EVALUATION OF LIQUID LIFT APPROACH TO DUAL GRADIENT DRILLING

A Thesis

by

UGOCHUKWU NNAMDI OKAFOR

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

December 2007

Major Subject: Petroleum Engineering

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Approved by:

Chair of Committee,	Hans C. Juvkam-Wold
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ABSTRACT

Evaluation of Liquid Lift Approach to Dual Gradient Drilling. (December 2007)

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Chair of Advisory Committee: Dr. Hans C. Juvkam-Wold

In the past, the oil and gas industry has typically used the single gradient system to drill wells offshore. With this system the bottom hole pressure was controlled by a mud column extending from the drilling rig to the bottom of the wellbore. This mud column was used to achieve the required bottom hole pressure. But, as the demand for oil and gas increased, the industry started exploring for oil and gas in deep waters. Because of the narrow margin between the pore and fracture pressures it is somewhat difficult to reach total depth with the single gradient system. This led to the invention of the dual gradient system. In the dual gradient method, heavy density fluid runs from the bottom hole to the mudline and a low density fluid from the mudline to the rig floor so as to maintain the bottom hole pressure. Several methods have been developed to achieve the dual gradient drilling principle.

For this research project, we paid more attention to the liquid lift, dual gradient drilling (riser dilution method). This method of achieving dual gradient drilling was somewhat different from the others, because it does not utilize elaborate equipment and no major changes are made on the existing drilling rigs.

In this thesis the technical feasibility of using the liquid lift method over the other methods of achieving dual gradient drilling was determined. A computer program was developed to simulate the wellbore hydraulics under static and dynamic conditions, injection rate and base fluid density required to dilute the riser fluid and finally, u-tubing phenomena.

In this thesis we also identified some problems associated with the liquid lift method and recommendations were made on how these problems can be eliminated or reduced. Emphases were placed on the effect of u-tubing, injection rate of base fluid at the bottom of the riser and well control issues facing this system.

DEDICATION

I would like to dedicate this work to God for his blessing and to my mother and father for their love, support and encouragement.

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I wish to express my profound gratitude to Dr. Hans Juvkam-Wold for his guidance and support in the completion of my M.S. thesis and throughout my education at Texas A&M University.

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Thanks to my family for their support and encouragement.

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CHAPTER I

INTRODUCTION

As the demand for oil and gas increases, in response to the ever increasing demand of countries like China and India, more deposits of oil and gas must be explored in order to meet demand. One potential area would be the deep waters of the U.S Gulf of Mexico. Recently, the number of lease sales in this area shows that there is a great potential for more discovery of petroleum products. But, one of the major challenges is the narrow margin between the pore pressure gradient and the fracture pressure gradient. For successful oil and gas exploration to take place in this area, new drilling methods must be developed to safely and successfully carry out drilling operations in deep waters. This method must be able to address the issue of narrow margin between the pore and fracture pressure gradients (pore pressure is the pressure of the fluid within the formation and fracture pressure is the pressure, a formation can withstand before fracture occurs) that exist in deep waters.[1]

Prior to the introduction of dual gradient drilling in deep waters, the industry was only familiar with the conventional method of drilling, known as single gradient drilling.[1] The use of the conventional drilling method posed a lot of difficulties in deep waters.

This thesis follows the style and format of the *Journal of Petroleum Technology*.

This method could not address the problem related to the narrow margin between pore and fracture pressure gradients. [2-3] **Fig 1.1** is a graphical representation of the margin between the pore and fracture gradients using the conventional methods.

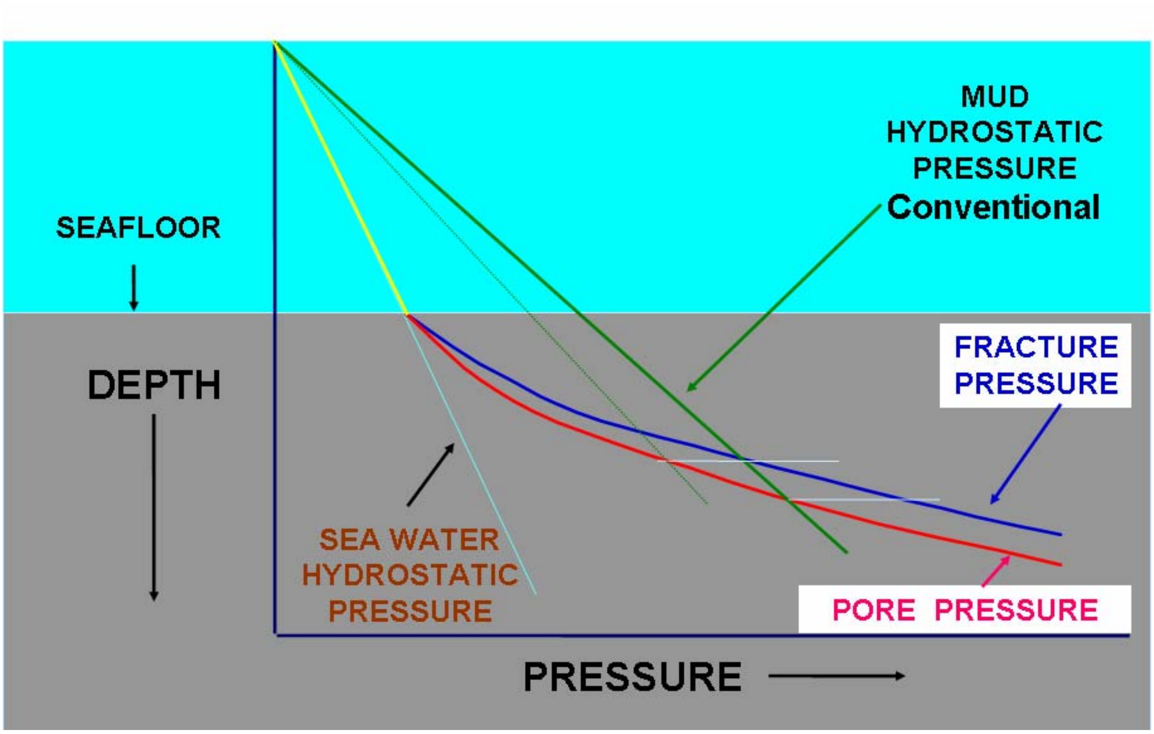

Fig 1.1— Wellbore pressure profile in the conventional drilling method.[2]

As depicted in **Figure 1.1** a single mud column is used to maintain the bottom hole pressure. This same bottom hole pressure can be achieved by using a combination of two different mud columns. This method (dual gradient drilling) addresses the narrow margin issue between the pore and fracture pressure gradients. **Figure 1.2** is a graphical representation comparing the margins between the pore and fracture pressure gradients when using the conventional drilling method or the dual gradient drilling (DGD) method.[2]

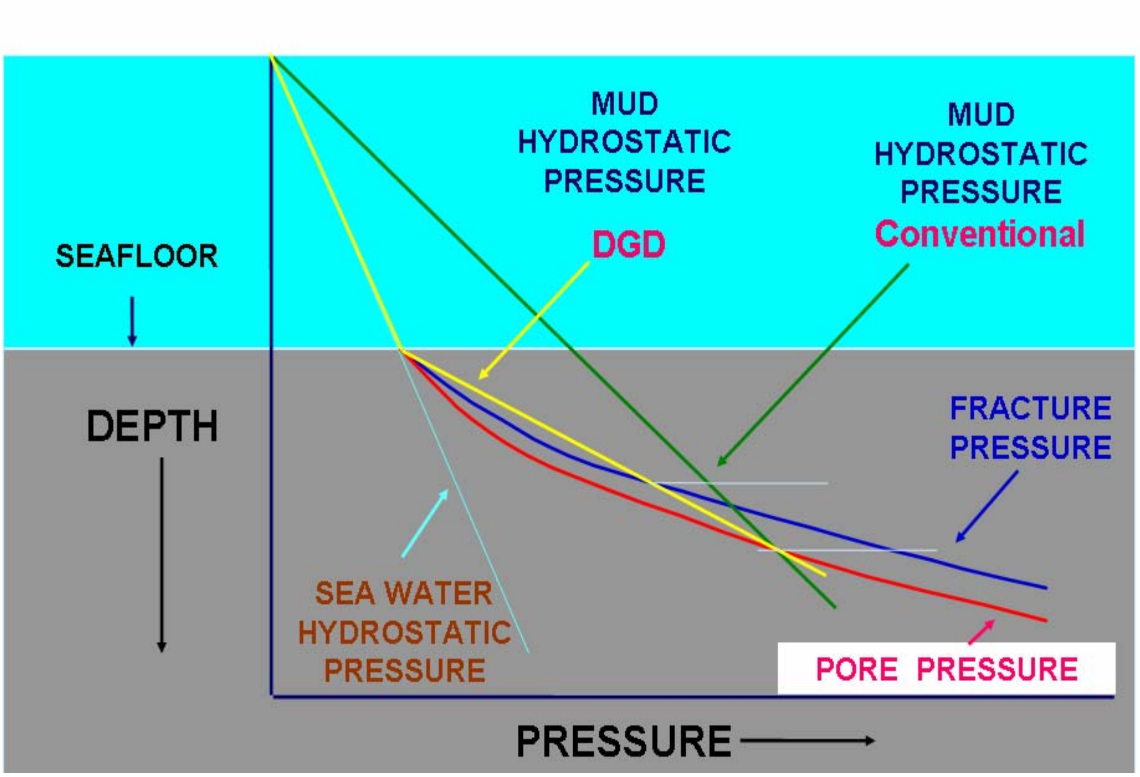

Fig 1.2—Wellbore pressure comparison between DGD and conventional drilling methods.[2]

From the diagram above we can see that the margin between the pore and fracture pressure gradients was improved when the DGD method was applied. This alone makes the dual gradient drilling method very attractive.

CHAPTER II

LITERATURE REVIEW

The introduction of dual gradient drilling can be dated back to the 1960s. But at that time the demand for oil and gas was not as high as it is today. The increasing demand has pushed the oil and gas industry to explore for hydrocarbons in deep waters and this has led to the development of dual gradient drilling technology. Several methods of achieving dual gradient have been developed in order to improve deep water drilling.[4-6]

In this chapter, we are going to discuss the concept of conventional drilling and dual gradient drilling. In addition we are going to discuss the different methods of achieving dual gradient, the advantages of the dual gradient method over the conventional method and finally kick detection and well control in the dual gradient drilling method.

2.1 Conventional Drilling Method

The conventional method involves the use of a marine riser; the marine riser serves as a link between the drilling rig and the wellhead at the sea floor. It is also used as a guide for the drill string, a return path for the drilling fluid, and it provides support for the control cables, choke and kill lines. A single mud density runs from the drilling rig down to the bottom of the well, maintaining the bottom hole pressure. But, as the water depth (3000-7500 ft)[1] increases the conventional technique often becomes unreliable. The narrow margin between the pore and fracture pressures in deep waters is one of the major reliability issues affecting the use of conventional drilling in deep waters.[4-5] When using the conventional technique "the exposed sediment of the wellbore sees a pressure tending to cause formation fracture, this pressure is caused by the full column of mud in the drilling riser"[4]. This led to the invention of the dual gradient drilling method.

2.2 Dual Gradient Drilling Method

The dual gradient drilling technique involves the use of two different pressure gradients in maintaining the bottom hole pressure. The same bottom hole pressure in the conventional method can be achieved using the dual gradient method. Several methods have been proposed to achieve dual gradient in the industry today. In one of the methods the marine riser is filled with a low density fluid (sea water, 8.66 ppg), this helps in reducing the pressure in the exposed sediments of the wellbore while heavy density fluid runs from the sea floor to the bottom hole. **Figures 2.1 & 2.2** represent a schematic diagram of the conventional and dual gradient systems and the pressure profiles of conventional drilling and dual gradient drilling respectively.

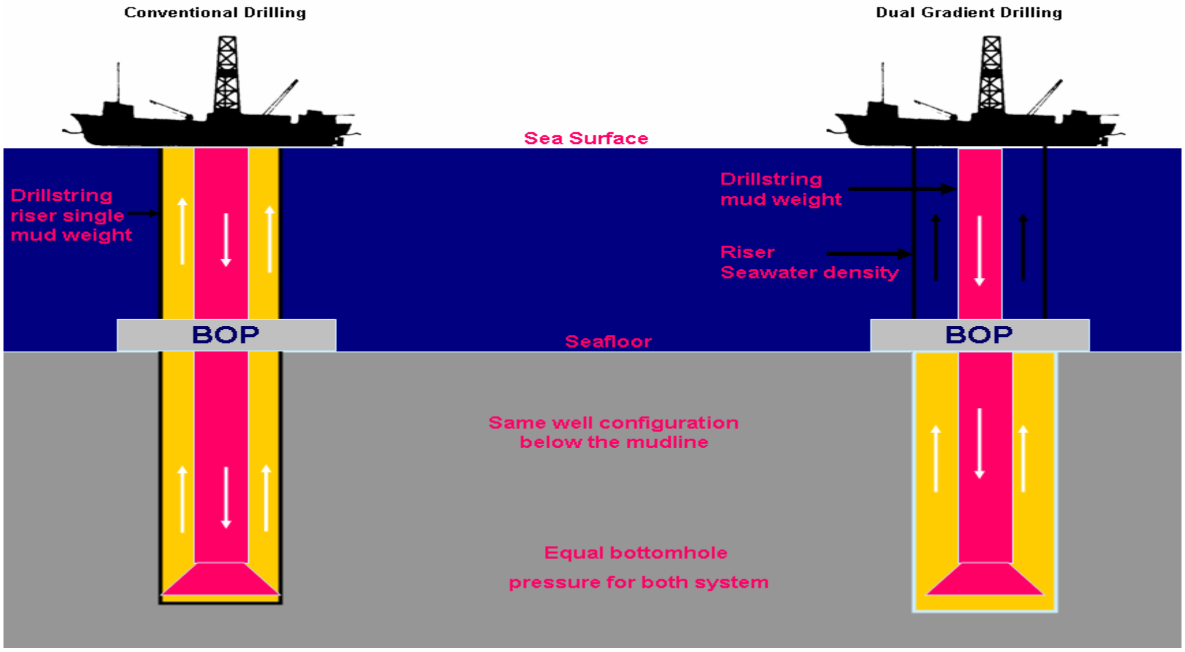

Fig 2.1— Conventional and dual gradient drilling systems.[2]

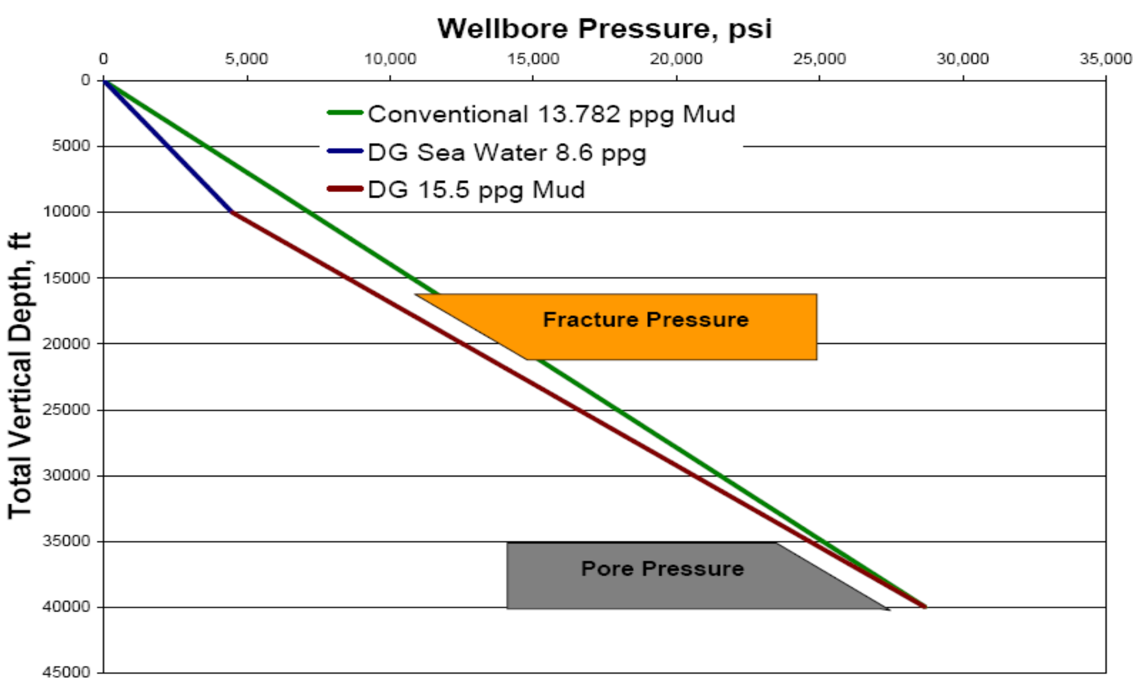

Fig 2.2— Conventional and dual gradient drilling wellbore pressure profiles.

In dual gradient drilling all pressure gradients (formation pore and formation fracture pressure gradients) are referenced to the sea floor and in so doing the margin between the formation pore and formation fracture pressures is greatly increased. But, in the case of the conventional drilling method all pressure gradients are referenced to the rig floor. This can be seen in **Figures 2.3** and **2.4** respectively.[6] One primary benefit of the wider margin between the pore and fracture pressures in dual gradient drilling is the elimination of several casing strings.[6] A comparison between casing selection in dual gradient drilling and conventional drilling can be seen in **Figures 2.3** and **2.4** respectively. Lesser number of casing strings allows for deeper target depths, greater final hole size, and setting larger production tubing strings. It is also important to note that well kicks and lost circulation would be minimal because of the wide margin between these pressure gradients. Other benefits of dual gradient drilling include cost and time savings; which allows drilling in any water depth and has lower weight and space requirements on the drilling rig.[3-6]

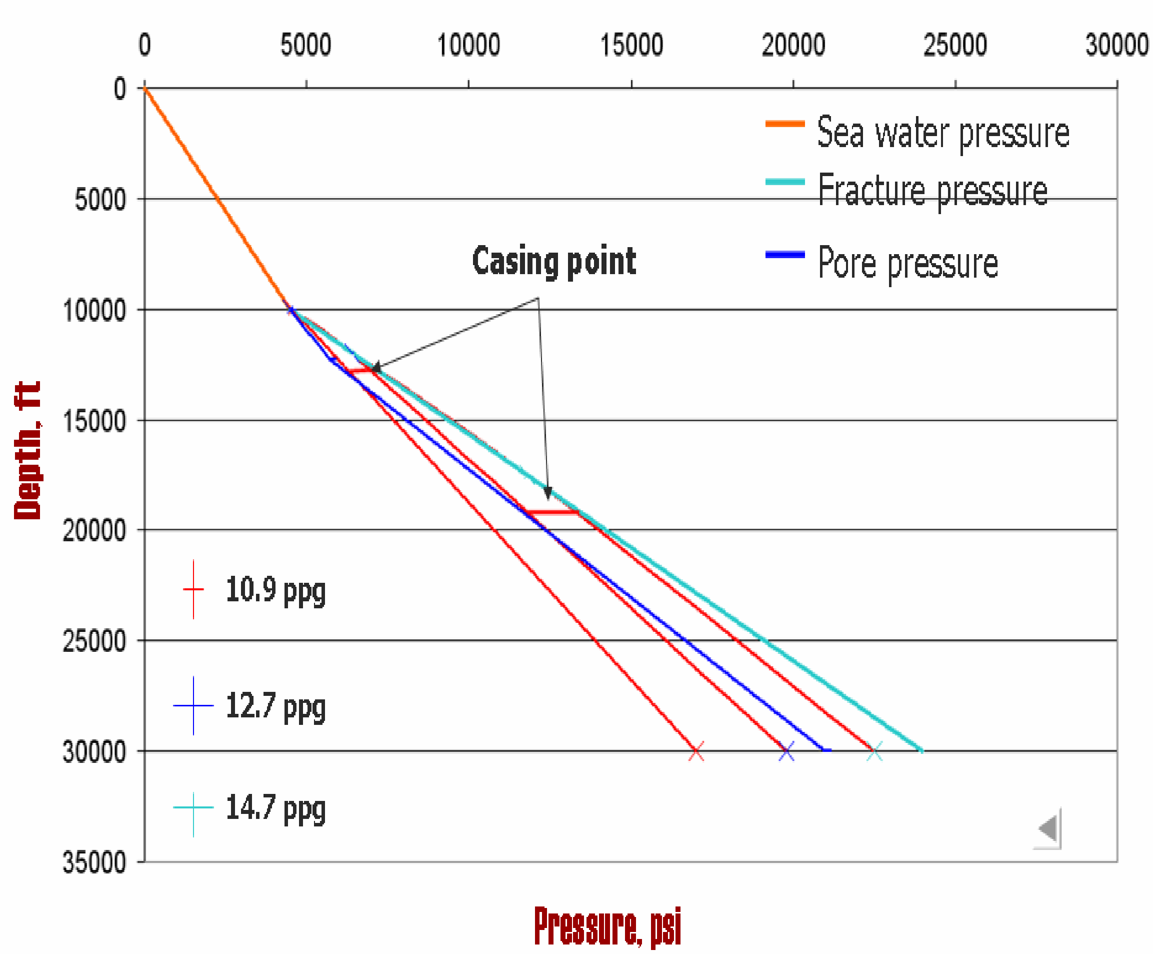

Fig 2.3 — Casing selection in dual gradient drilling.[6]

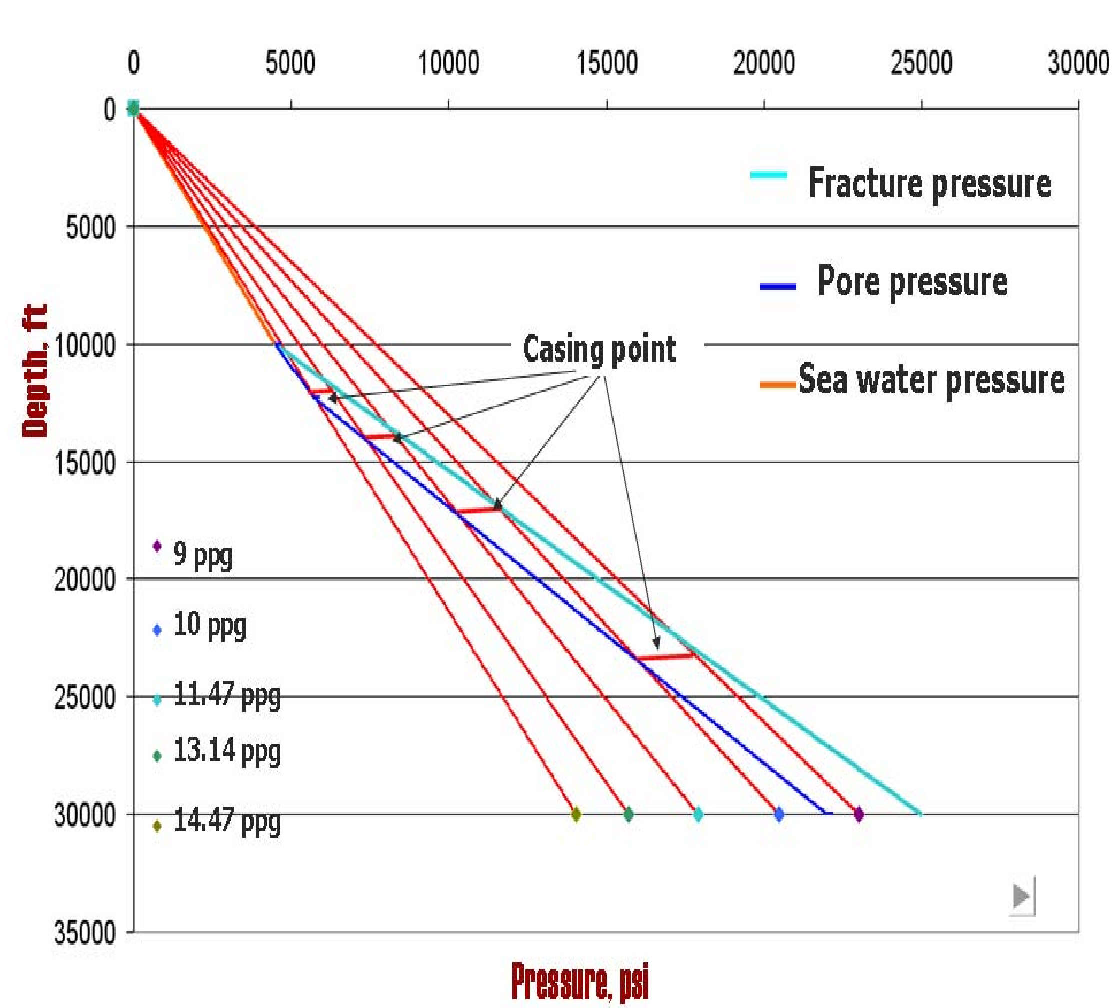

Fig 2.4— Casing selection in conventional drilling.[6]

2.3 Methods of Achieving Dual Gradient Drilling

Different methods of achieving dual gradient drilling in deep waters have been proposed in the industry today. We will briefly discuss these methods.

- Mechanical Lifting (Subsea Mudlift drilling (SMD), Deep Vision and Shell)
- Hollow Glass Spheres
- Mud Dilution (Gas or Liquid)

These methods are designed to create two different pressure gradients in the annulus, by diluting the return mud in the marine riser with a low density fluid or completely eliminating the marine riser and using a combination return line and subsea pumps[6].

2.3.1 Subsea Mudlift Drilling

This method involves the use of a pumping system and return lines. In this case the marine riser may be eliminated. The pumping system (positive displacement diaphragm pump) is located at the sea floor and it is designed to send the return mud to the drilling rig through the return line. The return line has a small diameter of about 6 inches and runs from the sea floor to the drilling rig.[5-6] During drilling operations the drill string and the annulus are filled with drilling mud while the marine riser is filled with sea water. Just above the subsea pump inlet a Subsea Rotating Device (SRD) is installed, its primary function is to provide a mechanical barrier between the return mud in the annulus and the sea water in the marine riser[7]. The return mud in the annulus goes through the return line to the drilling rig. This is made possible by the presence of positive displacement diaphragm pumps located at the sea floor [7-8]. These pumps are designed to lift drilling fluid and cuttings in the annulus up to the drilling rig through the return line. In this method the dual gradient concept is achieved by keeping the hydrostatic pressure in the return line from being transferred to the wellbore[3]. When the return mud reaches the drilling rig the separation process is carried out just like in the conventional drilling method. Deep Vision and Shell's subsea pumping system utilize this same concept. Although this method provides flexibility in handling any drilling operation, some disadvantages do exist in this method[9]. The use of complex subsea pumps is very costly and it can lead to the introduction of reliability issues. **Figure 2.5** represents an illustration of a modified subsea mudlift dual gradient drilling method (no riser).[9]

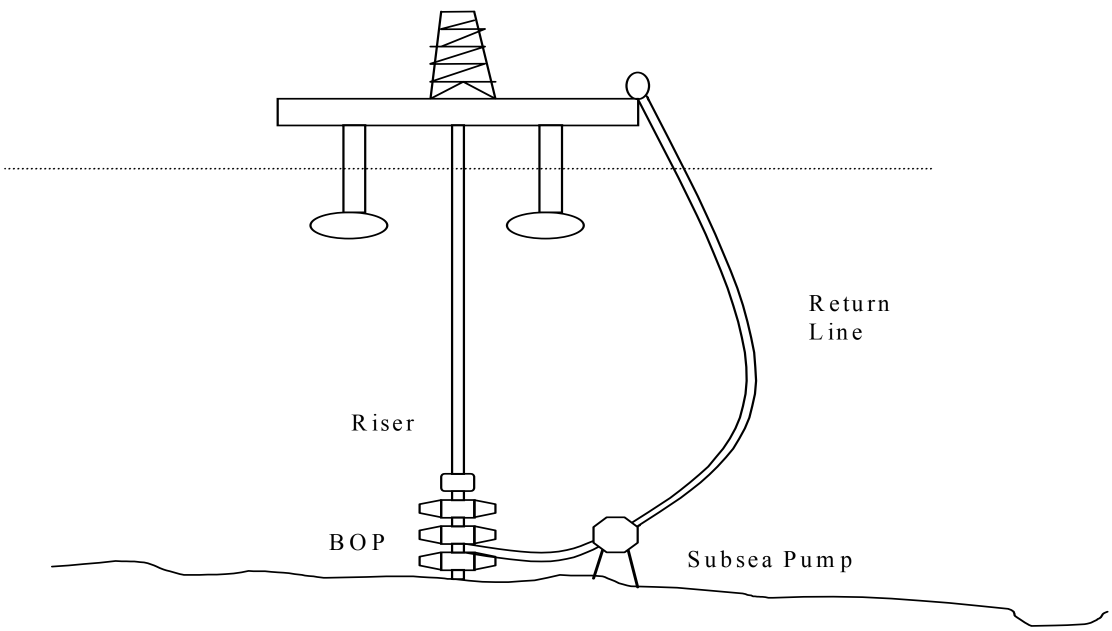

Fig 2.5— Schematic diagram of a modified subsea mudlift system.[10]

2.3.2 Hollow Glass Spheres

The hollow glass spheres method of achieving dual gradient was invented by Maurer Technology. Hollow-spheres are used as lightweight additive. This additive is pumped into the riser to reduce the return mud density in the riser[9]. The design concept of the hollow-spheres, dual gradient system is very similar to the conventional drilling method, except for the introduction of an injection point at the bottom of the riser.

Here, hollow spheres are mixed in a slurry and pumped into the riser at the sea floor. The injected slurry at the sea floor reduces the density of the return mud in the riser. Once the slurry mixture containing mud, cuttings and the hollow-spheres gets to the drilling rig it is transferred to a separator system. The separator system separates the hollow spheres from the mud and these spheres are used again in the cycle. **Figure 2.6** is a schematic representation of the hollow-spheres method.[9]

Some of the advantages of using the hollow-spheres in achieving the dual gradient concepts are as follows; the hollow spheres are incompressible and they produce a linear pressure gradient, they can be easily and safely mixed into the drilling mud during drilling operations and no equipment is required on the sea floor.[9] Possible drawbacks of this method are breakage of the hollow-spheres and difficulties in separating the hollow-spheres from the drilling mud.[9]

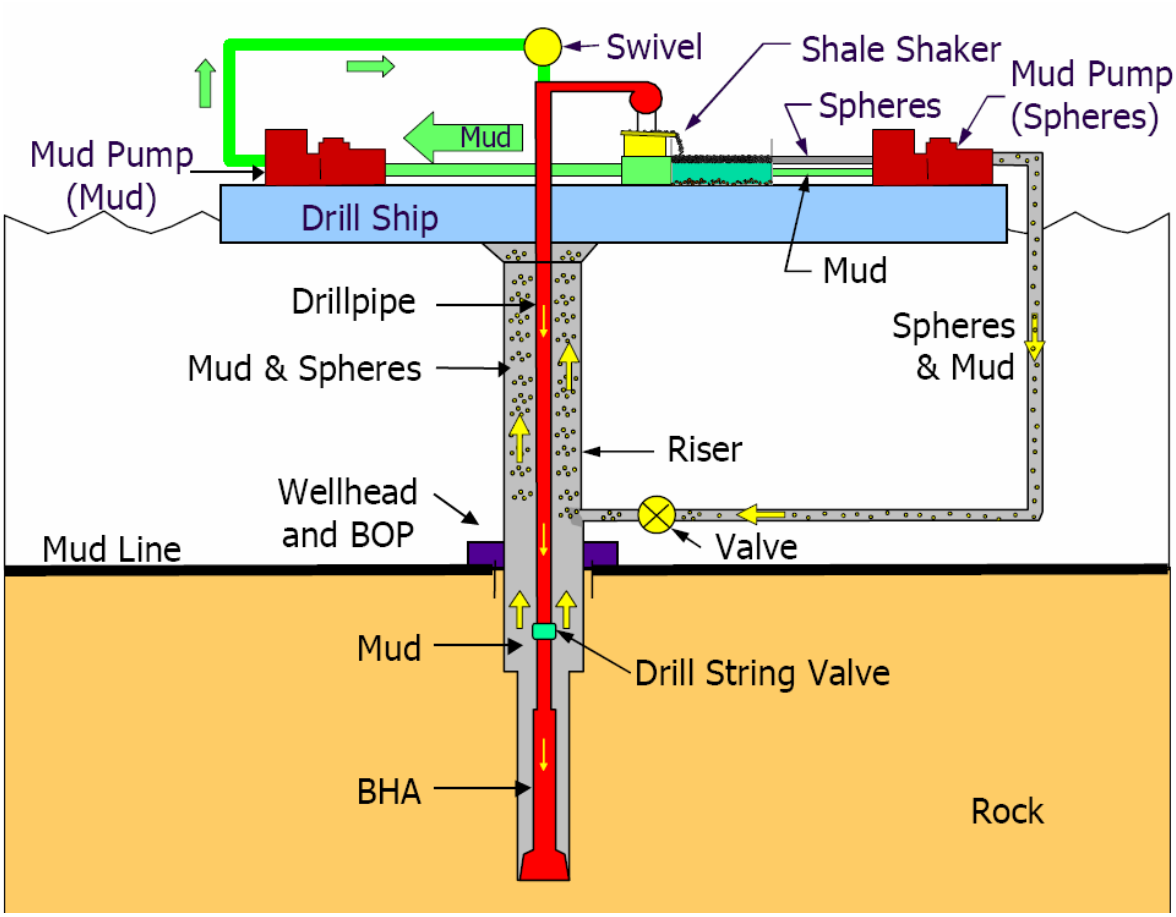

Fig 2.6— Hollow glass-spheres dual gradient drilling system. [9]

2.3.3 Riser Dilution (Gas or Liquid)

The riser dilution method is very similar to the hollow-spheres method. Here, gas or liquid can be used as the lightweight additive. Several authors have studied the use of gas injection to achieve dual gradient drilling. Clovis A. Lopes and Adam T. Bourgoyne[1] presented a paper on the use of an automated gas-lift system for a marine riser that will maintain the hydrostatic pressure in the subsea well-head equal to the hydrostatic pressure of the sea water at the sea floor. Abnormal formation pressure can still be maintained in this system by using a weighted mud system that is not gas-cut below the sea floor[1]. Herrmann R.P et al[11] propose the use of nitrogen injection with a high pressure concentric casing riser. This will reduce greatly the gas required in the system. Problems associated with the gas lift method are high compressor costs, the compressors are large so they occupy space on the drilling rig, difficulties in degassing mud before it is re-injected into the well, and gas is a compressible fluid, this will lead to nonlinear pressure gradients.[9,11]

Not much work has been done on the liquid lift approach. This approach is very similar to the gas lift method. In this method a low density liquid is injected into the riser at the sea floor. The low density liquid reduces the density of the return mud in the riser just like in the gas lift and hollow-sphere methods. When the mixture reaches the rig floor the liquid is separated into low density liquid and heavy mud.

In this project, we plan to pay more attention to the liquid lift method (riser mud dilution method). This method of achieving dual gradient drilling is somewhat different from the others, because it does not utilize subsea pump or a complex pumping system, no compressors are required (high compressor and nitrogen gas costs are not applicable), difficulties in degassing mud before it is re-injected into the well are not applicable and compressibility problems associated with the gas lift method are not applicable.

2.4 Description of the Liquid Lift Approach

The liquid lift approach is one of the latest methods of achieving dual gradient in deep waters. Very little research work has been done on this method. de Boer Luc, [12] described and patented the liquid lift approach (riser dilution) method. As discussed earlier, this system pumps drilling mud down the drill pipe, through the nozzles in the drilling bit and then into the open hole where it picks up cuttings. The drilling mud and cuttings then move up the annulus, into the Blowout Preventer (BOP) stack. The BOP is a device installed at the sea floor or at the surface used to contain the wellbore and to prevent a kick from becoming a blowout.[12] Just above the BOP stack is a riser charging line which runs to the drilling rig. The riser charging line introduces a low density fluid (base fluid 6 ppg) into the riser to mix with the return mud that travels up to the drilling rig. The base fluid is introduced at the bottom of the riser, so as to achieve a riser density lesser or equal to sea water density.[12] In offshore operations it is well know that the pressure at the sea floor is equal to sea water hydrostatic pressure.[12] Therefore, the pressure at the beginning of the wellbore is equal to sea water hydrostatic; in order to maintain the integrity of the wellbore it is important that sea water density is maintained above the wellbore and heavier density down the wellbore. Therefore, by combining the appropriate quantities of drilling mud with base fluid the required riser density can be attained. Equation **(2.1)** can be used to determine the return mud density in the riser.[12]

$$\frac{(Q_i \times \rho_m)+(Q_l \times \rho_{sw})}{(Q_i + Q_l)} = \rho_{RM} \quad \text{---} \textbf{ (2.1)}$$

Where;

Qi = flow rate in the annulus (gpm)

Q_l = flow rate in the riser charging line (gpm)

ρ_m = mud density in the annulus (ppg)

ρ_{sw} = base density in the charging line (ppg)

ρ_{RM} = diluted riser density (ppg)

Figure 2.7 is a schematic representation of the liquid lift, dual gradient drilling method.

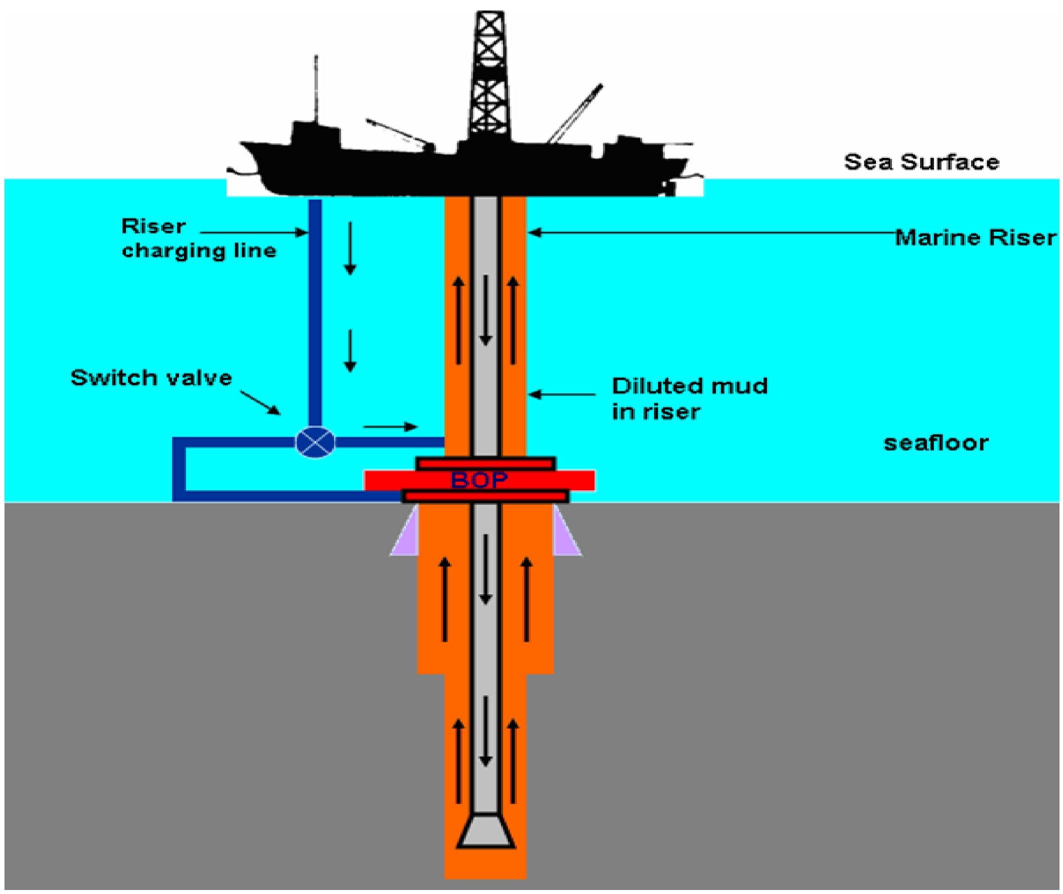

Fig 2.7— A typical offshore drilling rig modified for liquid lift drilling.

Upon, getting to the drilling rig the return mud passes through the shale shaker and the cuttings are separated from the return mud. These cuttings are discarded while the return mud is passed through a separation system (centrifuge device) where the return mud is separated into wellbore fluid and base fluid. **Figure 2.8** is a schematic representation of the separation system.[12]

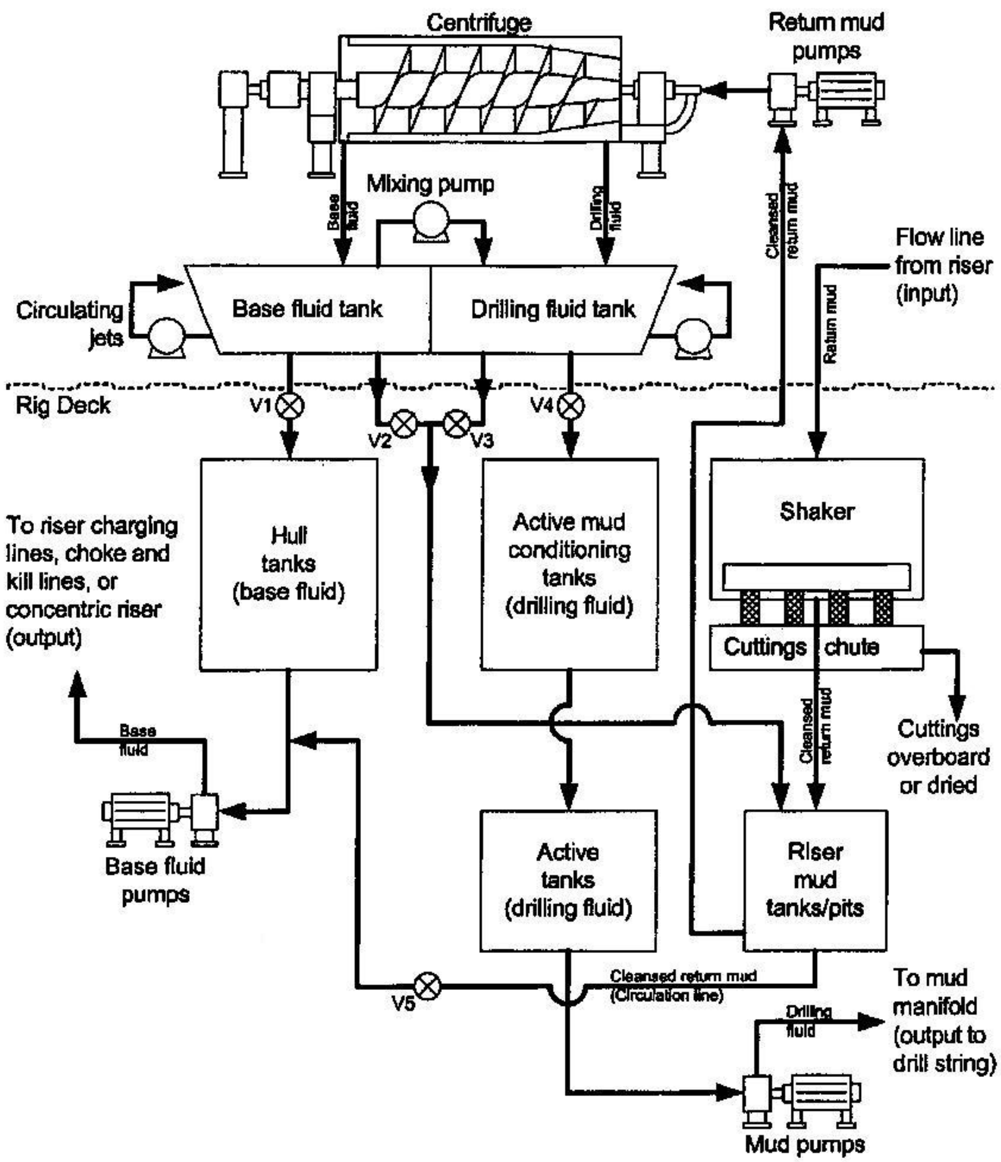

Fig 2.8 — Schematic representation of the separation system.[12]

The liquid lift method is a simplified method of achieving dual gradient drilling. This system is very similar to the conventional method of drilling. An elaborate pumping system and large gas compressors are not required in the liquid lift method making this method more attractive compared to the others. **Figure 2.9** represents a schematic diagram showing the similarities between the liquid lift, dual gradient drilling and the conventional drilling methods.

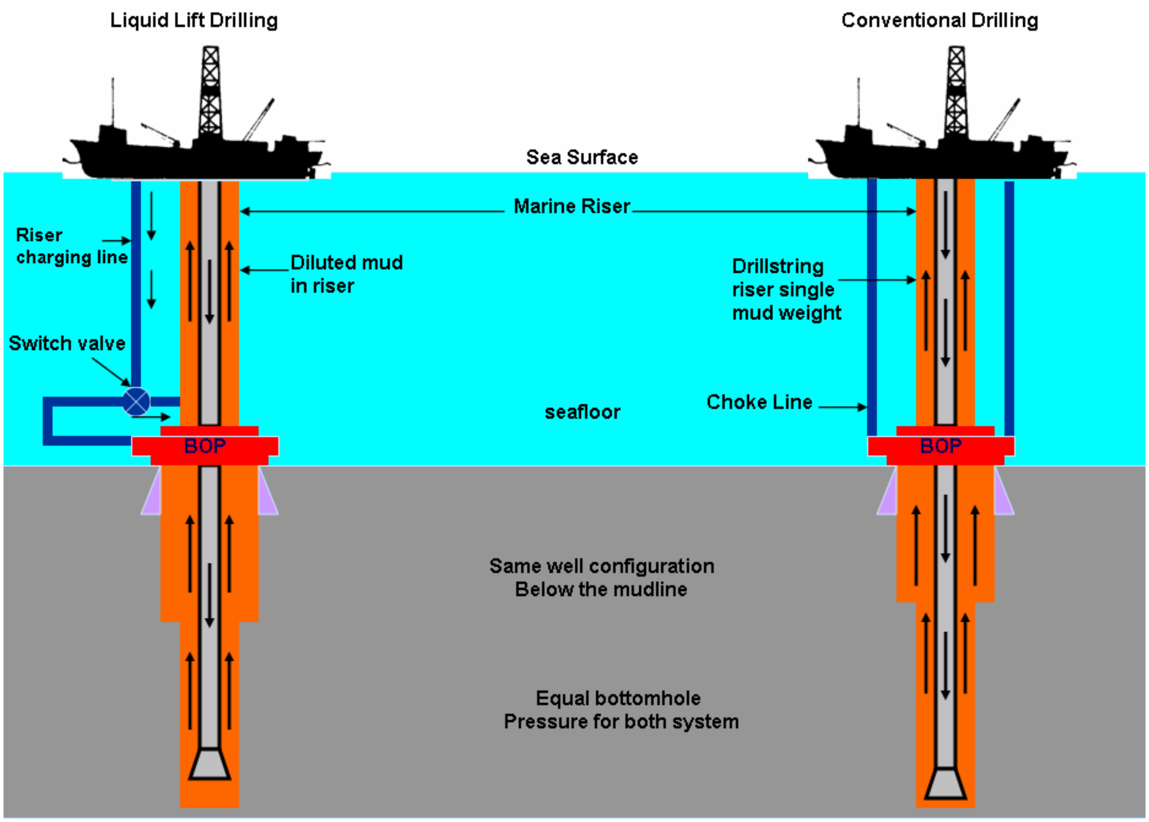

Fig 2.9— Schematic diagram of liquid lift and conventional drilling systems.

2.5 Advantages of Dual Gradient over Conventional Drilling

Many of the problems associated with deep water drilling when using the conventional drilling method have been minimized or eliminated through the use of dual gradient drilling, achieved through return line and subsea pump or marine riser filled with sea water.

One major advantage of dual gradient drilling over conventional drilling is the wider margin between the pore and fracture pressure gradients.[6] As stated earlier, in deep waters the pressure gradient between the pore and fracture pressures is narrow. During drilling operations the pressure at the sea floor is equivalent to sea water density. Therefore, it is necessary to maintain the required riser density from sea surface to sea floor. This can be achieved by using the dual gradient concept. Because the increased margin between the pore and fracture pressure gradients when the dual gradient drilling concept is applied, the number of casing strings required in deep water drilling is reduced. The reduction in casing strings brings about several advantages such as reduced well cost and time savings, improved primary cement capabilities, hole size availability at deeper depths, and also weight and space requirements for rigs used in deep water drilling can also be reduced substantially.[1-6]

The elimination of several casing points has a direct impact on cost and time savings. The elimination of a casing point saves about 4 to 6 days of rig time, plus the cost of hole evaluation, casing and logging. If the dual gradient drilling technique is applied successfully the cost of drilling a well will be reduced drastically. The reduced cost will improve the overall development economics by making more wells economical, it may facilitate more complex well completions that will increase production and it also allows for more exploratory wells to be drilled thereby reducing geologic risks.[6]

From a safety perspective in a dual gradient system with a riser filled with sea water, an unplanned or emergency disconnect will not result in a sudden underbalance situation in the wellbore. This is related the presence of the riser margin. But, in conventional drilling, this leads to a sudden decrease in the hydrostatic pressure imposed on the wellbore, thereby causing an underbalance situation.[6]

In the case of well control (influx of formation fluid in the wellbore), in the subsea mudlift, dual gradient drilling method, an improved managed pressure drilling technique has been employed in the subsea mudlift dual gradient drilling method.[11-13]

We can boldly say that dual gradient drilling eliminates or minimizes the problems associated with conventional drilling, but, there are a lot of uncertainties surrounding the use of the dual gradient drilling system. There is a shortage in the amount of trained personnel that can handle these systems, and the introduction of additional equipment may bring about reliability issues.[13]

2.6 Kick Detection and Well Control in Dual Gradient Drilling

In deep water drilling operations kick detection and well control are two very important issues that also apply to conventional drilling. A kick occurs when there is an influx of formation fluid into the wellbore. Keeping the formation fluid out of the wellbore is of primary importance during most drilling operations. This can be achieved as long as the mud-column hydrostatic pressure in the drill string plus any annular-friction pressure exceeds the pore pressure in the wellbore. In spite of this intent formation fluid influx still occurs, therefore, it is of great importance to quickly detect and control the formation fluid influx.[13-14]

There are several methods of detecting possible kicks in dual gradient drilling; these detection methods could be visual or audible. Some of the common methods of kick detection are:

- Return rate increase.
- Pit gain.
- Drop in standpipe pressure.
- Drilling Break.
- Increased hook load.
- Increase in rotary torque, drag and fill.

These methods have been successfully utilized in conventional and dual gradient operations in deep waters. The first three methods listed above are known as primary kick detection while the others are known as secondary kick detection methods.[5]

After a kick is detected the next step is to stop the further influx of formation fluid in the wellbore. At this point the major difference between dual gradient drilling and conventional drilling comes into play. In conventional drilling once a kick is detected the well is immediately shut in. But, in dual gradient drilling this is not the case, because of the pressure imbalance. The well cannot be shut-in until equilibrium is reached. Otherwise it may lead to formation fracture and lost circulation, therefore, the well is allowed to flow until equilibrium is reached.[12-13] This process is known as the u-tubing effect. The u-tubing effect occurs when the surface pumps are shut down. This causes the system to equalize the hydrostatic pressure difference between the drill string and the annulus. Below the mudline the pressures in the drill string and annulus are balanced while above mudline the height of the mud column inside the drill string is essentially balanced against sea water inside the riser. Therefore, for equilibrium to occur the mud level inside the drill string will drop until the hydrostatic head in the drill string above the mudline is equal to the hydrostatic head of the annulus above the mudline, by draining the fluid in the drill string through the bit nozzle and up the annulus.[1, 3, 4, 13]

The u-tubing phenomenon can be prevented by the introduction of a drill string valve (DSV). A DSV is placed near the bottom of the drill string; it prevents the flow of drilling mud when the pumps are turned off. The DSV was designed to arrest u-tubing by sustaining the hydrostatic pressure of the full column of mud in the drill string whenever the surface pumps are shut down.[13]

When a kick is detected it is very important to take the necessary action so as to prevent excessive pressure from damaging the casing or fracturing the formation. A well should be shut-in once a kick is detected. But, in the case of dual gradient drilling without a DSV the mud in the drill string is allowed to u-tube.[13] During that process it is difficult to stop the further influx of formation fluid into the wellbore. That is why it is very helpful to use a DSV in dual gradient drilling so that upon detection of a kick the BOP can be shut-in immediately and the well control procedures can be initiated in a manner similar to the conventional method.[6] When a drillstring valve is not employed a modified driller's method proposed by J.J Schubert et al[13] can be used. Note that this method is only used for subsea mudlift, dual gradient drilling systems.[1, 5, 6, 13, 14,]

1. Slow the subsea pumps to the pre-kick rate (maintain the rig pumps at constant drilling rate)
2. Allow the drill string pressure to stabilize, and record this pressure and the circulating rate.
3. Continue circulating at the drill string pressure and rate recorded in step 2 until kick fluids are circulated from the wellbore.
4. The constant drill string pressure is maintained by adjusting the subsea pump inlet pressure in a manner similar to adjusting the casing pressure with the adjustable choke on a conventional kill procedure.

5. After the kick fluids are circulated from the wellbore, a kill fluid of higher density is circulated around to increase the hydrostatic pressure (HSP) imposed on the bottom hole.

In the case of liquid lift dual gradient drilling the choke line circulation method is used. With this approach, the well is shut in with the blowout preventers (BOPs) and the choke line valve is opened. The choke line should be kept filled with a fluid having a density similar or equal to sea water density. The kick is then circulated up the choke line while base fluid is being injected into the choke line in order to keep the density of the fluid in the choke line at sea water density. A detailed description of the procedure can be seen in chapter III.[9]

CHAPTER III

CONCEPTS OF LIQUID LIFT DUAL GRADIENT DRILLING

As discussed in chapter II, liquid lift dual gradient drilling involves the use of a lighter density fluid known as base fluid to dilute the return mud in the riser. This fluid is injected at the bottom of the riser. One major function of the drilling fluid in any drilling operation is its ability to suspend and transport drilling cuttings from bottom hole to the drilling rig. Therefore, the drilling fluid used in the liquid lift approach must be able to perform these functions even when a lighter density fluid is mixed with the return mud. It is important to note that to achieve the required riser density, the right concentration and injection rate of the base fluid must be determined.

It is very important to note that, for an effective liquid lift dual gradient system, separation of the return mud to base and wellbore fluids must be possible. For this system to work efficiently the return mud must be separated into base and wellbore fluids continuously. De Boer[12] provided first hand insights into the use of a centrifuge separation system.

3.1 Type of Drilling Fluid Used in Dual Gradient Drilling

Drilling fluid is a very important component that should be taken into great consideration in drilling operations. To ensure success during any drilling operation the drilling fluid must be able to perform the following functions.[15]

- Must be able to clean wellbore

- Must be able to maintain stable drilling fluid rheological and filtration properties under varied temperature and pressure conditions
- Possess good barite suspension capabilities
- Stabilize reactive formation
- Well control (hold back formation fluid)

In deep water drilling operations, synthetic-base mud (SBM) is highly recommended as the fluid of choice for deep water operations. This is due to its superiority in achieving high penetration rates and maintaining desired wellbore stability. The SBM also have their drawbacks, in deep waters the temperature can easily reach 40^0C or 104^0F and below. This in turn can cause the drilling mud to cool down, thereby increasing the viscosity of the SBM. The increase in viscosity directly affects the equivalent circulation densities (ECDs) and surge pressures which can lead to lost circulation during drilling operations. Because a narrow margin exists between the pore pressure and fracture pressure gradients in deep waters, large fluctuations of the fluid theology are unacceptable. Therefore, it is very important that the SBM rheology be maintained. [16]

When designing a SBM for deepwater drilling the mud properties must be taken into consideration. These properties have a direct effect on barite suspension, equivalent circulating density (ECD), effective hole cleaning and most of all, its ability to perform these functions when the fluid is diluted. Some of the mud properties that should be taken into consideration are listed below.[17]

- Plastic viscosity can be defined as the slope of the shear stress to shear rate line above the yield point.[18] It measures the resistance of drilling mud to flow as a liquid.[15-16] When the plastic viscosity is low the drilling mud has the ability to drill fast. But, in the case of high plastic viscosity the ECD will be excessive which may lead to loss of circulation.
- Yield point has to do with the cuttings carrying ability of the drilling mud. If the yield point is low the drilling fluid loses its cuttings carrying ability. The yield point in a drilling mud can be increased by adding a flocculent.[17-18]
- Mud weight of a drilling fluid is determined based on the wellbore pressures (pore pressure and fracture pressure).[18]
- Emulsion stability has to do with how well the water phase is held in the overall emulsion.[18]

In the case of the dilution fluid, a density lower than or equal to sea water density is desirable. It is important to ensure that the dilution fluid has the capability of diluting the drilling fluid in the riser. Another important aspect to note is the temperature fluctuation in the wellbore. The dilution fluid must be able to maintain its stability in these fluctuating conditions. [15, 17]

3.2 Separation System

The separation system is a very important component in the liquid lift, dual gradient drilling. The return mud from the riser, which is a combination of drilling fluid and base fluid, must be separated into useable drilling fluid and dilution fluid. For these fluids to be useable they must have the right densities and rheological properties.

The separation of the riser fluid into drilling fluid and dilution fluid takes place on a separation skid located on the drilling rig. This skid consists of a centrifuge device, a set of return pumps and collection tanks for the separated fluids.[12] Firstly; the return mud in the riser is pumped to the shale shaker. The shale shake is a device designed to separate most of the cuttings from the return mud, thereby, producing a return mud relatively free of cuttings. The clean return mud is then pumped into the centrifuge device where the actual separation takes places. The centrifuge device is composed of a bowl with a tapered end and helical conveyor which is located inside the bowl. Both components rotate along a horizontal axis of rotation with the bowl having a faster rotating speed compared to the helical conveyor.[12] Once the clean return mud is fed into the centrifuge device the return mud is separated into two layers: drilling fluid layer and base fluid layer. During the process of separation the heavier density fluid is located closer to the circumference of the tapered bowl while the lower density fluid is located close to the helical conveyor. The centrifuge device is designed in such a way that the drilling fluid exits the centrifuge device through the tapered end while the dilution fluid exits through the other end of the bowl. **Figure 3.1** is a schematic representation of the centrifuge device.[12]

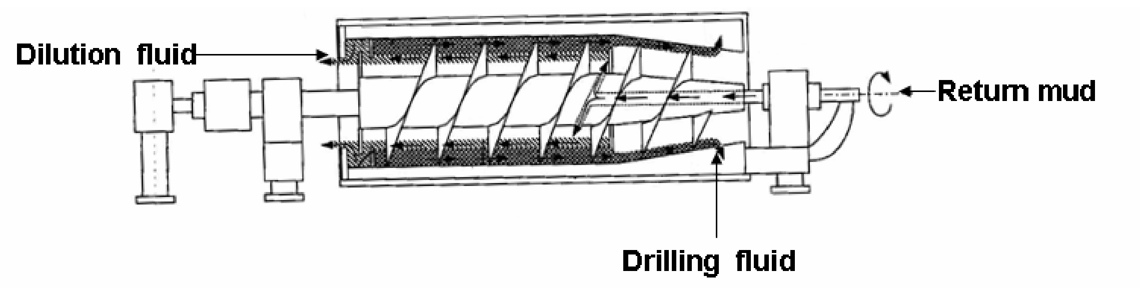

Fig 3.1 – Schematic representation of the centrifuge device.[12]

3.3 Kick Detection and Well Control

As discussed earlier, kick detection and well control are of great importance in deepwater drilling operations. The best method of well control is to actually prevent a kick from occurring but most time kicks do occur during drilling operation. Therefore, a more practical approach is early detection and control of the kick. Several kick detection methods have been used successfully in conventional onshore and offshore drilling operations.[1, 14] Some of these methods can be used in dual gradient drilling. The major difference between the dual gradient drilling and the conventional drilling is the u-tubing effect. The conventional flow-show (check for flow in the wellbore with pumps off) which is used as a kick indicator cannot be utilized in dual gradient drilling because of the u-tubing effect.[5, 13] This is caused by the imbalance in hydrostatic pressure between the drill string and annulus. Once the surface pumps are turned off in a dual gradient system the well will continue to flow until the pressure in the drill string is equal to the pressure in the annulus. Hence, it is difficult to determine if the well is actually taking a kick or just u-tubing. But, in the case of the mudlift dual gradient drilling system a more accurate kick detection method was employed. In this method the subsea mud pumps are closely monitored. The subsea pumps are usually set at a constant inlet pressure, so when a kick occurs the annular flow rate increases; this increase is also seen by an increase in subsea pump rate. This alone can be used as an adequate kick indicator in mudlift dual gradient drilling.[5, 13]

In the case of the liquid lift dual gradient drilling, early kick detection presents a challenge. The above mentioned kick detection method cannot be used, because the liquid lift system does not utilize a subsea pumps. Therefore, the liquid lift system has to rely on the conventional methods of kick detection. However, the pressure while drilling (PWD) tool can be used as a kick indicator in the liquid lift system. PWD tool was designed for real-time monitoring of the bottom hole pressure (BHP) while drilling. This tool provides the driller with the BHP, thereby allowing the driller to stay within safety operating limit.[19-21]

Once a kick is detected the next step is to stop the further influx and circulate the kick fluid out of the wellbore. In the mudlift dual gradient system once a kick is detected the subsea pump is set to the prekick rate while the surface pumps are set at constant circulation. This leads to an increase in the wellbore pressure generated by the further influx of kick fluid. Once the drill string pressure stabilizes, the drill string pressure and the pump rate should be recorded while circulating the kick fluid out of the wellbore. Kill weight mud is then circulated once the kick fluid is out of the wellbore completely. **Figure 3.2** is a graphical representation of kick detection and dynamic shut-in in the mudlift dual gradient system.[1-2]

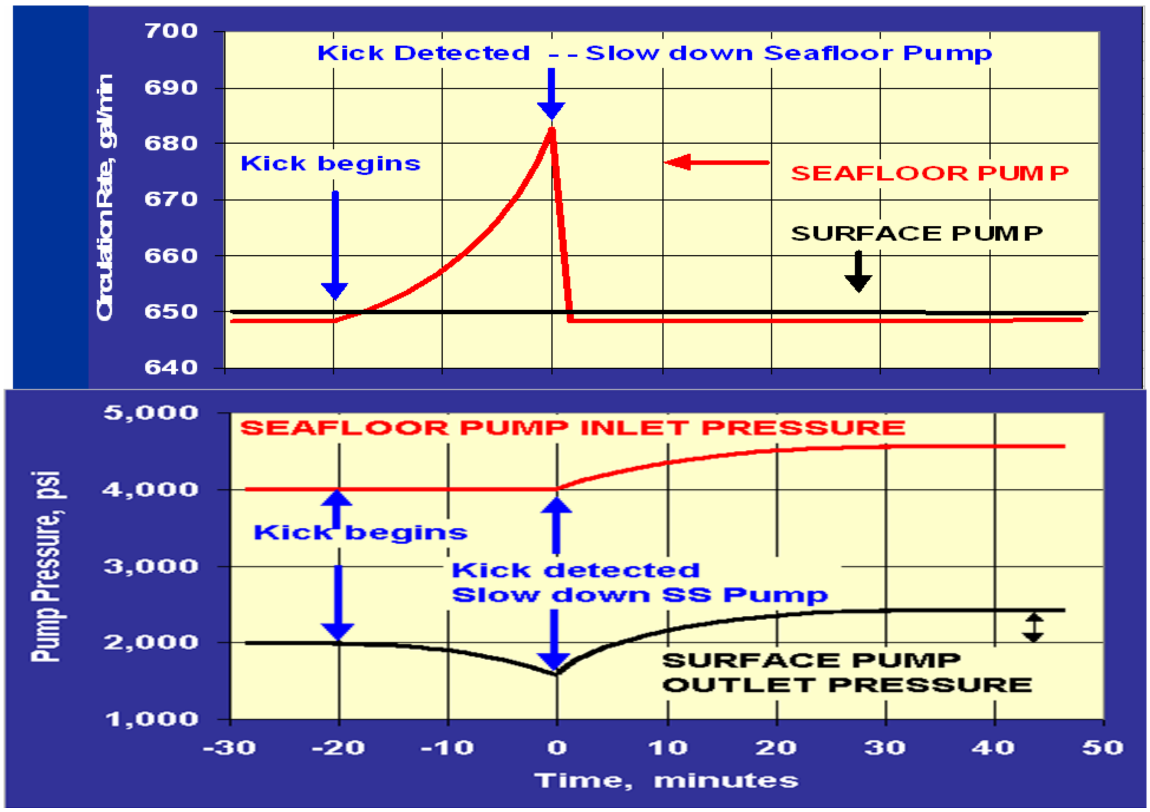

Fig 3.2— Graphic depiction of kick detection and dynamic shut-in for mudlift drilling.[1]

For the liquid lift dual gradient system, circulating the kick fluid out of the wellbore is very challenging. Lopes,[22] proposed a shut-in procedure for the gas lift, dual gradient system. This shut-in procedure can be utilized in the liquid lift, dual gradient system. In this procedure once a kick is detected (PWD or pit gain) the mud pump should be shut down, the well should be closed with the subsea BOP, the liquid injection into the riser should be shut down and the choke line should be kept in the open position. The choke line is expected to be filled with sea water.

Because the differential pressures between the drill string and the combined column of the annulus and choke line, u-tubing phenomenon will take place. This lowers the mud level in the drill string until equilibrium is reached.

At the end of u-tubing, if the influx of formation fluid into the wellbore continues the surface choke should be used to introduce a backpressure in the annulus. The amount of backpressure required to stop the influx of formation fluid can be determined from the actual BHP obtained from the PWD tool. Once the kick has been contained the kick fluid is then circulated out of the wellbore through the choke line. After the kick has been circulated out of the wellbore the kill weight mud is introduced and the liquid injection rate is adjusted to achieve the required base fluid and drilling fluid mixture that will maintain the BHP. **Figure 3.3** represents a schematic diagram of the process. [20-22]

According to Lopes,[22] once the u-tubing stops the choke line should be closed and the BHP should be determined. Lopes,[22] proposed the use of a well sounder to determine the fluid level in the drill string at the end of u-tubing. Once the BHP is known the liquid injection rate is adjusted to achieve the required mixture density to maintain the BHP. The kick is then circulated through the choke line.

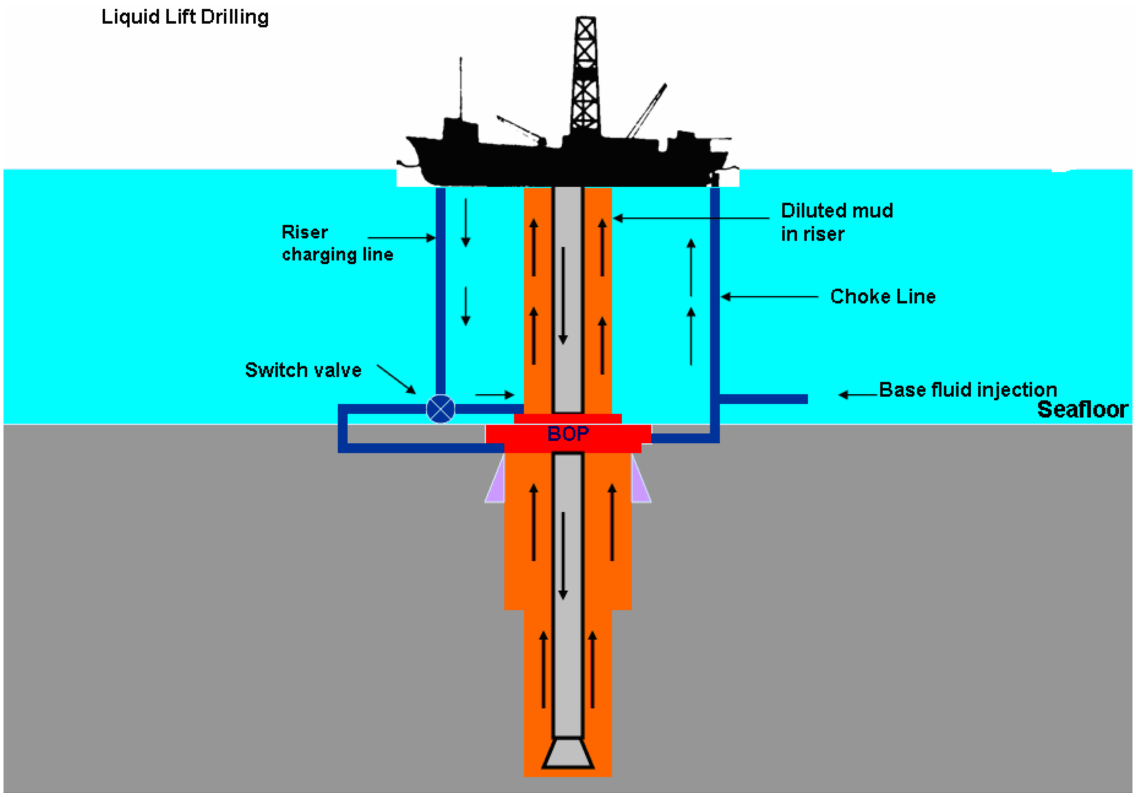

Fig 3.3— Circulating kick through the choke line.[2]

CHAPTER IV

DESCRIPTION OF PROGRAM, EQUATIONS AND RESULTS

Introduction

For a better understanding of the liquid lift, dual gradient drilling a computer program was developed. This computer program was designed to compute the following;

- Wellbore hydraulics
- Pressure profile (static and dynamic)
- Rate of injection of base fluid into the riser
- U-tubing rate

In this chapter a detailed description of the theoretical concepts, running the program, data input and output results are provided.

4.1 Entering Data and Running the Program

The computer program was developed using the visual basic application in Microsoft Excel. The computer program starts up like every normal Excel file after the Microsoft Excel Marco is enabled. After opening the computer program, the input data sheet is displayed. A picture of the input data sheet can be seen in **Figure 4.1**. The computer program contains 5 Microsoft Excel sheets. The first sheet contains the input data which is displayed at the start of the program. The second contains the output 1 sheet. It displays the output results for density in riser after injecting the base fluid; the hydrostatic pressures in drill pipe, annulus and the charging line, also displayed are the frictional pressure losses in the drill pipe, drilling bit, annulus and charging line. The third contains the output 2 sheet which displays the output results of the u-tubing rate (flow rate, time, volume of fluid displaced after u-tubing, fluid level drop in drill string). This sheet also contains the u-tubing graphs. The last 2 sheets contain the static and dynamic (circulating) pressure profiles in a dual gradient system respectively.

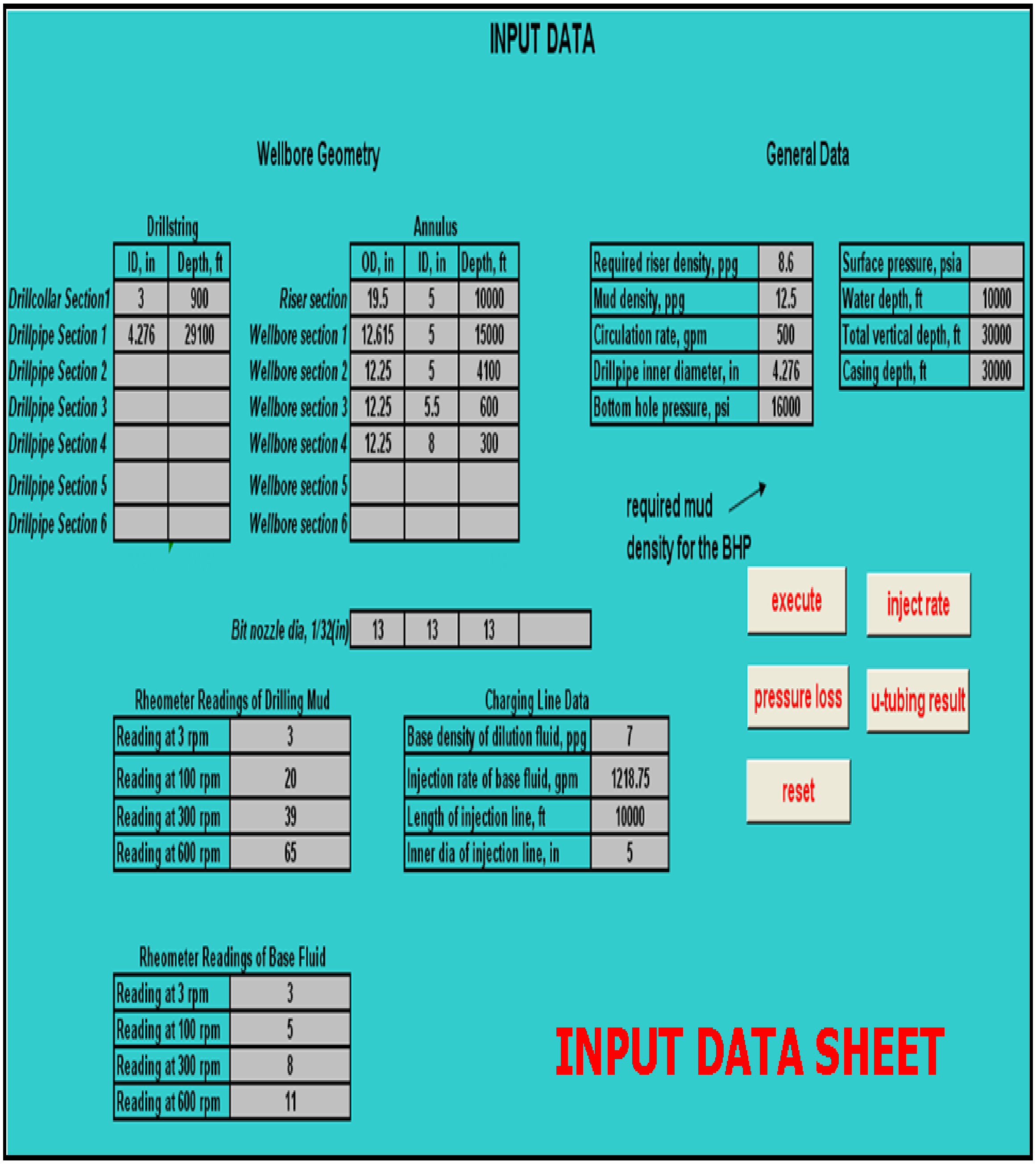

Fig 4.1— Input data sheet.

The input data sheet contains five control buttons. These buttons allow the user to run the program and navigate around the output results. All the necessary input data are entered in the cells shaded grey.

The data input sheet is kind of divided into four sections. The wellbore geometry input section allows for one drill collar section, six drill pipe and annular sections and one riser section. In the drill pipe section the input data for the pipe is entered from bottom to top while the annulus input data is entered from top to bottom and provision was made in the computer program for four nozzle input diameters at the drill bit. Two rheometer readings are displayed on the input data sheet; one represents the drilling fluid while the other represents the base fluid. The charging line data section contains base fluid density which ideally should be less than sea water density, injection rate of the base fluid into the riser, length of the charging line which is usually the water depth and finally, the inner diameter of the charging line. The general data section contains the sea water density or the required fluid density in the marine riser, drilling mud density which runs from top to bottom in the drill string and from bottom to sea floor in the annulus, circulation rate which is also known as mud flow rate, water depth, total vertical and last casing depth.

After all the right input data has been entered into the input data sheet, the user is required to press the execute button on the right side of the input data sheet for the program to run. Note if a wrong data is entered into the input data sheet an error message would be displayed, informing the user of an input error. This error message is very precise; it tells the user where the error is located. Once the program is executed properly the output results and graphs can be viewed using the control buttons on the right side of the sheet.

4.2 Hydraulics Computation

Hydraulics computation in the liquid lift, dual gradient drilling is somewhat different from the subsea mudlift and the conventional drilling methods. When compared to the subsea mudlift method, the pressure jump at the sea floor caused by the subsea pump is not applicable in the liquid lift method. In the case of the conventional method the dual mud density is the main difference.[5] **Figures 4.2, 4.3 & 4.4** are graphical representations showing the differences in the circulating pressure profiles in the wellbore of the liquid lift, subsea mudlift and conventional drilling methods.

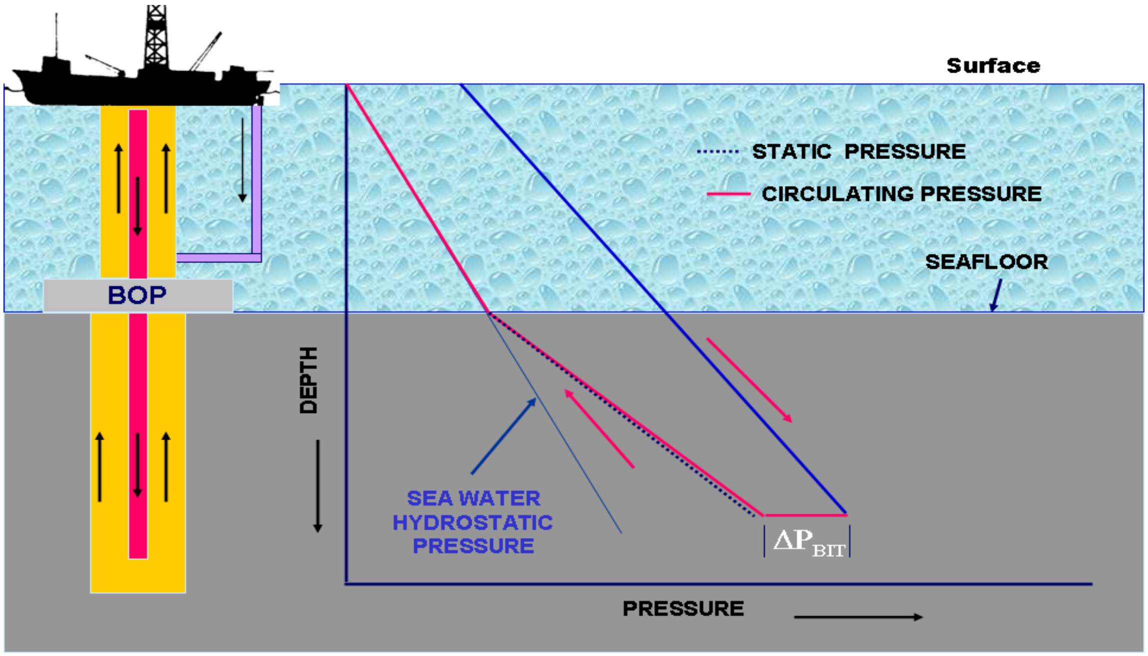

Fig 4.2— Circulating pressure profile for liquid lift dual gradient drilling.[2]

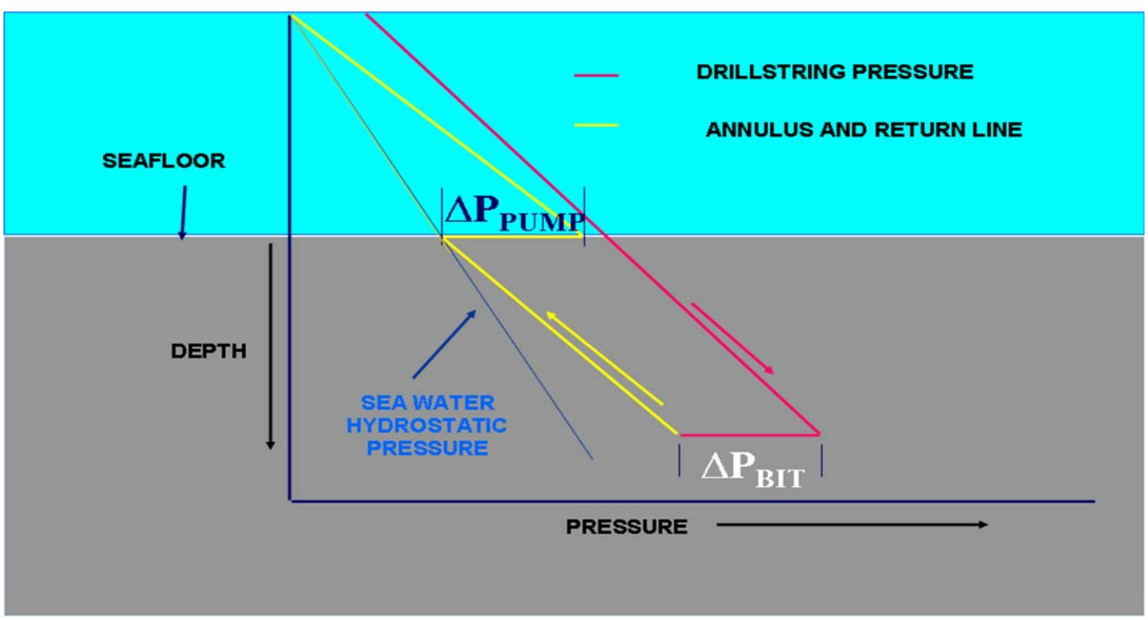

Fig 4.3— Circulating pressure profile for subsea mudlift drilling.[2]

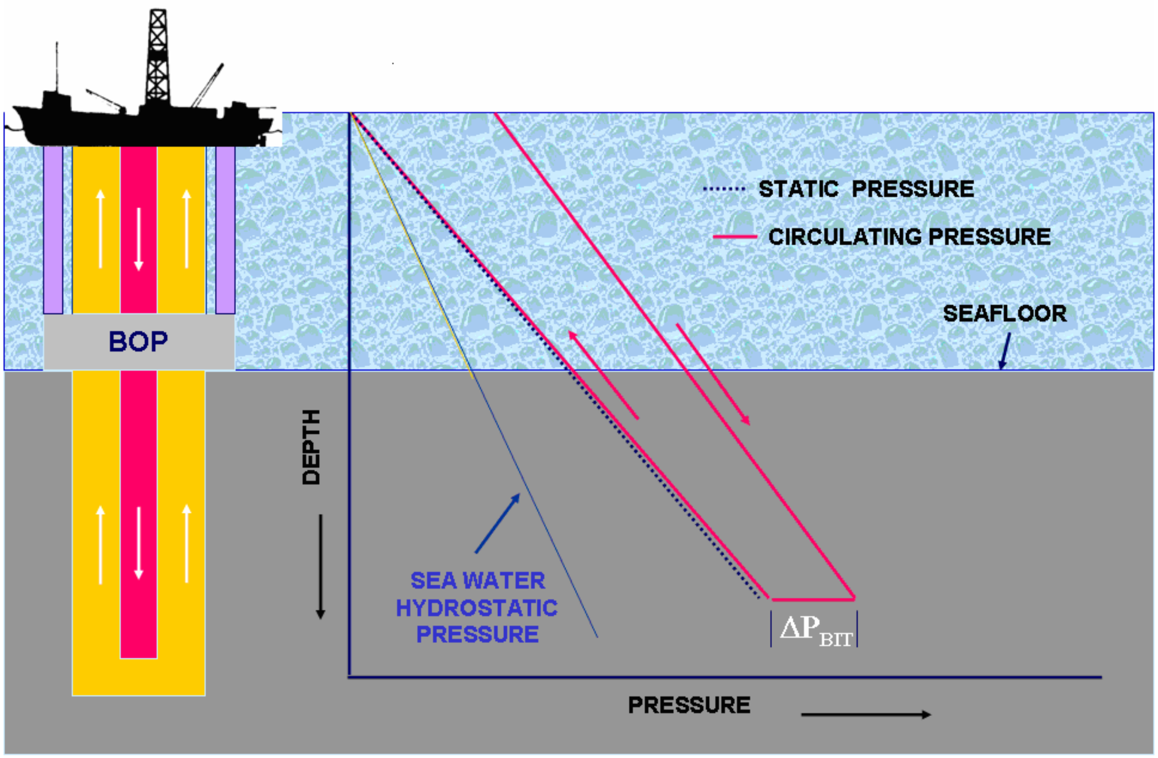

Fig 4.4 — Circulating pressure profile for conventional riser drilling.[2]

There are several rheological models that can be used to compute the wellbore hydraulics (Newtonian model, Bingham model and Power-law model). The API power-law rheological model was use for this computer program. This model combines the flow behavior parameters n and k, friction factor and the wellbore geometry to determine the pressure loss in the system.[23-24] Below is a list of the power-law equations used in the computer program.

Power-law equations are listed below. [24]

Flow behavior parameters.

$$n = 3.32 \log \frac{R_{600}}{R_{300}} \quad 4.1$$

$$k = \frac{510R_{300}}{511^{np}} \quad 4.2$$

Mean velocity

For the pipe

$$V = \frac{q}{2.448(d_1^{\ 2})} \quad 4.3$$

For the annulus

$$V = \frac{q}{2.448(d_2^{\ 2} - d_1^{\ 2})} \quad 4.4$$

Effective viscosity

For the pipe

$$\mu e = 100k\left(\frac{96v}{d_1^{\ 2}}\right)^{n-1}\left(\frac{3n+1}{4n}\right)^{n} \quad 4.5$$

For the annulus

$$\mu e = 100k\left(\frac{144v}{d_2 - d_1}\right)^{n-1}\left(\frac{2n+1}{3n}\right)^{n} \quad 4.6$$

To determine turbulence flow or laminar flow we use the Reynolds number

For the pipe

$$Nre = \frac{928dv\rho}{\mu e} \qquad 4.7$$

For the annulus

$$Nre = \frac{928(d_2 - d_1)v\rho}{\mu e} \qquad 4.8$$

If Nre >2100 the friction factor for both pipe and annulus are

$$f = \frac{a}{Nre^b} \qquad 4.9$$

where $a = \frac{(\log n + 3.93)}{50}$ 4.10

$$b = \frac{(1.75 - \log n)}{7} \qquad 4.11$$

If Nre <2100 the friction factor

For the pipe

$$f = \frac{16}{Nre} \qquad 4.12$$

For the annulus

$$f = \frac{24}{Nre} \qquad 4.13$$

Frictional pressure gradient

For the pipe

$$\left(\frac{\Delta P}{\Delta L}\right) = \frac{fv^2\rho}{25.81d} \qquad 4.14$$

For the annulus

$$\left(\frac{\Delta P}{\Delta L}\right) = \frac{fv^2 \rho}{25.81(d_2 - d_1)} \qquad 4.15$$

The above power-law equations are used in the computer program to determine the pressure losses in the drill pipe, wellbore annulus, the marine riser and in the charging line. Some minor adjustments where made in the calculation of the pressure drop across the marine riser. This is caused by the presence of the charging line at the bottom of the marine riser. When the charging line injects fluid into the marine riser it changes the flow rate, the mud density and the rheological properties of the mud. In order to account for these changes the following steps were taken. To obtain the new fluid density and rheological properties in the marine riser a weighted average of both fluids were taken. For the flow rate a summation of both flow rates was taken (injection and riser flow rates). The pressure loss across the drilling bit can be determined by using equation **4.16.**

$$Pbit = \frac{156 \rho Q^2}{\left(d_{n1}^2 + d_{n2}^2 + d_{n3}^2\right)^2} \qquad 4.16$$

4.3 Pressure Profile (Static and Circulating)

The pressure profile in the liquid lift, dual gradient drilling differs in so many ways from the conventional drilling method. When the mud pumps are shut down, the fluid level in the drill string will drop until the hydrostatic pressure in the drill string above the sea floor is equal to the hydrostatic pressure related sea water above the sea floor.[5] It is important to note that in the process of u-tubing, the base fluid is still being injected into the marine riser, so as to keep the marine riser density close to sea water density or the required density in the riser. The maximum mud level drop is a function of mud density, sea water density and water depth and it can be determined by equation **4.17**.[5]

$$h_{\max} = D_w \frac{(\rho_m - \rho_{sw})}{\rho_m} \qquad 4.17$$

where h_{max} is the maximum mud level drop in the drill string, D_w is the sea water depth, ρ_m is the mud density and ρ_{sw} is sea water density.[5] Also the mud density required to maintain the bottom hole pressure in the liquid lift, dual gradient drilling can be determined by using equation **4.18.**[3]

$$\rho_m = \frac{BHP - 0.052\rho_{sw} D_w}{0.052(D - D_w)} \qquad 4.18$$

Figure 4.5 is a graphical representation of the static pressure profile from the computer program. As depicted in the static pressure profile, the fluid level in the drill pipe dropped to 3120 ft, in order for the hydrostatic pressure in the drill pipe to be in equilibrium with the annular pressure. **Figure 4.6** represents the circulating pressure profile in the wellbore for liquid lift, dual gradient drilling. As depicted in the graph this pressure profile differs from the conventional drilling. Note that pressure loss across the drilling bit occurs only during circulation.[5] In order to obtain the pressure profile; we need to determine the standpipe pressure. The standpipe pressure is a function of the frictional pressure drop in the system, surface pressure and the hydrostatic differences between the annulus and the drill string. Equation **4.19** is a mathematical representation of the standpipe pressure.[3]

$$SPP = 0.052 \times D_w \times \left(\rho_{sw} - \rho_m\right) + \Delta Pf_{drop} + P_{surface} \qquad 4.19$$

where SPP is the standpipe pressure, ΔP_{fdrop} is the frictional pressure drop in the system and $P_{surface}$ is the annulus surface pressure.[3, 5] From equation 4.19 we can see that an increase in frictional pressure drop across the system, which is a function of the circulation rate, will cause an increase in the standpipe pressure. **Figure 4.6** shows a slight increase in the annulus pressure, this increase reflects the friction pressure in the annulus during circulation.[3] **Figure 4.7** is a wellbore representation of the liquid lift, dual gradient drilling system showing the pressure distribution and pressure losses with a 12.5 ppg mud at the annulus and sea water density in the riser. (wellbore depth = 30,000 ft and water depth 10,000)

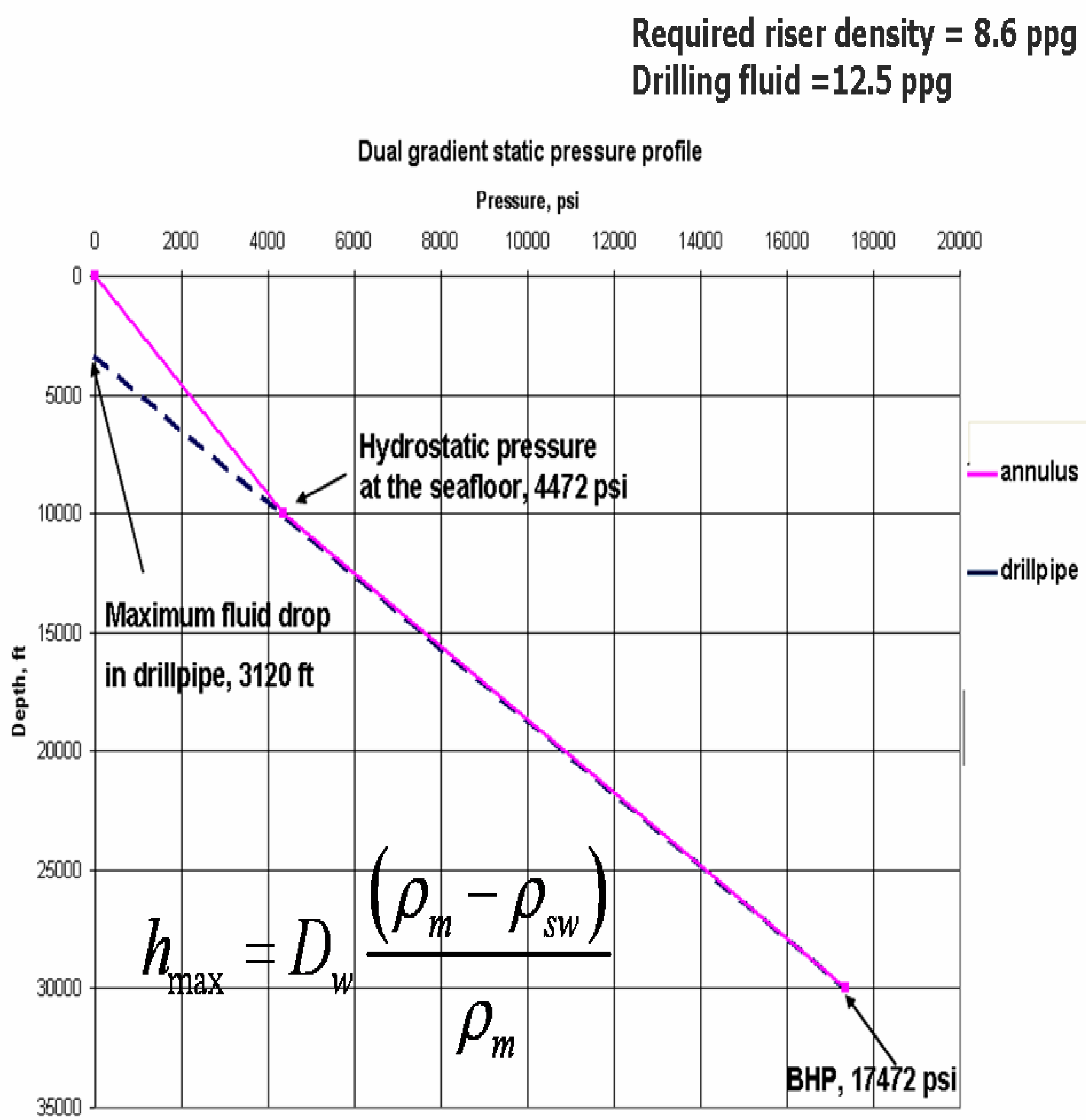

Fig 4.5 — Spreadsheet result for the static pressure profile with a maximum mud level drop of 3120 ft with a 12.5 ppg mud.

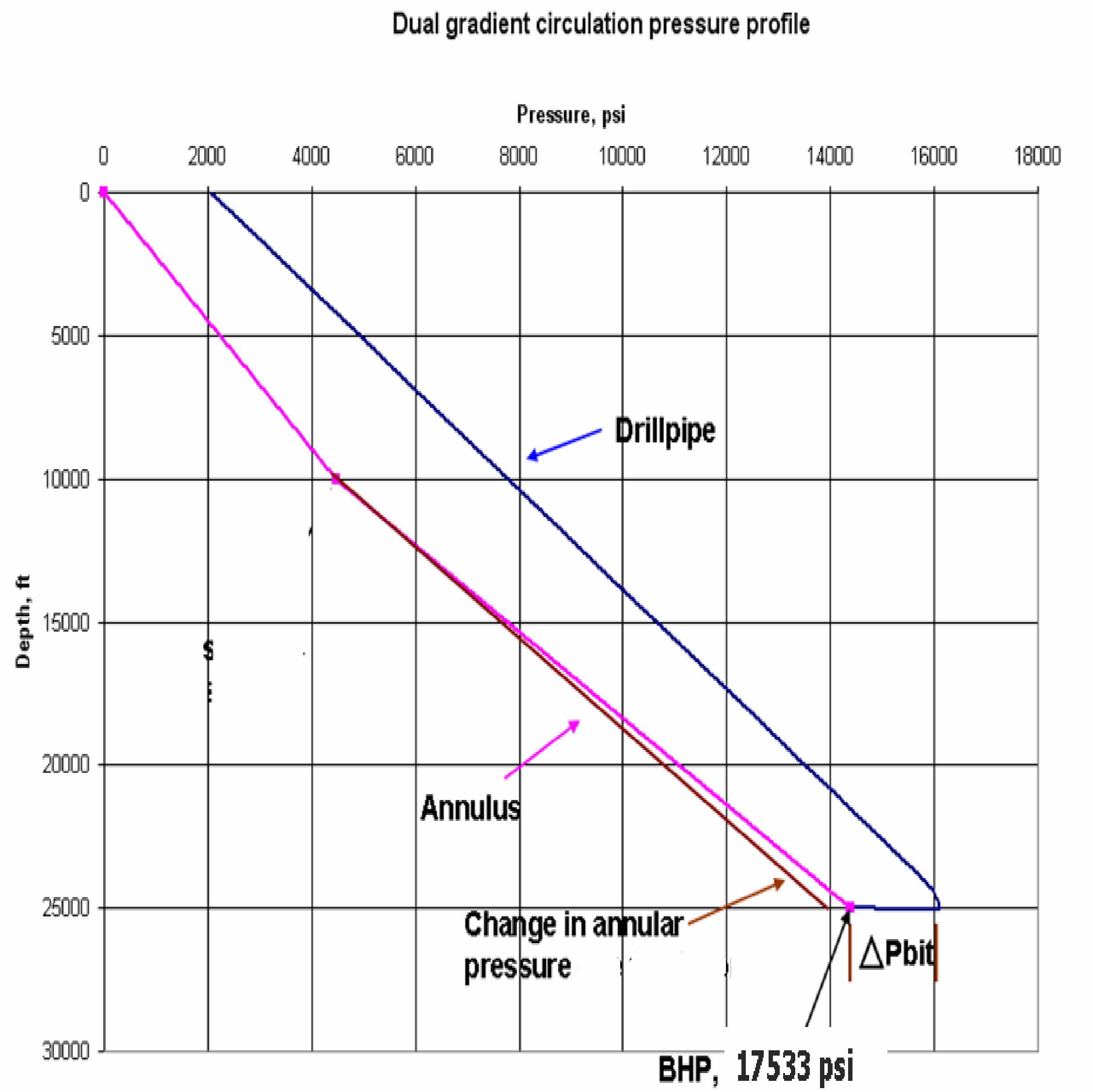

Fig 4.6 — Spreadsheet result for circulation pressure profile with a 12.5 ppg drilling fluid, 7 ppg base fluid, 500 gpm circulation rate and at BHP of 17472 psi.

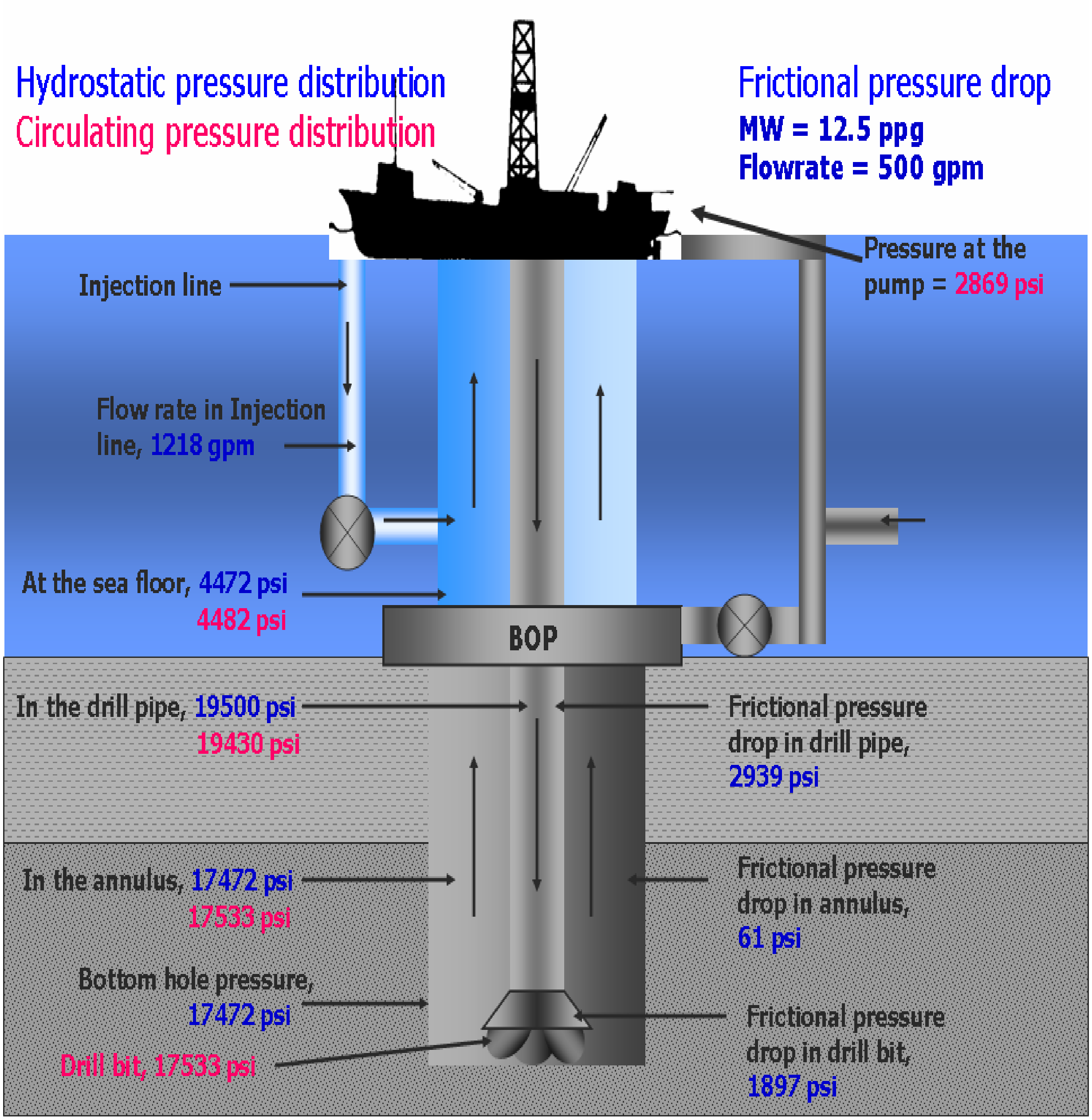

Fig 4.7 — Spreadsheet results showing the hydrostatic pressure distribution, circulating pressure distribution and frictional pressure drop.

4.4 Injection Rate in the Marine Riser

For this system to work it is very important to keep the marine riser density equal or slightly higher than sea water density or the required density to maintain the bottom hole pressure. For the convenience of the user the injection rate required to keep the riser density at sea water density or required density can be determined. The user can obtain the injection rate by pressing the button" inject rate". This action calculates the injection rate with the input data specified in the charging line section of the input data sheet. The required injection rate would be displayed in a red cell next to the input injection rate cell. Injection rate of base fluid into the riser is a very important part of this system; this can be seen in the graphs below.

Figures 4.8 & 4.9 are graphical representations of mixture density (base density and drilling fluid density) versus injection rate with a drilling fluid of 12.5 ppg. The graphs show the mixture densities when the injection rate is varied. From figure 4.8 we can see that a high flow rate requires a high injection rate to achieve the required density in the riser. By comparing figures 4.8 and 4.9; we see that a lesser injection rate is required to dilute the riser when a 6 ppg base fluid is used against a 7 ppg base fluid.

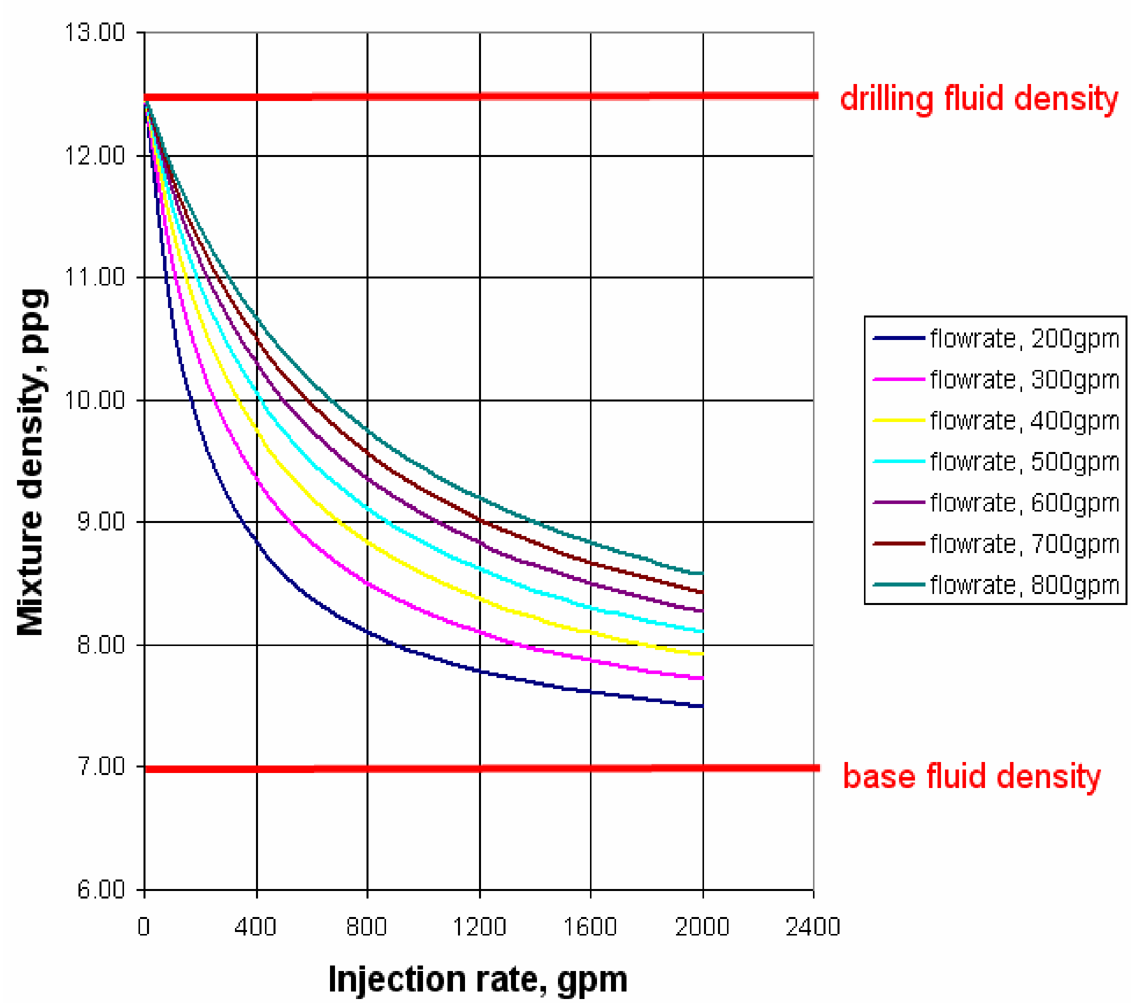

Figure 4.8 — Spreadsheet result showing the effect of injection rate (gpm) on the mixture density in the riser (base fluid and drilling fluid) with a 7 ppg base fluid.

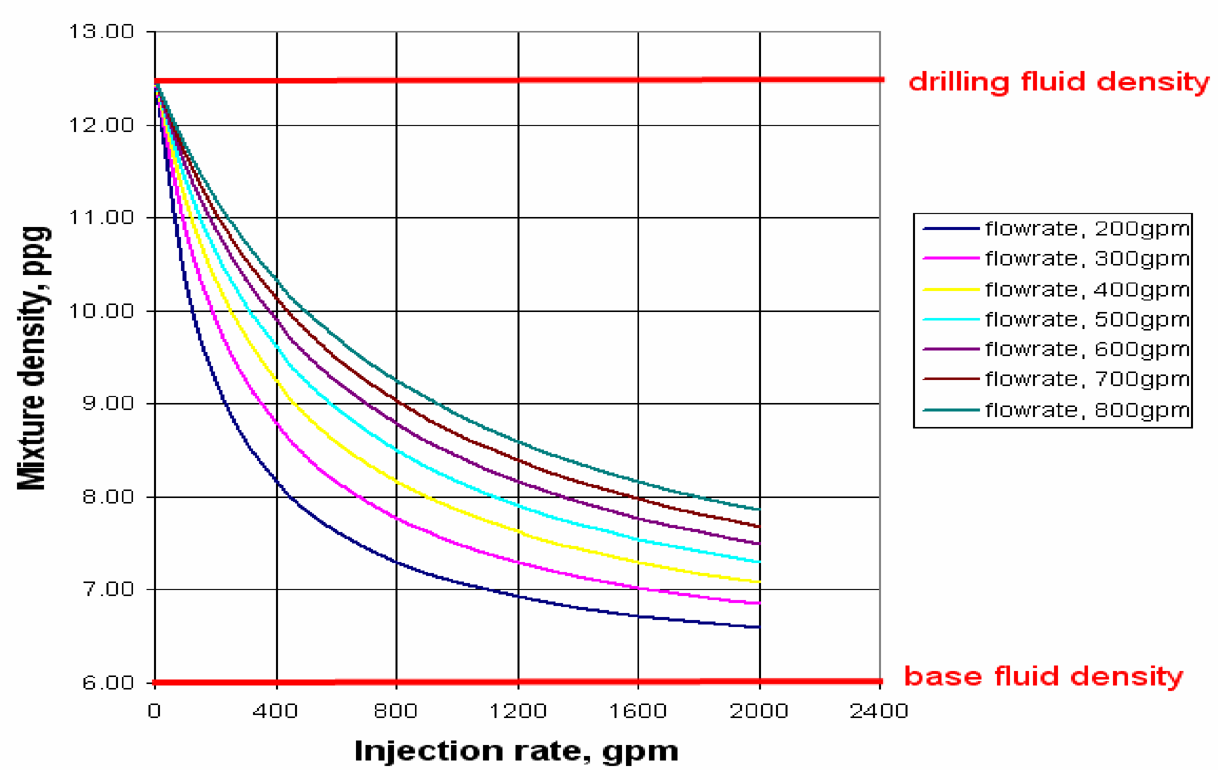

Figure 4.9 — Spreadsheet result showing the effect of injection rate (gpm) on the mixture density in the riser (base fluid and drilling fluid) with a 6ppg base fluid.

Figures 4.10 & 4.11 are graphical representations of the injection rate required to dilute the drilling fluid coming into the riser to a specified density (8.66 ppg) at different flow rate. **Figures 4.12 & 4.13** are graphical representations of the effect of injection rate at the riser on the hydrostatic pressure at the sea floor with a base fluid of 7 ppg and drilling fluid of 12 ppg. **Figure 4.13** is similar to figure 4.12 but a base fluid of 6 ppg is used.

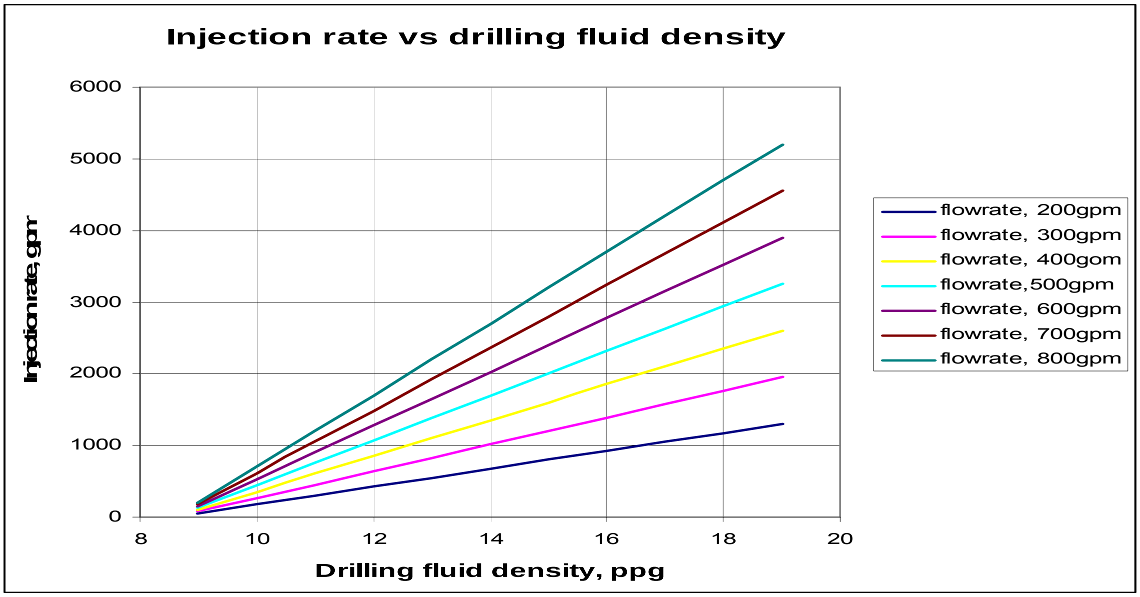

Fig 4.10 — Spreadsheet result showing the injection rate required to dilute the drilling fluid to the desired riser density (8.66 ppg) using a 7 ppg base fluid with a flow rate varied.

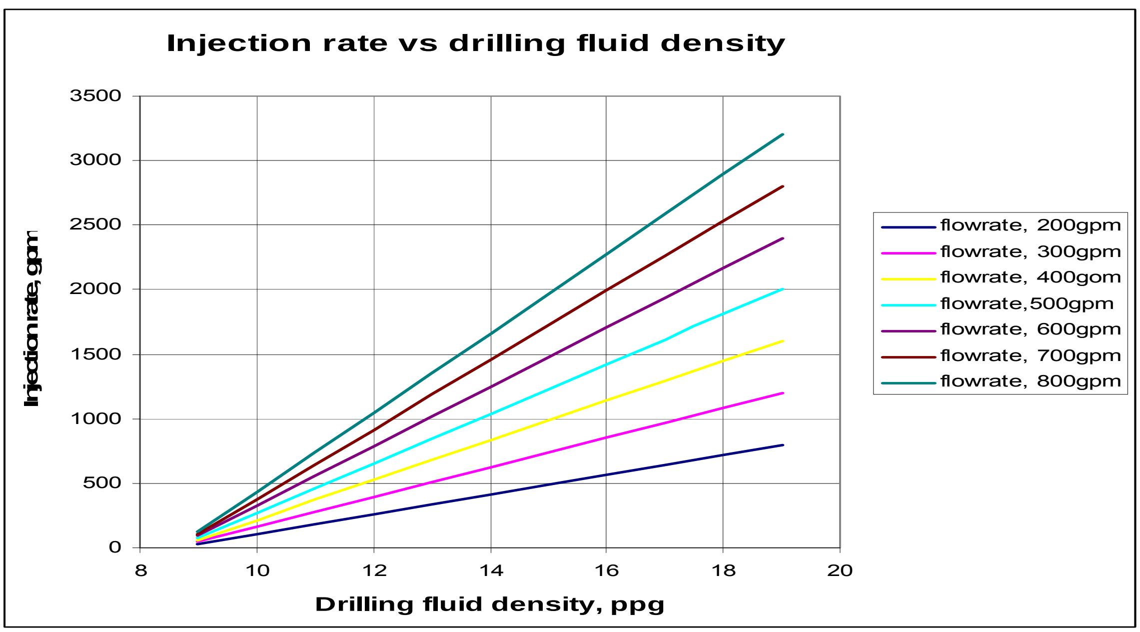

Fig 4.11 —Spreadsheet result showing the injection rate required to dilute the drilling fluid to the desired riser density (8.66 ppg) using a 6 ppg base fluid with a flow rate varied.

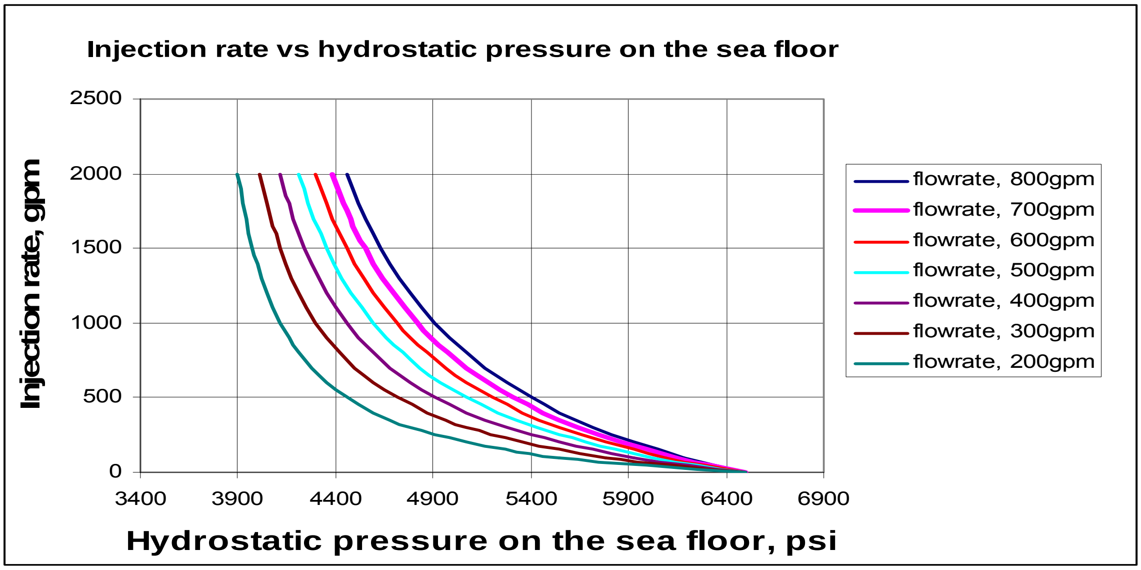

Fig 4.12 — Spreadsheet result showing the effect of injection rate on sea floor hydrostatic with a mixture of 7 ppg base fluid and 12.5 ppg drilling fluid.

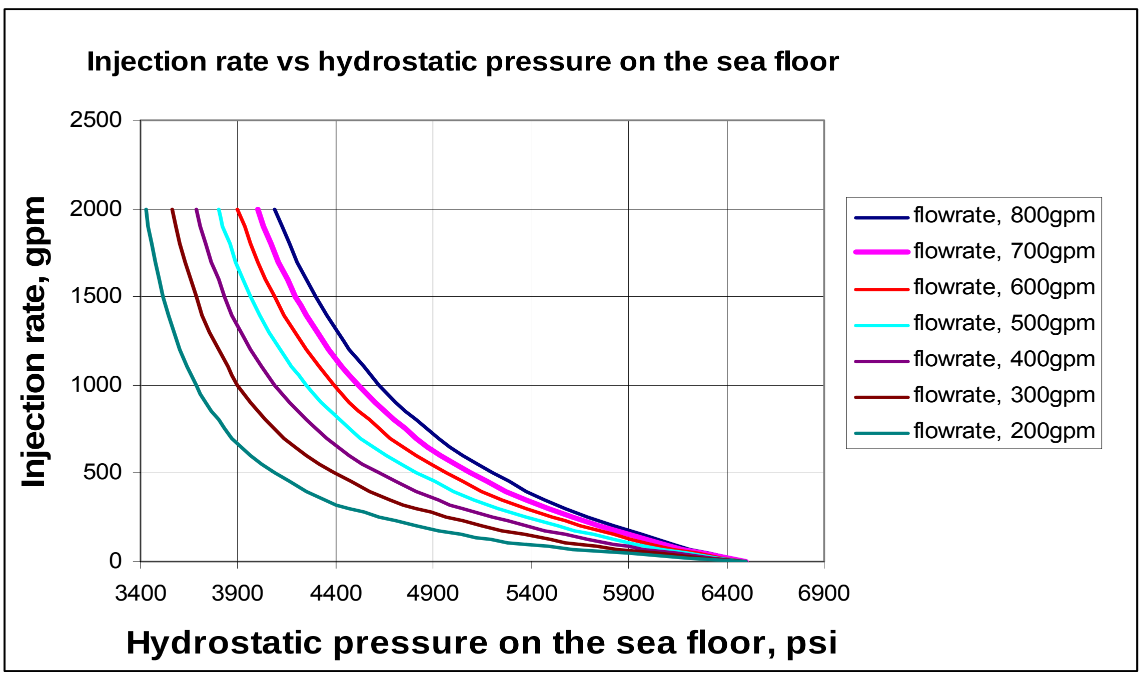

Fig 4.13 — Spreadsheet result showing the effect of injection rate on sea floor hydrostatic with a mixture of 6 ppg base fluid and 12.5 ppg drilling fluid.

4.5 U-tubing Computation

U-tubing is basically a phenomenon that occurs when the mud pumps are shut down in a dual gradient system. This phenomenon takes place in dual gradient drilling because the drill string is filled with heavy density mud while the annulus is filled with mud up to the sea floor and from the sea floor to the surface we have mixture fluid.[5] This arrangement creates a pressure difference between the drill string and the annulus. Once the mud pumps are shut down the hydrostatic pressure in the drill string drives the fluid column in the annulus until equilibrium is reached. This driving force works against the frictional pressure losses in the drill pipe, drill bit, annulus and hydrostatic pressure in the riser. In order to determine the flow rate at a certain mud level in the drill pipe, the driving force in the drill pipe is equated to the total frictional pressure drop in the system by varying the flow rate. This can be achieved by using the bisection numerical method.[3, 5] The driving force equation is represented by equation **4.20,** where h_x is the current mud level in the drill pipe.[3]

$$f = 0.052 \times \left(\rho_m \times \left(D_w - h_x\right) - \left(D_w \times \rho_{rm}\right)\right) \qquad 4.20$$

CHAPTER V

U-TUBING RATE IN LIQUID LIFT METHOD

5.1 Introduction

As discussed in previous chapters, u-tubing is phenomena that occur when the mud pumps are shut down. If the mud pumps are shut down the mud column in the drill string exerts a hydrostatic pressure that is greater than the hydrostatic pressure in the annular side. Therefore, this causes the mud in the drill pipe to free fall until it reaches equilibrium. According to Choe,[5] during u-tubing the annular pressure should be kept from increasing in order to prevent formation fracture. In subsea mudlift drilling, the right annular pressure can be maintained by varying the inlet pressure in the subsea pump. But, in liquid lift, dual gradient drilling a different approach is utilized to maintain the annular pressure. U-tubing is phenomena that occur in all methods of achieving dual gradient and the rate at which it occurs are very similar. **Figure 5.1** is a plot from the subsea mudlift drilling simulator of u-tubing rate against time in the drill string when the pumps are shut down (u-tubing rate dual gradient drilling). From the graph we can notice changes in the u-tubing rate pattern. According to Choe, [5] this pattern was described as follows; the initial circulation rate **(1)**, when the pumps are shut down, we see a dynamic effect as the fluid level drops **(2)**, drop in fluid level decreases the driving force of the mud column in the drill string **(3)**, change from turbulent flow to laminar flow is noticed **(4)** and finally the fluid comes to a stop **(5)**. [2, 5] But, dual gradient drilling systems, incorporated with DSV do not experience the u-tubing phenomena because the DSV in the drill pipe prevents the drilling mud from free falling.[3, 26]

According to Johansen,[26] there are several parameters that affect the rate of u-tubing in dual gradient drilling. Mud weight, initial circulation rate, drill pipe diameter, bit nozzle size, wellbore depth and fluid viscosity are the parameters that affect u-tubing rate.

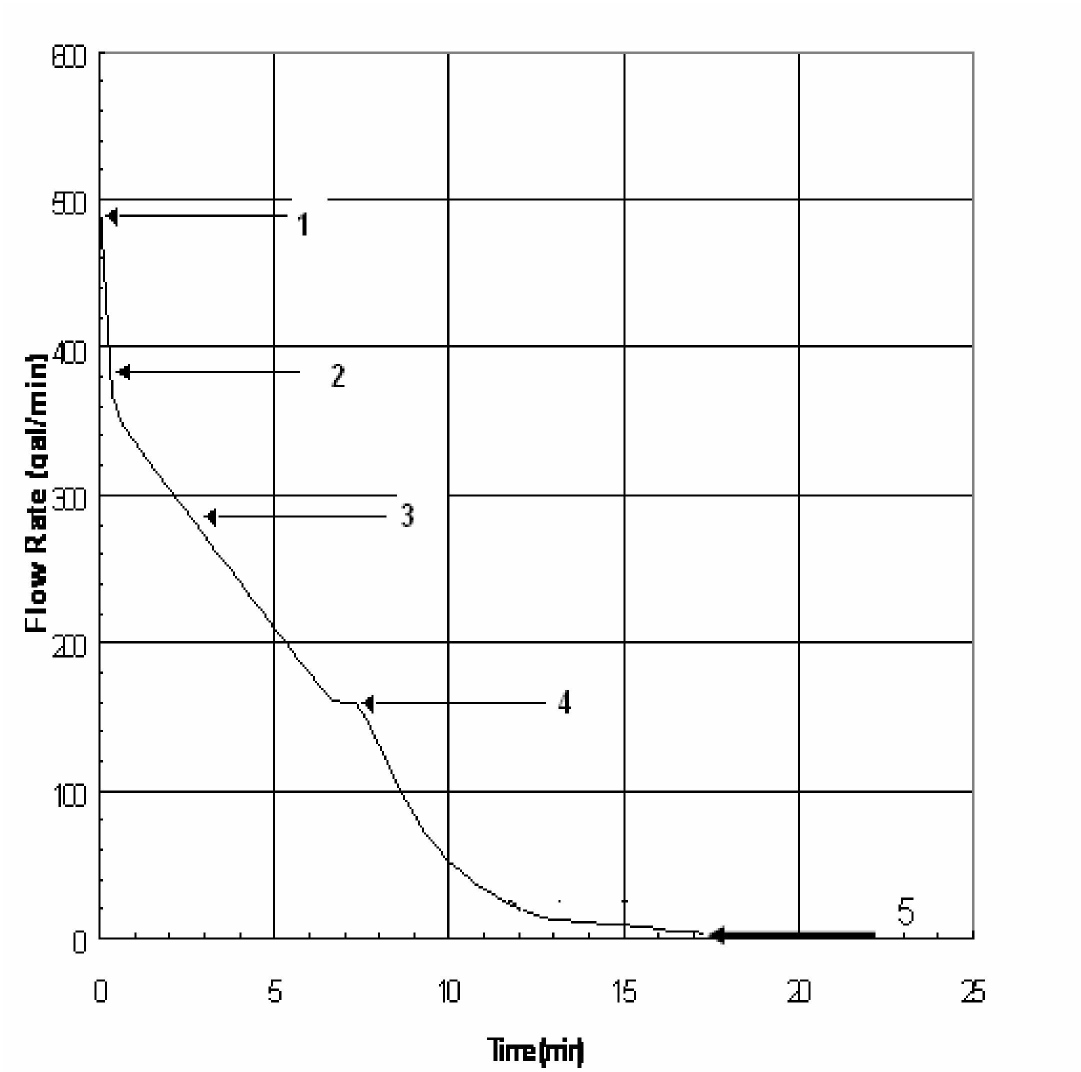

Fig 5.1— U-tubing rate (gpm) vs. time (min).[26]

5.2 U-Tubing in the Liquid Lift, Dual Gradient Drilling Method

In liquid lift dual gradient drilling, when u-tubing occurs, it is important that the density in the riser stays within the required sea water density in order to provide the right annular pressure needed to keep the formation fluid from entering the wellbore. Therefore, the injection of base fluid into the riser should be continued during u-tubing. If the injection of base fluid is shut down during u-tubing the mud inside the drill string will displace the light density liquid in the marine riser and replace it with the heavy mud. This will cause an increase in the hydrostatic pressure in the annular side which in turn can fracture the formation. **Figure 5.2** is a graphical representation of the pressure profile during u-tubing, without base fluid injection.

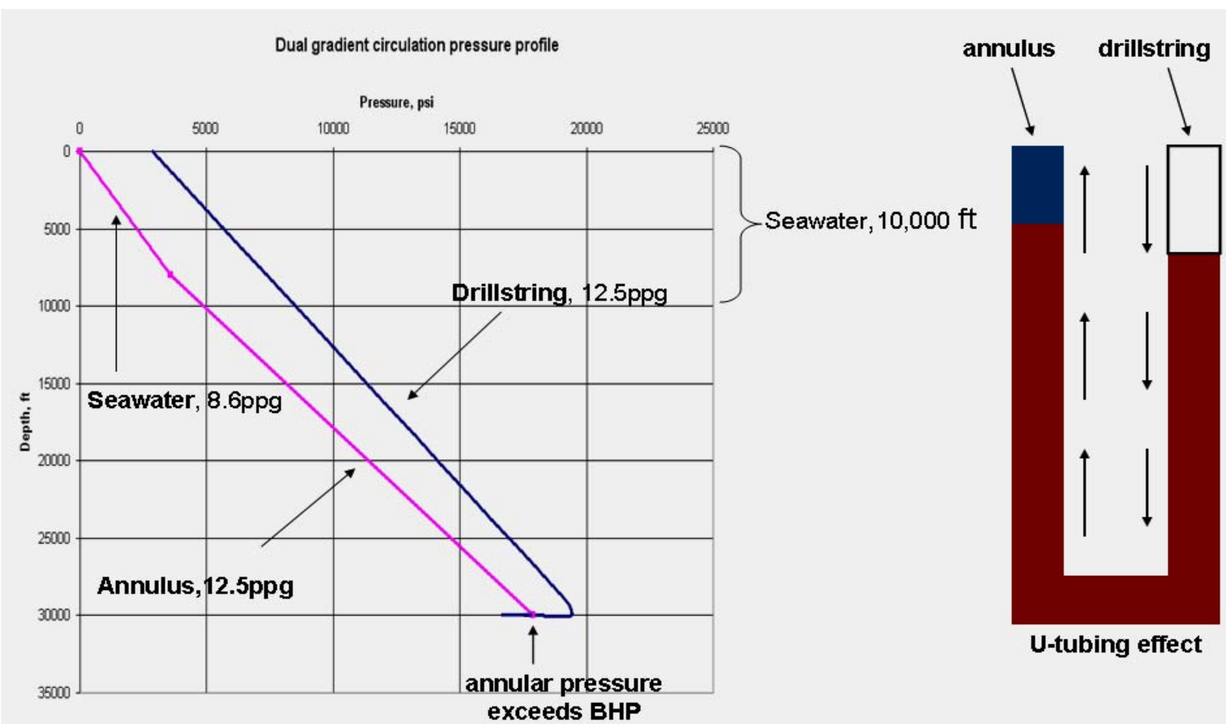

Fig 5.2 – U-tubing with riser injection shut-down.

But, the greatest issue is the determination of the injection rate of the base fluid during u-tubing in order to maintain the right annular pressure. This is related to the fact that as the mud level in the drill string drops there is a dynamic change in u-tubing rate. One possible way of handling this issue is to monitor the u-tubing rate. For example the current computer model can determine the injection rate required as the u-tubing rate changes. **Figure 5.3** shows the required injection rate at anytime during u-tubing. This graph is very similar to the graph of flowrate versus time during u-tubing shown in **Figure 5.4**.

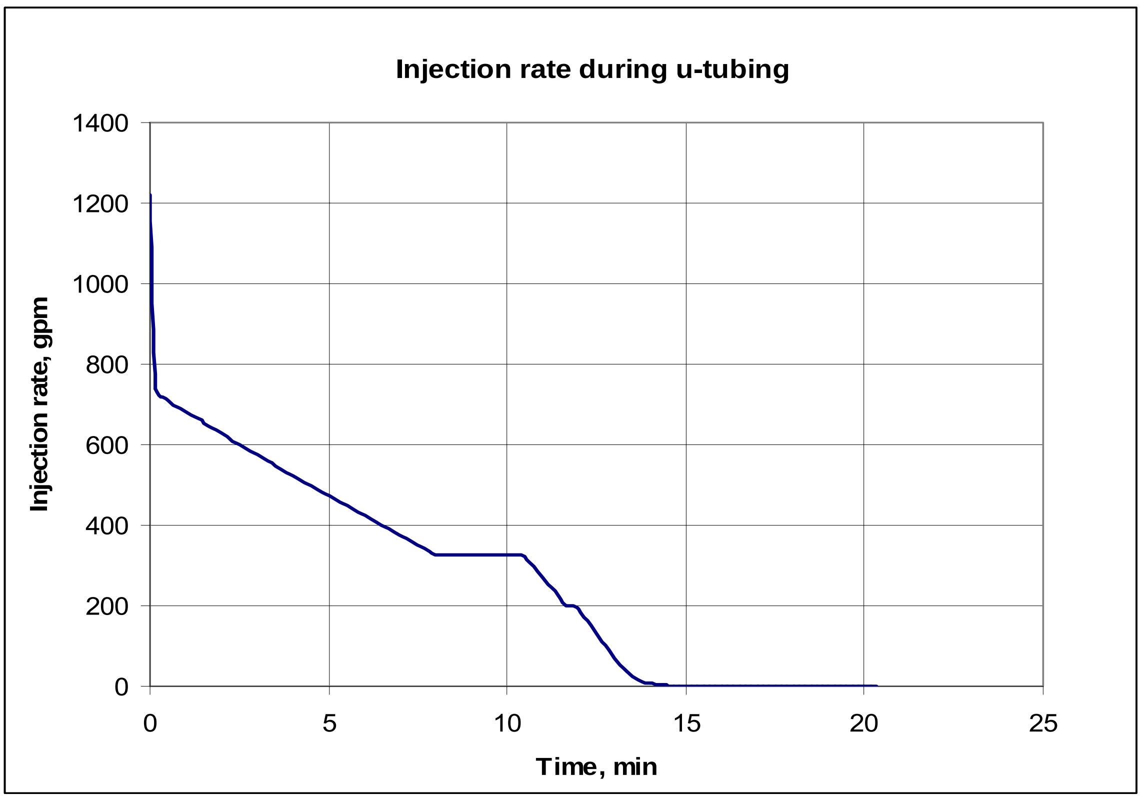

Fig 5.3 — Spreadsheet result showing the required injection rate at anytime during u-tubing with a base fluid of 7ppg, drilling fluid of 12.5 ppg and flowrate of 500 gpm

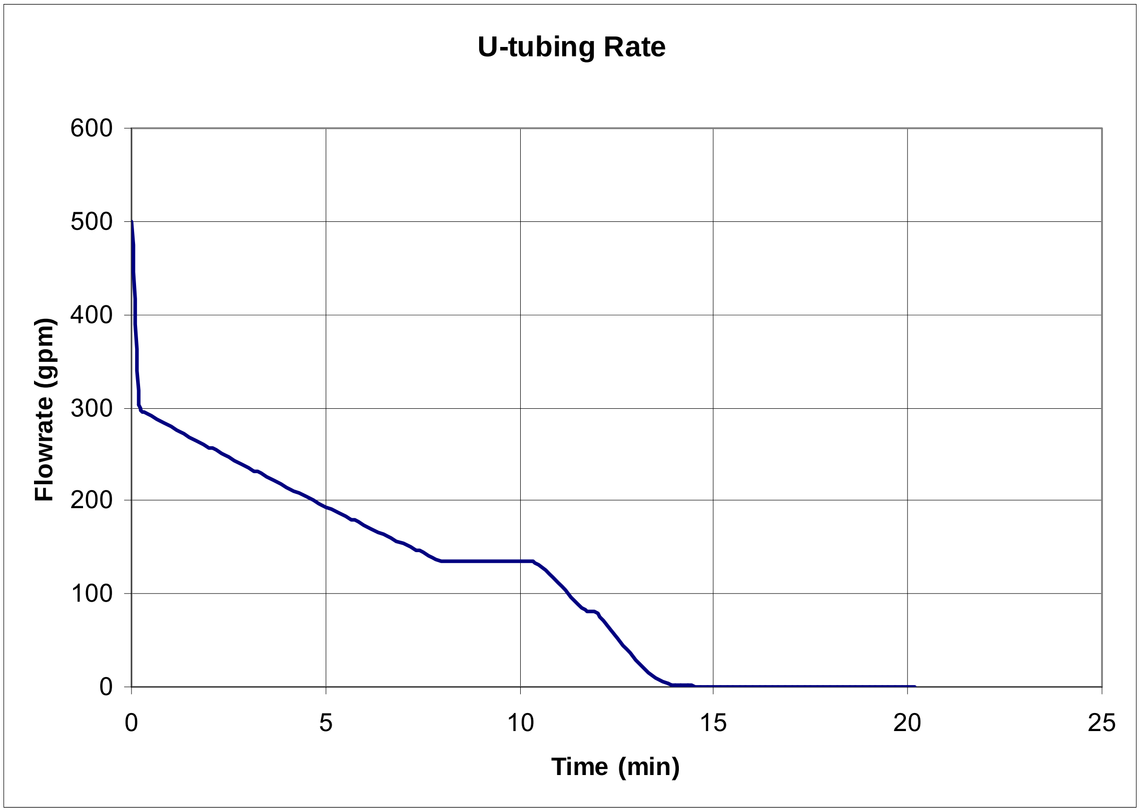

Fig 5.4 — Spreadsheet result showing the u-tubing rate with a base fluid of 7 ppg, drilling fluid of 12.5 ppg and an initial flowrate of 500 gpm.

Figure 5.5 is a graphical representation of injection rate versus flow rate as u-tubing takes place. The result obtained from these graphs can be used to monitor and determine the injection rate required during u-tubing. Therefore, in order to maintain the balance between the flow rate and injection rate during u-tubing, a device is required to monitor the change in u-tubing rate in the drill string and implement the new injection rate needed to dilute the marine riser. This problem is particular to the riser dilution method. In the case of riserless drilling, the pressure exerted by the sea water column, is replaced with the inlet pressure of the subsea pumps. This makes it easier to maintain the bottom hole pressure during u-tubing in subsea mudlift drilling. In the case of detecting a kick during u-tubing the PWD tool is a very good device to use. According to Ostermeier,[19] the PWD tool was designed to detect and provide an estimate of sand pore pressure when in overpressured sand.

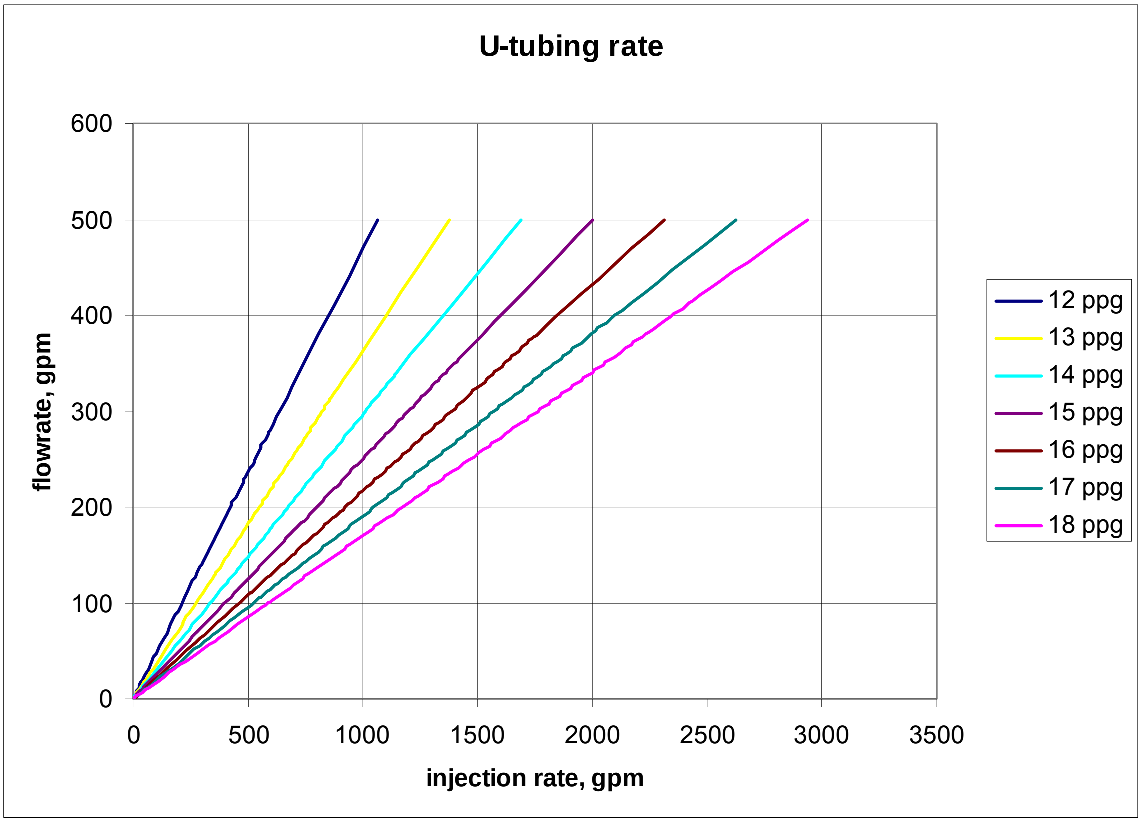

Fig 5.5 — Spreadsheet result showing injection rate versus flow rate during u-tubing with a 12.5 ppg drilling fluid and a 7 ppg base fluid.

CHAPTER VI

CONCLUSIONS AND RECOMMENDATION

6.1 Conclusion

The liquid lift method is a dual gradient drilling technique that does not utilize elaborate subsea pumps, a large gas compressor or hollow spheres that will introduce complications into the system. This makes it a more attractive system compared to the other methods of dual gradient drilling. Though, there are advantages and disadvantages to this method but the advantages outweigh the disadvantages.

In conclusion,

- At the riser, the fluid mixture of base fluid and drilling fluid must still have the suspension and transporting capacities.
- It is really important that the sea water density in the riser is maintained, so as not to cause formation fracture. Therefore, no matter the operation being carried out, as long as circulation is taking place in the wellbore, base fluid should always be injected into the riser to keep the riser fluid density at sea water density. During u-tubing, the injection rate of the base fluid must correspond to the u-tubing rate in order to maintain that balance in the riser.
- Well control, one of the biggest problems facing the drilling industry must be taken care of for this system to work effectively. In the liquid lift, dual gradient drilling a kick can be detected by using one of the conventional techniques (pit gain, increased hook load, drilling break) or the use of a PWD tool. The well

control procedure for the gas lift system can be applied in the liquid lift method. If a kick is detected the subsea BOP should be closed, mud pump shut down and the choke line should be kept in the open position filled with sea water. U-tubing should be allowed in the wellbore and then circulate up the choke line. The choke line should also be diluted with the base fluid in order to keep the fluid in the choke line at sea water density and maintain the bottom hole pressure.

6.2 Recommendation

One major issue facing this system is the u-tubing effect. The introduction of a drill string valve DSV will make this method a more reliable and cost effective method of achieving dual gradient drilling in deep waters.

Another concern is the difficulty in maintaining the right BHP, especially during well control operations. A PWD tool should be used to overcome this potential problem.

NOMENCLATURE

BHP	=	bottom hole pressure, psi
BOP	=	blowout preventer
d_1	=	inner diameter of drill pipe, in
d_1	=	annulus inner diameter, in
d_2	=	annulus outer diameter, in
d_{nz}	=	nozzles diameter, (1/32) in
D	=	total depth, ft
DGD	=	dual gradient drilling
DSV	=	drill string valve
D_w	=	water depth, ft
ECD	=	equivalent circulation density
f	=	frictional factor
F	=	frictional driving force during u-tubing rate, psi
gpm	=	gallons per minute
HSP	=	hydrostatic pressure, psi
h_{max}	=	maximum mud level drop inside drill string, ft
h_x	=	mud level drop inside the drill string at a certain time, ft
in	=	inches
ID	=	inner diameter, in
k	=	power-law consistency index
MWD	=	measurement while drilling

n	=	power-law fluid behavior
N_{re}	=	Reynolds number
OD	=	outer diameter, in
P_{bit}	=	bit pressure loss, psi
ppg	=	pounds per gallon
$P_{surface}$	=	pressure at the surface, psi
psi	=	pounds per square inches
PWD	=	pressure while drilling
q	=	fluid flowrate, gpm
Qi	=	flowrate in the annulus, gpm
Ql	=	flowrate in the riser charging line, gpm
R_{600}	=	viscometer reading at 600 rpm
R_{300}	=	viscometer reading at 300 rpm
R_{100}	=	viscometer reading at 100 rpm
R_3	=	viscometer reading at 3 rpm
SBM	=	synthetic base mud
SMD	=	subsea mudlift drilling
SRD	=	subsea rotating device
SPP	=	stand pipe pressure
v	=	fluid velocity
ρ_m	=	drilling fluid density, ppg
ρ_{sw}	=	base density in the riser charging line, ppg

ρ_{rm}	=	diluted riser density, ppg
μe	=	effective fluid viscosity
$\Delta P/ \Delta L$	=	frictional pressure loss per unit length
ΔP_{fdrop}	=	frictional pressure loss in the entire system
ΔP_{pump}	=	pump pressure

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APPENDIX A

Spreadsheet result showing the injection rate required to dilute different drilling fluid densities in the riser to the desired riser density (8.6 ppg) at a varied circulation rate. For example in fig A-1 if a 10 ppg drilling fluid is used and circulated at 800 gpm, an injection rate of approximately 1900 gpm is required to dilute the riser to 8.6 ppg.

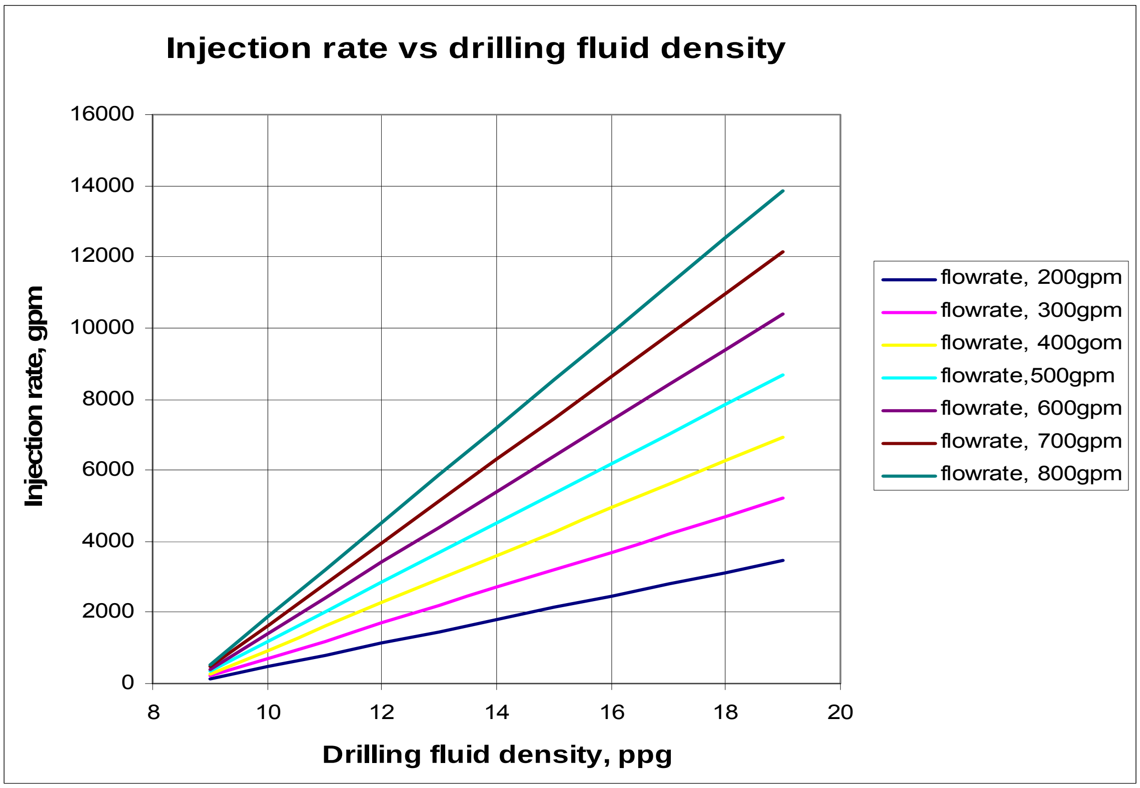

Fig A-1. —Spreadsheet result showing the injection rate required to dilute the drilling fluid to the desired riser density (8.66 ppg) using a 8 ppg base fluid.

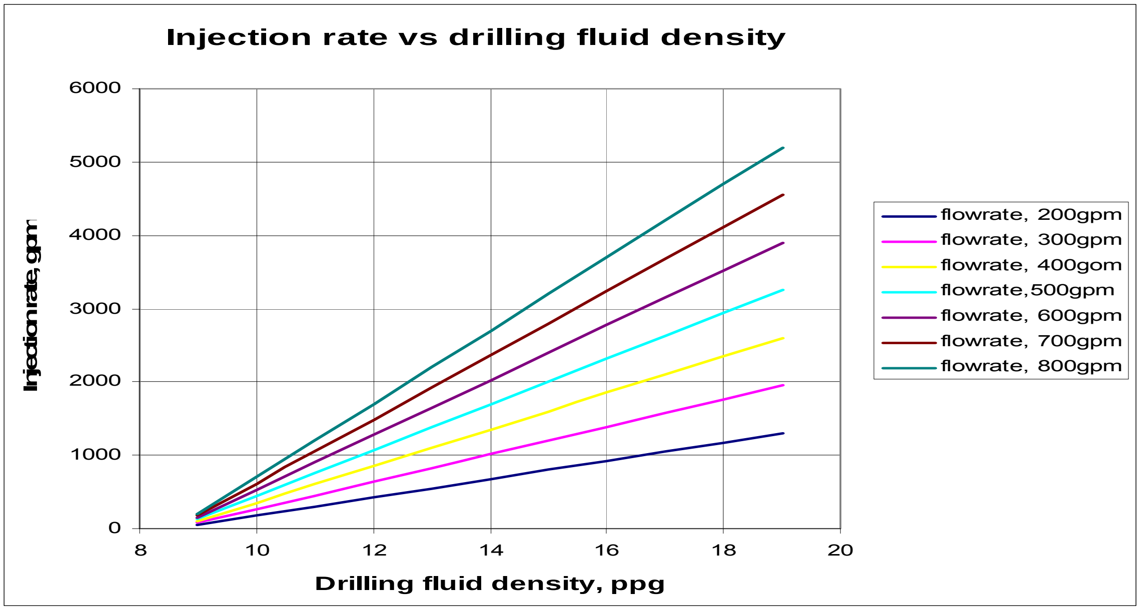

Fig A-2. —Spreadsheet result showing the injection rate required to dilute the drilling fluid to the desired riser density (8.66 ppg) using a 7 ppg base fluid.

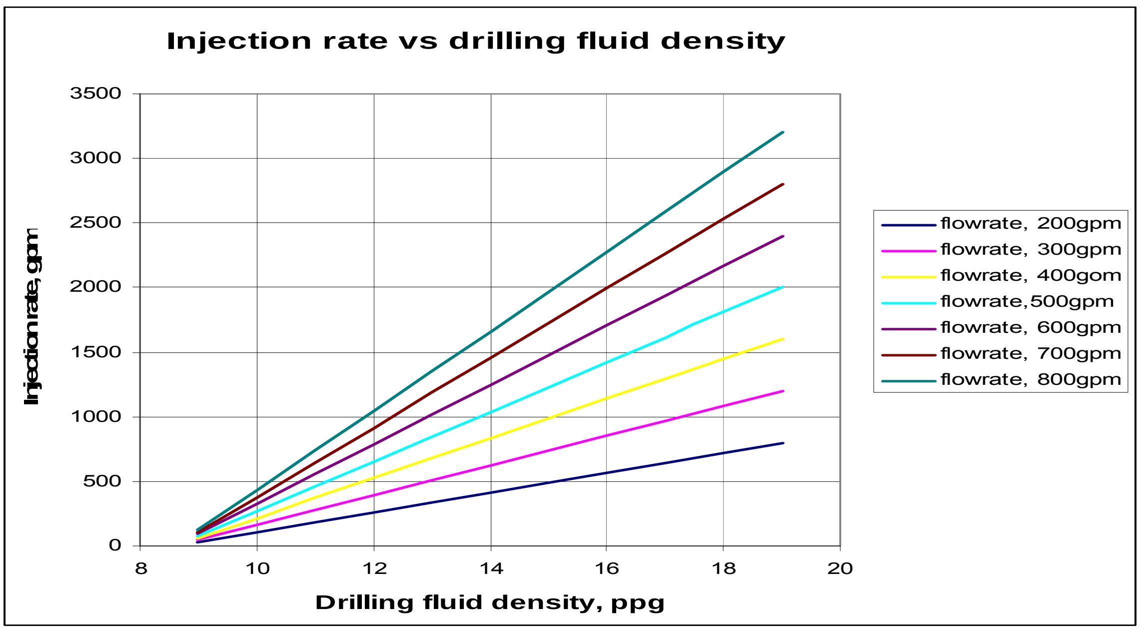

Fig A-3. —Spreadsheet result showing the injection rate required to dilute the drilling fluid to the desired riser density (8.66 ppg) using a 6 ppg base fluid.

The graphs below show the effect of injection rate in mixing the base fluid and the drilling fluid. As depicted in fig A-4, an increase in injection rate with a low circulation rate further decreases the mixture density in the marine riser. For example an injection rate of 1600 gpm with circulation rate of 500 gpm, results to a lower mixture density (drilling fluid and base fluid) to 8.36 ppg.

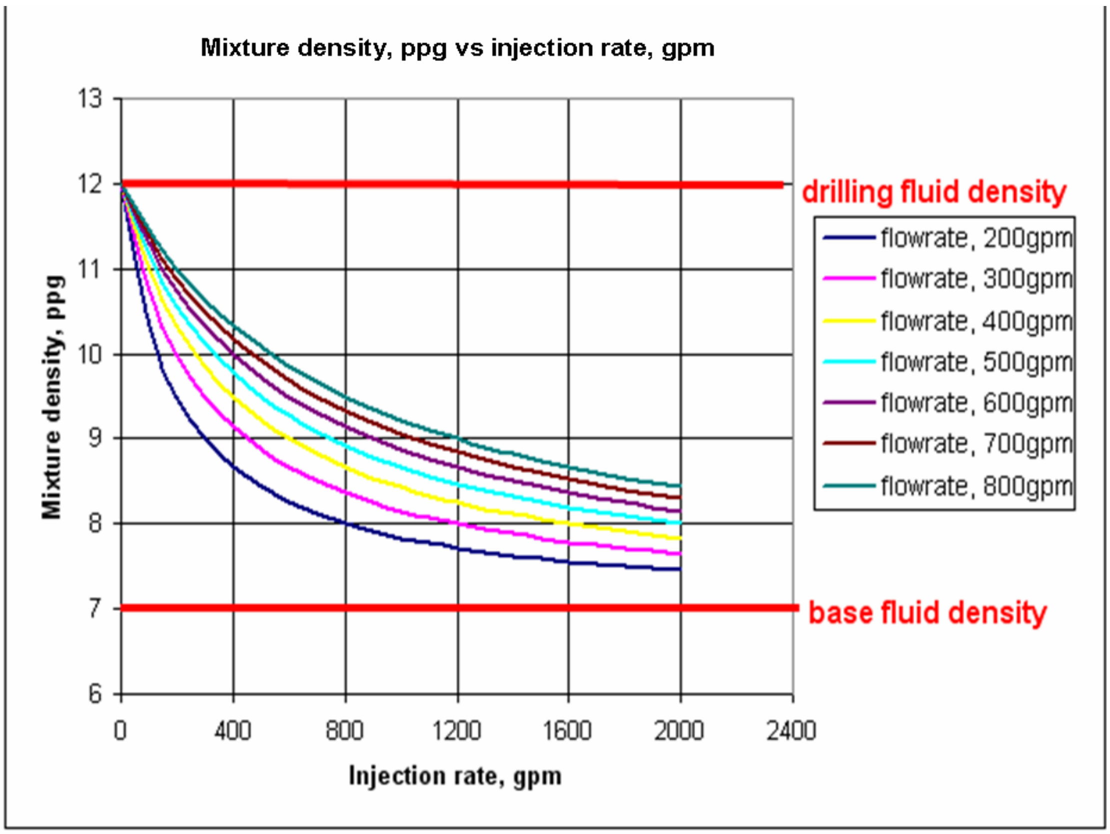

Figure A-4 — Spreadsheet result showing the effect of injection rate (gpm) on the mixture density in the riser (base fluid and drilling fluid) with a 7 ppg base fluid and 12 ppg drilling fluid.

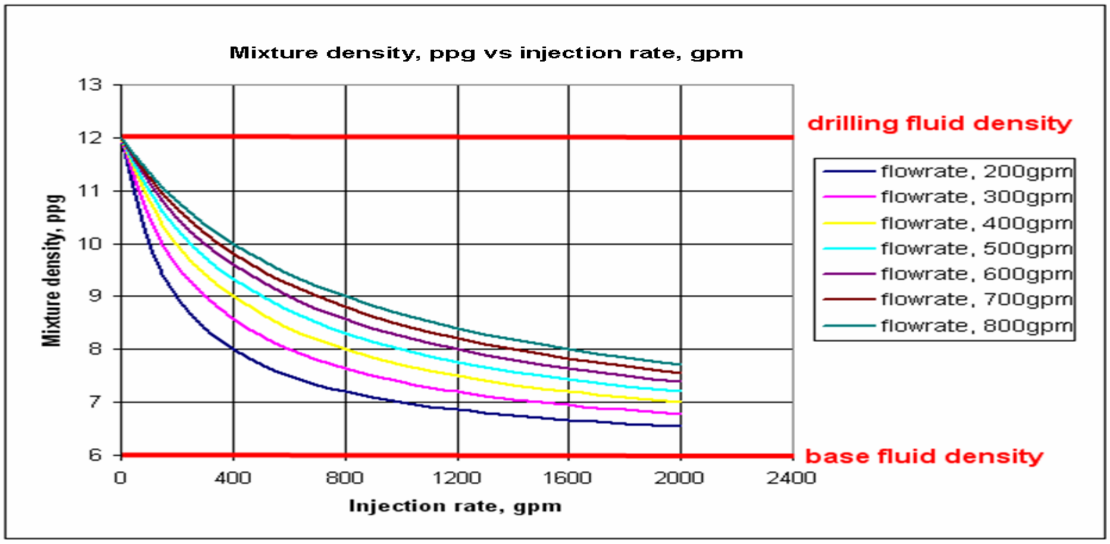

Figure A-5 — Spreadsheet result showing the effect of injection rate (gpm) on the mixture density in the riser (base fluid and drilling fluid) with a 6 ppg base fluid and 12 ppg drilling fluid.

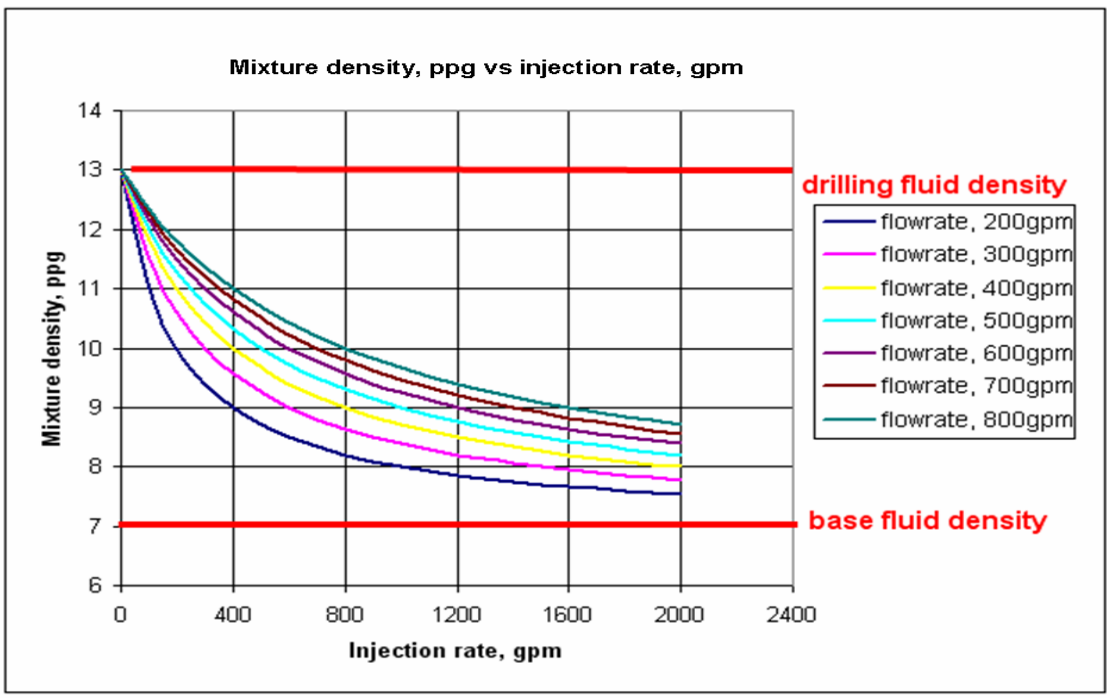

Figure A-6 — Spreadsheet result showing the effect of injection rate (gpm) on the mixture density in the riser (base fluid and drilling fluid) with a 7 ppg base fluid and 13 ppg drilling fluid.

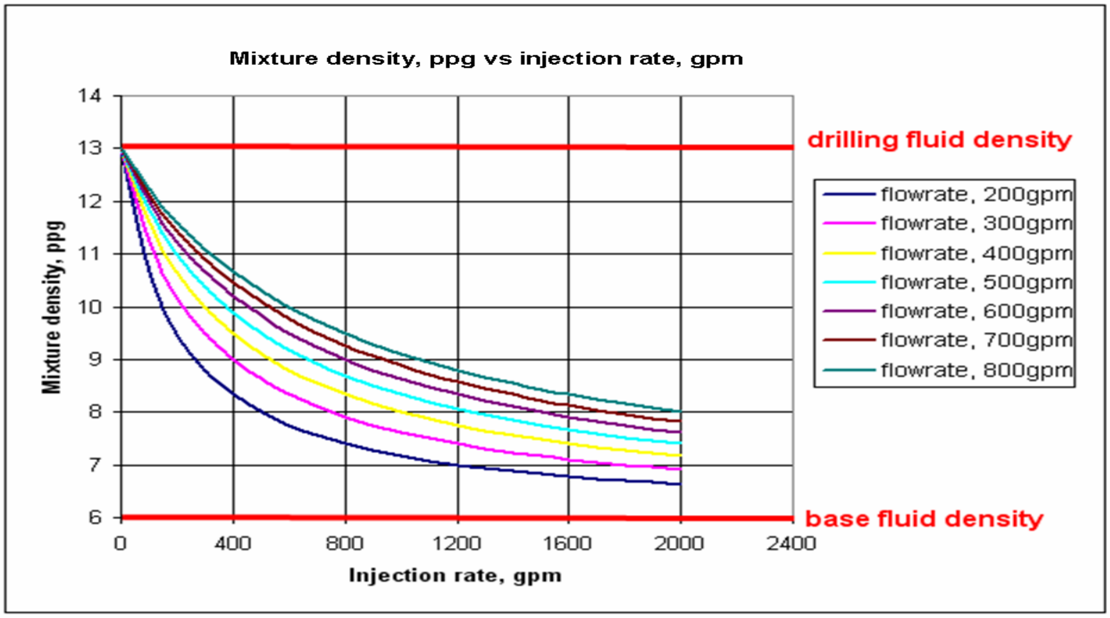

Figure A-7— Spreadsheet result showing the effect of injection rate (gpm) on the mixture density in the riser (base fluid and drilling fluid) with a 6 ppg base fluid and 13 ppg drilling fluid.

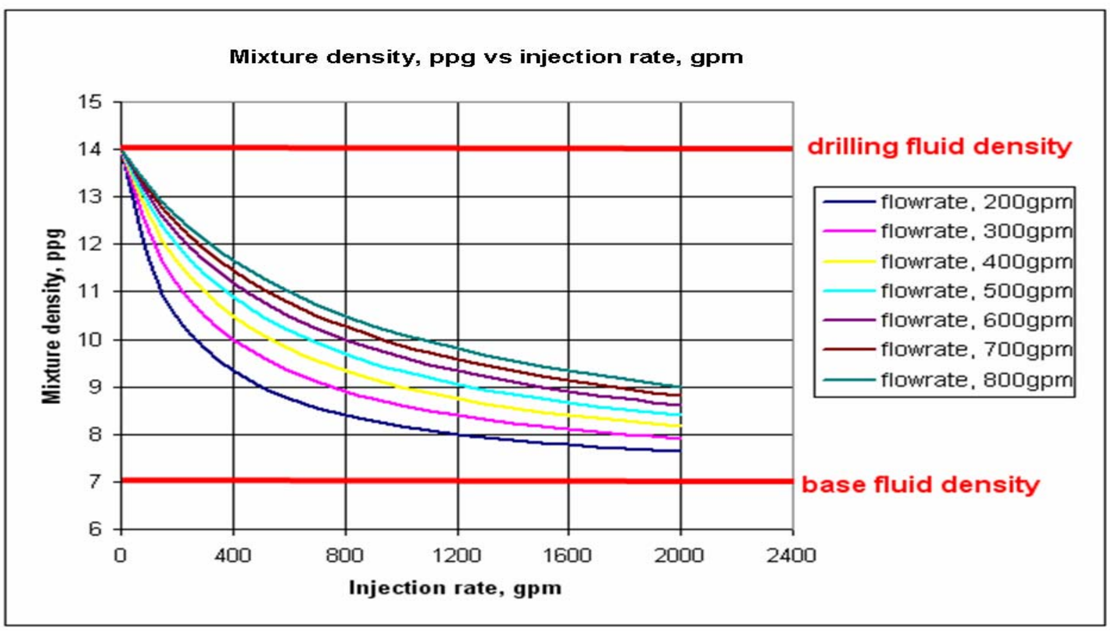

Figure A-8— Spreadsheet result showing the effect of injection rate (gpm) on the mixture density in the riser (base fluid and drilling fluid) with a 6 ppg base fluid and 14 ppg drilling fluid.

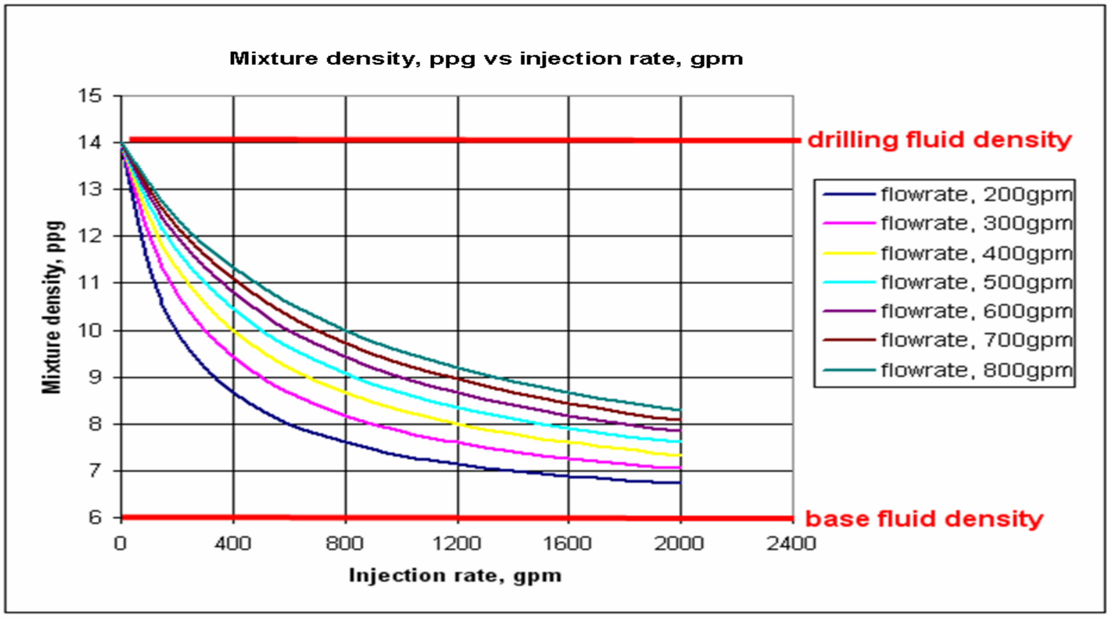

Figure A-9— Spreadsheet result showing the effect of injection rate (gpm) on the mixture density in the riser (base fluid and drilling fluid) with a 6 ppg base fluid and 14 ppg drilling fluid.

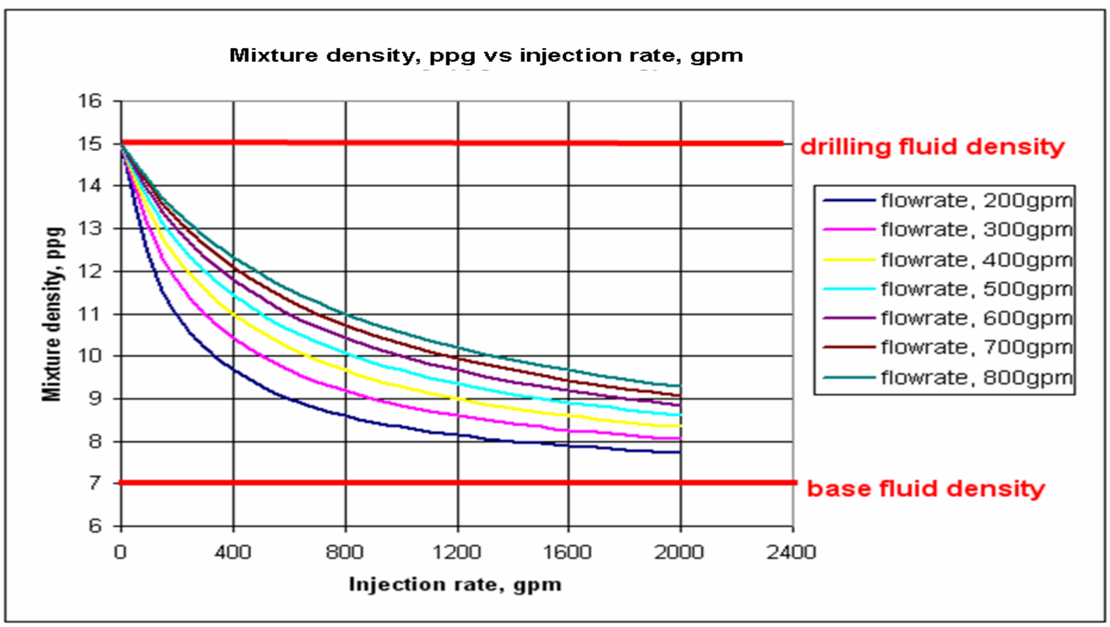

Figure A-10— Spreadsheet result showing the effect of injection rate (gpm) on the mixture density in the riser (base fluid and drilling fluid) with a 7 ppg base fluid and 15 ppg drilling fluid.

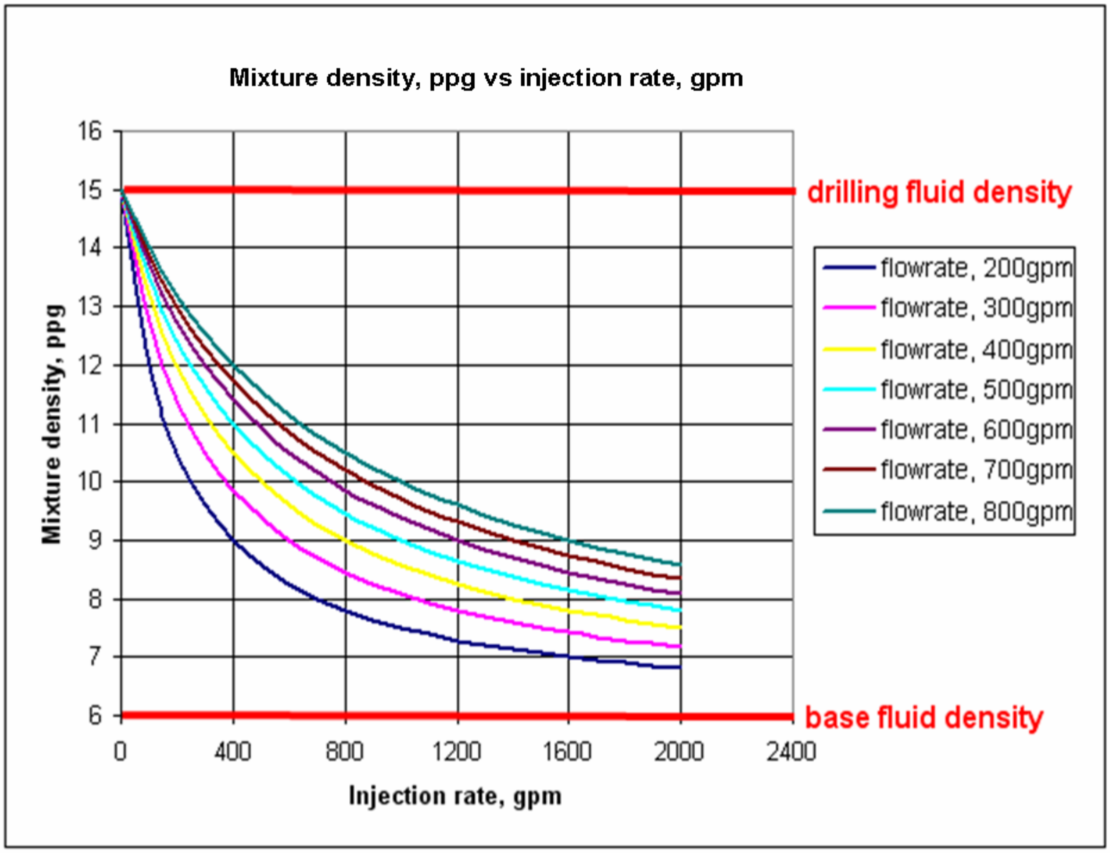

Figure A-11— Spreadsheet result showing the effect of injection rate (gpm) on the mixture density in the riser (base fluid and drilling fluid) with a 6 ppg base fluid and 15 ppg drilling fluid.

The graphs below show the effect of injection rate in mixing the base fluid and the drilling fluid. The base fluid injected into the riser is greater than or slightly less than sea water density. It is important to note that sea water density is not required at all times. But, it is of utmost importance that the composite column of fluid in the annulus and the riser stay within the pore and fracture pressures of the wellbore. The graph below represents mixture density versus injection rate when base fluid is greater than sea water density.

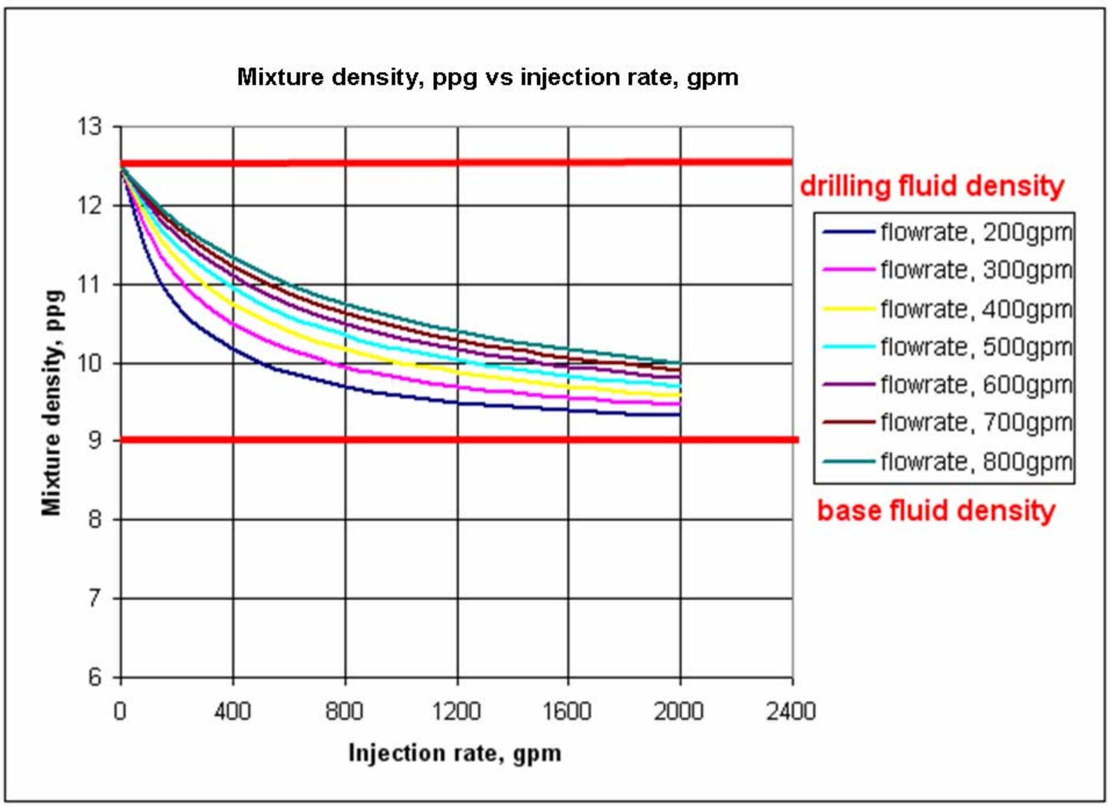

Figure A-12— Spreadsheet result showing the effect of injection rate (gpm) on the mixture density in the riser (base fluid and drilling fluid) with a 9 ppg base fluid and 12.5 ppg drilling fluid.

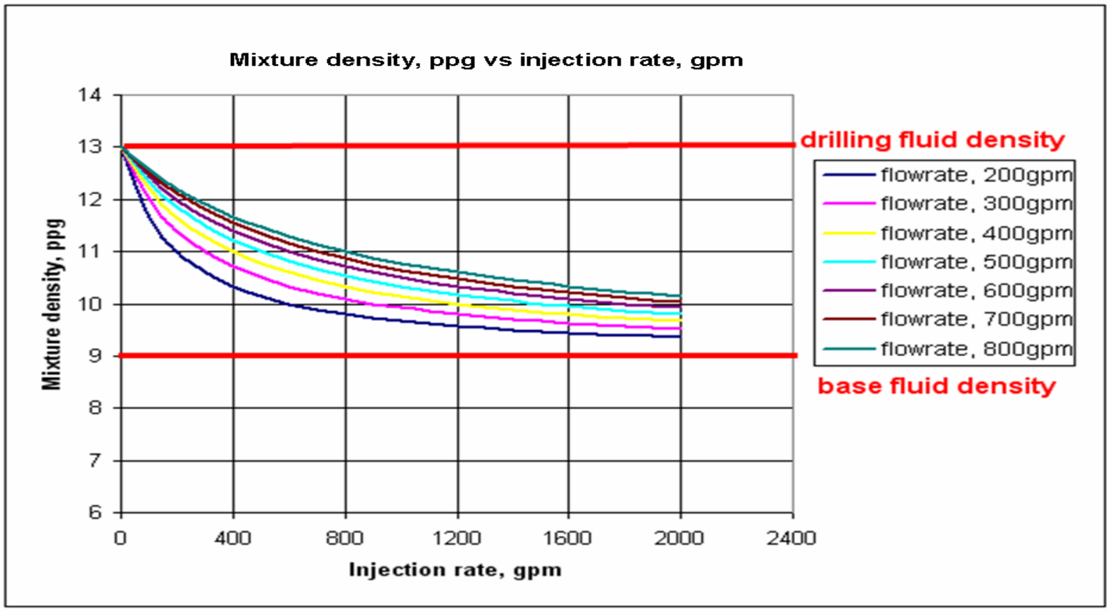

Figure A-13— Spreadsheet result showing the effect of injection rate (gpm) on the mixture density in the riser (base fluid and drilling fluid) with a 9 ppg base fluid and 13 ppg drilling fluid.

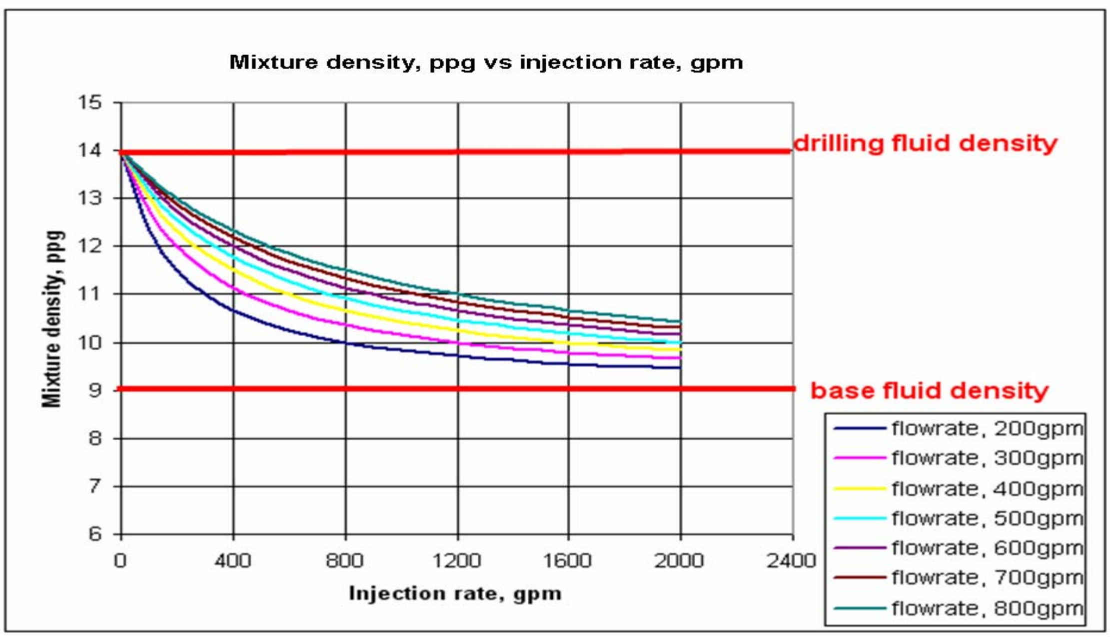

Figure A-14— Spreadsheet result showing the effect of injection rate (gpm) on the mixture density in the riser (base fluid and drilling fluid) with a 9 ppg base fluid and 14 ppg drilling fluid.

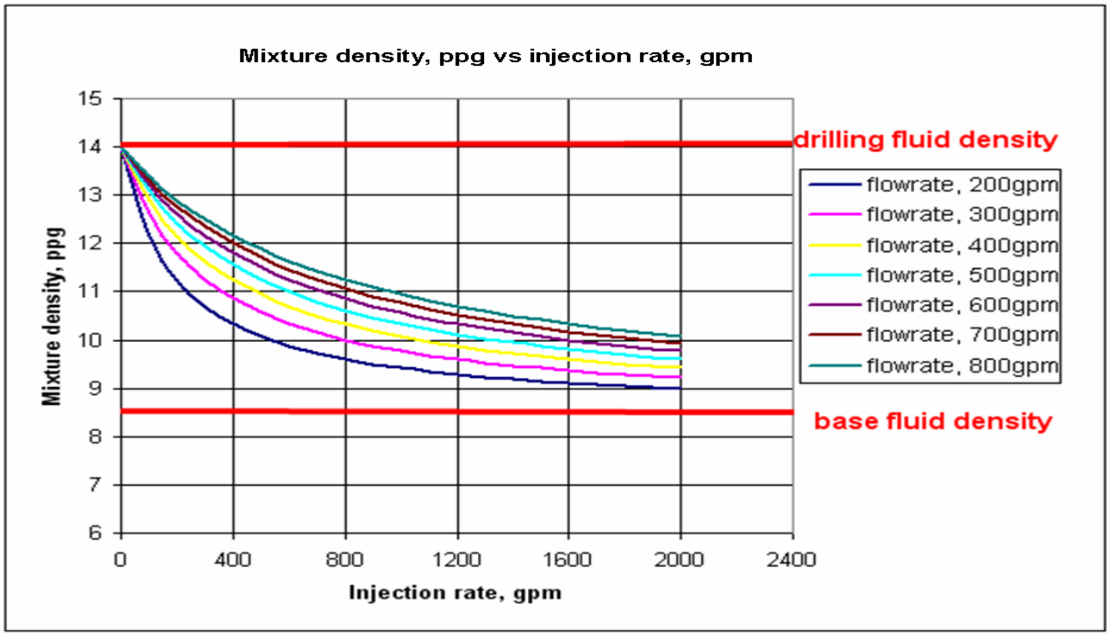

Figure A-15— Spreadsheet result showing the effect of injection rate (gpm) on the mixture density in the riser (base fluid and drilling fluid) with an 8.5 ppg base fluid and 14 ppg drilling fluid.

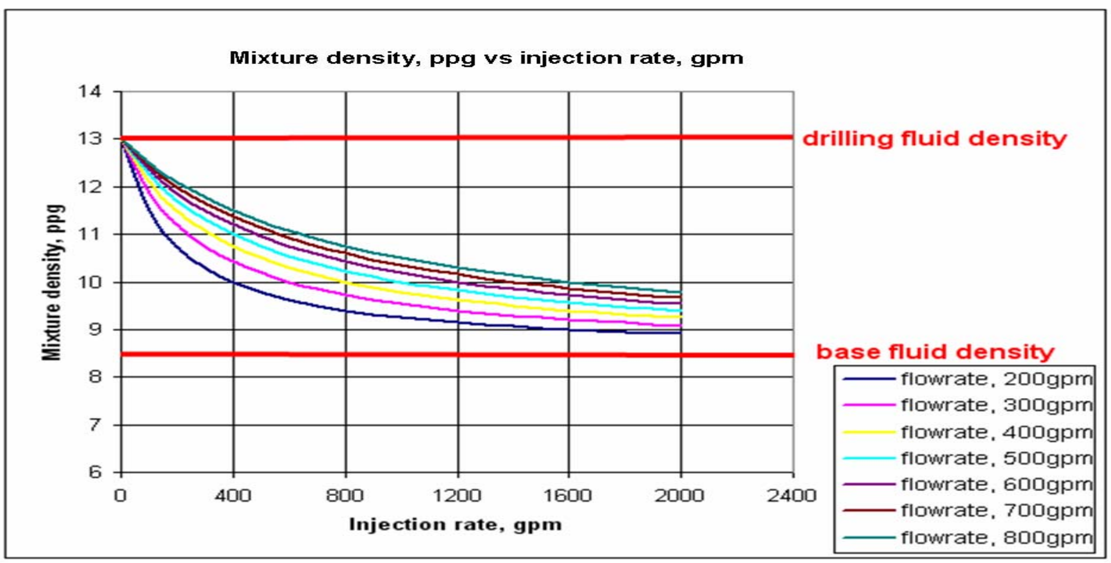

Figure A-16— Spreadsheet result showing the effect of injection rate (gpm) on the mixture density in the riser (base fluid and drilling fluid) with an 8.5 ppg base fluid and 13 ppg drilling fluid.

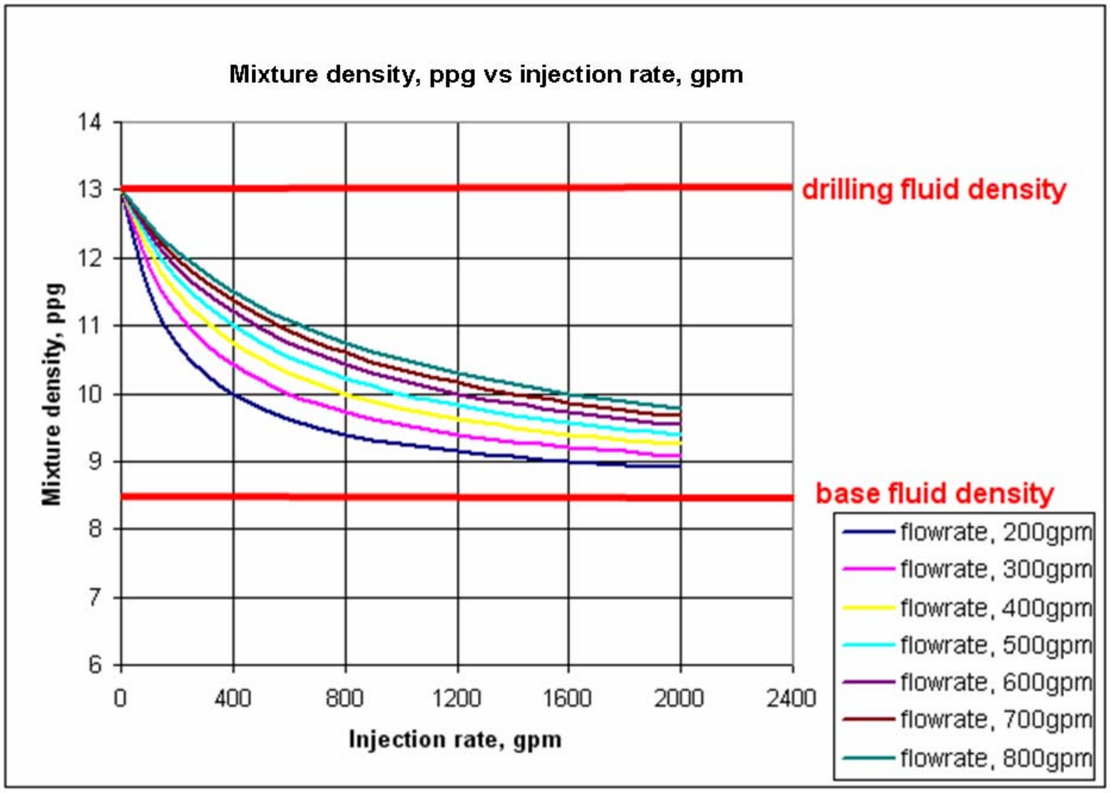

Figure A-17— Spreadsheet result showing the effect of injection rate (gpm) on the mixture density in the riser (base fluid and drilling fluid) with an 8.5 ppg base fluid and 13 ppg drilling fluid.

The graphs below show a comparison between u-tubing rate and the required injection rate at any time during u-tubing. From these results, the injection rate at anytime during u-tubing can be determined.

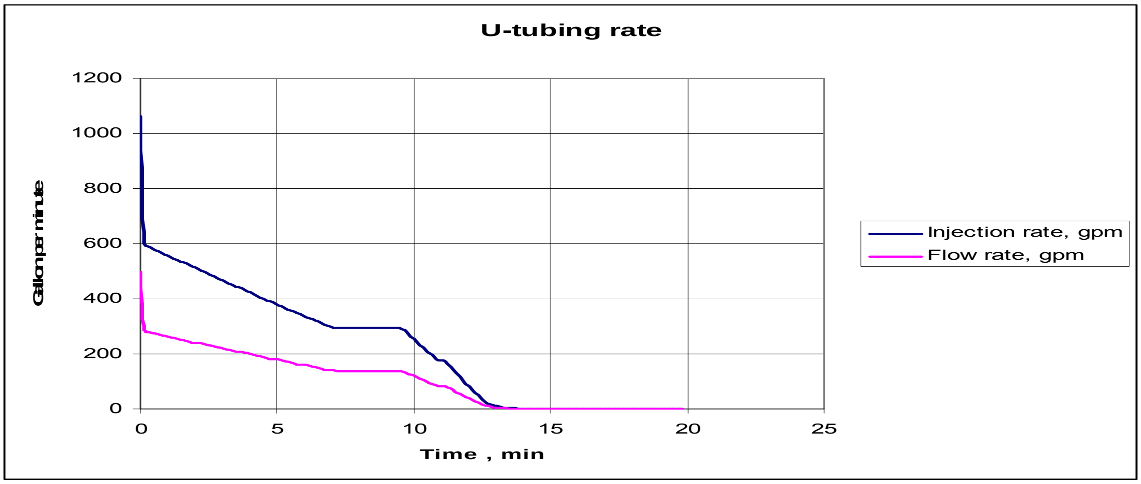

Figure A-18— Spreadsheet result showing u-tubing rate and the corresponding injection rate required to maintain the riser density with a 12 ppg drilling fluid, 7 ppg base fluid and drill pipe diameter 4.276 in.

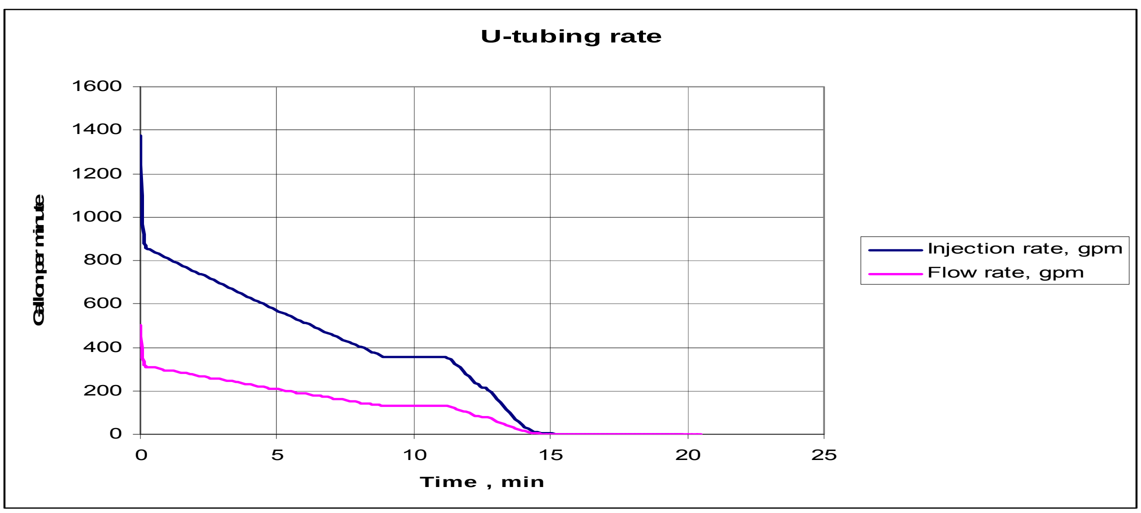

Figure A-19— Spreadsheet result showing u-tubing rate and the corresponding injection rate required to maintain the riser density with a 13 ppg drilling fluid, 7 ppg base fluid and drill pipe diameter 4.276 in.

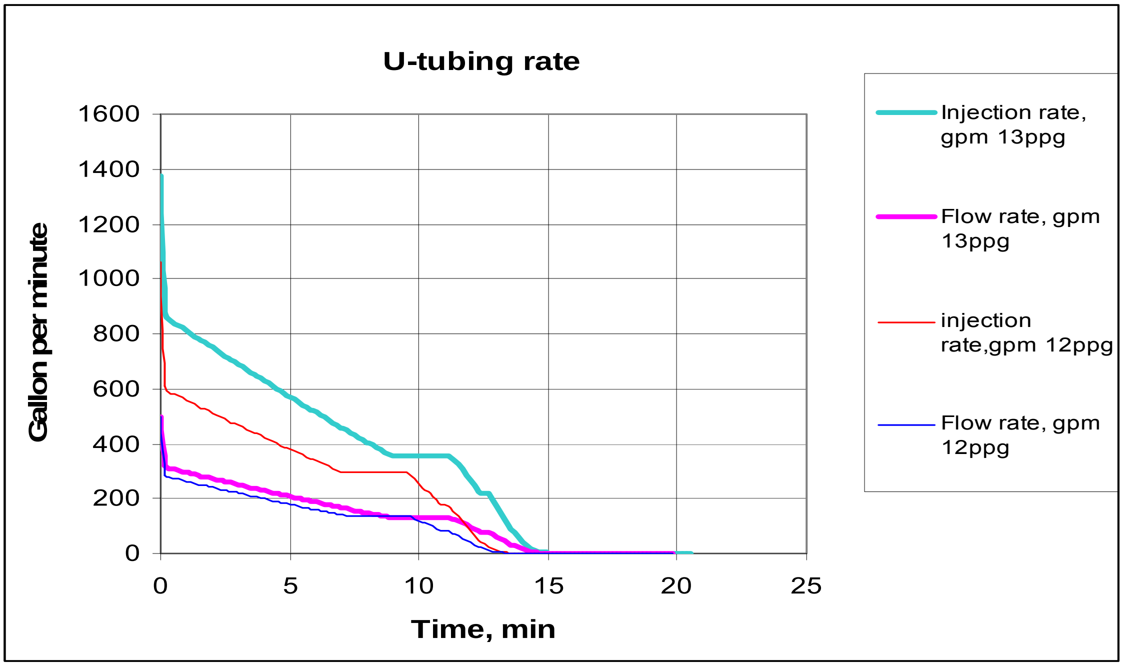

Figure A-20— Spreadsheet result showing u-tubing rate and the corresponding injection rate required to maintain the riser density with a 7 ppg base fluid and drill pipe diameter 4.276 in.

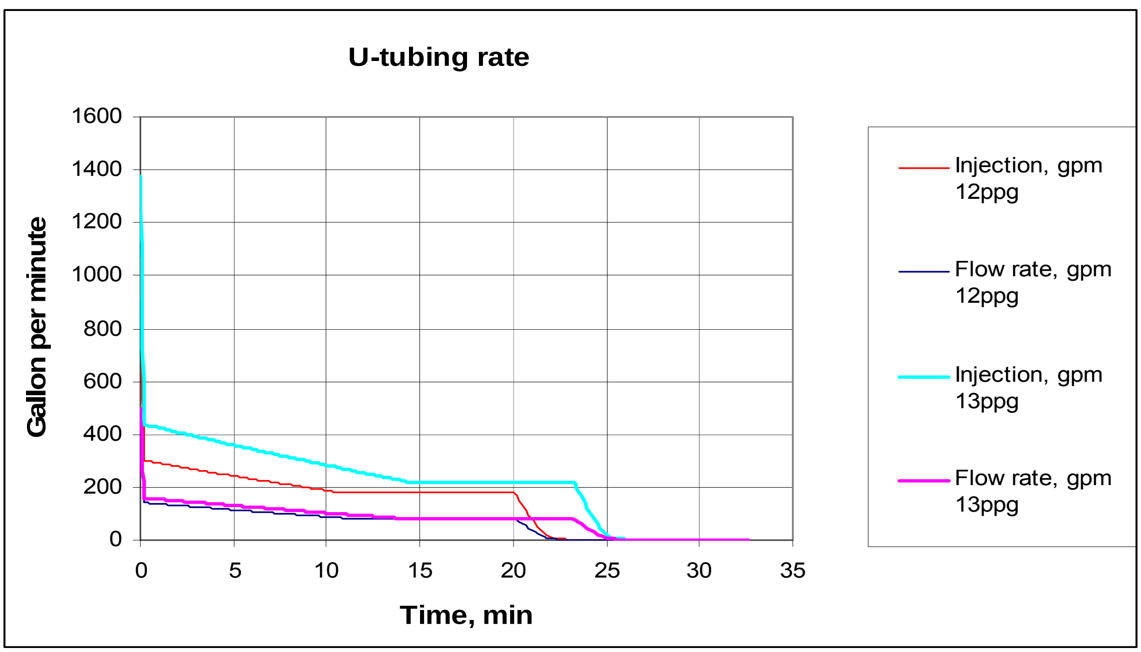

Figure A-21— Spreadsheet result showing u-tubing rate and the corresponding injection rate required to maintain the riser density with a 7 ppg base fluid and drill pipe diameter 3 in.

Spreadsheet result showing u-tubing rate with corresponding injection rate at any time during u-tubing with varying parameters that affect u-tubing as such, base fluid density, drilling fluid density and drill pipe diameter.

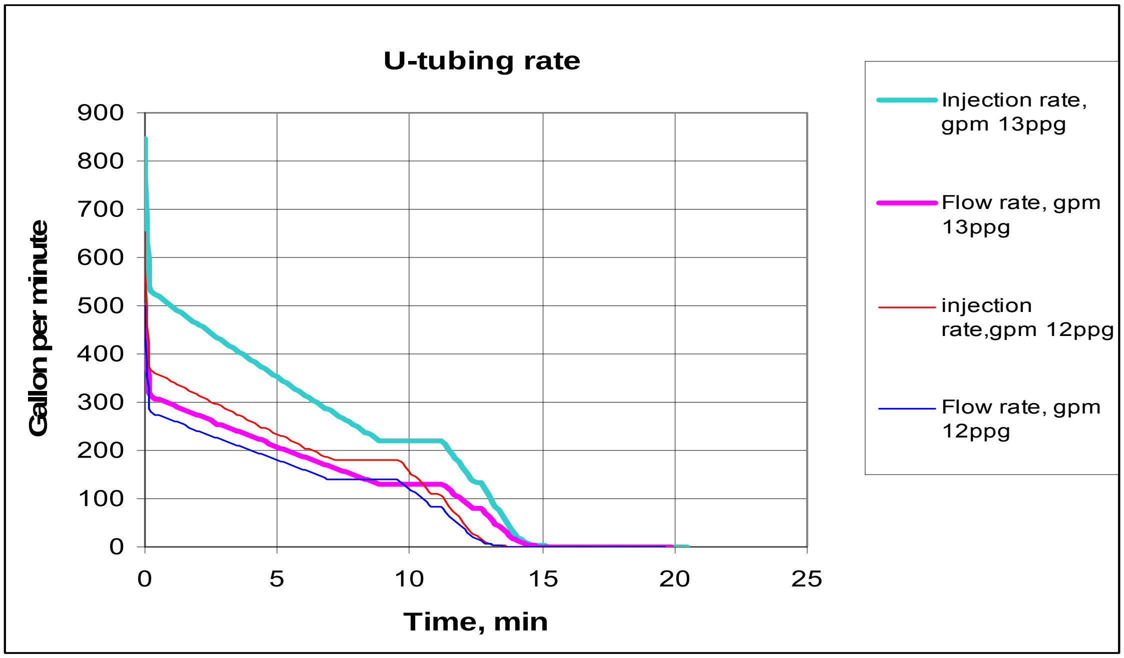

Figure A-22— Spreadsheet result showing u-tubing rate and the corresponding injection rate required to maintain the riser density with a 6 ppg base fluid and drill pipe diameter 4.276in.

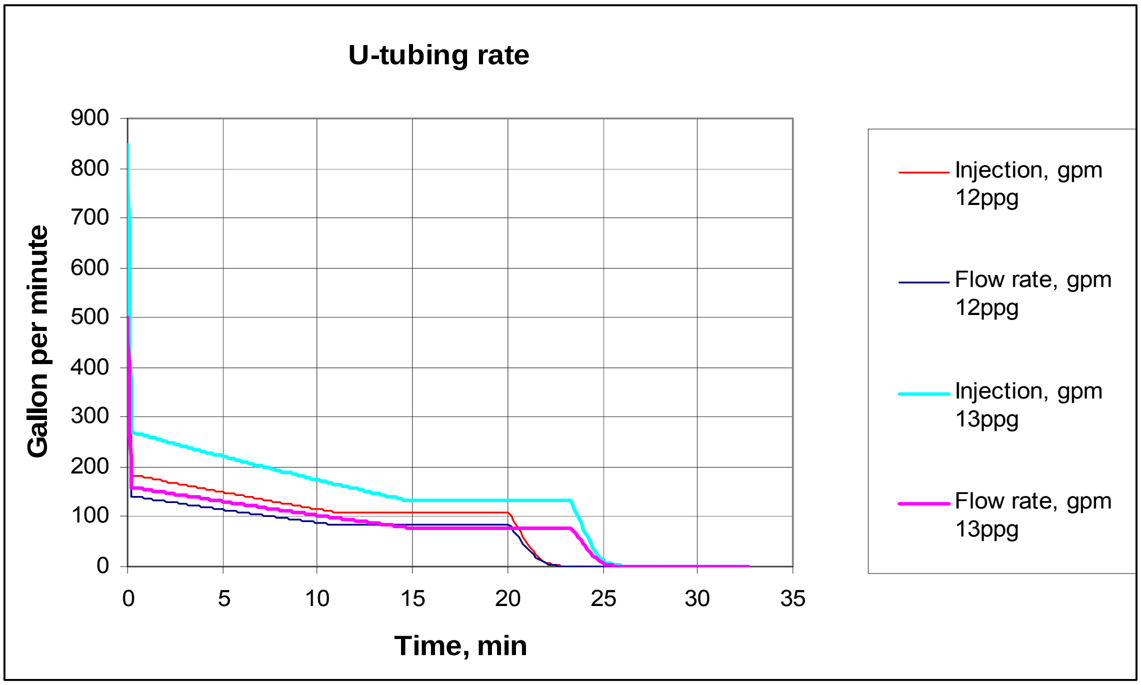

Figure A-23— Spreadsheet result showing u-tubing rate and the corresponding injection rate required to maintain the riser density with a 6 ppg base fluid and drill pipe diameter 3in.

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