from fig 5.5 that at a rate of penetration of 180ft/hr (line B), the required mud weight could not be achieved at any of the circulation rate tested. A reduction in either the rate of penetration or circulation rate, while keeping the other parameter constant actually helps in increasing the mud weight.

CHAPTER VI

CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions

Gas hydrates are crystalline or ice-like structures made up of water lattice and guest gases. These crystalline structures are part of a group called clathrate. The formation and stability of gas hydrates is favored at high pressure and low temperature. The gases that combine with water to form hydrates include light alkanes (methane and iso-butane), carbon dioxide, hydrogen sulfide, nitrogen, oxygen and argon. These conditions and availability of gases are most common in deep offshore areas or permafrost regions. Gas hydrates are usually a few hundred meters below the mudline but could extend a thousand meters in depth. A very important property of hydrates is the amount of natural gas that can be held in the lattice structure. $1ft^3$ of gas hydrate could hold as much as $170ft^3$ of gas.

Based on the increasing need for energy, more wells are being drilled in areas of deeper waters. These areas have provided cores which indicate the presence of gas hydrate. The need to study and understand the properties of gas hydrate lies in a number of factors. Gas hydrates contain an enormous amount of energy which is anticipated to provide alternative sources of energy in the near future. The presence of gas hydrate in deeper offshore areas emphasizes the need to deal with them as we try to harness the hydrocarbon found beneath these hydrate zones. Recently, the effect of gas hydrate on the environment and most specially on global warming has also brought the topic more research consideration.

The industry solution has always been to avoid gas hydrate bearing zones while drilling. This is in a bid to avoid the dangers associated with drilling through these formations. Some of the notable problems include wellbore stability, gas cut mud, and seafloor stability amongst others. Based on this research, we have been able to suggest some possible ways of drilling through gas hydrate formations and avoiding some of the afore-mentioned problems. Using the rate of penetration, circulation rate and effective mud weight as a basis, various relationships were observed between the 3 parameters mentioned. More parameters could be included in this analysis in order to improve the effectiveness of the process or help modify the results obtained. Such parameters would include drilling bit temperature, gas hydrate dissociation at the front of the well and drilling mud composition and property. The cost of operating an offshore rig is very high and so there is little or no room for errors. This further emphasizes the need to completely understand the behavior and dangers associated with drilling through gas hydrate formations. The depths at which the gas hydrate are encountered greatly affect the type of drilling fluid to be used in drilling. Either the water based drilling fluid or the synthetic based drilling fluid is used. Oil based fluid have been banned in most deep water operations for safety reasons.

The rate of penetration in deep offshore wells greatly affects the total cost of a drilling operation, hence the need to select an optimum and safe drilling rate. The rate of penetration into a gas hydrate bearing formation is directly proportional to the amount of gas produced (which can also be referred to as drilled gas). This amount of gas produced per hour is a function of the height of formation drilled which is used in the computation of the volume of gas.

The expansion of the gas based on temperature and pressure conditions from downhole to seafloor and possibly surface facility, is significant. The amount of gas produced due to dissociation of drilled hydrates at the bits is directly proportional to the volumetric expansion of the gas as it moves up the annulus unto the seafloor or to the surface. The lesser the volume of gas, the easier and less dangerous it is for the entire drill team. A lower volume of gas actually puts less stress on the wellhead or sub sea equipment.

The effect of the drilling fluid/mud circulation rate is felt in many stages of a drilling operation. The circulation rate plays an important role in hole cleaning, frictional pressure drop and in maintaining wellbore stability as seen in fig 5.4 and 5.5. As the rate of penetration increases, for a specific circulation rate, more gas is produced and hence the effective density of the mud is reduced. An economic and safety compromise could be reached between the rate of penetration and circulation rate in order to achieve a desired drilling fluid density. Based on the work done, it can be concluded that it is safer to select the circulation rate first before the rate of penetration. By selecting the circulation rate, based on the bottom hole pressure required, we can then set the rate of penetration to the maximum safety level based on the calculated hydrostatics of the annulus. This process allows us drill at the maximum possible rate of penetration having taken into control the effect of circulation rate and expected mud. From the results presented in the chapter V, by selecting 15bbl/min as the circulation rate (this does not cause downhole damage based on calculations carried out), the maximum drilling rate to keep the mud density within an acceptable limit would be 75ft/hr. Initially, the well might have been moved in order to avoid the problems associated with the hydrates zone, but with these type of analyses and calculations could shed more light on using the controllable drilling parameters to deal with the anticipated problems.

6.2 Recommendations and Future Work

Based on the results and conclusions, a better understanding of the properties of gas hydrates mixed with the available state of the art technology and knowledge of drilling, could help solve some or most of the problems associated with drilling through gas hydrate.

In future, a well documented core analysis from a known hydrate zone would surely provide more accurate results. It could improve the accuracy of analyzing the dangers attached to a particular field knowing very well that the dangers range from place to place based on the types and structure of hydrates present or recovered in that area.

The drill bit temperature has not been really included in the course of this work. We have assumed instantaneous dissociation of the hydrates while drilling. Future work should verify the dissociation rate of the drilled hydrates as that would affect the amount of gas entering the drilling mud.

Finally, more work is needed in understanding the effect of dissociation of the gas hydrate at the front or the edges of the drilled wellbore. This dissociation could worsen the hydrostatic effect on the wellbore by adding more gas to the drilling fluid or could actually lead to seafloor instability based on the temperature of the mud and drilling bit temperature. It is very likely that the continuous understanding of gas hydrate from a drilling perspective could actually improve the success in producing the enormous resource trapped in these formations.

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APPENDIX A

NOMENCLATURE

k = Constant of proportionality

S = compressive strength of the rock (psi)

W = Bit weight (Ibf)

W_0= Threshold bit weight (Ibf)

d_b = Bit diameter (in)

N = Rotary speed (rev/min)

R = Rate of penetration (ft/hr)

z = Compressibility factor

T_d = Temperature at hydrate depth (K)

q_m = Circulation rate (gal/min)

φ = Porosity

S_g = Formation saturation

P_d = Pressure at hydrate depth (psi)

K'= Constant dependent on depth of the formation

P = pressure (psi)

V= gas volume (cubic feet)

n= moles of gas

R= Universal gas constant

T= absolute temperature (K)

m_i = mass of component (Ibm)

V_i = volume of component (gal)

ρ_i= density of component (Ibm/gal)

f_i = volume fraction of component

BOP = Blow Out Preventer

ROV = Remote Operated Vehicle

TCRT = Tree Cap Return Tool

SGN = Self Generated Nitrogen

BHT = Bottom Hole Temperature

DWC = Drilling With Casing

BSR = Bottom Simulating Reflector

SBM = Synthetic Based Mud

HPWBM = High Performance Water Based Mud

SSSV = Sub Surface Safety Valve

MPD = Managed Pressure Drilling

APPENDIX B

Gas Hydrates at 3000ft of water

Description	Values	Units	Range
Diameter of hole	24	Inches	+/-6
Height of formation	50	Ft	+/-40
Density of hydrate	913	kg/m^3	+/-30
Molecular weight of hydrate	125.7		
Molecular weight of hydrate gas	17.74		
no of moles of H_2O per mole of gas	6		
molecular weight of H_2O	18		
Specific grav of gas	0.6		
Gas Constant ®	80.28		
Amount of gas in 1ft^3 of Hydrate at STP	170	ft^3	

STP Conditions		
Pressure	14.7	Psi
Temp	520	R
Z factor	1	
Seafloor		
Pressure	1353	Psi
Temp	500.4	R
Z factor	0.763	
Bottom Hole Conditions		
Hydrate location below mudline	850	Ft
Pore pressure gradient	0.465	psi/ft
Water gradient	0.447	psi/ft

Water depth	3000	Ft	
Temperature of hydrate downhole	510	R	
Pressure of hydrate downhole	1736	Psi	
Z factor	0.751		

Amount of possible hydrates, gas and water in a zone (A) as a fraction of total volume(Saturation)	1	0
Fraction of solid hydrates in A above (Porosity)	1	0

APPENDIX C

Gas hydrates at 6000ft of water

Description	Values	Units	Range
STP Conditions			
Pressure	14.7	psi	
Temp	520	R	
Z factor	1		
Seafloor			
Pressure	2682	psi	2691
Temp	498	R	
Z factor	0.763		
Bottom Hole Conditions			
Hydrate location below mudline	850	ft	
Pore pressure gradient	0.465	psi/ft	
Water gradient	0.447	psi/ft	
Water depth	6000	ft	
Temperature of hydrate downhole	510	R	
Pressure of hydrate downhole	3077	psi	
Z factor	0.751		

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