THE INSTITUTE OF MARINE ENGINEERS

76 Mark Lane, London EC3R 7JN   Telephone: 01-481 8493 Telex: 886841

TRANSACTIONS (TM)

Paper No. 26

OFFSHORE DRILLING OPERATIONS

J. M. Denholm

Read at 1730 on Monday 15 February 1982

ISSN 0309-3948
Trans I Mar E (TM)
Vol. 94 1982 Paper 26

Offshore Drilling Operations

J. M. Denholm

BP Petroleum Development Limited

SYNOPSIS

Offshore drilling evolved in the swamps of Louisiana, USA, and in Lake Maracaibo, Venezuela, during the 1920s. Limited exploration on the UK Continental Shelf began in the southern North Sea in the mid-1960s and it was not until the early 1970s that large-scale exploratory drilling began in the central and northern North Sea. Present drilling activity in the UK sector of the North Sea is at its highest level for many years and does not show any sign of easing off in the short term. This paper gives a basic insight into offshore drilling operations and some of the associated problems.

INTRODUCTION

During the last 100 years the world's industrial growth has demanded the need for increasing energy. This thirst for energy has to a great extent been satisfied by the discovery and development of oil and gas resources. The occurrence of these resources beneath the surface of the earth has resulted in the birth and development of the 'drilling industry'. Initially the industry concentrated on the exploitation of onshore resources but, as the demand for oil grew, the oil companies were forced to look offshore for an alternative source of supply.

For the drilling of the first offshore wells, a small structure was piled into the bottom of the lake or swamp. During the drilling of these wells, this small platform supported the hoisting equipment, derrick, drawworks, rotary tackle and power units. All the ancillary equipment was housed on a drilling tender moored alongside the platform. When the well had been drilled and completed the hoisting equipment was removed, leaving only the production wellhead on the platform. Although this type of operation can be classified as 'offshore drilling' the work was not performed by a totally self-contained unit.

It was not until the late 1940s that the first self-contained units were developed. These were flat-bottomed barges which were towed out to location and then ballasted down to the sea-bed. Such units could operate in water depths of up to 10 m but were limited in application because of stability problems during ballasting operations. Figure 1 shows rig developments with respect to increasing water depth.

To overcome this stability problem and therefore increase the water depth capability, a new and more familiar design of drilling unit was introduced in the mid-1950s. This was the 'submersible column stabilized' drilling barge, the forerunner of the modern semi-submersible (SSM).

It was also in this era that the first jack-up drilling rigs were developed. Early jack-up rigs had as many as 12 legs and could work in water depths of up to 120 m, given calm weather conditions.

Oil companies were still striving to move into deeper waters as the geology of the world's continental shelves indicated potential hydrocarbon sources. Rig designers thus directed their effort towards building a 'floating drilling rig'. The first anchored floating rigs in the late 1950s were conversions of the earlier bottom-supported barges. This design is still with us today, with much improved stability, mobility and deck loading characteristics. Alongside the development of the anchored semi-submersible was the development of the anchored drillship. These drillships were very widely used for two main reasons: ships were readily available for conversion at low cost; and the characteristics of deck loading and mobility were much better than those of semi-submersibles.

In the 1960s the first dynamic positioning (DP) equipment was installed on a drillship. Around the same period the first purpose-built drillships were constructed. Since then DP techniques have been utilized on drillships and, in one case, on a semi-submersible, when deep-water drilling was required. Modern DP drillships can drill in water depths of up to 1800 m.

Although there have been many major changes in offshore drilling units during their development over the past three decades, the basic principles for the wellbore have remained relatively unchanged. The following section outlines the types of well and a number of these basic drilling principles.

TYPES OF WELL

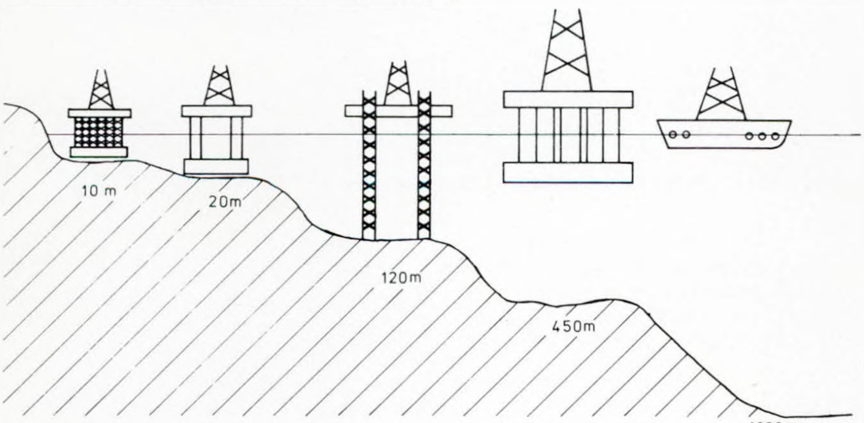
All onshore and offshore wells may be classified under one of three basic definitions:

(a) Exploration wells
(b) Appraisal wells
(c) Development wells

The exploration or 'wildcat' well is, as its name implies, the first well drilled on a given structure. Before such a well is proposed, seismic survey data are obtained. The interpretation of these data indicates the size, shape and depth of any geological structures in the area that may be potential hydrocarbon traps. It must be emphasized that seismic data can only indicate the presence of potential reservoir rocks that might contain hydrocarbons; they cannot detect the actual presence of hydrocarbons. In addition to a suitable structure, two further criteria must co-exist for the creation of a hydrocarbon reservoir; namely a source rock and a cap rock.

A typical but simplified illustration is given in Fig. 2, from which it is evident that the exploration drilling location will be selected towards the centre of the structure. The main objective of the exploration well is to confirm the presence of the 'hydrocarbon reservoir' and to obtain petrophysical data concerning the formation immediately surrounding the wellbore. These data are obtained from rock samples collected during the drilling of the well; electric wireline logs; and, ultimately, flowing the well under controlled conditions to surface.

FIG 1 Development of offshore drilling rigs



Assuming that the exploration well has given encouraging results, appraisal wells are the next step in assessing the viability of the hydrocarbon reservoir. Such wells are drilled to delineate the boundaries of the structure; the thickness of the reservoir (in terms of the gas/oil contact and oil/water contact); and to further add to the petrophysical data obtained from the exploration well. Figure 2 shows four such appraisal wells. For more complex structures as many as ten appraisal wells may be drilled before a decision on developing the field can be made.

Development wells are drilled to drain the reservoir as efficiently as possible. These wells are normally directionally drilled from a fixed platform (see Figs 3 and 4).

To illustrate the basic principles involved in drilling these types of wells, the case of drilling an exploration well from a semi-submersible will be considered.

THE EXPLORATION WELL

Given the current economic climate and well costs up to and above £10 000 000 per well, it is evident that much preplanning is required before any drilling operation can commence. Such preplanning will include investigation into the formations to be drilled; the pressures likely to be encountered; final drilling depth; water depth; weather conditions, and other factors likely to affect the choice of rig and the finalized well programme. For the majority of offshore exploration wells in the North Sea today, the semi-submersible is the most suitable rig to satisfy the above conditions.

Before drilling commences, the rig is towed to location and the anchors are set and pretensioned. To establish a 'link' between the rig and the sea-bed, a guide base with four guide wires attached is lowered and placed on the sea-bed. The 'link' will serve as the guidance mechanism for the duration of the well. The first drilling assembly is guided by these guide wires and spudded through the guide base into the sea-bed.

This section of hole, 36 inches in diameter, is drilled to some 80 m below the sea-bed. It is then lined with 30-in diameter steel conductor

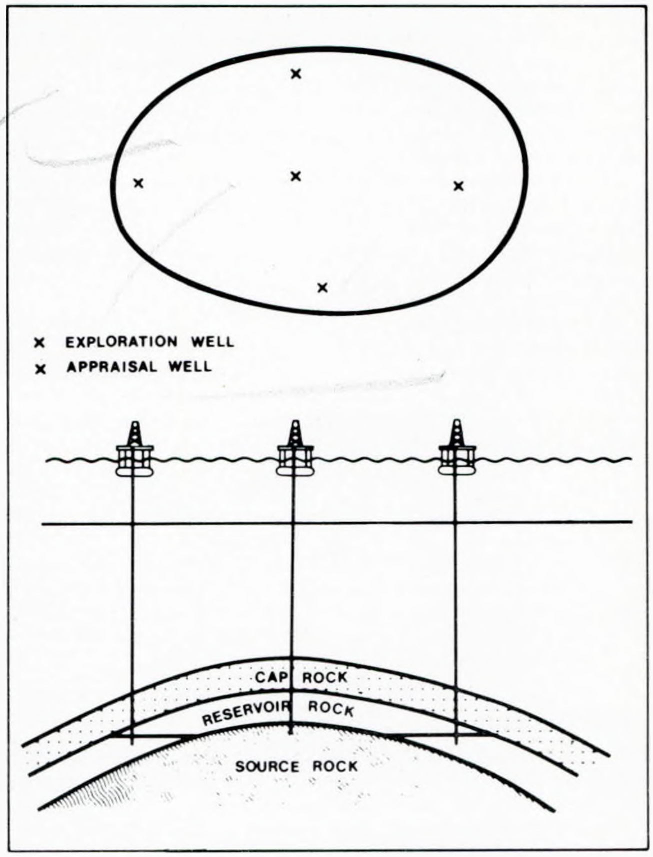
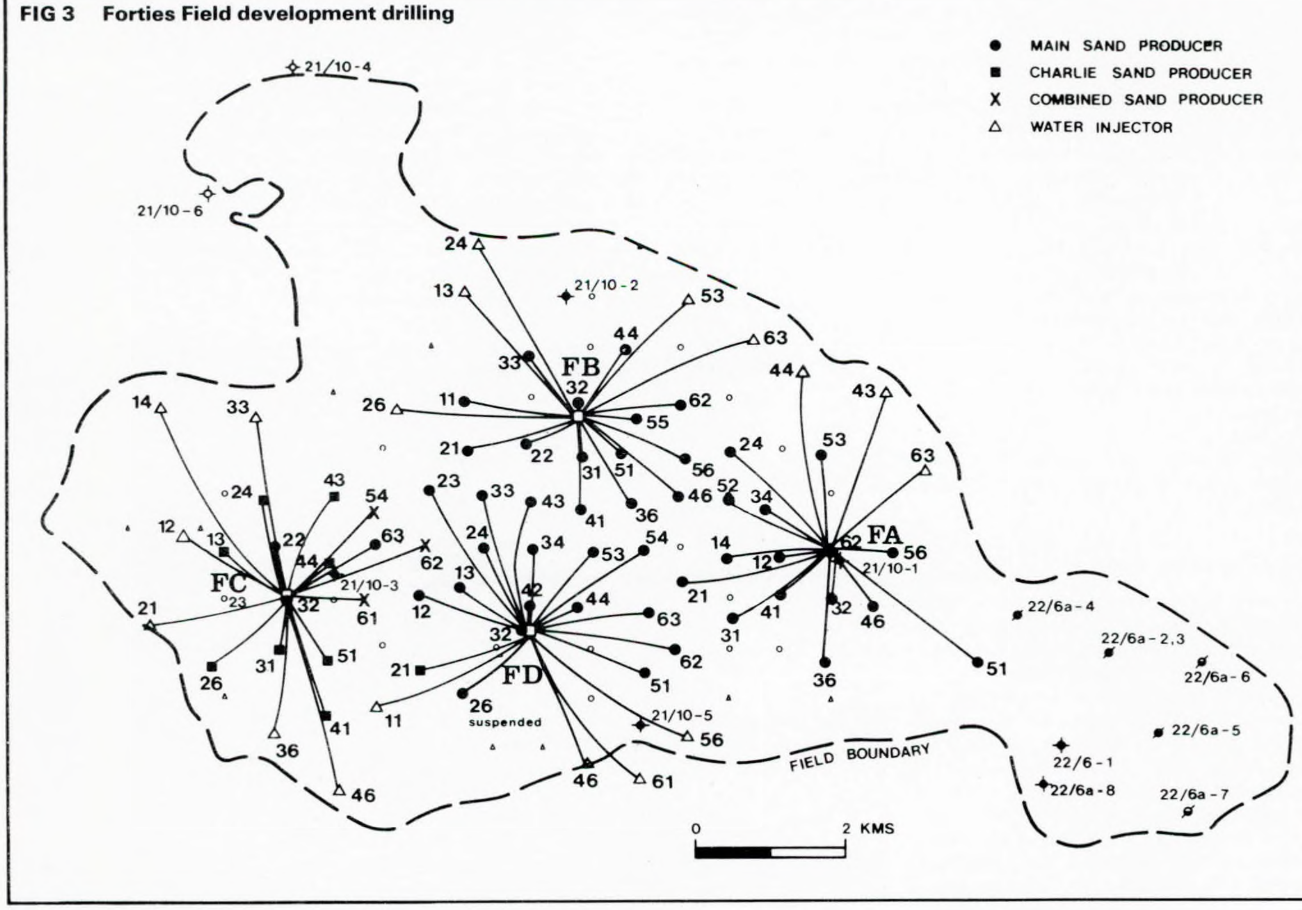


FIG 2 Exploration and appraisal wells

FIG 3 Forties Field development drilling



pipe (casing), which is cemented in place. This conductor pipe incorporates two vital components of the wellhead system:

(a) A suspension mechanism.
(b) A blowout preventer (BOP) guide frame.

The suspension mechanism is later utilized to support all subsequent strings of casing, and the BOP guide frame enables the BOP to be positioned on the wellhead body.

The subsequent hole sections are drilled with bits sized to pass through each previous string of casing so the well at final depth will have a telescopic appearance (Fig. 5). There are three main reasons why casing must be set and cemented in the wellbore before drilling the next section of hole:

(a) To control well pressure
(b) To seal off loss zones
(c) To prevent caving of the hole

The design of casing strings for any well is one of the fundamentals of well programming. From anticipated or known reservoir pressures it is possible to calculate the maximum pressure which may have to be controlled at the wellhead during drilling. Therefore, a system must be designed to contain these pressures. Three essential elements are required:

(a) The casing, which is designed for burst, collapse and tensile loadings.
(b) The wellhead, into which the casing strings are set, where a seal is effected between casings, and on to which the BOP is latched.
(c) The BOP, which is a series of valves, and can be operated to effect a closed system. This closed system can be considered as a pressure vessel.

The drillstring

Although the casing, wellhead and BOPs are necessary for the safe drilling of a well, the fundamental drilling mechanism is the cutting element or drilling 'bit' and its associated drillstring.

The drillstring is the physical link between the drilling bit and the rig. It must fulfil the following important functions (see Fig. 6).

WEIGHT: Part of the drillstring should be able to provide the weight which is necessary for the bit to drill. This is accomplished by using drill collars at the lower end of the string. These thick-walled sections of steel pipe, of up to 10-in diameter (3-in bore), are run in compression thus providing the required weight for the bit. The 5-in drillpipe, however, is a thin-walled tubular and must never be used in compression or buckling and eventual fatigue of the drillstring will result.

STABILITY: Stability or stiffness of part of the string is required to ensure that the angle of the hole can be controlled. Stabilizers, which are generally of the same diameter as the drill bit, are inserted between the drill collars for this reason. This combination is known as the bottom hole assembly. When drilling vertical wells, it is normal to have three stabilizers equally spaced at the lower end of the bottom hole assembly. This three-point contact mechanism will assist in keeping the hole straight. In drilling directional wells, different configurations of assembly are required to control hole angle.

TORQUE: In normal drilling situations the torque, which is used for the bit to drill, is provided by the rotary table on the rig. Thus every member in the drillstring must be able to transmit this torque.

CIRCULATION: The drillstring must be tubular to allow the drilling fluid to be circulated. This circulating system is described below.

The circulating system

The main function of any circulating drilling fluid (mud) system is the removal of formation cuttings from the wellbore. Figure 7 shows the flow around the circulating system. The mud flows from the mud pits through a centrifugal charge pump which supplies the main pumps. Modern pumps are generally of the triplex single-acting design, which has superseded the duplex double-acting type because of demand for higher performance pumps. Some of these pumps are capable of pumping 1900 l/min at 5500 $\mathrm{lbf/in^2}$ or 3400 l/min at 3200 $\mathrm{lbf/in^2}$, depending on liner size.

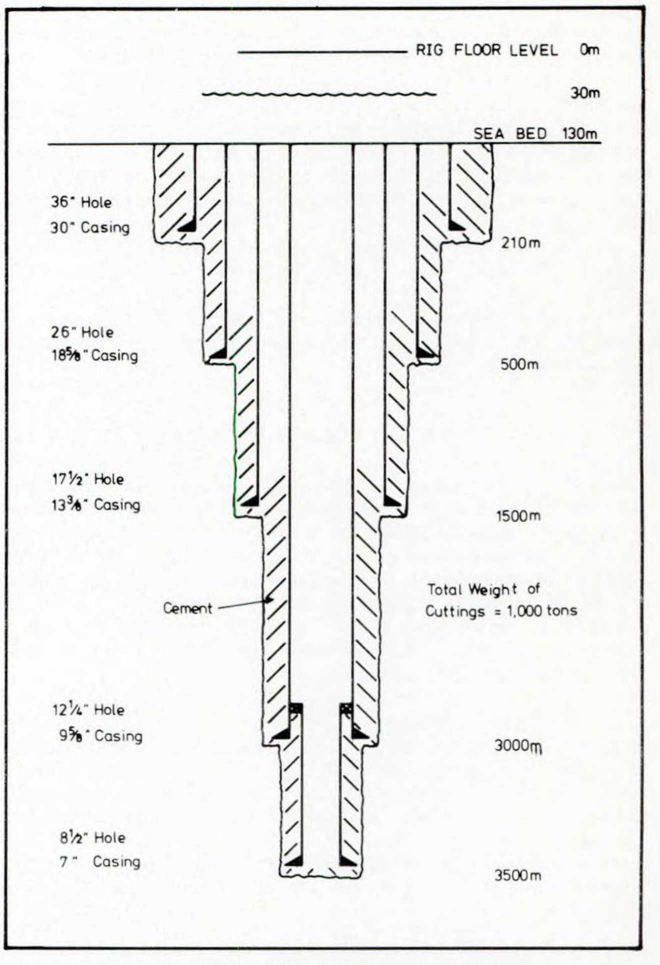


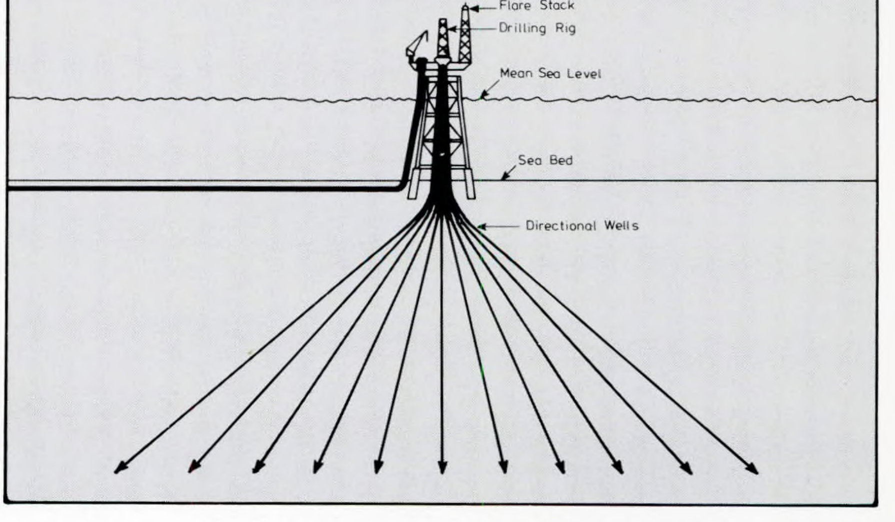
FIG 5 Typical North Sea casing design

The mud is then pumped up the standpipe through the kelly hose and kelly, through the drillstring and down to the bit. It removes cuttings from the bottom of the hole and transports them to surface where they are removed from the system, by a series of screens, for geological interpretation. Over 1000 Mt of cuttings are removed in this manner when drilling a typical North Sea well.

The mud itself has several important functions:

- To prevent entry of formation fluids into the wellbore by means of the mud hydrostatic head.
- To transport the cuttings to surface.

FIG 4 Platform development drilling



- To clean the bottom of the hole.
- To prevent the caving of the wellbore.
- To cool the bit and lubricate the drillstring.

The two main properties which fulfil most of the above conditions are weight and viscosity. Throughout the drilling of the well the hole conditions and drilling rates are observed and, from them, a pore pressure is estimated. The hydrostatic mud pressure must at all times be maintained slightly above this pore pressure by the addition of high-density solids. If the mud weight is allowed to fall too low, an influx to the wellbore will result. Alternatively, if the mud weight is too high mud will be lost to formation. These two situations are known as a 'kick' and 'lost circulation' respectively.

The viscosity and gel strength properties of the mud must be such as to ensure that the cuttings are satisfactorily transported to surface without extensive slippage occurring. Other properties of the mud which must be monitored include: pH for corrosive resistance; fluid loss control for wellbore stability; and sand content for erosion of equipment. All of these parameters are interdependent and are carefully measured and controlled by the Mud Engineer.

The majority of all exploration wells drilled today use a water-based mud circulating system with dissolved chemicals, clay particles, polymers and other finely-ground solids present in the mud. In particular areas where swelling clays are a great problem or damage to the reservoir occurs with water-based muds, oil-based muds are occasionally used. Their use involves far greater pollution preventative measures and, largely due to these, greater expense. These muds are not, therefore, commonly used for exploration work, although they are more economic for platform production drilling.

It must be remembered that many of the topics discussed in this and previous sections equally apply to both land and offshore drilling. There are, however, key factors which enable the drilling operation to function successfully offshore, and these will now be discussed.

THE DRILLING UNIT

Weather conditions for drilling in the North Sea are considered by drilling contractors to be amongst the most severe anywhere in the world. Even when using some of the largest and best-equipped rigs available, a recent North Sea survey showed that 10% of total

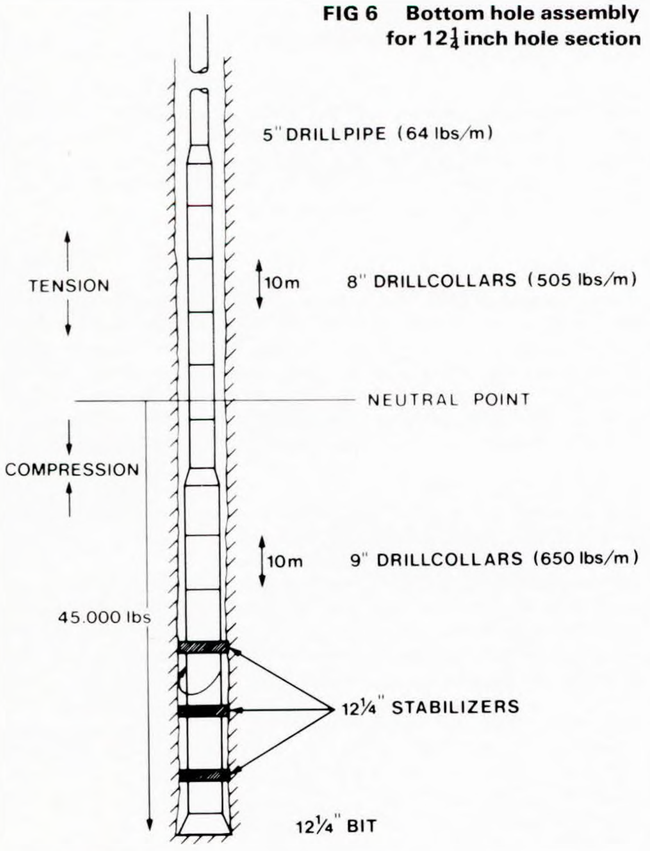


FIG 6 Bottom hole assembly for 12¼ inch hole section

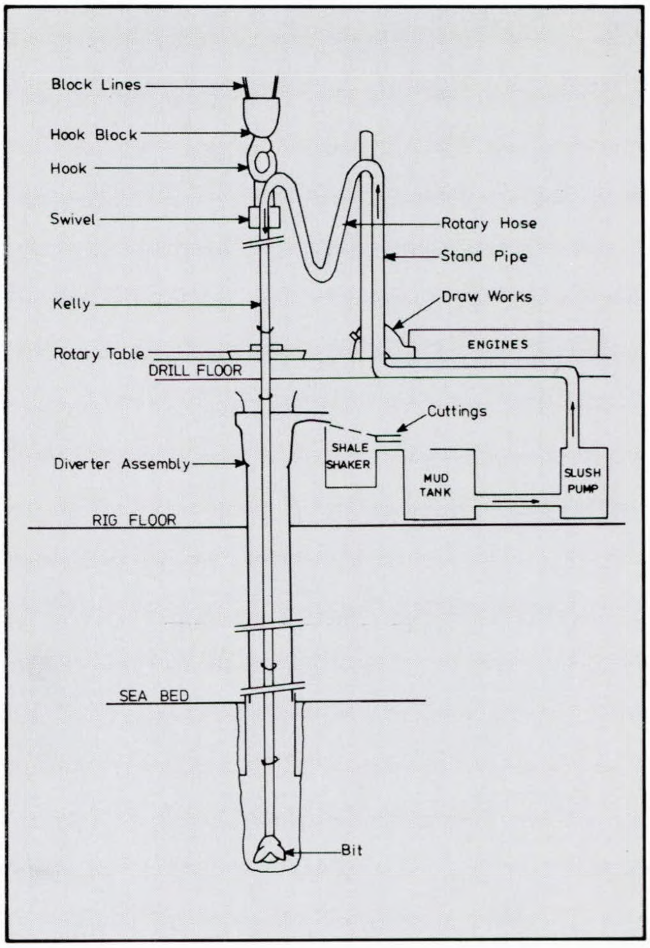


FIG 7 Mud system

operating time was lost solely due to adverse weather. Three of the factors which limit these operating conditions are discussed below.

Unit stability

The stability of a semi-submersible governs the amount of operational time available, throughout the drilling of a well. The term stability encompasses factors such as heave, pitch, roll and station-keeping ability.

Heave is probably the single most important motion of an offshore drilling unit in causing operational shutdown. To minimize heave and increase the overall stability of the rig, it is advantageous to build SSMs with long natural periods of motion. Such long periods are achieved by designing a rig with a small waterplane area in relation to the displacement of the rig. However, such conditions are not conducive to static stability. Therefore, to provide both dynamic stability and a sufficient deck loading capacity, a compromise between the two must be reached.

The large twin-hulled floating rigs of today have maximum variable deck loading capacity of around 3500 Mt. Deck loading capacity is becoming an increasingly important design factor as the drilling industry drills deeper wells in deeper water. Indeed, some SSMs under construction today are designed to have a variable deck loading in excess of 5000 Mt.

Station-keeping ability is another essential property for an SSM. The limiting factor in this context is the riser. A lateral displacement of 8% of water depth is acceptable but anything over this can cause excessive bending stresses in the riser and ball joint. Modern anchoring systems are normally capable of maintaining the rig within this tolerance even under the most severe weather conditions.

The marine riser

When drilling an offshore well some form of contact with the well must be maintained at all times. This is achieved by the use of the marine riser. The riser consists of sections of pipe (normally 15 m in length by

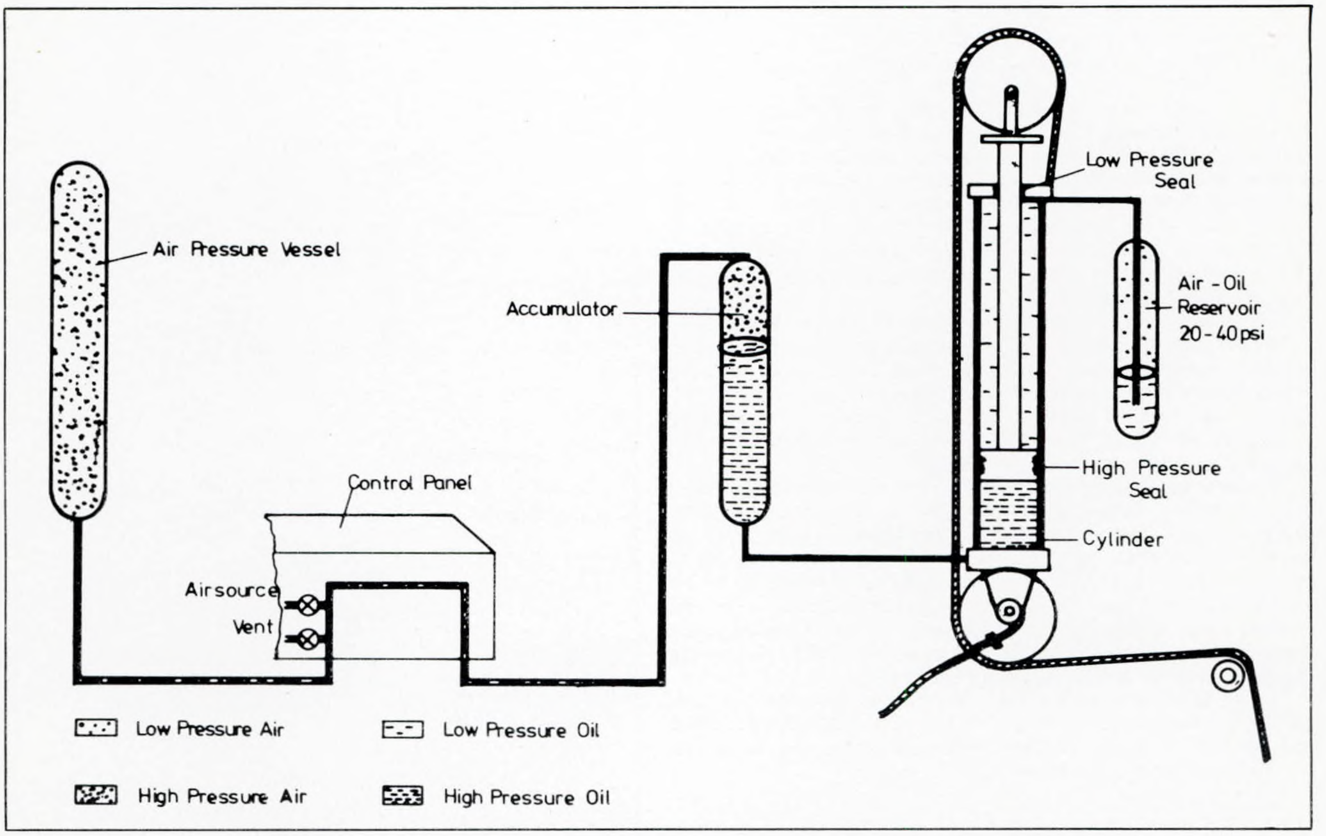


FIG 8 Wire rope riser tensioner system

20-in diameter) which are coupled together, attached at the bottom to the BOP stack and at the top to the rig itself.

To allow for the heave, pitch, roll and lateral movement of the rig a ball joint and a telescopic joint are installed directly beneath the rig. A second ball joint is also placed at the base of the riser immediately above the BOP. The limiting conditions for these items of equipment are 10 deg for the ball joint and 15 m for the telescopic joint; although, for practical purposes, operations would be halted well before these conditions were reached.

The riser serves a number of main functions. It enables:

(a) The mud to be returned to surface.
(b) Formation cuttings to be recovered at surface.
(c) Drilling tools to be guided into the wellbore.
(d) The well to be controlled by the use of choke and kill lines attached to the riser.

It is necessary to support the weight of the riser and stiffen it against the effects of waves and tidal currents. This is accomplished by using the riser tensioner.

The riser tensioner

The riser tensioner (see Fig. 8) is a pneumatic device whose purpose is to maintain all parts of the riser in tension, at all times, regardless of the heave of the rig. The riser is suspended by cables shackled to the female section of the telescopic joint. These cables pass over sheaves to the tensioners. A typical arrangement would include eight tensioners supporting weights of up to 640 000 lb.

When the barge heaves upwards from its mean position, the tension in the cable begins to increase, causing the air in the tensioner cylinder to become compressed. These pneumatic cylinders are connected to a large air pressure vessel (APV). Thus, when the tensioner is compressed on the up-heave of the rig, air flows into the APV; while on the down-heave the tensioner piston moves out because of the airflow from the APV to the tensioner cylinder. The system thus works like a spring and is damped by oil-filling the chamber behind the piston. The capacity of the APV governs the magnitude of variation in the riser tension but it is usually designed for a $\pm 3\%$ tension value for a 3.5 m heave.

A similar system is used to compensate for the four guide wires and for the motion of the drillstring relative to the bottom of the hole. Constant 'weight on bit' is an important factor in optimizing drilling rates and controlling hole angle in deviated wells.

PROBLEMS

Although unplanned, each well will have its share of problems, which must be overcome. In solving them, time and therefore money are lost. In the event of problems occurring on any offshore rig, every effort is directed towards solving them as speedily as possible. Three of the most common troublesome situations which occur in the North Sea are: stuck pipe and fishing; lost circulation; and kicks.

Stuck pipe

Amongst the most likely interruptions to drilling progress at any time is some mechanical failure of the drillstring down the hole. The parting of the drillstring can be either a planned back-off or a twist-off. The twist-off is the fracture of the drillpipe or one of the connections joining the drill collars or drill pipe. The planned back-off can arise when the pipe is stuck. The stuck pipe situation, a common problem in North Sea drilling, is generally caused by one of the two following reasons.

Differential sticking

This can occur when the mud hydrostatic pressure is greater than the formation pressure in permeable zones. Figure 9 illustrates what can happen downhole, particularly in a deviated well.

A combination of the drill collars and debris create a hydraulic seal between the mud and the formation. A pressure differential and hence a horizontal force therefore acts on the pipe, holding it to the wall of the hole. Very large forces can be generated as illustrated by the following example.

Example: $12\frac{1}{4}$-in hole/9-in drill collar
Hydraulic sealed pressure area: 7 in
Pressure differential (say): 300 lbf/in^2
Length of BHA (say): 200 ft
Force $= P \times A_c = 300 \times (200 \times 12) \times 7 = 5$M lbf
Drag from sticking $= C_F \times 5$M lbf

There are two effective solutions for this:

(a) Reduce the hydrostatic head by
 Reducing the mud weight;
 Replacing some of the mud by a less dense fluid.
 This may not always be possible due to pressured formations above.

(b) Pump a quantity of a pipe freeing agent, which will strip away some of the debris of wallcake and thus reduce the large hydraulic seal area.

Formation problem

In North Sea drilling, large hydratable clay sections often have to be drilled. Problems occur in two forms: (a) the hole caving in; and (b) the clays swelling and making the hole 'tight'.

Again, good mud control is essential in the prevention of this problem. If the hole has caved in and circulation is not possible, apart from working the pipe for some time, little can be done. If the hole is becoming tight it is generally recognized in advance; the salt content of the mud is increased to prevent further hydration and the mud weight is increased to hold back the walls of the hole.

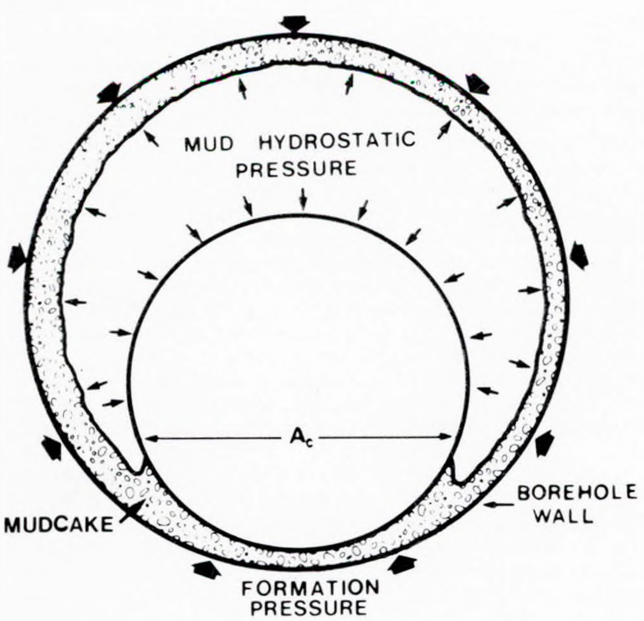
Throughout any 'tight hole' or 'stuck pipe' situation the drillstring should be 'worked' continuously to prevent any further deterioration in the position.

Fishing

In the event of the pipe sticking, the first action is to decide at what point the pipe is still free. This is achieved by the use of a free point indicator (FPI) which is run down the inside of the pipe on a multicore electric cable. The pipe is either torqued up or tensioned to a maximum safe value, and the FPI transmits information to the surface on whether the torque or tension imparted at the rig is reflected in the drillstring alongside the instrument. The FPI is operated progressively at various points until the free point is known.

The free point having been detected, some reverse torque is put in the drillstring and a small explosive charge is lowered to a convenient tool joint just above the lowest free point. This is fired and the explosion is sufficient to loosen the threads of the joint in the pipe adjacent to the charge and the drillstring can be removed.

If available, a higher grade of drillpipe is run with a set of 'jars' and matched up to the fish. (A 'fish' is any tool or part of a drillstring or similar item which is lost in a hole; a jar is a fishing tool used to recover a fish.) This mechanism enables any tension exerted on the jars to be held by them for a few seconds and then suddenly released, giving an immediate upward or downward blow at the point where the string is stuck. If a connection is not available to screw back into, 'overshots' and 'taper taps' are used to grip the top of the fish.



Sticking force $= (P_M - P_F) \times A_c$
Drag force $= C_F(P_M - P_F) \times A_c$

FIG 9 Differential sticking mechanism

Many other fishing tools are available for specific problems but, due to the numerous situations which can exist, tools are often made for particular operations. Drilling costs are so great today that often the most economic solution is to try fishing for a short while only and, if unsuccessful, cement in the fish and sidetrack around it.

Lost circulation

One of the serious and expensive problems in the drilling industry is lost circulation. This is the loss of drilling fluid to porous or fissured formations. It is indicated on the drilling rig by the drop of level in the mud tanks since more mud is circulated down the drillstring than is returned up the annulus to the mud tanks. This is carefully measured by sophisticated monitoring equipment.

Lost circulation is expensive for two main reasons. One is the delay caused to the drilling operation and the second is the expense of the mud itself. A typical mud cost on a standard well would be £150 000. These mud losses should be differentiated from seepage to formation which is normal and is the loss of small quantities of mud filtrate to the wellbore.

The formations to which large quantities of mud can be lost are:

1. Cavernous and open fissured formations
2. Very coarse and permeable shallow formations
3. Natural intrinsically fractured formations
4. Easily fractured formations

Lost circulation generally occurs when the total pressure exerted by the mud is greater than the pore pressure/fracture pressure of the formation. The total pressure of the mud is a function of the following:

(a) Mud weight
(b) Mud composition/viscosity/yield point
(c) Circulation rates
(d) Surging and swabbing with casing/bottom hole assembly (BHA)

Mud losses come in various degrees of severity. The first stage in the process of solving the problem is to alter the above four parameters to try and reduce the pressure differential. Minor loss problems can be solved in this way.

The next step in the solution is the addition of bulk material to the fluid system. This can take many forms but such materials as walnut shells, mica and hemp are commonly used. If these steps do not cure or even reduce the losses to an acceptable level, thickening or cementing compositions can be employed. These are pumped downhole as a viscous plug which invades the loss zone and then sets to form a seal. More care must obviously be taken when the losses occur in a reservoir itself—plugs which can be acidified/dissolved should be used in this context.

The most severe type of lost circulation occurs in cavernous formations. In this situation it is almost impossible to effect a seal by any of the afore-mentioned methods. The accepted method of continuing in this case (particularly in known areas) is to drill 'blind', i.e. without returns to surface. Although this is not normally a recommended practice it is sometimes the only method of proceeding without considerable delay. When drilling through this cavernous zone is complete, casing is set and cemented in stages.

Prevention better than cure

When planning a drilling programme the possibilities of lost circulation should be considered and all practical measures for preventing such losses should be taken. Every effort should be made to maintain optimum conditions for the mud coupled with good drilling practices. These considerations should include the following:

1. The casing programme should be planned to protect potential loss zones before high mud weights become necessary.
2. The mud programme should advise minimum weight to ensure a minimum safe margin above expected formation pressure.
3. Viscosity and gel strengths should be held at a minimum.
4. A good selection of bulk materials to combat lost circulation should be provided.

Kicks

When the total bottom hole pressure exerted by the mud column in the hole is less than the formation pressure at that depth, formation fluid can enter the wellbore and displace mud from the annulus. As the intrusion of formation fluid reduces the hydrostatic head of the mud column, a continually increasing rate of flow results. This uncontrolled flow of fluid into the wellbore is known as a 'kick'. If the kick reaches the wellhead and fluid flows out of control, then it is termed a blowout.

The first principle of safe operating is never to allow an influx to the wellbore. This is the objective of all oil companies operating in the North Sea today. An influx is normally caused by one of the following:

(a) The hole not being kept full of mud;
(b) The bore pressure increasing without being detected;
(c) Mechanical swabbing of the hole reducing the effective bottom hole pressure.

In all instances, the influx must be circulated from the system by applying back pressure at the BOP. In case (b) there is also the necessity to raise the mud weight to a higher level but in cases (a) and (c) the mud weight need not necessarily be increased. There are several recognized methods of kick control well known to the industry, each having their own advantages. It should be emphasized that the BOP is the last line of defence in pressure control. Normal and safe practice is to control formation pressures entirely by mud column hydrostatics.

THE FUTURE

Offshore drilling on the UK continental shelf uses some of the most advanced techniques and equipment known anywhere in the world. Since drilling in the North Sea began, we have been working at the limits of technology not only with drilling and drilling rigs, but also with diving systems, production platforms and subsea production systems.

As we look to the future, the drilling of deeper wells in deeper water at higher pressures will generate problems that have yet to be overcome. For example, although it is possible to drill in 1800 m of water or at reservoir pressures of up to 15 000 lbf/in^2, at present there are no production systems capable of producing from these conditions.

Work is currently progressing on modern subsea completions and on a new concept, the tension leg platform, which can perhaps be extended for deep-water production systems.

With the experience gained in drilling and producing from the severe conditions encountered in the North Sea, an effort should be made to promote our expertise in this field in other areas of the world, as a contribution to increasing overall world energy resources.

ACKNOWLEDGEMENTS

The author is indebted to BP Petroleum Development (UK) Limited for permission to publish this paper. Thanks are given to Mr K. Floyd and other colleagues for their assistance in the preparation of this paper.

BIBLIOGRAPHY

Our Industry Petroleum, 1977, The British Petroleum Company Ltd.

Rotary Drilling, 1976, Petroleum Extension Service in co-operation with the International Association of Drilling Contractors. Published by the University of Texas.

Floating Drilling Equipment and its Use, 1980, Riley Sheffield. Gulf Publishing Company.

Drilling Practices Manual, 1974, Dr Preston L. Moore. The Petroleum Publishing Company.

James Morton Denholm graduated in Mechanical Engineering from Strathclyde University in 1977. Since then he has been involved in offshore exploration and subsea development systems, mainly in the North Sea. At present he is based in Greenock working on the construction of a new semi-submersible drilling rig for BP.

Discussion

C. A. SINCLAIR FIMarE: Could the author indicate whether the dynamic positioning system allows the vessel to stay on station during heavy weather for a longer or a shorter time than the conventional anchored vessel?

I am surprised that the North Sea downtime is as little as 10%, especially in view of the heavy weather encountered during winter.

Has the author considered that, in view of the international concern as to safety, the oil industry may find it prudent and indeed advisable to make more use of weather-forecasting services and to discontinue drilling operations earlier?

In view of the author's expressed opinion that the British have both good experience and a good operational safety record available for use abroad, I should like to ask whether this will mean us taking an interest in Arctic developments? I understand that interests in this country have been involved in looking at the possibility of developing an air cushion (hovercraft) drilling rig to be dynamically positioned on the ice fields. Could the author comment on this?

C. S. M. HAMILTON (Furness Withy Shipping): In view of the alarming amount of redundancies in the British Merchant Navy, would the author care to comment on their possible re-employment in the North Sea, and in the offshore oil industry in particular?

I should also be grateful if the author would explain how the wells are angled to the required degree.

J. CRAWFORD (Senior Surveyor (Offshore Section), Lloyd's Register of Shipping): I should like to congratulate the author on a very interesting paper and would ask his views on the following points:

Relief valve arrangements on pressure vessels and other equipment
It appears to be an accepted practice in the petrochemical industry to include isolating/blocking valves in conjunction with pressure relief devices. Such an arrangement could in itself present a hazard should the isolating valve be inadvertently closed, irrespective of whether the isolating valve be located upstream or downstream of the pressure relief device. On offshore installations it is a requirement that where such isolating valves are fitted then not less than two relief devices are to be provided, the blocking/isolating valves being so interlocked that one relief device will always be open to the pressure vessel/system when the other is closed.

There is, however, a further source of hazard in the design of the safety valves: again, it is common practice to design the safety device on the basis of the upstream side being suitable for maximum relief pressure whilst the downstream section including any isolating valve is designed for a lower pressure (e.g. 600 lb rating upstream; 150 lb rating downstream).

It will be appreciated that, should the relief device be actuated whilst the downstream isolating valve is closed, this would result in the lower rated items being subject to full relief pressure with possible hazard to personnel in the immediate vicinity of equipment.

Relief devices on high-pressure cement units
Whilst the reason for not providing a relief valve in the 'cement' system is fully appreciated, it is considered essential that some protective arrangements must be provided to prevent the system being subjected to excessive pressure.

Where pumping units of the centrifugal type are employed then it is a straightforward arrangement to design the system to be suitable for the maximum 'dead head' pressure that can be applied. Where positive (piston-type) displacement pumps are provided, and this is usually the type employed in the 'cement' system, damage could be effected if pressure relief devices are not provided. Further, it is not unusual to note that cross-connections may be provided between the cement system (WP at 10 000 lb/in^2) and the mud systems (WP at 5000 lb/in^2).

A rheostat dial setting for pressure limits is not considered an acceptable arrangement since such settings could be subject to possible alteration, say due to vibration or other causes.

It is often argued that activation of a relief valve could lead to difficulty under possible emergency conditions; however, at least some pressure would be available. This would not be the case should failure of the pipe occur.

Note
Unfortunately the author was unable to reply to the above comments and questions.

Published for THE INSTITUTE OF MARINE ENGINEERS by Marine Management (Holdings) Ltd (England Reg. No. 1100685) both of 76 Mark Lane London EC3R 7JN
Printed in England by Gibbons Barford Print, Wednesfield Road, Wolverhampton WV10 0JA