CHAPTER 1

Introduction

The Origins, Migration and Trapping of Petroleum and Exploring For It

The origin of petroleum

During certain geologic ages, when the climate was suitable, petroleum began as organic material derived from plants and animals which grew in abundance. As these organisms went through their cycles of growing and dying, buried organic material slowly decayed and became our present-day fossil fuels: oil, gas, coal and bitumen. Oil, gas and bitumen were dispersed in the sediments (usually clay-rich shales). Over millions of years, these organic-laden shales expelled their oil and gas under tremendous pressures from the overburden. The oil and gas migrated into permeable strata below or above them, then migrated further into traps that we now call *reservoirs*. It's interesting to note that the word "petroleum" is derived from the Latin words for "rock" (*petra*) and "oil" (*oleum*), indicating that its origins lie within the rocks that make up the earth's crust.

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These ancient petroleum hydrocarbons are complex mixtures and exist in a range of physical forms — gas mixtures, oils ranging from thin to viscous, semi-solids and solids. Gases may be found alone or mixed with the oils. Liquids (oils) range in color from clear to black. The semi-solid hydrocarbons are sticky and black (tars). The solid forms are usually mined as coal, tar sand or natural asphalt such as gilsonite.

As the name "hydrocarbon" implies, petroleum is comprised of carbon atoms and hydrogen atoms bonded together; the carbon has four bonds and the hydrogen has one. The simplest hydrocarbon is methane gas (CH_4). The more complex hydrocarbons have intricate structures, consisting of multiple carbon-hydrogen *rings* with carbon-hydrogen side chains. There are often traces of sulfur, nitrogen and other elements in the structure of the heavier hydrocarbons.

The migration and trapping of petroleum

Sedimentary rocks. Oil is seldom found in commercial amounts in the source rock where it was formed. Rather, it will be found nearby, in reservoir rock. These are normally "sedimentary" rocks — layered rock bodies formed in ancient, shallow seas by silt and sand from rivers. Sandstone is the most common of the sedimentary rock types. Between the sand grains that make up a sandstone rock body there is space originally filled with seawater. When pores are interconnected, the rock is *permeable* and fluids can flow by gravity or pressure through the rock body. The seawater that once filled the pore space is partially displaced by oil and gas that was squeezed from the source rock into the sandstone. Some water remains in the pore space, coating the sand grains. This is called the reservoir's *connate water*. Oil and gas can migrate through the pores as long as enough gravity or pressure forces exist to move it or until the flow path is blocked. A blockage is referred to as a *trap*.

Carbonate rock, limestones (calcium carbonate) and dolomites (calcium-magnesium carbonate) are sedimentary rocks and are some of the most common petroleum reservoirs. Carbonate reservoirs were formed from ancient coral reefs and algae mounds that grew in ancient, shallow seas. Organic-rich source rocks were also in proximity to supply oil and gas to these reservoir rocks. Most limestone strata do not have a matrix that makes them permeable enough for oil and gas to migrate through them. However, many limestone reservoirs contain fracture systems and/or interconnecting vugs (cavities formed when acidic water dissolved some of the carbonate). These fractures and vugs, created after deposition, provide the porosity and permeability essential for oil to migrate and be trapped. Another carbonate rock, dolomite, exhibits matrix permeability that allows fluid migration and entrapment. Dolomites also can have fracture and vugular porosity, making dolomite structures attractive candidates for oil deposits.

...oil and gas accumulate... in traps...

Salt domes. A significant portion of oil and gas production is associated with salt domes which are predominately classified as *piercement-type* salt intrusions and often mushroom shaped. Piercement-type domes were formed by the plastic movement of salt rising upward through more dense sediments by buoyant forces resulting from the difference in density. The surrounding strata (sand, shale and carbonate) is deformed by this upward

Structural Traps

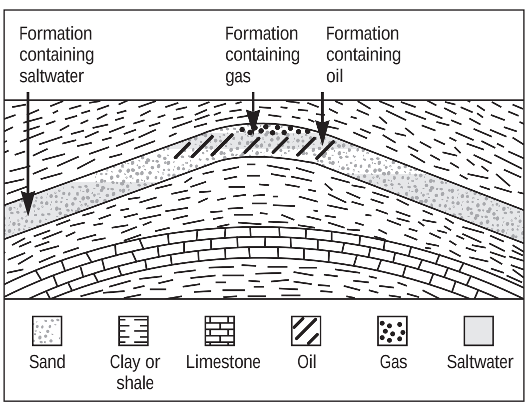


Figure 1a: Anticlinal trap.

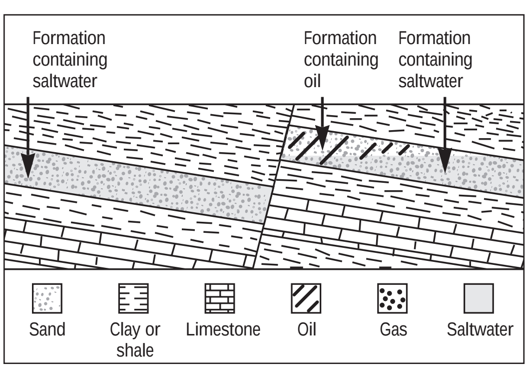


Figure 1b: Fault trap.

intrusion of salt forming stratigraphic and structural traps (see Figure 2c). These traps are formed around the flanks and under the overhang of salt domes in the sandstone layers that were faulted and folded by the movement of the salt. Being impermeable to oil and gas, salt forms an excellent barrier for the accumulation of hydrocarbons.

Salt layers. Major oil and gas reservoirs have been found in recent years beneath horizontal salt beds. Until recently, it was a mystery what was beneath these extruded salt layers called salt sills, salt sheets and salt lenses. They could not be explored economically by drilling, and seismic interpretation through plastic salt was unreliable. Now, “sub-salt” formations can be evaluated through modern three-dimensional seismic analysis to identify potential reservoirs. Once likely formations are located, wells are drilled through the salt layer to determine if oil and gas deposits exist.

Traps. Oil, gas and water slowly migrate through permeable rocks, driven by natural forces of gravity (buoyancy) and pressure gradients. When they meet an impermeable barrier, they can go no farther, so oil and gas accumulate. This barrier is generally referred to as a *trap*. Varying densities make the gas phase rise, while the water settles to the lowest point, and the oil remains in the middle. Traps are categorized as *structural* or *stratigraphic*.

Structural traps result from a local deformation such as folding and/or faulting of the rock layers. Examples of structural barriers are anticline traps, fault traps and traps associated with salt domes (see Figures 1a, 1b and 2c).

Stratigraphic traps are formed by geological processes other than structural deformation and relate to variations in rock properties (lithology). The remains of an ancient limestone or dolomite coral reef buried by impervious sediments is an example. An ancient, Stratigraphic Traps

...determining the likelihood of oil and gas in the trapped region...

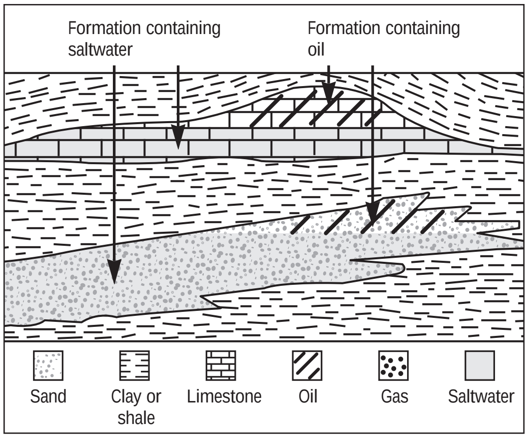


Figure 2a: Stratigraphic trap. Organic reef embedded in shale and wedging out sand.

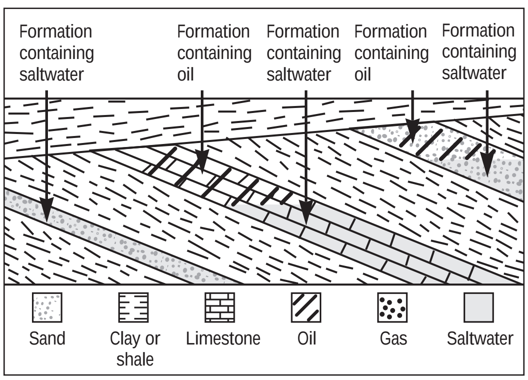


Figure 2b: Unconformity trap.

sand-filled river bed that has been silted out by clay is another type of stratigraphic trap. Sedimentary layers may change laterally in lithology or may die out and reappear elsewhere as a different rock type. Such changes can cause a lateral decrease in porosity and permeability, creating a trap (see Figure 2a). Another type of stratigraphic trap is an *unconformity*. Unconformities occur where a succession of rock strata, including the future oil reservoir, have been uplifted, tilted, eroded and are subsequently overlain by sediments which form an impermeable barrier. An unconformity represents a break in the geologic time scale (see Figure 2b).

Exploring for petroleum

Locating petroleum: Knowing that petroleum traps exist is one thing, but pinpointing traps far below the

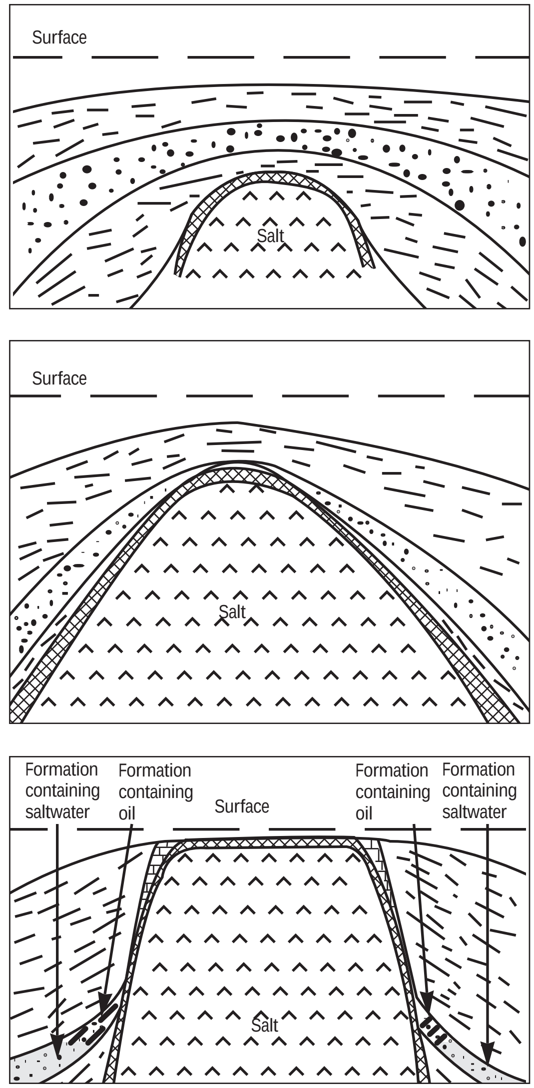


Figure 2c: Typical salt structure development (from Geology of Petroleum, *A. I. Levorson).*

earth's surface is quite another. Then determining the likelihood of oil and gas in the trapped region is yet another concern. Many methods have been used to locate petroleum traps, but the most important methods are aerial surveying, geological exploration, geophysical (seismic) exploration and exploratory drilling.

Aerial and satellite. Surveys from high altitudes give a broad picture of a geographic area of interest. Major surface structures such as anticlines and faulted regions can be clearly observed by these methods. This information

...seismic exploration in which shock waves...

helps locate areas where more detailed study is warranted. In the early years of petroleum exploration, visualization from an aircraft or mapping river and creek drainage patterns were successful surveying techniques. Modern aerial and satellite surveying is more sophisticated allowing a number of features to be evaluated, including thermal anomalies, density variations, mineral composition, oil seepage and many others.

Surface geological exploration. Observations by trained geologists of rock outcrops (where subsurface layers reach the surface), road cuts and canyon walls can identify lithology and assess the potential for hydrocarbon source rocks, reservoir-quality rocks and trapping mechanisms in an area under study. Much has been learned about ancient deposits from studying modern river deltas, for example. Detailed geologic maps, made from these observations, show the position and shape of the geologic features and provide descriptions of the physical characteristics and fossil content of the strata.

Geophysical exploration. Through the use of sensitive equipment and analytical techniques, geophysicists learn a great deal about the subsurface. Chief among these techniques is seismic exploration in which shock waves, generated at the surface and aimed downwards, are reflected back to the surface as echoes off the strata below. Because rocks of varying density and hardness reflect the shock waves at different rates of speed, the seismologist can determine depth, thickness and type of rock by precisely recording the variances in the time it takes the waves to arrive back at the surface. Modern 3-D seismic has improved the success rate of the exploration process, especially in areas beneath salt, as discussed above. Continual improvements in seismic measurement and the mathematical methods (algorithms) used to interpret the signals can now give a clearer "picture" of subsurface formations. Other geophysical methods use variations in the earth's gravity and magnetic properties to detect gross features of subsurface formations.

Drilling for Petroleum

Drilling methods

When it has been established that a petroleum reservoir probably exists, the only way to verify this is to drill. Drilling for natural resources is not a new idea. As early as 1100 A.D., brine wells as deep as 3,500 ft were drilled in China, using methods similar to cable tool drilling.

Cable tool drilling. This was the method used by pioneer wildcatters in the nineteenth and early twentieth centuries and is still used today for some shallow wells. The method employs a heavy steel drill stem with a bit at the bottom, suspended from a cable. The tool is lifted and dropped repeatedly. The falling steel mass above the bit provides energy to break up the rock, pounding a hole through it. The hole is kept empty, except for some water at the bottom. After drilling a few feet, the drill stem (with its bit) is pulled out and the cuttings are removed with a bailer (an open tube with a valve at the bottom). The cable tool method is simple, but it is effective only for shallow wells. Progress is slow because of the inefficiency of the bit and the need to pull the tools frequently to bail out cuttings.

Introduction

Rig Components

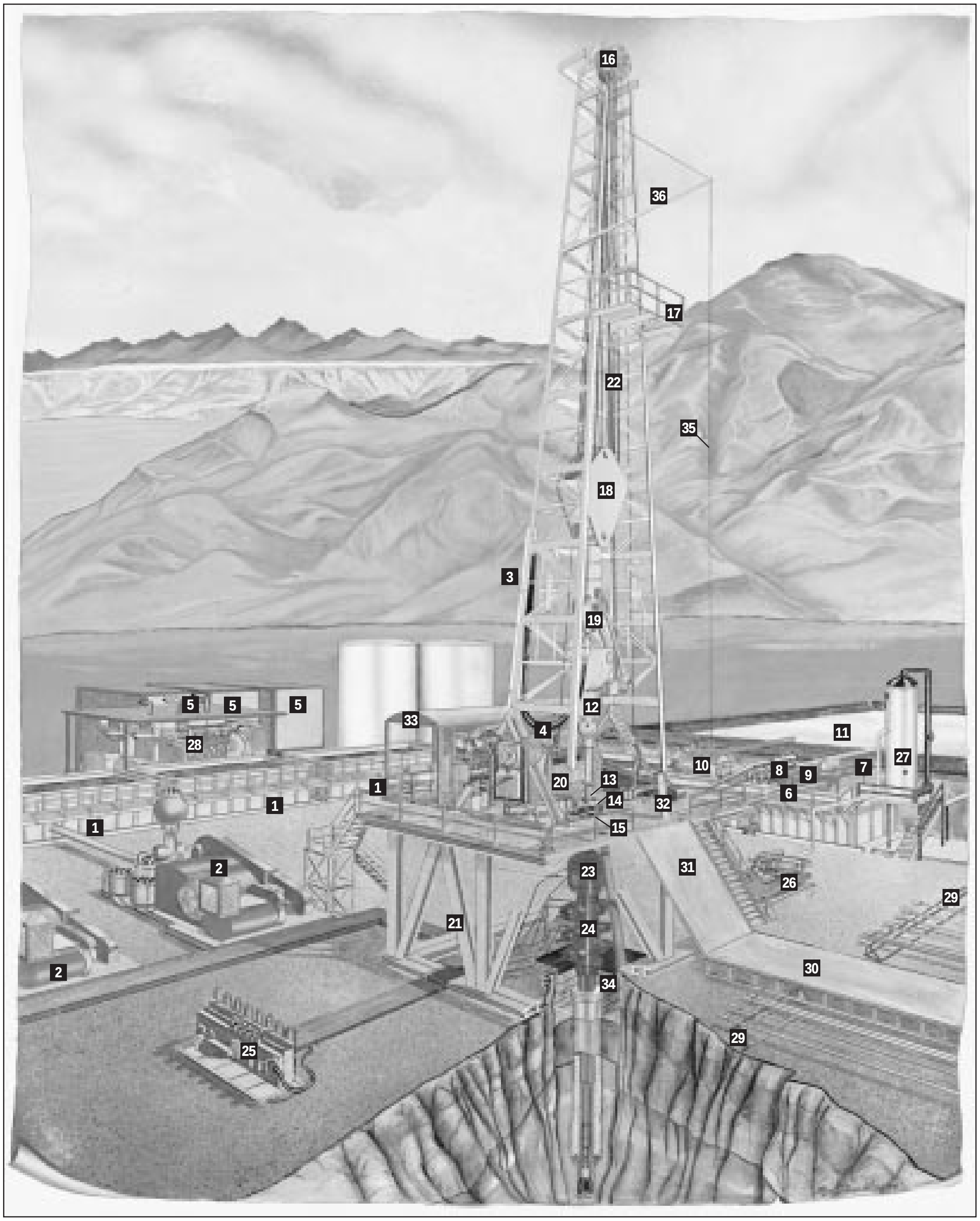


Figure 3: Diagrammatic view of rotary drilling rig (after Petex).

Circulating System
1. Mud pits
2. Mud pumps
3. Standpipe
4. Rotary hose
5. Bulk mud storage
6. Mud return line
7. Shale shaker
8. Desilter
9. Desander
10. Degasser
11. Reserve pits

Rotating Equipment
12. Swivel
13. Kelly
14. Kelly bushing
15. Rotary table

Hoisting System
16. Crown block
17. Monkeyboard
18. Traveling block
19. Hook
20. Drawworks
21. Substructure
22. Drilling line

Well-Control Equipment
23. Annular blowout preventer
24. Ram blowout preventers
25. Accumulator unit
26. Choke manifold
27. Mud-gas separator

Power System
28. Generators

Pipe and Pipe-Handling Equipment
29. Pipe racks
30. Catwalk
31. V-door
32. Rathole

Miscellaneous
33. Doghouse
34. Cellar
35. Hoisting line
36. Gin pole

Rotary drilling. Rotary rigs are used for a variety of purposes — drilling oil, gas, water, geothermal and petroleum-storage wells; mineral assay coring; and mining and construction projects. The most significant application, however, is oil and gas drilling. In the rotary method (introduced to oil and gas drilling in about 1900), the drill bit is suspended on the end of a tubular drillstring (drill stem) which is supported on a cable/pulley system held up by a derrick (see Figure 3). Drilling takes place when the drillstring and bit are rotated while the weight of the drill collars and bit bears down on the rock.

...keep the bit cool and lubricated, and to remove the rock cuttings...

To keep the bit cool and lubricated, and to remove the rock cuttings from the hole, drilling fluid (mud) is pumped down the inside of the drillstring. When it reaches the bit, it passes through nozzles in the bit, impacts the bottom of the hole and then moves upward in the annulus (the space between the drillstring and the wellbore wall) with the cuttings suspended in it. At the surface, the mud is filtered through screens and other devices that remove the cuttings, and is then pumped back into the hole. Drilling mud circulation brought efficiency to rotary drilling that was missing from cable tool drilling — the ability to remove cuttings from the hole without making a trip to the surface.

Equipment for rotary drilling is illustrated in Figure 3.

DRILL BITS

A good place to begin the description of rotary drilling equipment is where the action takes place — at the drill bit. As it rotates under the weight of the drillstring, the bit breaks up or scrapes away the rock beneath it. Early rotary bits were “drag bits” because they scraped at the rock. Because they resembled the tail of a fish, they earned the name “fishtail bits.” They were effective in drilling soft formations, but their blades wore out quickly in hard rock. An improved rotary bit was needed and in the early 1900s, the roller cone bit was introduced.

Roller cone (rock) bits. A roller cone bit — also known as a *rock bit* — has either two or three cone-shaped cutters that roll along as the bit is turned. The surface of the rolling cone has teeth that contact most of the hole bottom as the cones roll over the surface (see Figure 4a). These bits drill by fracturing hard rock and by gouging softer rock. There is also some scraping action because the cones’ axes are off-center compared to the center of rotation. Weight on the bit, rotational speed, rock hardness, differential pressure, and drilling fluid velocity and viscosity affect how fast bits drill. Nozzles in the bit’s body give the mud extra velocity, creating a jetting action as it exits through the bit. This contributes to faster drilling.

Rock bits are classified according to the types of bearings and teeth they have. Bearing types include (1) non-sealed roller bearings, (2) sealed roller bearings and (3) journal bearings. When referring to bits by the type of teeth they have, the terms: (1) *milled tooth* and (2) *Tungsten Carbide Insert* (TCI) are used. Bearing design is important to a bit’s service life; sealed bearings and journal bearings provide longer life than unsealed bearings, but they are more expensive. A rock bit’s teeth — their shape, size, number and placement — are important to drilling efficiency in different formations. Milled tooth bits have teeth that are machined from the same metal billet as the cone (see Figure 4c). In some cases the teeth have hard-facing applied for extra life. This type is designed for soft to medium formations where long teeth can gouge out the rock. The teeth on insert bits are actually tungsten carbide studs inserted into holes drilled into the cones (see Figure 4a). TCI bits drill by generating a crushing action, for harder and more abrasive formations. Some insert bits are enhanced with special inserts that feature a layer of polycrystalline diamond applied over the tungsten carbide. This gives them an even longer service life than tungsten carbide alone.

Diamond and PDC bits. Fixed-cutter bits with diamond cutting surfaces are used for drilling medium to hard formations, when extra-long bit life is needed or for special coring operations. Single-piece, fixed-cutter bits use either natural diamond chips or man-made diamond wafers as cutters. Natural diamond bits use industrial-grade, natural

Types of Bits

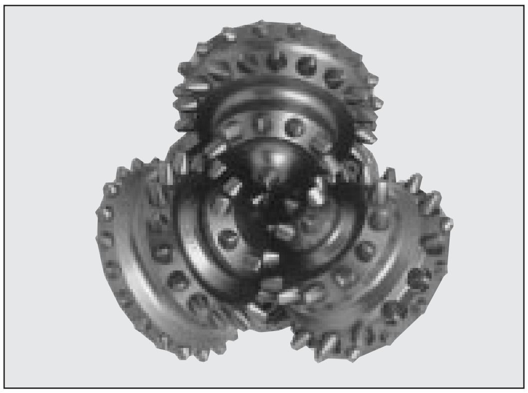
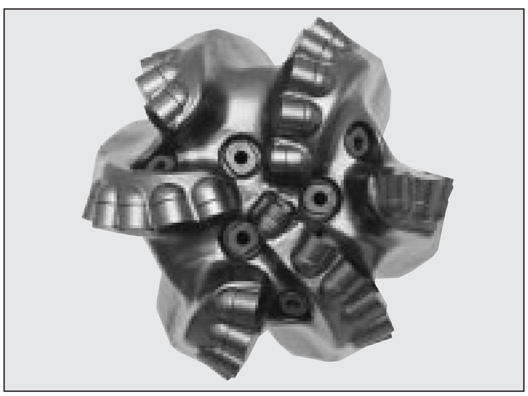


Figure 4a: Rock bit (TCI type).



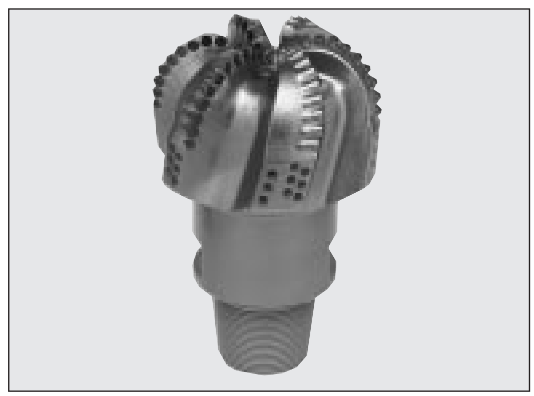


Figure 4b: PDC bit.

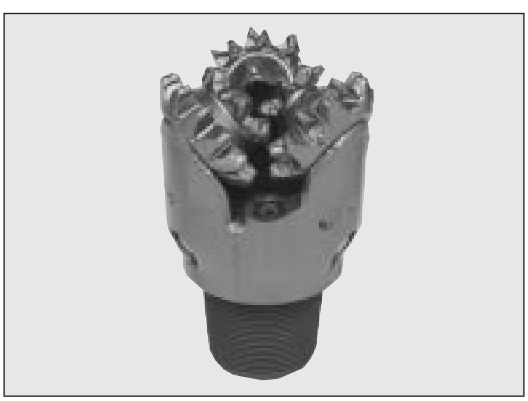


Figure 4c: Milled tooth rock bit.

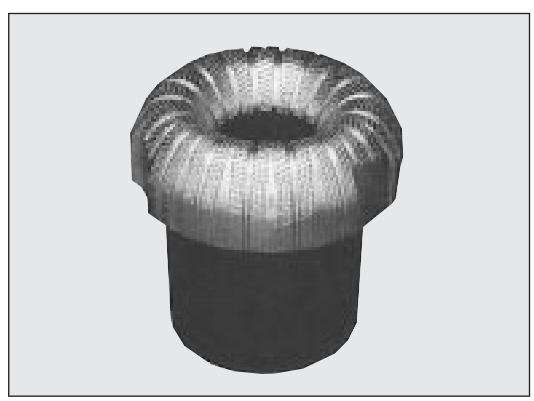


Figure 4d: Natural diamond core bit.

diamonds set in a steel matrix on the cutting area, as shown on the natural diamond core bit in Figure 4d. During rotation, the exposed natural diamonds drag and grind out the hole. Man-made diamond cutters, called *Polycrystalline Diamond Cutters* (PDC), are configured so that the cutters shear the rock beneath the bit producing large cuttings and high penetration rates (see Figure 4b). PDC bits are in demand for drilling in many types of rock, but especially for long sections of medium-hard formations. PDC bits are very durable and efficient offering higher penetration rates and long bit life. A variety of PDC bit designs are manufactured to optimize drilling particular formations. Typically PDC bits drill faster in shales than in sandstones and are used most often to drill long shale sections. Both types of diamond bits work in a manner similar to older style fishtail drag bits because they scrape the rock.

PDC bits are very durable and efficient…

THE DRILLSTRING

Starting at the bottom, a basic drillstring for rotary drilling consists of the (1) bit, (2) drill collars and Bottom-Hole Assemblies (BHAs), and (3) drill pipe (see Figure 5).

The BHA is located just above the bit and consists of drill collars combined with one or more bladed stabilizers (to keep the BHA and bit concentric), possibly a reamer (to keep the hole from becoming tapered as the bit diameter wears down) and other tools. MWD tools and mud motors are generally located low in the BHA, usually just above the bit. Sometimes, a set of "jars" is located near the top of the BHA. Jars can free stuck pipe by giving a hammering action when they are set-off by pulling hard.

Drill collars are thick-walled, heavy joints of pipe used in the BHA to provide weight to the bit. Usually, one of the collars is made of non-magnetic metal so that a magnetic compass tool (survey tool) can be used to determine the inclination of the lower BHA and bit without interference from magnetic metals.

Each joint of drill pipe is approximately 30 ft long, and has a box (female connection) welded onto one end and a pin (male connection) welded to the other. These threaded couplings (tool joints) must be strong, reliable, rugged and safe to use. They must be easy to make up (connect) and break out (disconnect). Outer diameters for drill pipe range from $2\frac{3}{8}$ to $6\frac{5}{8}$ in.

The hollow drillstring provides a means for continuous circulation and for pumping drilling mud under high pressure through the bit nozzles as a jet of fluid. The blast of mud knocks rock cuttings from under the bit, gives a new rock surface for the cutters to attack and starts the drill cuttings on their trip to the surface. This transmission of hydraulic horsepower from

Regardless of bit type, it must be rotated...

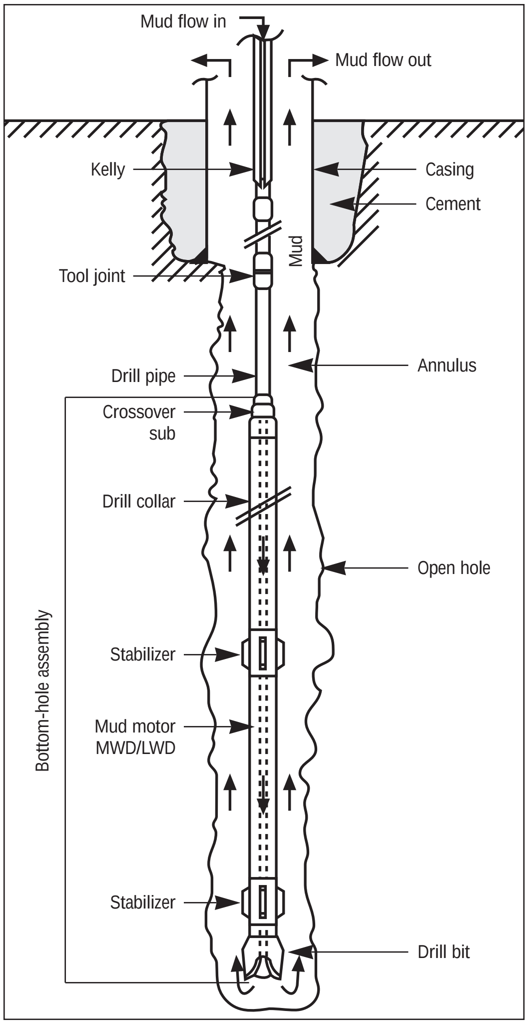


Figure 5: Drillstring components.

the mud pumps to the bit is a very important function of the mud.

Coiled-tubing drilling. This method employs a continuous string of coiled tubing and a specialized, coiled-tubing drilling rig. Rather than drilling with separate joints of the traditional, large-diameter, rigid drill pipe, the drillstring is smaller-diameter, flexible tubing. Unlike drill pipe which is screwed together to form the drillstring, and which must be disconnected into stands that are racked in the derrick during trips, the tubing comes rolled on a reel that unwinds as drilling progresses and is subsequently rewound onto its spool during trips. The coiled-tubing method greatly facilitates lowering and retrieving the drilling assembly.

Traditionally, coiled-tubing rigs have been used for workover and completion operations where mobility and compact size were important. With the development of downhole mud motors which do not require the use of a rotating drillstring to turn the bit, coiled-tubing units are now functioning as true drilling rigs.

Drill bit rotation

Regardless of bit type, it must be rotated in order to drill the rock. There are three methods used to turn the bit downhole:

1. The drillstring and bit are turned by a rotary table and kelly.
2. The drillstring and bit are rotated by a “top-drive” motor.
3. Only the bit is rotated by a hydraulic mud motor in the drillstring. (The drillstring can be held still or rotated while using a mud motor, as desired.)

Rotary table and kelly. A rotary table is a gear- and chain-driven turntable mounted into the rig floor that has a large open center for the bit and drillstring. The rotary table kelly bushing is a large, metal “donut” with a 4-, 6- or 8-sided hole at its center. This bushing can accept a special piece of 4-, 6- or 8-sided pipe, called the *kelly*. The kelly, which is about 40 ft long, is turned by the kelly bushing in the rotary table, just as a hex nut is turned by a wrench. The kelly is free to slide up and down in the kelly bushing so it can be raised while a 30-ft joint of drill pipe (the topmost joint in the drillstring) is attached to its bottom. The drill pipe is then lowered into the hole until the bit touches bottom, and the kelly can be rotated. The driller starts the rotary table, and as the bit drills down, the kelly moves down, too. When the top end of the kelly is level with the bushing (at rig floor level), the kelly is broken out from the drill pipe, raised while another joint is added, and the process of drilling down is repeated. In order for the drilling mud to get into

Higher bit RPM results in improved ROP...

the drillstring, a rotary hose and mud *swivel* are attached to the top of the kelly to supply mud from the mud pumps. The swivel is a hollow device that receives mud from the stand pipe and rotary hose and passes it through a rotating seal to the kelly and into the drillstring. One disadvantage of the kelly/rotary arrangement is that while pulling pipe with the kelly disconnected, no mud can be pumped and pipe rotation is minimal.

Top drive. A top-drive unit has important advantages over a kelly/ rotary drive. A top-drive unit rotates the drillstring with a large hydraulic motor mounted high in the derrick on a traveling mechanism. Rather than drilling one 30-ft joint before making a connection, top drives use 3-joint (90-ft) “stands” of drill pipe and greatly reduce the number of connections and the time to make a trip. One key advantage — the driller can simultaneously rotate the pipe while going up or down over a 90 ft distance in the hole and circulate mud. This allows long, tight spots to be quickly and easily reamed without sticking the pipe. Due to these advantages, top drive units are being installed on most deep rigs and offshore rigs.

Mud motor. While the first two rotation methods involve turning the drill pipe in order to turn the bit, this method is different. In this case, there is a hydraulic motor (turbine or positive-displacement mud motor) mounted in the BHA near the bit. During drilling, hydraulic energy from the mud passing through the motor turns the bit. This is achieved through the use of multiple rotor/stator elements inside the motor which rotate a shaft to which the bit is attached. This offers several advantages. Mud motors can achieve much higher bit rotational speeds than can be achieved by rotating the entire drillstring. Less energy is required to turn just the bit. The hole and casing stay in better condition, as does the drillstring, when only the bit (and not the pipe) rotates. Higher bit RPM results in improved Rate of Penetration (ROP), and vibration is less of a problem. Mud motors are used extensively for directional drilling where it is essential to keep an orienting tool positioned in the desired direction.

MWD AND LWD

In “the old days,” when a driller wanted to check the angle of a directional well, or when he wanted to log the well to obtain certain downhole or formation-related information, he was faced with only one course of action. He had to stop drilling and run special measurement or logging instruments down into the wellbore; sometimes this involved pulling the entire drillstring before measurement could proceed.

Introduction

Today, there are sophisticated electronic instruments that can perform Measurement While Drilling (MWD) and Logging While Drilling (LWD) functions while the drilling process continues uninterrupted. The measurements they perform are varied, and while they are important to the driller, there is another factor that is more important to mud engineers. That is the fact that both MWD and LWD instruments transmit their findings back to the surface by generating pulse waves in the drilling mud column inside the drillstring. For that reason, mud conditions (density, viscosity, gas entrainment, etc.) will be especially important on rigs that are running MWD and LWD instruments.

Derrick's hoisting system

Drilling rigs must have tremendous power to lift and suspend the weight of long drillstrings and casing strings. This hoisting system must have the capacity to overcome any resistance caused by tight spots in the hole and pull-on or "jar" stuck pipe. While the weight of the equipment is suspended from the top of the derrick, the lifting power comes from an engine or motor operating the drawworks. The drawworks controls a reel of wire cable which runs through a system of pulleys to reduce the mechanical requirements.

Here's an overview. A stationary block (crown block) is mounted at the top of the derrick, and a movable block (traveling block) is suspended by cable, also known as *wire rope*. One end of this wire rope, the *drum line,* is wound around the drum of the drawworks, and then it is passed between the sheaves of the crown block and sheaves of the traveling block several times. The dead end of the wire rope, *dead line,* is secured to the base of the derrick. This multi-sheave block and tackle system offers high mechanical advantage to the hoisting system.

On the bottom of the traveling block there is a large hook. During drilling, a rotary swivel hangs from the hook on a bail. The swivel provides a rotating pressure seal so that mud can flow under pressure down the kelly and into the drillstring. The hook also suspends the drillstring, which is being turned by the kelly.

Drawworks and tongs. While tripping, the swivel (with the kelly attached) is set aside. Devices called *elevators* hang on the hook to hoist the drillstring out of the hole. When making a trip, three-joint stands (about 90 ft of drill pipe) are pulled. While a stand is being unscrewed and placed back into the derrick, the rest of the drillstring weight is supported from the rotary table by pipe slips that grip the pipe below the tool joint. Tool joints are made up tight or broken-out using pipe tongs (large pipe wrenches). A spinning chain is used to rotate the joints together rapidly. A mechanical cathead is the device that pulls the spinning chain and pulls the pipe tongs. The friction cathead, with a rope around it, allows the rig crew to perform various tasks, such as light pulling and hoisting. The friction cathead and mechanical cathead operate off the cat shaft.

The drawworks has in it a large drum hoist used to wrap and pull the wire rope (drilling line), as mentioned earlier. On the drum is the main brake, which has the ability to quickly stop and hold the weight of the drillstring. When heavy loads are being lowered, the main brake is assisted by a hydraulic or electric auxiliary brake, or *retarder,* to absorb the great amount of energy developed by the mass of the traveling block, hook assembly and drillstring.

...the driller controls the brake, catheads...

The mud then travels down the drillstring to the bit.

Driller's console. Located next to the drawworks is the driller's control console. From this vantage point, the driller controls the brake, catheads, rotary table (or top drive), the rate at which the drillstring is pulled or lowered, mud pump speed, and other important functions.

MUD CIRCULATION AND SOLIDS REMOVAL

A logical place to begin the discussion of a mud circulation system is at the mud pumps (see Figure 6). These pumps and the engines that power them, represent the "heart" of the mud system just as the circulating mud is the lifeblood of the drilling operation. Mud pumps are positive-displacement piston pumps, some of which produce up to 5,000 psi. They are powered by diesel engines or electric motors. To produce the required pressure and flow rate for a specific set of drilling conditions, the correct piston and liner sizes must be selected for the pumps and the right nozzle sizes must be specified for the bit. This is called *hydraulics optimization*, and it's a key factor in efficient drilling.

After exiting the mud pump at high pressure, the drilling fluid travels up the *standpipe*, a long, vertical pipe attached to the derrick leg, then through the kelly hose (rotary hose), through the swivel and down the kelly. The mud then travels down the drillstring to the bit. A bit will usually have two or more nozzles (jets) which accelerate the mud to a high velocity. This jet of mud scours the bottom of the hole to keep the bit cutters clean and keep a fresh rock surface for the bit to attack. From the hole bottom, the mud moves upward in the annular space between the drillstring and the wellbore, carrying the cuttings generated by the bit.

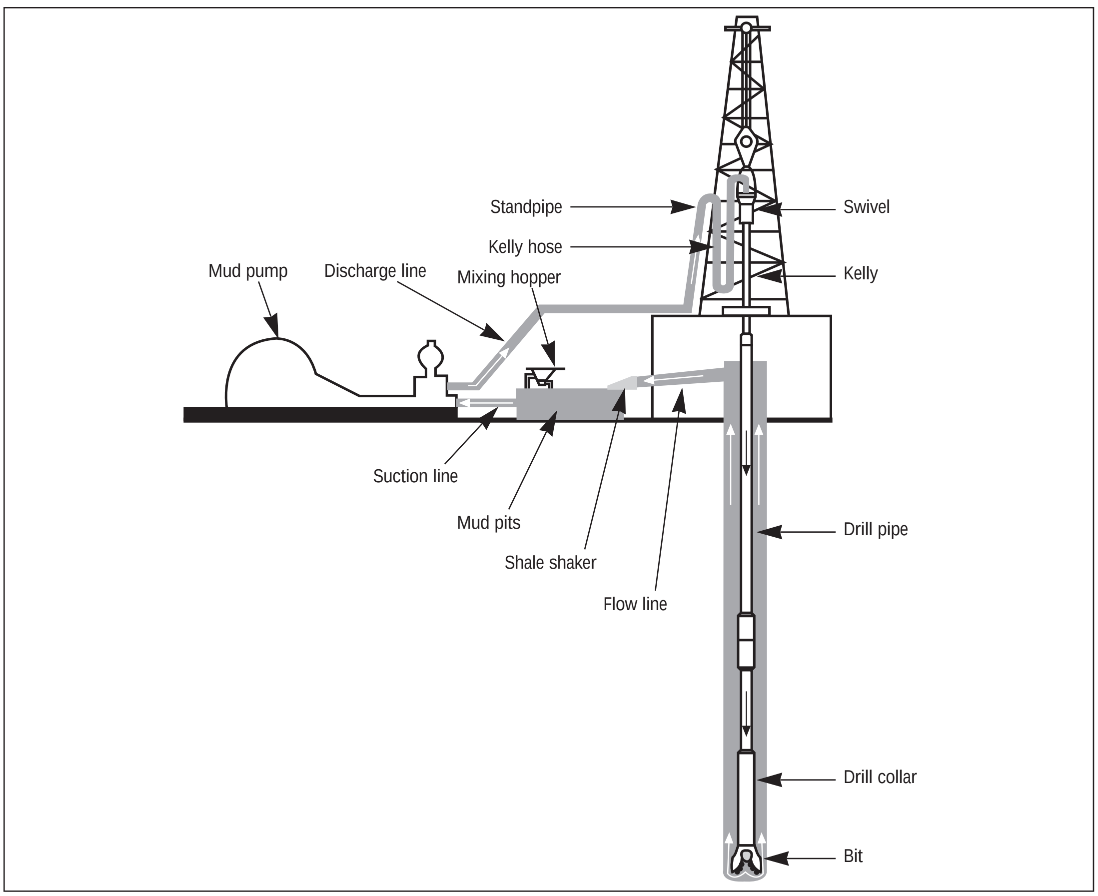


Figure 6: Mud circulating system.

The mud and its load of cuttings flow out of the "bell nipple" and through a large-diameter, sloping pipe (flow line) onto one or more vibrating wire-mesh screens mounted on the *shale shaker*. The idea is that the mud falls through the screens and most of the cuttings (which are bigger than the screen's mesh) are separated from the circulating system. When the mud falls through the screen, it drops into a settling pit. These pits are large, rectangular, metal tanks with pipe or troughs connecting them. The settling pit is not stirred so that any remaining larger solids can settle out of the mud. From the settling pit, the mud moves into stirred mud pits downstream where gas, sand and silt are removed. After that, the mud moves to the suction pit where the pumps pull it out for recirculation downhole. The suction pit is also used for the addition of treating chemicals and mud conditioning additives. A mud hopper with a venturi is used in this pit for adding dry additives such as clays and weighting agents.

Blowout preventers

A drilling mud should have sufficient density (mud weight) to prevent (hydrostatically) any gas, oil or saltwater from entering the wellbore uncontrolled. Sometimes however, these formation fluids do enter the wellbore under great pressure. When this happens, a well is said to "take a kick." It is especially risky if the fluid is a gas or oil.

To guard against the dangers of such events, rigs are usually equipped with a stack of Blowout Preventers (BOPs). Depending on the well depth and other circumstances, there will be several BOP units bolted together and then to the surface casing flange. One or more of these BOPs can be engaged to seal off the wellbore if a kick occurs. Multiple BOPs in the stack provide flexibility and redundancy in case of a failure.

At the top of the BOP stack is a bag-type preventer commonly referred to as a *Hydril*™. This unit contains a steel-ribbed, elastomeric insert which can be expanded hydraulically to seal the annulus. Below the bag preventers are the ram-type preventers with hydraulically driven rams that close against the pipe or against themselves, thrusting in from opposite sides of the pipe. These preventers can be pipe, blind or shear rams. Pipe rams have heads with a concave shape to grip the pipe and form a seal around it; they accomplish the same function as the bag preventer but are rated at higher pressure. Blind rams come together over the hole to form a fluid-tight seal against one another in the event the pipe is not in the well or if it has parted and fallen down into the wellbore. Shear rams sever the pipe before sealing together.

Below the blowout preventers is the drilling spool. It has an opening in its side to allow drilling mud and the kick fluids to be pumped out. A high-pressure choke line connects to the spool with a special back-pressure valve (the choke) in the line. During well-control procedures, the choke is used to hold back-pressure on the annulus while heavier mud is pumped down the drillstring to kill the kick. If the invading fluid contains gas, the gas must be removed from the mud exiting the well. Gas-cut mud from the choke is sent to a mud-gas separator vessel. The gas is flared and the mud is returned to the pits for reconditioning.

Casing and liner

When a well is being drilled, exposed formations must be periodically covered and protected by steel pipe. This is done for several reasons — to keep the hole from caving in, to protect the formations being drilled and/or to isolate different geological zones from each other. These protective pipes are called *casings* and *liners*. *Casing* refers to pipe

Several methods are used to identify geological strata...

that starts at the surface or mud line and extends down into the borehole. The term *liner* applies to pipe whose upper end does not reach the surface or mud line but is inside and overlaps the bottom of the last casing or liner. Casing and liners are either totally or partially cemented in place.

Casing. Two, three or more casing strings may be run in a well, with the smaller pipe being run inside the larger sizes, and the smaller ones going deeper than the larger. The “surface casing” is run and cemented at a depth to protect freshwater aquifers and to avoid mud seepage into shallow sand and gravel beds; it might be set at about 2,000 ft. The next string is the “intermediate” casing. It is run and cemented when there’s a need to change the mud to a density that can’t be tolerated by the exposed formations or by the surface casing. Below the intermediate casing may be another string of casing or a liner.

Liners. It may not be necessary, economical or practical to line the entire, already-cased hole all the way to the surface just to protect the lower open hole. This is especially true as the hole nears total depth and becomes smaller. So a liner is run from the bottom of the hole, up into the casing, overlapping it by several hundred feet. Liners are held in place inside the casing by special tools called *liner hangers*. The practice of running a liner protects the last open hole interval, which often includes the reservoir section.

Cementing

After a string of casing or a liner has been properly landed in the hole, a cement slurry is mixed and quickly pumped down the inside of the casing (or liner). Pressure drives it out the bottom and up into the annular space between the pipe and the hole wall. Cement is followed downhole by just enough fluid to push all but the last part of it out of the casing or liner. Once all the cement hardens, that small quantity still inside the casing or liner is drilled out and the hole proceeds into a few feet of new rock beyond the end of the casing. Then the casing or liner is pressure-tested to see how much mud weight it will be able to hold, for future reference. If it fails the test, a remedial cement job (squeeze) may be required. Once the cement job passes the pressure test, drilling can resume.

Mud logging

Several methods are used during the drilling of a well to identify geological strata by age and type, and to look for signs of oil and gas. Mud logging is one of these methods. It involves examination of the cuttings for lithology and fluorescence as evidence of oil called *shows*. By analyzing the gases in the mud returning from downhole, the presence of hydrocarbons is determined. Depth, ROP and other parameters are correlated with oil shows and lithologic changes.

Coring and core analysis

A valuable reservoir evaluation method is core analysis. A core is a piece of the actual rock taken from the reservoir under study. Cylindrical pieces of rock (cores) several feet long can be obtained by drilling with a special coring bit attached to a core barrel. The bit cuts only the outer circumference of the formation, and the cylinder of rock that remains is captured inside the core barrel. Small sidewall cores can be obtained with wireline logging equipment after a zone is drilled. Cores are examined to some extent on the rig by a geologist, but they are usually sent to a core analysis laboratory for full evaluation. Labs can directly measure porosity, permeability, clay content, lithology, oil shows and other valuable formation parameters. Coring is expensive and is used only when necessary to have the best, direct data about the formation.

DRILL-STEM AND FORMATION-INTERVAL TESTING

Drill-Stem Testing (DST) and Formation-Interval Testing (FIT) are two similar methods used to measure directly the production potential of a formation, to capture samples of the fluids from the zone tested, and to obtain pressure and temperature data.

A DST is a temporary completion through the drill pipe, using a retrievable packer/tester at the bottom of the string. The packer is set to seal off the annulus, and the tester tool is opened to allow flow from the open zone. Then the tester is closed, the packer is unseated and the drillstring is pulled out of the hole. A sample of fluid is captured. Instruments contained in the tool record the pressure and temperature.

An FIT is run into the hole on a wireline rather than the drillstring. The tool seats itself against the side of the hole. A fluid sample is taken, and pressure and temperature are measured. The FIT is then pulled out of the well to capture the sample under pressure. The sample can be transferred, under pressure, to another container for shipment to a laboratory for fluid analysis.

WIRELINE LOGGING

The most widely used method of formation evaluation is wireline logging. Specialized tools run into the wellbore measure the electrical, acoustical and/or radioactive properties of the formations. An electrical cable connects the tool to a recording unit on the surface where the signals from the tool are amplified and recorded or digitized for computerized analysis. Logs can be used to locate and identify formations in the well and for geological correlations with nearby wells. Various logs can indicate lithology, porosity, permeability, fluid type (oil, gas, freshwater, saltwater), fluid contacts and, to some extent, where to find the best part of the reservoir. Logs measure downhole pressures, temperatures and the hole size. Logs also check casing wear and the integrity of the cement bond behind the casing.

...[Logs] measure the electrical, acoustical and/or radioactive properties of the formations.

DIRECTIONAL DRILLING

Until recently, most wells were drilled vertically, but more and more, situations today require an increasing number of wells to be drilled at high angles or even horizontally (90° from vertical). In addition to high angles, radical changes in direction (azimuth) can now be made up to 180°. There are many and varied reasons for doing this, but most of them are economic, environmental and/or technical. Deviated wells can access more of the reservoir than would be reached if holes were simply drilled vertically. Horizontal drainholes have become a technical success and are steadily increasing in number. In one application, the directional wellbore intersects several adjacent, but isolated and discrete, vertical fractures with a single drainhole (as in the Austin Chalk). In another, the directional well exposes a longer producing section such as in a thin or lens-type reservoir.

Due to the enormous expense of offshore drilling, one platform usually serves as the “launch pad” for several, highly deviated, long-reach wells to cover most or all of a big reservoir. These wells constitute an extended-reach drilling project such as is common in the North Sea, Gulf of Mexico and other areas. In some cases, the deviated hole may have changes in azimuth direction and inclination, resulting in an S- or U-shaped configuration.

Producing Petroleum

WELL COMPLETION

The next step, after setting casings and liners, is the completion phase of a well. Completion simply means making the well ready to produce oil and gas under controlled pressures and flow rates. Figure 7 shows the four common completion techniques. In all four, the casing prevents the formations above the producing zone from collapsing into the wellbore. If the producing formation is strong enough, as in the case of limestone, a length of casing can be cemented immediately above it, leaving the producing formation unsupported. This is called an *open hole completion*. If the reservoir rock needs support, other methods can be used:

...casing prevents the formations from collapsing...

Perforated casing or liner. In this method, casing or liner is run all the way through the producing zone and cemented in place. Then, holes are shot (by explosive charge) through the casing and cement, into the formation. These perforations are created with a perforating gun that is lowered into the hole on a wireline. The gun is then fired electrically, and powerful, shaped charges perforate the pipe and the zone at predetermined intervals. Once the perforations have been made, oil and/or gas can flow into the casing.

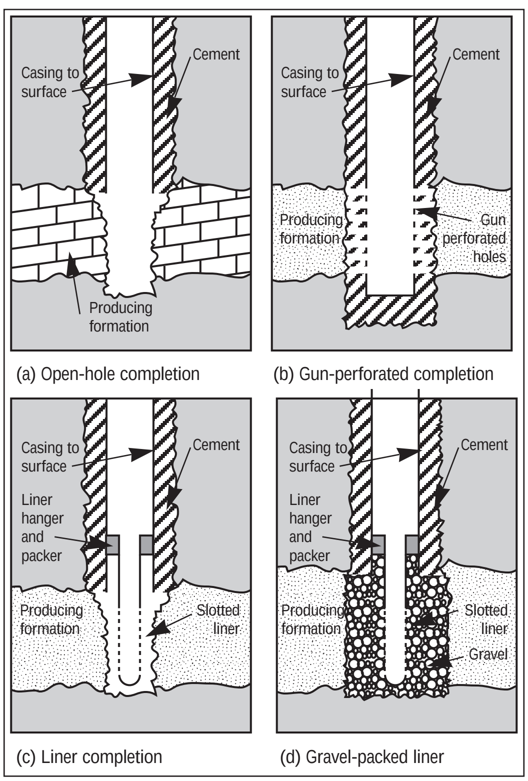


Figure 7: Bottom-hole arrangement of some types of completions.

Perforated or slotted liner. In the second method, a pre-perforated or slotted liner (with holes or slots that are level with the producing zone) is hung from the bottom of the last string of casing. If the producing formation is weak or poorly consolidated, sand and other solids will be carried into the well as the oil or gas is produced. To prevent this "sand production," the slotted or perforated liner may contain a wire-wrapped or a pre-packed-gravel protective layer to keep the sand from entering the wellbore.

Gravel packing. Another approach that is helpful if the producing formation is weak (such as loose sand), and must be supported or held back, is the conventional *gravel pack*. A gravel-packing operation consists of circulating and placing carefully sized gravel into the annular space between the liner and the wellbore wall. The pack forms a permeable layer to exclude any formation particles from the wellbore that become loose during production.

PRODUCTION TUBING

A string of pipe (tubing) through which oil and gas are produced is a production string. It is hung inside the casing or liner. Tubing sizes range between ¾ and 4½ in. in diameter, with the most common sizes being 2⅜, 2⅞ and 3½ in. Because of its relatively high ratio of wall thickness to diameter, tubing can withstand much more pressure than the

Pumping is an economical method of lifting oil...

casing, permitting high-pressure reservoirs to be safely controlled and produced. In a high-pressure completion, the casing/tubing annulus is sealed off near the bottom with a tubing packer. (A packer is a sealing device which can expand to seal an annular space between two concentric pipes.)

With a packer set and sealed, oil and gas flow into the cased hole below the packer then into the tubing and up to the surface where pressure and rate are controlled by surface valves and chokes. If a well produces from two or more zones, a multiple-zone packer must be used to accommodate production from different zones flowing into a single tubing string. Another alternative is to complete the well with multiple tubing strings and use multiple packers to direct oil and gas production from each zone into separate tubing strings.

A stable, non-corrosive packer fluid is left static in the annular space above the packer and surrounding the tubing. This fluid will be left in place for years. Packer fluids are needed to help balance pressure and mechanical forces on the casing, tubing and packer.

PRODUCTION EQUIPMENT

Once the well has been completed, it is ready to be put on-line and start producing. At the surface, a variety of equipment comes into play at this stage. This equipment will vary from well to well and will change as a given well becomes depleted. A fundamental consideration is whether the reservoir has enough internal pressure to flow naturally or whether it must be assisted.

If the well flows without assistance, then only a wellhead will be required. The wellhead (Christmas tree) is a series of flow-control valves, chokes and gauges mounted on spools. From the Christmas tree, the oil and gas move to a separator, perhaps a heater/treater to break any emulsion and prepare the oil for transfer to a storage tank or oil pipeline, and prepare the gas for a pipeline. Gas may have to be compressed before being put into a pipeline.

PUMPING METHODS

If reservoir pressure is too low to force the oil, gas and water to the surface, some type of artificial lift is needed. Pumping is an economical method of lifting oil to the surface. The pump itself is located downhole, below the level of standing oil. A reciprocating-type (plunger) pump lifts oil on the upstroke and refills the pump on the downstroke. A sucker rod from the pump up to the surface is connected to a pump jack.

Downhole electrical pumps are another commonly used method for getting oil and water to the surface. They are placed downhole and are powered by electricity supplied by a cable.

Another common method for lifting oil is gas-assisted lift or simply *gas lift*. This method uses gas (from the same well or another source) injected into the oil column downhole to lift the fluids. Gas is injected under pressure into the casing/tubing annulus through a series of gas-lift valves. Fluids (oil and water) that are above the gas-inlet port are displaced upwards, becoming less dense as they rise to the surface because of the gas that's been injected into them. Gas, oil and water can be lifted this way until it is no longer economical.