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Wireline Logs

At suitable intervals during drilling a suite of wireline logs is taken. With the drill string out of the hole a recording device known as a "sonde", is lowered to the bottom on an electrical multi-conductor cable (Fig. 3.31). While the sonde is pulled up steadily, measurements of particular rock properties against the corresponding depths are recorded. The properties measured are electrical, acoustic or radio-active and different sondes are used, some combining several different sets of readings.

The particular property recorded is not of direct significance but can be related to reservoir properties such as porosity or the fraction of the pore space which is saturated with hydrocarbons. The type of rock can also be identified fairly accurately from the logs.

Further detail on wireline logs and on the techniques used to interpret them is given in the section under Petrophysics (p. 83).

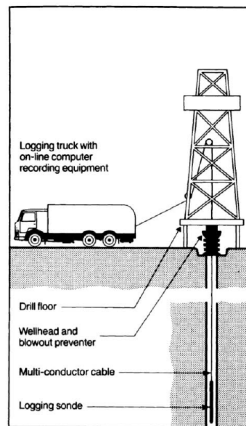


Figure 3.31 Wireline logging operations

Coring

When rock properties have been derived from logs, it is desirable to check the results against values accurately measured on actual formation samples from corresponding depths. Samples big enough for laboratory examination are obtained from known depths by "coring". The drilling bit is replaced by a "core barrel" and a "core head" by means of which a cylinder of the formation being drilled passes through the core head into the core barrel where it is retained and brought to the surface (Fig. 3.32). In some formations the cores are badly broken and in soft sandy formations they may be washed away by the drilling fluid and a representative sample cannot therefore always be obtained. Moreover, progress is usually slower than when drilling normally, and the drilling string has to be pulled more frequently because of the limited length of core barrel. Coring is thus an expensive and uncertain process. It is used in the early stages of field appraisal, more so than in exploration wells, where the location of formations of interest is not known until they have been passed, by which time it is too late to core them.



Figure 3.32 Core samples.

tional methods used to design and monitor primary and secondary recovery projects. Whereas the actual reservoir can be produced only once and at high cost, the simulation model can be used many times, and at a relatively low cost, to evaluate probable results for a variety of production policies.

Reservoir Modelling

The construction of a "reservoir model" is a joint effort of petroleum engineers and geologists. It takes into account geological information obtained from the wells as well as interpretations of pressure test data and laboratory measurements of rock and fluid characteristics. Volumetric calculations are made to determine the amounts of oil and gas initially in place. Porosity and permeability maps are prepared for the various strata that can be defined in the reservoir. Sealing shales between these strata, and other barriers to flow, such as faults and field boundaries, are identified. The initial distribution of water, oil and gas throughout the reservoir is calculated.

Reservoir Simulation

The calculations described in the previous section give a considerable insight into the characteristics of the reservoir concerned, and enable the reservoir engineer to assess at least qualitatively the relative merits of various methods for producing oil and gas from it. At this stage he will be able to define clearly the objectives of his study and to choose a modelling approach in line with these objectives.

Firstly, a choice has to be made from a variety of reservoir simulation computer programs. One class of models ("black oil" models) takes account of only two hydrocarbon components in the liquid phase (oil plus its dissolved solution gas) and one in the vapour phase (the free gas). This type of model is quite adequate for the development and planning of many reservoirs. For other reservoirs, however (for example those containing very light oil), a more sophisticated compositional model may be required, which takes into account the individual hydrocarbon components in the liquid and vapour phases.

Secondly, a decision has to be taken on the size of the model in relation to the amount of detailed information available and the objectives of the study. This choice also depends on whether the entire field, a single well or a representative symmetry element is being modelled.

Various techniques have been (and are being) developed to facilitate the preparation of data input and the display of output for reservoir simulation studies. For instance, to improve understanding of the reservoir processes Shell companies have developed a dynamic colour display technique, which allows the distribution in the reservoir of oil, water and gas (as well as the pressure and

temperature distributions) to be displayed on a video screen. This approach is a valuable aid in optimising oil recovery, in diagnosing and checking simulator performance and in presenting final study results.

A thorough analysis of past reservoir performance is then made. The amount and quality of these data can differ considerably between individual reservoirs. For example, for a recently discovered North Sea reservoir only limited data may be available from a few appraisal and early production wells but fortunately these data are usually of high quality. Production data may cover only a short period (say one year) and relate to only a small fraction of the oil initially in place. On the other hand, there may be an abundance of data (partly contradictory and partly of doubtful quality) for a large reservoir that has been producing for a number of years. These data on past reservoir performance may concern pressures and individual well production rates (including gas/oil and water/oil ratio trends).

Calculations are then made to compare "current" and "initial" fluids in place with cumulative production, with the objective of estimating the possible amount of water that may have entered the reservoir. These calculations also indicate the relative importance of the various reservoir mechanisms (water drive, solution gas drive, gas cap expansion).

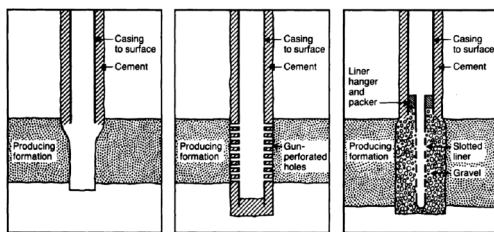
In all these calculations, mini-computers are of vital importance. These mini-computers are equipped with peripherals (printers, plotters, visual display screens, hard copy units) and are linked with data base management systems on large computers. In this way adequate analysis, processing and display of reservoir data, both for study and reporting purposes, is assured.

Production Technology — Engineering and Chemistry

This branch of petroleum engineering is concerned with the design and layout of downhole equipment for production wells and the treatment of the formation around the borehole. Usually the production engineer deals with the mechanical aspects of such designs while the production chemist looks after the chemical aspects. The latter will also be involved with the chemical aspects of the drilling of wells (e.g. drilling fluids) and of oil and gas handling (e.g. dehydration).

Completion Methods

Should logging and testing indicate the presence of a potentially productive formation, the well must be completed in a manner which will permit the production of oil or gas. The walls of the hole must be supported against collapse. The entry into the well of fluids from formations other than the producing layer, and the flow of the oil from the producing layer into other formations via the well, must be prevented.

Figure 3.58
Bare-foot completionFigure 3.59
Perforated casing completionFigure 3.60
Gravel-packed completion

According to the nature of the producing formation, different completion methods are used, but a string of casing is always run and cemented, at least to the top of the producing layer.

When the producing layer is firm and not liable to cave in, the casing can be cemented immediately above it, leaving it unsupported. This method is sometimes used in wells producing from limestone formations and is called a "bare-foot completion" (Fig. 3.58). If the producing layer is not firm enough, as is usually the case, it must be supported by casing. Casing is necessary anyway when there are several producing layers and any of these is to be excluded from production.

The casing is run through the producing layer to the bottom and cemented, after which holes are shot through the casing opposite the producing layer (Fig. 3.59) by means of a "perforating gun". Most types of gun are lowered on a conductor cable into the hole and carry explosive charges that are electrically detonated. Small explosive charges are used, so shaped that the explosive force is focussed and intensified into a small-diameter jet which penetrates casing and cement.

In poorly consolidated sand formations, sand may be carried into the well with the oil and gas. This should be prevented, or at least kept to a minimum, to avoid plugging the well and to lessen wear of such items as pumps, valves and liners. The erosion of large quantities of sand can also cause caving of the overlying strata and damage to the casing. Various types of liner are used to prevent ingress of sand into the well (e.g. slotted pipe, wire-wrapped pipe and liners in which fine gravel is washed into place between the liner and the formation wall or casing to form a sand-excluding screen) (Fig. 3.60).

The sand can also be consolidated by means of special chemical products such

as epoxy resins, to bind the sand grains together without materially affecting the productivity of the well.

Marine Completion and Production

In general, the same methods used for completing and producing wells on land are used for wells in the open sea. This is particularly true for wells which can be completed with their wellheads above the water surface, which is possible where operations are handled from fixed platforms. However, with floating platforms, where wells are completed with their wellheads on the sea floor, the inaccessibility of the well control equipment in deep water beyond the reach of human divers requires the use of remote controls which can be operated either automatically or by surface-actuated underwater robots. (See *Offshore Oilfield Development*, p. 156).

Stimulation and Removal of Impairment

The formation immediately around the wellbore is a bottleneck in the production process. The flow of oil (or gas) from the producing formation converges towards a small hole (the wellbore) and the situation is much like a large crowd of people trying to go through a door. At this point therefore the formation is extremely sensitive to any form of impairment. Solids left behind by the drilling fluid or loose clay particles from within the formation may partly block the pores and severely reduce the well's production. Such impairment may sometimes be removed by squeezing acids and/or other chemicals into the formation.

Even if not impaired, many formations of low permeability need some form of stimulation to increase their production to an economically acceptable level. Stimulation is usually done by increasing the inflow area for the oil from the formation to the wellbore. Returning to the analogy of the crowd going through a small door, it is simply like increasing the size of the door. In limestone formations, which dissolve easily in acids, the formation is fractured open by pumping acids into it under high pressure. The acid etches away part of the walls of the fracture and conductive channels remain after the fracture has closed upon release of the pumping pressure. Through these channels the oil now flows towards the wellbore more easily.

Sandstone formations (which do not dissolve in acid) are fractured in a similar manner, but to prevent closure of the fracture, sand, sintered bauxite pellets or other material is mixed with the fracturing fluid. Due to the high pressures and large fluid volumes involved, the larger of these fracturing jobs require an equipment set-up which is very impressive indeed (Fig. 3.61).



Figure 3.61 Close-up view of some of the large amount of equipment required at the well-site for an hydraulic fracturing job. (Photo: NAM)

Production Modes

After a producing well has been completed (see Completion Methods, p. 112) the means must be provided to bring the oil to the surface. In most fields, the earlier wells will produce by natural flow, i.e. the oil will flow to the surface without assistance. At a later stage, as the reservoir pressure decreases, artificial lift such as gas lifting and, later, pumping may have to be employed. Some fields, especially those producing very viscous crudes, will require artificial lift immediately after completion. The three systems, natural flow, gas lifting and pumping, are described below.

The oil is usually brought to the surface via a string of pipe up to 7 inch (18 centimetres) diameter, called the "tubing", which is of smaller diameter than, and separate from, the casing. This tubing is run into the well and hung from the wellhead with the bottom just above the producing formation. The function of the tubing varies with the type of production method. In general, it forms a replaceable string that enables production methods or equipment to be changed at will, protects the casing from wear or corrosion, and enables the well to be filled with water or drilling fluid should it be necessary to "kill" the well to effect repairs.

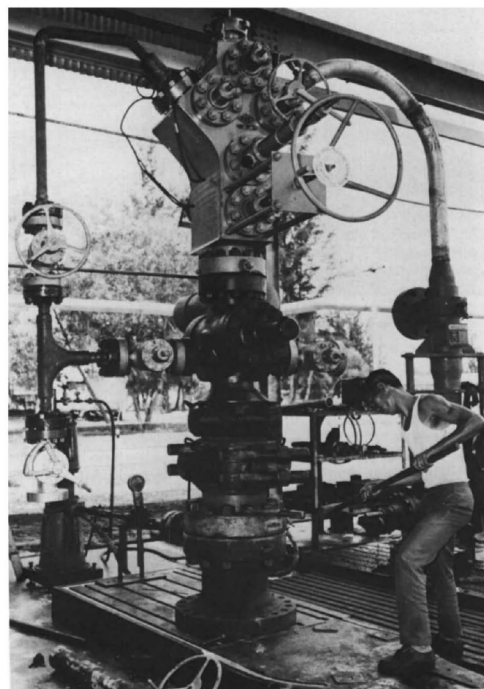


Figure 3.62 Christmas tree for offshore use being prepared onshore.

Natural Flow. With natural flow, the reservoir pressure forces the oil from the bottom of the well to the surface. The size of the tubing plays an important part in determining the pressure loss as the oil flows upwards through it, and consequently influences the production rate. Gas coming out of solution in the oil helps it to rise up the tubing. Too large a tubing diameter would allow much of this gas to bypass the oil without aiding its upward movement. Too small a diameter would result in too high a friction between fluid and tubing. There is thus an optimum size of tubing for any given conditions.

Offtake from the well is controlled at the surface by varying the size of a choke or "bean" through which the fluid passes. The assembly of valves and fittings at the wellhead, whereby flow can be diverted through alternative chokes or the well can be closed in, is known as the "Christmas tree" (Fig. 3.62).

Many flowing wells, particularly gas wells, have very high pressures at the surface, 10,000 psi (700 bars) or more, and adequate precautions must be taken against the well getting out of control. Equipment is provided which automatically shuts off production in the event of damage to or failure of the wellhead, automatic surface safety valves at the wellhead and, particularly for offshore operations, special valves installed in the well itself (subsurface safety valves).

An oilfield may contain more than one producing horizon, each with marked differences in pressure, specific gravity of oil, and other variables, and thus

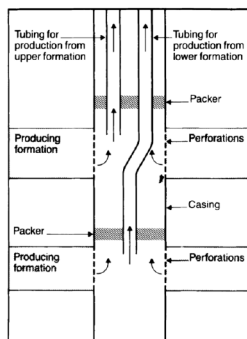


Figure 3.63 Diagram of dual completion

needing separate production. This may sometimes be done within the same well by means of a "dual" or "multiple" completion. A simple form of dual completion is shown in Figure 3.63. This type of completion is frequently much cheaper than the alternative of drilling separate wells to each layer or exploiting the layers consecutively within each well. However, flow rates are more limited, artificial lift is more complicated and costly, and repairs to any of the intervals are costlier and result in temporary loss of production from the other intervals. The overall economic picture is therefore not always as favourable as that indicated by the savings during the completion stage.

More oil is produced by natural flow than by all other methods combined; it is a high-capacity method which is both simple and cheap. However, its efficiency diminishes as the reservoir pressure and flow rate decrease, and eventually a stage will usually be reached when production can only be maintained by installing gas lift or a pump, as described below, or by a form of reservoir pressure maintenance such as water injection.

Gas Lift. Production by gas lift is, in effect, an extension of natural flow. The amount of gas produced with the oil is artificially increased by injecting gas into the flowing column, usually by means of special valves set at various depths and controlling the amount of gas entering the flow stream through ports in the tubing. This increase in gas/oil ratio reduces the pressure needed to lift the oil to the surface, delaying the necessity for the installation of pumping equipment.

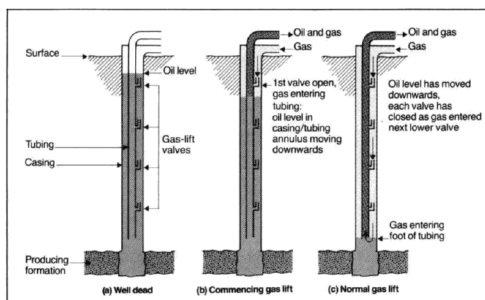


Figure 3.64 Operation of gas-lift valves

To commence injection at the foot of the tubing in a "dead" well partially filled with "dead" liquid (containing little or no gas), an initial injection pressure would be required substantially higher than that subsequently needed to maintain production. To avoid the need for a high-pressure gas supply solely for starting, gas-lift valves are often installed in the tubing at predetermined points when the tubing is run into the well (Fig. 3.64). These valves allow the gas to enter the tubing and to blow out the dead liquid at progressively lower points until the well starts to produce. Eventually all the gas enters the flowing column at or near the foot of the tubing, where it is used with the greatest efficiency.

A gas-lift installation often requires a large capital investment to provide a gas compression plant when high-pressure gas is not available from the wells, but it is relatively easy to maintain and operates at low costs per unit of production. Its chief application is where large production rates have to be handled and it may be the final lifting method in a well that produces large quantities of water in the later stages of its life.

Pumping. When the formation pressure diminishes to the point where insufficient liquid flows from the formation to the borehole, gas-lift gas starts to slip continuously through the fluid column to be lifted, and the process of gas lift becomes ineffective. It is then necessary to introduce an alternative form of artificial lift. The method normally adopted is pumping, of which three main types are available: beam or rod pumping, hydraulic pumping, and submersible electric pumping. The system chosen for use in a particular field depends on various operating factors, such as gas/liquid ratio, depth, sand, deviation, space, power and workshop availability.

The simple reciprocating plunger pump with surface power unit connected by “sucker rods” to the foot of the tubing is still the most widely used. The modern beam system comprises: prime mover, pumping unit, sucker-rod string, and subsurface pump. Figure 3.65 shows the layout of a conventional beam pumping installation.

The surface pumping unit (Fig. 3.66) changes the rotary motion of the power unit to an up-and-down motion of the "sucker rod" at the required speed. The size of power unit (usually an internal combustion engine or an electric motor) depends on the power necessary to lift the fluid to the surface. The weight of the sucker rods and the fluid being lifted is counterbalanced by an adjustable weight. The pump lifts the oil up the tubing while the casing forms a passage for the gas which would otherwise seriously interfere with the pumping of the oil.

Despite their superficial simplicity and wide acceptance, rod-operated plunger pumps are subject to certain disadvantages: alternate stretching and contracting of the sucker rods leads to a reduction in the length of the plunger stroke, a reduction which increases with the depth of the pump. Also rods sometimes break

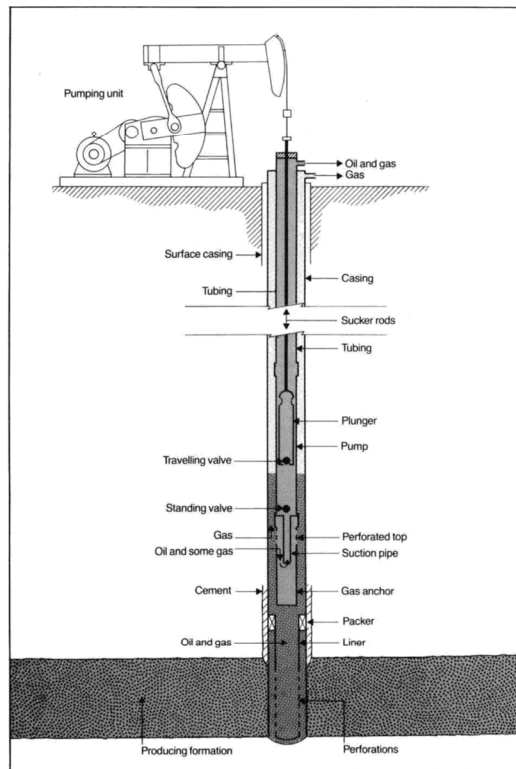


Figure 3.65 Diagram of pumping installation



Figure 3.66 Surface pumping units in the Schoonebeek oil field, the Netherlands. (Photo: NAM)

as a result of cyclical stresses and of wear caused by friction between the rods and the tubing.

Hydraulic pumps are similar to rod pumps in that they are also of the plunger type. However, there the similarity ceases. Power is transmitted from the surface pump to the reciprocating-type subsurface hydraulic engine/pump assembly by means of hydraulic fluid under high pressure (power fluid). The hydraulic control valve (also called the distribution or engine valve) directs the flow of power fluid alternately to each side of the working cylinder or engine. This is connected to the single or double acting production cylinder or pump by a rod and thus produced fluid is pumped to the surface. This fluid may be mixed with hydraulic fluid (the open system) or the hydraulic fluid may be returned by separate line (the closed

system). The ratio of engine to pump plunger size determines the efficiency of the pump.

The subsurface pump can either be installed at the bottom end of the tubing (fixed type) or may be pumped down through the tubing into a locking device at the end of the tubing (free type). In this latter type, reversing the flow of hydraulic fluid brings the pump back to surface. It is obvious that the free pump is attractive from the point of view of maintenance. However, the size of the fixed pump is not restricted by the size of the tubing and it can therefore handle larger volumes of liquid. A special type of hydraulic pump, the jet pump, operates without moving parts by converting pressure energy into kinetic energy through a nozzle.

One of the main disadvantages of the subsurface hydraulic engine is that it will not withstand sand or other abrasive materials in the power oil.

Submersible pumps are centrifugal pumps submerged in the well fluid and driven by an electric motor installed immediately below the pump. Power is transmitted to the motor via an electric cable clamped to the tubing.

The pump may be installed on the bottom of the tubing (tubing-suspended system) or run on the electric cable into a locking device in the bottom of the tubing (cable-suspended system). This latter method is applied in large capacity wells (up to 5,000 barrels a day) and is well suited for use in crooked holes. However, the electric cable is a disadvantage in running and pulling the pump and is a possible source of failure. Moreover, this type of pump is sensitive to solids in the produced fluid and shutdowns resulting from power cuts or fluctuations. Among the advantages of this type of pump is the fact that the power supply to the pump can be easily varied, and along with it the pump's throughput, over a wider range than is possible with other types of pump.

ENGINEERING, DRILLING AND PRODUCTION OPERATIONS

Drilling

Historical

The technique of well drilling goes far back into history. It is first mentioned in ancient Chinese manuscripts, which describe wells drilled as early as the third century AD to tap underground strata for brine (Fig. 3.67). The wells were drilled with a heavy "bit", which hung from a rope and was jerked up and down by relays of men bouncing on a spring board. The weight of the periodically rising and falling bit drove it deeper and deeper into the ground. This method was the precursor of the "cable tool" method, a percussion system used in oil well drilling in the 19th century and predominantly in the first two decades of the 20th.