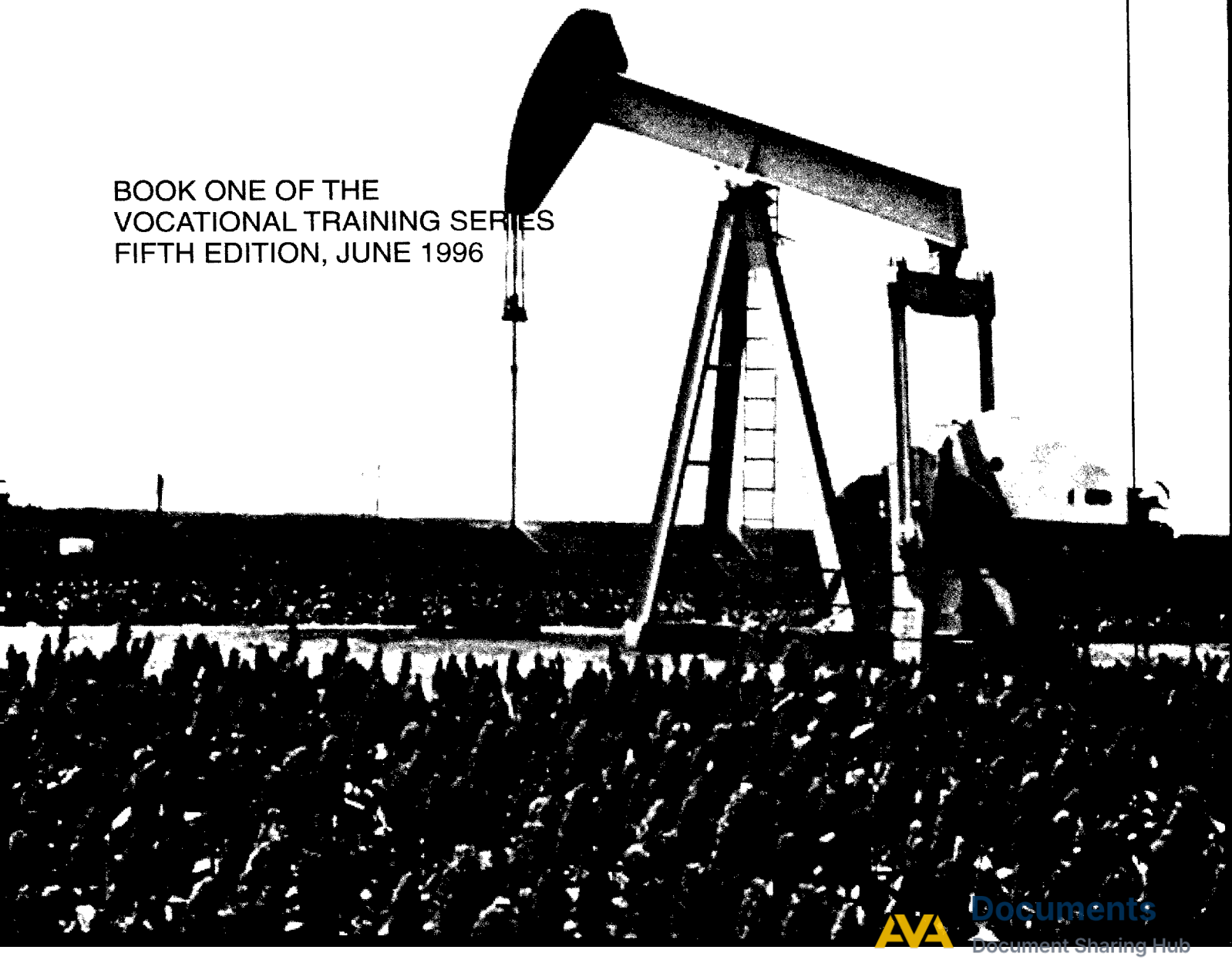
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American Petroleum Institute

Introduction to Oil and Gas Production

BOOK ONE OF THE
VOCATIONAL TRAINING SERIES
FIFTH EDITION, JUNE 1996



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Introduction to Oil and Gas Production

Exploration and Production Department

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Introduction to Oil and Gas Production

SECTION 1—ORIGIN AND ACCUMULATION OF OIL AND GAS

1.1 Introduction

Progress in solving the secrets of the origin and accumulation of petroleum took a giant step forward in 1859 with the drilling of the first oil well. This initial well was drilled to a depth of 69 feet. Oil and gas deposits had been encountered at various locations since ancient times, but these instances were relatively rare in 1859. Today we have widely accepted geologic theories along with good supporting evidence that help explain how oil and gas were formed. Once formed in the sedimentary source beds, the oil and gas then migrated to other sedimentary rocks where we find them today. This two-step sequence is the starting place for this introduction.

Life on earth possibly began hundreds of millions of years ago in vast seas and inland lakes. This is one of the initial concepts in developing the current geologic organic theory of petroleum. These marine areas are thought of as being reasonably shallow. The hydrogen and carbon material which makes up the composition of petroleum is presumed to have come from the decomposed plants and animals that were living on land and in the sea. It is probable that the greatest contribution of organic material was deposited in a marine environment rather than a continental environment. Also, it is believed that the small plant and animal forms were of more importance than the larger forms as a petroleum source.

1.2 Organic Theory of Origin

Figure 1 illustrates the vast seas that at several times in the geologic past covered large portions of the present continents and near offshore areas supported abundant populations of marine plant and animal life. As these organisms died, their remains were buried and preserved in the sedimentary record. As shown in Figure 2, this evidence of ancient seas is found in the rocks on, and underlying much of, the present land area. The Mid-Continent United States, for example, is part of one of these old seas.

Throughout millions of years, rivers flowed down to these seas and carried with them great volumes of mud and sand to be spread out by currents and tides over the sea bottoms near the constantly changing shorelines. During these times, plant and animal life flourished.

As Figure 3 illustrates, the ocean floors slowly sank under the increasing weight of the accumulating sediments, so that thick sequences of mud, sand, and carbonates were formed and preserved. Figure 4 shows how these sequences were squeezed by the weight of thousands of feet of overlying organic and inorganic material and eventually became what

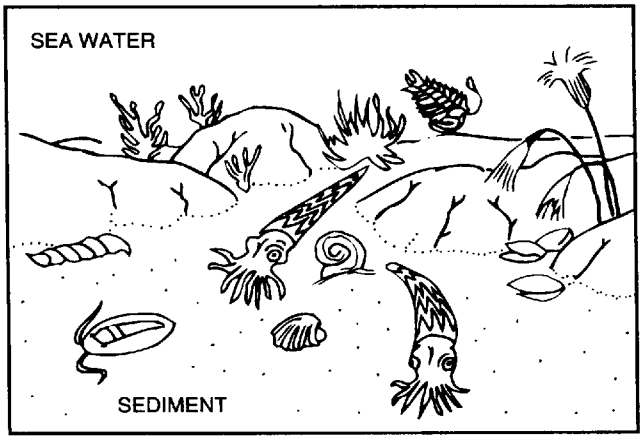


Figure 1—In the geologic past, ancient sea bottoms abounded with marine plant and animal life.

are called sedimentary rocks—the sediments that nature has turned into rocks. These sedimentary rocks include the dark marine shales and marine limestones that scientists think are the source beds of petroleum. Also grouped in this series of marine sedimentary rock are the sandstones, limestones and dolomites that are the reservoir rocks in which we sometimes find oil and gas.

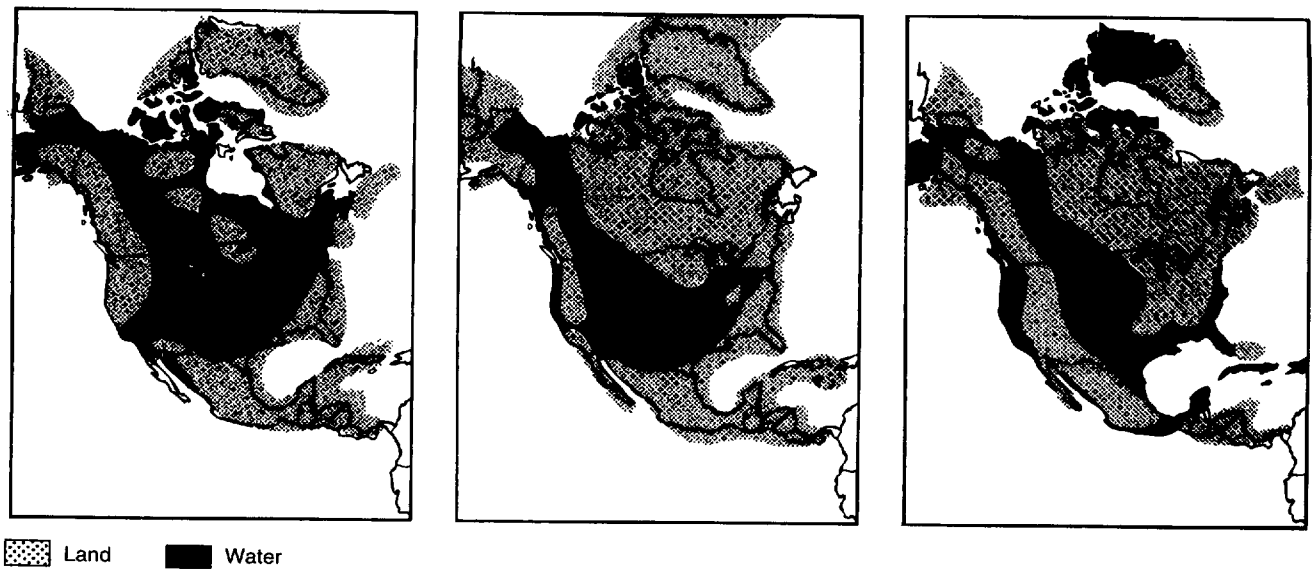
1.3 Accumulation and Occurrence

A large amount of very small plant and animal remains came into the shallow seas with river silts and muds. This material joined a much greater volume of similar tiny remains of marine life already settled to the sea bottom. These small organisms, dying and settling to the bottom of the sea, were repeatedly buried by mud and sealed from the air. They were further protected from ordinary decay by the salty sea water. Through geologic time, as more and more layers of organic material, sand, silt, clay, and lime accumulated, the deeper sediments were compressed and eventually hardened into rock. As time passed, the weight of the overlying sediments caused tremendous pressure to be exerted on the deeper sedimentary layers. Then this pressure, along with high temperature, bacterial action, and chemical reactions, produced the changes that caused the formation of oil and natural gas. Continued squeezing of these source rocks resulted in pressures and temperatures sufficient to cause primary oil and gas migration out of the source rocks into adjoining porous and permeable rocks. One common form of permeable rock in which oil and gas are found is sandstone.

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It is made up of sand grains usually mixed with particles of other material. Porous limestones and dolomites are other types of sedimentary rocks in which petroleum occurs.

After this primary migration, secondary migration occurred wherein the oil and gas migrated from the tiny spaces or pores between the particles in the sediments to the reservoir where it accumulated. This accumulation occurred as the underground rock masses were folded in certain forms and shapes that halted the oil movement and caused the petroleum to be trapped and gathered in large quantities. The movement of petroleum from the place of its origin to the traps where the accumulations are now found was both vertical and lateral. This movement took place as the result of the tendency for oil and gas to rise through the ancient sea water with which the pore spaces of the sedimentary formations were filled when originally laid down.

An underground porous formation or series of rocks, which occur in some shape favorable to the trapping of oil and gas, must also be covered or adjoined by a layer of rock that provides a covering or seal for the trap. Such a seal, in the form of a layered, dense, non-permeable rock, halts further upward movement of petroleum through the pore spaces.

1.4 Oil and Gas Segregation

As oil and gas migrated into a trap, they ordinarily displaced salt water already there. The oil and gas gather in the upper part of the trap because of the differences in weight of

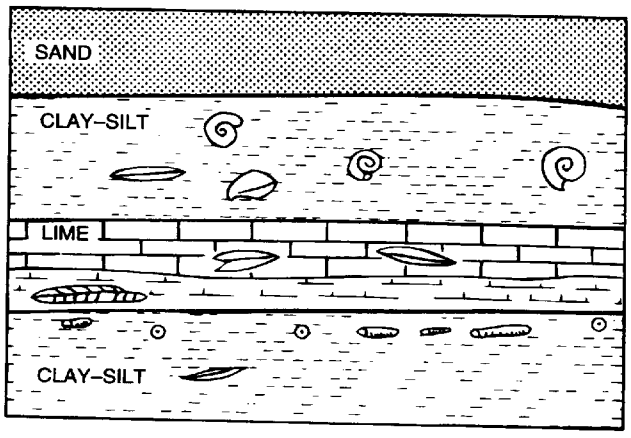


Figure 3—As the plants and animals died, their remains were buried in the accumulating sediment.

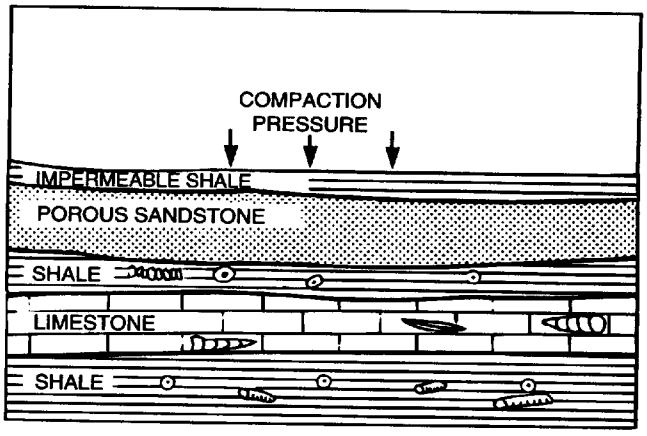


Figure 4—The weight of the overlying sedimentary layers caused compaction of earlier sediments into rock such as sandstone, limestone and shale.

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gas, oil, and salt water. These three fluids, if all are present, separate vertically (in a similar manner as if they were contained in a bottle). If any gas is present, it is ordinarily found in the highest part of the trap because it is lightest. Oil, and oil with dissolved gas, is found below the gas, and salt water below the oil.

Salt water, however, was not completely displaced from the pore spaces in the trap. Often the pore spaces contain from about 10 percent to more than 50 percent salt water in the midst of the oil and gas accumulation. This remaining salt water (called *connate water*) fills the smaller pore spaces and forms a film over the surfaces of the rock grains surrounding the larger pores. The oil, or oil and gas, occupies these water-jacketed pore spaces.

The geological structures to which petroleum has thus migrated and within which it has been trapped and has accumulated are called *petroleum reservoirs* and are the oil and gas fields that we explore for and produce today.

Therefore, in order for an oil or gas field to have been formed, there must have been:

a. A source of carbon and hydrogen that developed from the remains of land and sea life buried in the mud and silt of ancient seas.
b. Conditions which caused the decay or decomposition of these remains and the recombining of carbon and hydrogen to form the mixture of hydrocarbons that make up petroleum.
c. A porous rock or series of such rocks within which the petroleum was able to migrate and displace the water originally in the rock.
d. A local structure or trap, having a top layered seal, that forms a reservoir where petroleum has gathered.

1.5 Reservoir Rock

Within a reservoir rock, the oil and gas occupy the void spaces between the grains that make up the rock. The ratio of the pore volume to the total rock volume is called *porosity,* and is usually expressed as a percent. A good sandstone reservoir may have up to 30 percent porosity. If the majority of the pores within a rock are interconnected, the rock is said to be permeable. Permeability is defined as the ability of a material to transmit fluids.

1.6 Geologic Types of Reservoirs

There are many different shapes, sizes, and types of geologic structures that provide reservoirs in which petroleum is found. Most of the fields discussed in 1.6.1 through 1.6.7 are oil reservoirs. There are, however, gas fields that have been found in all of these general types of structures. Some areas of production today are predominately gas fields, such as the very large Panhandle Hugoton Field that stretches from the Texas Panhandle across the Oklahoma Panhandle into southwest Kansas. Other areas, notably the Gulf Coast and west Texas as well as Oklahoma, have large oil fields and large gas fields that are completely separate from each other. A simple means of classifying reservoirs is to group them according to the conditions causing their occurrence, as in the seven divisions following.

1.6.1 DOMES AND ANTICLINES

Reservoirs formed by folding of the rock layers or strata usually have the shape of structural domes or anticlines as shown in Figures 5 and 6. These traps were filled by migration of oil or gas (or both) through the porous strata or beds to the location of the trap. Here, further movement was arrested by

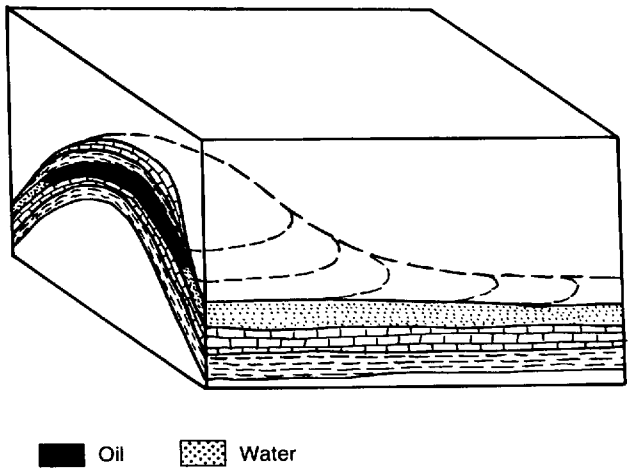


Figure 5—This sketch illustrates an oil accumulation in a dome-shaped structure. This dome is circular in outline.

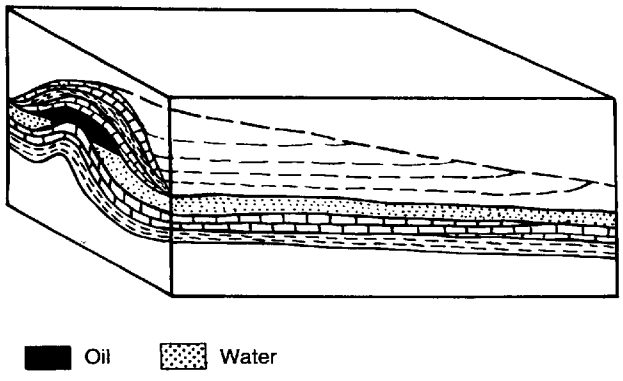


Figure 6—An anticlinal type of folded structure is shown here. An anticline differs from a dome in being long and narrow.

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a combination of the form of the structure and the seal or cap rock provided by the formation covering the structure.

It is common to find traps which apparently are big enough to hold larger quantities of oil or gas than have accumulated, and which remain partially filled with salt water underneath the oil or gas as indicated in Figures 5 through 9. Examples of reservoirs formed by domal structures are the Conroe Oil Field in Montgomery County, Texas, and the Old Ocean Gas Field in Brazoria County, Texas. Examples of reservoirs formed on anticlinal structures are the Ventura Oil Field in California, the Rangely Field in Colorado, and the giant Yates Field in west Texas.

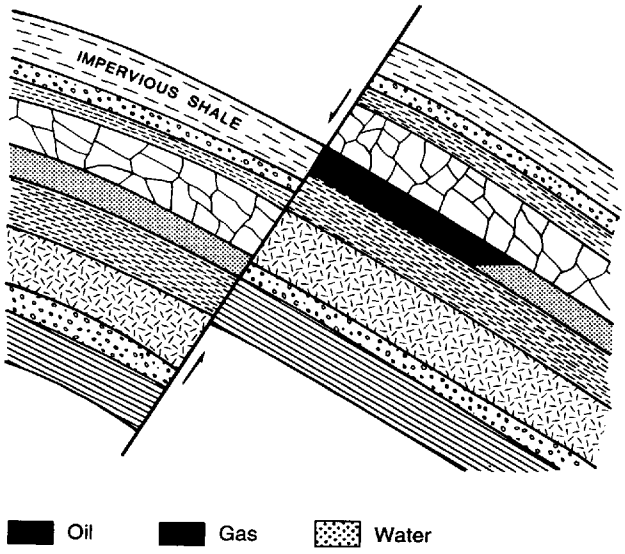


Figure 7—This is a trap resulting from faulting in which the block on the right has moved up with respect to the one on the left.

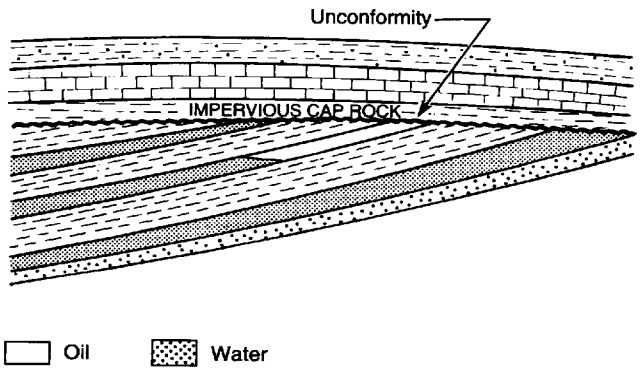


Figure 8—Oil is trapped under an unconformity in this illustration.

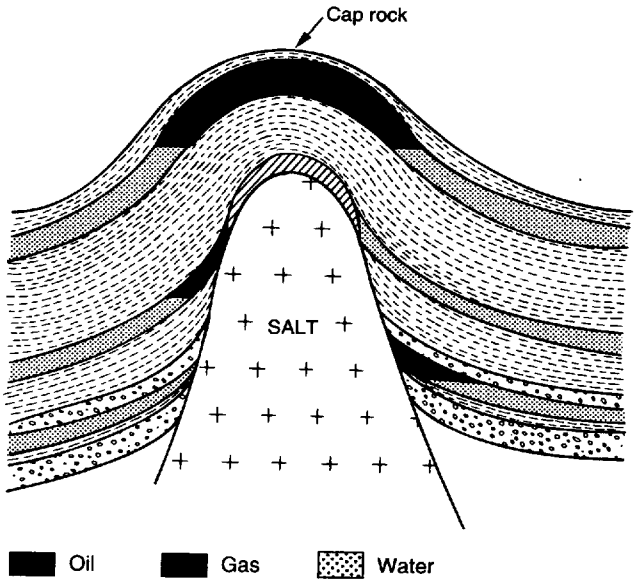


Figure 9—Salt domes often deform overlying rocks to form traps like the ones shown here.

1.6.2 FAULT TRAPS

Reservoirs formed by breaking or shearing and offsetting of strata (called faulting) are illustrated in Figure 7. The escape of oil from such a trap is prevented by impervious rocks that have moved into a position opposite the porous petroleum-bearing formation. The oil is confined in traps of this type because of the tilt of the rock layers and the faulting. The Elk Hills Field in California and the many fields in the Overthrust Trend of Wyoming and Utah are examples of fault trap fields.

1.6.3 UNCONFORMITIES

The type of reservoir formed as a result of an unconformity is shown in Figure 8. Here, the upward movement of oil has been halted by the impermeable cap rock laid down across the cut-off (possibly by water or wind erosion) surfaces of the lower beds. The great East Texas Field and the Oklahoma City Field are this type of reservoir. An unconformity is a significant part of the trapping mechanism for the super giant Prudhoe Bay Field on the North Slope of Alaska.

1.6.4 DOME AND PLUG TRAPS

Accumulations of oil are found in porous formations on or surrounding great plugs or masses of salt that have pierced, deformed, or lifted the overlying rock layers. Some typical accumulations of this type are shown in Figure 9, which illustrates a nonporous salt mass that has formed dome-shaped traps in overlying and surrounding porous rocks. The Avery Island and Bay Marchand Fields in

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Louisiana are examples of salt dome reservoirs. Another is the famous Spindletop Field near Beaumont, Texas, where rotary drilling was first used, introducing the modern drilling era.

1.6.5 REEF TRAPS

A type of reservoir formed as a result of limestone reef buildups in the ancient oceans is shown in Figure 10. These reefs formed where the environmental conditions were favorable for certain marine animals and plants, and the remains of these organisms formed thick accumulations of limestones and dolomites. Local porosity in these reefs resulted from a combination of the original open spaces between rock grains and subsequent dissolving of the limestone by waters moving through the rocks. The Greater Aneth Field in Utah, Kelly Snyder Field in west Texas, and the many fields in the Michigan Basin are examples of reef reservoirs.

1.6.6 LENS TRAPS

Another type of reservoir is one that is sealed in its upper regions by abrupt changes in the amount of connected pore space within a formation. This may be caused in the case of sandstones by irregular deposition of sand and shale at the time the formation was laid down. In these cases, oil is confined within porous parts of the rock by the nonporous parts of the rock surrounding it. This is also termed a stratigraphic trap. A sand reservoir of this type is shown in Figure 11. The Burbank Field in Osage County, Oklahoma, is an example of a lens trap. A limestone reservoir of this type is shown in Figure 12, examples of which are some of the limestone fields of west Texas. Another example is the Hugoton Field in which the reservoir rock is made up of porous limestone and dolomite.

1.6.7 COMBINATION TRAPS

Another common type of reservoir is formed by a combination of folding, faulting, and changes in porosity or other conditions. Examples of reservoirs of this nature are the Midway-Sunset Field in California, the Wasson Field in west Texas, and the Bradford Field in Pennsylvania.

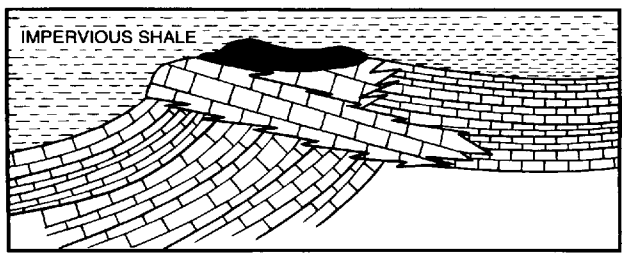


Figure 10—Reefs sometimes form reservoirs similar to that shown here.

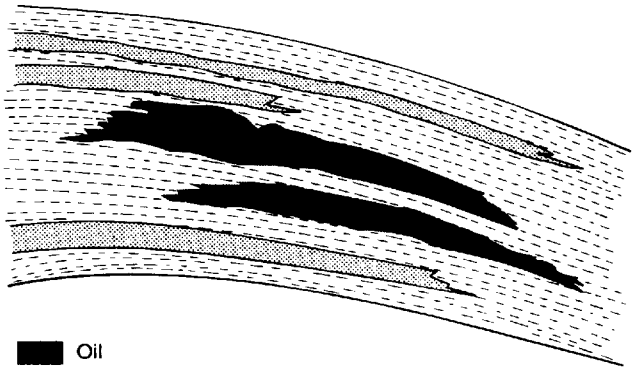


Figure 11—Bodies of sand in a non-porous formation often form traps like this one.

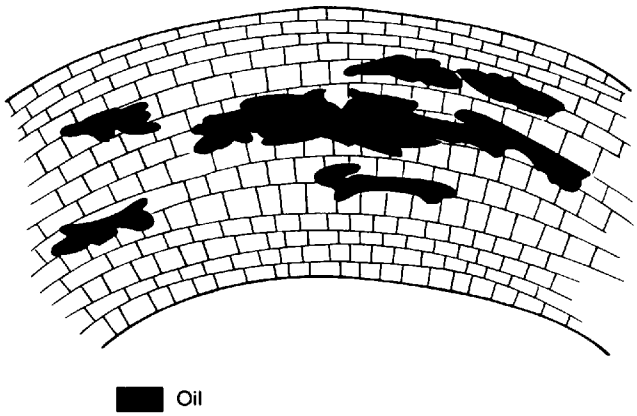


Figure 12—Limestone formations often have areas of high porosity that form traps like this one.

1.7 Types of Production Processes

Oil and gas reservoirs and fields have also been classified according to the type of natural energy and forces available to produce the oil and gas. At the time oil was forming and accumulating in reservoirs, pressure and energy in the gas and salt water associated with the oil was also being stored, which would later be available to assist in producing the oil and gas from the underground reservoir to the surface.

Oil is unable to move and lift itself from reservoirs through wells to the surface. It is largely the energy in the gas or the salt water (or both), occurring under high pressures with the oil, that furnishes the force to drive or displace the oil through and from the pores of the reservoir into the wells.

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1.7.1 GAS DRIVE RESERVOIRS

Oil in an underground reservoir contains varying quantities of dissolved gas that emerges and expands as the pressure in the reservoir is reduced. As the gas escapes from the oil and expands, it drives oil through the reservoir toward the wells and assists in lifting it to the surface. Reservoirs in which the oil is produced by dissolved gas escaping and expanding from within the oil are called solution-gas-drive reservoirs. This oil production process is illustrated in Figure 13, and is generally considered the least effective type, yielding maximum recoveries between 10 to 25 percent of the oil originally contained in the reservoir.

In many cases more gas exists with the oil in a reservoir than the oil can hold dissolved in it under the existing conditions of pressure and temperature. This extra gas, being lighter than the oil, occurs in the form of a cap of gas over the oil as shown in Figures 7, 9, and 14. Such a gas cap is an important additional source of energy. As production of oil and gas proceeds and the reservoir pressure is lowered, the gas cap expands to help fill the pore spaces formerly occupied by the oil and gas produced. Also, where conditions are favorable, some of the gas coming out of the oil is conserved by moving upward into the gas cap to further enlarge the gas cap. The gas cap drive production process is illustrated in Figure 14. It is substantially more effective than solution-gas drive alone, generally yielding oil recoveries ranging from 25 to 50 percent.

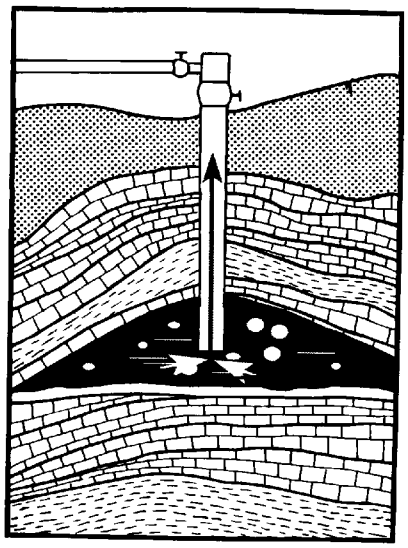
The solution-gas-drive production process described is typically found with the discontinuous, limited or essentially closed reservoirs illustrated in Figures 10, 11, and 13. It may also be the dominant energy force in any type of reservoir where the porous part of the formation is limited to the part actually forming the reservoir and containing the oil and gas.

1.7.2 WATER DRIVE RESERVOIRS

If the formation containing an oil reservoir is fairly uniformly porous and continuous over a large area compared to the size of the oil reservoir itself, vast quantities of salt water exist in surrounding parts of the same formation, often directly in contact with the oil and gas reservoir. This condition is shown by Figures 5, 6, 7, 8, 9, and 15. These tremendous quantities of salt water are under pressure and provide a great additional store of energy to aid in producing oil and gas.

The energy supplied by the salt water comes from expansion of the water as pressure in the petroleum reservoir is reduced by production of oil and gas. Water actually will compress, or expand, to the extent of about one part in 2,500 per 100 pounds per square inch (psi) change in pressure. This effect is slight for any small quantity, but becomes of great importance when changes in reservoir pressure affect enormous volumes of salt water that are often contained in the same porous formation adjoining or surrounding a petroleum reservoir.

The expanding water moves into the regions of lowered pressure in the oil- and gas-saturated portions of the reservoir caused by production of oil and gas, and retards the decline in pressure. In this way, the expansive energy in the oil



■ Oil

Figure 13—Solution-gas drive.

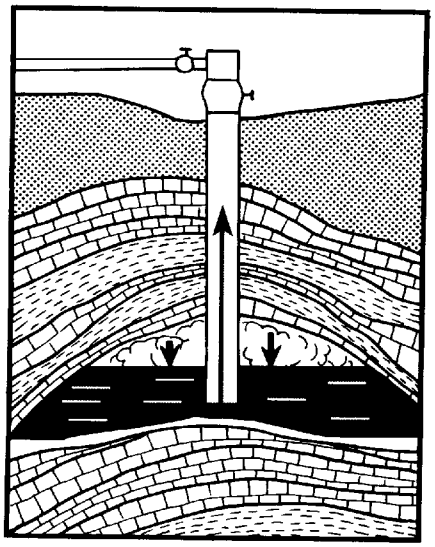


Figure 14—Gas-cap drive.

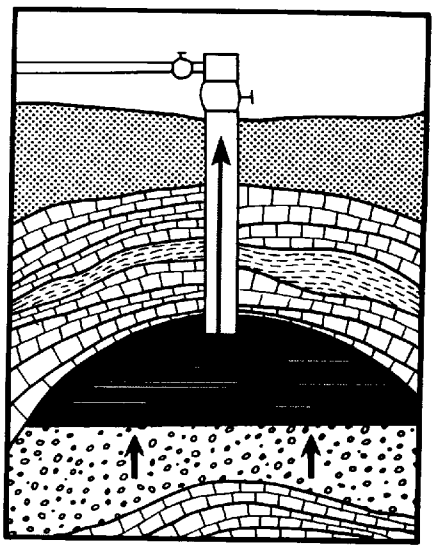


Figure 15—Water drive.

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and gas is conserved. The expanding water also moves and displaces oil and gas in an upward direction out of lower parts of the reservoir, as illustrated in Figure 15. By this natural water drive process, the pore spaces vacated by oil and gas produced are filled with water, and oil and gas are progressively moved toward the wells.

Water drive is generally the most efficient oil production process. Oil fields with an effective water drive are capable of yielding recoveries of 30 to 50 percent and, under the best conditions, recovery can approach 70 percent of the oil originally in place. Oil recovery from a water drive reservoir depends on:

a. The physical nature of the reservoir rock and oil.
b. The care exercised in completing and producing the wells.
c. The rate of oil and gas production from the field or reservoir as a whole.

These factors also greatly affect the oil-recovery efficiency in the case of gas-cap-drive reservoirs. However, rate of production seems to exert only minor effect on oil recoveries obtainable from solution-gas-drive fields except where conditions are favorable for gas caps to form.

In many cases, reservoirs have combination drives. For these reservoirs the kind of operation and total rate of production will determine which type of drive is actually effective. These factors greatly affect the oil recovery. Careful monitoring of individual well rates of oil, gas, and water production may be necessary to identify which types of drives are occurring.

For the best recovery to be obtained from each field, it is sometimes desirable to inject excess gas and water back into the reservoir. This can result in one of the improved recovery drives becoming the dominant influence in the reservoir. Often, however, when these steps are considered, there will also be investigations into additional specialized injection processes. Such projects require extensive engineering and economic studies as well as installation of special equipment. A discussion of enhanced recovery projects may be found in Section 11.

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SECTION 2—THE WELL

2.1 Introduction

A well is a hole drilled through the earth's surface layers to recover fluids from a subsurface formation. Crude oil, natural gas, and water reservoirs are found in formations below the surface of the earth; the well is drilled to these formations. Pipe is then run into the hole to provide a conduit for the fluid to flow to the surface. Wells may be grouped into two relatively broad categories: straight holes and directionally drilled wells. Straight hole wells, shown in Figure 16, are those drilled to targets essentially beneath the surface location of the well, although some small deviations in the well bore are likely to occur during the drilling process.

Directionally drilled wells are those which are drilled to targets not directly beneath the surface location of the well. Directionally drilled wells can be classified further into *straight kick, S-kick,* and *horizontal* wells.

In straight kick wells, the well bore is deviated until the desired angle is achieved. This angle is then maintained all the way to the bottom of the hole as seen in Figure 17. In S-kick wells, the well bore is deviated to achieve the desired horizontal displacement and then returns to a vertical direction before penetrating the producing zone. The term "S-kick" is derived from the shape of the course that the well bore follows as seen in Figure 18. Horizontal wells, as the name implies, are those wells that are deviated until the well bore achieves a horizontal direction. The well bore may then continue in the horizontal direction for hundreds or even thousands of feet, depending on the results desired as shown by Figure 19. For a further discussion of horizontal drilling, see Section 19.

2.2 Casing

A drilled hole must be stabilized to prevent freshwater sand contamination, lost circulation, hole sloughing, or charging shallow sands with abnormal pressures. To do this, successively smaller diameter casing strings are set in the well starting with the conductor pipe, then surface pipe, intermediate string (if needed due to operational problems), and finally the production or oil string. The depth that each string is set is determined by the particular conditions at the well site. For example, surface casing can be set at depths from 200 to 5,000 feet and an oil string can be set from depths of 2,500 to 25,000 feet or more. A sketch of a well is shown in Figure 20. Each time a casing string is set and

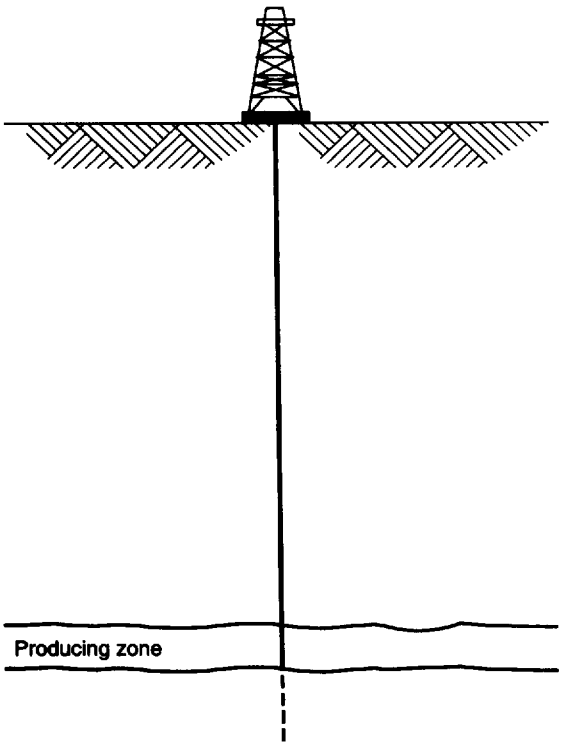


Figure 16—Straight Hole Well

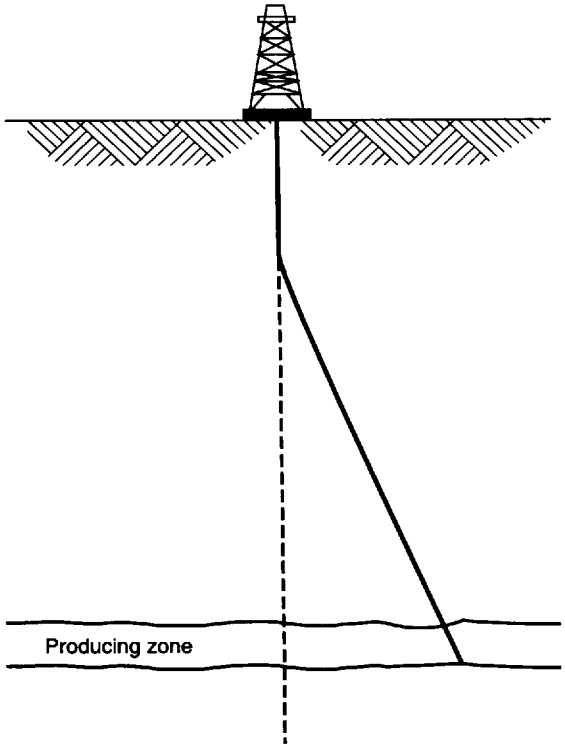


Figure 17—Straight Kick Well

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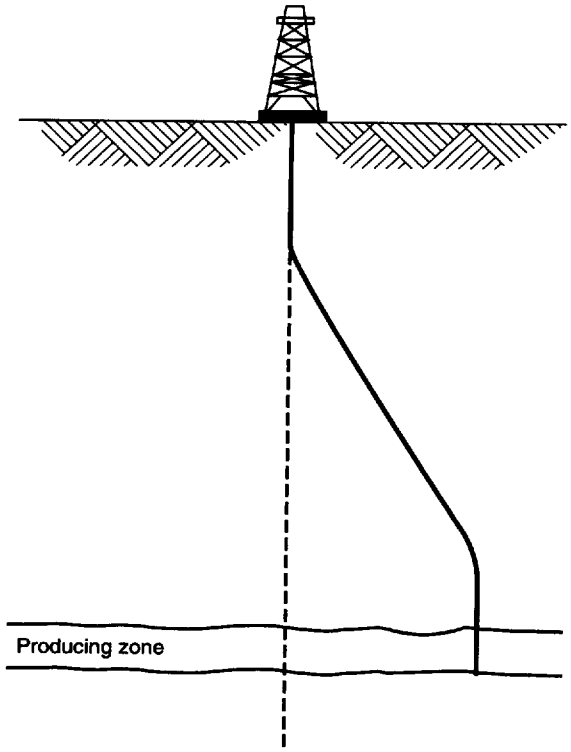


Figure 18—Kick Well

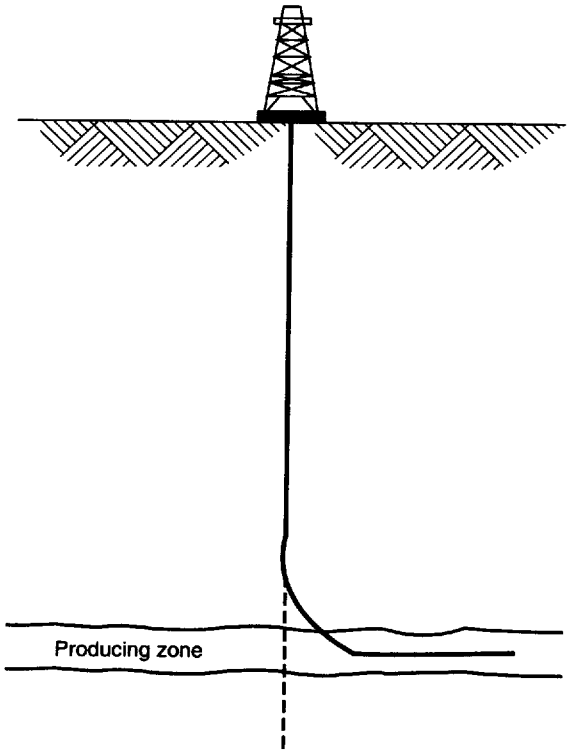


Figure 19—Horizontal Well

brought to the surface, a blowout preventer (BOP) of appropriate size and pressure rating is flanged onto the casing by a casinghead to control pressure in the drilling well.

Casing must be designed to meet the physical conditions imposed on the pipe. A well with 10,000 psi surface pressure requires much heavier casing than a well with 2,000 psi surface pressure. By the same reasoning, the collapse resistance of the casing must be much higher for a string that is to be set at 20,000 feet than a string to be set at 2,000 feet.

API has very carefully established specifications for size, grade, weight per foot, type of threaded connection, and length of each section (joint) of casing. Figure 21 shows the relative sizes of casing and tubing, various types of connections identifying the threads on the casing, and a tabulation of common sizes of casing. Some of the connections are for specialized use.

2.3 Completion Methods

There are many methods of preparing an oil well to produce. They are governed by the type of reservoir (see Section 1). If the well is completed in a hard formation, the oil-producing zone may be left entirely open, with no perforated casing or liner used to protect the hole. This is called an open-hole completion. In loose, soft sands, it may be necessary to cement the production string through the producing zone and use a slotted screen or a gravel pack in the producing interval. One of the most common types of completion, shown in Figure 23, consists of setting the oil string or production casing through the producing formation, cementing it in place, and then perforating through the casing and cement into the producing formation. Other types of completions are shown in Figures 22 and 24. Some completions are made using casing liners to extend the cased interval below an upper casing string. Production liners are commonly sections of smaller diameter casing that are run on a liner hanger (Figure 25) and cemented in place. This eliminates the need to extend the smaller diameter production casing back to the surface. A schematic of a well using a casing liner is shown in Figure 20.

A multiple completion is another process which allows production from different pay zones to be produced through the same wellbore. This affords a means of obtaining the maximum amount of oil with the minimum use of casing. Figure 26 shows how this is accomplished.

2.4 Tubing

Because the casing and liner must remain in a well for a long time and their repair or replacement would be costly, another string of pipe is placed in the well through which the oil is usually produced. This is called tubing. During the later life of the well, the same tubing may be used to accommodate a downhole pump or other means of artificial lift. Tub-

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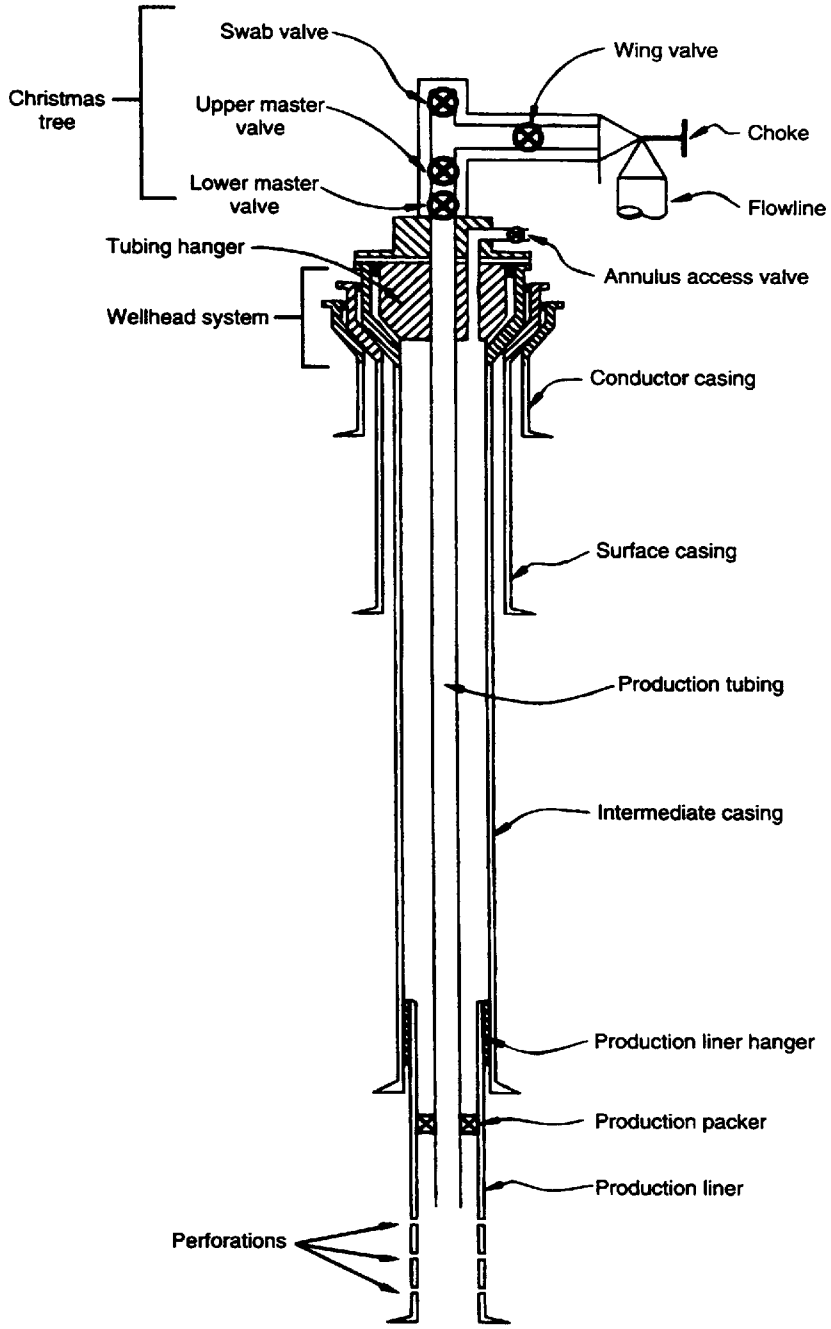
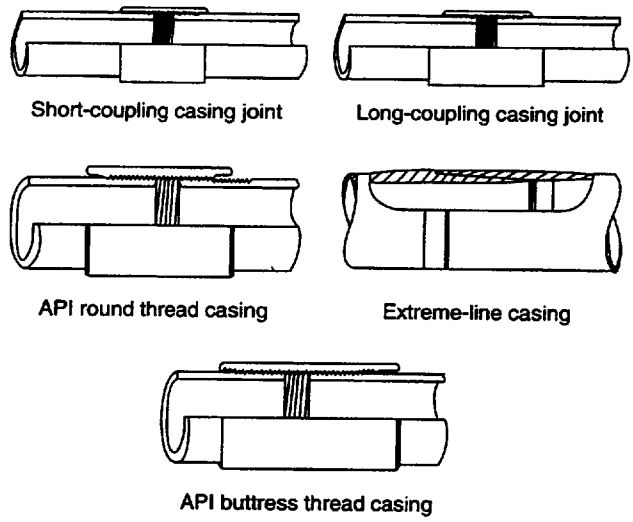
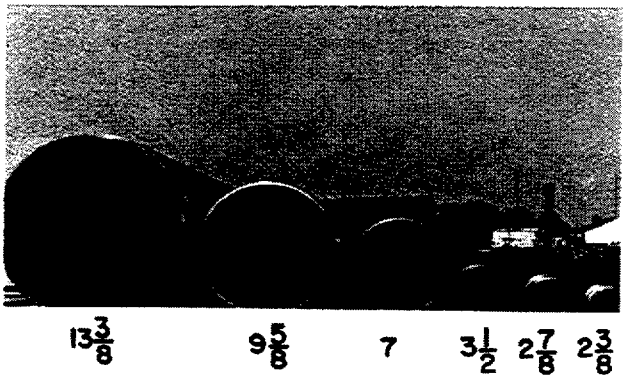


Figure 20—Simplified Diagrammatic Representation of a Well Showing the Casing Strings, Production Tubing and Christmas Tree

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Common Sizes of Casing

Outside Diameter Inches	Weight lb. per foot	Resistance to Collapse, psi	Internal Yield Pressure, psi
4 1/2	9.50	3310	4380
5 1/2	17	4500	5320
7	23	3290	4360
7 5/8	26.40	3010	4140
8 5/8	36	2740	3930
9 5/8	40	2770	3950
10 3/4	40.50	1730	3130
13 3/8	54.50	1140	2730

All sizes above are Grade K-55, seamless steel, threaded and coupled, API joint. Other grades and weights of casing are available. Common lengths are: Range 2, from 25 ft to 34 ft, range 3, 34 ft or more.

Figure 21—Relative size of casing and tubing, types of casing connections, and common sizes of casing.

ing sizes range from 1 1/4 inch to 4 1/2 inches in diameter. The tubing is suspended from the wellhead (surface) and usually reaches to within a few feet of the bottom of the well. Tubing is also used as the flow string because casing is usually too large to permit the well to flow efficiently or, in some cases, to maintain continuous flow.

Tubing packers are sometimes used in the tubing string to seal off the space between the tubing and the production casing. This is done particularly in wells where there are high reservoir pressures. By sealing off this space, the casing is not exposed to high pressure, and the chances of a casing failure are reduced. Tubing anchors and packers also support part of the weight of the tubing in the casing and prevent the tubing string from "working" (moving up and down). One kind of tubing packer is shown in Figure 27.

Occasionally it is both practical and economical to drill a small-diameter hole and use conventional tubing as casing in completing the well. This is called a tubingless completion since no retrievable inner string of tubing is used to conduct fluids to the surface. The casing is cemented from bottom to surface and perforated opposite the producing interval. The equipment used is essentially the same as a conventional well, including a float collar, guide shoe with back pressure valve, and landing nipple as shown in Figure 28. Tubingless completions with pipe as small as 2 7/8-inch outside diameter provide for well control, well stimulation, sand control, workover, and an artificial lift system.

2.5 Safety Valves

When a well is first put on production, it usually flows because of pressure in the reservoir. Often wells are located where an accident could cause danger to the environment, people, or facilities. To provide needed protection, there are several types of safety valves used to shut in the well in case of an accident or equipment failure in areas where accidents could occur. One type is a subsurface valve which will close off when a predetermined rate of flow is exceeded. An alternate type is the surface-controlled subsurface safety valve that is actuated by an external hydraulic pressure system. This valve is shown in Figure 29. Both of these types of safety valves are installed in the tubing string, commonly at depths of 100 to 200 feet beneath the sea floor, or at similar depths beneath the ground surface when installed in onshore wells.

Another commonly used type of safety valve is installed on the wellhead. This valve is known as a *fail safe* device; that is, the valve is held open against a spring by an external means, usually gas pressure. Removing this control pressure will cause the valve to close. Safety shut-in systems are designed so that the valve will close when there is a fire, a broken flow line, a malfunction of production equipment, or a remote manual bleed-off of the control pressure.

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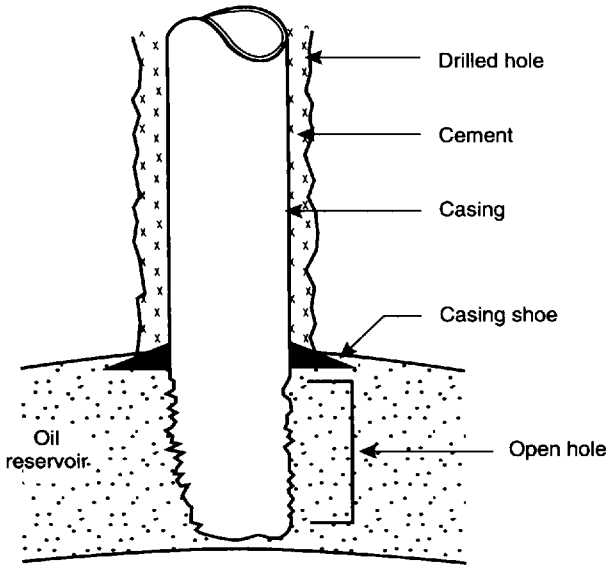


Figure 22—When the oil-producing zone is well consolidated, casing through the oil zone is sometimes not necessary. In this case it is an open-hole completion, sometimes called "bare-foot."

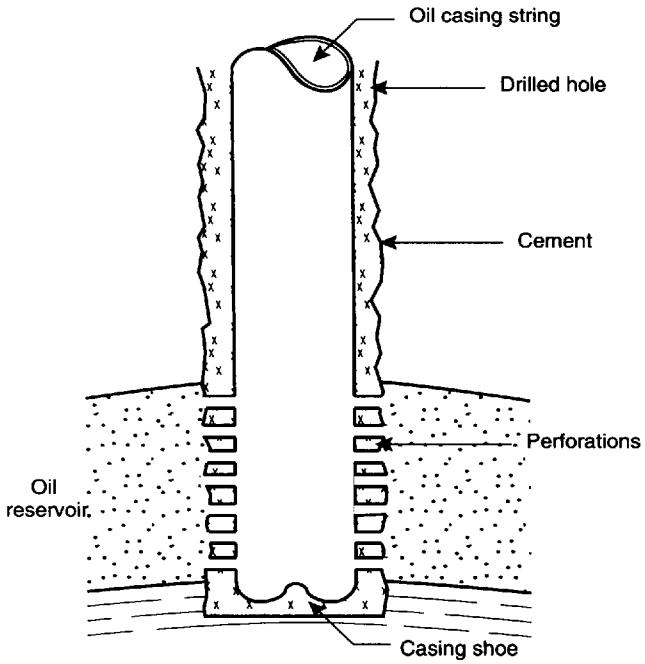


Figure 23—A perforated casing or liner is made by actually shooting bullets or shaped charges (jets) through a section of centered casing at the level of the oil-zone that is to be produced.

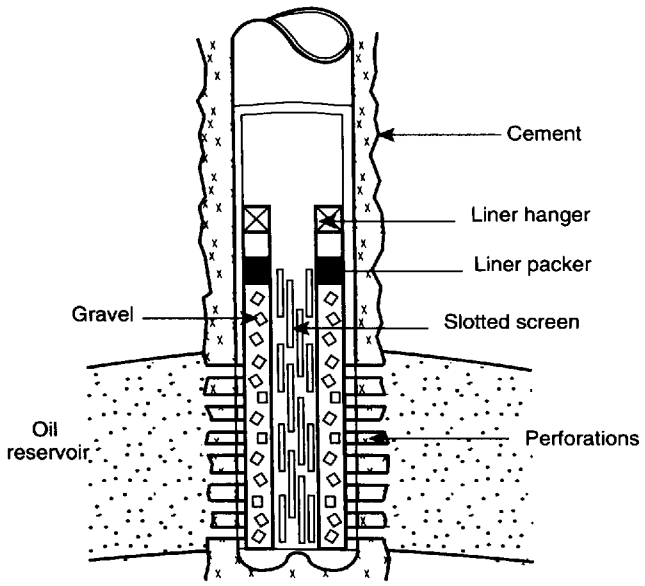


Figure 24—A gravel-packed liner is used in a well in which the producing sands are fine-grained and loose. The gravel in the space around the liner acts as a filter and keeps the sand out of the well.

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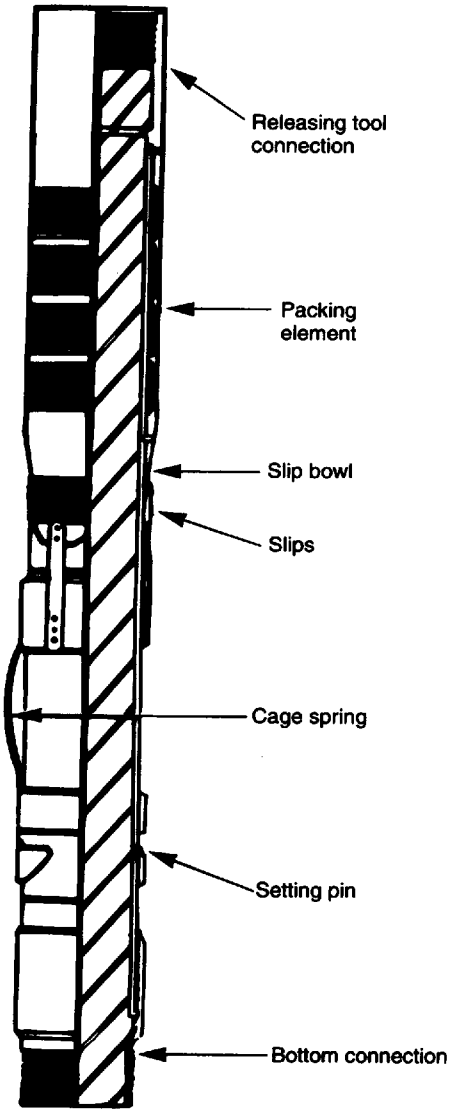


Figure 25—Liner hanger

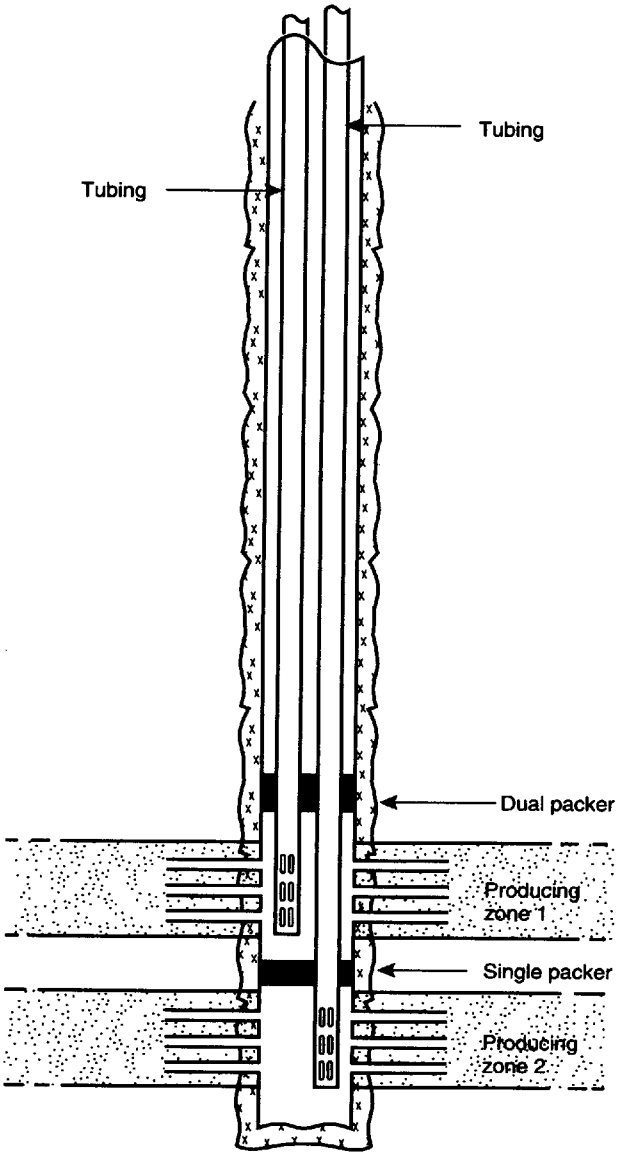


Figure 26—Schematic drawing showing subsurface details of dual type well completion.

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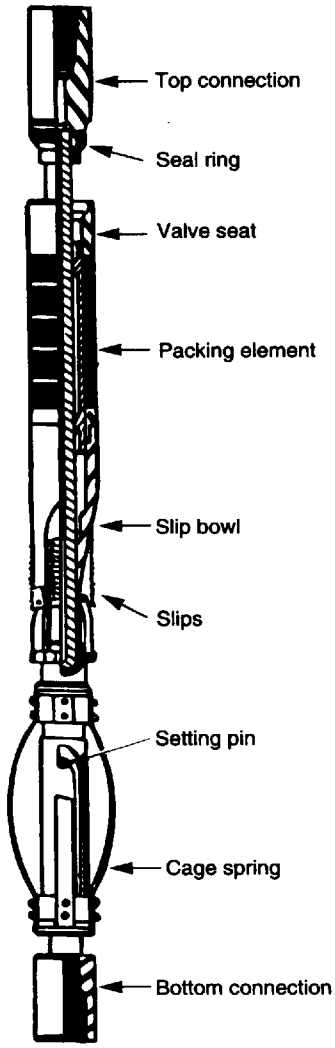


Figure 27—Type of tubing packer

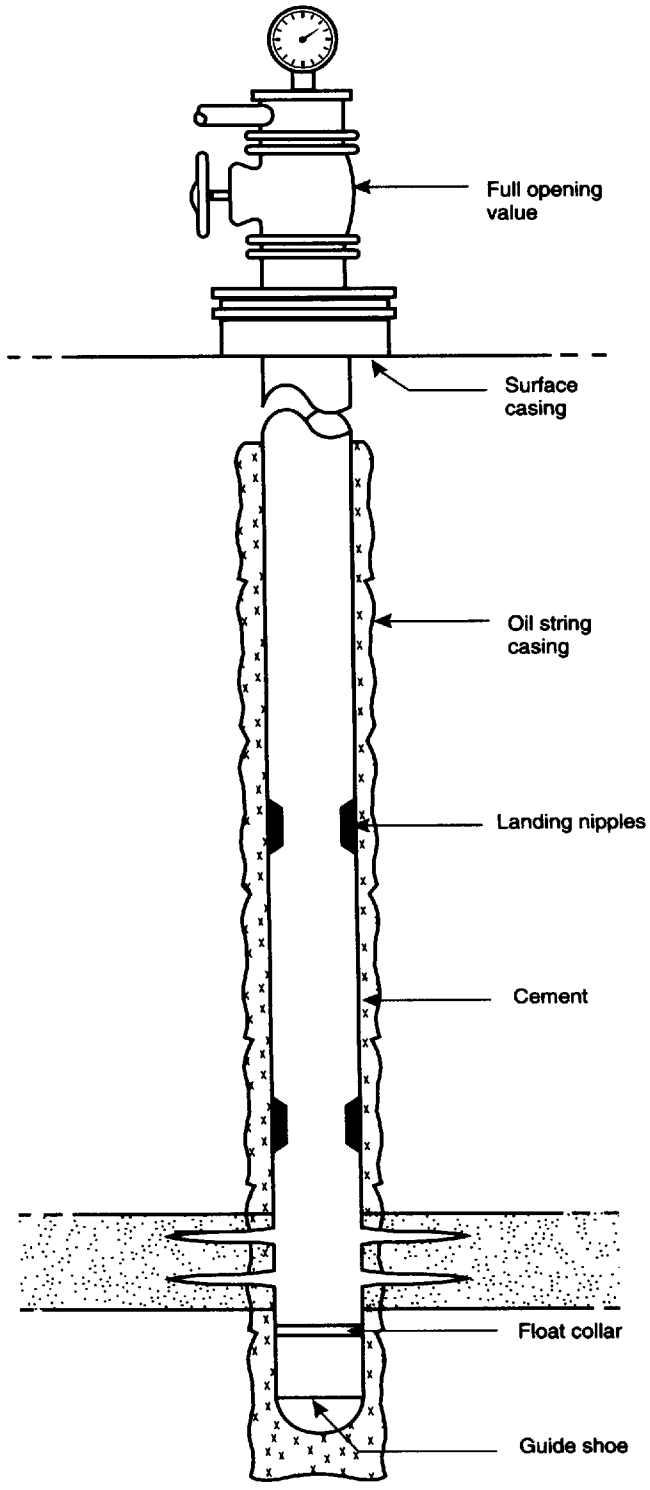


Figure 28—Schematic drawing of a tubingless completion

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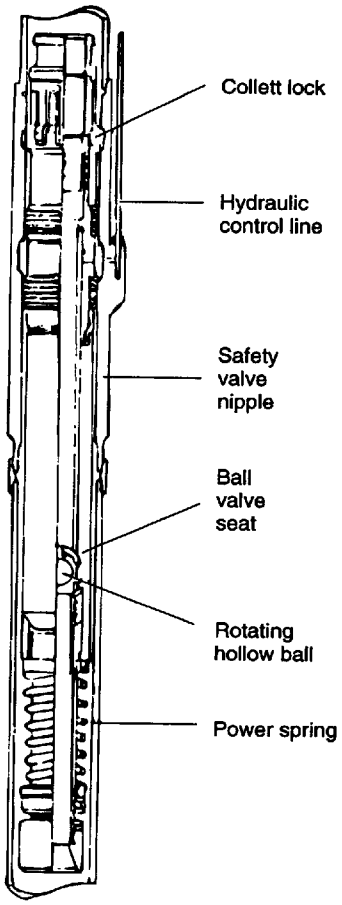


Figure 29—This retrievable sub-surface remote controlled safety valve is set in the tubing string and held open by hydraulic pressure. The power spring forces the ball to rotate shut if the hydraulic pressure is released. This valve is used in offshore wells and is set a prescribed distance below the mud line so that in the event of an operational problem the well will be shut in.

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SECTION 3—WELL TREATMENT

3.1 Introduction

Wells often must be treated to improve the recovery from a reservoir, or to remove barriers within the producing formation which prevent easy passage of the fluid into the wellbore. Such processes are known as *well-stimulation treatments*. These include fracturing, acidizing, and other chemical treatments. These processes are often used in combination since they frequently help each other. Programs for individual wells vary according to well characteristics, economics, and desired result.

3.2 Fracturing

Fracturing is a process that uses high-pressure pumps to develop fluid pressure at the bottom of a well sufficient to actually break (crack) the formation. This makes it possible to introduce proppant materials such as sand, walnut hulls, or other small particles of material into the newly created crevices to keep the fractures propped open when the pressure is relieved. This process increases the flow of reservoir fluids into the wellbore as shown in Figure 30.

3.3 Acidizing

Acidizing is a process of cleaning the formation face to allow fluids to enter the wellbore. A limited amount of dissolving of formation particles can occur if the acid can be forced far enough into the formation before the acid is expended (see Figure 31).

3.4 Chemical Treatment

Chemical treatments are those in which acid is not a significant part. Although many of the materials in this group are often used in conjunction with fracturing and acidizing, they have definite application in their own right.

Due to surface tension, water can sometimes create a blockage when present in the tiny pore spaces of a formation. Certain chemicals may be applied to lower sur-

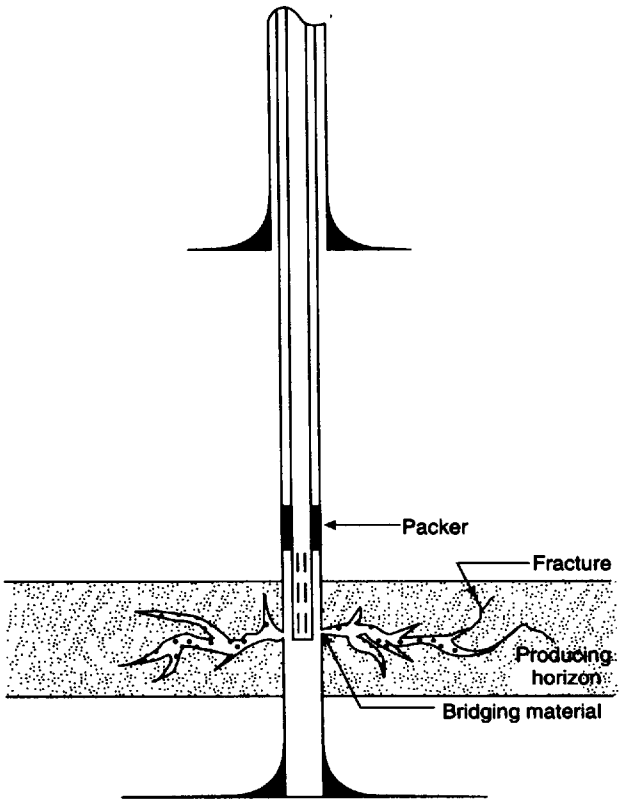


Figure 30—Shows fractures opened in the producing formation. The bridging (propping) materials are placed in the fractures to keep them open.

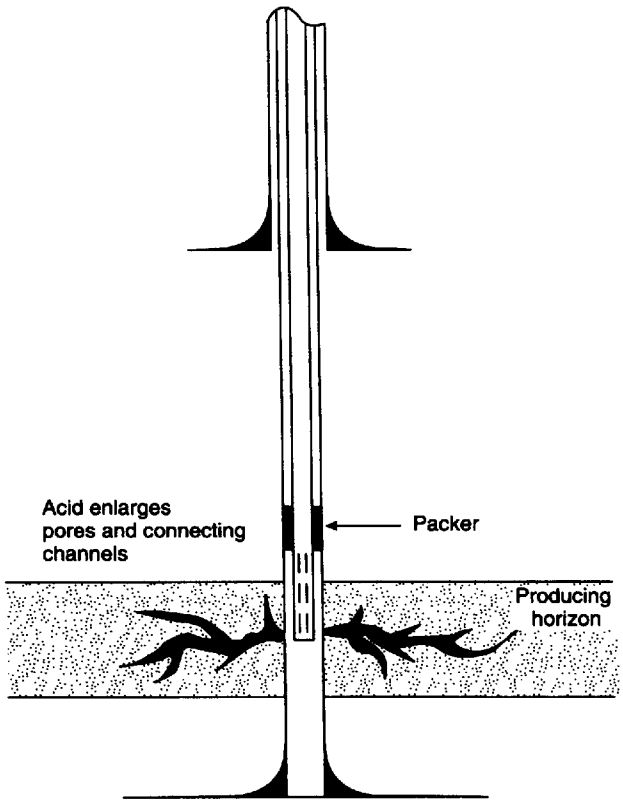


Figure 31—Shows crevice acidizing to increase the flow capacity of the pay-zone into the wellbore.

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face tension. By contact, the chemicals break large drops of water into several smaller ones thus allowing fluid, previously trapped by surface tension, to be released to flow to the wellbore.

In many instances, when oil and water become intimately mixed they form an emulsion. With continued agitation, the emulsion may form a thick viscous liquid which impairs flow of fluids to the well bore. Chemicals may be used to break this emulsion. The resulting decrease in viscosity frees the fluids to move into the well.

3.5 Sand Control

Some wells produce from loosely consolidated sands, and some means of stabilizing these sands must be used. Pressure differential (drawdown) or increased water production can cause the material that holds sand grains together in a formation to dissolve. This may cause movement of sand into the wellbore. Slotted screens or gravel packs can be used to mechanically prevent this sand migration (see Figure 32).

3.6 Frac Packing

In recent years, techniques and equipment have been developed which allow fracturing and gravel packing (frac packing) to be accomplished in one operation. This results in greater well productivity and reduces the well workover operations that would otherwise have been necessary because of sand production.

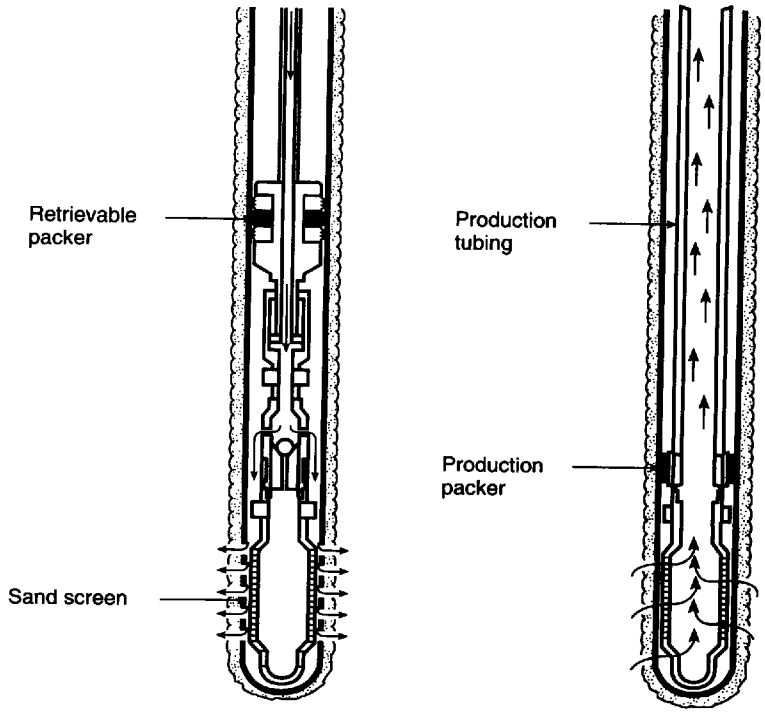


Figure 32—Illustrates one means of placing gravel opposite perforations to stabilize the formation and allow the fluid to be produced. Figure 32(a) on the left, shows the gravel flow into the formation in the annulus between the screen and the casing; Figure 32(b) shows the flow of fluids through the gravel pack after the running tool has been replaced by a production packer.

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SECTION 4—THE WELLHEAD

4.1 Introduction

The wellhead is the equipment used to maintain surface control of the well. It is usually made of cast or forged steel and machined to a close fit to form a seal and prevent well fluids from blowing or leaking at the surface. The wellhead is sometimes made up of many heavy fittings with certain parts designed to hold pressures up to 30,000 psi. A high-pressure assembly is shown in Figure 33. Other wellheads may be just a simple assembly to support the weight of the tubing in the well and may not be built to hold high pressure.

The kind of wellhead configuration to be used is determined by well conditions. The high-pressure wellhead is required where formation pressures are extremely high. Pressures higher than 20,000 psi have been found in some fields, requiring the use of a heavy wellhead. Where production and pressures are very low, the simple wellhead may be used.

The wellhead is formed of combinations of parts called the casinghead, tubing head, Christmas tree, stuffing box, and pressure gauges.

4.2 The Casinghead

During the drilling of the well, as each string of casing is run into the hole, it is necessary to install heavy fittings at the surface to which the casing is attached. Each part of the casinghead is supported by a part of the casinghead which was installed at the top of the next larger string of casing when it was run (see Figure 33).

Each part of the casinghead usually provides for use of slips or gripping devices to hold the weight of the casing. The head provides a way of sealing between the casing strings to prevent flow of fluids. Openings (commonly called gas outlets) are usually provided for reducing gas pressure which may collect between or within casing strings. Also, the outlets may sometimes be used for production of the well when oil is produced through the casing.

The casinghead is used during drilling and workover operations as an anchor for pressure control equipment which may be necessary. Conventional wellheads accommodate the progressively smaller casing sizes, as drilling progresses and additional casing strings are set, by use of a system of flanges and adapter spools (see Figures 33 and 34). This requires removal and reinstallation of the BOPs as each additional string of casing is run in the well. As additional flanges and spools are installed, they form an integral part of the permanent wellhead. *Unitized* wellheads accomplish the same thing with an internal weight suspension and packing system which avoids the necessity of changing BOPs until this is required by having to install equipment to withstand higher pressure. This may become important if more than one intermediate string of casing must be set. This also affects the height of the production wellhead and may eliminate the need for a cellar or a high rig substructure.

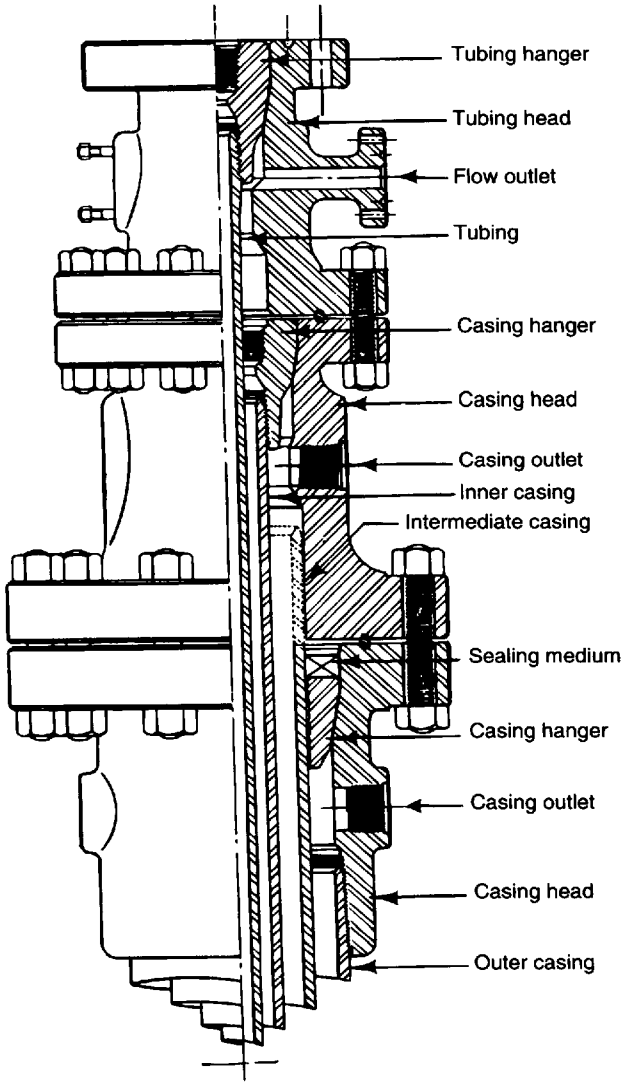


Figure 33—Typical Wellhead Assembly

4.3 The Tubing Head

The tubing head is similar in design and use to the casinghead. Its most important purposes are to:

a. Support the tubing string.
b. Seal off pressures between the casing and tubing.
c. Provide connections at the surface for controlling the flow of liquid or gas.

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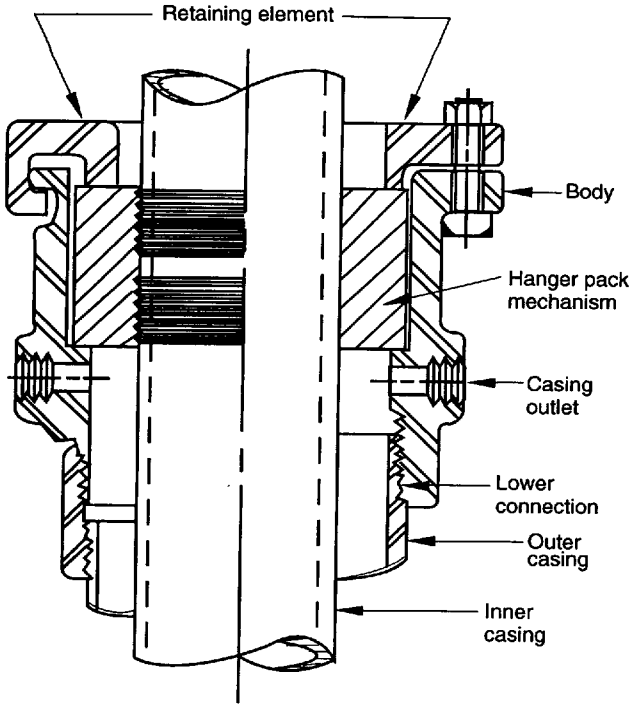


Figure 34—Independent Casinghead

The tubing head is supported by the casinghead where casingheads are used.

In many low-pressure or pumping wells that have only one string of casing, the casinghead is not used and the tubing head is supported on the top of the casing at or near ground level. Tubing heads vary in construction depending upon pressure. Figures 35, 36, and 37 show types of tubing heads.

The tubing head is designed so it can be easily taken apart and put together to make well servicing operations easier. Many different types have been developed for use under high pressures, with different designs and pressure ratings to fit expected well conditions, including the use of multiple tubing strings.

4.4 The Christmas Tree

Wells which are expected to have high pressures are equipped with special heavy valves and control equipment about the casinghead or tubing head before such wells are completed. This group of valves controls the flow of oil and gas from the well, and is called a Christmas tree because of its shape and the large number of fittings branching out above the wellhead. Figure 38 shows a typical Christmas tree on a well.

Low-pressure or pumping wells are sometimes equipped with simple kinds of Christmas trees. See Figure 39 for one type of low-pressure Christmas tree assembly.

Figure 40 shows a type of Christmas tree assembly used for dual completions.

Pressure gauges are usually used as a part of the wellhead and Christmas tree to measure the casing and tubing pressures. By knowing the pressures under various operating conditions, it is possible to have better well control.

The cutting effect due to abrasion by very fine sand particles or erosion by high-speed liquid droplets in high-pressure wells may cut out valves, fittings or chokes. Since the choke is the point at which the well flow rate is controlled, the pressure drop and cutting action are often the most damaging to the choke. When replacing the choke (Figure 41), the flow valve (also called the wing valve) upstream from the choke is closed, the pressure in the line bled off, and the choke replaced.

Because the flow valve is used to open or shut in the well, it is also subject to cutting. When the flow valve becomes cut and needs replacement, the master valve is closed, the pressure bled off the tree, and the flow valve replaced.

The key to closing the well in an emergency is the master valve. It must be kept in good and dependable condition. It is an accepted practice to use it only when absolutely necessary to avoid its being cut. With such practice, it is possible to use the same valve for the life of the well. Should the master valve have to be replaced, special procedures are required to

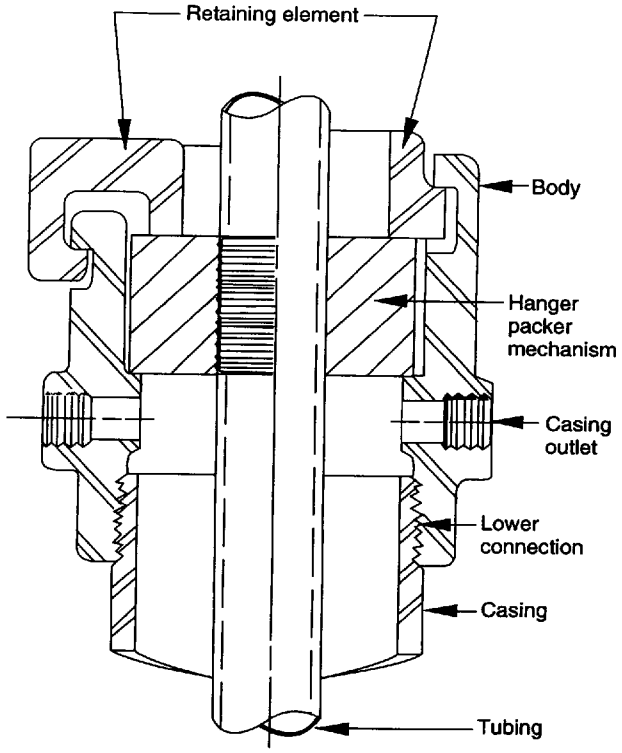


Figure 35—Independent Tubing Head

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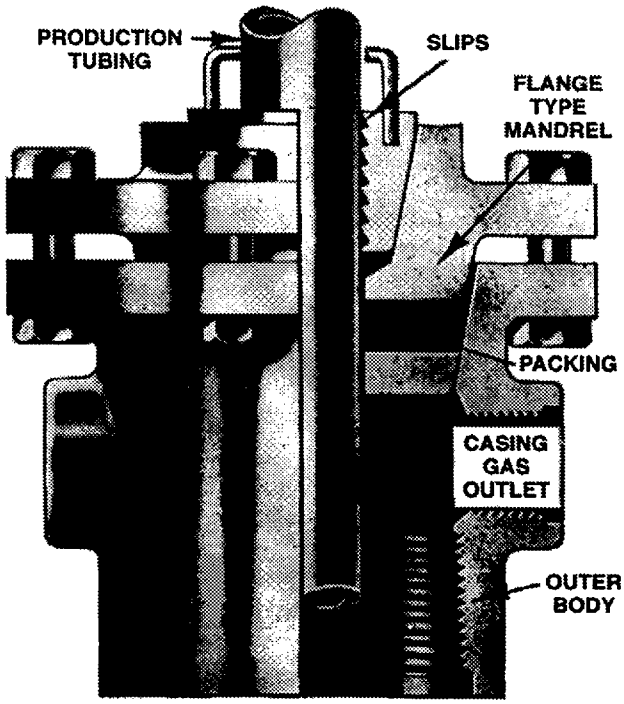


Figure 36—Another kind of slip and bowl type tubing head is shown in this cutaway drawing. The weight of the tubing and a bolted flange compress a gasket to provide sealing.

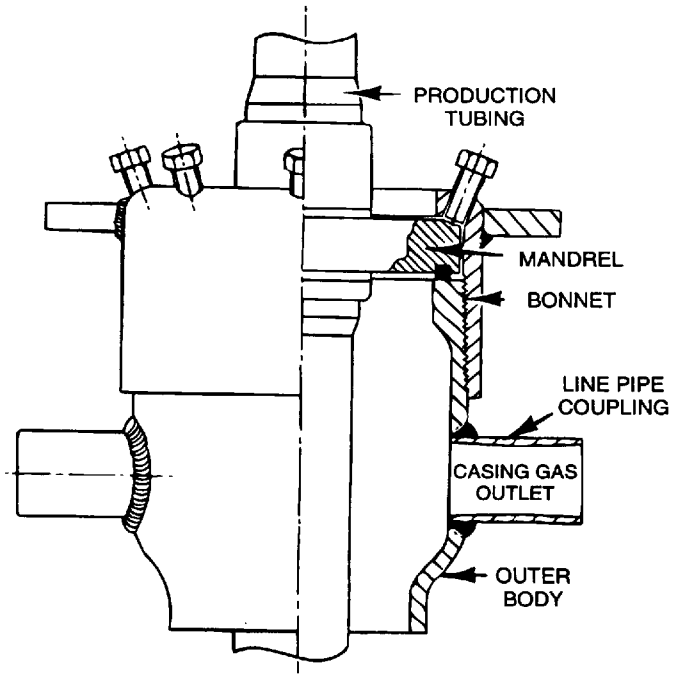


Figure 37—Low pressure tubing head. Sealing is provided by packing that is backed by a bonnet and cap screws.

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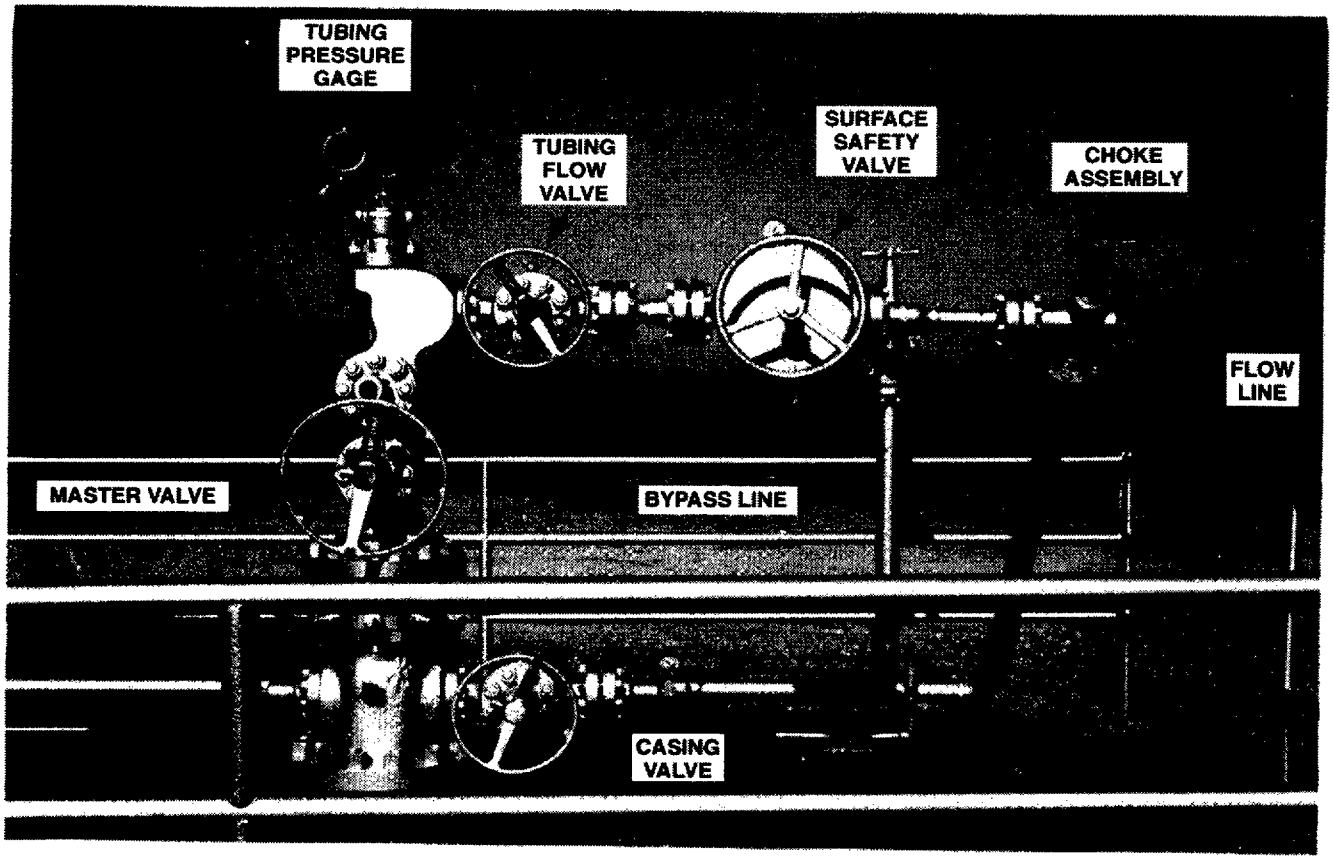


Figure 38—Single-wing type of Christmas tree on a well is shown in this photograph. Main valves and fittings are named.

ensure the well cannot flow while the valve and tree are off the well.

Where a double wing Christmas tree (Figure 41) is utilized, it may be possible to repair a flow valve without closing the well and sacrificing production. This can be done by using special equipment to install a plug behind the valve seat and then replacing the seat and trim of the valve while the well produces through the other wing valve.

Many offshore wells use a mudline suspension system to permit abandonment of such wells without leaving the navigation hazard of casing and wellhead equipment projecting above the sea floor. This permits the casing strings to be cemented up to the sea floor and disconnected above that point after the well has ceased to produce.

4.5 Subsea Trees

Some of the first underwater wells were completed in the Canadian sector of Lake Erie in the early 1940s for the purpose of developing a gas field. The trees used were conventional land trees installed by divers. In this application, underwater completions were used to eliminate the need for ice-resistant structures.

As exploration moved offshore, it was inevitable that new techniques and equipment would be developed. Subsea wellhead systems, subsea connectors, subsea drilling blowout preventers, subsea drilling risers, subsea control systems, and subsea trees were among the developments. Typically, the trees that have been used in subsea completions are configured like conventional trees, but are modified to one extent or another. Such modifications may include any or all of the following:

- Hydraulic operators on the valves.
- Mechanical or hydraulic wellhead connector.
- Mechanical or hydraulic flowline connectors.
- A subsea control system.

These devices may reduce or eliminate the need for divers when installing or operating these trees.

Horizontal trees are a relatively new development and a departure from conventional tree design. Subsea completions provided the impetus for their development. They are described in more detail in Section 19.

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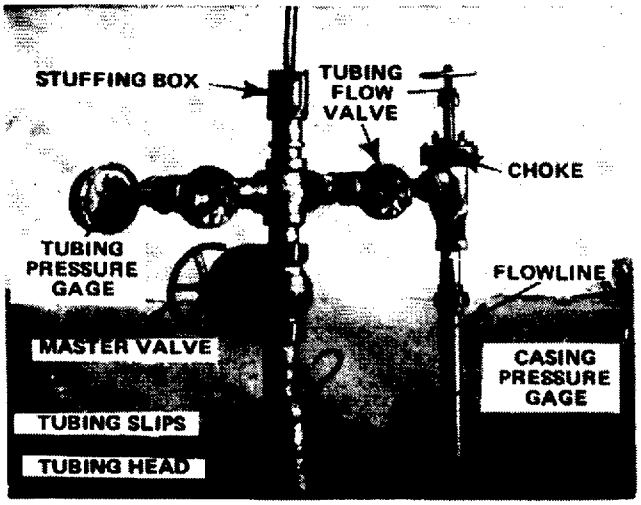


Figure 39—A very simple type of Christmas tree is installed on pumping wells. This photograph shows one example.

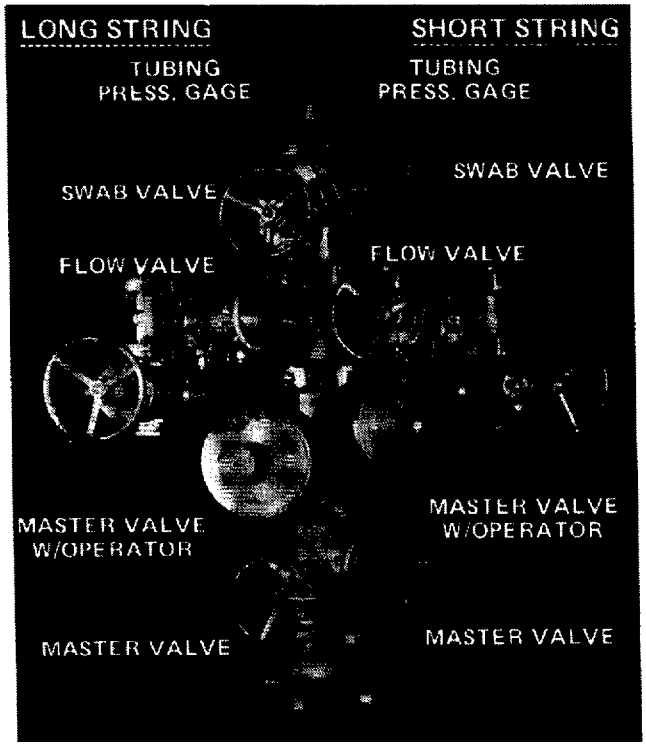


Figure 40—A dual completion type Christmas tree assembly ready for installation on a well.

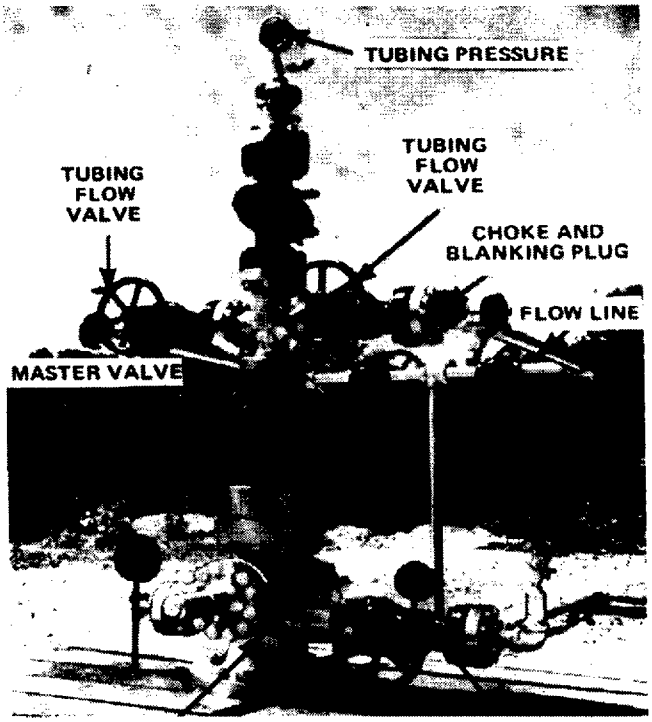


Figure 41—A high-pressure double wing Christmas tree is shown here. Flow from the well can go through tubing flow valves on either side.

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SECTION 5—ARTIFICIAL LIFT

5.1 Introduction

When pressures in the oil reservoir have fallen to the point where a well will not produce at its most economical rate by natural energy, some method of artificial lift should be used.

The most common methods of artificial lift are:

- Sucker rod pumping.
- Gas lifting.
- Subsurface electrical pumping.
- Subsurface hydraulic pumping.

Sucker rod pumps are by far the most widely used method, although because of weight and space limitations their use is largely restricted to onshore wells.

5.2 Sucker Rod Pumping

The pumping unit is the machine used to impart an up-and-down motion, generally through a sucker rod string, to the subsurface sucker rod pump. Several types of pumping units are available.

The most popular unit is the beam pumping unit. A prime mover furnishes the power to run a beam pumping unit. Figure 42 shows the parts of a conventional crank counterbalanced beam pumping unit. Figure 44 shows a field installation of a conventional beam unit.

Because of their better applicability to automatic start-stop control, most beam pumping unit prime movers are electric motors, but internal combustion engines are still widely used. The size prime mover required depends upon the depth from which the fluid must be lifted to the surface and the volume of fluid to be produced.

Speed reduction between the prime mover and cranks is commonly accomplished by a combination of V-belt drive and gear reducer. Rotary motion becomes reciprocating motion at the wellhead through the conventional unit lever system. The walking beam gives the necessary up-and-down movement to the rod string and downhole sucker rod pump in Figure 43. The strokes per minute (SPM) operating speed of the unit may be changed by changing the size of one or both of the V-belt drive sheaves. The optimum SPM at

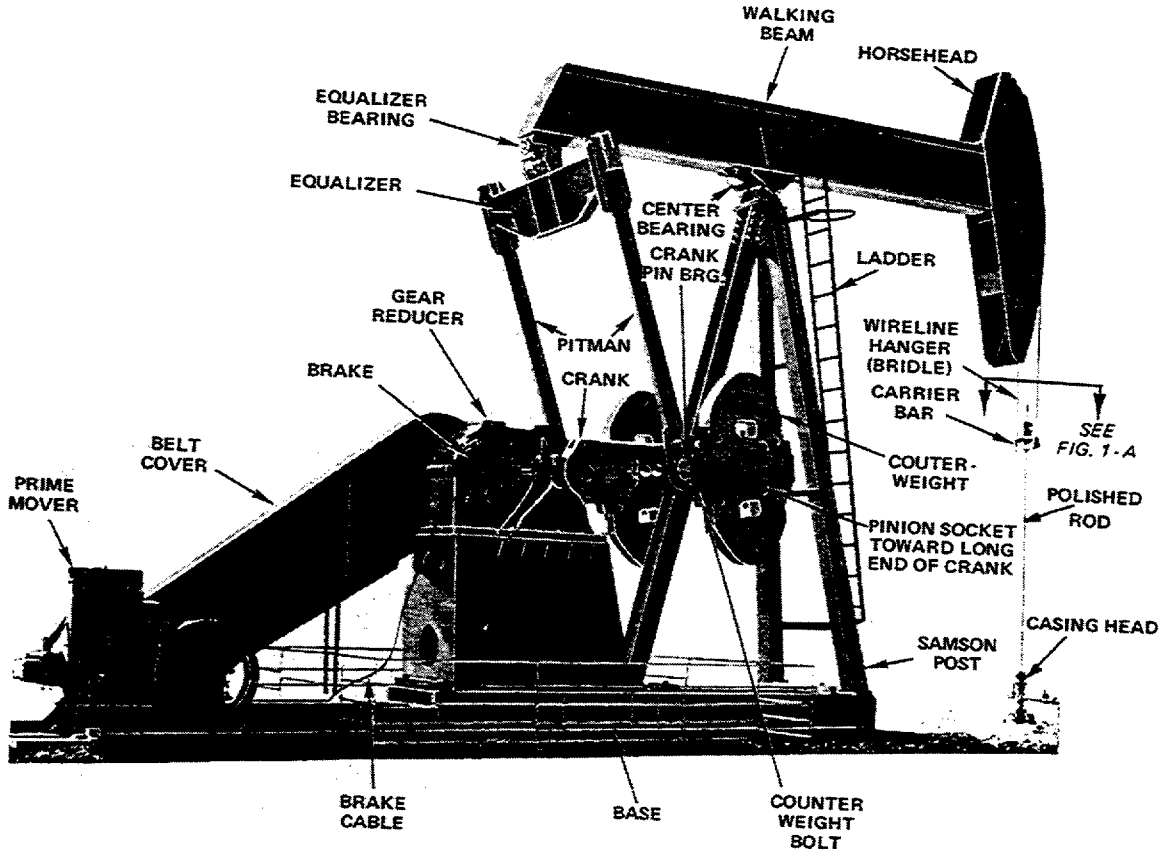


Figure 42—The major parts of a conventional crank counterbalanced beam pumping unit are shown in this drawing. All units are not exactly like this one, but they operate generally in the same way.

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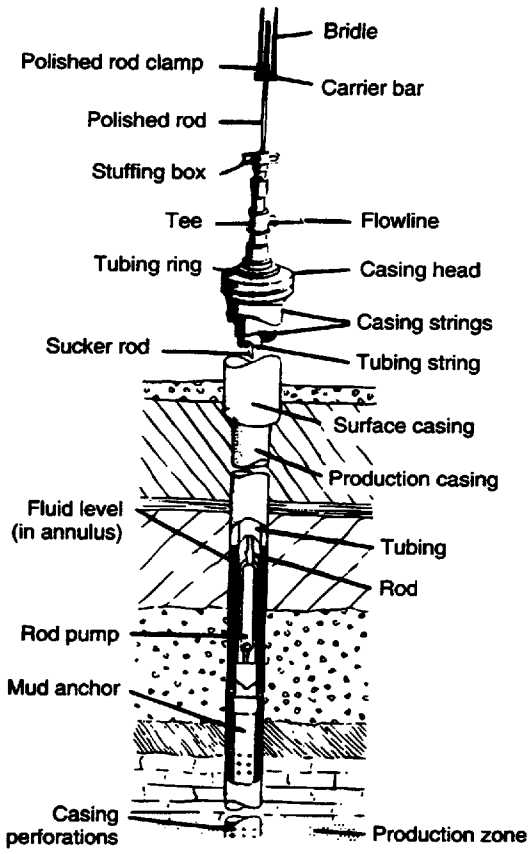


Figure 43—This sketch shows the principal items of wellhead and down-hole equipment installed for a typical sucker rod pumping system.

which a unit should be operated depends on many factors, some of which are:

a. Produced fluid characteristics.
b. Producing rate.
c. Depth of pump.
d. Length of stroke.
e. Gear box size.
f. Unit loading.
g. Pumping speed acceleration.

Conventional units use counterweights on the cranks or on the pitman end of the walking beam to counterbalance the weight of the sucker rod string immersed in well fluid plus about half of the fluid weight on the plunger during the up stroke. Prime mover and gear reducer size are minimized by optimum counterbalancing. The smaller conventional units usually have beam counterbalance only. Medium-sized conventional units are usually crank counterbalanced, but a beam counterbalance extension can be added if required. If a very large beam unit is required, a unit with air counterbalance is available. Medium and relatively large special

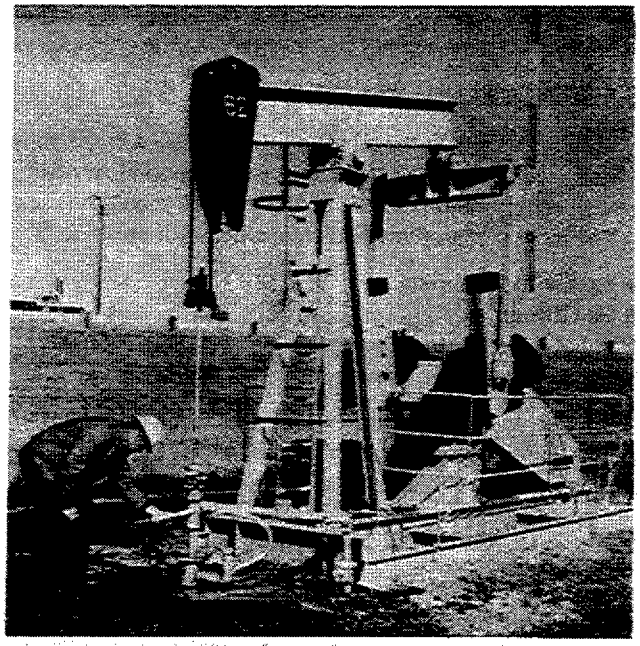


Figure 44—Field installation of a conventional beam pumping unit.

geometry beam units are also available. The special geometry units (Figure 45) and air balanced units (Figure 46) can, in some instances, result in more economical pumping installations.

Pumping wells need a means of packing or sealing off the pressure inside the tubing to prevent leakage of liquid and gas around the polished rod. The stuffing box, shown in Figure 43, is used for this purpose. It consists of flexible mate-

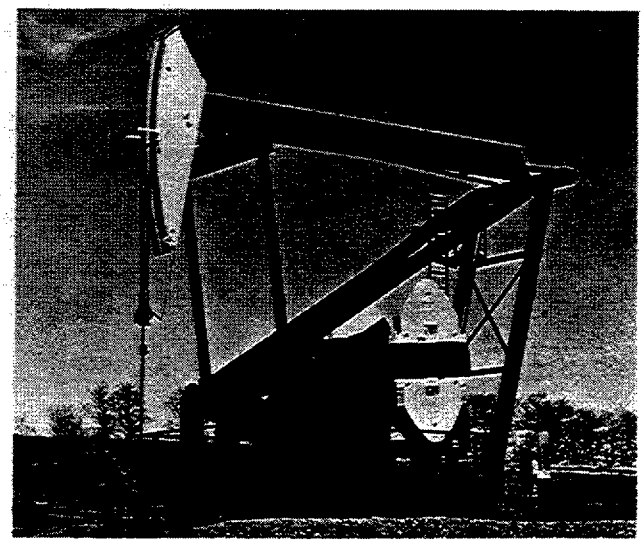


Figure 45—Field installation of a special geometry beam pumping unit.

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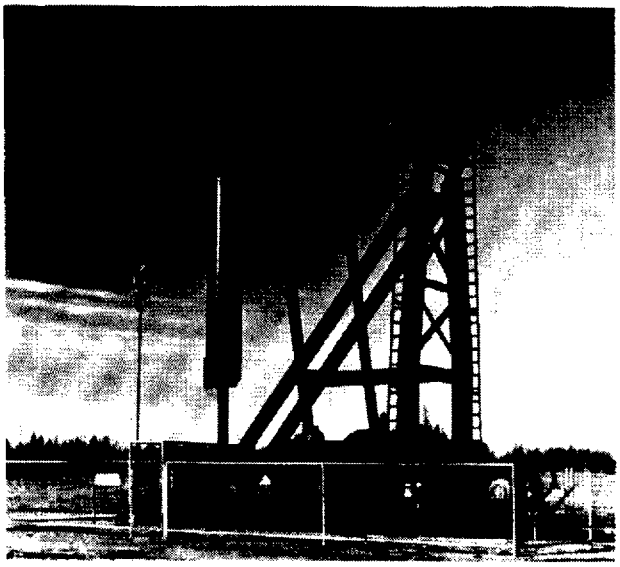


Figure 46—Air balanced beam pumping unit

rial or packing housed in a cast- or forged-steel box which provides a method of compressing the packing. The stuffing box packing is replaced by field operating personnel when it becomes worn and loses its seal.

Sucker rods are run inside the production tubing string to connect a sucker rod pump to the pumping unit. The most commonly used sucker rods are solid, one piece, round, steel rods. They are made in sizes from $^{5}/_{8}$-inch through $1^{1}/_{4}$-inch diameter, in $^{1}/_{8}$-inch increments. The standard length is 25 feet, with 30 feet being available on special order. The standard rod has threaded pins on each end to permit the rod to be connected with a coupling, as shown in Figure 47.

Subsurface sucker rod pumps are cylindrical, reciprocating, positive displacement pumps that lift liquid from the well to the surface. They are divided into two general types: rod pumps and tubing pumps.

Complete rod pump assemblies are installed on the sucker rod string. The pumps are either stationary barrel pumps with top or bottom hold-down, or traveling barrel pumps. Stationary barrel pumps have reciprocating plungers actuated by valve rods, which connect to the sucker rod string. In traveling barrel pumps, the barrel is actuated by the rod string and reciprocates over the plunger which is held in place by a bottom hold-down.

Tubing pumps are run on the lower end of the tubing string with the barrel assembly being an integral part of the tubing string and the plunger assembly part of the sucker rod string.

The operation of either type of pump is basically the same. The principal pump parts include the outer shell or barrel, the plunger, a standing valve, a traveling valve, and a seating assembly. Both types of pumps are shown in Figure 48. The service life and operating efficiency obtained from a pump depends upon proper selection and care used in the original installation, proper operation, and the quality of subsequent maintenance.

Good practice in all pumping operations is to provide reasonable pump submergence and then to match pump displacement to the actual production rate of the well. This can be accomplished by either of two basic methods. One is to provide an excess of pumping capacity and then control the production rate by intermitting the pumping times. This is most commonly practiced with an electric motor as the prime mover, using either a time clock or a pump-off motor controller. The other method is to select the bottomhole pump size, pumping unit stroke, and pumping unit speed in a practical combination to reasonably match the production rate and operate the well on a continuous basis.

The pumping cycle for the types of pumps shown in Figure 48, where the plunger travels, starts with an upward stroke of the rods, which strokes the plunger upward in the barrel. The traveling valve closes, the standing valve opens, and fluid enters the barrel from the well. On the downward stroke of the rods and plunger, the standing valve closes, the traveling valve opens, and the fluid is forced from the barrel through the plunger and into the tubing. Fluid is lifted toward the surface with each repeated upstroke.

5.3 Pump-Off Controllers (POC)

Pump-off controllers (POC) are used to prevent sucker rod pumps from operating when the fluid level in the well bore

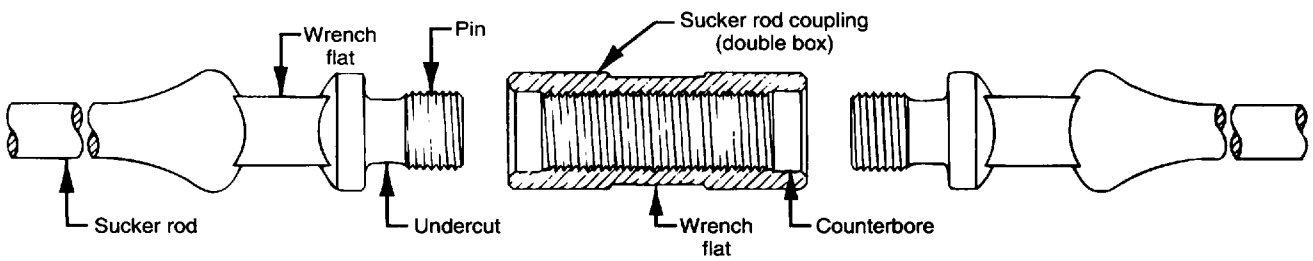


Figure 47—Typical sucker rod joint

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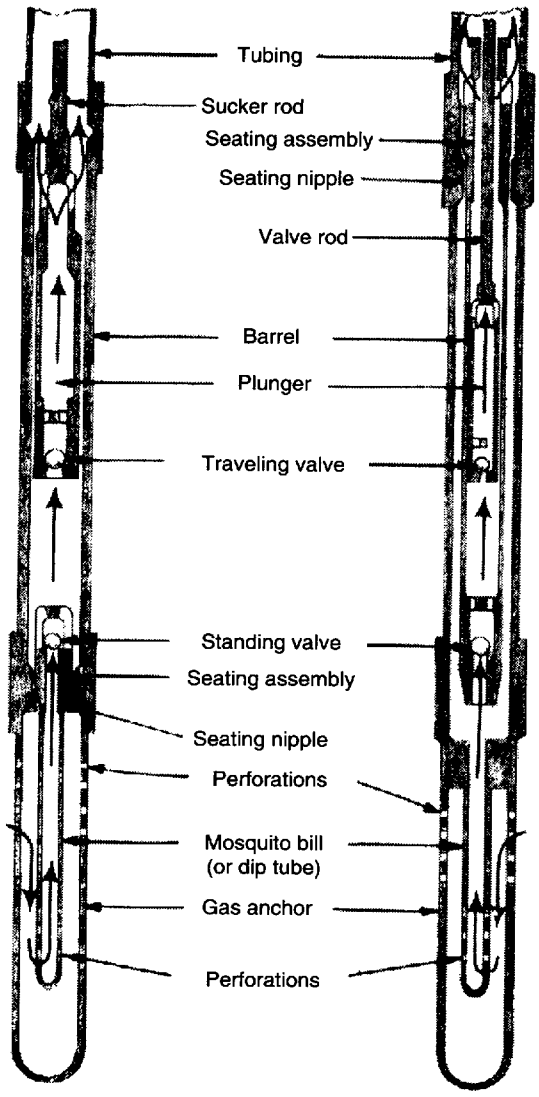


Figure 48—This shows two types of sucker rod pumps. The pump at left is a tubing type. On the right is a stationary barrel, top hold-down, rod type. The rod type pump and barrel can be removed from the well without removing the tubing. These simplified sketches do not show the seating assembly cups.

is too low. POC design may be based on any of several principles. The simplest is the use of a timer allowing fluid levels to build up between pumping cycles. The operator must estimate the appropriate lengths of the on time and off time. Other devices may turn off the pump by detecting the increased temperature of the sucker rod and packing at the wellhead when the well is pumped dry, or by responding to the pounding that occurs in the sucker rods and plunger on the down stroke when fluid levels get too low in the well bore. Pump-off controls can reduce well maintenance and energy usage.

5.4 Gas Lifting

Gas lifting is a method of producing oil in which gas under pressure is used to lift the well fluids. There are two basic types of gas lift installations: continuous flow and intermittent lift. This method of lifting oil is accomplished by a combination of the following processes:

a. Aeration (mixing of the gas and liquid) of the fluid column in the well.
b. Work of expansion of compressed gas.
c. Displacement of fluid by the compressed gas.

Present gas lift practices include the use of specially designed gas lift valves which are installed on the tubing string, as shown by Figure 49. These valves are placed in openings spaced along the tubing string and are run to provide an injection gas flow path between casing and tubing. Gas lift valves can also be run in side pocket mandrels and pulled and replaced with a wireline unit. The operation of running and pulling valves by wireline is shown in Figure 50. In operation, gas under pressure is injected into the space between casing and tubing, and enters the tubing through the open gas lift valve. Liquid in the tubing above the operating gas lift valve is displaced or lightened by mixing with gas, and is raised to the surface by the expanding gas. Continuous flow gas lift is characterized by continuous injection of high pressure gas into the well annulus and continuous gas and liquid production from the well. In a low productivity well, where considerable time is needed for liquid to build up in the tubing, gas is injected into the well at predetermined intervals and displaces the fluid to the surface in slugs. This is known as the intermittent gas lift system.

Gas lift is the most widely used artificial lift technique in offshore operations. The primary reason for this is that the surface well equipment is minimized and gas is usually available from high-pressure gas wells or a compression system which can double as compression for sales as well as gas lift applications. Offshore, wireline retrievable gas lift valves are run extensively since removing the tubing to pull gas lift valves from the well usually requires a workover rig. This is extremely costly compared to wireline operations. Continuous flow gas lift is the preferred method of gas lifting offshore wells, since the high and low pressure piping systems are usually of limited capacity. There are also many onshore gas lift installations.

5.5 Subsurface Electrical Pumping

A subsurface electrical pump is a specially built centrifugal pump, the shaft of which is directly connected to an electric motor. The entire unit is sized so that it may be lowered into the well to the desired depth with an insulated cable extending from the surface through which electricity is supplied to the motor. Operation is controlled by a control box at the surface. In operation, the motor causes the pump to re-

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