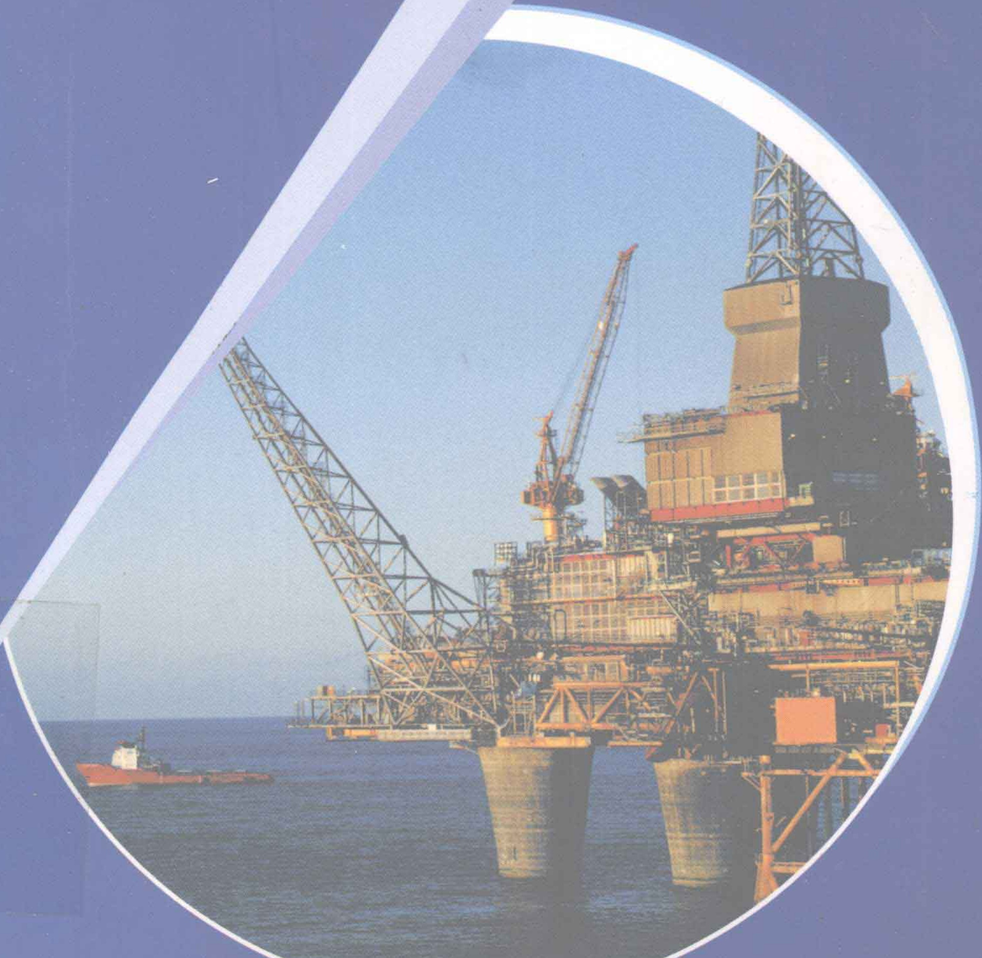
石油工程专业建设基金、油气田开发工程学科点建设基金资助

石油工程专业系列教材

石油工程专业英语

朱芳冰　谢丛姣　编



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Petroleum Engineering Special English

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内 容 提 要

本书是石油工程专业的实用专业英语教材。主要包括钻井工程、油藏描述、油藏工程、采油工程及石油经济评价等内容，共14章。每章除课文外，还附有关键词、难点注释及思考题。课文均选自最新英美石油工程专业原著，按石油工程专业学科内容编排。该书题材广泛、内容丰富、重点突出、难度适中，具有系统性和可读性，既可作为石油工程专业教学用书，亦可供其他地质及工程人员参考。

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前　言

21世纪是知识经济时代，知识和经济更具全球化和信息化的特点。石油工程专业的学生在掌握了一定实用英语的基础上，需进一步掌握一些专业英语，以便更好地了解国外的最新信息，追踪国际前沿。

《石油工程专业英语》共14章，按石油工程专业学科内容编排，主要包括钻井工程、油藏描述、油藏工程、采油工程及石油经济评价等内容，除课文外，每课还包括关键词、课文注释及思考题。课文皆选自最新英美石油工程专业原著，内容涉及石油工程的主要环节。本书另有附录，包括8篇有关石油工程专业的阅读材料、常用石油工程专业词汇和缩略词及中英文地质年代表。

该教材选题广泛、重点突出、难度适当、自成体系，适于石油工程专业的本科高年级学生使用，也可供本专业硕士学位进修生使用，旨在帮助学生逐渐熟悉并掌握本专业的英语常用词汇、语法现象及文章结构，扩大石油工程专业方面词汇，提高阅读和翻译本专业的科技英语文献的能力，以使本专业的学生在将来的工作中能迅速而准确地获取和传递来自英语文献的先进石油科技信息。

在该书编写过程中，中国地质大学资源学院石油系的老师对本书提出了很多宝贵意见，给予了大力的支持和帮助，在此表示衷心的感谢！本书由资源学院石油系教师朱芳冰、谢丛姣编写，研究生肖伶俐同学协助编辑部分文字和词汇。由于编者的英语水平和专业知识有限，加之经验不足及时间仓促，书中的错误和不妥之处在所难免，敬请读者指正。

编　者

2005.6

Contents

Chapter 1 The Field Life Cycle

Keywords: exploration, appraisal, feasibility, host country, development planning, production profile, production, abandonment, project economics, cash flow

This chapter provides an overview of the activities carried out at the various stages of field development. It includes exploration phase, appraisal phase, development planning, production phase and decommissioning.

1.1 Exploration Phase

For more than a century petroleum geologists have been looking for oil. During this period major discoveries have been made in many parts of the world. However, it is becoming increasingly likely that most of the "giant" fields have already been discovered and that future finds are likely to be smaller, more complex, fields. This is particularly true for mature areas like the North Sea.

Fortunately, the development of new exploration techniques has improved geologist' understanding and increased the efficiency of exploration. So although targets are getting smaller, exploration and appraisal wells can now be sited more accurately and with greater chance of success.

Despite such improvements, exploration remains a high risk activity. Many international oil and gas companies have large portfolios of exploration interests, each with their own geological and fiscal characteristics and with differing probabilities of finding oil or gas. Managing such exploration assets and associated operations in many countries represents a major task.

Even if geological conditions for the presence of hydrocarbons are promising, host country[1] political and fiscal conditions must also be favorable for the commercial success of exploration ventures. Distance to potential markets, existence of an infrastructure, and availability of a skilled workforce are further parameters which need to be evaluated before a long term commitment can be made.

Traditionally, investments in exploration are made many years before there is any opportunity of producing the oil (Fig. 1.1).

It is common for a company to work for several years on a prospective area before an exploration well is spudded[2]. During this period the geological history of the area will be studied and the likelihood of hydrocarbons being present quantified. Prior to spudding the first well a work programme will have been carried out. Field work, magnetic surveys, gravity surveys and seismic surveys are the traditional tools employed.

1.2 Appraisal Phase

Once an exploration well has encountered hydrocarbons, considerable effort will still be required to accurately assess the potential of the find. The amount of data acquired so far does not yet provide a precise picture of the size, shape and producibility of the accumulation.

Two possible options have to be considered at this point:

1. To proceed with development and thereby generate income within a relatively short period of time. The risk is that the field turns out to be larger or smaller than envisaged, the facilities will be over or undersized and the profitability of the project may suffer.

2. To carry out an appraisal programme with the objective of optimizing the technical development. This will delay 'first oil' to be produced from the field by several years and may add to the initial investment required. However, the overall profitability of the project may be improved.

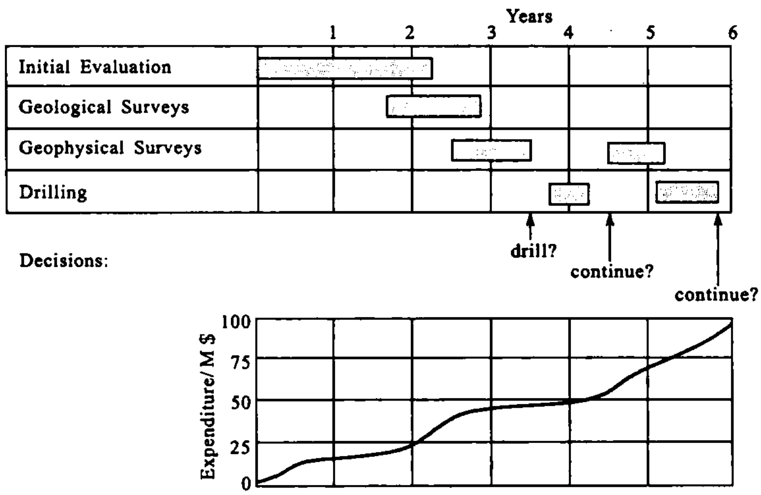

Fig. 1.1 Phasing and expenditure of a typical exploration programme

The purpose of development appraisal is therefore to reduce the uncertainties, in particular those related to the producible volumes contained within the structure. Consequently, the purpose of appraisal in the context of field development is not to find additional volumes of oil or gas!

Having defined and gathered data adequate for an initial reserves[3] estimation, the next step is to look at the various options to develop the field. The objective of the feasibility study is to document various technical options, of which at least one should be economically viable. The study will contain the subsurface development options, the process design, equipment sizes, the proposed locations (e. g. offshore platforms), and the crude evacuation and export system. The cases considered will be accompanied by a cost estimate and planning schedule. Such a document gives a complete overview of all the requirements, opportunities, risks and constraints.

1.3 Development Planning

Based on the results of the feasibility study, and assuming that at least one option is economically viable, a field development plan can now be formulated and subsequently executed. The plan is a key document used for achieving proper communication, discussion and agreement on the activities required for the development of a new field[4].

The field development plan's prime purpose is to serve as a conceptual project specification for subsurface and surface facilities, and the operational and maintenance philosophy[5]. It should give management and shareholders confidence that all aspects of the project have been identified, considered and discussed between the relevant parties. In particular, it should include:

- Objectives of the development
- Petroleum engineering data
- Operating and maintenance principles
- Description of engineering facilities
- Cost and manpower estimates
- Project planning
- Budget proposal

Once the field development plan (FDP) is approved, there follows a sequence of activities prior to the first production from the field.

- Field Development Plan (FDP)
- Detailed design of the facilities
- Procurement of the materials of construction
- Fabrication of the facilities
- Installation of the facilities
- Commissioning of all plant and equipment

1.4 Production Phase

The production phase commences with the first commercial quantities of hydrocarbons ('first oil') flowing through the wellhead. This marks the turning point from a cash flow[6] point of view, since from now on cash is generated and can be used to pay back the prior investments, or may be made available for new projects. Minimizing the time between the start of an exploration campaign and 'first oil' is one of the most important goals in any new venture.

Development planning and production are usually based on the expected production profile[7] which depends strongly on the mechanism providing the driving force in the reservoir. The production profile will determine the facilities required and the number and phasing of wells to be drilled. The production profile shown in Figure 1. 2 is characterized by three phases:

1. Build-up period During this period newly drilled producers are progressively

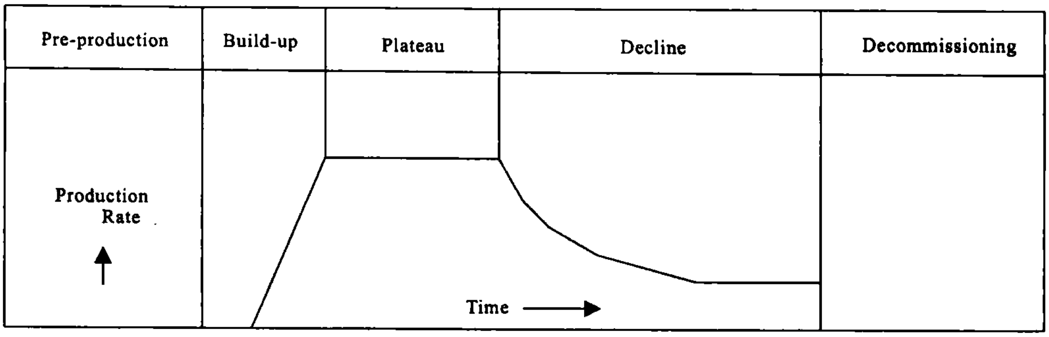

Fig. 1.2 The Filed Life Cycle and a Simplified Business Model

brought on stream.[8]

2. Plateau period Initially new wells may still be brought on stream but the older wells start to decline. A constant production rate is maintained. This period is typically 2 to 5 years for an oil field, but longer for a gas field.

3. Decline period During this final (and usually longest) period all producers will exhibit declining production.

1.5 Decommissioning

Eventually every field development will reach the end of its economic lifetime. This is the time at which income from production no longer exceeds the costs of production, and marks the point when decommissioning should occur. That is, the economic lifetime of a project normally terminates once its net cash flow turns permanently negative, at which moment the field is decommissioned. Since towards the end of field life the capital spending and asset depreciation are generally negligible, economic decommissioning can be defined as the point at which gross income no longer covers operating costs (and royalties[9]). It is of course still technically possible to continue producing the field, but at a financial loss.

Most companies have at least two ways in which to defer the decommissioning of a field or installation (Fig. 1.3):

1. Reduce the operating costs
2. Increase hydrocarbon throughput

Of course the operators will strive to use both of these means of deferring abandonment.

In some cases, where production is subject to high taxation, tax concessions may be negotiated, but generally host governments will expect all other means to have been investigated first.

Operating strategies and product quality should be carefully reassessed to determine whether less treatment and more downtime can be accommodated and what cost saving[10] this could make. Living with periodic shutdowns may prove to be more cost effective in decline. Intermittent production may also reduce treatment costs by using gravity segregation[11] in the reservoir to reduce water cuts[12] or gas influx.

Maintenance and operating costs represent the major expenditure late in field life. These

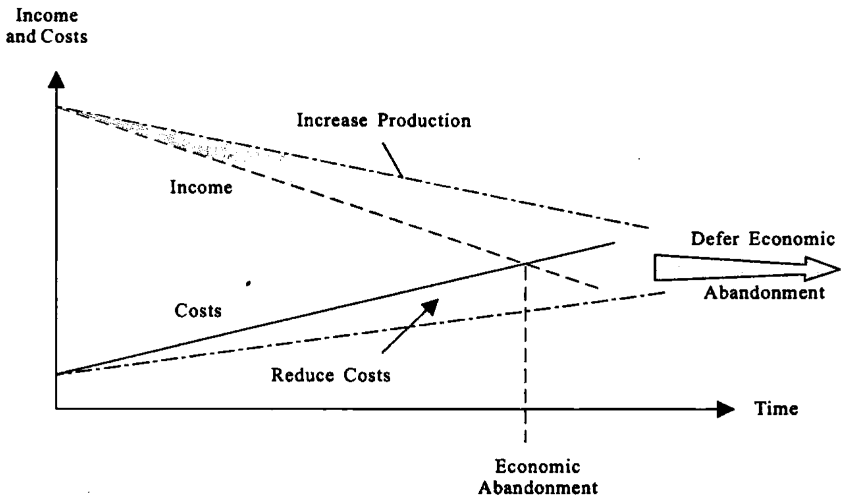

Fig. 1. 3 Deferring decommissioning

costs will be closely related to the number of staff required to run a facility and the amount of hardware they operate to keep production going. The specifications for product quality and plant up-time can also have a significant impact on running costs.

As decommissioning approaches, enhanced oil recovery e. g. chemical flooding processes are often considered as a means of recovering a proportion of the hydrocarbons that remain after primary production. The economic viability of such techniques is very sensitive to the oil price, and while some are used in onshore developments they can rarely be justified offshore at current oil prices.

When production from the reservoir can no longer sustain running costs but the technical operating life of the facility has not expired, opportunities may be available to develop nearby reserves through the existing infrastructure. This is becoming increasingly common where the infrastructure already installed is being exploited to develop much smaller fields than would otherwise be possible. These fields are not necessarily owned by the company which operates the host facilities, in which case a service charge (tariff) will be negotiated for the use of third party facilities.

Ultimately, all economically recoverable reserves will be depleted and the field will be decommissioned. Much thought is now going into decommissioning planning to devise procedures which will minimize the environmental effects without incurring excessive cost. Steel platforms may be cut off to an agreed depth below sea level or toppled over in deep waters, whereas concrete structures may be refloated, towed away and sunk in the deep ocean. Pipelines may be flushed and left in place. In shallow tropical waters opportunities may exist to use decommissioned platforms and jackets as artificial reefs in a designated offshore area.

Management of decommissioning costs is an issue that most companies have to face at some time. On land sites, wells can often be plugged and processing facilities dismantled on a phased basis, thus avoiding high spending levels just as hydrocarbons run out. Offshore decommissioning costs can be very significant and less easily spread as platforms cannot be removed in a piecemeal fashion. The way in which provision is made for such costs depend partly on the size of the company involved and on the prevailing tax rules.

Usually a company will have a portfolio of assets which are at different stages of the described life cycle. Proper management of the asset base will allow optimization of financial, technical and human resources.

Notes:

1. host country 资源国
2. spud 开钻; spud in 开钻,开始钻井
3. initial reserves 原始储量
4. The plan is a key document used for achieving proper communication, discussion and agreement on the activities required for the development of a new field. 这个计划是一个关键性的文件,用以达成开发一个新油田所需的合适的联系、讨论和协商
5. the operational and maintenance philosophy 操作和维护的理念
6. cash flow 现金流量;流动现金;现金收支表
7. production profile 开采曲线,生产剖面
8. bring on stream 投入生产,开始通油
9. royalty 矿区使用费;矿藏开采权
10. cost saving 节省费用
11. gravity segregation 重力分异;重力分离;重力分层
12. water cut 含水量,含水率

Comprehensive Questions:

1. How many main stages in the field life cycle? What are they?
2. What is the purpose of development appraisal?
3. What does production profile show?
4. What are the traditional tools employed? Could you explain them in detail?
5. Explain the figure 1.3. If the economic life time of a field approaches, what will you do to defer the decommissioning?

Chapter 2 Drilling Engineering

Keywords: well objective, well planning, rig selection, rotary drilling, drilling fluid, casing, cementing, drilling costs.

Drilling operations are carried out during all stages of field development and in all types of environments. The main objectives are the acquisition of information and the safeguarding of production. Expenditure for drilling represents a large fraction of the total project's capital expenditure (typically 20% to 40%) and an understanding of the techniques, equipment and cost of drilling is therefore important.

2.1 Well Planning

Oil and gas wells are being drilled in almost every country in the world, on land, in marshes, and offshore.

The drilling of a well involves a major investment. Drilling engineering is aimed at maximizing the profitability of this investment by employing the most appropriate technology and business processes, to drill a quality well at the minimum cost, without compromising safety or environmental standards. Successful drilling engineering requires the integration of many disciplines and skills.

Careful planning of drilling activities will avoid unnecessary expenditure or risks. The planning process is vital for achieving the objectives of a well. Usually, wells are drilled with one, or a combination, of the following objectives:

- to gather information
- to produce hydrocarbons
- to inject gas or water
- to relieve a blowout

To optimize the design of a well it is desirable to have an accurate a picture as possible of the subsurface. Therefore, a number of disciplines will have to provide information prior to the design of the well trajectory and before a drilling rig and specific equipment can be selected.

Geologists and seismic interpreters will predict type and depth of the different rock formations to be encountered during drilling. They will advise the drilling engineer where the objective zone should be penetrated by the drill bit and they will provide the targets of the well. Petrophysicists will advise on the fluid distribution and reservoir engineers will provide a prognosis of pressures along the planned well trajectory. These subsurface disciplines will also specify what information they expect to be gathered, from which formation they want to produce or where gas or water should be injected to maintain reservoir pressure. The accuracy of the parameters used in the well planning process will depend on the knowledge of the field or the region. Particularly during exploration drilling and during the early stages of field development considerable uncertainty in subsurface data will prevail. It is important that the uncertainties are clearly spelled out and preferably quantified. Potential risks and problems expected or already encountered in offset wells (earlier wells drilled in the area) should be discussed and incorporated into the design of the planned well.

In summary, the drilling engineer will be able to design the well in detail using the information obtained from the petroleum engineers and geoscientists. In particular he will plan the setting depth and ratings for the various casing strings, mud weights and mud types required during drilling, and select an appropriate rig and related hardware, e. g. drill bits. Considerable effort will go into optimization of the well path ('well trajectory'), i. e. at what angle and in which direction the hole will be drilled.

2.2 Drilling Systems and Equipment

Whether onshore or offshore drilling is carried out, the basic drilling system employed in both cases will be the rotary rig (Fig. 2. 1).

The main function of a rotary rig is to drill a hole, or as it is known in the industry, to make hole. Making hole with a rotary rig requires not only qualified personnel, but a lot of equipment as well. In order to learn about the components that it takes to make hole, it is convenient to divide them into four main systems: power, hoisting, rotating, and circulating.

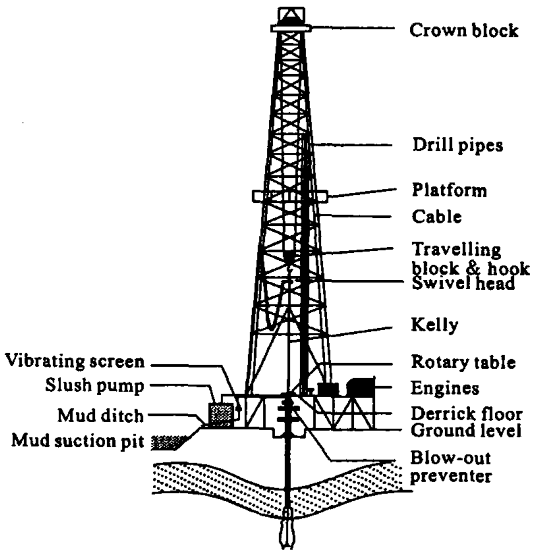

Fig. 2. 1 The rotary rig

Three basic functions are carried out during rotary drilling operations:

- torque is transmitted from a power source at the surface through a drill string to the drill bit
- a drilling fluid is pumped from a storage unit down the drill string and up through the annulus. This fluid will bring the cuttings created by the bit action to the surface, hence clean the hole, cool the bit and lubricate the drill string
- the subsurface pressures above and within the hydrocarbon bearing strata are controlled by the weight of the drilling fluid and by large valve assemblies at the surface

We will now consider the rotary rig in operation, visiting all parts of the system starting at the drill bit.

The most frequently used bit types are the roller cone or rock bit and the polycrystalline diamond cutter or PDC bit.

On a rock bit, the three cones are rotated and the attached teeth break the rock under-

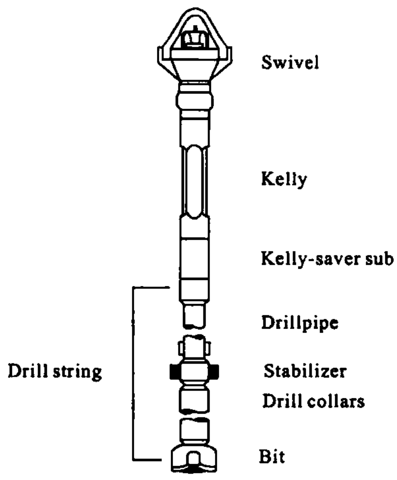

Fig. 2. 2 The drill string

neath into small chips ("cuttings"). The cutting action is supported by powerful jets of drilling fluid which are discharged under high pressure through nozzles located at the side of the bit. After some hours of drilling (between 5 and 25 hours depending on the formation and bit type), the teeth will become dull and the bearings wear out. The PDC bit is fitted with industrial diamond cutters instead of hardened metal teeth. This type of bit is becoming increasingly popular because of its better rate of penetration, longer life time and suitability for drilling with high revolutions per minute (rpm) which makes it the preferred choice for turbine drilling. The bit type selection depends on the composition and hardness of the formation to be drilled and the planned drilling parameters.

Between the bit and the surface, where the torque is generated, we find the drill string (Fig. 2. 2). While being mainly a means for power transmission, the drill string fulfils several other functions.

The drill string consists of the pipe and special, thick-walled pipe called drill collars. Drill collars, like drill pipe, are steel tubes though which mud can be pumped. They are heavier than drill pipe and are used on the bottom part of the string to put weight on the bit. Stabilizers are added to the drill string at intervals to hold, increase or decrease the hole angle. The bottom hole assembly ("BHA") described so far is suspended from the drillpipe, made up of 30 feet long sections of steel pipe ("joints") screwed together. The drill string is connected to the kelly[1] saver sub. A saver sub is basically a short piece of connecting pipe with threads on both ends. In cases were connections have to be made up and broken frequently[2], the sub "saves" the threads of the more expensive equipment. The kelly is a six-sided piece of pipe which fits tightly into the kelly bushing which is fitted into the rotary table. By turning the latter, torque is transmitted from the kelly down the hole to the bit. It may take a number of turns of the rotary table to initially turn the bit thousands of meters down the hole. Incidentally, kellys are available in lengths of 40, 46, or 54 feet.

The kelly is hung from the travelling block. Since the latter does not rotate, a bearing is required between the block and the kelly. This bearing is called a swivel. Turning the drill string in a deep reservoir would be equivalent to transmitting torque through an everyday drinking straw dangling from the edge of a 75 story-high building! As a result, all components of the drill string are made of high quality steels.

After the drilling has progressed for some time, a new piece of drill pipe will have to be added to the drill string. Alternatively, the bit may need to be replaced or the drill string has to be removed for logging. In order to "pull out of hole", hoisting equipment is required. On a rotary rig this consists of the hook which is connected to the traveling block. The latter is moved up and down via a steel cable ("block line") which is spooled through the crown block on to a drum ("draw works"). The draw works, fitted with a large brake, move the whole drill string up and down as needed. The derrick or mast provides the overall structural support to the operations described.

Most rigs are now fitted with a system whereby the drill string is rotated by a drive mechanism in the mast rather than by the rotary table at rig floor level. Thus 90 feet sections can be drilled before connections need to be made, and the drill string can be rotated while pulling out of the hole in 90 feet sections. This improved system, which speeds up the operation and allows better reaming of the hole, is known as top drive[3].

For various reasons, such as to change the bit or drilling assembly, the drill string may have to be brought to surface. It is normal practice to pull stands consisting of 90 feet sections of drill string and rack them in the mast rather than disconnecting all the segments. The procedure of pulling out of hole ("POOH") and running in again is called a round trip.

Drilling fluid serves several very important functions. It cools the bit and also removes the cuttings by carrying them up the hole outside the drill pipe. At the surface the mud runs over a number of moving screens, the shale shakers (Fig. 2. 3) which remove the cutting for disposal. The fine particles which pass through the screens are then removed by desanders and desilters, usually hydrocyclones.

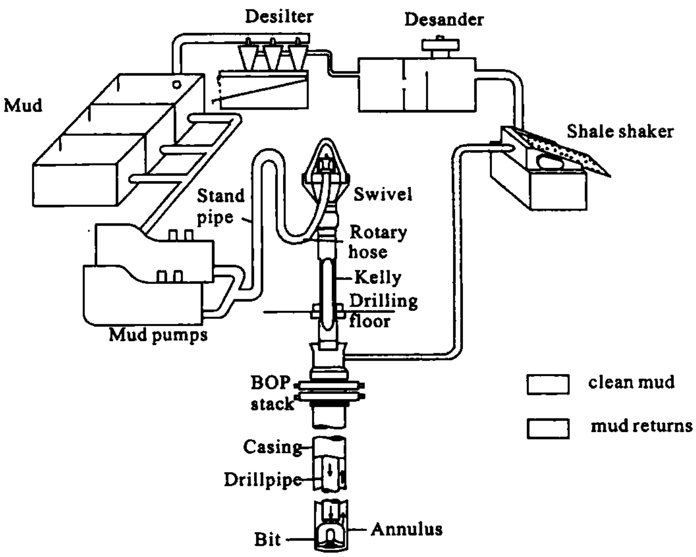

Fig. 2. 3 Mud circulation systems

Having been cleaned, the mud is transferred into mud tanks, large treatment and storage units. From there a powerful pump brings the mud up through a pipe (stand pipe) and through a hose connected to the swivel (rotary hose) forcing it down the hole inside the drill string. Eventually the cleaned mud will exit again through the bit nozzles.

Drilling fluid or mud is usually a mixture of water, clay, weighting material, and a few chemicals. Sometimes oil may be used instead of water, or a little oil is added to the water to give the mud certain desirable properties. Today the preparation and treatment of drilling fluid has reached a sophistication which requires specialist knowledge. The reason for this becomes clear if we consider the properties expected.

In order to effectively lift the cuttings out of the hole a certain viscosity needs to be achieved, yet the fluid must remain pumpable. If the mud circulation stops, for instance to change the bit, the mud must gel and any material suspended in it must remain in suspension to avoid settling out at the bottom of the hole. It has to be stable under high temperatures and pressures as well as at surface conditions. Mud chemicals should not be removable by the mud cleaning process. Drilling fluids have to be capable of carrying weighing material such as barites in order to control excessive formation pressures. They have to be compatible with the formations being drilled, e. g. they should prevent the swelling of formation clay and not permanently damage the reservoir zone. Last but not least[4], since these fluids are pumped, transported and disposed in large quantities they should be environmentally friendly and cheap!

Most drilling fluids are usually made up using water and are called water based mud ("WBM"). Another frequently employed system is based on oil, oil based mud ("OBM"). The advantage of OBM is better lubrication of the drill string, compatibility with clay or salt formations and a much higher rate of penetration. Diesel fuel is usually used for the preparation of OBM. During operations, large quantities of contaminated cuttings were formerly disposed of onto the sea-bed. This practice is no longer considered environmentally acceptable and the cost of adequate disposal of OBM has reduced its use. New mud compositions and systems are continuously being developed, for instance currently the industry is introducing synthetic drilling fluids which rival the performance of OBM but are environmentally benign. The choice of drilling fluid has a major impact on the evaluation and production of a well.

An important safety feature on every modern rig is the blowout preventer (BOP). As discussed earlier on, one of the purposes of the drilling mud is to provide a hydrostatic head of fluid to counterbalance the pore pressure of fluids in permeable formations. However, for a variety of reasons the well may "kick", i. e. formation fluids may enter the wellbore, upsetting the balance of the system, pushing mud out of the hole, and exposing the upper part of the hole and equipment to the higher pressures of the deep subsurface. If left uncontrolled, this can lead to a blowout, a situation where formation fluids flow to the surface in an uncontrolled manner.

The blowout preventers are a series of powerful sealing elements designed to close off the annular space between the pipe and the hole through which the mud normally returns to the surface. By closing off this route, the well can be "shut in" and the mud and/or formation fluids are forced to flow through a controllable choke, or adjustable valve. This choke allows the drilling crew to control the pressure that reaches the surface and to follow the necessary steps for "killing" the well, i. e. restoring a balanced system. Fig. 2. 4 shows a schematic of a typical set of blowout preventers. The annular preventer has a rubber sealing element that is hydraulically inflated to fit tightly around any size of pipe in the hole. Ram type preventers either grip the pipe with rubber lined steel pipe rams, block the hole with blind rams when no pipe is in place, or cut the pipe with powerful hydraulic shear rams to seal off the hole.

Blowout preventers are opened and closed by hydraulic fluid stored under a pressure of 3 000 psi[5] in an accumulator.

All drilling activity will be carried out by the drill crew which usually works eight or twelve hour shifts. The driller and assistant driller will man the drilling console on the rig floor from where instrumentation will enable them to monitor and control the drilling parameters, specifically:

- hookload
- torque in drill string
- weight on bit (WOB)
- rotary speed
- pump pressure and rate
- rate of penetration (ROP in min/ft)
- mud weight in and out of the hole
- volume of mud in the tanks

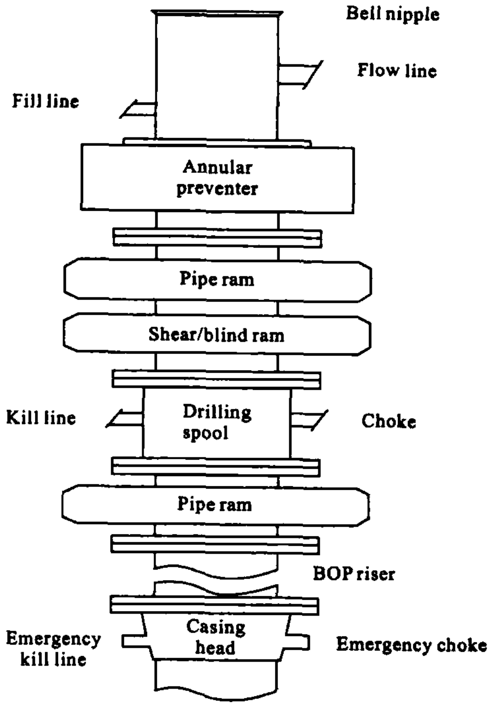

Fig. 2. 4 Schematic of a blowout preventer (BOP)

The roughnecks[6] work on the rig floor, adding singles, round tripping etc. The derrick man[6] handles the pipe up in the mast. In addition to the drilling crews, drilling operations require a number of specialists for mud engineering, logging, fishing etc., not to forget maintenance crews[6], cooks and cleaning staff. It is not uncommon to have some 90 people on site. The operation is managed on site by a drilling engineer or "tool pusher[6]".

2.3 Casing and Cementing

Imagine that a reservoir is at a depth of 2 500 m. We could attempt to drill one straight hole all the way down to that depth. That attempt would end either with the hole collapsing around the drill bit, the loss of drilling fluid into formations with low pressure, or in the worst case with the uncontrolled flow of gas or oil from the reservoir into unprotected shallow formations or to the surface (blowout). Hence, from time to time, the borehole needs to be stabilized and the drilling progress safeguarded. This is done by lining the well with steel pipe (casing) which is cemented in place. In this manner the well is drilled like a telescope (Fig. 2. 5) to the planned total depth. The diameters of the "telescope joints" will start usually with a 23″ (conductor), then 18 5/8″ (surface casing), 13 3/8″ (intermediate casing above reservoir), 9 5/8″ (production casing across reservoir section) and possibly 7″ 'liner'