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Deepwater Drilling Problems

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ABSTRACT

Several problems encountered in the deepwater makes it very difficult in terms of accessibility for drilling. In this work, the major problems in the deepwater are identified, and discussed from different perspectives.

Discussion of the deepwater environment provides a good basis in determining how this environment contributes to deepwater problems and the extent of the problems encountered. Two major categories of problems in deepwater are considered. The first category is the problems associated with drilling facilities while the second are those associated with operations. The former includes: modular offshore drilling units (MODU), the risers and tension leg platforms; while the latter includes hydrate problems, loss of risers, cuttings transport in the annulus and well control problems. Possible solutions were recommended for some of these problems.

The calculations and analysis in this work focused on deepwater problems due to riser loss, and this served as good basis to evaluate the integrity of the formation and that of the riser when riser mud loss due to riser disconnect is experienced in the deepwater. To achieve this, two parameters were defined and used: riser margin (in terms of pressure difference) for evaluation of formation integrity and critical sea water hydrostatic pressure for evaluation of riser integrity. The critical sea water hydrostatic pressure is equivalent to the collapse pressure of the riser, and its relationship with bust pressure of the riser was established under the deepwater condition. It is suggested that these values are compared with API pressure ratings for safe operating conditions in the deepwater.

TABLE OF CONTENTS

1. Introduction 1

2. Deepwater Environment Conditions 3

2.1. Currents 3

2.2. Temperature 4

2.2.1. Salt Content and Temperature Effect 4

2.3. Pressure 5

2.4. Density 6

2.5. Hydrostatic Pressure 6

2.6. Other Considerations 6

3. Deepwater Drilling Concepts 8

3.1. Conventional Riser Drilling 8

3.2. Riserless Drilling 10

3.2.1. Definition 10

3.2.2. Riserless Drilling Concept 10

3.2.3. Advantages of Riserless Drilling 11

3.2.4. Disadvantages and Limitations of Riserless Drilling 12

4. Deepwater Drilling Problems Associated with Drilling Facilities 14

4.1. Rig Positioning Problems 14

4.1.1. Drive -Off 16

4.1.2. Drift -Off 16

4.2. Riser Management Problems 16

4.2.1. Axial Oscillation due to Weather/Environmental Conditions(heave of the ring) .. 17

4.2.2. Lateral Oscillation due to Ocean Loop Current 19

4.2.3. Failure due to Riser Emergency Disconnect from BOP 22

4.3. Tension Leg Platform 22

4.3.1. Derivation of Equation 24

4.3.2. Example 26

5. Deepwater Drilling Problems Associated with Drilling Operations 27
5.1. Hydrates 27
5.1.1. Mechanism of Hydrate Formation 27
5.1.2. Hydrate Formation Conditions 27
5.1.3. Hydrate Formation Conditions by Gas-Gravity 29
5.1.4. Hydrates Problems in Real Life.. 30
5.1.5. Hydrate Prevention Methods 31
5.1.6. Hydrate Prevention during Drilling in Offshore/Deepwater Environment 31
5.1.6.1. Hydrate Prevention in Drilling Fluids 32
5.2. Riser Loss 33
5.2.1. Well Barrier 33
5.2.2. Riser Margin 34
5.2.3. What Happens When Riser Mud Loss Occurs? 36
5.2.3.1. Sub-Seabed Section(Below the Seabed in the Well) 36
5.2.3.1.1. Artificial Seabed: Proposed Solution to Riser Margin Problems in sub-seabed 38
5.2.3.2. Above-Seabed Section(Deepwater Interval) 39
5.3. Cuttings Transport in Riser Annulus 40
5.3.1. Riser Size and Diameter 41
5.3.2. Riser Length 42
5.3.3. Slimhole Drilling : Proposed Solution to Cuttings Transport Problem in the Riser Annulus 42
5.3.4. Application of Slimhole Drilling to Offshore Drilling 45
5.3.4.1. Floating Drilling 45
5.3.4.2. Ultra Deepwater 46
5.3.4.3. Other Areas of Application 48

5.3.5. Limitations 48
5.3.5.1. Kick Control 48
5.3.5.2. Other Concerns 48
5.3.6. Challenges 48
5.3.6.1. Primary Challenges 48
5.3.6.2. Secondary Challenges 50
5.4. Well Control Related Problems 50

6. Analysis and Discussion on Riser Loss Problems 53
6.1. Sub-Seabed Section : Formation Integrity and Well Control 53
6.2. Above-Seabed Section (Deepwater Interval) : Riser Integrity 61
6.2.1. Pipe Friction Consideration on Critical Seawater Hydrostatic Pressure 64
6.2.2. API Collapse Pressure Consideration 65
6.3. Riser Burst and Collapse Pressure 66

7. Conclusion 68
Nomenclature 70
References 71
Appendix A 73
Appendix B 74
Appendix C 75
Appendix D 76
Appendix E 77

TABLES

3.1. Conventional Riser Drilling Problems In Deepwater 8

3.2. Advantages of Riserless Drilling 12

5.1. Excerpt from NORSOK D-010 on Riser Margin 35

FIGURES

1.1. World Distribution of Deepwater Wells 2

2.1. Density Distribution in Oceans 3
2.2. Temperature and Salinity Influence on Freezing Point of Surface Seawater 5
2.3. Deepwater Interaction with the Earth 7

3.1. Sketch to Illustrate Riserless Drilling Concept 11
3.2. Sketch of a Seal Problem for Riserless Drilling 13

4.1. Drilling Ship 15
4.2. Semi -Submersible 15
4.3. Riser Configuration for Drilling 18
4.4. Finite Element Model for Load Effect on Riser 19
4.5. Loads on Riser during Drilling 20
4.6. Vortex Induced Vibration Effect 21
4.7. Tension Leg Platform 24

5.1. Water Temperature vs. Depth, Gulf of Mexico 28
5.2. Hydrate-Formation Curves for Various Gas Gravities 29
5.3. Well Barrier Schematic 34
5.4. Conventional Configuration for Riser Margin(Before Artificial Seabed) 36
5.5. Deepwater Riser with Artificial Seabed 39
5.6. Riser Disconnect Illustration for Above-Seabed Consideration 40
5.7. Typical Casing Program as Compared to Slimhole 44
5.8. Ultradeepwater Slimhole Drilling 47

6.1. Diagrammatic Illustration of Deepwater Well Environment 54
6.2. Riser Margin vs. Water Depth 56
6.3. Riser Margin vs. Water Depth with Safety Gradient 57

6.4. Riser Margin vs. Water Depth for Depth Dependent Pore Pressure 59
6.5. Seabed Depth vs. Pore Pressure 60
6.6. Deepwater Pressure Consideration for Disconnected Riser 61
6.7. Critical Seawater Pressure vs. Water Depth 63
6.8. Collapse Modes Based on API Calculation 66

Chapter 1: INTRODUCTION

As proven petroleum reserves decline through continued production, exploration for new oil and gas resources will extend to environment that present significant economic risks and technical hurdles such as the deepwater environment. For instance, a detailed study using multi-company data disclosed about 8 to 10 billion bbls of oil equivalent in the deepwater areas of the Gulf of Mexico (GOM) outer continental shelf.[1]

What are Deepwaters? Deepwaters are typically water depths greater than 1000 ft (300m) while water depths in excess of 5000ft are considered ultra deepwater. Well drilled in water depths in excess of 5000ft will typically be drilled with dynamically positioned rigs, and not the conventionally moored drilling vessels used to drill wells in shallow water.

The distribution of deepwater wells around the globe is illustrated in a pie-chart as provided below (see figure 1.1) with almost 65% of the known world deepwater hydrocarbon reserves located in the GOM.[2]

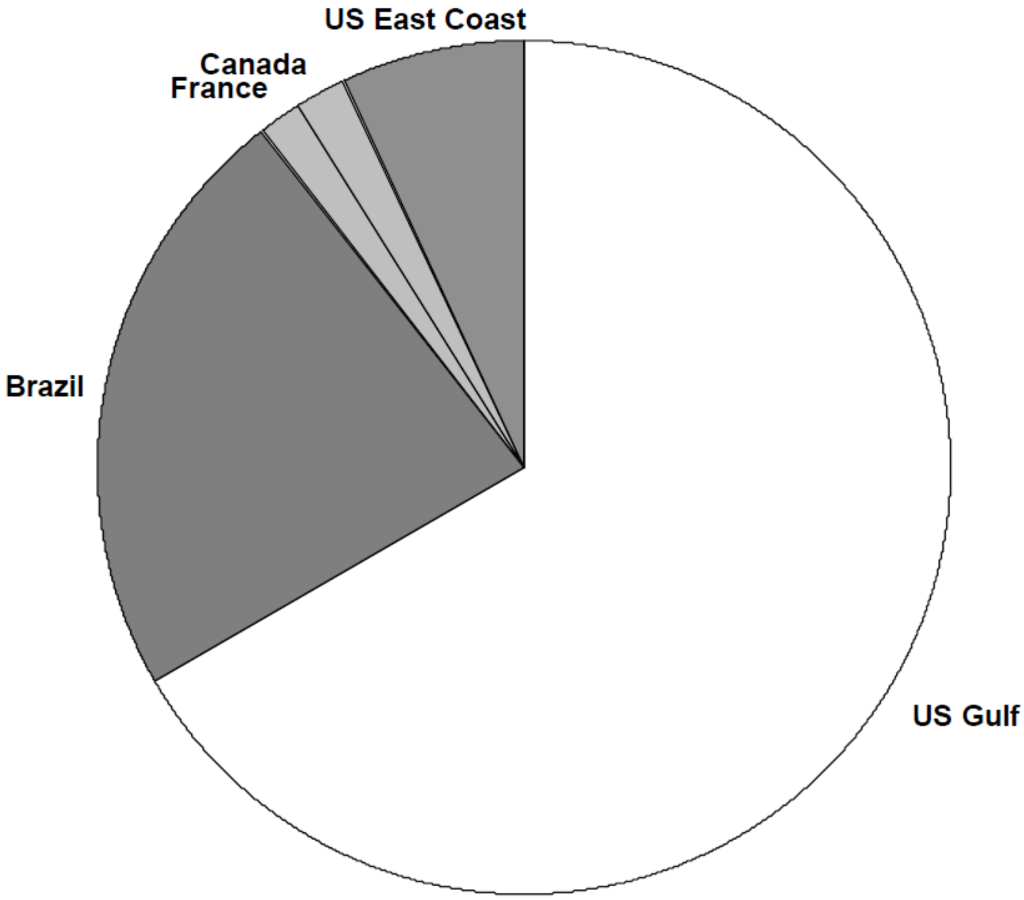


Fig. 1.1- World Distribution of Deepwater Wells

Deepwater activities have been on the increase in recent years as world's oil reserves are being depleted. However, the deeper we go the more challenging it becomes due to limitations in terms of facilities, operational and weather. Deepwater problems include problems of dynamic rig positioning, riser management, tension leg platform, and hydrates-formation, cuttings transport in riser annulus, riser loss and well control. Most of the problems encountered in deepwater will be discussed in this work, with proposed solutions to these problems. It is believed that future research or work on these solutions could be another milestone in deepwater drilling activities.

This work is intended to introduce in details the deepwater environment and the various problems encountered in the deepwater with emphasis on the riser problem. Riser is mostly employed in most deepwater drilling except in cases of riserless drilling. It is important to know the safe operational range or interval whenever the riser is employed in deepwater drilling.

Chapter 2: DEEPWATER ENVIRONMENT CONDITIONS

This section is largely retrieved from ”Oceanography, an Introduction to the Planet Oceanus” by P.R Pinet.[3] To fully understand the deepwater drilling problems and to be able to suggest good solutions to these problems, it is necessary to shed some light on what happens in the deepwater environment (the environmental conditions). In this work, this is discussed under the following headings.

2.1 CURRENTS

Contrasts in water density may arise due to temperature, salinity and turbidity. The result is a steep boundary interface, separating two distinct water masses. As a result, the light surface water spreads over the dense deepwater inducing complex flow patterns (currents).

Deepwater is characterized by low speed as compared to surface water due to low temperature, high density and less exposure to ocean wind at ocean depths. Its masses move continually and slowly, in response to density gradients that result from differences in salinity and temperature of the water. Dense water sinks and displaces less dense water as illustrated in figure 2.1 below.

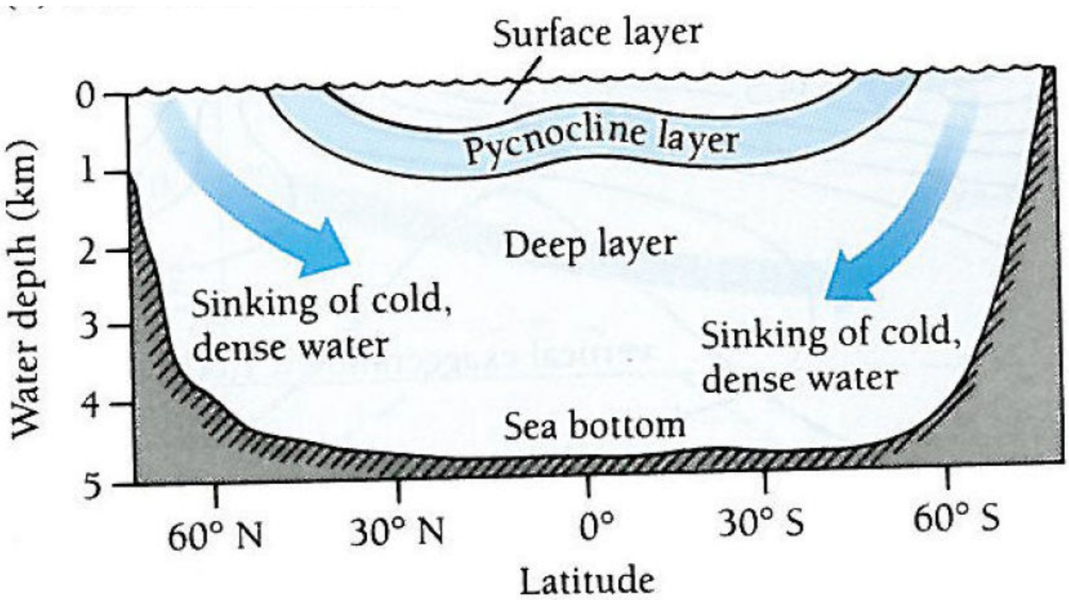


Fig. 2.1- Density Distribution in Oceans

2.2 TEMPERATURE

Both vertical profiles and longitudinal cross sections of water temperature reveal that the oceans have a layered thermal structure. Warm, tropical and subtropical surface water, several hundred meters in depth, float over colder, denser water. These two water masses are separated by a band of water, the thermocline, which has a steep temperature gradient.

Unlike the surface water, where temperature changes with seasons, water below the permanent thermocline remains remarkably uniform to a particular depth and stable in temperature over time, averaging $< 4\ ^{o}$ C. The temperature of the ocean water decreases as water depth increases. There are two major considerations regarding the behavior of the ocean water in relation to temperature interactions:

(a) Salt Content and temperature effect: Exposure of the big ocean seawater (saltwater) to fresh water could alter its salt content.
(b) Pressure and temperature

2.2.1 Salt Content and Temperature Effect

Deepwater is normally salt water (seawater). To understand how salt content affects the temperature behavior of the seawater in the deepwater, we discuss a little comparism between seawater and freshwater.

Freshwater: For fresh water, as water temperature decreases, density increases. This continues until the temperature drops to $+4\ ^{o}$ C. Below this temperature, water expands as temperature decreases and becomes ice at $0\ ^{o}$ C. Hence, freshwater density normally increases with deceasing temperature except for the range between $0\ ^{o}$ C and $4\ ^{o}$ C where the density decreases due to expansion. Fresh water has a normal water density of $1000 kg/m^3$ (salinity = 0%) at standard atmospheric conditions.

Seawater: In the case of seawater, the presence of salt (salinity) affects this trend. Salt presence further decreases the freezing point of water. Water freezes at a temperature lower than $0\ ^{o}$ C due to salinity effect where freezing point decreases with increasing salinity. We would observe that water will not freeze as easily as in the case of freshwater. Seawater has a water density > 1000kg due to the salt presence .i.e. salinity >0%.

Figure 2.2 below illustrates the effect of salinity on freezing point for normal surface water. From the figure, points A, B, C and D indicates the freezing point in the curves, and there is a shift to the left with increasing salinity in the figure which indicates decreasing freezing point. Hence, we have point A for freshwater having the lowest freezing point of 0 ^{o} C and point D with 3.5% salinity having a lowest freezing point of -1.5 ^{o} C. Below +4 ^{o} C, further decrease in temperature of the water changes its response from expansion to contraction as salinity increases from A to D.

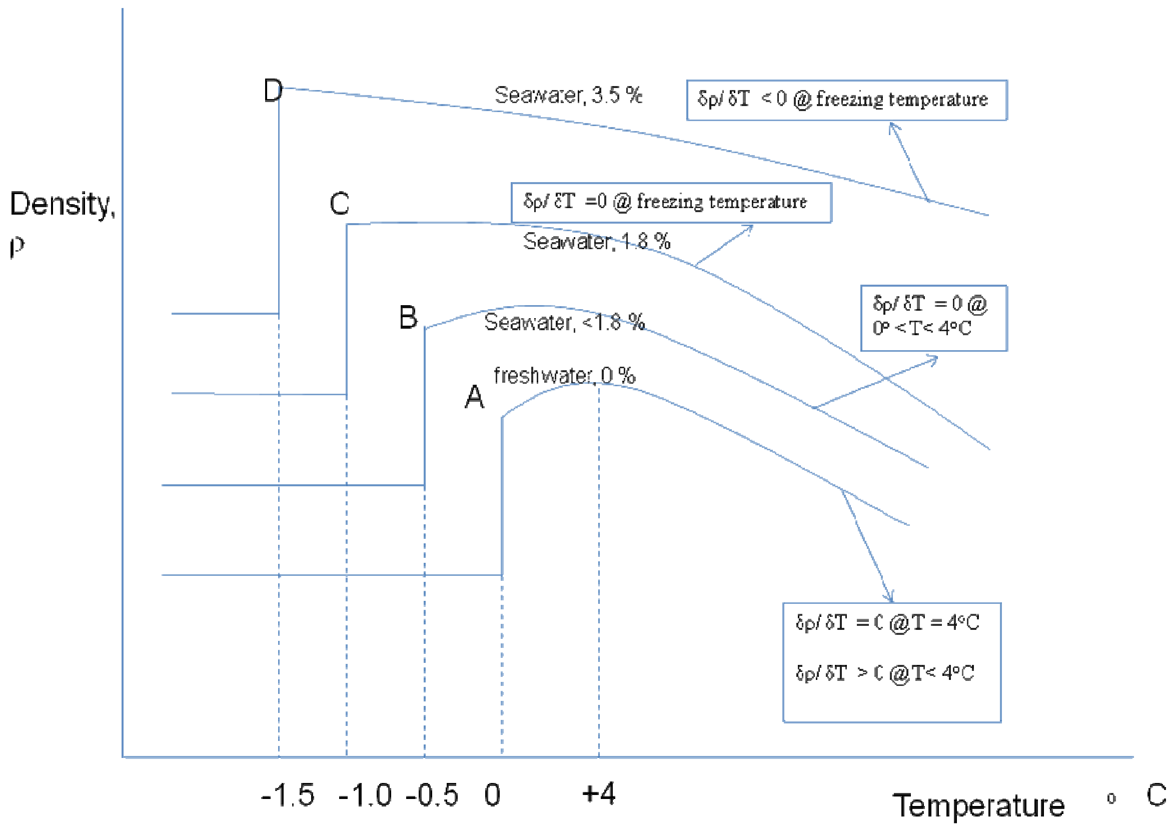


Fig. 2.2 – Temperature and Salinity Influence on Freezing Point of Surface Seawater
From the graph, increasing salinity of the water decreases the freezing point.

2.3 PRESSURE

For surface conditions, pressure is another factor that prevents freezing, or decreases freezing point. Ice expands when it freezes, but it does this against pressure. Hence, the more pressure, the difficult it is for ice to expand .i.e. it becomes more difficult for ice to form.

2.4 DENSITY

The surface water layer is thin, averaging about 100m in thickness, and has the least density of sea water largely because of its warm temperatures (but not the same in the far north). The water of the deep layer constitutes the vast bulk of the total ocean volume (about 80 percent). This cold (< 4 ^{o} C), dense water sinks as it flows slowly.

2.5 HYDROSTATIC PRESSURE

As we go down in the seawater, there is a rapid increase in hydrostatic pressure (the pressure created by the height of a static water column) as a consequence of the density of seawater. The effect of temperature, salinity, and pressure on density increases with increasing deepwater depths.

Calculations show that the pressure associated with a 10-m high column of water equals the pressure exerted by the full height of atmosphere above the earth- a pressure amounting to 1 atmosphere.

2.6 OTHER CONSIDERATIONS

Deepwater is usually saltier than surface water with increasing salinity with depth, which decreases the freezing point of water (figure 2.3). Although deepwater is known for relatively colder temperatures, sometimes, extremely cold surface temperatures in winter time could make the surface water colder than that of the deepwater and this would make the surface water to sink and displace the warmer deepwater. Also, the deepwater temperature could be affected by the heating effect from hot magma present in the core or center of the earth; though the effect is very mild.

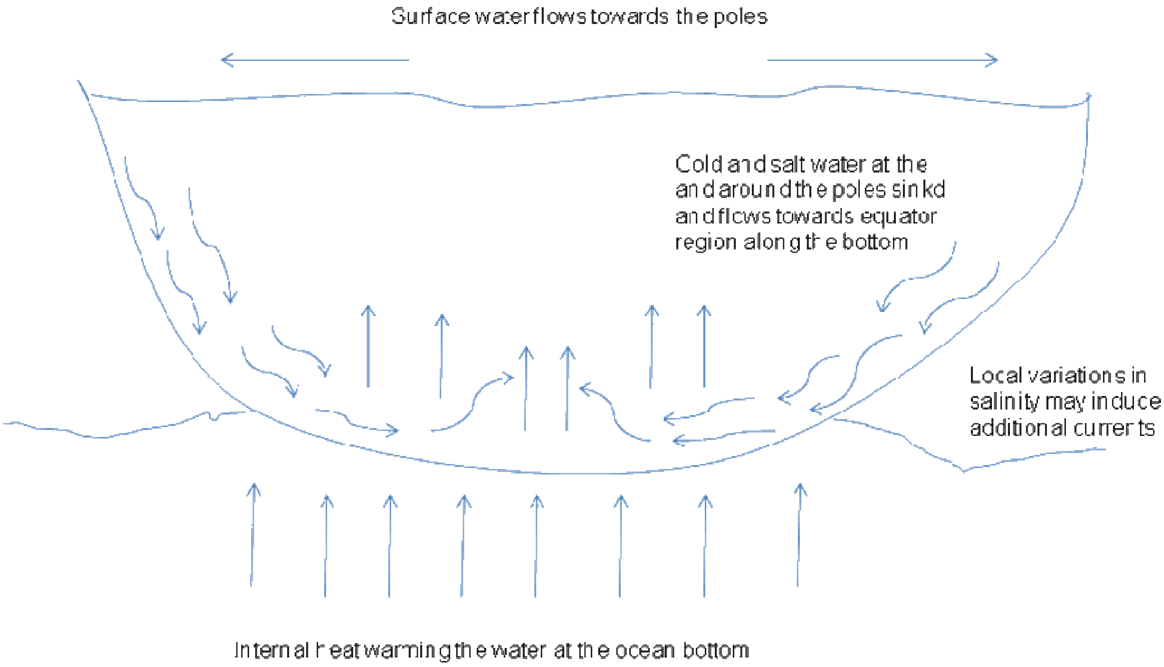


Fig. 2.3- Deepwater Interaction with the Earth

Chapter 3: DEEPWATER DRILLING CONCEPTS

With a view to overcome the problems of deepwater drilling, several alternative drilling concepts have been investigated in the past. **Riserless Drilling (RD)** is a proposed concept which has not yet gained confidence in the industry nor been tested to a convincing extent. Hence, Conventional Riser Drilling (CRD) is still the most suitable method for deepwater drilling up till today. The discussion below examines both Conventional Riserless Drilling and the proposed Riserless Drilling.

3.1 CONVENTIONAL RISER DRILLING

Conventional Riser Drilling is a technique usually used in deepwater drilling where normal riser is employed to protect drill strings. The main function of a CRD is to provide pressure control (or support) of the well and a return flow channel for mud and cuttings. CRD is the most reliable single concept employed in deepwater drilling; even though there are various problems associated with it that increase as water depth goes from shallow to deepwater (discussed in the next chapter).

TABLE 3.1—Conventional Riser Drilling Problems in Deepwater

- Huge weight and space requirements
- Large mud volume in a riser
- Severe stresses in a riser
- Difficult station keeping
- Long tripping time
- Numerous casing points due to narrow gap between pore and fracture pressures: Mud column in the riser contributes to high hydrostatic pressure gradient, and necessitates having more casing points to protect the fragile formation.
- Highly limited fleet of rigs able to handle deepwater risers
- Inability to drill an adequate hole size: Holes sizes could be reduced to limit the extent of exposed formation section to hydrostatic mud column.

One of the basic and most challenging problems of deepwater operations is the use of a marine riser.[1] A marine riser is used to provide a connection between the drilling vessel and the wellhead. This serves as a guide for the drill pipe into the hole and as a mud return path to the vessel. It also supports the choke and kills lines. Floating drilling operations in deepwater presently involve the use of a 21 in. outside diameter (OD) marine riser. For a 19.5 in. internal diameter (ID) marine riser, internal capacity is about 370 bbls for every 1,000 ft of length and net steel weight of the riser is about 160kips for every 1,000ft of length. The riser weight in seawater with 14.5 ppg mud in it will be 230 kips per 1,000ft of length without additional buoyancy units which gives 2,300 kips for 10,000 ft water depth. The riser weight will further increase because of choke and kill lines attached and the riser couplings. Therefore, it will require huge buoyancy units which results in increase of riser OD and causes riser handling problems. Only fifth generation semisubmersibles may have adequate space and weight capacities to handle these requirements. Composite materials can be used to reduce the weight requirement. Compared to a 6 in. ID returns line, the 19.5 in. ID riser would naturally require an additional mud to circulate through the riser. It also costs more to prepare and maintain such a large volume of mud.

The riser may be exposed to severe stresses resulting from the weight of the riser with mud inside, the movement of a floating vessel, and the surface and subsea water currents. As water depth increases, the riser wall thickness has to increase: to handle severe stresses, to resist burst pressures resulting from mud weight, and to attach buoyancy units. These factors significantly escalate riser unit costs and weight as water depth increases. The running of a large-diameter, long riser can be very difficult, or even impossible, where high currents are present.

In order to maintain station keeping within operational ranges, it may require a larger and more expensive drilling vessel. It also increases waiting-on-weather time and takes a long time to trip the riser in and out of its drilling position. Another crucial area is the casing program. Because of the narrow gap between pore and fracture pressures, especially in the deepwater areas of the Gulf of Mexico (GOM), Conventional Riser Drilling requires numerous casing points. Although a “super” drill ship to be available in the future may possibly drill in 10,000 ft water depth, it may not reach a target depth deeper than 10,000 ft below the mudline. In other words, required hole size will not be achieved at target depth using conventional riser drilling.

It is important to note that:

(a) These problems are not only associated with risers; they could arise due to some other reasons.

(b) These problems become aggravated as water depth increases in deepwater.

3.2 RISERLESS DRILLING

In the early stages of offshore development, especially for shallow water, it was possible to solve problems associated with water depth increase by increasing the size of both marine riser and subsea wellhead. However, it is impractical to extend current technologies with a large diameter marine riser and wellhead to drill much beyond 6,000 ft water depth because of the many problems listed in Table 3.1. Many alternatives to the use of the conventional marine riser system for deepwater drilling have been investigated. One of such is the injection of gas at the BOP level in order to reduce the effective density in the marine riser down to seawater density. This process is similar to a gas lifting operation. Another is elimination of the conventional large diameter marine riser which is called **Riserless Drilling (RD).** [1]

3.2.1 Definition

Riserless drilling is suggested to be a concept that might probably eliminate all the problems of conventional drilling in future, but its technology is still relatively new in the industry and has not yet been tested for a long period of time like CRD. It is a term used to describe an unconventional technique which uses a relatively small diameter pipe as a mud return line from the sea floor instead of a large diameter riser.

Although marine risers have been used successfully for water depths in excess of 7000ft, it is impractical to extrapolate current technologies with marine riser to 10,000ft water depth due to the problems which have been highlighted in the previous discussion(see table 3.1). This is what has led to the concept of riserless drilling, for deepwater operations above the reach of conventional riser drilling.

3.2.2 Riserless Drilling Concept

The system consists of a bare drill string and a separated non-concentric return line (see figure 3.1). RBOP (rotating BOP) caps the return mud and forces the mud to circulate through the return line to surface. More than one return line can be used for the returns depending on system configuration and flow rate. One 6 in. ID or two 4.5 in, ID lines appear to be adequate from a hydraulics point of view. Choke and kill lines can be used as return lines, to be tied together with return line(s) or separated from the return line(s).

One of the important concepts for deepwater applications is to balance internal and external pressures at the sea floor by reducing the internal pressure. Gases can be injected to reduce mud hydrostatic pressure in the return line.

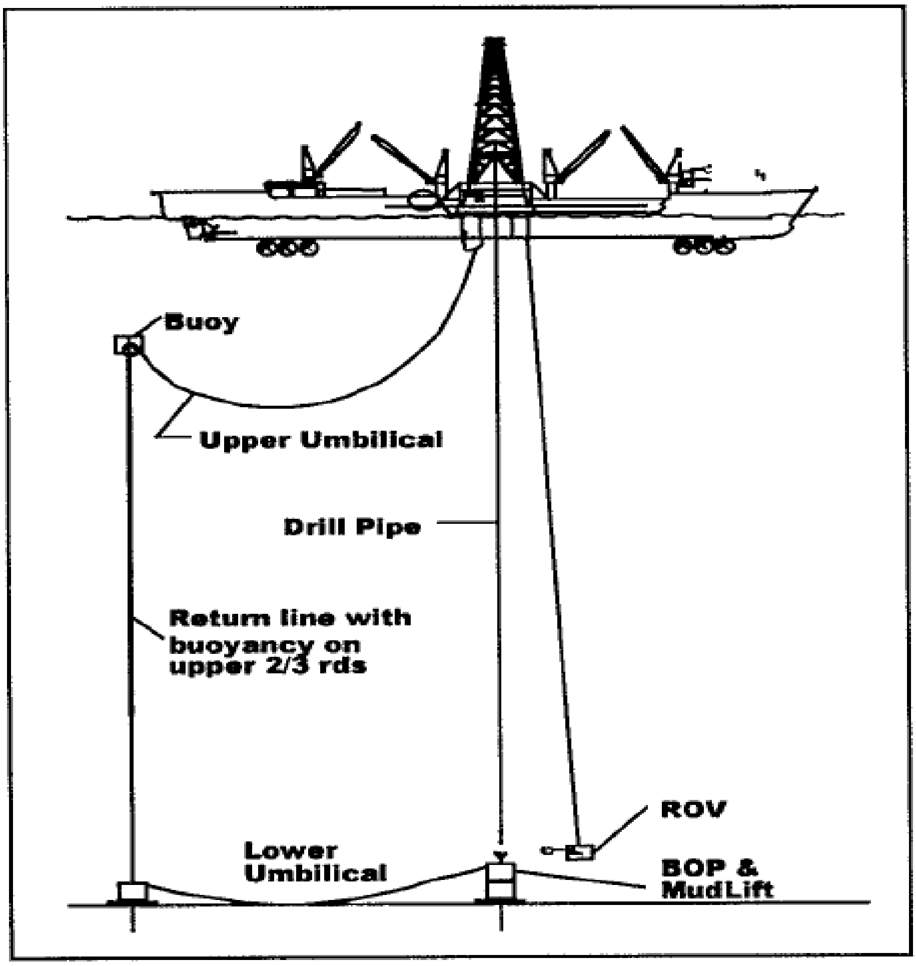


Fig. 3.1 - Sketch to Illustrate Riserless Drilling Concept

3.2.2 Advantages of Riserless Drilling

Studies and experience on the use of riserless drilling have highlighted the following advantages listed under table 3.2 below:

TABLE 3.2—Advantages of Riserless Drilling

- No conventional riser and riser associated cost
- Theoretically no limit on water depth
- Use of smaller return line(s)
- Less mud volume requirement
- Less space and weight requirements
- Reduced environmental forces
- Easy Station keeping
- Reduction of non-operational time
- Reduction of casing points
- No "hidden choke effect"
- No riser loss in case of emergency disconnection
- Mitigation of well control problems in deepwater
- Adequate hole size at target depth for high production rate expected
- Extension of the capacity of existing drilling units
- Possible rig upgrade

3.2.3 Disadvantages and Limitations of Riserless Drilling

One of the critical disadvantages for RD is that RD does not have proven technologies, procedures and equipment to date. A particular and possible disadvantage that would be envisaged if the concept of riserless drilling was practical or possible to drill deep wells, would be the problem of having a leak proof seal on the strings at the wellhead(point of entry into the well). Having a perfectly tight seal around the drill string to ensure that returning mud are efficiently diverted to mud return line could be a big challenge as has been illustrated below in figure 3.2.

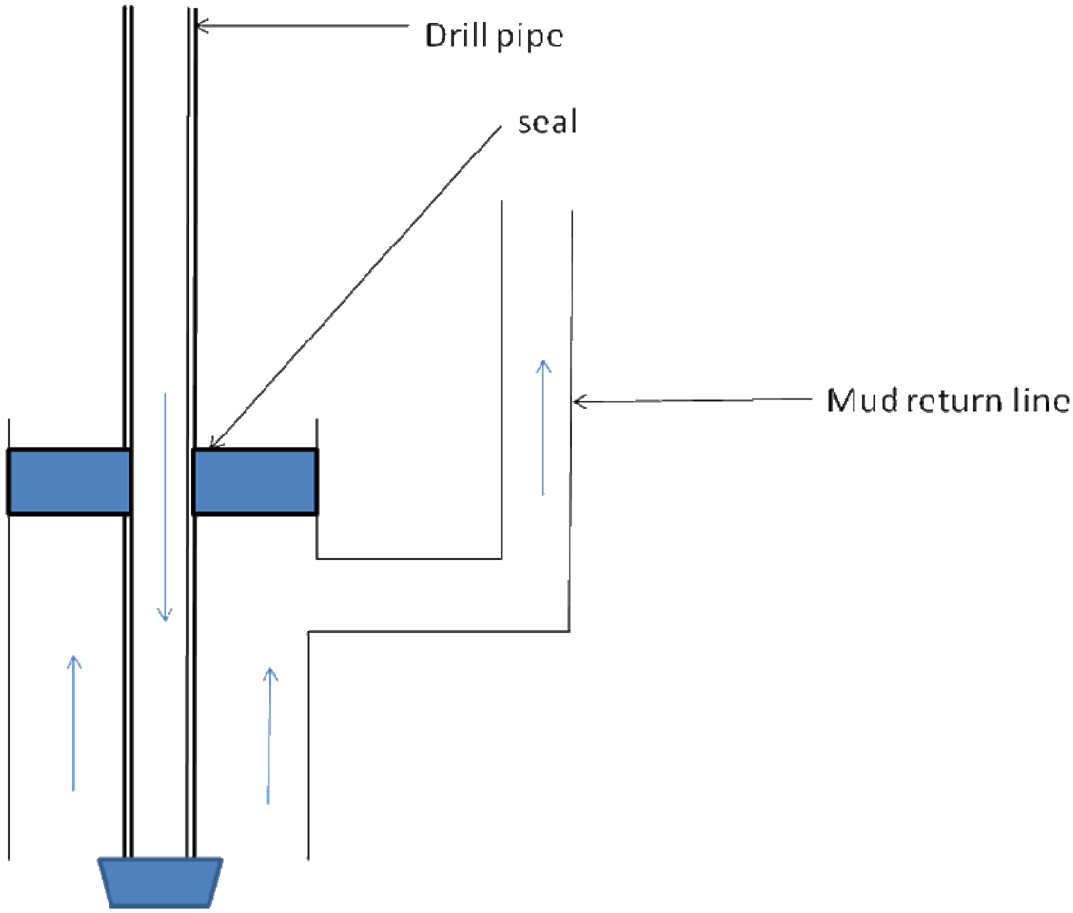


Fig. 3.2- Sketch of a Seal Problem for Riserless Drilling

Despite the fact that presently the 36 and 26 inches sections are drilled riserless (centrifugal pump moves cuttings 70m away from wellhead), cuttings still goes to the rig once the BOP is installed. The problem is that deeper cuttings are contaminated by mud, and the mud usually contains (often harmful) additives as one drills deeper. And since, environmental regulations require cuttings to be brought onshore; this is thought to be the reason why a mud return line is included in a case of the concept of riserless drilling.

Although riserless drilling has large potential benefits for deepwater applications, because of the cost of installing and removing the riser, the technology has not been used in practical terms for complete drilling in deepwater. Also, it has not gained as much acceptance and confidence as CRD However, it is envisaged that this would change in the near future.

Chapter 4: DEEPWATER DRILLING PROBLEMS ASSOCIATED WITH DRILLING FACILITIES

Deepwater drilling problems could take several forms due to environmental conditions, equipment response/failure, operational limitations etc. In this chapter, some of these problems due to drilling facilities in deepwater will be discussed.

4.1 RIG POSITIONING PROBLEMS

Dynamic positioning (DP) is a computer controlled system used to automatically maintain a vessel's position and heading by using her own propellers and thrusters.[2] Position reference sensors, combined with wind sensors, motion sensors and gyro compasses provide information to the computer pertaining to the vessel's position and the magnitude and direction of environmental forces affecting its position. Examples of vessel types that employ DP include, but are not limited to ships and semi-submersible Mobile Offshore Drilling Units (MODU) as shown in figures 4.1 & 4.2.

The computer program contains a mathematical model of the vessel that includes information pertaining to the wind and current drag of the vessel and the location of the thrusters. This knowledge, combined with the sensor information, allows the computer to calculate the required steering angle and thruster output for each thruster. This allows operations at sea where mooring or anchoring is not feasible due to deepwater, congestion on the sea bottom (pipelines, templates) or other problems.

Fig. 4.1- Drilling Ship

Fig. 4.2- Semi Submersible

Dynamic positioning may either be absolute in that the position is locked to a fixed point over the bottom, or relative to a moving object like another ship or an underwater vehicle. One may also position the ship at a favourable angle towards wind, waves and current, called weathervaning. Dynamic positioning is much used in the offshore oil industry, for example in the North Sea, Persian Gulf, Gulf of Mexico, West Africa and off Brazil. Nowadays there are more than 1000 DP ships.

A dynamically positioned (DP) rig is required for ultra deepwater drilling. Redundant computer based DP systems actively keep the rig on location. Redundancy is the ability to cope with a single failure without loss of position. All rig operations in ultra deepwater must identify and allow for a positioning system failure at any time. The most serious positioning system problems are a ***drive-off or drift-off***.

4.1.1 Drive-off

During a drive-off, the rig is powered to a position away from the well. In this situation, the BOP must seal off the well and release the riser before the riser system, wellhead or casing is damaged.

A drive-off results when the positioning system directs the rig away from the location. The same result could be caused by the thruster misinterpreting its command.

4.1.2 Drift-off

A drift-off occurs when the rig loses its power and environmental forces push it away from the location. Again the riser must be disconnected and the well integrity protected. A drive-off can become drift-off by cutting power to the thrusters.

Apart from these operational problems mentioned above, one minor concern is power consumption for the dynamic positioning system as it is a power consuming facility.

4.2 RISER MANAGEMENT PROBLEMS

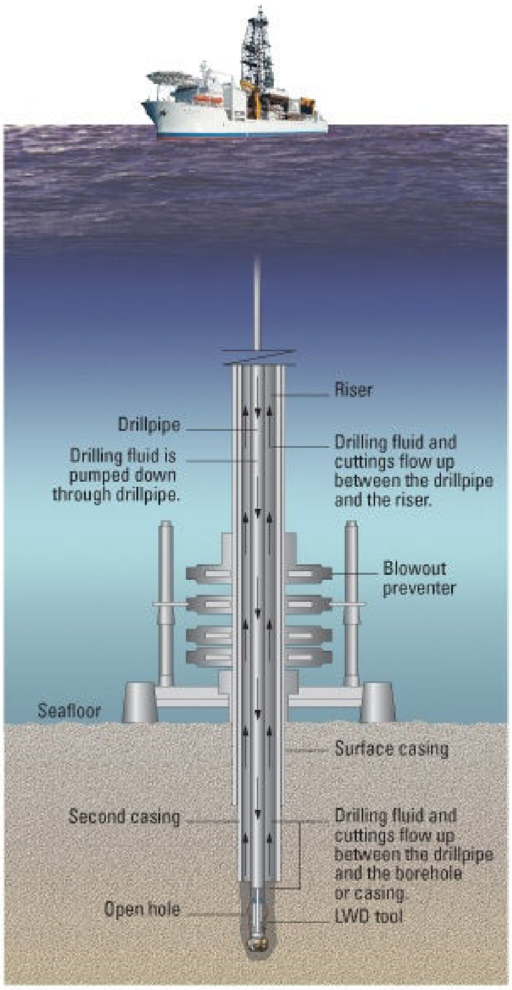
For a typical riser (figure 4.3), riser problems in deepwater could be discussed based on the following considerations:

4.2.1 Axial Oscillation due to weather/environmental condition (heave of the rig)

Most of the time, rigs being used in deepwater environment are subject to bad/violent weather conditions that could sometimes lead to excessive heave of the rig (vertical oscillation).

During drilling, the riser management system in ultra deepwater must deploy, control, and recover a heavy riser mass that may have an axial natural period close to the rig's heave period.[2] Like the other ultra deepwater rig systems, it must also be designed for emergency disconnect. Upon being disconnected, it must convert the riser from being fixed on the bottom with a mud weight load to a hanging unlocked riser, thus releasing the mud weight. Additionally, the rig's riser tensioners must maintain minimum riser angle to reduce potential wear on the riser and the drill through equipment.

Accurately predicting the behaviors of a freely hanging riser particularly during storms is a problem. Dynamics dominate and the riser spring mass system is close to resonance in typically encountered seas. The drag on the risers varies significantly over its length depending on vessel motion and current profile. The effect of the risers' structural dampening is not well known.



Schlumberger Oilfield Glossary

Fig. 4.3 - Riser Configuration for Drilling[26]

Upon disconnect, the mud in the riser is dumped to the sea unless the Lowe Marine Riser Package (LMRP) annular is closed. There is a temptation to try to save the mud by closing the annular. The motivation is the expense of lost mud, avoidance of pollution, and the elimination of collapse problems from U-tube mud. Unfortunately, when trapped by the lower annular, the additional mass of this mud inside the riser increases the natural period of the spring-mass system and causes the riser to become dynamically excited.

The natural period of a hanging drilling riser can be approximated by:

$\tau = 2\pi\sqrt{(m/k)}$ k = the spring stiffness of the riser (lbf/ft)

m = the effective mass of the riser = dry mass of BOP + 0.4 mass of riser

For a typical 10,000 ft riser: mass BOP = 575,000 lbm

Mass of riser = 5,400,000 lbm

Stiffness k = 141,000 lbf/ft

Here, we do not consider the mass of the BOP because it does not form part of the disconnected riser.

Thus, effective mass = 0 + (0.4 * 5,400,000) = 2,160,000 lbm

The natural period for this riser is approximately 5 seconds:

$$\tau = 2\pi\sqrt{2160000/(141000 \times 32.2)} = 4.33\,\mathrm{sec}\,onds$$

However, if the annular was closed to capture the mud, the riser mass is increased, hence, the period. Although these oscillations end up creating some fatigue in the riser or the drill strings, drilling rigs are usually provided with systems to prevent vertical oscillation of the rig such as heave compensators in floating rig, tensioned legs in tensioned leg platforms, etc. Hence, they minimize axial oscillation of the risers due to rig movements**.**

4.2.2 Lateral Oscillation due to Ocean Loop Current

This section is inspired by the paper presentation from subsea7.[5] Apart from the vertical vibration (axial), we also have lateral oscillation of the riser. In ultra deepwater where several stands of risers are used to get to the water depth at seabed from the surface, a similar behavior to that of a long stand of string is believed to be existing. For a riser stretching over thousands of feet in deepwater, lateral oscillations is believed to be inevitable in the manner shown in the figure 4.4 (a subsea7 illustration) below:

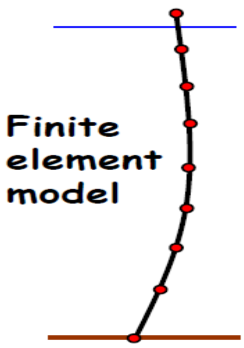


Fig. 4.4 – Finite Element Model for Load Effect on Riser.[5]

Several loads (as illustrated in figure 4.5) result in lateral vibration of riser string used in drilling in the deepwater. The following contribute to the load:

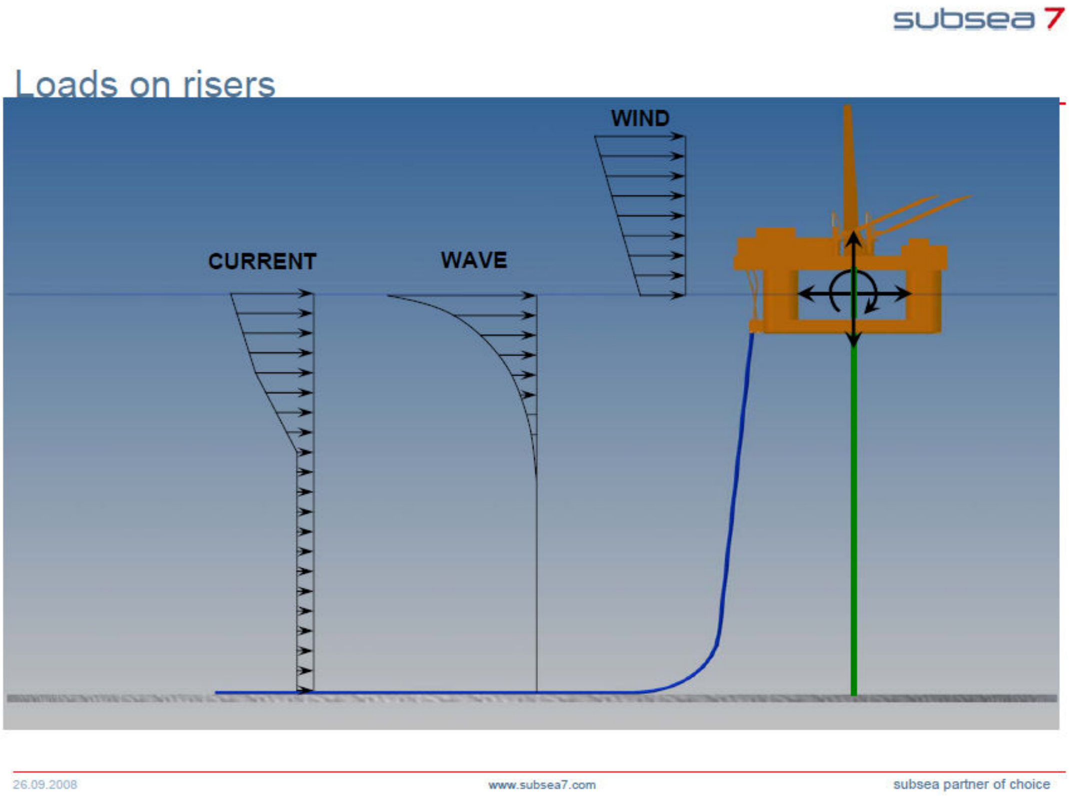


Fig. 4.5- Loads on Riser during Drilling.[5]

Load on the riser includes:

Wave

- Platform motions: Heave, sway, pitch and roll.
- Direct wave forces on risers
- Wave induced fatigue

Current

- Slow drift of the platform: vessel offset
- Direct current load along the waves
- Vortex induced vibration (VIV) on risers: fatigue

Vortex induced vibration (VIV) is a type of lateral movement in deepwater drilling normally due to ocean current as shown in figure 4.6 on the next page. As earlier mentioned in section 2.1 the deepwater current and wind near the surface water is very high while that near the bottom of the deepwater is low. This creates the **Vortex Induced Vibration.**

Wind

Slow drift of the platform: vessel offset

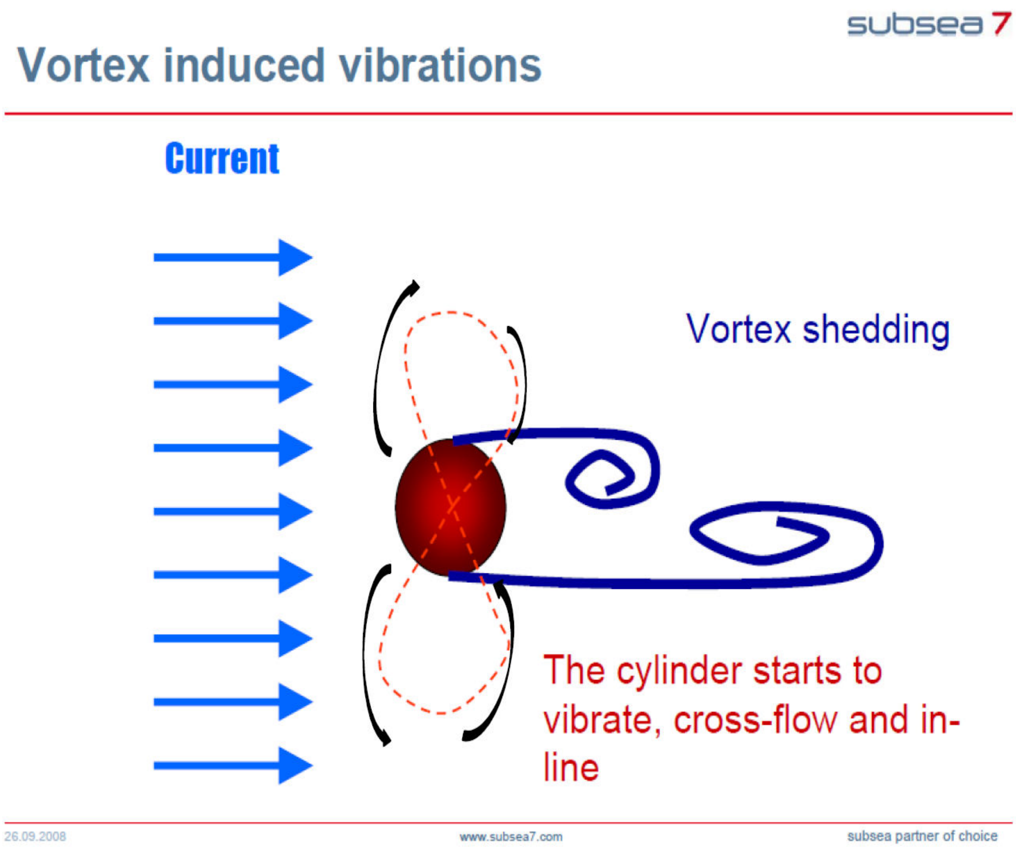


Fig. 4.6- Vortex Induced Vibration Effect

Different failure modes for risers:

Metal risers

- Pressure effects: internal or/and external pressure

- Tension and bending stress: combined load effects
- Fatigue

Flexible risers

- Pressure effects
- Tension and curvature
- Fatigue
- End fitting design

The lateral movements discussed during riser drilling in deepwater usually result in fatigue due to oscillation or vibration of the strings, and seldom cause instant failure. However, fatigue could pose future problems.

Fatigue

- In metal risers
- Is due to repeated loading and unloading
- Critical failure mode for welds

4.2.3 Failure Due To Riser Emergency Disconnect From BOP

In a case of rig positioning problem where the riser emergency disconnect from BOP fails, the riser will end up being damaged due to forceful disconnect.

4.3 TENSION LEG PLATFORM

A **Tension-leg platform** or **Extended Tension Leg Platform (ETLP)** is a vertically moored floating structure normally used for the offshore production of oil or gas, and is particularly suited for water depths greater than 300 meters (about 1000 ft).[4] Hence, it can be used for deepwater drilling. The Tension Leg Platform (TLP) is a buoyant platform held in place by a mooring system. The TLP's are similar to conventional fixed platforms except that the platform is maintained on location through the use of moorings held in tension by the buoyancy of the hull (figure 4.7).

The mooring system is a set of tension legs or tendons attached to the platform and connected to a template or foundation on the seafloor. The platform is permanently moored by means of tendons grouped at each of the structure's corners. A feature of the design of the tendons (tethers) is that they have relatively high axial stiffness (low elasticity), such that virtually all vertical motion of the platform is eliminated. The template is held in place by piles driven into the seafloor. This method dampens the vertical motions of the platform, but allows for horizontal movements. The topside facilities (processing facilities, pipelines, and surface trees) of the TLP and most of the daily operations are the same as for a conventional platform.

The hull is a buoyant structure that supports the deck section of the platform and its drilling and production equipment. A typical hull has four air-filled columns supported by pontoons, similar to a semisubmersible drilling vessel. The deck for the surface facilities rests on the hull. The buoyancy of the hull exceeds the weight of the platform, requiring taut moorings or "tension legs" to secure the structure to the seafloor. The columns in the hull range up to 100 ft in diameter and up to 360 ft in height; the overall hull measurements will depend on the size of the columns and the size of the platform.

Tension Legs (tendons) are tubular structures that secure the hull to the foundation; this is the mooring system for the TLP. Tendons are typically steel tubes with dimensions of 2-3 ft in diameter with up to 3 inches of wall thickness, the length depending on water depth. A typical TLP would be installed with as many as 16 tendons.

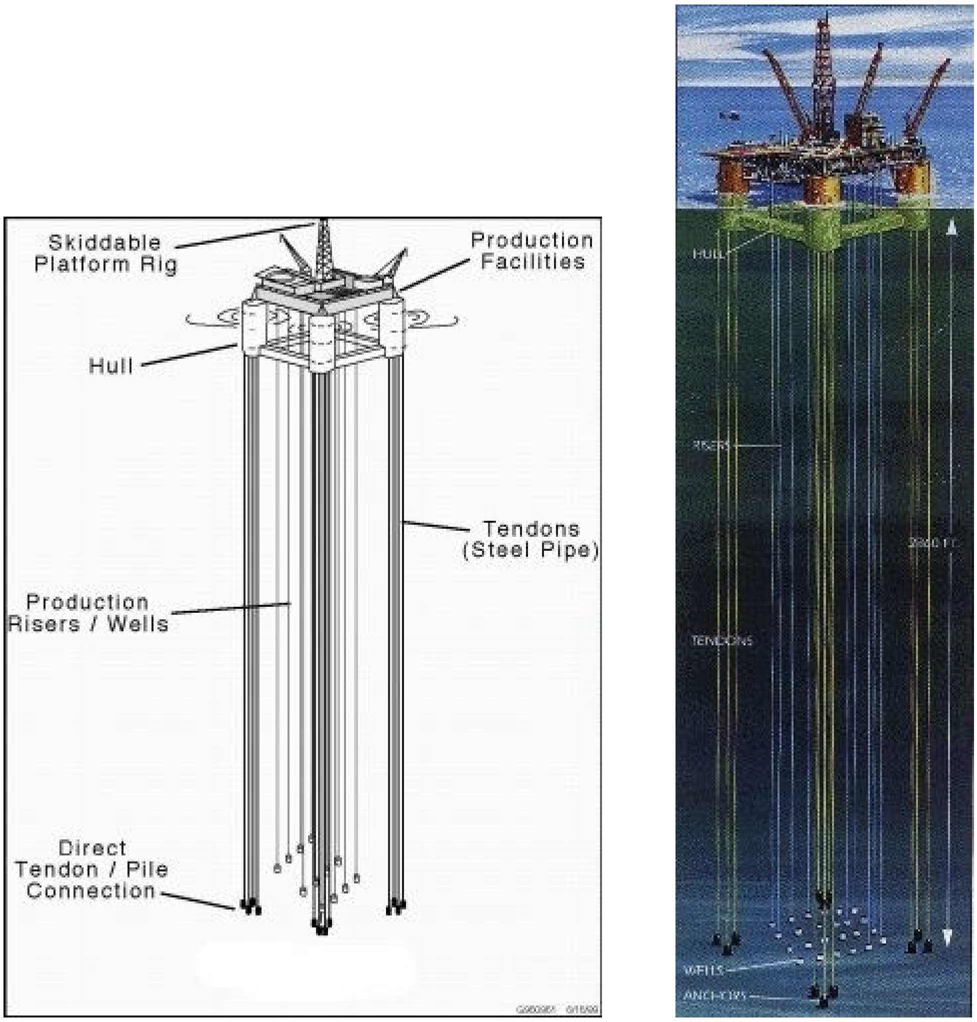


Fig. 4.7 - Tension Leg Platform

To avoid problems in deepwater drilling, the cross-sectional area of the hull of the TLP is constructed based on the load it would support. .i.e. the number or weight of risers and drill strings it would support for drilling.

4.3.1 Derivation of Equation

To determine the permissible weight that can be supported by the TLP, we can employ this calculation:

For a platform kept afloat with the tendon pipes in tension due to buoyancy, we can infer that the more area of the hull we have, the more the buoyancy in water, and the more the tension in the tendons.

Buoyancy = weight of water displaced = equivalent volume of seawater x density of water. For safe operation, tensile strength of the tendons ≥ buoyed weight of the platform + weight of weight of tendons in seawater i.e. (maximum buoyancy force – weight of platform) + weight of tendons in seawater.

The following are defined:

A= cross-section of all supports between platform and pontoons (hull), m^2

h = maximum wave height from bottom to top, m

D = sea depth, m

A_s = minimum cross-section of all tendons, m^2

ρ_s = density of tendon steel, kg/m^3

ρ_w = density of seawater, kg/m^3

g = acceleration due to gravity, m/s^2

F = maximum tendon load, Pa

K = buoyancy factor

σ_y = yield stress of tendon steel, Pa/m^2

We obtain the following:

$$K = 1 - \frac{\rho_w}{\rho_s}$$

Weight of tendons in seawater $= A_s D \rho_s K g$

Load due to maximum wave height of seawater $= A h \rho_w g$

Then,

$$F = A_s \sigma_y = A h \rho_w g + A_s D \rho_s K g$$

$$A_s = \frac{Ah\rho_w g}{\sigma_y - D\rho_s gK}$$

This means that the minimum cross-section of all the tendons must not be less than $1.32m^2$ in order to avoid the maximum tendon load being greater than the yield stress of tendons. The tendons are normally kept taut or stretched by buoyancy force, and increased wave height could also be contributing extra stretching force on the tendons as reflected in the derived equation. In a stretched drilling string in deepwater, we should have the maximum tension at the top of the string, and the minimum at the bottom.

However, we can envisage a scenario where we could have minimum wave height falling below mean sea level. This might lead to having our neutral point in the string further higher up from the bottom. In this case, the string might experience some buckling at the bottom below the neutral point. A safety factor should be considered in our calculation to avoid this scenario.

4.3.2 Example

If we have,

A = $1000m^2$, h = 50m, ρ_w= $1030kg/m^3$, ρ_s= $8000kg/m^3$, 9=$10m/s^2$, D= 3000m,

σ_y =600,000,000 Pa(6000bars)

$$K = 1 - \frac{1030}{8000} = 0.871$$

$$A_s = \frac{1000 \times 50 \times 1030 \times 10}{600 \times 10^6 - 3000 \times 8000 \times 10 \times 0.\ 871} = 1.3173m^2 \approx 1.32m^2$$

Chapter 5: DEEPWATER DRILLING PROBLEMS ASSOCIATED WITH DRILLING OPERATIONS

5.1 HYDRATES

5.1.1 Mechanism of Hydrate Formation

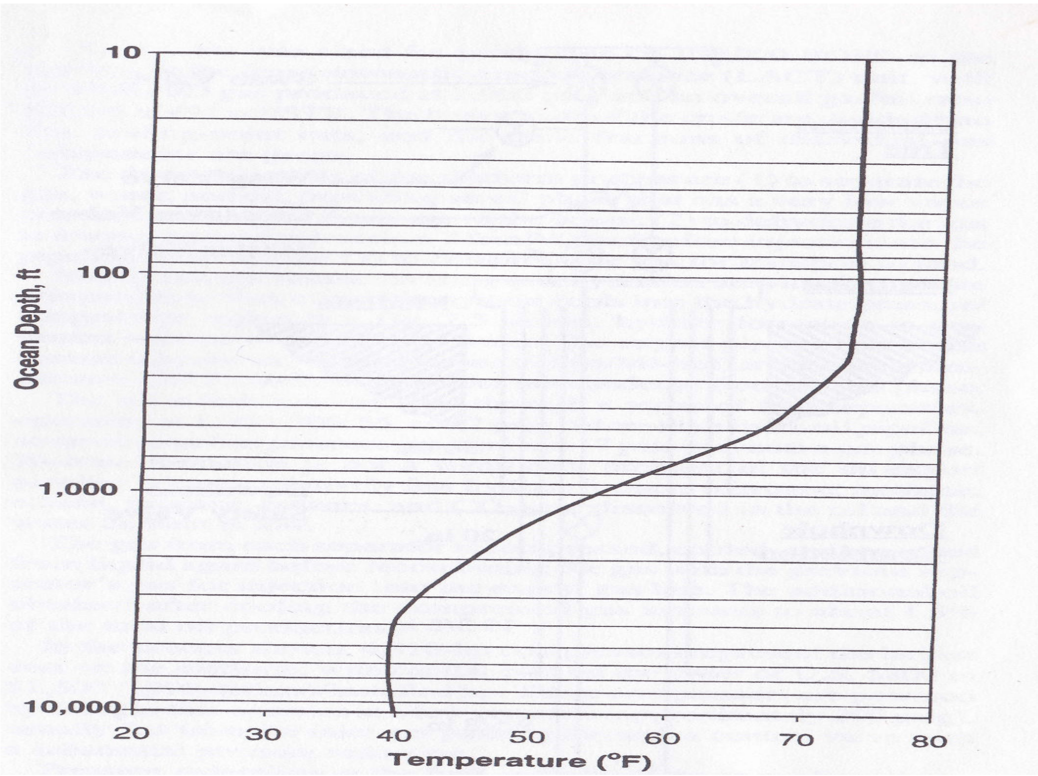
Under favorable conditions of high pressure and low temperature, hydrocarbon gas and liquid water can combine to form crystalline solids, which resemble wet snow or ice, these are known as hydrates. The crystal structure is composed of cages of hydrogen bonded water molecules which surround 'guest' hydrocarbon molecules such as methane, ethane and propane. These ice-like structures agglomerate to block tubing, mud return lines, flow lines, and/or mud handling facilities.[6] Note that hydrocarbon gas and liquid water must be present to form hydrates.

5.1.2 Hydrate Formation Conditions[7]

1. Free water and natural gas components must be present. Gas molecules ranging in size from methane to butane are typical hydrate components, including CO_2,N_2 and H_2S. The water in hydrates can come from the free water produced in reservoirs, from condensed water due to the cooling of the hydrocarbon fluids or from water –based drilling mud.
2. Low temperature is normally needed for hydrate formation; however, even though hydrates are 85 mol% water, the system temperature does not need to be below 32^{o} F (the freezing point of water) for these ice-like solids to occur. Offshore, below approximately 3000ft of water depth, the ocean-bottom (mudline) temperature is remarkably uniform at 38 to 40^{o}F and pipelines gas readily cool to this temperature within a few miles of the wellhead. Hydrates can form easily at temperatures higher than 70^{o}F at the pipeline high pressures (as well).
3. High pressures commonly promote hydrate formation. At 38^{o} F, commonly natural gases form hydrates at pressures as low as 100psig; at 1500 psig, common gases form hydrates at 66^{o}F.

In deepwater drilling, one major unusual aspect is the water depth which may range from 6000ft to 10000ft. Such depths and distances provide cooling for the mudline fluids to low temperature and high pressures, which are well within the hydrate –stability region. At a typical ocean temperature of 39^{o}F, 400ft of water depth provides pressures required for hydrate formation. The system temperature and pressure at the point of hydrate formation must be within the hydrate-stability region, as determined.

Figure 5.1 shows a typical plot of the water temperature in the Gulf of Mexico (GOM) as a function of water depth. The plot shows that a high temperature of 70^{o}F (or more) occurs for the first 250ft of depth. However, when the depth exceeds 3,000ft, the bottom water temperature is very uniform at approximately 40^{o}F, no matter how high the temperature is at the air/water surface. This remarkably uniform water temperature at depths greater than 3,000 ft occurs in almost all the Earth's oceans (caused by water-density inversion), except a few that have cold subsea currents.



Comment: As explained in chapter 2, a possible reason for a slightly increasing temperature at the bottom is due to heating effect from the earth core.

Fig. 5.1- Water Temperature vs. Depth, Gulf of Mexico

Presence of salt in the case of produced water in oil wells could prevent/inhibit formation of hydrates. For gas wells, only saturated water vapour is produced, this partly condenses to fresh water in the cooler part of the well. And if no salt is present in the condensed water, it could result in hydrate formation if hydrate-formation conditions are present.

5.1.3 Hydrate Formation Conditions by Gas-Gravity[7]

The simplest method to determine the hydrate-formation temperature and pressure is by means of gas gravity, defined as the molecular weight of the gas divided by that of air. Figure 5.2 is a chart of hydrate–formation curves for different gas gravities. To use this chart, the gas gravity is calculated and the highest temperature of the hydrate formation process is specified. The pressure at which hydrate form is read directly from the chart at the gas gravity and temperature; to the left of every line, hydrates form with a gas of that gravity, while for pressures and temperatures to the right of the line, the system is hydrate-free.

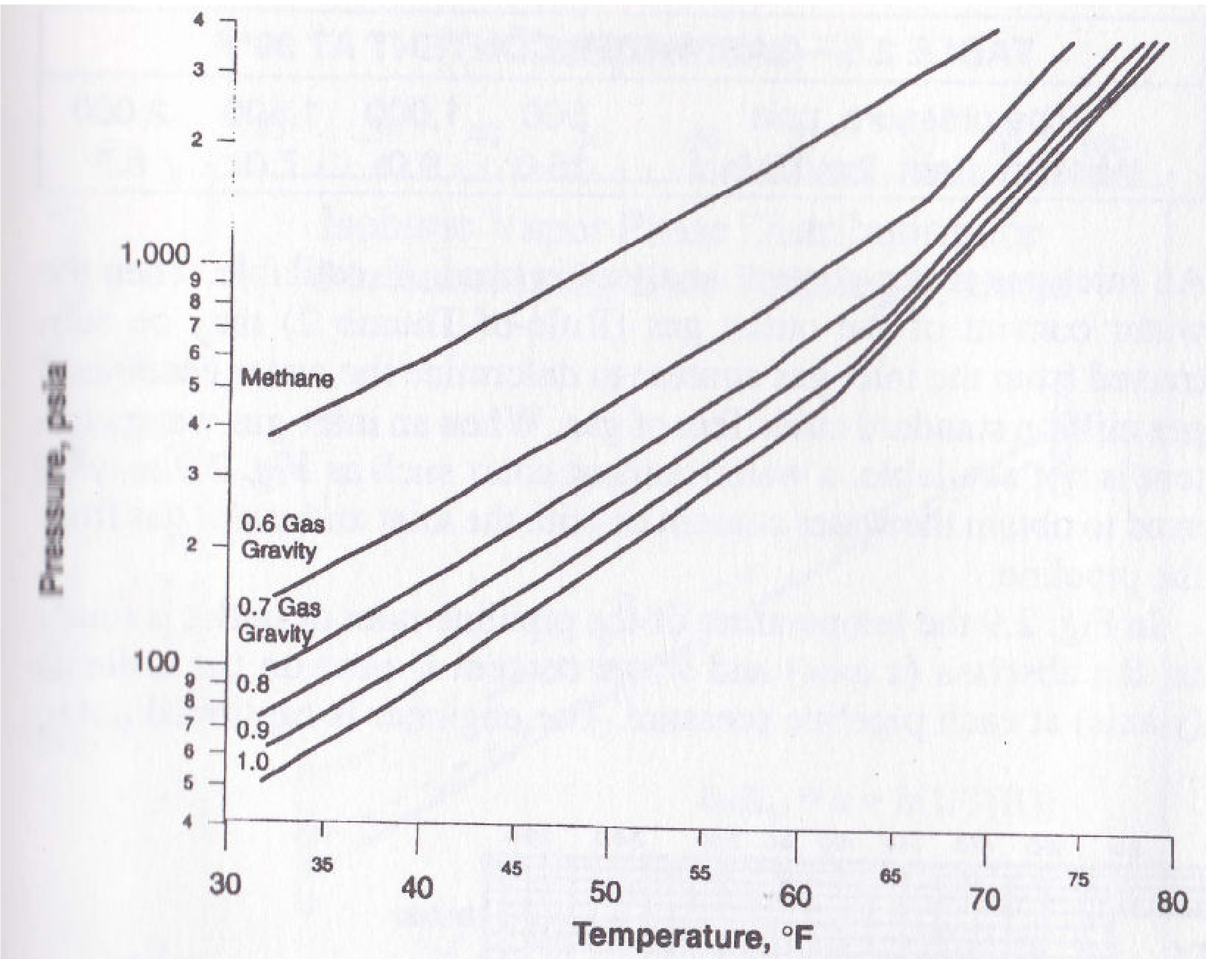


Fig. 5.2 –Hydrate-Formation Curves for Various Gas Gravities

5.1.4 Hydrates Problems in Real Life

In real life, flowing well or mud being circulated for drilling never gives enough time for hydrate formation due to constant agitation. In the case of flowing oil or gas from the well, addition of warm or hot fluid from the well bore to the initial fluid being cooled at the deepwater condition keeps the fluid constantly mobile and prevents hydrate formation; though low temperature conditions could have an overall effect of cooling the flowing fluid.

In a case where we have temporary shut-in of the well, presence of gas from the formation in the mud line or the well bore below the mud line due to gas migration or phase segregation may result in hydrate formation and develop into blockage.

We could also have high pressure build up in the pipe when we have a hydrate plug. Hydrate formation below the wellhead could also block off part of the high pressure from the well flow, hence, not giving the true picture of the high well pressure. Should the well be shut-in with a mud not heavy enough based on this false impression, opening up the well when re-visited for drilling could be a catastrophe.

Shutting down a well could also be problematic due to hydrates if the formation contains some gas, and oil and gas keeps accumulating at the hydrates blockage over time when the well is shut in. This accumulation would cause high pressure build-up in the deepwater pipe from the well. For such a pipe, should there be a leakage or loss of the hydrate plug or an attempt to start production in the well, it could lead to a catastrophic kick.

One of the most commonly found hydrates in offshore drilling industry are those formed from methane gas. These hydrates formed from reactions between water and methane under certain conditions of high pressure and low temperatures can cause costly operational problems.[8]

Other problems encountered due to hydrates include operational problems in the wellhead and riser connectors. A modification can be made to the wellhead or riser connector to prevent hydrate formation in critical areas susceptible to methane migration. For example, this can be achieved through the addition of a methane gas seal, which is a large cross section excluder seal that prevents the migration of hydrate forming methane gas in the connector.

5.1.5 Hydrate Prevention Methods[7]

The three conditions necessary for hydrate formation lead to four classic thermodynamic prevention methods used for general hydrates problems:

1. **Water removal**: This provides the best protection as separation removes free water which we have identified as one of the main constituents necessary for hydrate formation. Water condensation from the gas phase is prevented by drying the gas, either with triethylene glycol to obtain water content less than 7lbm/MMscf or with molecular sieves to obtain lower water content.
2. **Maintaining high temperature**: This keeps the system in the hydrate–free region. High reservoir fluid temperature may be retained through insulation and pipe bundling, or heat may be added through hot fluids or electrical power, although this latter option is not economical in many cases.
3. **The system pressure may be decreased below the hydrate-formation pressure:** To do so, one can design system pressure drops at high temperature points, e.g. bottomhole chokes. However this is not recommended for drilling systems.
4. **Injection of inhibitor:** Hydrate prevention is achieved most frequently by injecting an inhibitor, such as methanol (MeOH) or monoethylene glycol (MEG) which acts as an antifreeze, to decrease the hydrate –formation temperature below the operating temperature. There are two new means of hydrate inhibitors added to the industry list that have been brought to common practice. They are:

   Kinetic inhibitors: low molecular weight polymers and small molecules dissolved in a carrier solvent and injected into the water phase in pipelines.

   Antiagglomerants: dispersants that cause the water phase to be suspended as small droplets in the oil or condensate. When the suspended water droplets are converted to hydrates, pipeline flows are maintained without blockage.

5.1.6 Hydrate Prevention during Drilling in Offshore/Deepwater Environment[7]

In most onshore drilling, the reservoir temperature is sufficient to prevent hydrate formation except large pressure drops in the downstream, such as at chokes. In Arctic and offshore environments, however, low temperatures often cause hydrate formation in the drilling process in addition to the hazards of drilling through hydrated reservoirs.

5.1.6.1 Hydrate Prevention in Drilling Fluids

The principal concerns in deepwater drilling fluids are the formation of plugs in choke and kill lines. The presence of hydrate in deepwater drilling result in the following adverse effects:

- Choke and kill line plugging, preventing their use in well circulation.
- Hydrate-plug formation at or below the BOP, preventing well pressure monitoring below BOP.
- Hydrate-plug formation around the drillstring in the riser, BOP's, or casing, which prevent drillstring movement.
- Plug formation in the ram cavity of a closed BOP, which prevent the BOP from opening fully.

Hydrate prevention in deepwater drilling can be achieved based on the following:

Synthetic Oil-Based Drilling Fluids: Synthetic oil-based drilling fluids have very low toxicity and good bioremediation qualities-two properties that allow disposal of cuttings offshore. Because of these inherent drilling advantages, synthetic oil-base drillings fluids (mud) predominate in deepwater drilling. Hydrate occurrences are unlikely in oil-based fluids (mud), particularly if the internal brine phase has a high salt content (e.g. 25 to 30% $CaCl_2$).

Water-Based Drilling Fluids: It is becoming more difficult to use oil-based drilling fluids (mud) offshore due to increasing stringent environmental regulations. Thus, acceptable water-based fluids are needed. Their use are governed by the given rule of thumb to predict the formation of hydrates,

"The water and the water –soluble drilling fluid components determine the conditions of hydrate formation. Concentration of salts, alcohols, glycols, and glycerol in water determine the hydrate-formation temperature and pressure''.[7]

Very few problems have been encountered with hydrates while using either oil base mud or synthetic base mud systems. Inhibited water base mud is available to reduce potential for forming hydrates in the wells if oil/synthetic base mud cannot be used. Most drill rig hydrate troubles occur after a period of time without circulation.[2]

5.2 RISER LOSS

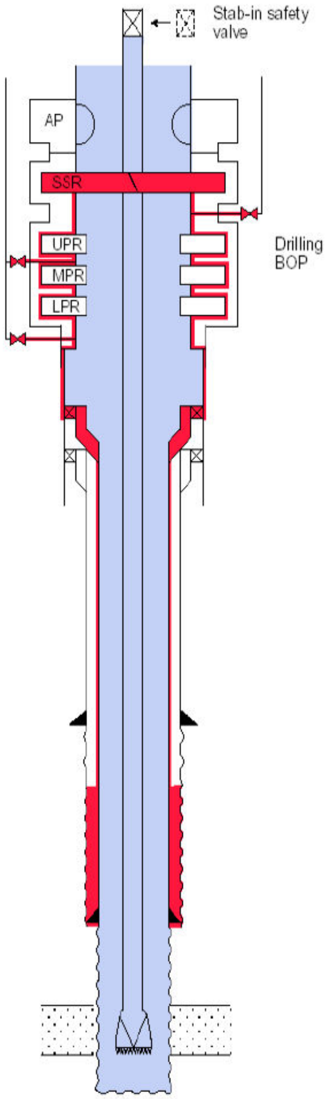
5.2.1 Well Barrier

According to NORSOK Standard D-010 Rev. 3 August 2004, [9] it is recommended that well barrier schematics are developed as a practical method to demonstrate and illustrate the presence of the defined primary and secondary well barriers in the well. Well barriers are always put in place before drilling operations start; however, deepwater drilling requires special consideration due to the possibility of the occurrence of riser loss.

The well barrier elements that constitute the primary and secondary well barriers for general drilling conditions are illustrated in figure 5.3:

5.8 Well barrier schematic illustrations

5.8.1 Drilling, coring and tripping with shearable drill string



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

Note

None

Comment: Only one barrier is not allowed in Norway.

Section 5.8.1, page 33- NORSOK Standard D-010

Fig. 5.3- Well Barrier Schematic

5.2.2 Riser Margin

Safety considerations require that an additional mud weight be included for drilling offshore, to be able to contain the well pressure in a situation where you lose the riser, which in turn would lead to loss of the mud column in the riser initially providing the hydrostatic support. This additional mud weight is called the **riser margin**. Instead of a column of mud from the rig deck and down to the well head, there would be a column of seawater from the sea surface and down to the well head. This would significantly reduce the hydrostatic pressure due to the vertical column of liquid above the well head as the density of seawater is usually less than that of drilling mud. From the well barrier schematic, an additional requirement to the fluid column in case we use marine riser as applies to deepwater is provided in table 5.1 below, as specified from NORSOK Standard D-010.

TABLE 5.1: Excerpt from NORSOK D-010 on Riser Margin

<table>
<tr><th>Element name</th><th>Additional features, requirements and guidelines</th></tr>
<tr><td>Fluid column</td><td>
Riser margin (only applicable for vessels with a marine riser)
The fluid column is not a qualified well barrier when the marine riser has been disconnected. Planned or accidental disconnect of the marine riser, resulting in loss of the fluid well barrier shall be planned for. Procedures for planning and implementation of compensating measures shall be established.
If the uncased borehole has penetrated hydrocarbon bearing formations or abnormally pressured formations with a flow potential and the hydrostatic pressure in the well with the riser disconnected may become less than or equal to the pore/reservoir pressure of these formations, risk reducing measures shall be established with the following priority :
A. reduce the probability of having an influx during the disconnect period
B. strengthen the availability/reliability of the remaining well barrier.
The following table is listing some examples of risk reducing measures that could be applied.
<table>
<tr><th>Priority</th><th>Risk reducing measures</th><th>Comments</th></tr>
<tr><td>A</td><td>Drill with “Riser Margin”</td><td>Maintain a drilling fluid density that will provide an overbalance with the marine riser disconnected.
This alternative shall be assessed as the primary compensating measure.</td></tr>
<tr><td>A</td><td>Spot a weighted fluid</td><td>Displace the entire well or part of the well to a fluid with a density that will provide an overbalance towards zones with a flow potential with the marine riser disconnected.</td></tr>
<tr><td>B</td><td>Install a bridge plug</td><td>Install a bridge plug with storm valve below the wellhead.</td></tr>
<tr><td>B</td><td>Two shear-/seal rams</td><td>Use two shear-/seal rams in the drilling BOP as an extra seal element during hang-off / drive-off situations.</td></tr>
<tr><td></td><td></td><td></td></tr>
</table>
</td></tr>
</table>

Section 5.4.2, Table 1, page 27- NORSOK D-010

During the drilling operation offshore, we start losing the mud inside the riser when we have **riser loss** (the riser disconnects from BOP at seabed planned or unplanned). This condition is called **Riser Mud Loss**. Several factors could be responsible for this disconnect ranging from weather conditions to equipment failure. This condition could culminate into riser loss problems.

5.2.3 What Happens When Riser Mud Loss Occurs?

5.2.3.1 Sub-Seabed Section (Below the Seabed in the Well)

When the riser is lost in the case of deepwater, fluid column inside the riser and the BOP are majorly affected (mud is lost and BOP could get damaged). Hence, the fluid column (mud column or water column) is the primary barrier while the BOP is the secondary barrier as discussed under barrier requirements (see section 5.2.1).

The riser column of the mud hydrostatic could be completely lost when we have riser disconnect for any reason, in which case we lose the mud in the riser to the seabed water. As mentioned earlier, such an occurrence is referred to as **riser loss**. When this happens, how much well control can be ascertained becomes questionable. Figure 5.4 below shows a simple set up using the riser for deepwater drilling.

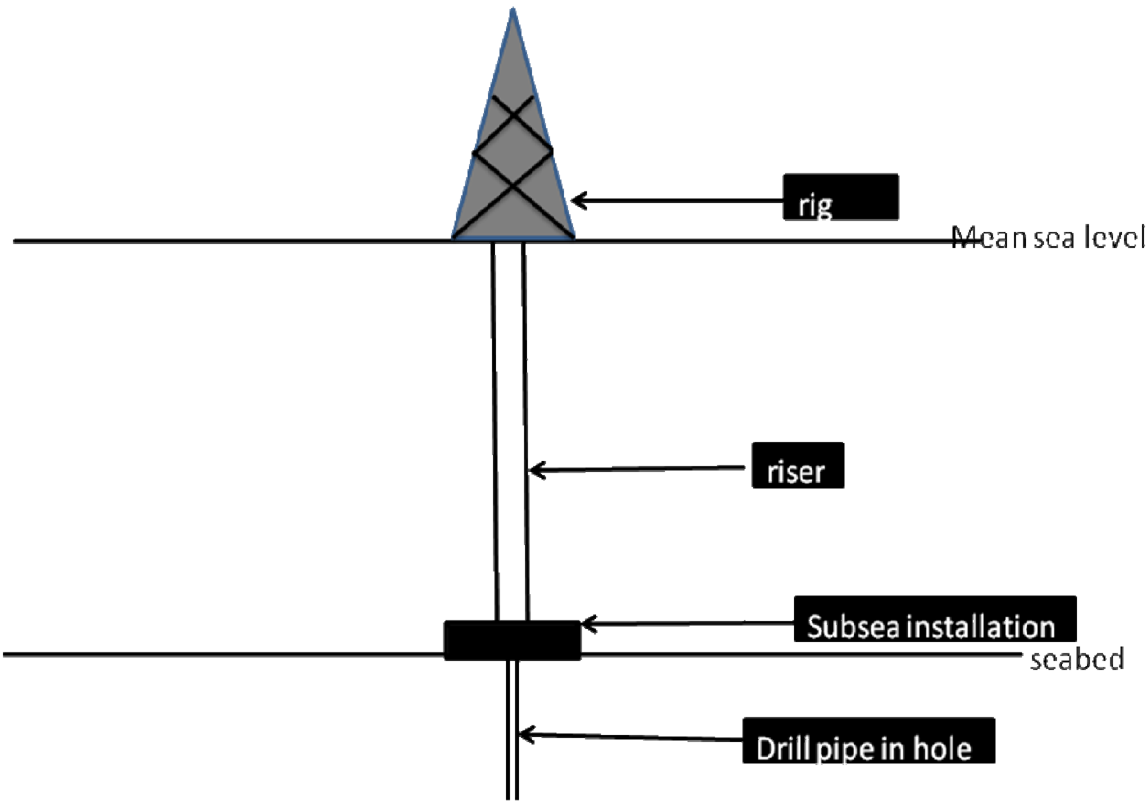


Fig. 5.4 - Conventional Configuration for Riser Margin (Before Artificial Seabed)

Consider a deepwater well being drilled with mud column in the riser contributing to the hydrostatic pressure in the deepwater for well control. Since water is not as dense as mud; if the riser column of mud is lost, a kick (or worst case of a blowout) would most likely occur when this mud column is replaced by the water column which in turn is dependent on the hydrostatic parameter and wellbore pressure.

In order to avoid this, mud weight just a bit higher than the exact weight required to drill in deepwater is used, so that well control can be maintained even when riser loss occurs and sea water column replaces the hydrostatic column initially provided by the mud in the riser(as mentioned under riser margin discussion(see section 5.2.2). . For shallow water drilling, this riser margin is usually small and easily determined with no complications.

However, in the case of deepwater, the situation is much more complex and it is difficult to determine the most suitable riser margin to be applied to the drilling mud.

For deepwater resources, a narrow margin between formation pore and fracture pressure exists in many over-pressured basins around the globe including the Gulf of Mexico.[10] This limited margin between pore and fracture pressure often becomes narrower with increasing water depth due to reduced overburden pressure and shallow onset of abnormal pressure. As a result, reaching the target depth for deepwater wells while retaining a useable borehole size is often difficult, and this complication limits the extent to which we can increase the weight of the mud used for deepwater drilling in case we lose our riser.

A too low riser margin, in order to avoid damaging the formation, would not be enough to provide adequate initial hydrostatic column by the drilling mud. Hence, it could lead to loss of well control and eventual blowout when the riser is lost. On the other hand, a too high value of riser margin, in order to provide adequate hydrostatic weight to compensate for the lighter seawater column that cannot alone give as much hydrostatic support as the drilling mud, poses a threat of damaging the fragile formation which as highlighted in this paper is a characteristic of the deepwater environment.

There is a major concern in the case of deepwater about how to determine what is the safest value of riser margin to be used in drilling in view of these two contradicting constraints. The first being how to determine how heavy mud can be made to ensure adequate riser margin in the case of deepwater since we have a very large column of mud in the riser to account for. While the second constraint is determining how light the mud should be (considering the fragile nature of most deepwater formation) in order to avoid damage of the formation at wellbore.

For deepwater drilling, we introduce the riser margin. The analysis for this concept is discussed in details in the next chapter**.** There is a need to accurately determine the best option or value of mud weight (MW) that would ensure well control. Also, consideration for unexpectedly high well bore pressure build-up overtime after shut-in due to gas migration would even tempt one to employ much higher value for riser margin for well control purposes posing further threat to the formation.

5.2.3.1.1 Artificial Seabed: Proposed Solution to Riser Margin Problems in Sub-Seabed

Considering the complication involved in choosing the safest mud weight (riser margin) for the sub-seabed section, a concept of **artificial seabed** could be suggested in order to eliminate the challenges over choosing the most suitable riser margin.

For this suggestion of artificial seabed, an artificial floating sea bottom could be conceived. Here, we consider an artificial seabed far above the real seabed and very near to the water surface supported like a tension leg platform with a column of riser attached to it running from this artificial seabed to the real seabed as shown in figure 5.5. Another riser can be assumed to connect the artificial seabed to the rig, and this is the riser that can be lost i.e. removable riser**.** This means that the distance between the artificial seabed and water surface is small, and this distance is equivalent to the mud column in the riser that would be lost when riser disconnect is experienced.

The mud in the riser below the artificial seabed would remain and still provide hydrostatic support in the case of loss of the unstable riser above it. Therefore, only the relatively short column of mud in this removable riser would be lost in case the riser is lost (could be 100 - 200m). The effect of riser margin for a very short column of removable riser can be considered negligible. However, cost consideration is important in evaluating this option.

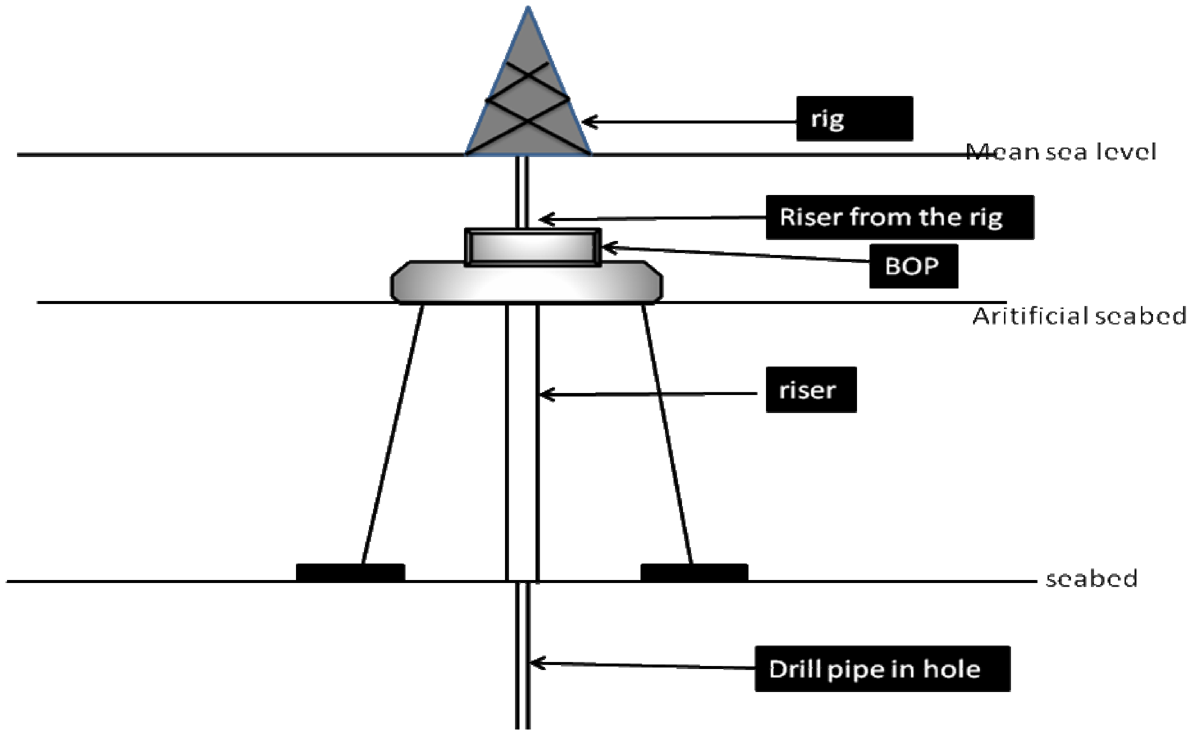


Fig. 5.5- Deepwater Riser with Artificial Seabed

Note: The depth of the artificial seabed should be sufficient to avoid significant water movements due to large waves (influence of sea current at the surface is relatively much higher than at the sea bottom).

5.2.3.2 Above-Seabed Section (deepwater interval)

Having looked at the problem associated with riser loss in the sub-seabed section for the in-hole condition (integrity of the formation versus well control), it is important to also describe the kind of problem faced in the deepwater above the seabed. If riser disconnect occurs, and the weather condition becomes so bad that the rig would have to move away or shift, it would be observed that the mud gradually pours out at the bottom of the riser. We are considering the integrity of the riser when losing its mud content in the deepwater as the pressure from the sea water might damage/collapse the column of the riser being emptied. Calculations could be made to determine/ascertain if our riser is good enough to continue the drilling when reconnected to BOP as discussed in the next chapter under analysis and discussion. This problem can be illustrated in the schematics below in figure 5.6.

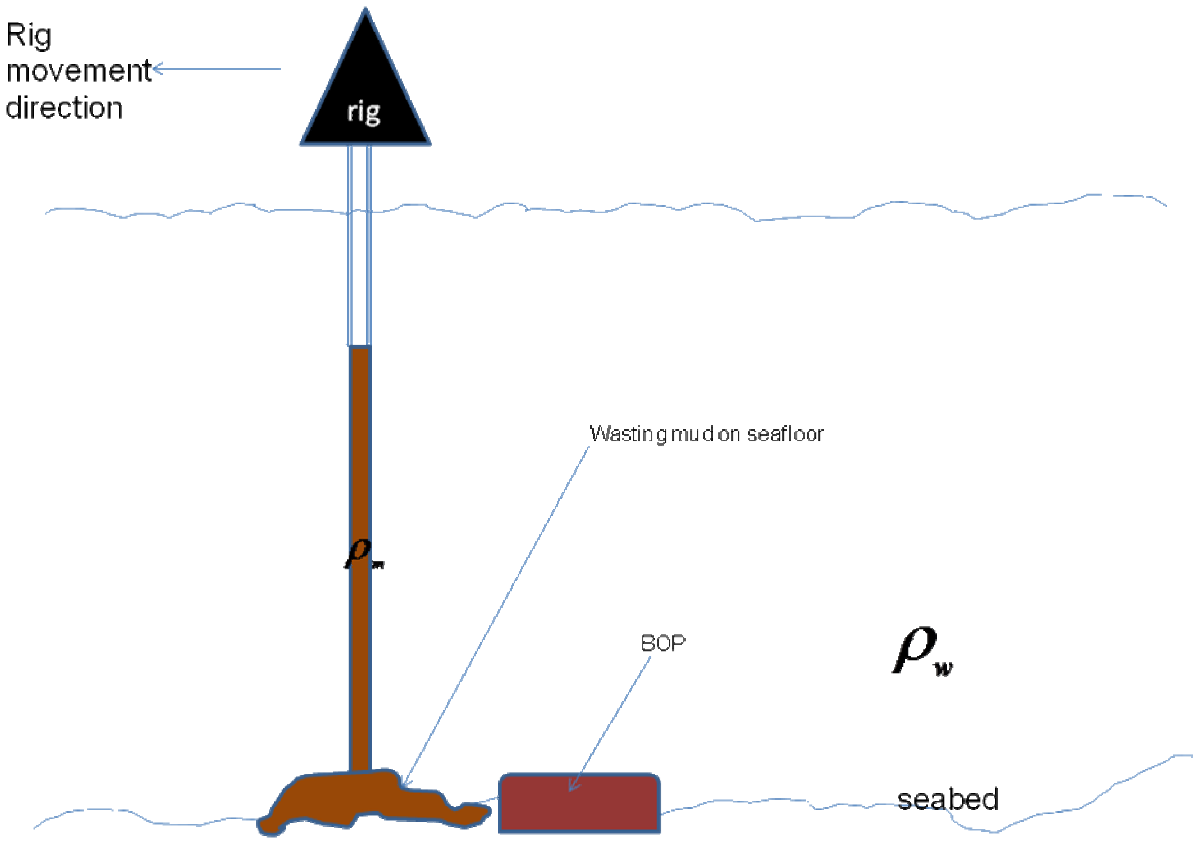


Fig. 5.6- Riser Disconnect Illustration for Above-Seabed Consideration.

The figure above describes the situation where the mud starts pouring out at the seabed as we experience riser disconnect from the BOP in the deepwater. The mud is gradually poured onto the sea floor as the rig drifts away from its position after riser disconnect.

5.3 CUTTINGS TRANSPORT IN RISER ANNULUS

The use of riser to protect the drill string, provide well control and a return channel for mud and cuttings(hole cleaning) is almost unavoidable in drilling except in the case of riserless drilling. Risers are often employed for deepwater drilling purposes where cuttings transport in the riser annulus is affected by several factors among which are

- Well hydraulics

  -Fluid density: mud weight

  - Fluid rheology: viscosity, rheological model, rheological properties (plastic viscosity (PV), yield point (YP), gel strength

-Shear characteristics: shear strength, shear rate

- Flow rate
- Flow regimes: laminar or turbulent
- Riser design: size , riser booster

Amongst these factors, riser size and design is mainly based on deepwater considerations. However, the challenge is choosing the right riser specification and design to allow cutting transport and at the same time withstand the harsh deepwater environment at the seabed. Mud carrying heavy cuttings flows from the relatively smaller diameter annulus in the hole into a larger diameter riser; this significantly reduces the flow rate and thus necessitates several ECD management methods to ensure the cuttings are transported to the surface. Basically, the following are among the considerations related to the riser and are very critical for cutting transport.

- Riser size and diameter
- Riser Length

Both are points under riser dimensions.

5.3.1 Riser Size and Diameter

Deepwater risers come in relatively bigger sizes than casings depending on the material and specification in order to withstand the high hydrostatic inside or outside pressure condition, associated with deepwater. The bigger the riser , the lower the velocity of return cutting carrying return mud being transported to the surface, and the lower the cutting carrying ability of the return mud. Riser sizes in deepwater determine to a large extent the flowrate of the cuttings carrying mud; hence, a limiting factor to the hole cleaning (cutting transport top surface) when a wrong size is used. Right choice of riser is important to permit enough velocity for the cutting.

Risers used for deepwater drilling are called top-tensioned risers and the range of sizes is mostly within the range of 8" to 24" in sizes depending on the type of application. Cutting transport is more difficult in the big sizes i.e. 24" because of the extremely high flowrate high values required for such riser sizes. Such high flowrate is usually above the pump limit, but riser boosters are often employed to achieve the required flowrate.

The area of the riser and flow velocity is related by the simple equation: [11]

$$v = \frac{Q}{A}$$

A= cross-sectional area of riser for flow, Q= flowrate

The equation above shows, that the bigger the riser size, the larger the area and the smaller the average flow velocity. However in practical terms, there are two constraints:

- Deepwater of several hundred of meters of water depth require a riser that is big enough to withstand the deepwater condition so that it does not collapse.
- The riser must be as small in size or diameter as possible to make cuttings transport to the surface possible.

5.3.2 Riser Length

Deepwater of several thousands of feet requires several connections of riser forming a great distance to the seabed. However, the challenge here is that the longer the riser, the more difficult it is to achieve the required velocity for cuttings transport because the mud return flow would experience more pressures losses over long distances.

In summary, although riser booster has proven to be very helpful in achieving required flowrate for cutting transport, riser dimension remains an area requiring attention to avoid cutting transport problem in the riser. To achieve a particular required mud flowrate for cuttings transport in the riser annulus to the surface in deepwater, riser consideration is an important limiting factor even when riser booster is employed. In this work, Slimhole Drilling is a proposed method/solution to the riser cutting transport problems.

5.3.3 Slimhole Drilling: Proposed Solution to Cuttings Transport Problem in the Riser Annulus

Slimhole drilling is believed to be a possible solution to the riser annulus cuttings transport problem in deepwater due to the inadequate flowrate for cutting transport in the big risers sizes used in conventional deepwater. Slimhole wells may be defined as wells where 90% or more of the length of the well is drilled with bits less than 7 inches in diameter.[12] Such small drill bits diameter drilling would require similar small diameter size risers which would greatly improve cuttings transport flowrate in the riser annulus.

Slimhole drilling involves drilling a major portion of the length of the well with drillbits less than 7 inches (17.8 cm) in diameter. It is not necessarily new technology.[13] Slimhole drilling has been actively utilized since the early 1920s and was studied in-depth in the 1950s by at least one major company which had an active slim hole development program. The technology as described is not new, but is a technology borrowed from the continuous –coring mining drilling industry.

The sole reason for drilling a slimhole is cost reduction**.** Slimhole drilling is a method for lowering cost by reducing consumables used in drilling and completions processes.[14]It is a system to drill small holes at total depth rapidly and reliably which would allow wells to be made slimmer from top down. Further cost savings would accrue through the following areas: [15]

- Use of smaller surface casing and the substitution of liners for intermediate casing strings.
- The smaller upperhole sections could be drilled with improved penetration rates
- Reductions in cement and mud costs, and environmental impact would be achieved and with increasing confidence, rig size could also be reduced.

Although typically only the bottom five percent of the well is slim (< 6 1/4"), cost reductions apply to the whole well.

Figure 5.7 illustrates the generic differences between the drilled hole diameter and sizes of casing typically run in conventional and slim hole wells.[16] A major characteristics of Slim Hole Drilling are the utilization of high RPM diamond bits with low weight on bit (WOB) to achieve optimal penetration rates. This result in primary equipment differences as compared to conventional drilling rigs, the precise WOB control is typically accomplished using hydraulics for feed and WOB control. Because of the high RPM requirements, the diameter of the hole being drilled is only fractionally larger than the drill rod because of lateral drill string stability requirements. Therefore, smaller annular clearances are associated with slimhole well than with conventionally drilled wells.

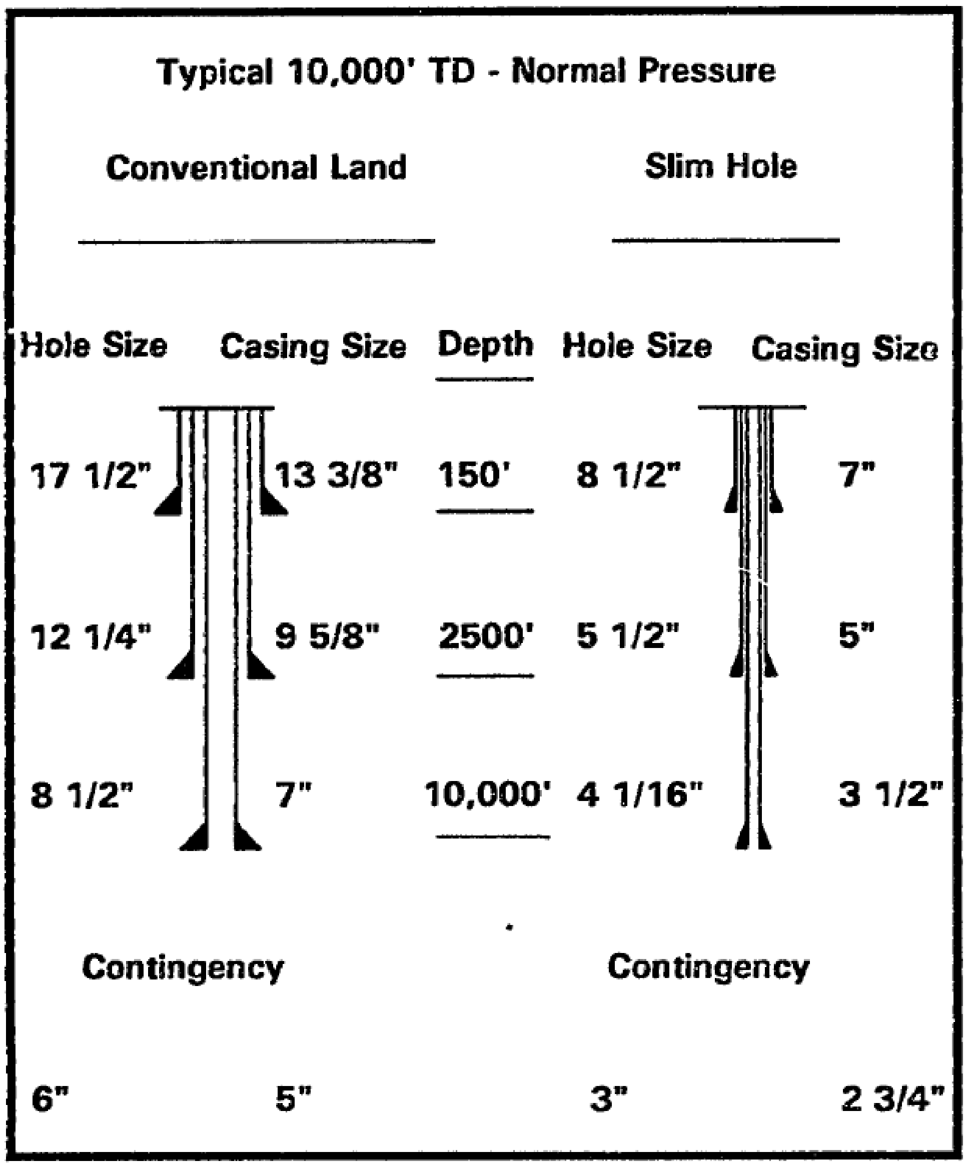


Fig. 5.7 - Typical Casing Program as Compared to Slimhole.

The reduced annular clearance affects several major areas of drilling engineering requirements. In conventional well bores, the cross sectional area of the annulus is much larger than the inner area of the drill pipe. For long strings of pipe, or deep holes, the pressure loss in the drill pipe dominates over the annulus because of flow area. However, in slimholes, the cross section area of the drill rod is greater than the area of the annulus, Therefore, the greatest pressure loss would occur in the annulus. With the pressure losses occurring in different geometries of the wellbore between conventional and slim hole, the historic data and equations for hydraulic design of wellbores of conventional wells are not valid. Major features of slimholes include:

Penetration Rate
Generally diamond core heads are used in slim hole coring. And in combination with low weight (2,000- 8,000 lbs) and high RPM (350-1000),they provide adequate penetration rates (2-15m/hr). The single most important factor in rate of penetration appears to be RPM. The small annular clearances seem to benefit the rotational capability by providing lateral stability to the drill string**.**

High ECDS
High ECDS are associated with the small annular clearance of slimhole coring. This can lead to lost circulation in fractured or non competent formations. Care must be taken to plan and control fluid properties, especially viscosity during drilling.

Depth Limitations
Depth limitations for slim holes vary, depending on how the rigs can be modified for slim hole drilling. The rig could be rated to 15,000 feet and above.

5.3.4 Application of Slimhole Drilling to Offshore Drilling

The application of slimhole technology was primarily for economic reasons. However, its application can be extended to deepwater environment which to a large extent would reduce costs and at the same time probably serve as a solution to the cuttings transport problem in the riser annulus. Offshore applications include jack-up, shallow water floating drilling and deepwater.

5.3.4.1 Floating Drilling

Essentially all of the necessary technology for this design already exists in other applications in the drilling industry; the development of this system would not require major research effort. Rather, the majority of the development efforts would be spent repackaging existing designs for this application. Existing motion compensators on floating drilling rigs are used to reduce the bit weight variation to within 3000 to 6000 pounds with an average bit weight of about 40,000 lb.

Slim Hole Technology requires weight on bit that may be as low as 2000 lb and the high speed diamond coring bits would not tolerate any significant fluctuation of the weight on bit without damage to the bit. This technology uses high RPM diamond bits with relatively low weight on bit to achieve optimal penetration rates. The reason slimhole drilling has not been very successful offshore is due to the problem of maintaining a constant precise weight on bit. This because the motion compensators used on offshore drilling rigs do not have the capability to maintain accurate low weight on the bit.

To utilize slimhole technology in offshore drilling applications, a means which would allow accurate control on bit is necessary. To modify the existing designs would present difficult and costly solutions. This design would allow existing surface motion compensation to be utilized with the addition of a seafloor device to remove the remaining load fluctuations in the drill pipe, provide a controlled weight on bit and controlled feed rate to control the rate of drilling penetration. The seafloor compensator concept essentially takes the important components of a surface slimhole drilling rig and places them on the seabed. These components control the weight on bit and hydraulically feed the drill pipe down hole. The only difference is that the driller controls the components remotely at the surface and the pipe is rotated from the surface.

5.3.4.2 Ultradeepwater

Today's economics do not warrant huge expenditures by any single company or group of companies to develop equipment for ultradeepwater exploration (ultra-deepwater refers to water depths between 6000 and 11,000 feet). Therefore, in order to justify deepwater and ultradeepwater exploration, a lower cost alternative must be available.

Slim Hole Drilling Technology has been used in more than 8000 feet of water by Mobil.
A schematic of the system is shown in Figure 5.8.

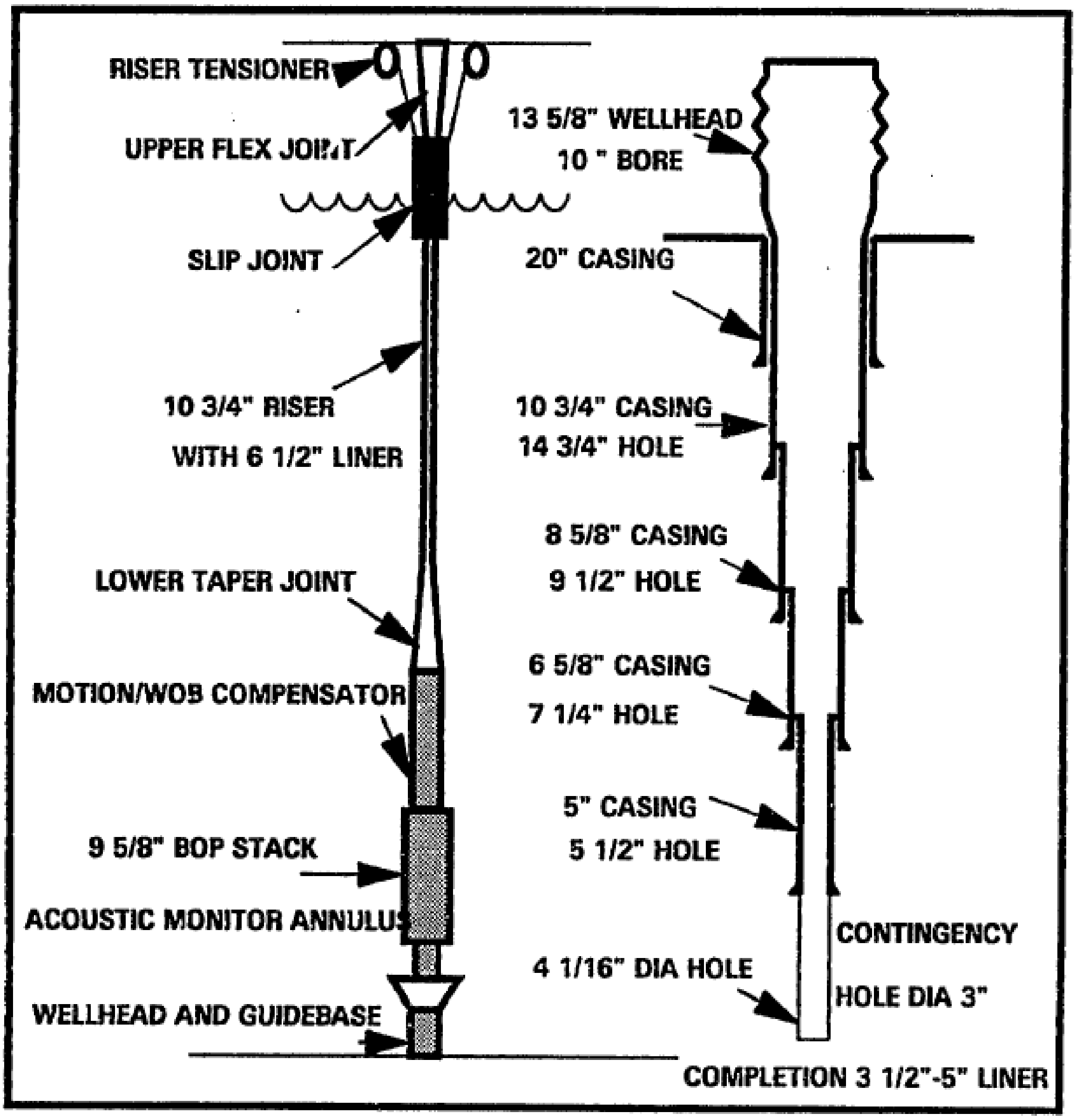


Fig. 5.8- Ultradeepwater Slimhole Drilling

The design, which has been developed essentially, includes the same type of components normally found on deepwater drilling systems; the only differences are the size and the addition of the seafloor compensator. A dedicated built design uses a reduced diameter riser with much lower weight than a conventional riser. This allows the system to be utilized on existing dynamically positioned drilling vessels with minimal modification. The smaller riser allows a smaller Blowout Preventer (BOP) and a smaller wellhead to be used. Smaller casing sizes are also used. In this case utilizing smaller equipment translates directly into reduced costs and also a reduced cross-sectional mud flow area in the smaller riser which would translate into increased cuttings velocity to achieve good hole cleaning. Because of the unique system design, it is perceived that total depths of greater than 20,000 feet can be achieved in water depths to 10,000 feet. As with conventional slimhole drilling systems, drilled depths approaching 12-1500 feet are feasible.

5.3.4.3 Other Areas of Application

Slimhole drilling techniques have been applied in drilling High-Pressure and High-Temperature wells in the North Sea using an **Enhanced Kick Detection System.**[14] Also, slimhole drilling technology has been successfully used in drilling horizontal wells.[13]

5.3.5 Limitations

5.3.5.1 Kick Control

The key issue in slim hole well control considerations is the reduced annular volume as compared to larger conventional holes. This condition can greatly reduce kick tolerance in the sense that a conventional size influx can evacuate enough of the annulus to produce a well control problem. For this reason, flow returns must be monitored closely and may include calibrating PVT equipment to measure in gallons versus barrels. Depending on the hole size and drill string used, pressure drop scenarios may reverse with the annulus having the greatest pressure drop due to the reduced annular clearance. Selection of the well control method is dependent on the annular clearance available.

5.3.5.2 Other Concerns

Another concern against drilling a convectional slimhole well has been production limitations imposed by the small-diameter pipe and the difficulty in working over such wells. Other arguments often cited are the lack of good penetration rates with small diameter three-cone bits, cementing a small hole, the apparent deficiency of logging tools that would fit into slimholes, and problems of inability to do multiples completion.[12]

5.3.6 Challenges

5.3.6.1 Primary Challenges

Kick control is the major problem or challenge of drilling a slimhole. What was cited initially by most opponents for the use of slimhole was the heightened chance of blowout.[17] The greatest operational deterrent for the use of slim hole drilling is the critical issue of detecting kick quickly and taking the corrective action to handle the influx.[12]

A unit of reservoir gas entering a slimhole would occupy a much greater height in the annulus than in conventional wells due to the smaller annular clearances in the slimhole. This could result in the maximum allowable pressure in the casing being approached faster than in a conventional well. The capability of early kick detection is therefore essential.[18]

For example, the containment of a kick within 10-15 bbl (1.5-2.5 m3) in a conventional well is considered reasonable. This volume of gas in a slimhole would give a blowout. The capability to detect an inflow of about one barrel (0.2 m3) would be required for slimhole to be sure of retaining safe control.

The small hole diameter and narrow annulus in slimholes pose many challenges which are not experienced in conventional holes. Unlike conventional hole or drill string geometries, the frictional pressure losses in slimholes are very sensitive to rotation speed of the pipe. As drill pipe rotation is increased, a significant additional pressure loss can be added to the annular pressure loss. In addition, the pressure measured at the standpipe would be affected by other operational changes such as pump rate, pipe movement and coring. The cause of an increase in return mud flow-rate is more difficult to identify when the effects of more than one of the above operations occur simultaneously. Also, the most likely time for the occurrence of a kick is during a connection, when the pumps are switched off and the pressure exerted against the formation is reduced to mud hydrostatic.

However, in order to detect "kick" early enough in slimhole, sensitive **Kick detection System (KDS)** is used based on measurement of mud flow-in and flow-out of the well, corrected for system dynamics using a computer.[15] The system is continuously manned at present but is being developed to be capable of detecting kicks while drilling, making connections, reaming, tripping, running liners, wire line logging, etc. with minimum false alarms and lower manning requirements. The system is used in addition to other kick indicators such as the drilling break.

The second challenge is the reduced borehole diameter which limits the stimulation possibilities (fracturing, injection rates), production rates, and the inability for multiple completions.

5.3.6.2 Secondary Challenges

Secondary criticisms of slimhole are the inability to log, test, cement, fish, obtain adequate penetration rates, to handle wellbore stability problems to do directional work and the lack of good commercially available tubular.

5.4 WELL CONTROL RELATED PROBLEMS

Ultradeepwater well control problems are expansion of problems encountered in floating drilling of shallow water, but worsens due to increased water depth.[2] The friction pressure seen circulating through choke and kill lines are increased relative to shallow water due to greater length and higher fluid viscosities caused by colder temperatures. Many new rigs designed to drill in up to 10000ft water depth will utilize 4 1/2 "ID choke and kill lines rather than the 3" lines currently in service. The larger diameter reduces the back pressure applied to the well bore when circulating and allow higher rates of circulation.

Deepwater drilling mud at the seabed belongs to one of group of fluid under the Power law model. Using the Power law model for mud viscosities, the best mathematical description of the viscosity of a mud at constant temperature and pressure can be obtained. A Power-law fluid is a type of generalized fluid for which the shear stress, τ, is given by[19]

$$\tau = K\left(\frac{du}{dy}\right)^n = K(\gamma)^n$$

Where:

- K is the flow consistency index , $Pa.s^n$
- du/dy is the shear rate or the velocity gradient perpendicular to the plane of shear, s^{-1} a
- n is the flow behaviour index (dimensionless).
- τ, is the shear stress, N/m^2.i.e.Pa

The general equation for

Shear stress,

$$\tau = \mu \frac{du}{dy}$$

We can combine the power law equation and the shear stress equations to give effective viscosity which for non-newtonian fluids is a function of shear rate.

$$\mu_{eff} = K\left(\frac{du}{dy}\right)^{n-i}$$

By considering the logarithm of the equation for shear rate, we obtain a linear form of the Power Law model,[20]

$$\tau = K\gamma^{n}$$

$$\ell n\tau = \ell nK + n\ell n\gamma$$

The analysis of the pressure and temperature effects shows that the logarithm of the shear stress is directly proportional to the pressure p, and inversely proportional to temperature, T. These relationships can be expressed by the following equations

$$\ell n\tau \propto p, \ell n\tau = (Ap)_{T=cons\tan t}$$

$$\ell n\tau \propto \frac{1}{T}, \ell n\tau = \left(\frac{B}{T}\right)_{p=cons\tan t}$$

Where A and B are constants

Then,

For a given mud, the linear form of the power-law model can be modified to describe the effect of temperature and pressure on the flow properties by the equation.
$\ell n\tau$ is a linear function of p if T is constant, and 1/T, that is $\ell n\tau$ =constant + Ap + B(1/T).

For p= p_o and T= T_o

$\ell n\tau = \ell nK + n\ell n\gamma$ is linear

$$\ell n\tau = \ell nK + n\ell n\gamma + A(p - p_o) + B\left(\frac{1}{T} - \frac{1}{T_o}\right)$$

$$\ell n\tau = \ell nK - Ap_o - B\left(\frac{1}{T_o}\right) + n\ell n\gamma + Ap + B\left(\frac{1}{T}\right)$$

$$\ell n\tau = \ell nK' + n\ell n\gamma + Ap + B\left(\frac{1}{T}\right)$$

$$\ell nK' = \ell nK - Ap_o - B\left(\frac{1}{T_o}\right)$$

$$K' = e^{\ell nK - Ap_o - B\left(\frac{1}{T_o}\right)}$$

$$K' = \frac{K}{e^{Ap_o + B\left(\frac{1}{T_o}\right)}}$$

In essence, pressure losses in a circulating well can be estimated provided the viscosity of the mud is known or can be determined as in the case of deepwater. If the viscosity of the actual mud is determined under temperature and pressure conditions, it can be reduced to

$$\ell n\tau = \ell nK' + n\ell n\gamma + Ap + B\left(\frac{1}{T}\right)$$

Once the shear stress τ is obtained from the power law model obtained, this can be used to obtained our frictional pressure losses in the annulus by considering the following:

For a pipe of

$$length = l$$

$$diameter = d$$

Frictional pressure loss = ΔP

$$\tau\pi dl = \frac{\Delta P\pi d^2}{4}$$

$$\Delta P = \frac{4\tau l}{d}$$

Chapter 6: ANALYSIS AND DISCUSSION ON RISER LOSS PROBLM

For the purpose of this work, this analysis is based on the riser loss problem among the deepwater drilling problems discussed in the previous chapter. From the previous discussion on the deepwater riser loss problems, two major categories of problems associated with riser loss were identified:

- **Sub-seabed section (below seabed in the well):** Integrity of the formation vs. well control depending on the hydrostatic of the drilling mud after riser loss.
- **Above-seabed section (deepwater interval)**: Integrity of the riser on losing the mud content.

6.1 SUB-SEABED SECTION: Formation Integrity and Well Control

The concept of riser margin can be translated to reasonably accurate calculations which are described in this chapter. In order to clearly illustrate riser margin environment, figure 6.1 below was proposed, and proper analysis presented.

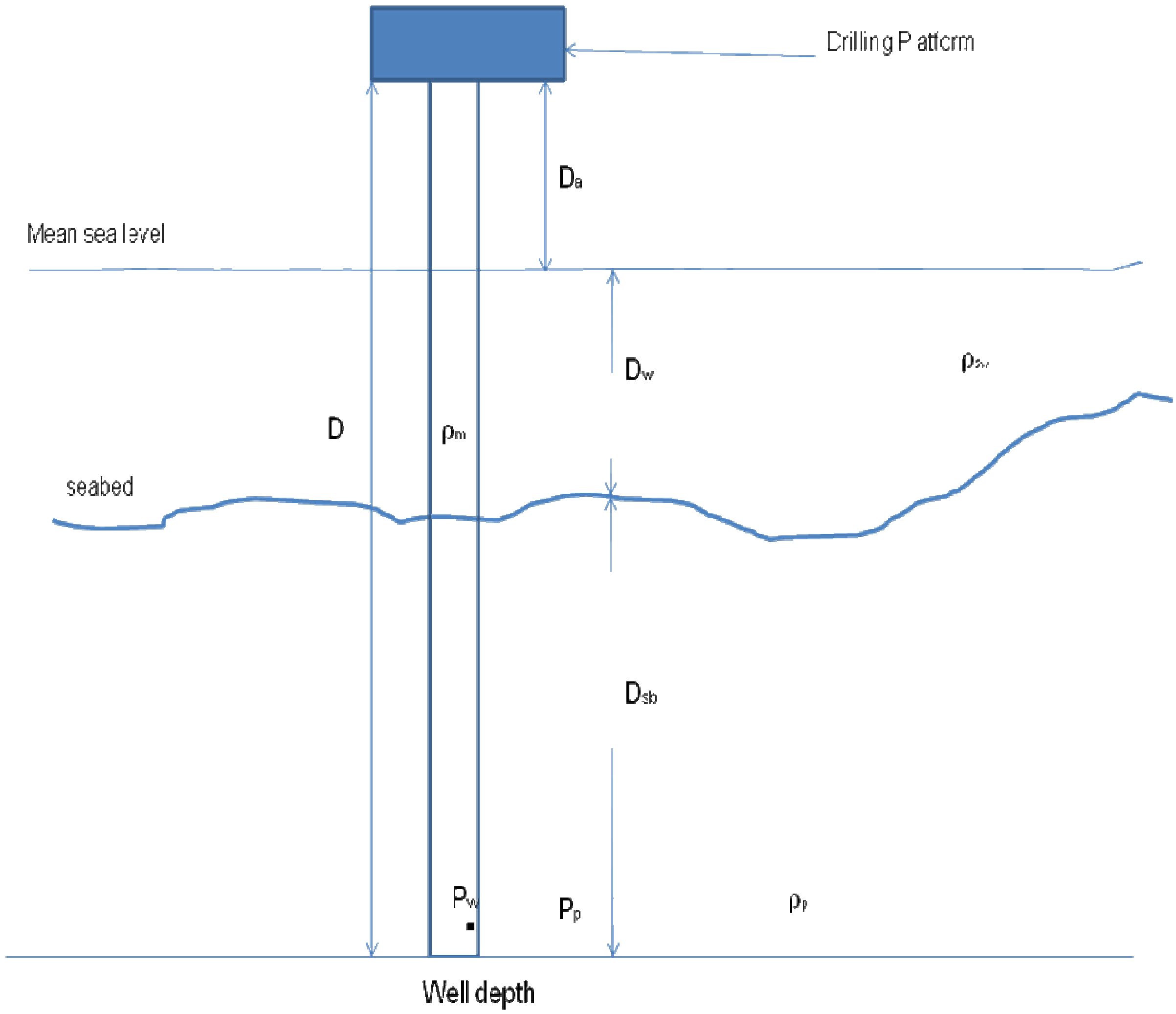


Fig. 6.1 – Diagrammatic Illustration of Deepwater Well Environment

We define the following:

D = total well depth from platform

D_w = water depth from ocean surface

D_{sb} = seabed depth from seabed surface

D_a = depth of air column from platform

$\rho_p g$ = pore pressure gradient

ρ_w = seawater density

ρ_m = drilling mud density

P_p = pore pressure

P_w = well bore pressure

Then, we have

$$P_p = \rho_{sw} g D_w + \rho_p g D_{sb}$$

$$P_w = \rho_m g D = \rho_m g\left(D_a + D_w + D_{sb}\right)$$

Minimum requirement for riser margin is as follows,

$$\rho_{sw} g D_w + \rho_m g D_{sb} > P_p = \rho_{sw} g D_w + \rho_p g D_{sb}$$

$$\rho_{sw} g D_w + \rho_m g D_{sb} = \rho_{sw} g D_w + \rho_p g D_{sb}$$

$$\rho_m > \rho_p$$

Then,

$$P_w = \rho_m g(D_a + D_w + D_{sb}) > \rho_p g\left(D_a + D_w + D_{sb}\right)$$

If we define riser margin as ΔMW, our minimum pressure difference between well and pore pressure must then be

$$\Delta MW = P_w - P_p = \rho_p g\left(D_a + D_w + D_{sb}\right) - \left(\rho_{sw} g D_w + \rho_p g D_{sb}\right)$$

$$= \rho_p g\left(D_a + D_w\right) + \rho_p g D_{sb} - \rho_{sw} g D_w - \rho_p g D_{sb}$$

$$= \rho_p g\left(D_a + D_w\right) - \rho_{sw} g D_w$$

$$= \rho_p g D_a + \left(\rho_p - \rho_{sw}\right) g D_w$$

Note: all generated data and plots were prepared in the excel sheet attached to this report.

In the equation above, if we make a plot of ΔMW against D_w in order to analyze that effect water depth on riser margin when we lose our riser, a straight line as shown in figure 6.2 with intercept of $\rho_p g D_a$ on the x-axis (ΔMW) with a gradient of ($\rho_p - \rho_{sw}$)g, and y-axis would be D_w.

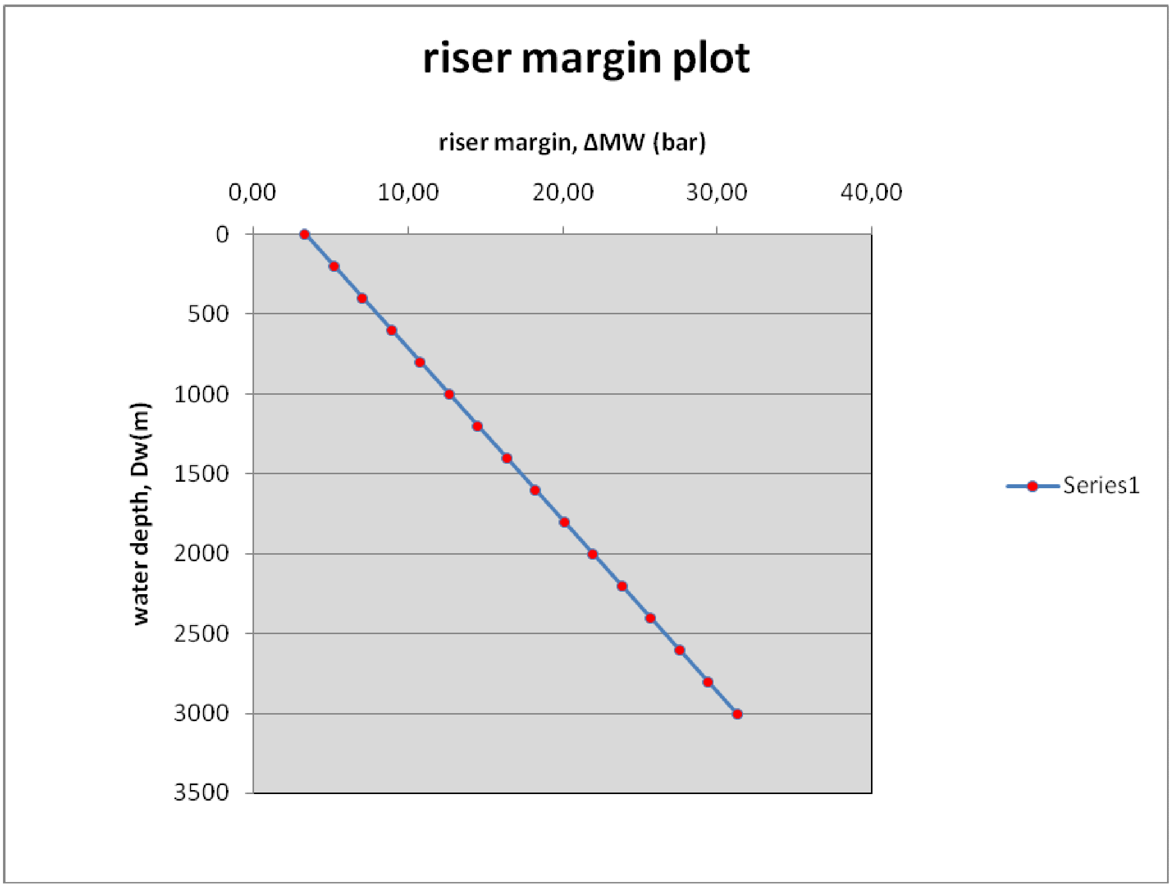


Fig. 6.2- Riser Margin vs. Water Depth

To include safety gradient, we define

$$P_w - P_P \geq SGh$$
$$\rho_m gh - P_p \geq SGh$$
$$SG \leq \rho_m g - \frac{P_p}{h}$$

Hence,

$$\Delta MW = (\rho_p g + SG)(D_a + D_w + D_{sb}) - (\rho_{sw} gD_w + \rho_p gD_{sb})$$

$$= (\rho_p g + SG)(D_a + D_w) + (\rho_p g + SG)D_{sb} - \rho_{sw} gD_w - \rho_p gD_{sb}$$

$$= (\rho_p g + SG)(D_a + D_w) + \rho_p gD_{sb} + SGD_{sb} - \rho_{sw} gD_w - \rho_p gD_{sb}$$

$$= (\rho_p g + SG)(D_a + D_w) + SGD_{sb} - \rho_{sw} gD_w$$

$$= \rho_p g(D_a + D_w) + SG(D_a + D_w) + SGD_{sb} - \rho_{sw} gD_w 2$$

$$= (\rho_p g + SG)D_a + (\rho_p g + SG - \rho_{sw} g)D_w + SGD_{sb}$$

Safety gradient, SG gives that at a depth 'h', the pressure P_w is larger than the pore pressure, P_p by SGh.

In figure 6.3, the intercept on x-axis would now be (ρ_p g+SG) D_a + SGD_{sb} , which is higher and the new gradient would be (ρ_p g+SG $-\rho_{sw}$g).

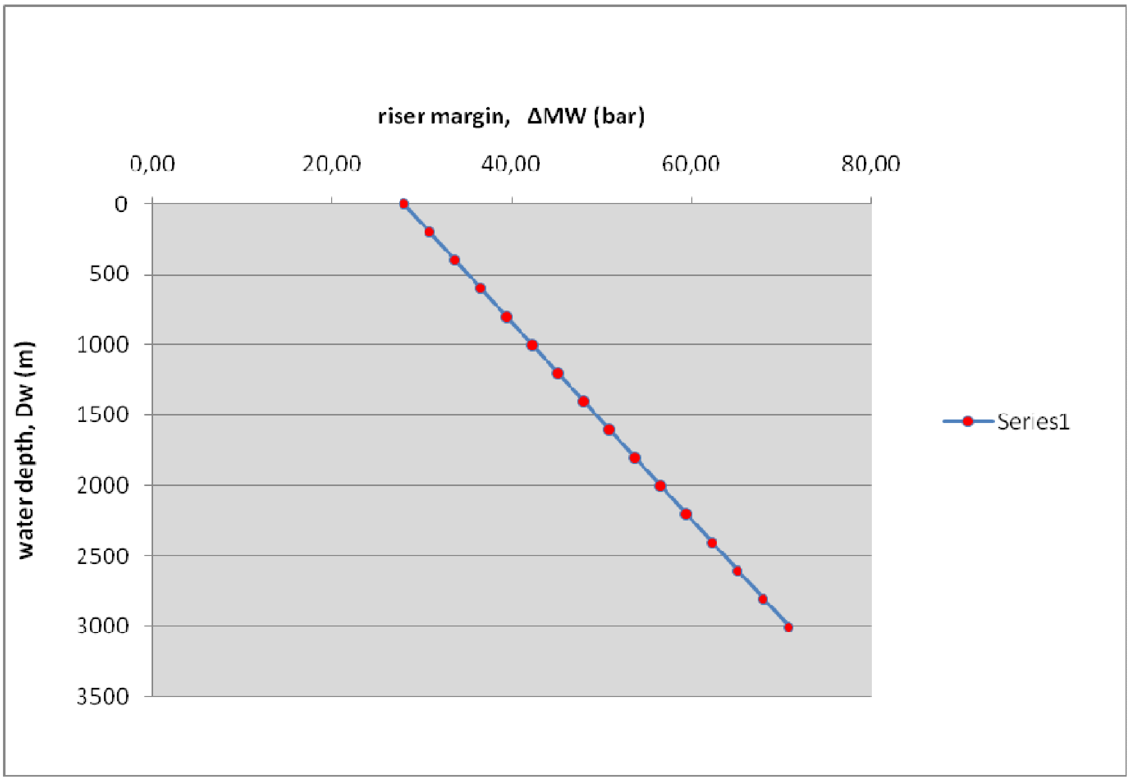


Fig. 6.3- Riser Margin vs. Water Depth with Safety Gradient

The calculation done so far assumes a constant pore gradient for the formation. However, it is possible to have a formation having depth dependent pore gradient .i.e. pore gradient changing with depth. In this case, we have an increasing pore gradient with increasing depth of seabed.

If we define the following:

$\Delta\rho g$ = increase in pore pressure gradient per specific depth, D_o

D_o = depth increase for which we experience pore pressure increase, $\Delta\rho g$

$\rho_d g$ = pore pressure gradient at a particular depth

$$\rho_d g = \left(\rho_{sw} + \frac{\Delta\rho}{D_o} D_{sb} \right) g$$

If we insert this into original equation for riser margin,

$$\Delta MW = \rho_p g D_a + (\rho_p - \rho_{sw}) g D_w$$

$$= \left(\rho_{sw} + \frac{\Delta\rho}{D_o} D_{sb} \right) g D_a + \left\{ \left(\rho_{sw} + \frac{\Delta\rho}{D_o} D_{sb} \right) - \rho_{sw} \right\} g D_w$$

By expanding this, we have

$$= \rho_{sw} g D_a + \frac{\Delta\rho}{D_o} D_{sb} g D_a + \rho_{sw} g D_w + \frac{\Delta\rho}{D_o} D_{sb} g D_w - \rho_{sw} g D_w$$

$$= \rho_{sw} g D_a + \frac{\Delta\rho}{D_o} D_{sb} g D_a + \frac{\Delta\rho}{D_o} D_{sb} g D_w$$

Figure 6.4 shows the result of the calculations done at each seabed depth, D_{sb} f or increasing water depth and a changing pore pressure gradient due to increasing seabed depth. Each straight line using this equation would have an intercept $\left(\rho_{sw} g D_a + \frac{\Delta\rho}{D_o} D_{sb} g D_a \right)$ on the y-axis and gradient $\frac{\Delta\rho}{D_o} D_{sb} g$.

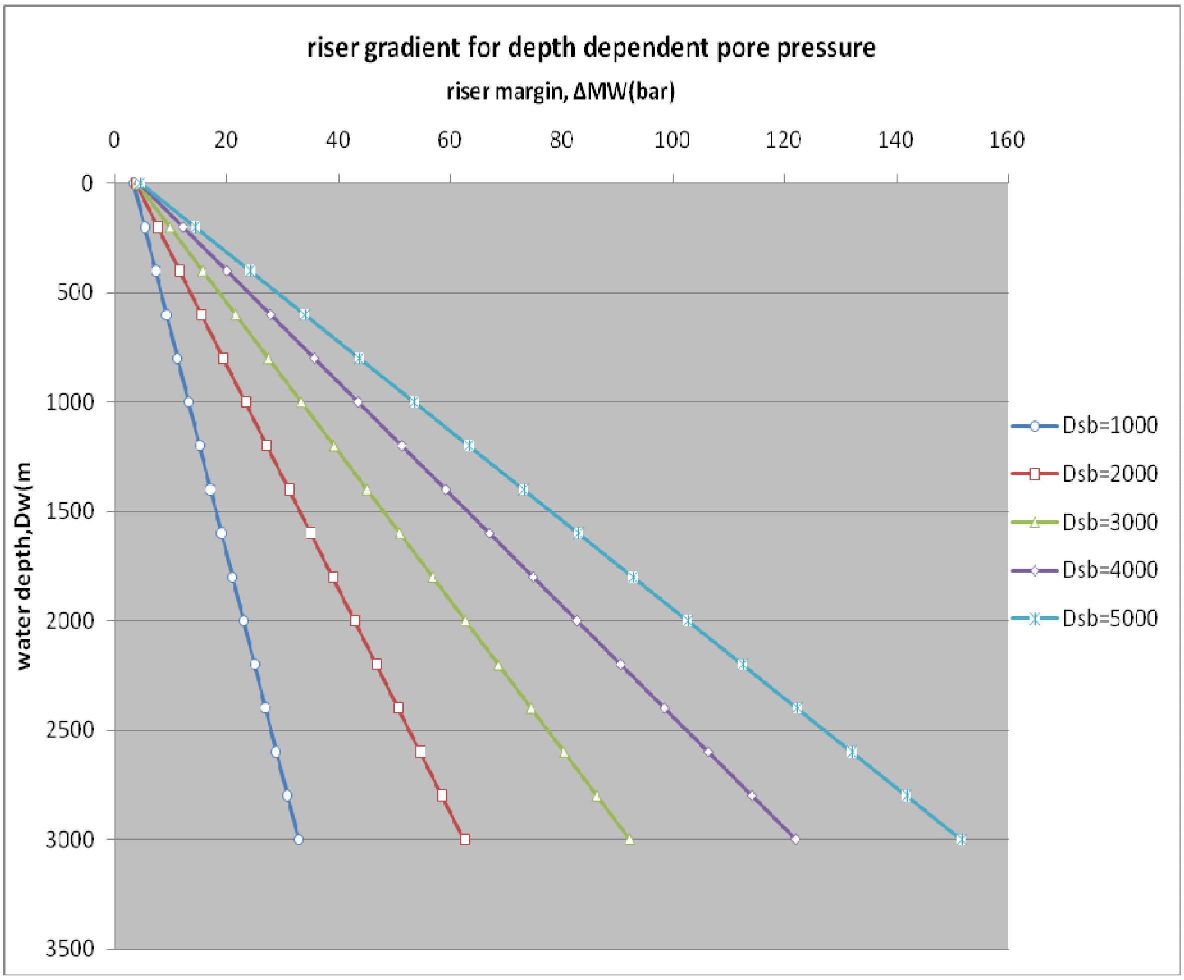


Fig. 6.4- Riser Margin vs. Water Depth for Depth Dependent Pore Pressure

Note:

For well of constant total depth from the drill floor i.e. $D = D_a + D_w + D_{sb}$,

If D_a is constant, then, $(D_w + D_{sb})$ is also constant, K

$D_w = K - D_{sb}$ (decrease in water depth means equivalent increase in depth of seabed).

We can also do the analysis for the pore pressure.

For a particular water depth, D_w and varying depth of seabed, D_{sb}:

$$P_p = \rho_{sw} g D_w + \rho_d g D_{sb}$$

$$= \rho_{sw} g D_w + \left(\rho_{sw} + \frac{\Delta\rho}{D_o} D_{sb} \right) g D_{sb}$$

$$= \rho_{sw} g D_w + \rho_{sw} g D_{sb} + \frac{\Delta\rho}{D_o} g D_{sb}^2$$

This results in a quadratic equation. A plot of P_p against D_{sb} would give a curve as shown in figure 6.5.

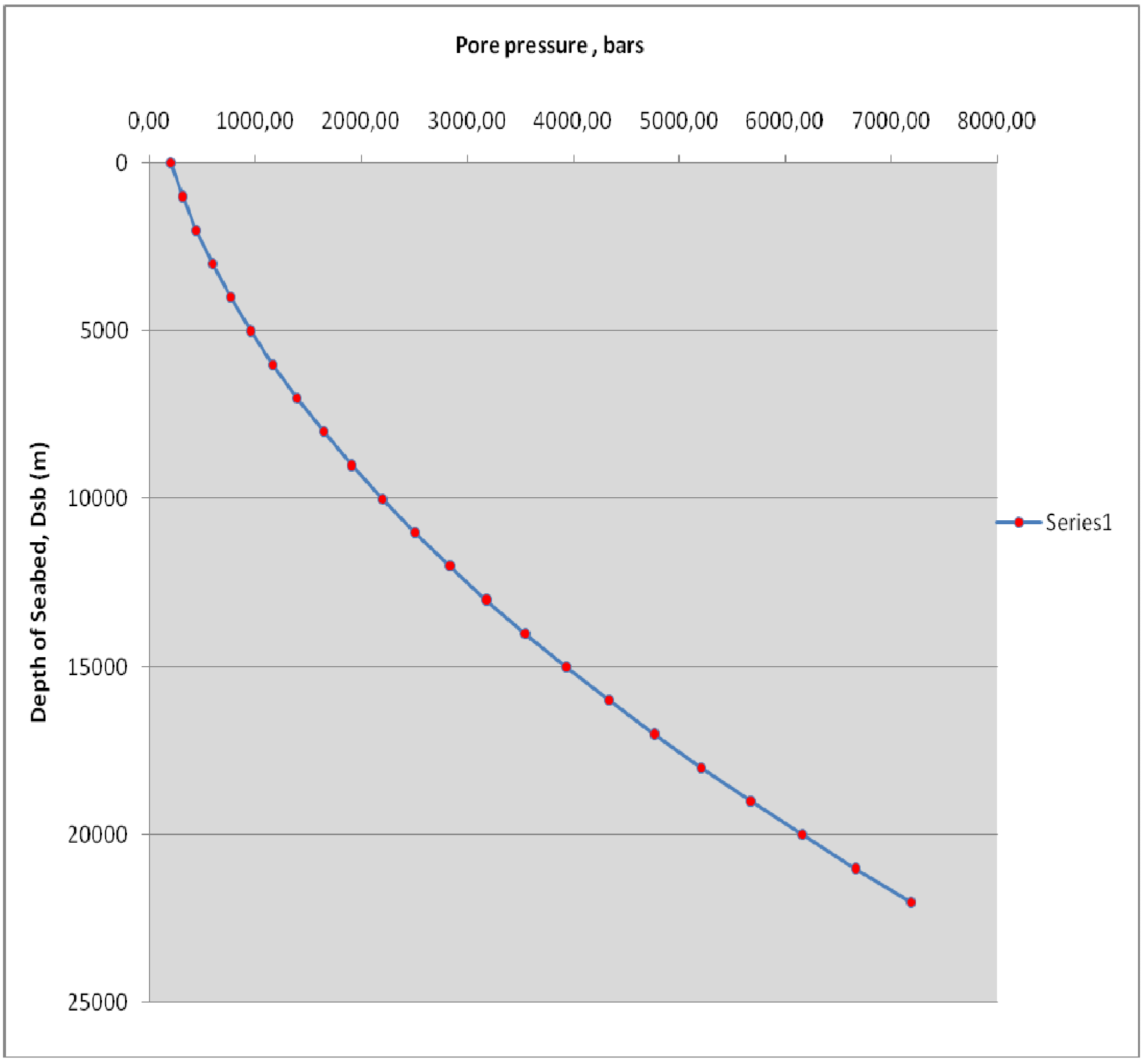


Fig. 6.5- Seabed Depth vs. Pore Pressure

From the graph above, at shallow seabed depths, an increase in pore pressure in response to increasing depth is not as much as the increase in pore pressure due to increasing depth at greater depths further down in the formation. This is an indication that the pore pressure needs to be more closely monitored at this great depth.

6.2 ABOVE SEABED SECTION (Deepwater Interval): Riser Integrity

Figure 5.6 can be re-presented as given below (figure 6.6) for the analysis in this section.

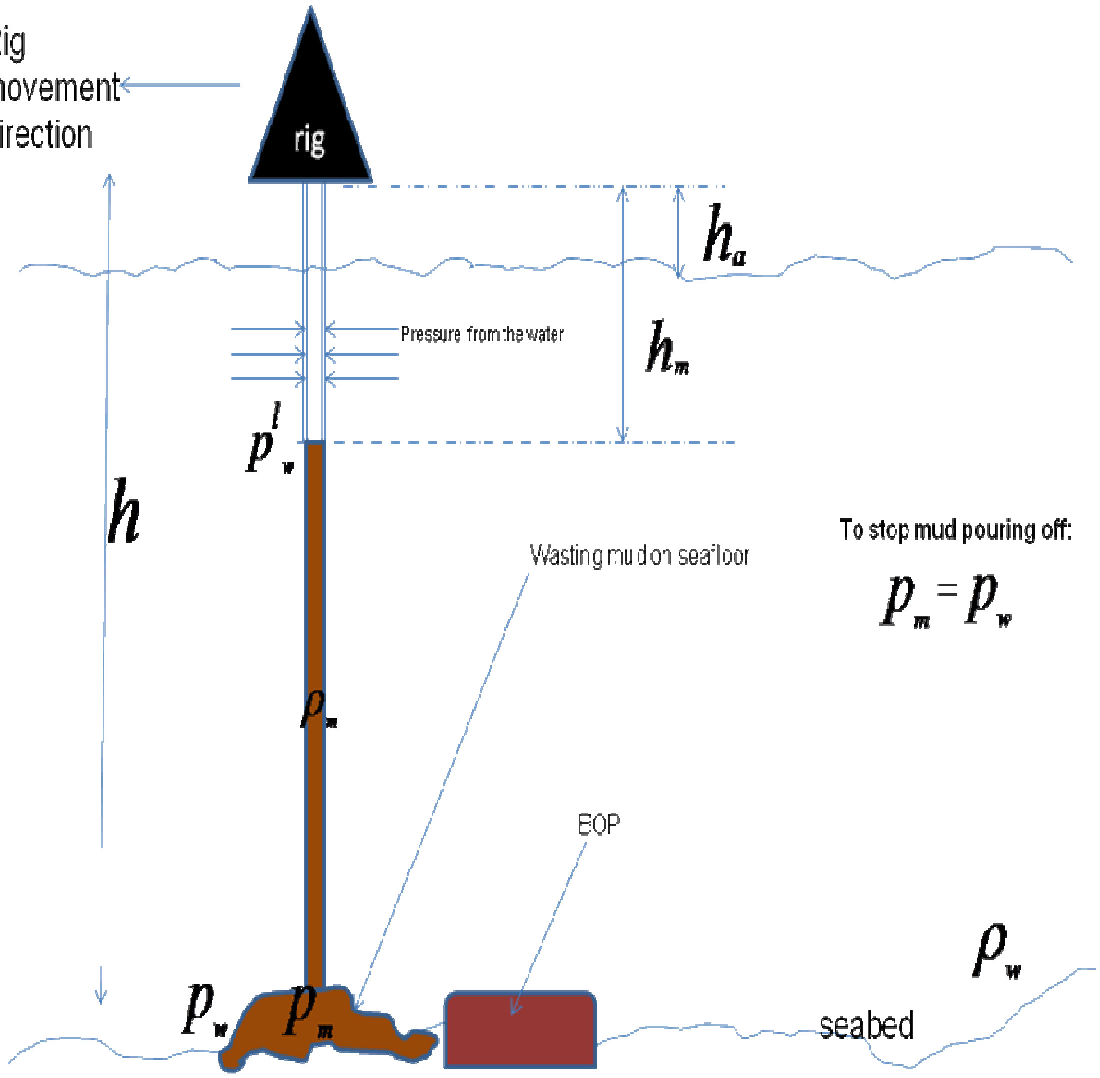


Fig. 6.6 - Deepwater Pressure Consideration for Disconnected Riser

Figure 6.6 shows the pressures acting on the riser in the deepwater.

We consider a riser with an inside drilling mud of density, ρ_m and the outside or surrounding seawater of density, ρ_w.

If the height of the riser mud column lost is, h_m and the total vertical height of the riser column is h , then length of column still filled with mud in the riser becomes , $h - h_m$. The mud level in the riser falls to a level referred to as critical level with a critical seawater hydrostatic pressure, ρ_w^l outside the riser at this point. This pressure is most critical in the investigation of the riser integrity when the inside mud is lost.

The mud column in the riser continues to fall as mud pours off on the ocean floor until a point is reached where the hydrostatic pressure of the mud column in the riser equals the hydrostatic pressure of seawater at the bottom of the riser where mud is released to the ocean floor.

At this point, the mud is expected to have enough resisting pressure from the water column to stop it from pouring off from the bottom of riser, thus we have:

$$P_m = P_w$$

Hence, we have the following in our calculation:

ρ_m = density of the mud in the riser

ρ_w = density of the seawater

ρ_m = density of the mud in the riser

h_m = height of lost column of mud

ρ_m = hydrostatic pressure due to remaining mud column in the riser

P_w = critical seawater hydrostatic pressure due to seawater column at the bottom

P_w^l = critical seawater hydrostatic pressure

$$P_m = \rho_m g(h - h_m)$$

$$P_w = \rho_w g(h - h_a)$$

Then, to have a stabilized condition where the mud stops pouring off,

$$P_m = P_w \Leftrightarrow \rho_m g(h - h_m) = \rho_w g(h - h_a)$$

Which gives

$$h_m = \frac{(\rho_m - \rho_w)h + \rho_w h_a}{\rho_m}$$

$$P_w^l = \rho_w g(h_m - h_a) = \rho_w g\left\{\frac{(\rho_m - \rho_w)h + \rho_w h_a}{\rho_m} - h_a\right\}$$

$$= \frac{\rho_w}{\rho_m} g[(\rho_m - \rho_w)(h - h_a)]$$

This pressure plays an important role in determining the state of our riser.

If this pressure is greater than the riser collapse pressure rating, then we might have a failure or a problem. Equation above assumes that space above the mud in the riser i.e. h_m is an empty space. Figure 6.7 below shows how changing hydrostatic seawater pressure varies drilling mud weight.

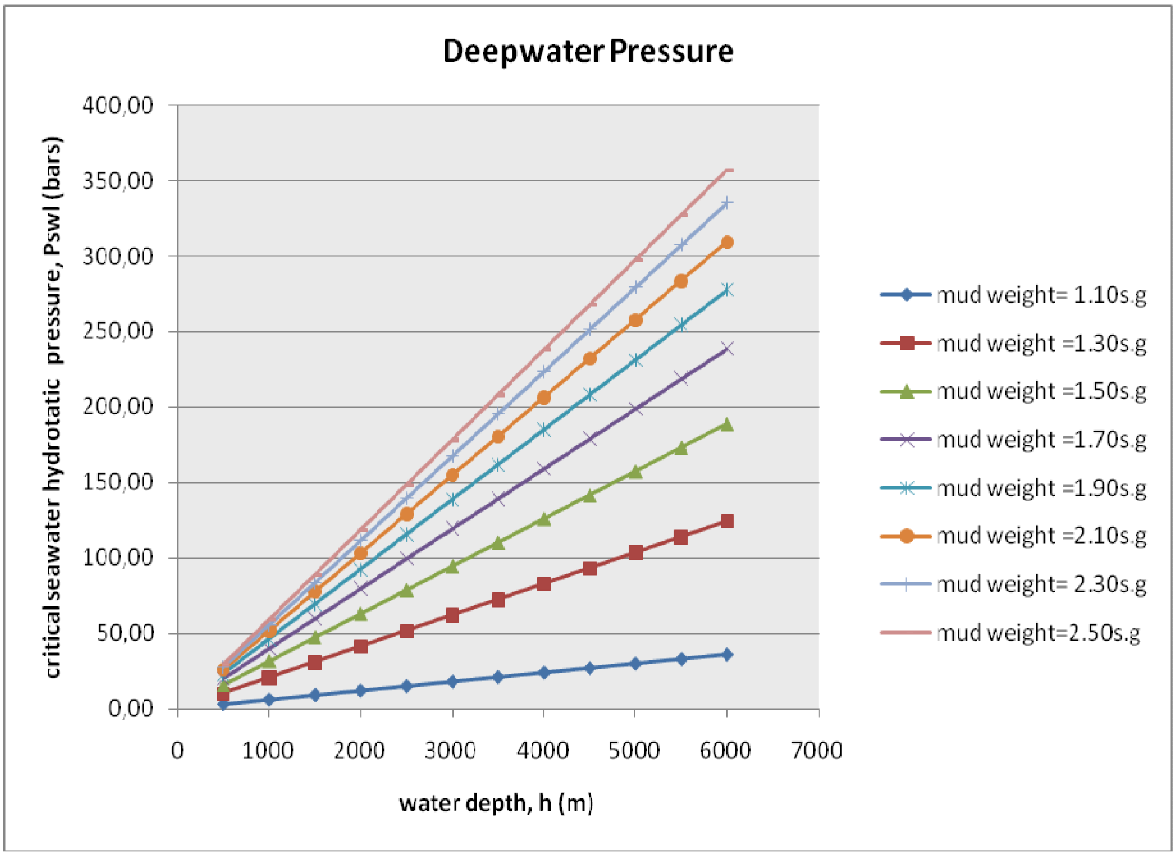


Fig.6.7- Critical Seawater Pressure vs. Water Depth

From the graph, increasing mud weight leads to increased fallen height of the mud in the riser .i.e. length of empty space in the riser, hence, increased risk of riser collapse.

A critical seawater pressure of about 180 bars in a 3000m deepwater when we use a mud of 2.5s.g is too close to collapse limit. We seem to face risk of failure due to riser disconnect by using a too heavy mud as some big casing sizes(not risers) from the drilling data handbook have collapse resistance value of far less than 100bars depending on the steel material.

In reality, if this problem occurs, seawater at the bottom mouth of the riser forces its way up the riser through the heavier mud in the riser since seawater is lighter than mud after pressure balancing.

This should not be a problem as it does not happen so quickly. One can envision this to be actually good as water in the riser annulus provides more support from the inside against the high hydrostatic pressure of seawater column outside the pipe in this column as this leads to increased level of mud when the mud mixes with seawater.

6.2.1 Pipe Friction Consideration on Critical Seawater Hydrostatic Pressure

Pipe friction present in the riser annulus seems to reduce the height of the hydrostatic mud column for the lost mud, h_m. This can be thought of as a situation where the mud level must have initially fallen to a lower level in the riser, where a higher value of critical pressure, P_w^l is present.

The actual height h_m must be somewhat more than the observed value for the initial fall of mud level due to riser disconnect before it comes up a little bit due to friction present inside the riser. Hence, the critical pressure, P_w^l which could actually lead to collapse of the riser, is higher than the calculated value when friction is not included.

When riser disconnects occurs, mud level falls due to mud being lost through the bottom at slow rate. Also, at a point in time, seawater starts entering from the bottom at slow rate because it is difficult for the system to keep the pressure balance at the bottom for a long time without seawater breaking through.

There has to be a balance among the falling riser mud due to its hydrostatic weight, friction in the riser trying to reduce the falling height, and seawater from the bottom which mixes with the mud which can cause relative increase in mud height. At this point, it would be difficult to define the state of pressure balance or categorically say what happens in the mud inside the riser.

6.2.2 API Collapse Pressure Consideration

To ascertain the condition of the riser after mud loss and for the purpose of the riser integrity, the seawater hydrostatic pressure values should be compared to the collapse pressure of the riser. The Drilling data handbook provides collapse pressure for various sizes of casing.[21]

API method of collapse pressure calculations serves as the foundation for most other methods of calculating the collapse pressure of the pipe. The API 5C3 bulletin is based on empirical collapse data and offers four recognized collapse failure modes and a set of formulas which are able to predict the minimum collapse resistance value for each mode: elastic, transition, plastic and yield. The factor that decides which collapse mode formula to use, is the ratio of outside diameter 'D', to wall thickness; this is D/t ratio. The different collapse modes include as illustrated graphically in figure 6.8 (on the next page), for N-80 pipe: [22]

- Yield collapse
- Plastic collapse
- Transition collapse
- Elastic collapse

According to API, plastic collapse formula for thick wall pipe (low D/t) was too liberal[22] therefore, a "yield collapse" formula was derived for thick-walled pipes. For large D/t, "Elastic Collapse" (buckling) equation was derived. Most risers, because of the dimensions i.e. large diameter would be thought of being associated with Elastic Collapse because of high D/t.

Plastic and elastic collapse curves do not intersect. Therefore, a transition region was defined to connect these two curves. For example, for an N-80 pipe, figure 6.8 below illustrates the different collapse mode as dictated by the pipe dimension factor, D/t.[23]

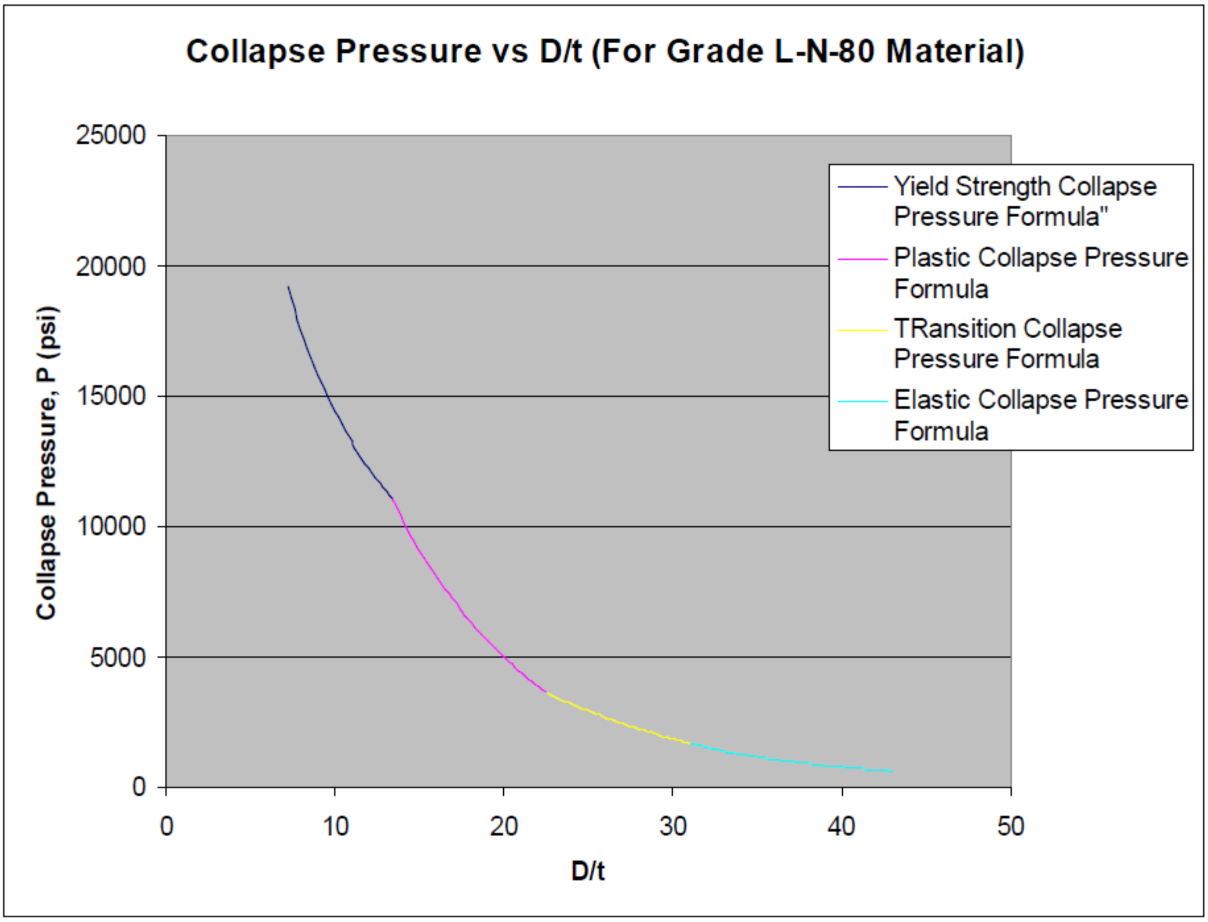


Fig. 6.8 – Collapse Modes Based on API Calculation

6.3 RISER COLLAPSE AND BURST PRESSURE

Having obtained an equation for determining collapse pressure in the riser due to disconnect, an equation can be obtained for riser burst pressure in like manner. From figure 6.6, burst pressure can be expressed as follows:

P_B = burst pressure

Pressure inside the riser $= \rho_m g h$

Pressure outside the riser $= \rho_w g(h - h_a)$

$$P_B = \rho_m g h - [\rho_w g(h - h_a)]$$

$$P_B = [(\rho_m - \rho_w)h + \rho_w h_a]g$$

From section 6.2, collapse pressure was already defined by the critical seawater hydrostatic pressure, P_w^l. However in this section, collapse pressure of the riser is redefined as P_c.

Hence,

$$P_C = P_w^l = \frac{\rho_w}{\rho_m} g\left[(\rho_m - \rho_w)(h - h_a)\right]$$

The values for the collapse and burst pressure for a riser at any particular deepwater depth can then be obtained. It is important to determine if the burst pressure requirement makes the riser safe against mud loss even when the collapse pressure is already calculated.

If no air column scenario is assumed, then $h_a = 0$.

$$P_C = \frac{\rho_w}{\rho_m}(\rho_m - \rho_w)hg$$

$$P_B = (\rho_m - \rho_w)hg$$

Then,

$$\frac{P_C}{P_B} = \frac{\rho_w}{\rho_m}$$

Since the mud is heavier than seawater, it can be inferred from the equation above that for a deepwater riser experiencing mud loss, the collapse pressure is less than burst pressure.

Chapter 7: CONCLUSION

Deepwater environmental conditions pose a lot of problems in deep offshore drilling. Interactions of these conditions make it difficult to analyze problems associated with each of these conditions in isolation.

Some of the proposed solutions to the deepwater problems require critical evaluation. In the case of the artificial seabed being a proposed solution to formation integrity problem when we have riser loss, the associated risks and costs of such a solution should be compared with the gain in overall performance. Slimhole drilling was proposed as a possible solution to cutting transport problems in deepwater risers. However, there are limitations such as low weight-on-bit, risk of a kick, etc. Slimhole drilling therefore requires critical considerations to ensure if it is a worthwhile application for the particular well.

The two aspects of riser loss highlighted in this work require close monitoring, that is, formation integrity and riser integrity. In ensuring formation integrity, application of riser margin to our drilling mud in deepwater drilling should be done with great care. This is because at shallow sea depths, increases in pore pressure with depth are lower than that occurring at greater depths. Hence, close monitoring of pore pressure at such great depths in deepwater is required. Indeed, a constant riser margin should not be assumed when drilling such sections. In the case of riser integrity, as the analysis in chapter 6 shows high mud weight used in deepwater riser poses a higher risk of riser collapse due to the effect of critical seawater hydrostatic pressure on the outside of the riser. Hence, minimum mud weight should be considered due to the possibility of riser collapse in case mud loss is experienced.

If the air gap is assumed to be negligible compared to water depth, riser collapse pressure would always be less than the burst pressure as mentioned in chapter 6. And as highlighted, for deepwater drilling, the ratio of the collapse pressure to the burst pressure is always equal to the ratio of seawater density to mud density under the same conditions. Thus, collapse pressure due to riser mud loss would be less than the operating burst pressure during drilling. However for risers, collapse resistance is usually less than internal yield pressure, making collapse pressure rating for these risers critical.

Nomenclature

BOP- Blow Out Preventer

RBOP- Rotating BOP

CRD- Conventional Riser Drilling

DP- Dynamic Positioning

ECD- Equivalent Circulation Density

GOM- Gulf of Mexico

ID- Internal Diameter

KDS- Kick Detection System

LMRP- Lower Riser Package

MW- Mud Weight

MODU-Modular Offshore Drilling Unit

OD- Outside Diameter

TD- Target Depth

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Appendix A

DEEPWATER RISER MARGIN WITHOUT SAFETY GRADIENT

air depth	Da	30,00	$\Delta MW = \rho_p g D_a + (\rho_p - \rho_{sw}) g D_w$
air gradient	pa	0,010	
seawater gradient	psw	1,035	pressure= hx0.0981xs.g
pore gradient	pp	1,130	
Gravity	g	9,810	

#	Dw (m)	riser margin, ΔMW (bar)
1	0	3,33
2	200	5,19
3	400	7,05
4	600	8,92
5	800	10,78
6	1000	12,65
7	1200	14,51
8	1400	16,37
9	1600	18,24
10	1800	20,10
11	2000	21,96
12	2200	23,83
13	2400	25,69
14	2600	27,56
15	2800	29,42
16	3000	31,28

Appendix B

DEEPWATER RISER MARGIN WITH SAFETY GRADIENT

$\Delta MW = (\rho_p\, g + SG) D_a + (\rho_p\, g + SG - \rho_{sw} g) D_w + SGD_{sb}$

	Assume	
safety gradient	SG	0,05
seabed depth	Dsb	5000

#	Dw (m)	riser margin, ΔMW (bar)
1	0	28,00
2	200	30,84
3	400	33,69
4	600	36,53
5	800	39,38
6	1000	42,22
7	1200	45,07
8	1400	47,91
9	1600	50,76
10	1800	53,60
11	2000	56,45
12	2200	59,29
13	2400	62,14
14	2600	64,98
15	2800	67,83
16	3000	70,67

Appendix C

DEEPWATER RISER MARGIN FOR DEPTH DEPENDENT PORE PRESSURE

$\Delta MW = \rho_{sw}\, g\, D_a + (\rho_{\Delta p} / D_o) D_{sb} g\, D_a + (\rho_{\Delta p} / D_o) D_{sb}\, g D_w$

air depth	Da	30,00
air gradient	pa	0,010
seawater gradient	psw	1,035
pore gradient	pp	1,130

let maximum seabed depth be 5000m

Seabed depth for 0.1sg porepressure increase=	Do	1000m
pore pressure increase for every 1000m=	ρΔpg	0.1sg

		riser margin, ΔMW (bar)				
#	Dw (m)	Dsb= 1000	Dsb= 2000	Dsb= 3000	Dsb= 4000	Dsb= 5000
1	0	3,340305	3,634605	3,928905	4,223205	4,517505
2	200	5,302305	7,558605	9,814905	12,07121	14,32751
3	400	7,264305	11,482605	15,70091	19,91921	24,13751
4	600	9,226305	15,406605	21,58691	27,76721	33,94751
5	800	11,188305	19,330605	27,47291	35,61521	43,75751
6	1000	13,150305	23,254605	33,35891	43,46321	53,56751
7	1200	15,112305	27,178605	39,24491	51,31121	63,37751
8	1400	17,074305	31,102605	45,13091	59,15921	73,18751
9	1600	19,036305	35,026605	51,01691	67,00721	82,99751
10	1800	20,998305	38,950605	56,90291	74,85521	92,80751
11	2000	22,960305	42,874605	62,78891	82,70321	102,6175
12	2200	24,922305	46,798605	68,67491	90,55121	112,4275
13	2400	26,884305	50,722605	74,56091	98,39921	122,2375
14	2600	28,846305	54,646605	80,44691	106,2472	132,0475
15	2800	30,808305	58,570605	86,33291	114,0952	141,8575
16	3000	32,770305	62,494605	92,21891	121,9432	151,6675

Appendix D

PORE PRESSURE VARIANCE PLOT AGAINST DEPTH OF SEABED

For a chosen water depth, 2000m, we have

$Pp = \rho_{sw} g\, D_w + \rho_{sw}\, gD_{sb} + (\rho_{\Delta p} / D_o) gD^2_{sb}$

#	Dsb (m)	Pp
1	0	203,07
2	1000	314,41
3	2000	445,37
4	3000	595,96
5	4000	766,16
6	5000	955,98
7	6000	1165,43
8	7000	1394,49
9	8000	1643,18
10	9000	1911,48
11	10000	2199,40
12	11000	2506,95
13	12000	2834,11
14	13000	3180,89
15	14000	3547,30
16	15000	3933,32
17	16000	4338,96
18	17000	4764,23
19	18000	5209,11
20	19000	5673,61
21	20000	6157,74
22	21000	6661,48
23	22000	7184,84

Appendix E

$$\boxed{p_w^l = \rho_w gh \frac{(\rho_m - \rho_w)}{\rho_m}}$$

=Pwl

$$\boxed{\rho_w = 1035\ kg / m^3}$$

water gradient = 1.035s.g

$$\boxed{\rho_m = 1300 kg/m^3}$$

water gradient =1.035s.g

h= Dw water depth

Hydrostatic pressure due to water column for empty riser column, Pwl(bar) @

#	h (m)	ρm=1.10s.g	ρm=1.30s.g	ρw=1.50s.g	ρm=1.70s.g	ρm=1.90s.g	ρm=2.10s.g	ρm=2.30s.g	ρm=2.50s.g
1	500	3,00	10,35	15,74	19,86	23,11	25,75	27,92	29,75
2	1000	6,00	20,70	31,48	39,72	46,22	51,49	55,84	59,50
3	1500	9,00	31,05	47,21	59,58	69,34	77,24	83,77	89,25
4	2000	12,00	41,39	62,95	79,44	92,45	102,98	111,69	119,00
5	2500	15,00	51,74	78,69	99,29	115,56	128,73	139,61	148,75
6	3000	18,00	62,09	94,43	119,15	138,67	154,48	167,53	178,50
7	3500	21,00	72,44	110,16	139,01	161,79	180,22	195,45	208,25
8	4000	24,00	82,79	125,90	158,87	184,90	205,97	223,37	237,99
9	4500	27,00	93,14	141,64	178,73	208,01	231,71	251,30	267,74
10	5000	30,00	103,49	157,38	198,59	231,12	257,46	279,22	297,49
11	5500	33,00	113,83	173,11	218,45	254,23	283,21	307,14	327,24
12	6000	36,00	124,18	188,85	238,31	277,35	308,95	335,06	356,99