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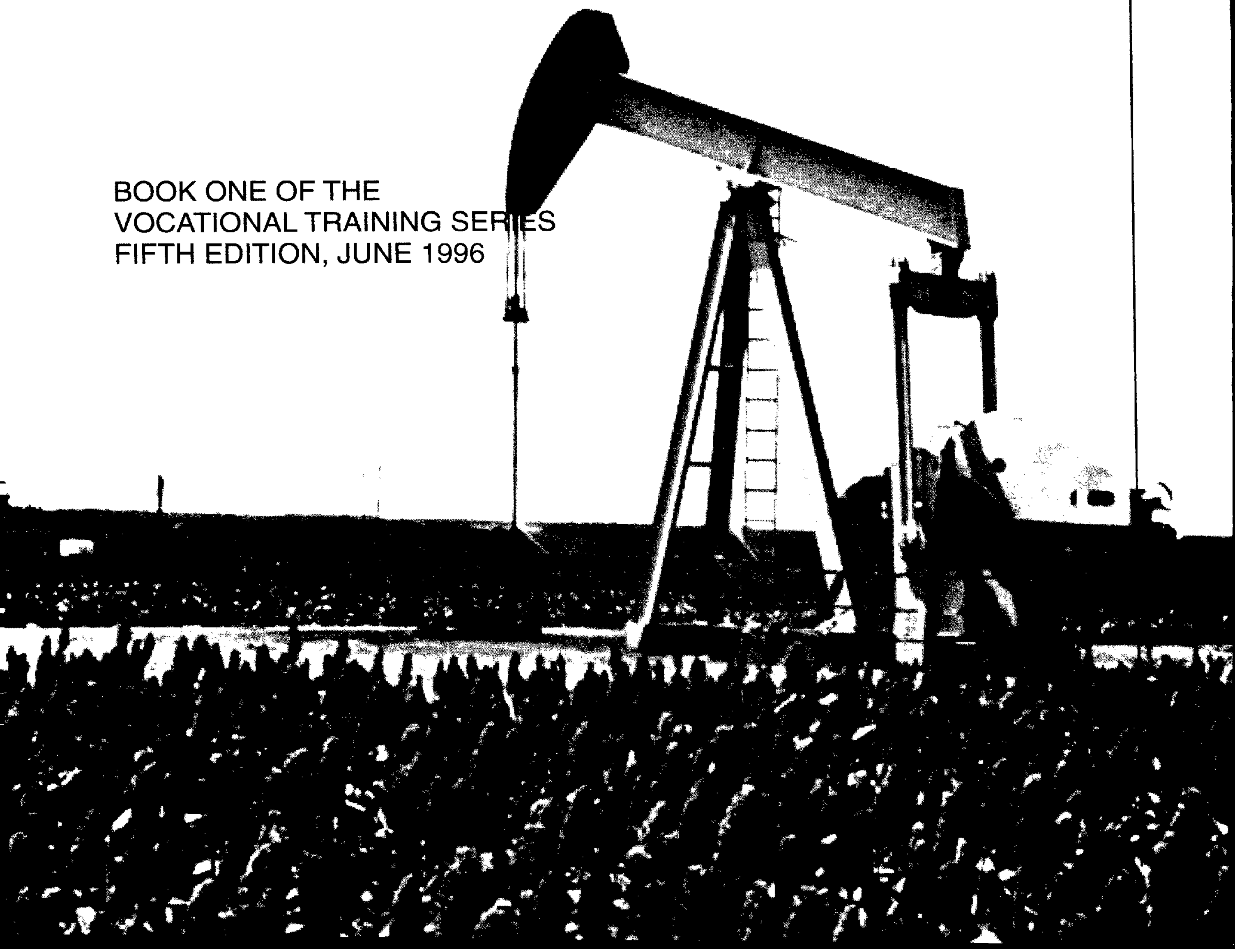
Introduction to Oil and Gas Production

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



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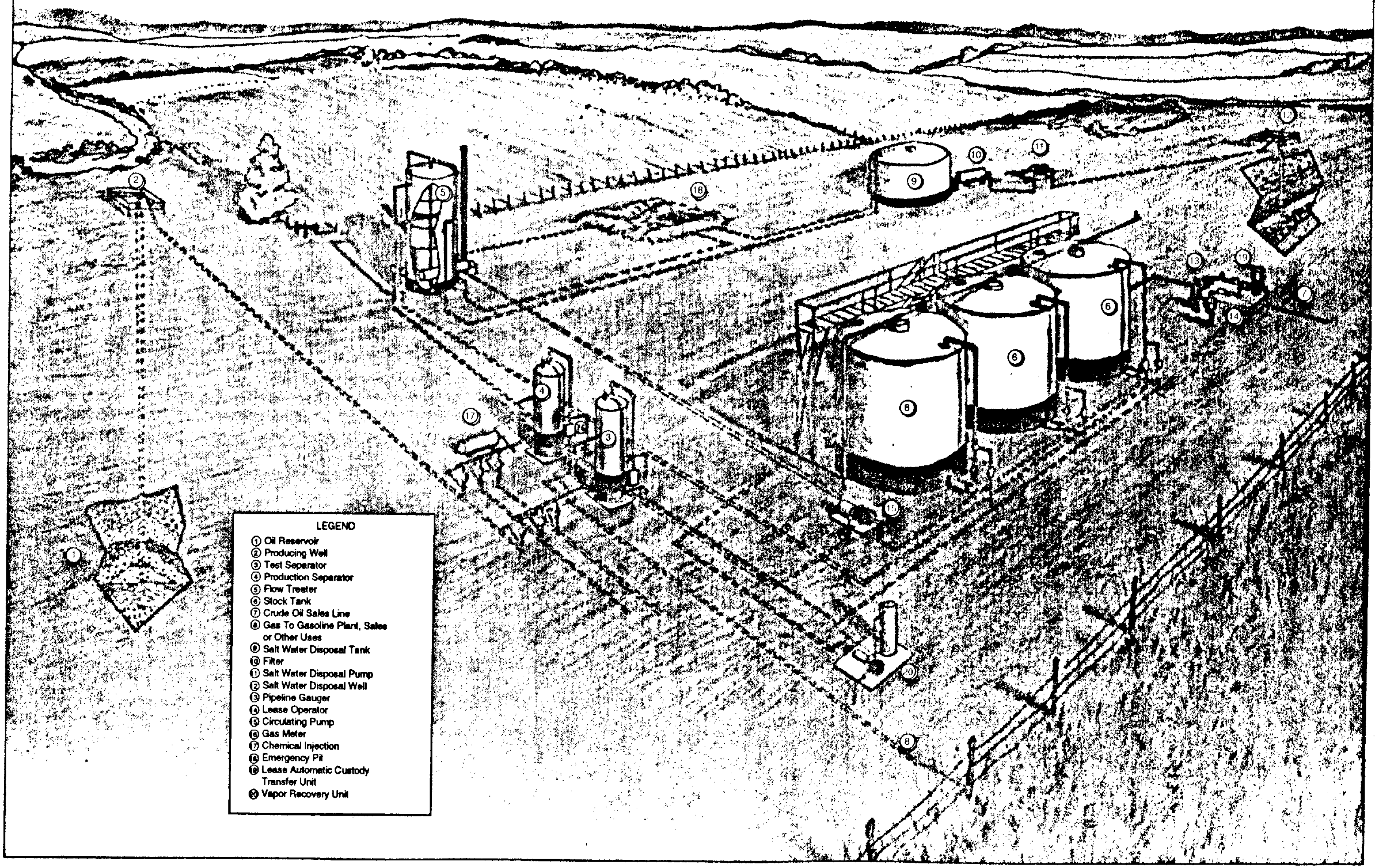
Oil Production Facility

Well and Flow Lines • Separation and Storage • Salt Water Disposal



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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.

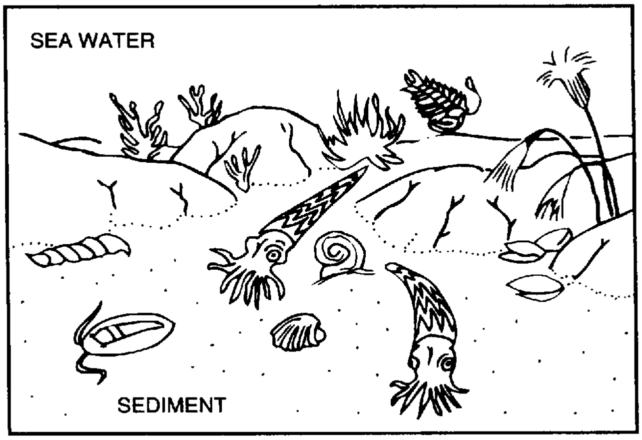

Figure 1—In the geologic past, ancient sea bottoms abounded with marine plant and animal life.

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 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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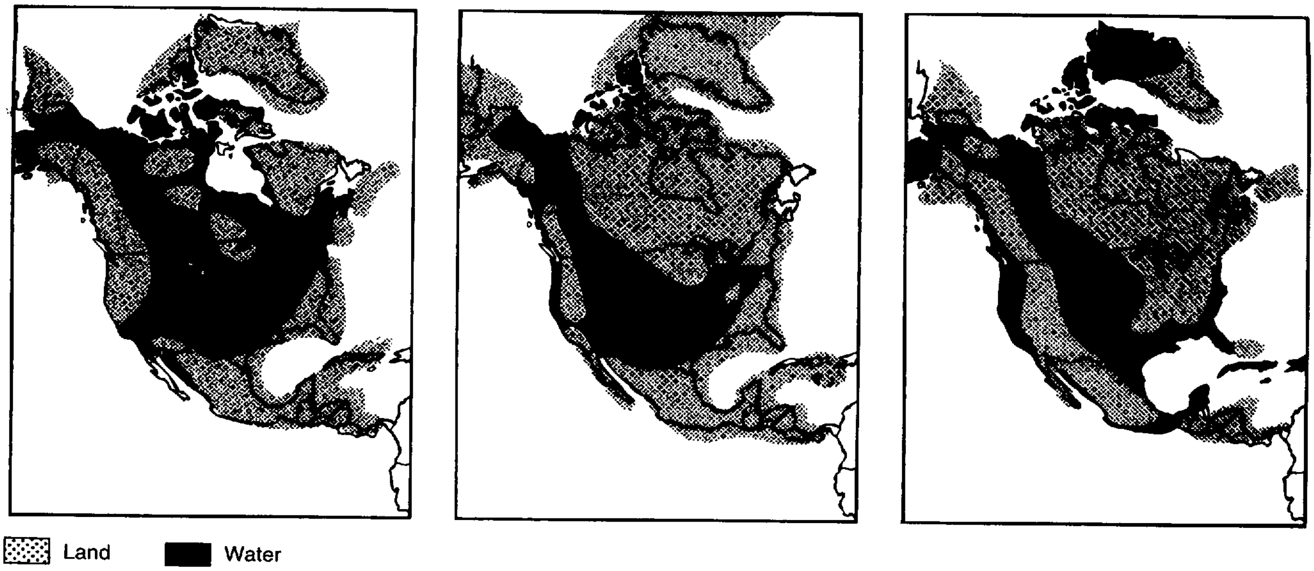

It is made up of sand grains usually mixed with particles of other material. Porous limestones and dolomites are other types of sedimentary rocks in which petroleum occurs.

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

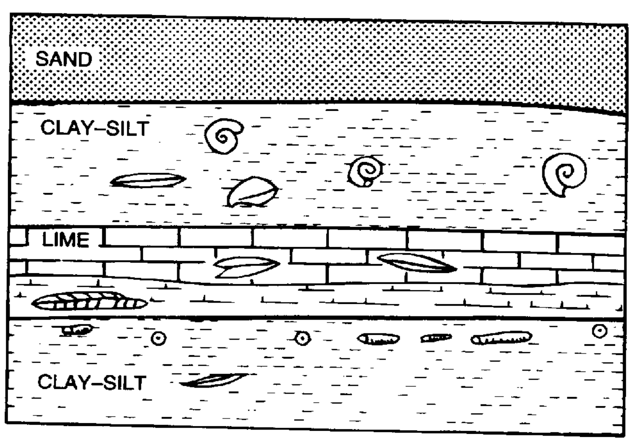

Figure 3—As the plants and animals died, their remains were buried in the accumulating sediment.

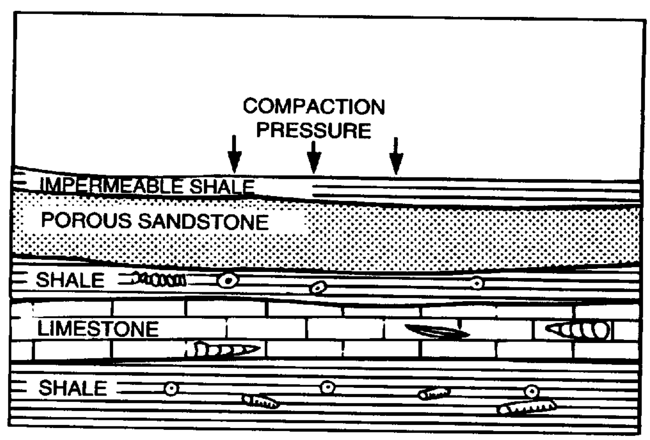

Figure 4—The weight of the overlying sedimentary layers caused compaction of earlier sediments into rock such as sandstone, limestone and shale.

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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

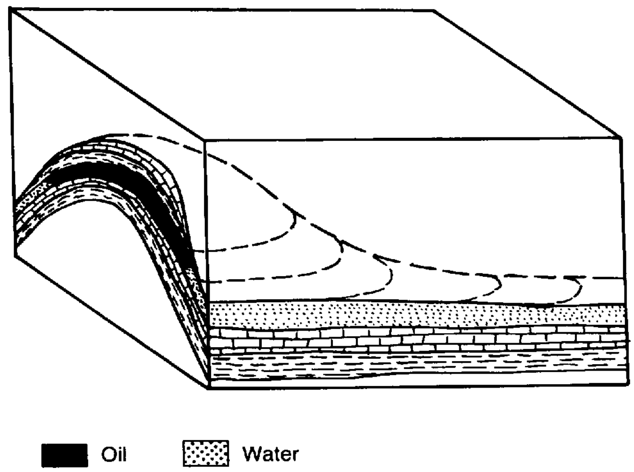

Figure 5—This sketch illustrates an oil accumulation in a dome-shaped structure. This dome is circular in outline.

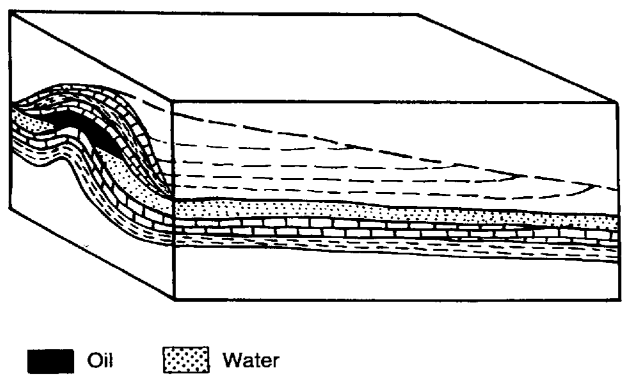

Figure 6—An anticlinal type of folded structure is shown here. An anticline differs from a dome in being long and narrow.

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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.

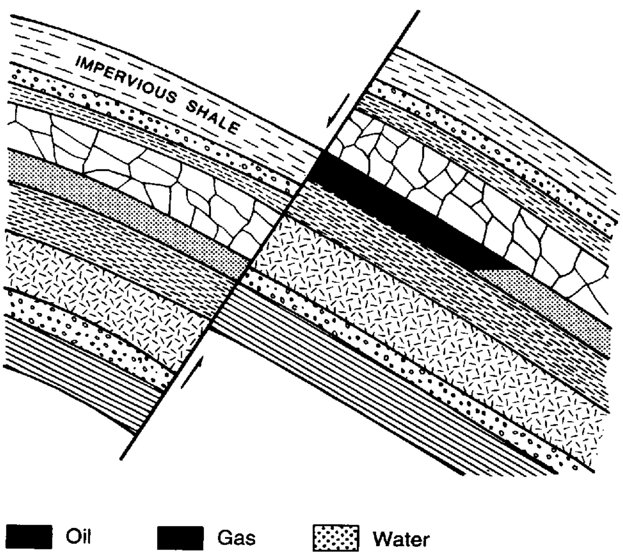

Figure 7—This is a trap resulting from faulting in which the block on the right has moved up with respect to the one on the left.

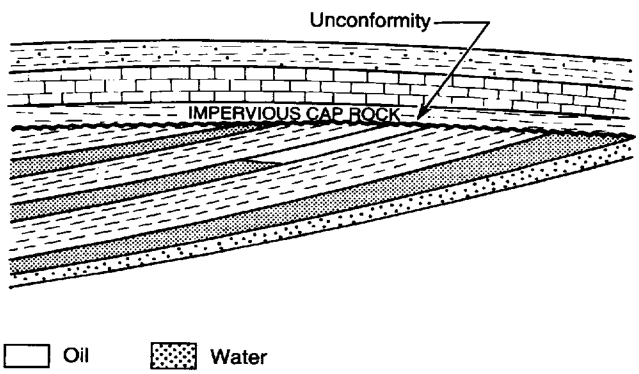

Figure 8—Oil is trapped under an unconformity in this illustration.

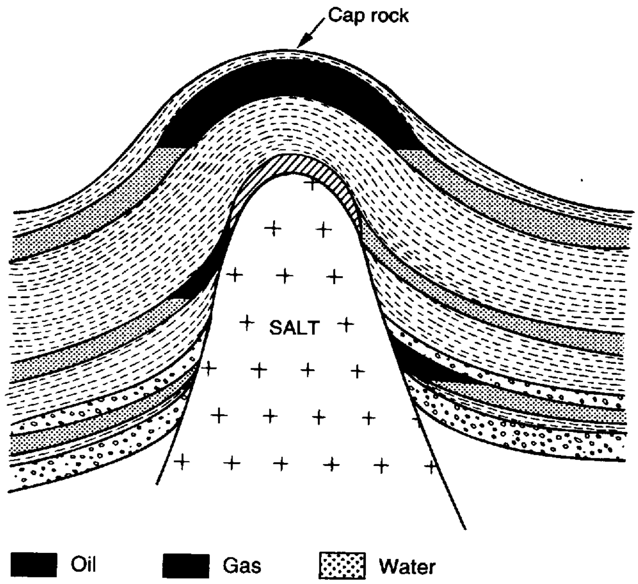

Figure 9—Salt domes often deform overlying rocks to form traps like the ones shown here.

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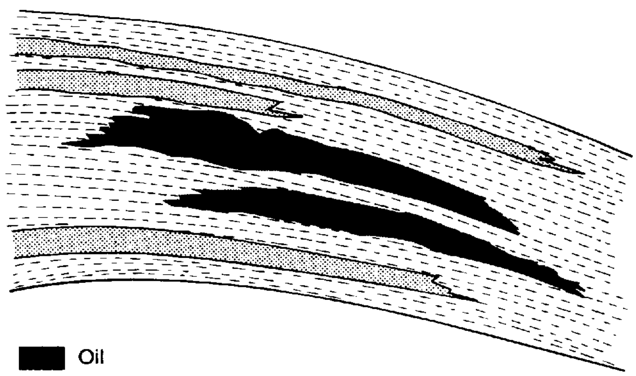
Louisiana are examples of salt dome reservoirs. Another is the famous Spindletop Field near Beaumont, Texas, where rotary drilling was first used, introducing the modern drilling era.

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.

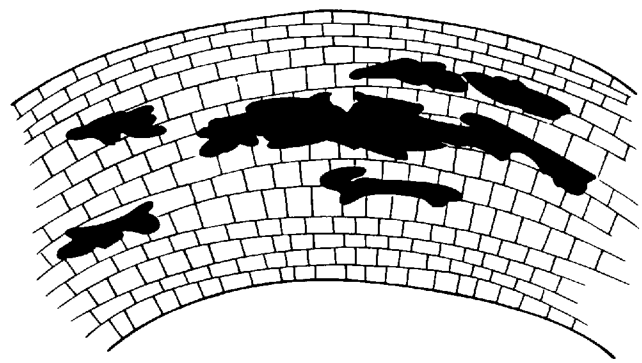
1.6.6 LENS TRAPS

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.



Oil

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

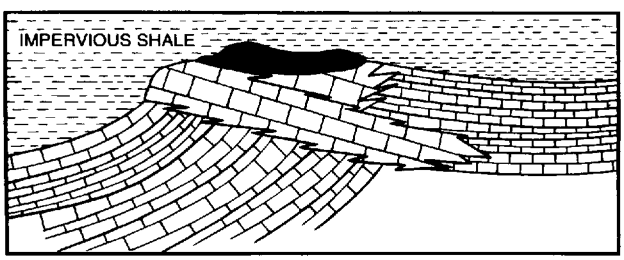


Oil

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

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.



Oil

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

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

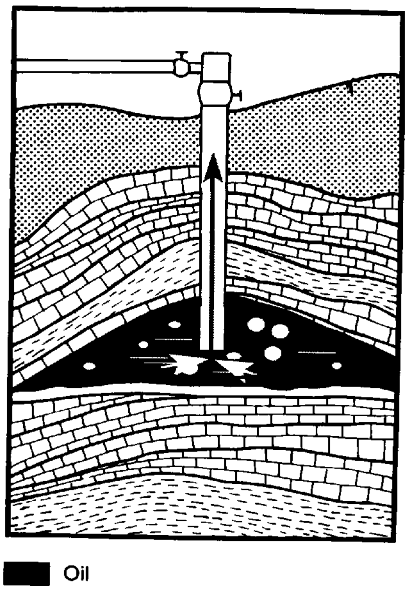

Figure 13—Solution-gas drive.

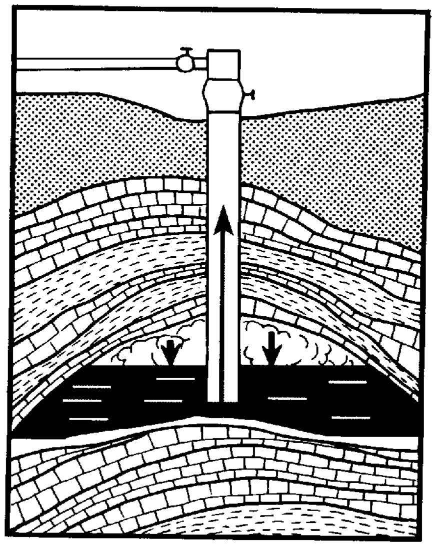

Figure 14—Gas-cap drive.

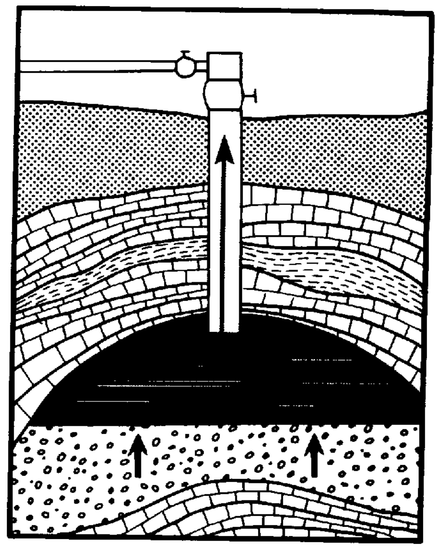

Figure 15—Water drive.

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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

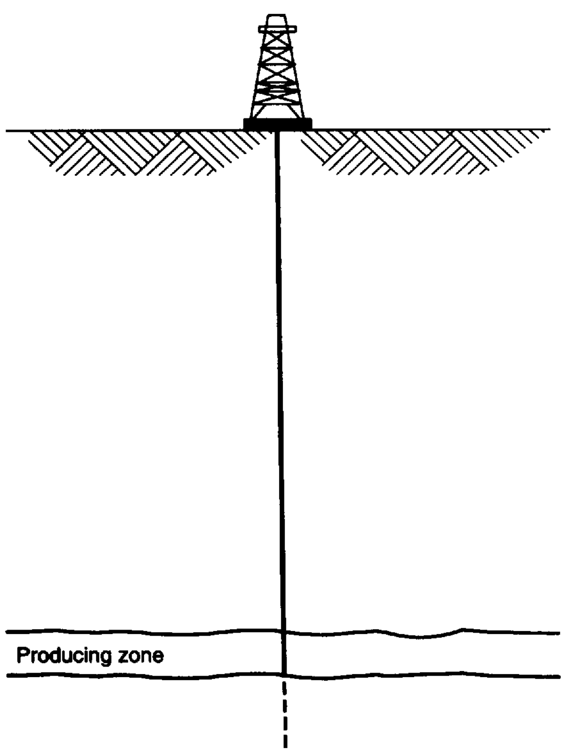

Figure 16—Straight Hole Well

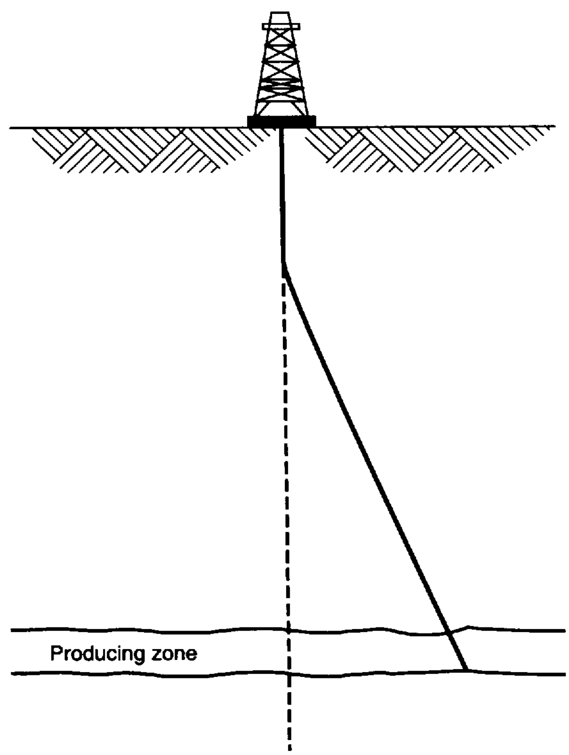

Figure 17—Straight Kick Well

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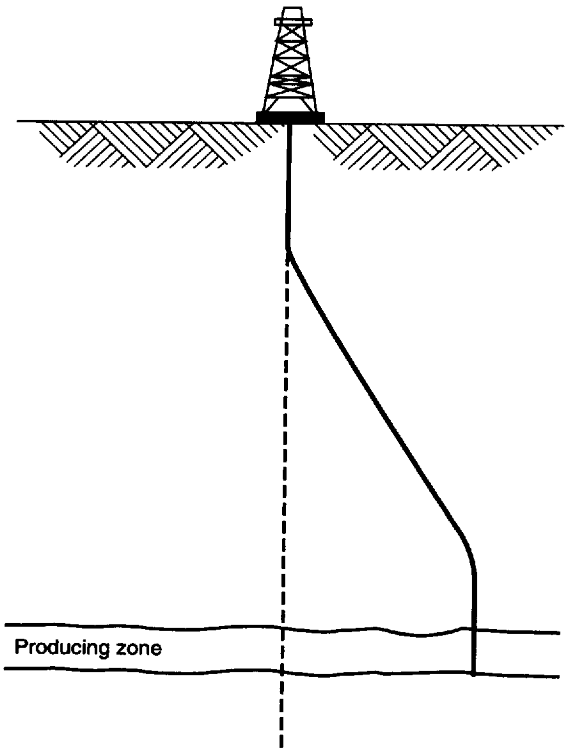

Figure 18—Kick Well

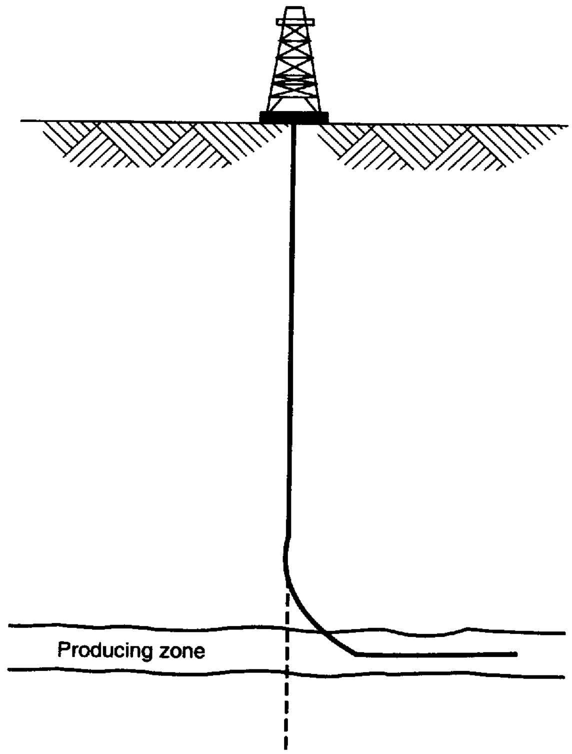

Figure 19—Horizontal Well

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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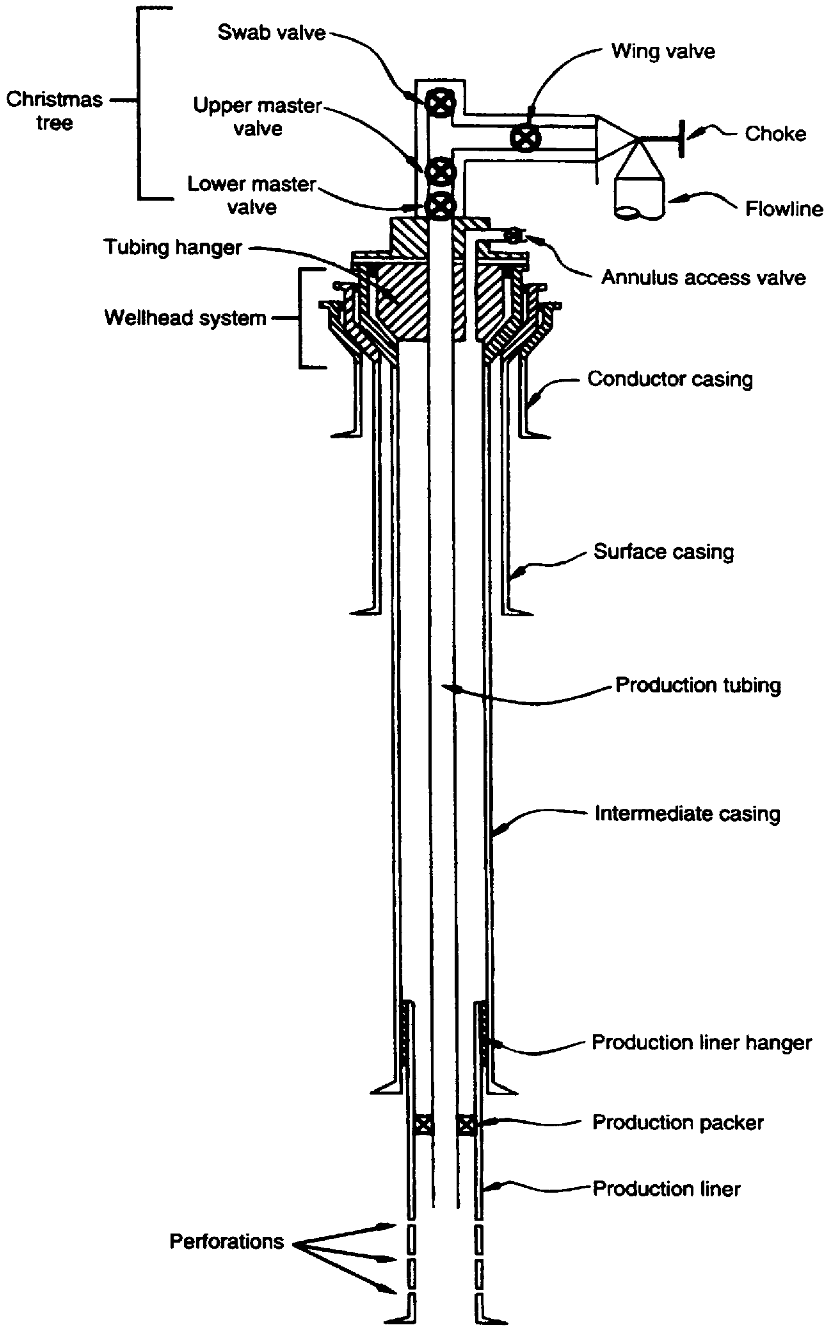

Figure 20—Simplified Diagrammatic Representation of a Well Showing the Casing Strings, Production Tubing and Christmas Tree

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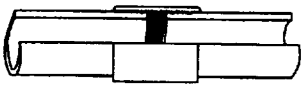
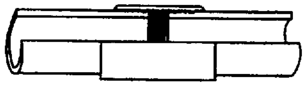
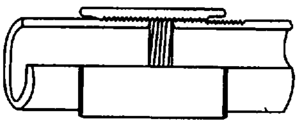


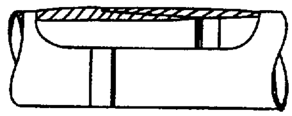
Short-coupling casing joint



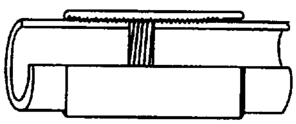
Long-coupling casing joint



API round thread casing



Extreme-line casing



API buttress thread casing

13 3/8 9 5/8 7 3 1/2 2 7/8 2 3/8

OUTSIDE DIAMETER (INCHES)

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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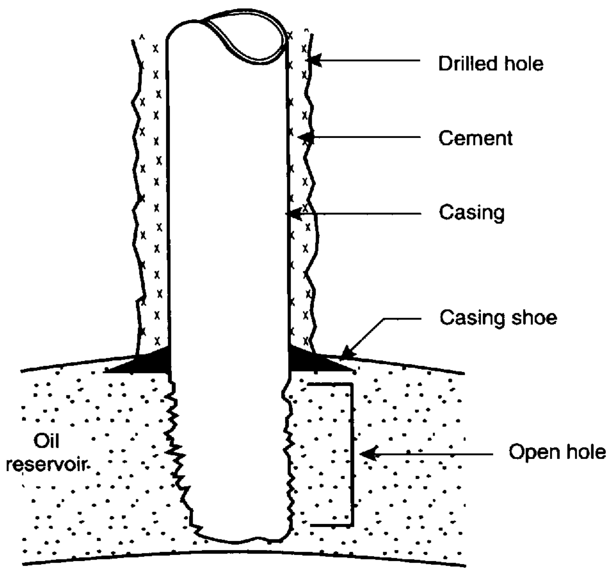

Figure 22—When the oil-producing zone is well consolidated, casing through the oil zone is sometimes not necessary. In this case it is an open-hole completion, sometimes called "bare-foot."

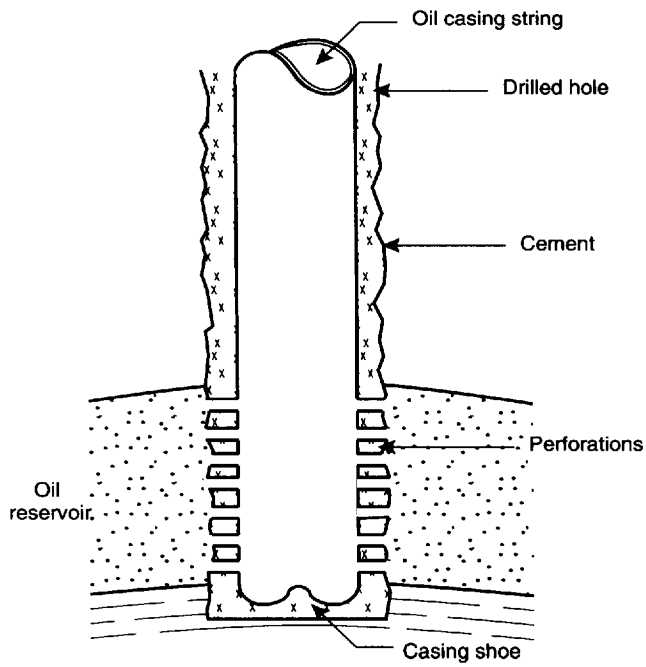

Figure 23—A perforated casing or liner is made by actually shooting bullets or shaped charges (jets) through a section of centered casing at the level of the oil-zone that is to be produced.

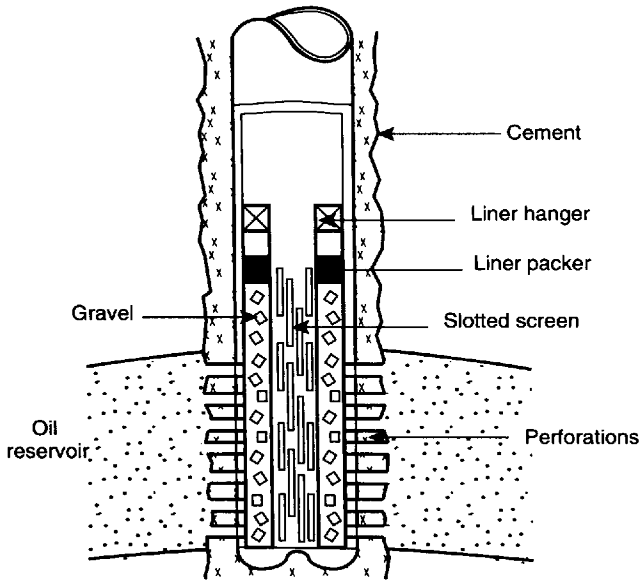

Figure 24—A gravel-packed liner is used in a well in which the producing sands are fine-grained and loose. The gravel in the space around the liner acts as a filter and keeps the sand out of the well.

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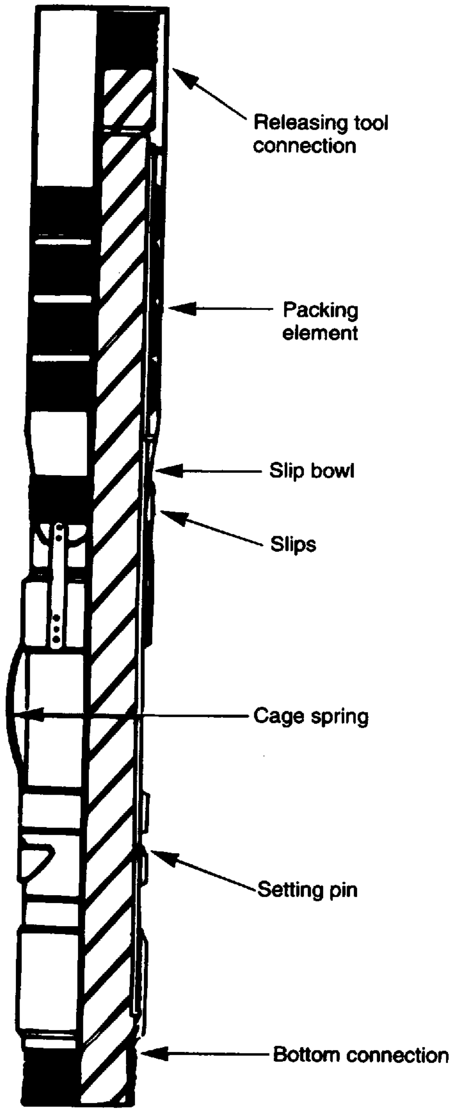

Figure 25—Liner hanger

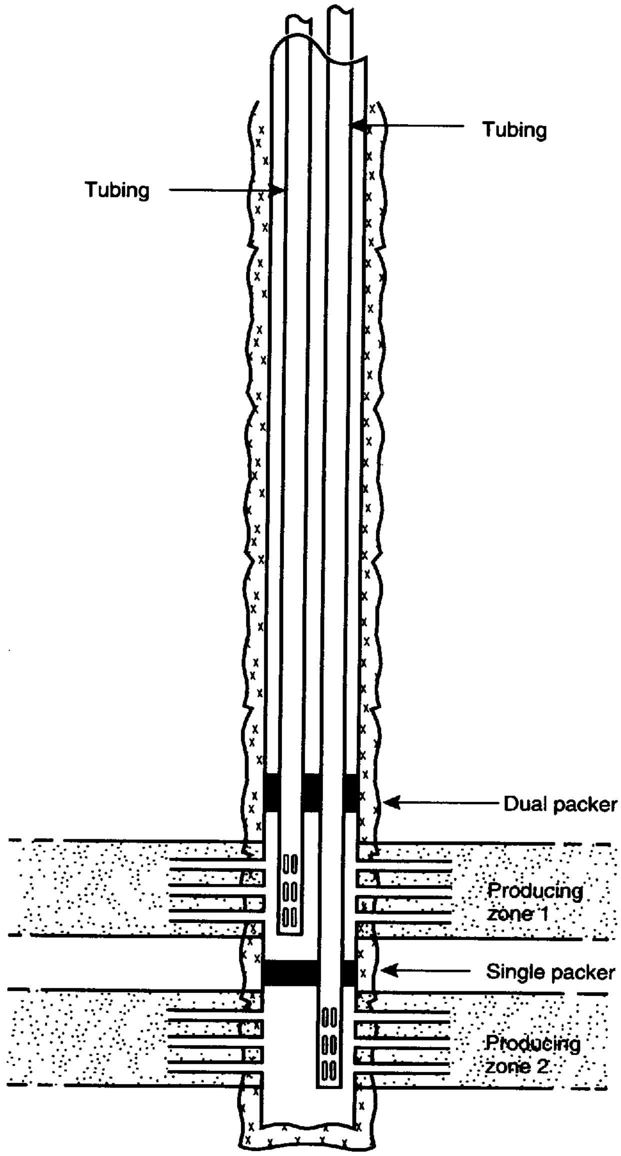

Figure 26—Schematic drawing showing subsurface details of dual type well completion.

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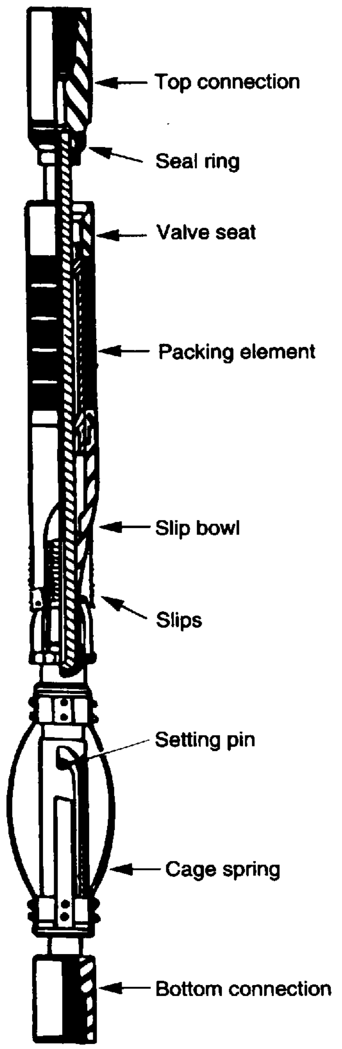

Figure 27—Type of tubing packer

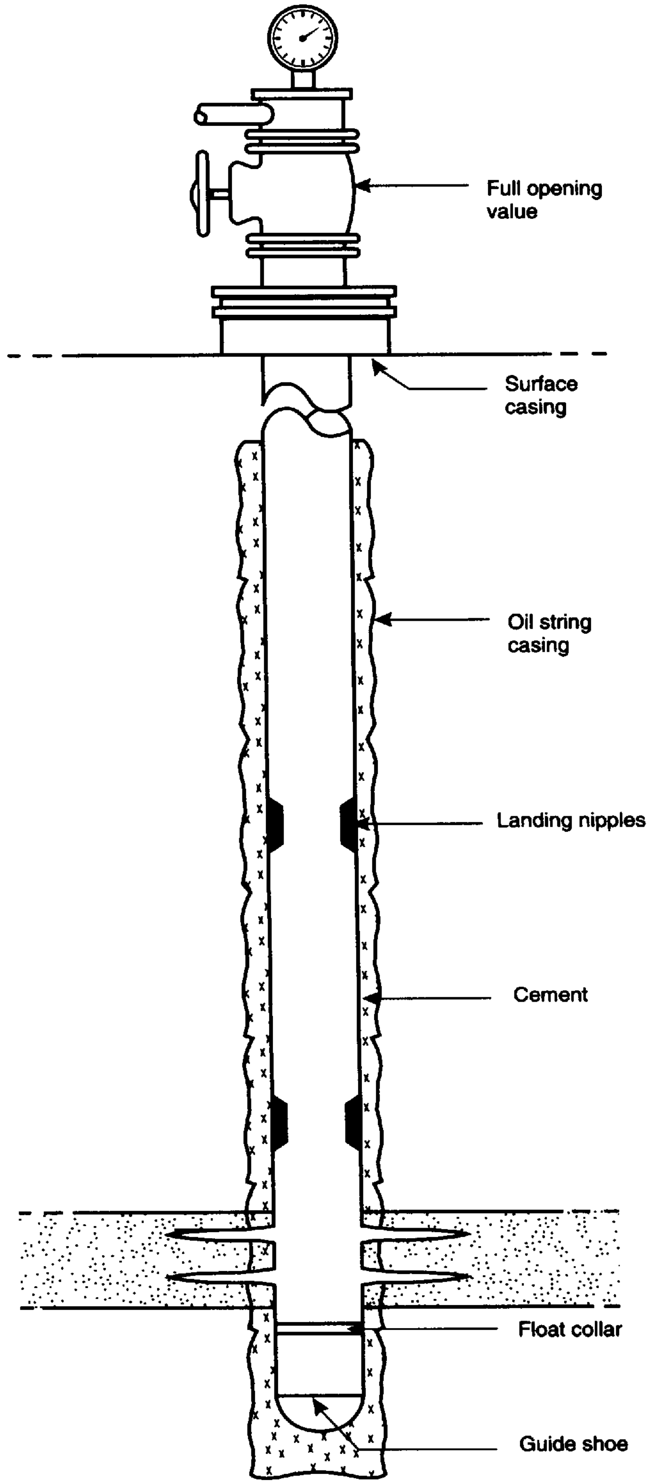

Figure 28—Schematic drawing of a tubingless completion

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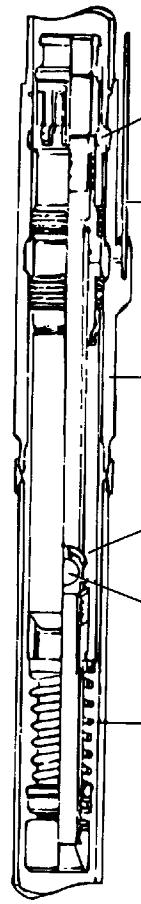

Figure 29—This retrievable sub-surface remote controlled safety valve is set in the tubing string and held open by hydraulic pressure. The power spring forces the ball to rotate shut if the hydraulic pressure is released. This valve is used in offshore wells and is set a prescribed distance below the 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-

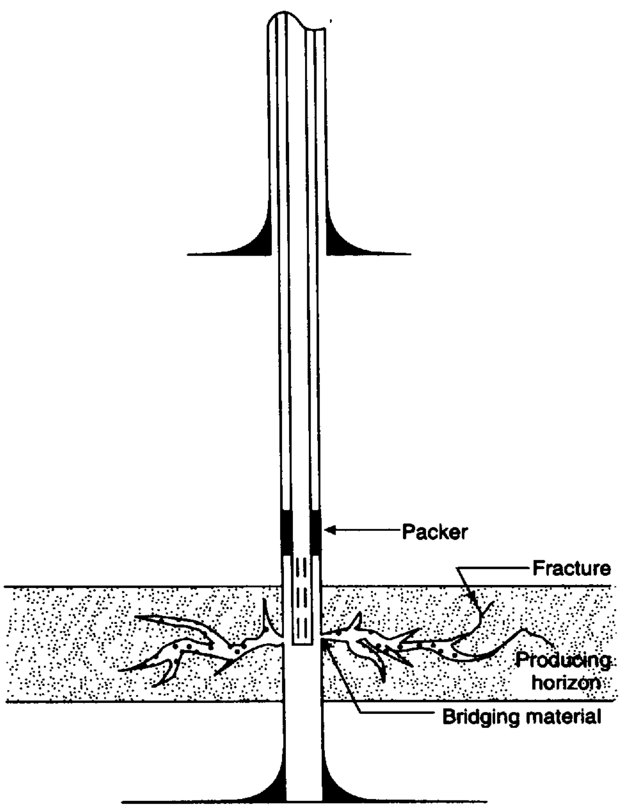

Figure 30—Shows fractures opened in the producing formation. The bridging (propping) materials are placed in the fractures to keep them open.

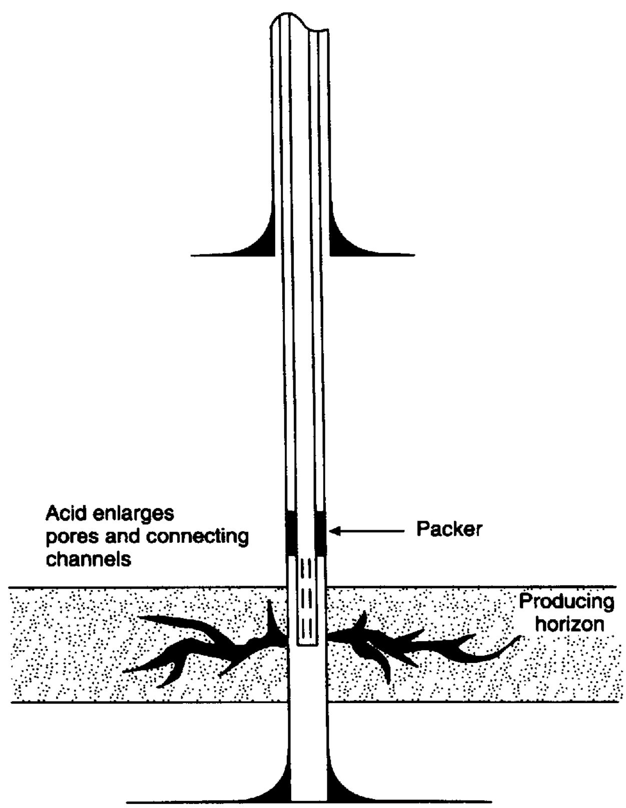

Figure 31—Shows crevice acidizing to increase the flow capacity of the pay-zone into the wellbore.

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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.

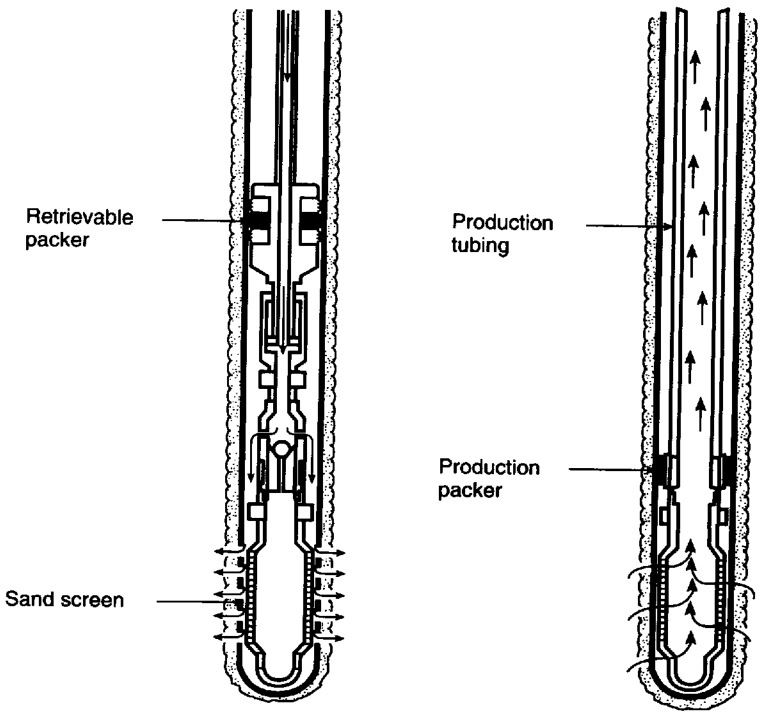

Figure 32—Illustrates one means of placing gravel opposite perforations to stabilize the formation and allow the fluid to be produced. Figure 32(a) on the left, shows the gravel flow into the formation in the annulus between the screen and the casing; Figure 32(b) shows the flow of fluids through the 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.

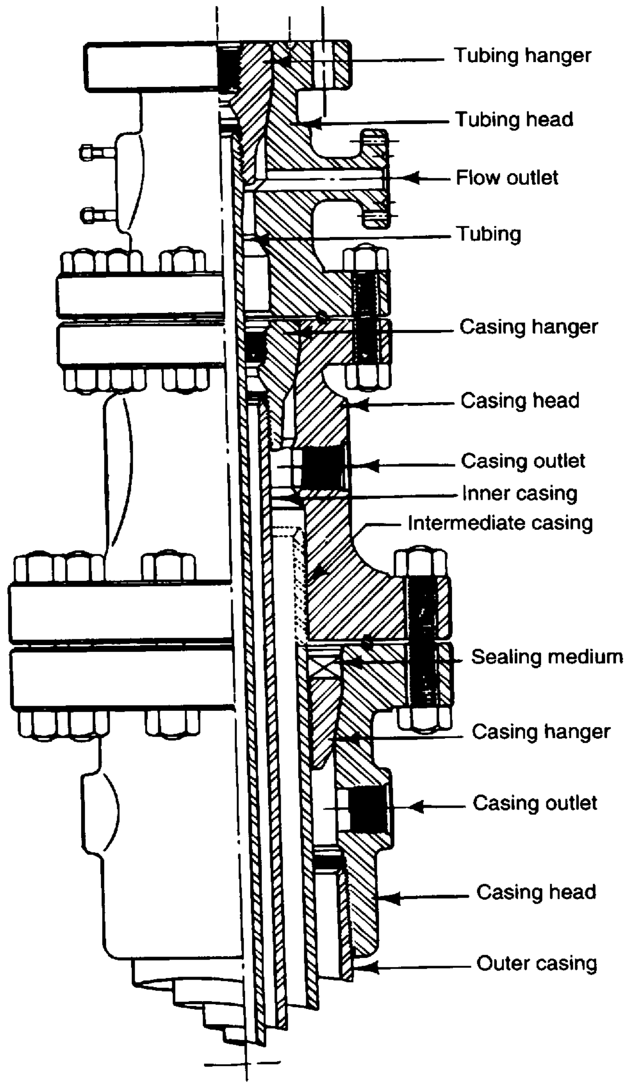

Figure 33—Typical Wellhead Assembly

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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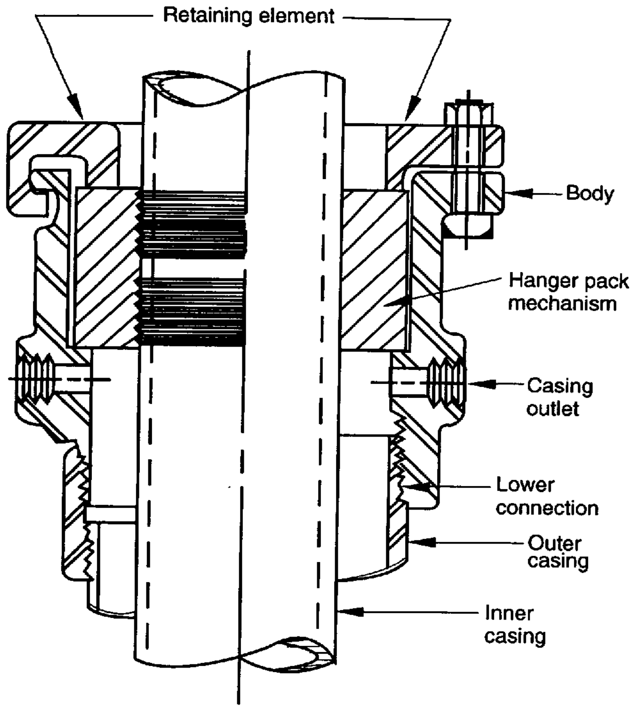

Figure 34—Independent Casinghead

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

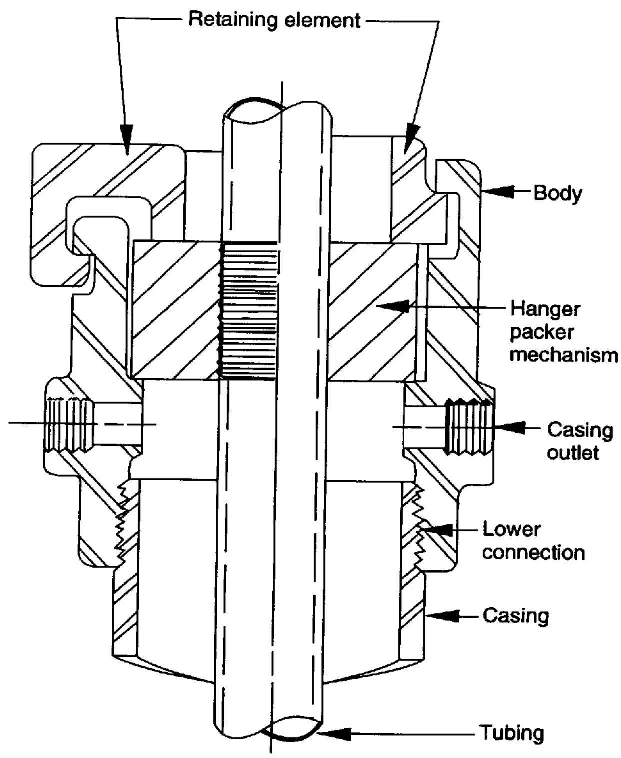

Figure 35—Independent Tubing Head

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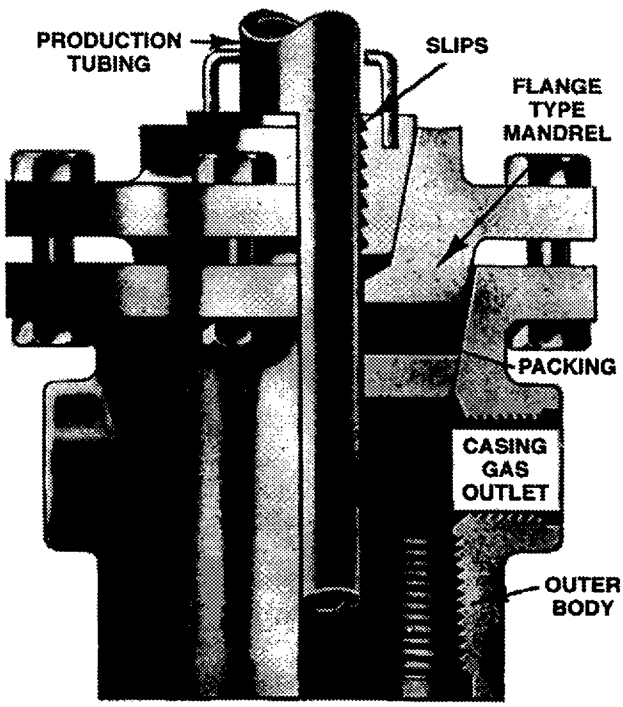

Figure 36—Another kind of slip and bowl type tubing head is shown in this cutaway drawing. The weight of the tubing and a bolted flange compress a gasket to provide sealing.

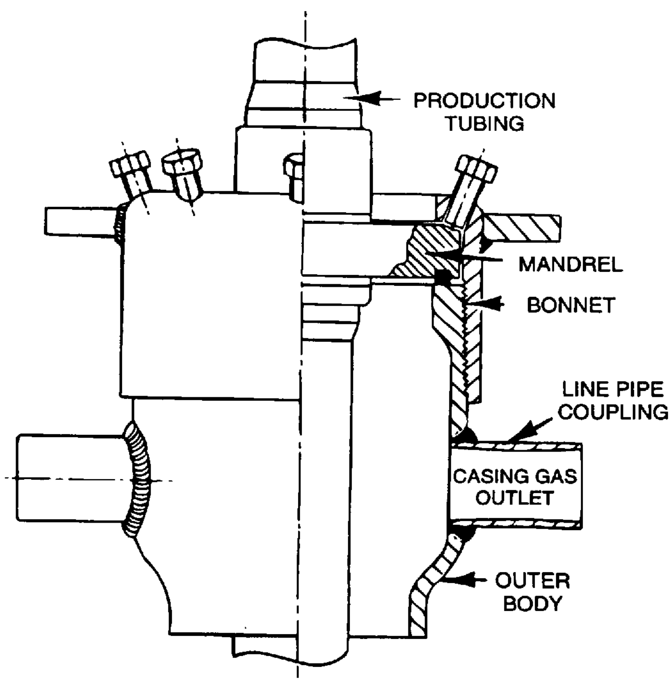

Figure 37—Low pressure tubing head. Sealing is provided by packing that is backed by a bonnet and cap screws.

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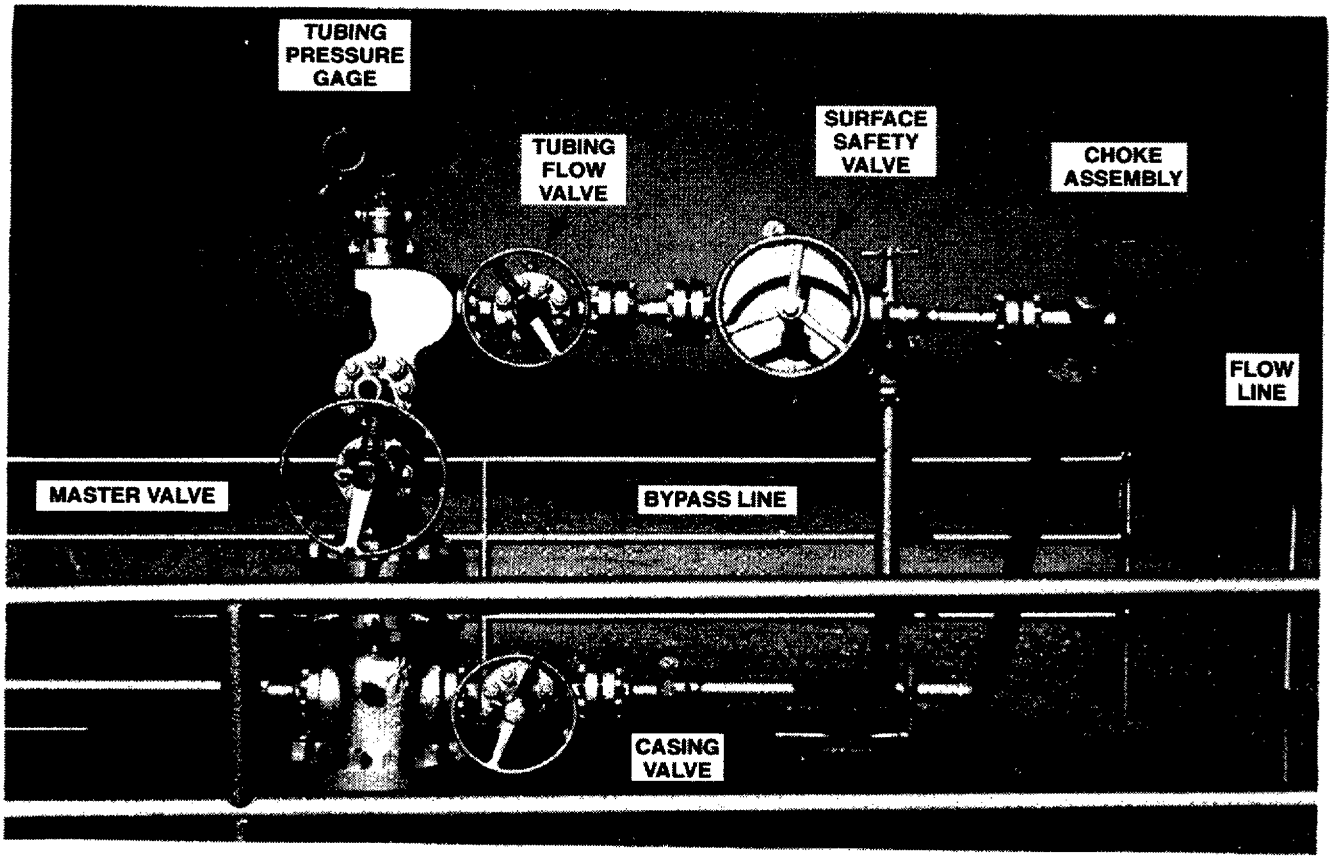

Figure 38—Single-wing type of Christmas tree on a well is shown in this photograph. Main valves and fittings are named.

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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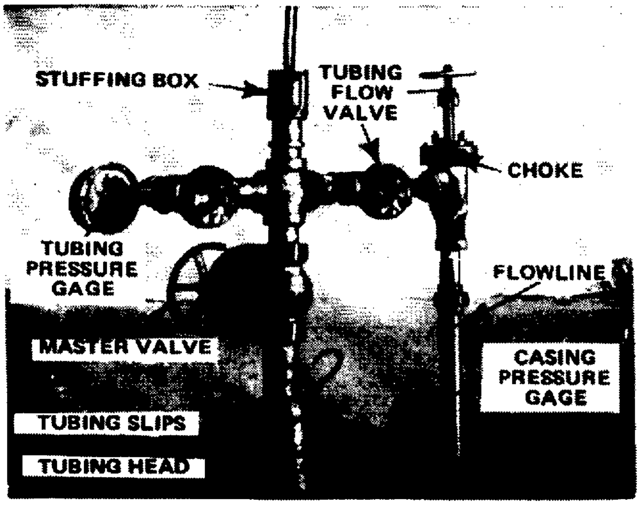

Figure 39—A very simple type of Christmas tree is installed on pumping wells. This photograph shows one example.

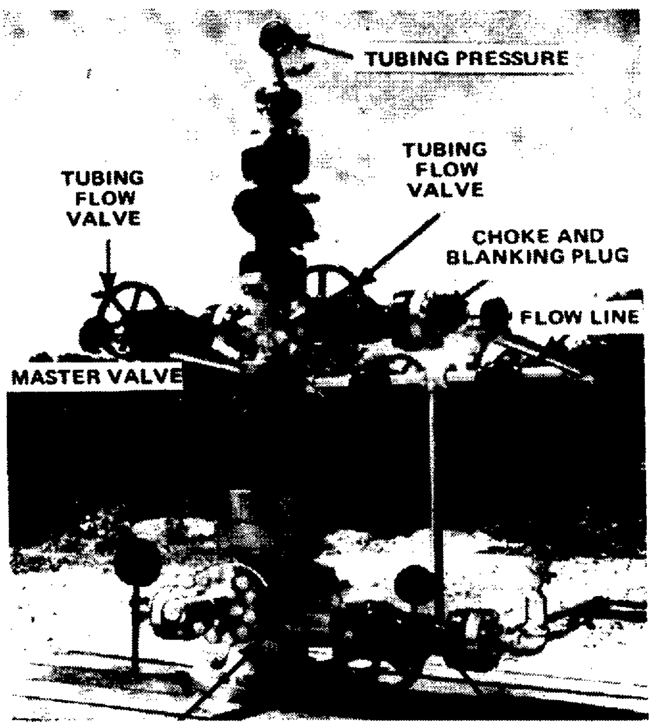

Figure 41—A high-pressure double wing Christmas tree is shown here. Flow from the well can go through tubing flow valves on either side.

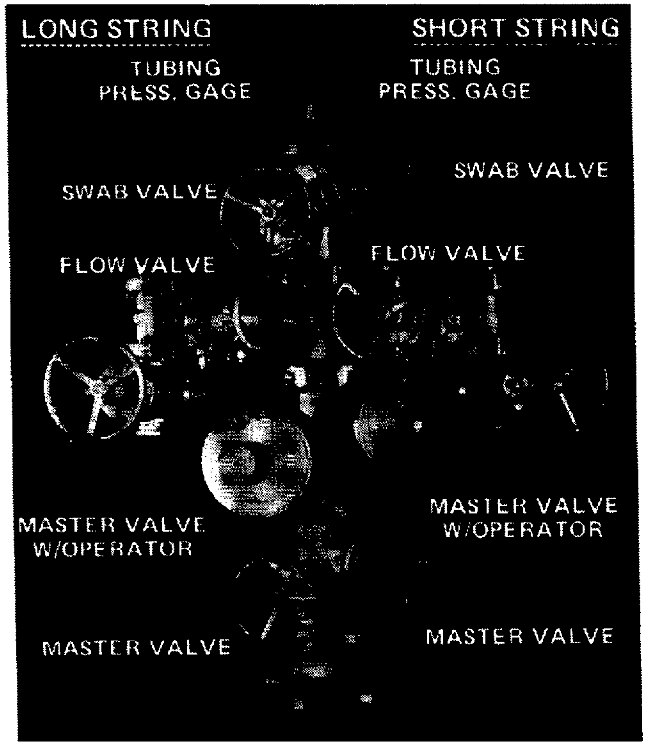

Figure 40—A dual completion type Christmas tree assembly ready for installation on a well.

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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 counter-balanced 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

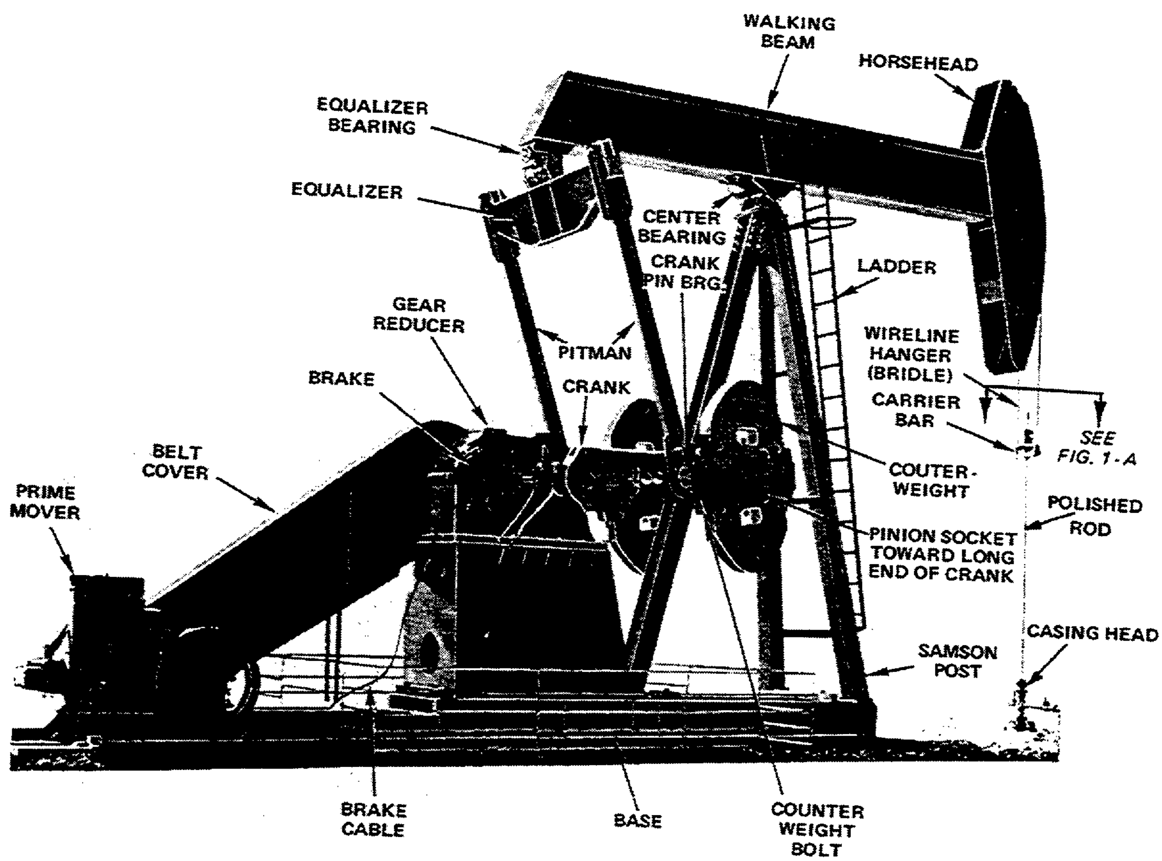

Figure 42—The major parts of a conventional crank counterbalanced beam pumping unit are shown in this drawing. All units are not exactly like this one, but they operate generally in the same way.

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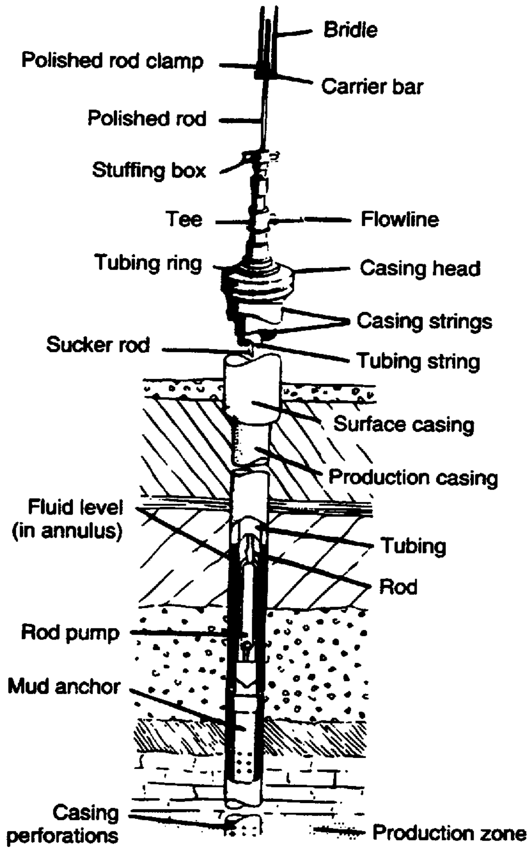

Figure 43—This sketch shows the principal items of wellhead and down-hole equipment installed for a typical sucker rod pumping system.

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

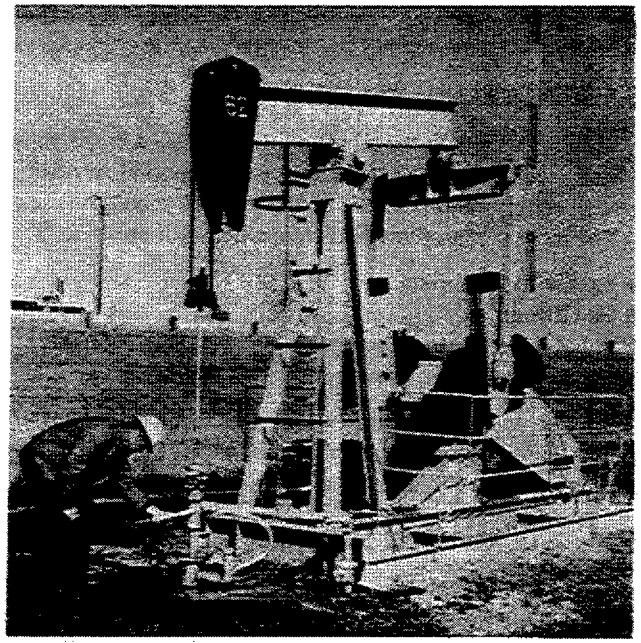

Figure 44—Field installation of a conventional beam pumping unit.

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-

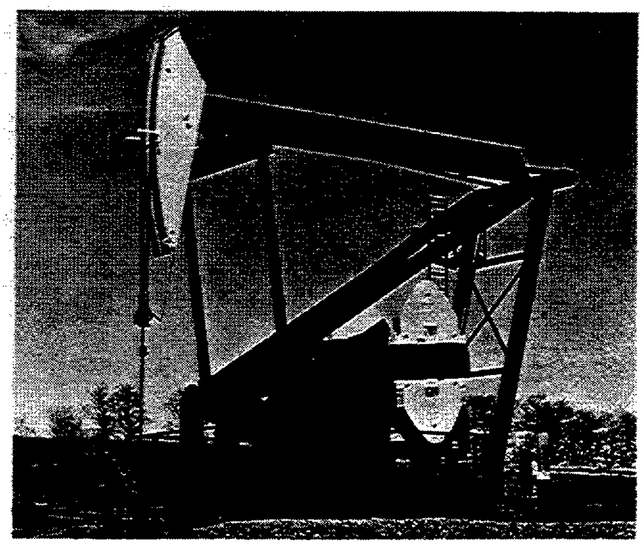

Figure 45—Field installation of a special geometry beam pumping unit.

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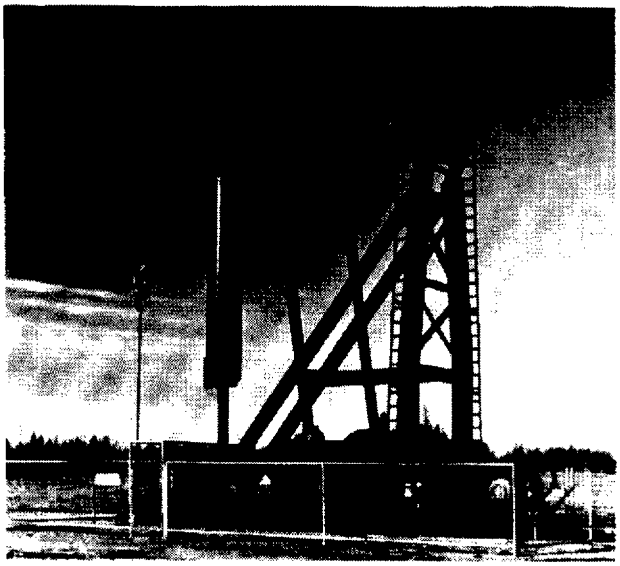

Figure 46—Air balanced beam pumping unit

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

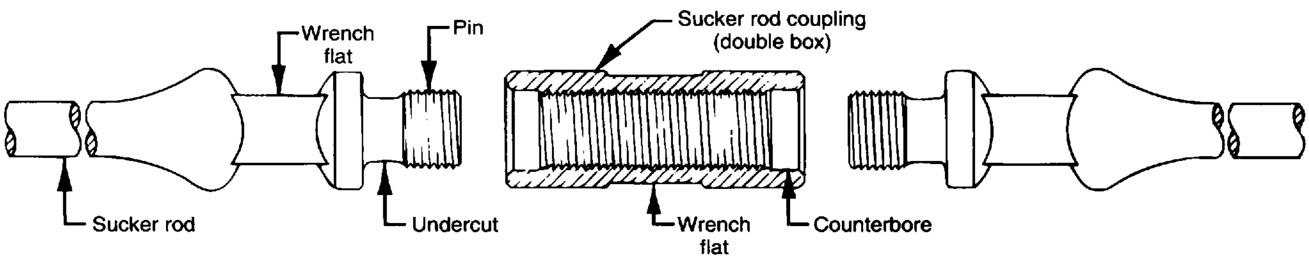

Figure 47—Typical sucker rod joint

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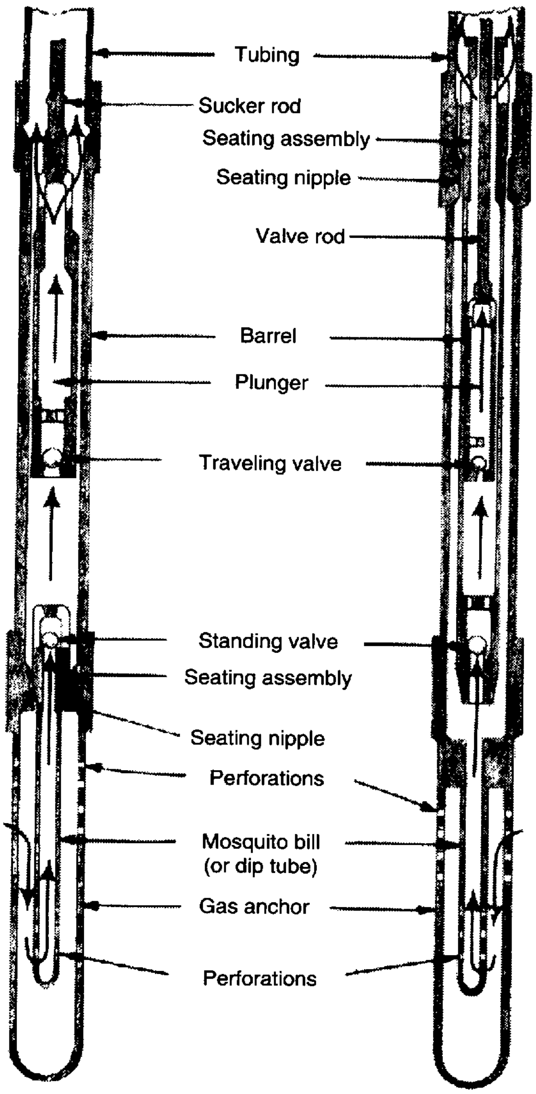

Figure 48—This shows two types of sucker rod pumps. The pump at left is a tubing type. On the right is a stationary barrel, top hold-down, rod type. The rod type pump and barrel can be removed from the well without removing the tubing. These simplified sketches do not show the seating assembly cups.

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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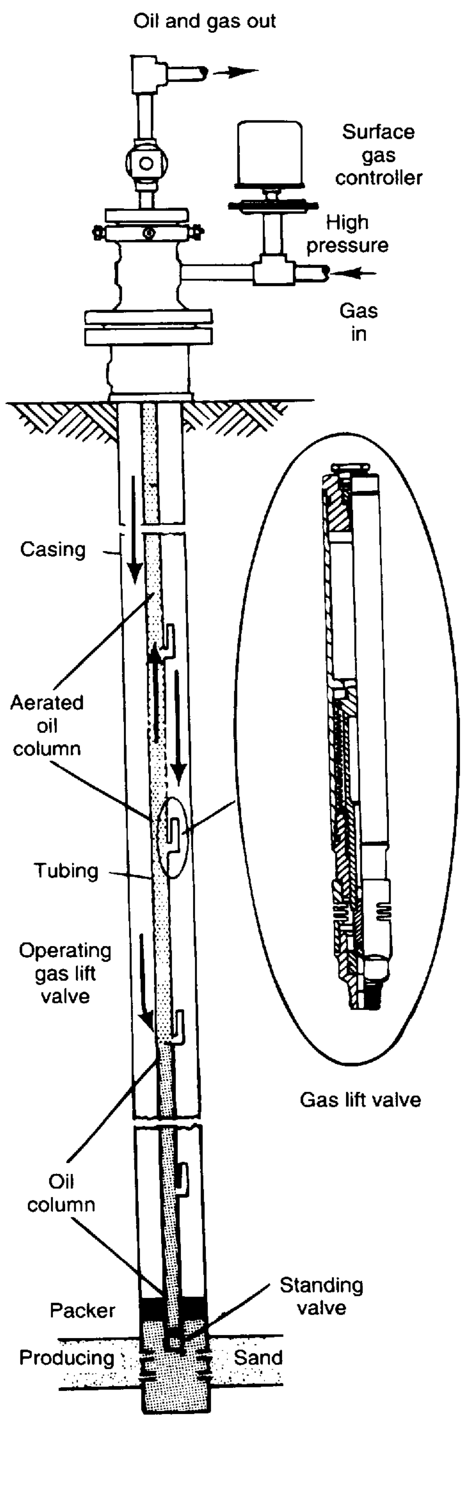

Figure 49—This is one kind of gas lift illustration. Gas is injected down the well through the space between the casing and tubing, enters the tubing through the operating gas lift valve, and inside the tubing mixes with the oil and lifts it to the surface.

volve so that impellers in the pump apply pressure upon the liquid entering the pump intake. The total pressure developed by the pump forces fluid up the tubing to the surface. Capacity for this type of pump ranges from 200 to 26,000 barrels per day (B/D) depending upon the depth from which the fluid is lifted and the size of casing. It is possible to pump 20,000 B/D from a depth of 2500 feet. Figure 51 shows the surface equipment for this type of system and Figure 52 is a drawing of a typical system installed in a well.

5.6 Subsurface Hydraulic Pumping

Subsurface hydraulic pumping is a method of pumping oil wells using a bottom-hole production unit consisting of a hydraulic engine and a direct coupled positive displacement pump. The hydraulic power is supplied from a pump at the surface.

This system of hydraulic pumping uses two strings of tubing alongside one another as shown in Figure 53, or the smaller string installed inside the larger tubing. The system in Figure 53 pumps clean crude oil (called power oil) from the high pressure pump down the larger size tubing to the hydraulic engine, causing the power (engine) piston to stroke. This, in turn, strokes the direct coupled production (pump) piston in the buttonhole pump. Fluid from the well and the exhausted power oil become mixed and return to the surface settling tank through the smaller tubing. The power oil is drawn from the top of the settling tank and piped to the pump for recirculation. In some instances clean water is used as the power fluid.

This type of pumping system may be used to pump several wells from a central source. Hydraulic lift has been successfully used to lift oil from depths greater than 15,000 feet. Maximum capacity of such equipment is dependent upon well conditions (size of tubing strings, ability of the well to produce, and well fluid characteristics).

Closed power oil systems are being used where there is limited surface area, such as offshore platforms, or where it is impractical to obtain consistently clean power fluid. This system requires an additional string of tubing to permit return of the power fluid separately from the produced well fluid.

5.7 Jet Pumps

Jet pumps are another means of using hydraulic power to artificially lift the produced fluids from the reservoir to the surface. Jet pumps have no moving parts and depend on the pressure-velocity relationship of the power fluid to provide the energy to produce lift.

The tubing is installed with a casing packer and the jet pump is installed above the producing zone. The power fluid may be sent down the tubing and returns together with the the produced fluids up the tubing-casing annulus, or vice-versa.

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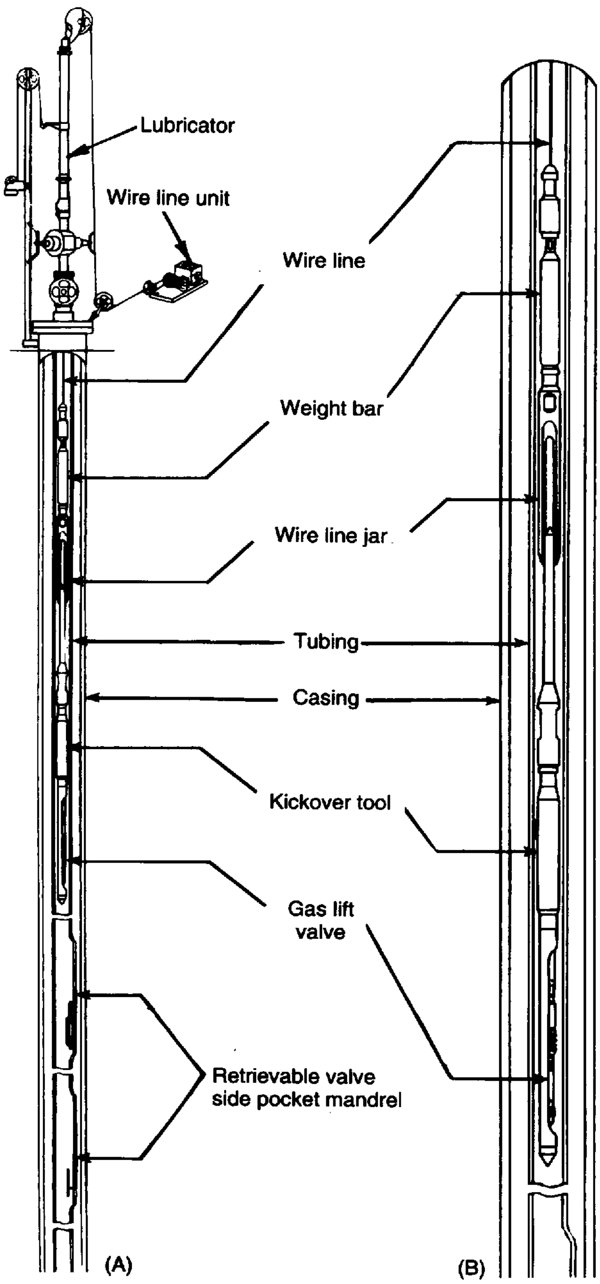

Figure 50—Gas lift valves may be run or pulled by a wire line unit when retrievable valve side pocket mandrels have been run on the tubing. Drawing (a), left, shows a wire line unit "rigged-up" on the well and a running/pulling tool assembly run into the well. The tool is "latched-on" to a valve. Drawing (b), right, is an enlarged view of the tool assembly and gas lift valve.

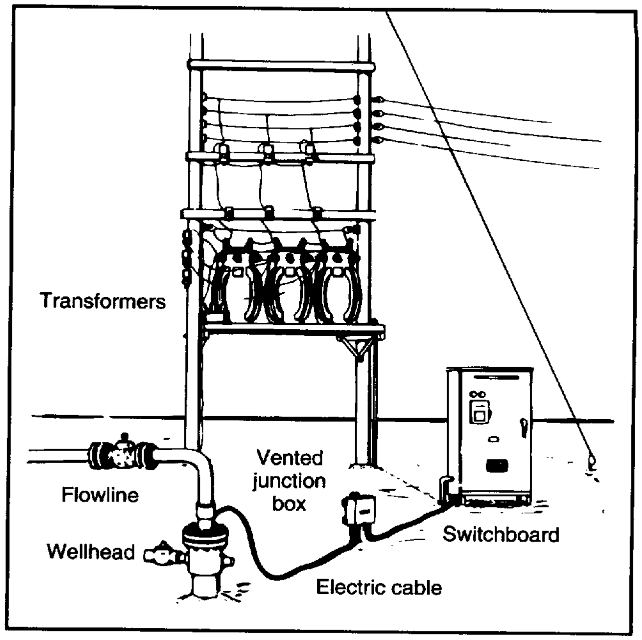

Figure 51—Shown here is the surface equipment needed for most down-hole subsurface electrical pumping systems.

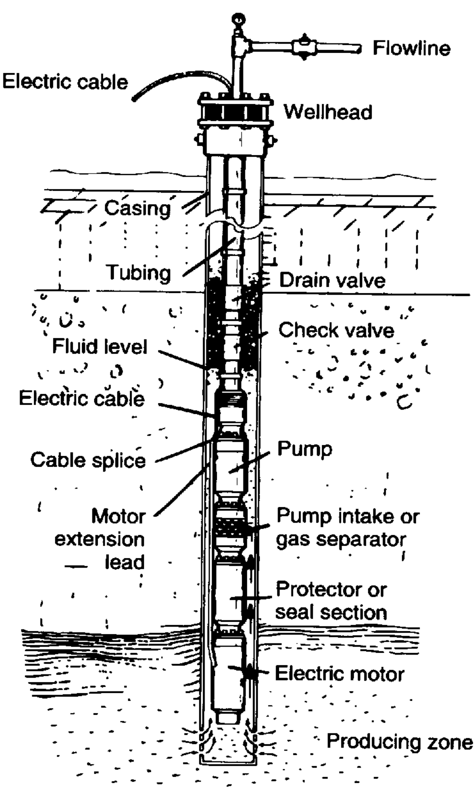

Figure 52—This drawing has been labeled to identify the main sections and special equipment for a typical conventional subsurface electrical pumping installation.

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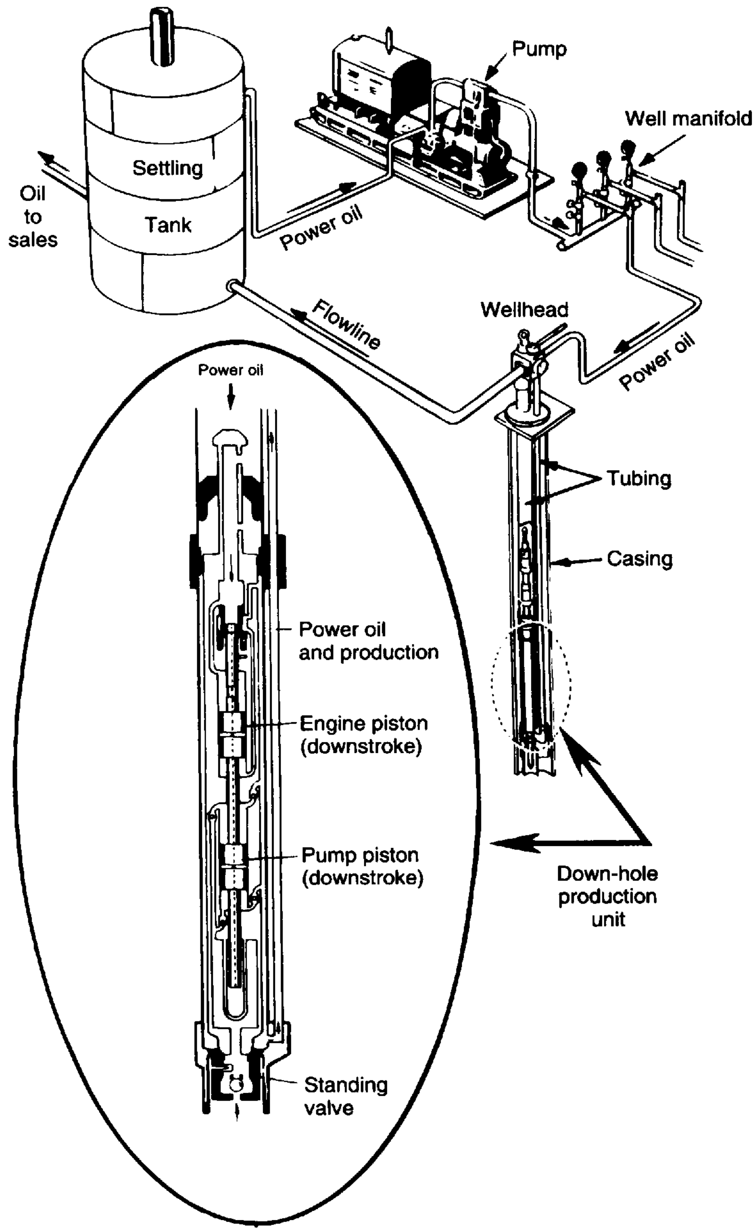

Figure 53—This is a common type of bottom-hole hydraulic pump. In this installation the pump and engine may be removed from the bottom of the hole by pumping the power oil down the small string of tubing. Normal operation has power oil going down the large string with a mixture of power oil and produced oil being pumped to surface through the small tubing.

The high-pressure power fluid, as it exits the restricting nozzle in the pump assembly, creates a low-pressure area which induces the produced fluid to flow into the diffuser. As the combined fluids leave the diffuser, the pressure increases sufficiently to lift the combined fluids to the surface. Water or oil can be used as a power fluid in jet pumps.

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SECTION 6—WELL TESTING

6.1 Introduction

More and more importance is being placed upon efficient performance of gas and oil wells. Generally, some kind of test must be made to determine the performance of an oil or gas well. There are many types of well tests, and each is conducted to obtain certain information about the well. Some types of tests are made often, and some may be made only on rare occasions.

Some of the well tests are simple and some are complicated. Standard lease production equipment may be all that is needed for some of the tests, while special equipment is necessary for other tests. It is very important that the test be done accurately since well test data document the performance of a well and the reservoir in which the test is completed. Very often these tests are performed by the producer to help in establishing proper production practices and to comply with regulatory requirements.

There are many types of well tests made by lease operators, well testers, or specialty companies. Some of the most frequently made well tests are discussed in 6.2 through 6.10.

6.2 Drill-Stem Test

When a well is being drilled, a drill-stem test is often run on a formation of unknown performance to determine if a formation contains oil, water, gas, or a combination of the three.

This procedure requires special tools and packers to be run on the drill pipe to isolate the interval to be tested. Fluid is thus permitted to flow from the formation, through the tester, and into the drill pipe. Fluid entering the drill pipe is trapped by a system of valves in the tester so that it may be withdrawn from the well with the drill pipe for subsequent examination. If the formation pressure is sufficient to cause flow to the surface, a sustained flow test through the drill pipe will provide a measure of the productive capacity of the interval tested.

The test results show the bottom-hole shut-in pressure, bottom-hole flowing pressure, bottom-hole temperature, and the type of fluid the well might be capable of producing.

The results of drill-stem tests on a well will often determine if a casing string should be run to complete the well as a producing well, or if the well is a dry hole. This information is often used as the design basis for the production system.

6.3 Potential Test

A potential test is a measurement of the oil, water, and gas that a well will produce in a 24-hour period under certain fixed conditions. This test is made on each newly completed well and at other times as might be requested by a state or federal regulatory agency or the well operator (see Figure 54.) Information from these tests is used to establish the producing rate for the well. Scheduled rates may be adjusted periodically, depending upon results of the tests (see Figure 55).

6.4 Bottom-Hole Pressure Test

A bottom-hole pressure test is a measure of the pressure of the well taken at a specific depth or at midpoint of the producing interval. The purpose of this test is to measure the pressure in the zone in which the well is completed. In making this test, a specially designed pressure gauge is lowered into the well to a selected depth where the pressure is recorded by the gauge (Figure 56). The gauge is then pulled to the surface and taken from the well to observe and record the pressure. There are several variations of this test, including the flowing bottom-hole pressure test, which is a measurement taken while the well continues to flow, and a shut-in bottom-hole pressure test, which is a measurement taken after the well has been shut in for a specified length of time. These shut-in tests also give information about fluid levels in the shut-in well.

A series of bottom-hole pressure tests conducted at scheduled intervals will furnish valuable information about the decline or depletion of the zone in which the well has been producing.

6.5 Transient Pressure Testing

In recent years transient pressure testing has played an increasingly important role in reservoir management. Bottom-hole pressures are recorded under various flowing and shut-in conditions. The information thus obtained can be used in modeling the reservoir, predicting its performance, and optimizing production alternatives in order to achieve maximum economic recovery of reserves.

6.6 Productivity Test

Productivity tests are made on both oil and gas wells and include the well potential and the bottom-hole pressure tests.

Fluid flow in a reservoir is caused by the movement of fluid from a high-pressure area to a low-pressure area. The rate of fluid flow from the higher formation pressure to the well bore pressure is proportional to the difference in these pressures.

The first procedure in conducting a productivity test is to measure the shut-in bottom-hole pressure. This pressure might be called static pressure or reservoir pressure. The well is then produced at several stabilized rates. At each stabilized rate of production, the bottom-hole flowing pressure is measured. These data, when interpreted by an engineer, provide an estimate of the maximum flow of fluid to be expected from the well. The open-flow potential of a gas well

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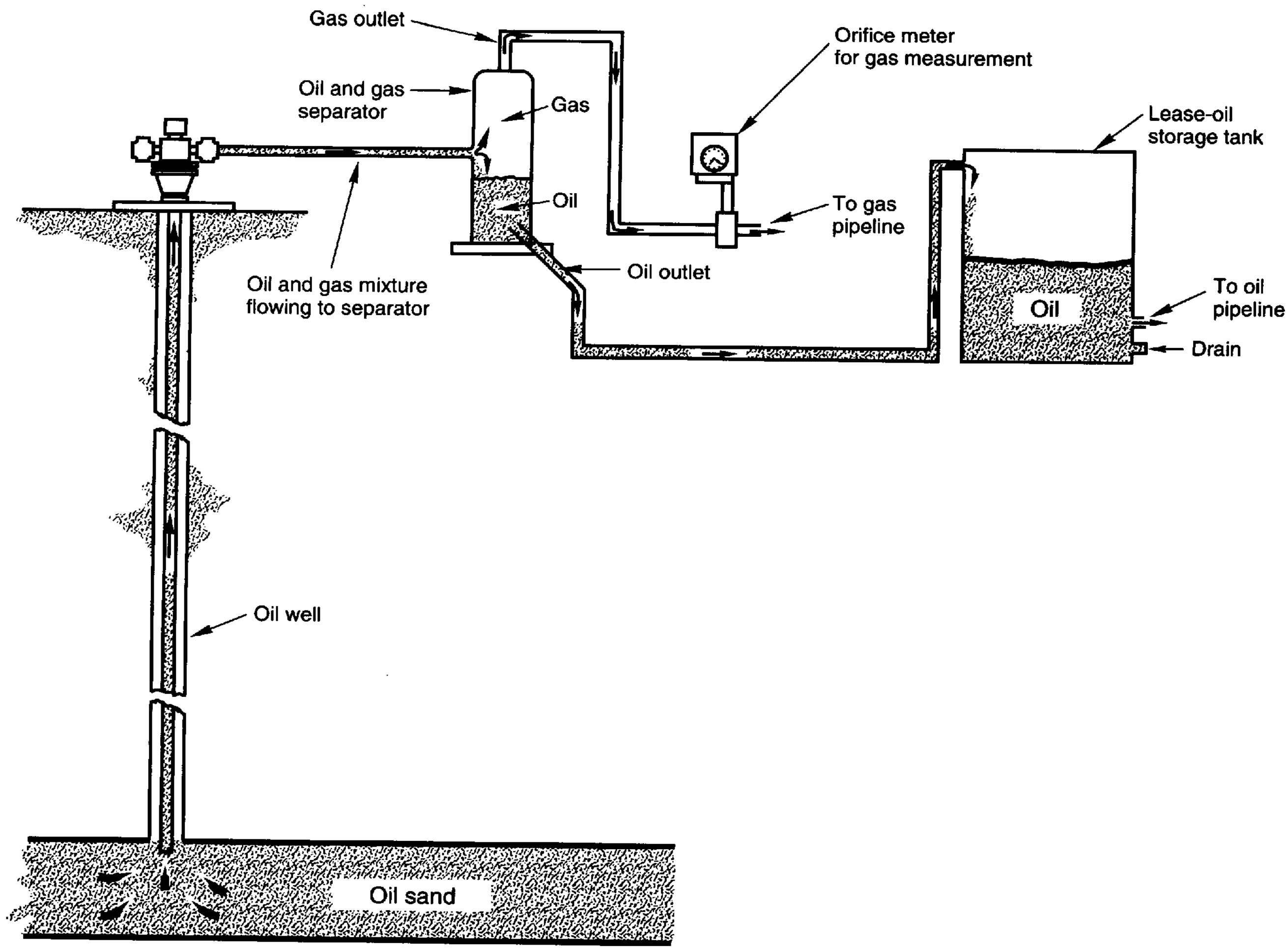

Figure 54—The main pieces of equipment necessary for making potential and associated tests are a part of the normal tank battery. The separator and tank cannot be used for producing operations while a test is being conducted. Oil from the test is measured in the tank, while gas production is measured with an orifice meter.

is calculated by extrapolating the gas production to atmospheric pressure at the face of the producing formation.

This type of testing is done on both oil and gas wells and, with slight variations, is the most widely accepted method of determining the capacity and allowables of gas wells.

6.7 Routine Production Tests

Routine production tests are normally made monthly to inform the well operator of any changes in the daily produced volumes of oil, water, and gas. These tests can be taken with various items of equipment ranging from simple tank measuring equipment and a gas meter to a completely automated test facility. An automated test facility consists of a control and readout panel; automatic time-controlled valves; separation vessels; meters for oil, water, and gas; and a net oil probe (see Figure 55). Where a computerized system is used, valve operation is upon computer command and test results are automatically transmitted to, and analyzed by, the computer.

6.8 Bottom-Hole Temperature Determination

This test is usually made in conjunction with the bottom-hole pressure test and is made to determine the temperature of the well at the bottom of the hole or at some point above the bottom. In conducting this test, a specially designed recording thermometer is lowered into the well on a wireline. After the thermometer is removed, the temperature of the well at the desired depth is read from the instrument.

These data and the bottom-hole pressure calculations are used by the engineer in solving problems about the nature of the oil or gas that the well produces. Temperature tests are sometimes helpful in locating leaks in the pipe above the producing zone.

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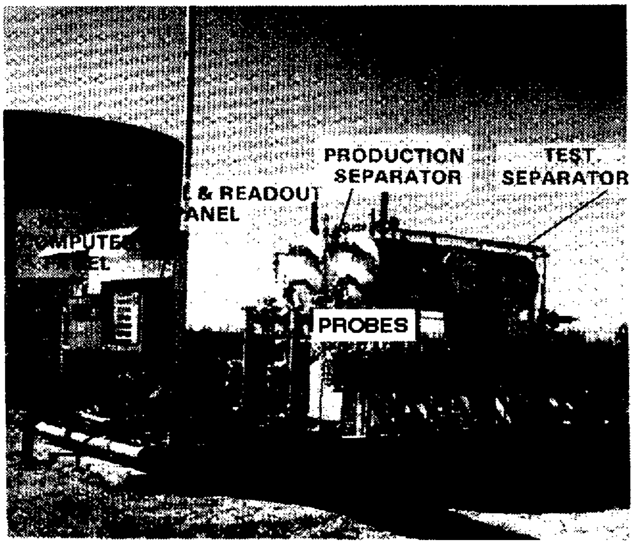

Figure 55—A production and test unit showing component parts for controlling individual well tests on a prearranged schedule.

Temperature surveys are also used to determine whether gas lift valves are operating, the location of top and bottom cement in newly cemented wells, and injection intervals in injection wells.

6.9 Sonic Fluid Level Determination

This test, which determines the depth to liquid in the casing annulus of a well, can be performed on wells that will not flow and are produced by artificial lift. It is a very useful test on wells produced by sucker rod pumping.

The procedure for this test is to fire a blank shell in a sealed wellhead attachment which is connected to the surface casing annulus valve. The sound pulse created by firing the blank travels down the casing annulus. A portion of the sound is reflected by each tubing collar and a larger portion by the liquid level. A microphone in the wellhead attachment picks up the sound reflections and amplifies them. They are then transmitted to a receiver, where they are converted to electrical pulses and recorded as blips on a moving paper strip. From here, the number of tubing collars (blips) may then be counted to liquid (large blip) and converted to feet, and the depth to liquid level can be determined.

This is a good test to help determine if more fluid is available for lift and how much. It is also a good test to help in sizing artificial lift equipment.

6.10 Water Analysis

The oil industry has used water analysis for many years for formation identification, compatibility studies, water-quality control, and evaluation of pollution problems. The end use of water analysis data should determine the sampling procedure, the analytical procedure, and data presentation. In some cases, the only concern is whether or not a particular substance is present; in other cases, complete mineral analysis are required; and in still other cases, the interest may be limited to knowing the concentration of trace constituents.

The chemical and physical properties of water are influenced greatly by the identities and amounts of the dissolved substances. The composition of the water can only be determined by chemical analysis and the physical properties by actual measurements.

A reliable water analysis is very important, since it is the initial step in solving scale, corrosion, or pollution problems. Water treatment is based on results of water analysis. Casing leaks in producing wells can be detected using results of water analysis. Compatibilities of waters for injection in enhanced recovery projects can often be predicted from water analysis data.

Water analysis data are often used to identify the source of water produced with oil and gas. Water analysis have proven to be very valuable in subsurface studies with respect to underground water migration, electric log interpretation, and well remedial and recompletion operations.

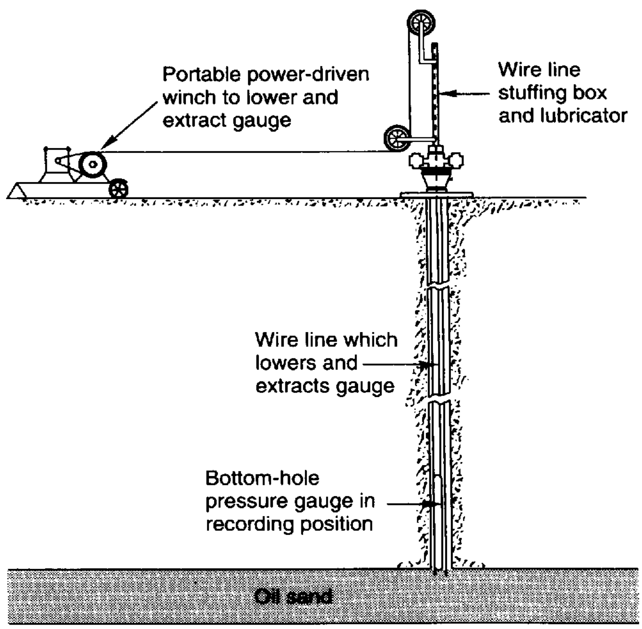

Figure 56—This sketch of a bottom-hole pressure measurement is very similar to a bottom-hole temperature measurement. The gauge is different, of course, but the procedure is the same.

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SECTION 7—SEPARATION, TREATMENT, AND STORAGE

7.1 Introduction

Well fluids are often a complex mixture of liquid hydrocarbons, gas, and some impurities. It is necessary to remove the gas and most of the impurities from the liquid hydrocarbons before they are stored, transported, and sold. Liquid hydrocarbons and objectionable impurities also must be removed from natural gas before the gas goes to a sales line. Impurities that might be found in some well streams are hydrogen sulfide, carbon dioxide, free water, water vapor, mercaptans, nitrogen, helium, and solids. Nearly all of the impurities cause various types of operating problems.

The separation of natural gas, liquid hydrocarbons, and impurities is accomplished by various field-processing methods, depending upon the composition of the well stream and the desired end product. These methods include time, chemicals, gravity, heat, mechanical or electrical processes, and combinations of these.

7.2 Separators

Separation of well-stream gas from free liquids is the most common and simplest form of field processing. The equipment most widely used for this type of processing is referred to as a separator. The separation of natural gas from liquids or impurities in a separator combines gravity, time, mechanical processes, and occasionally, chemicals.

The size of the separator is dependent upon rate of flow of the natural gas or liquids going into the vessel. The operating pressure of the vessel is dependent upon the pressure of the gas sales line, the flowing pressure of the well, and the operating pressure desired by the lease operator.

Separators are built in various designs, such as vertical, horizontal, and spherical. The internals of the vessel, to aid in the mechanical separation of the gas and liquids, are of a special design depending upon the manufacturer. Although most separators are two-phase in design to separate gas and liquids (Figure 57), they can also be built in three phases to separate natural gas, liquid hydrocarbons, and free water (Figure 58).

Depending upon the composition of the well fluids, it may be desirable to use more than one stage of separation to obtain more recovery of fluids. In general, the higher the flowing wellhead pressure, the greater the number of separation stages that will be suitable.

Although natural gas leaving the separator no longer contains free liquids, the gas may be saturated with water vapors (see 7.3). Liquid hydrocarbons leaving the separator do not contain free gas; however, they may contain water, basic sediment, and other impurities (see 7.6).

Natural gas contains substantial amounts of water vapor when produced from a gas well or separated from liquid hydrocarbons. When gas and oil are separated at a pressure below 100 pounds per square inch gauge (psig), the gas is normally gathered in a low-pressure gathering system. The gas goes to a gas plant where it is compressed and additional liquid hydrocarbons, water, and other impurities are removed. In the high-pressure separation of oil and gas (above 100 psig), the gas may be metered and sold to the pipeline company in the field or sent to a gas plant for further processing. The gas is then sold to a gas transmission company. Water vapor in gas at high pressure can cause serious operating problems. For example, gas is separated at 1000 psig and 90°F. At this pressure and temperature, gas at water saturation contains 46 pounds of water vapor per million cubic feet of gas. If the gas is cooled to 70°F, it will contain only 25 pounds of water vapor per million cubic feet of gas. This means 21 pounds of water vapor have condensed to free water. Free water has a tendency to cause corrosion and reduce flow rates in the gas transmission line. Free water also promotes the formation of gas hydrates. Gas hydrates are ice-like crystalline compounds formed in natural gas in the presence of free water under conditions of high pressure and turbulence. These hydrates form at various temperatures,

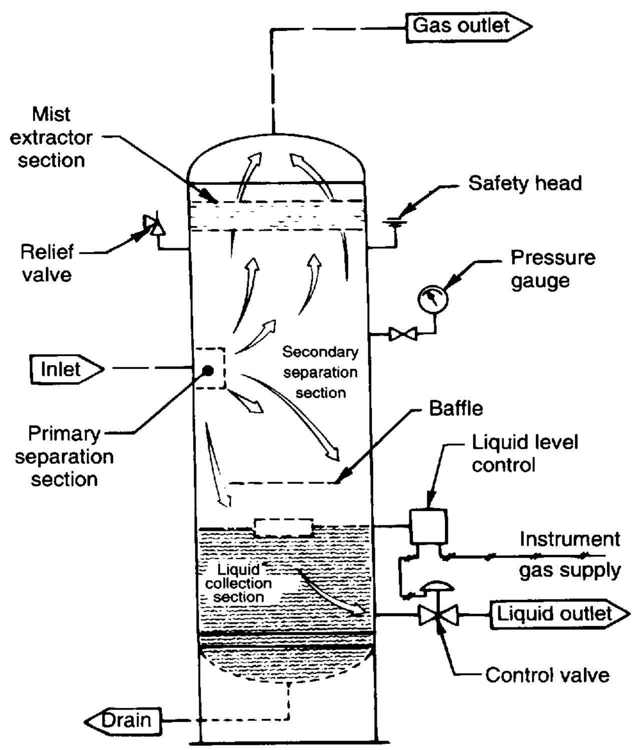

Figure 57—Vertical two-phase separator

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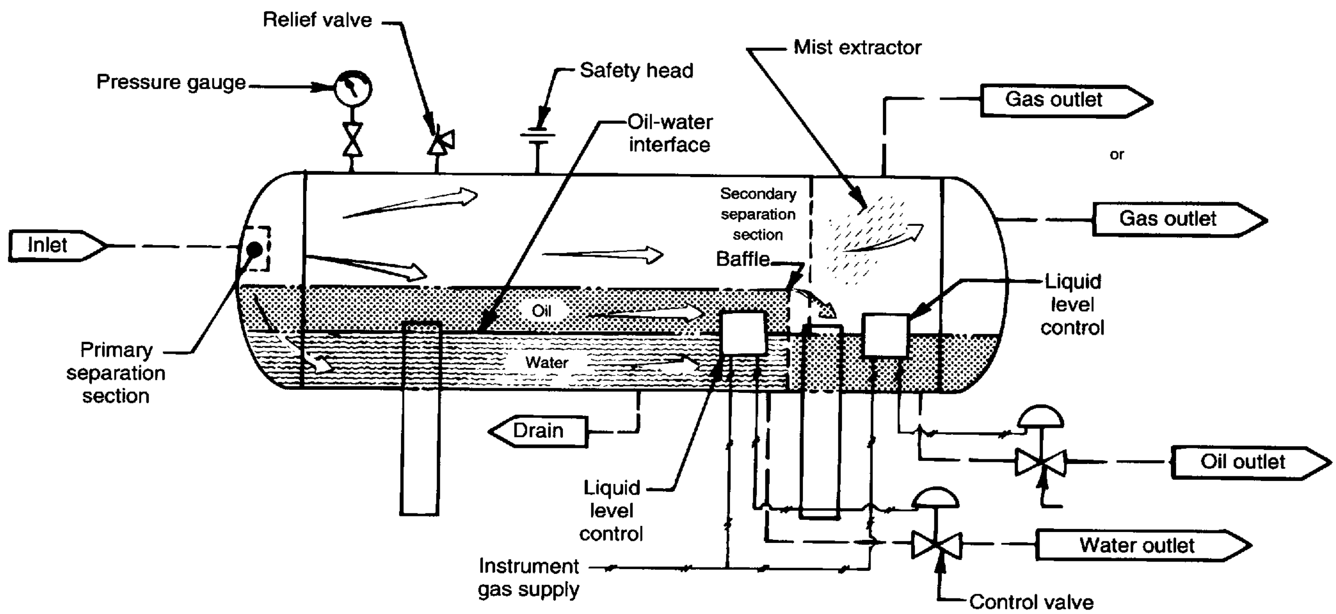

Figure 58—Horizontal three-phase separator

often well above the freezing temperature of water. When hydrates form in a gas-gathering or distribution line, total or partial blockage of the pipeline may result.

7.3 Dehydration of Natural Gas

There are several methods to prevent hydrates from forming in a gas line. Some of the most commonly used methods are:

a. Heating the gas stream so that the temperature of the gas will not drop to the level at which hydrates form.
b. Addition of an antifreeze agent such as methanol or glycol to the gas stream.
c. Removal of water vapor by use of a glycol dehydrator (Figure 59). The most common form of glycol dehydration consists of a vertical pressure vessel (called either a glycol absorber tower or a glycol contactor) that allows the glycol to flow downward as the gas flows upward. The mixing of the glycol and gas occurs as the gas bubbles through bubble caps of a tray. The pressure vessel usually has four to eight trays. As the gas comes in contact with the glycol, the glycol absorbs the water vapor from the gas. As the glycol becomes saturated with water, the glycol and water are circulated through a reboiler where the mixture is heated to 325°F to 350°F, boiling off the water vapor. The glycol is then recycled through the glycol absorber tower.
d. Dehydration using solid desiccants (drying agents) such as alumina, silica-gel, silicon alumina beads, and molecular-sieve. Gas flows through the desiccant bed where water is absorbed. On a time-cycle basis, the gas stream is switched through another bed and the first bed is heated to remove the water. There must be at least two beds for continuous operation.
e. Dehydration by expansion refrigeration, which can be accomplished if there is a sufficient pressure drop between well-flowing pressure and separator pressure. This is accomplished by use of heat exchangers and expansion of the gas.

Most dehydrated gas that goes to the sales line contains no more than seven pounds of water vapor per million cubic feet of gas.

Objectionable amounts of other impurities in the natural gas stream such as hydrogen sulfide and carbon dioxide are removed by various processes. The methods may be broadly categorized as those depending on chemical reaction, physical solution, and absorption.

Gas transmission companies set specifications on how free of impurities the gas must be before it is purchased.

7.4 Natural Gas Liquids Extraction Plants (Gas Plants)

Gas plants are used to remove and recover some of the heavier hydrocarbon compounds from the natural gas stream. Most natural gas contains methane, which is its main constituent, and varying quantities of ethane, propane, butane, and even heavier hydrocarbon compounds such as pentane. These compounds exist in the vapor phase at operating temperatures and pressures normally encountered in the surface production systems. There are two good reasons for removing these compounds from the natural gas stream. First, these compounds must often be removed to meet

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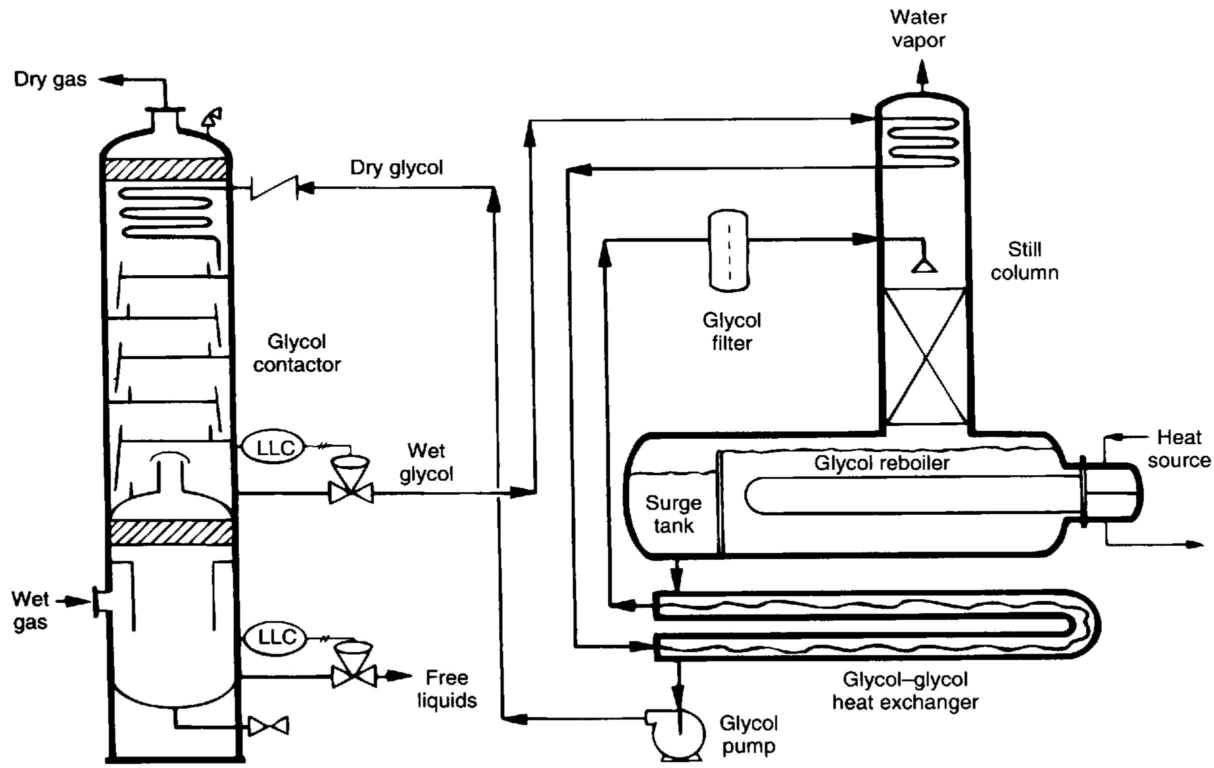

Figure 59—Glycol Dehydrator

safety and operational specifications of the natural gas pipeline and distribution systems. These heavier hydrocarbon compounds raise the heating value and dewpoint of the natural gas, which may result in some of these compounds condensing to a liquid in the pipelines due to cooling from the ground or other surroundings. Second, the heavier components generally are more valuable as a separate product than as a part of the natural gas; the natural gas liquid products are sold for use in petrochemical industries, petroleum refineries, and as rural and agricultural fuels.

Gas plants may be divided into two broad categories: *absorption plants* and *refrigeration plants.* Absorption plants utilize a light oil as a solvent to dissolve the heavier components which are then recovered from the solvent by a fractionation process. Most absorption plants were built before 1970 and are not very energy efficient.

There are three types of refrigeration plants. They are the J-T (Joule-Thompson), the turbo-expander (also called a cryogenic plant), and the mechanical refrigeration plant. In all three of these types of plants, chilling the natural gas stream causes the heavier hydrocarbon compounds to condense. They may then be separated from the remaining gas. A simplified schematic of a turbo-expander plant is show in Figure 60.

7.5 Liquefied Natural Gas (LNG) Plants

Liquefied natural gas plants go a step farther than the gas plants described above. These plants achieve temperatures in the range of –260°F by using several stages of refrigeration. At this temperature, all of the natural gas stream is liquefied. Liquid methane is the primary constituent of LNG. LNG is only economically attractive when the gas cannot be transported to market by pipeline, and when large enough quantities of gas are available to justify the cost of a gas liquefaction plant and its high energy requirements. Specially designed ships are used to transport LNG from one part of the world to another.

7.6 Oil Treating

When crude oil is produced, various amounts of gas, water, and other impurities are mixed with the oil. Some of this mixture comes as free oil, some as free water, and some as a homogeneous mixture known as an emulsion. The gas, water, and other impurities (known as *basic sediment and water* or BS&W) must be removed before selling the oil. This separation process is called oil treating.

Treating systems are important parts of lease equipment. Experience in a particular producing field or area is valuable in determining the best equipment for the application.

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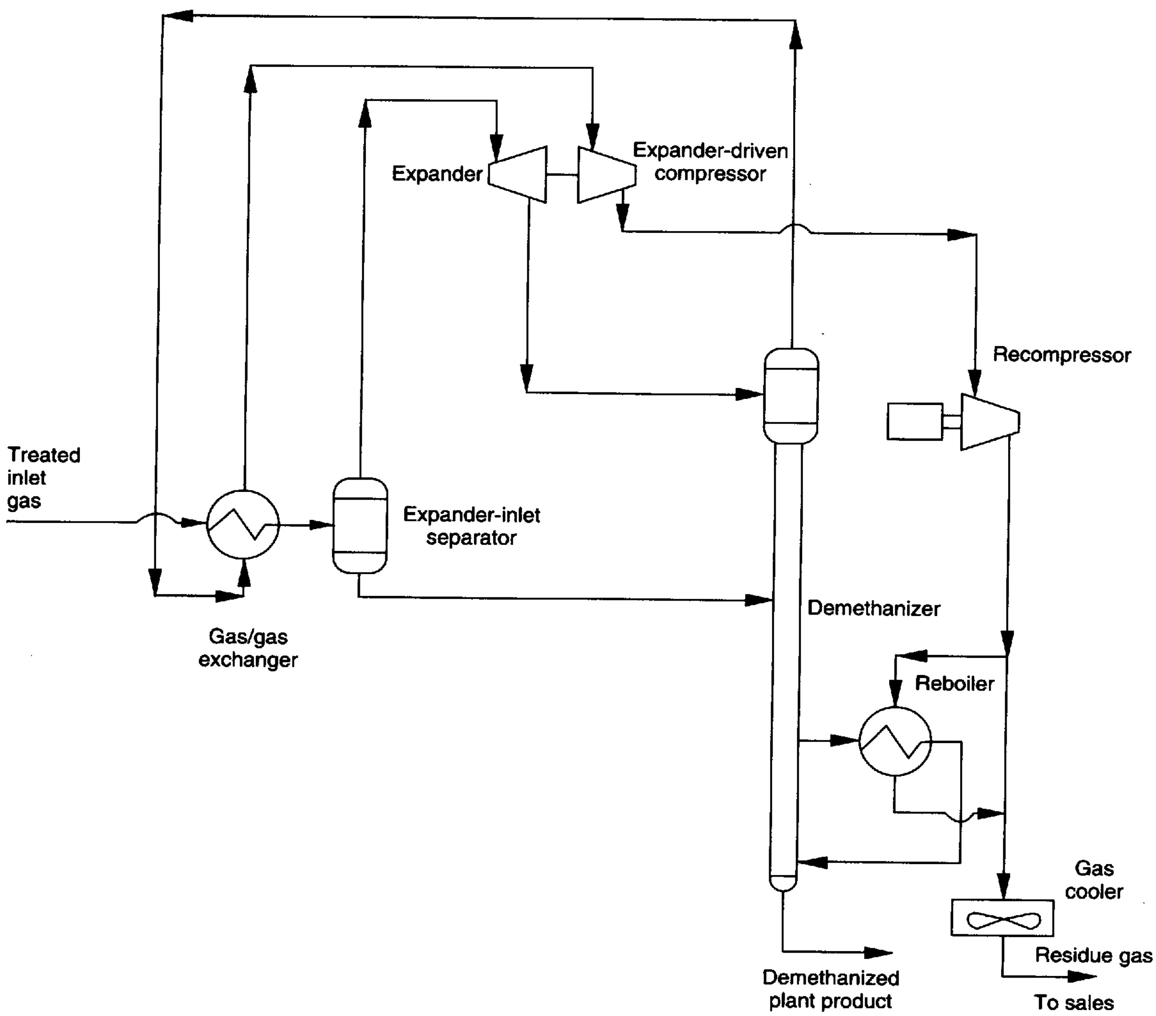

Figure 60—Turbo-expander Plant Simplified Schematic

In selecting a treating system, a number of factors should be considered to determine the most desirable method of treating the crude oil to pipeline requirements. Some of these factors are:

a. Tightness (stability) of emulsion.
b. Specific gravity of the oil and produced water.
c. Corrosiveness of the oil, gas, and produced water.
d. Scaling tendencies of the produced water.
e. Quantity of fluid to be treated and percent of water in the fluid.
f. Availability of sales line for the gas.
g. Desirable operating pressure for the equipment.
h. Paraffin-forming tendencies of the crude oil.

Oil field emulsions are usually water-in-oil; however, a few of the emulsions are oil-in-water and are called reverse emulsions. Emulsions are complex and each should be considered individually.

To break a crude oil emulsion and obtain clean oil, it is necessary to displace the emulsifier and its film. This displacement brings about the coalescence of droplets of water and requires a time period of undisturbed settling of the coalesced water drops. There are several methods used in conjunction with one another to treat an oil emulsion.

7.6.1 HEATER-TREATERS

A heater-treater (Figure 61) is normally used in treating oil emulsions. Oil treating equipment generally makes use of thermal, gravity, mechanical, and sometimes chemical or electrical methods to break emulsions.

Heater-treaters can be vertical or horizontal in design. The size is dependent upon the volume of oil and water to be handled.

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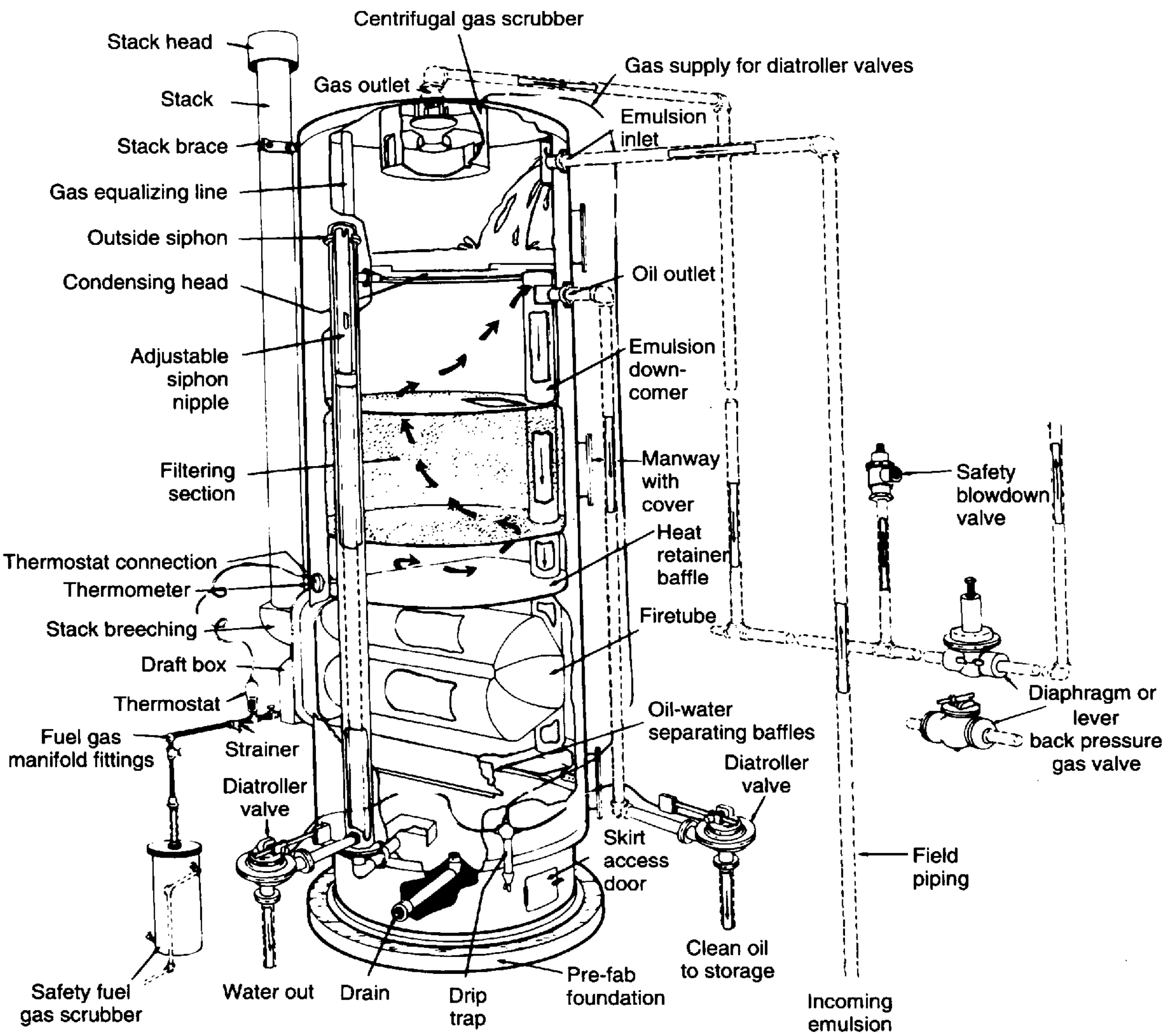

Figure 61—Flow Diagram for a Vertical Heater-treater

Treaters equipped with electrodes are normally horizontal in design. They are referred to as electrostatic coalescers or chem-electric treaters (Figure 62). In some applications these treaters are the most desirable because they treat at a temperature lower than a conventional heater-treater, saving fuel and conserving oil gravity.

7.6.2 FREE WATER KNOCKOUTS (FWKOs)

When there is sufficient free water production on a lease, a free water knockout (FWKO) (Figure 63) is often installed to separate free gas and free water from free oil and emulsion. This vessel can be either horizontal or vertical in design. The size is dependent upon the desired retention time and the volume of water per day to be handled.

The methods used to facilitate separation when FWKOs are used are time, gravity, mechanical, and sometimes, chemical.

When heat must be used to break an emulsion, much fuel gas can be saved by using the FWKO. Heating unnecessary water is not only useless, but it takes more than twice as many British thermal units (BTUs) to heat a given quantity of water to a given temperature as it does to heat an equivalent amount of oil. This can be very costly.

Hydrocyclones (see 7.9) are being used increasingly in place of conventional FWKOs.

7.6.3 DESALTERS

Desalters are similar to oil treaters in design and function. Although rarely seen in production operations in the United

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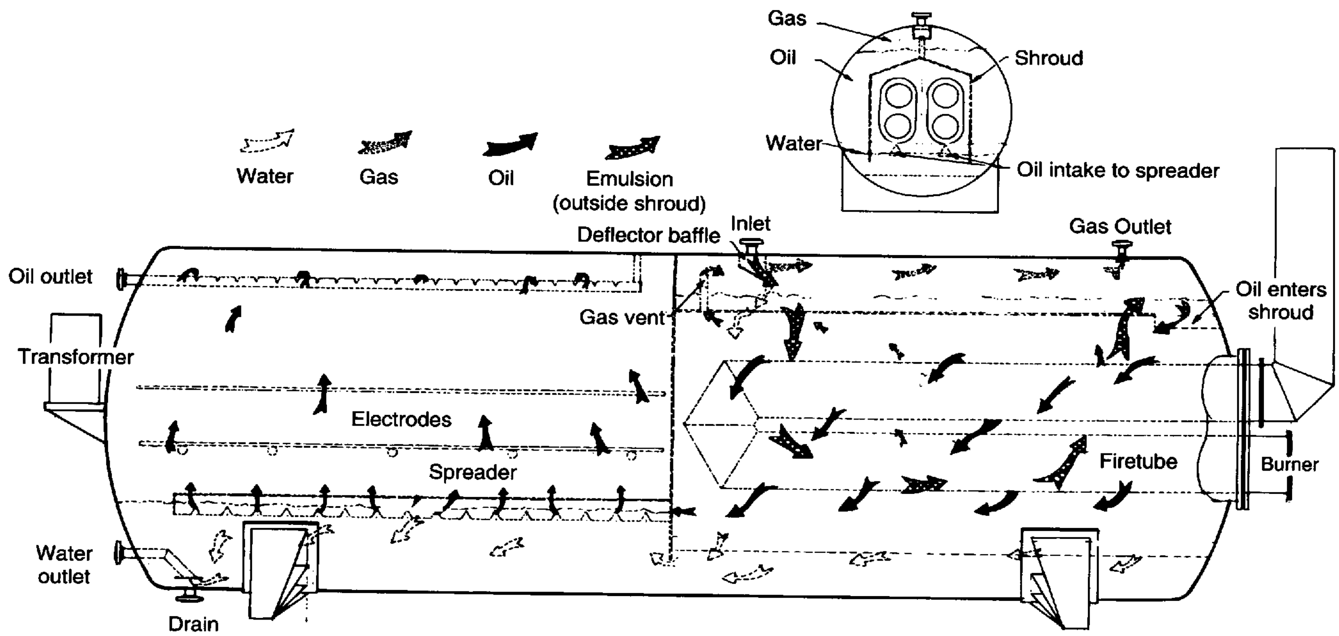

Figure 62—Electrostatic Coalescer

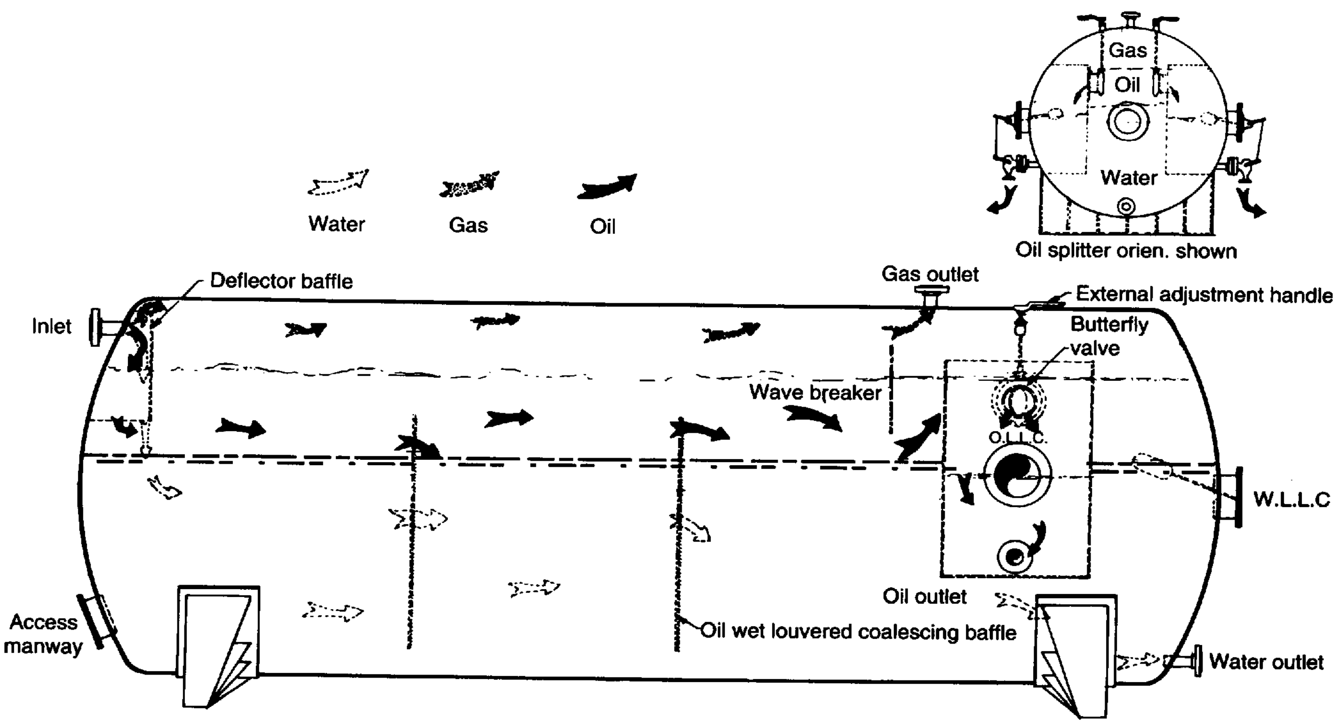

Figure 63—Free Water Knockout (with Oil Split Option)

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States, desalters are quite frequently used in other parts of the world where heavy brines are produced in conjunction with the oil. Desalters function by using fresh or brackish water to dilute the brine and increase the volume of salt water in the oil so that it can be more easily precipitated. Desalters generally make use of electrostatic precipitation.

7.6.4 GUN BARREL

In some cases an oil-water emulsion is not very stable. If sufficient time is allowed, water will settle toward the bottom of a tank and oil will rise to the top due to the water's having a higher specific gravity than the oil. Heat and chemicals may be used to shorten the time required for settling and to improve the separation of the two liquids. The settling vessel is known as a gun barrel or wash tank (Figure 64).

The gun barrel comes in various designs; however, it usually has sufficient height to allow the clean oil to gravity-flow into the stock tanks. The water is drawn off through the water leg, which also regulates the oil-water interface level.

7.6.5 STORAGE TANKS

Oil that is free of impurities to the extent that it will meet pipeline specifications is referred to as clean oil or pipeline oil. It is oil from a separator, FWKO, heater-treater, or gun barrel, depending upon the type of treating necessary to obtain the clean oil. The pipeline oil goes from the treating facilities to the storage tanks, known as stock tanks.

The number and size of stock tanks depend upon the volume of oil produced each day, the method of selling the oil to the pipeline, and how frequently and at what rate oil is taken by the pipeline company.

The separation, treating and storage facilities are commonly referred to as a tank battery (Figure 65).

The two basic types of stock tanks are bolted steel and welded steel. Bolted steel stock tanks are normally 500 barrels or larger and are assembled on location. Welded steel stock tanks range in size from 90 barrels to several thousand barrels. Welded tanks up to 400 barrels in capacity (and in some cases 500 barrels) are shop-welded and are transported as a complete unit to the tank battery site. Larger tanks are welded on location. Welded tanks can be internally coated to protect them from corrosion. Bolted tanks offer the option of internal lining or galvanized construction for protection against corrosion.

7.6.6 VAPOR RECOVERY SYSTEM

When oil is treated under pressure and then goes to a stock tank at near atmospheric pressure, some liquid hydrocarbons flash to gas. Some factors that determine the volume of flash gas are:

a. Type of liquid hydrocarbons.
b. Treating pressure.
c. Treating temperature.
d. Volume of liquid hydrocarbons.
e. Temperature of liquid hydrocarbons entering tank.
f. Diameter of tank.
g. How liquids enter the tank.
h. How long liquid hydrocarbons stay in the tank before going to the pipeline.

For many years the flash gas or vapors were vented to the atmosphere. It is no longer a question of economics to justify vapor recovery since government agencies are insisting on vapor recovery to reduce air pollution (see Section 11). Many improvements in production practices and equipment design in the past few years have made recovery of low-pressure hydrocarbon vapors practical, both economically and ecologically.

A vapor recovery unit (Figure 66) consists of a control pilot mounted on a tank for control of compressors, a scrubber to keep liquid hydrocarbons out of the compressor, a compressor, and a control panel. The electric motor-driven compressor will start by a signal from the control pilot at approximately one ounce of gas pressure. It will shut off at approximately ¼ ounce gas pressure. It is necessary to keep a positive pressure in the tank to keep out air and prevent evaporation of the crude oil. Air contamination of the gas can create explosive mixtures and accelerate corrosion of equipment. Stock tanks are normally designed to hold liquid hydrocarbons with a maximum of four ounces of positive gas pressure.

7.7 Handling Produced Water

Most oil and gas wells produce some water. Some of the produced waters are fresh while others are low, medium, or high in salt (chlorides) content. In many instances disposal of the produced waters presents an operational problem that must be solved to meet local, state, and federal environmental requirements.

The method of disposal of the produced waters depends on many factors, such as volume of water, type of water, location of oil or gas field, type of reservoir from which water is produced, or government regulations. The most acceptable methods of disposing of produced waters are:

a. Injection into underground salt water bearing formations.
b. Injection into oil bearing underground reservoirs from which the oil and water is produced.
c. Disposal of carefully treated water into the ocean from offshore production platforms.

Depending on the quality of the waters to be injected and the permeability of the formation, it may be necessary to treat the waters to remove as many solids and oil particles as possible.

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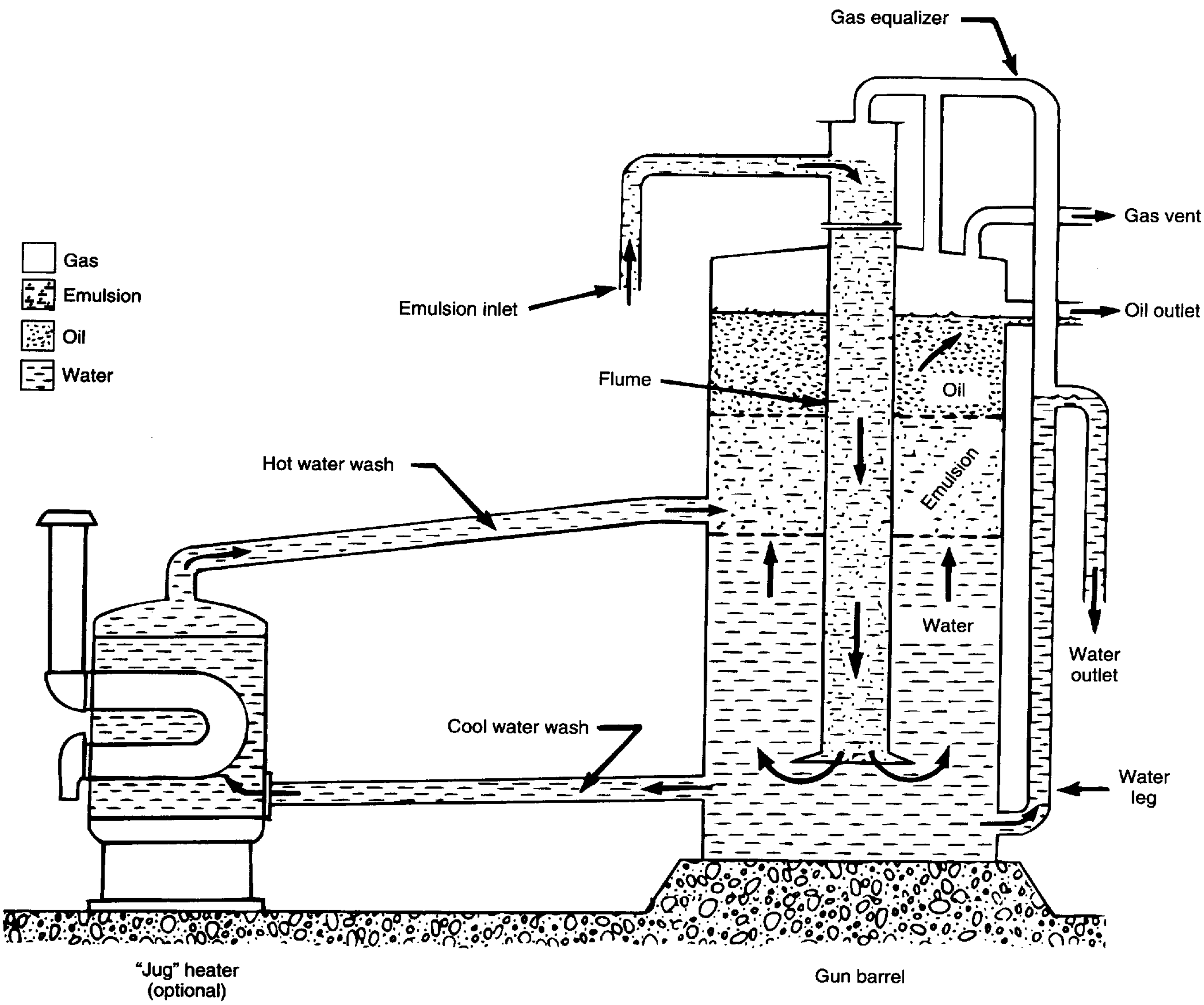

Figure 64—Schematic Flow Diagram of Gun Barrel (Wash Tank) Installation

A typical water disposal system consists of a treating vessel to remove solids and oil particles, an accumulation or storage tank, pump with prime mover, controls, and a water disposal well.

7.8 Water Treating Systems and Disposal

Water systems may consist of a number of equipment components designed to remove oil and solids to acceptable levels. A typical system will include a course separation followed by a polishing device. A coalescing vessel, used to treat produced water, usually contains material such as fine wood shavings or other packing material that provides a large surface contact area. This allows all but the smallest oil droplets to coalesce and separate from the water. The oil which coalesces is skimmed from the surface of the water and removed.

Instead of the conventional coalescer, a corrugated plate interceptor (CPI) may be used. This device contains a section of corrugated plates. As the oily water flows between the corrugated plates, oil droplets are more likely to come in contact with each other, coalesce and rise to the surface, thus reducing the amount of oil which is left dispersed in the water.

After leaving the coalescer or the CPI, the water is usually sent to a flotation cell. Here, many small bubbles of gas are released at the bottom of the vessel. As these gas bubbles rise to the surface, they become attached to small oil droplets causing them to coalesce. The resultant oil film is skimmed from the surface of the water. In most cases this completes

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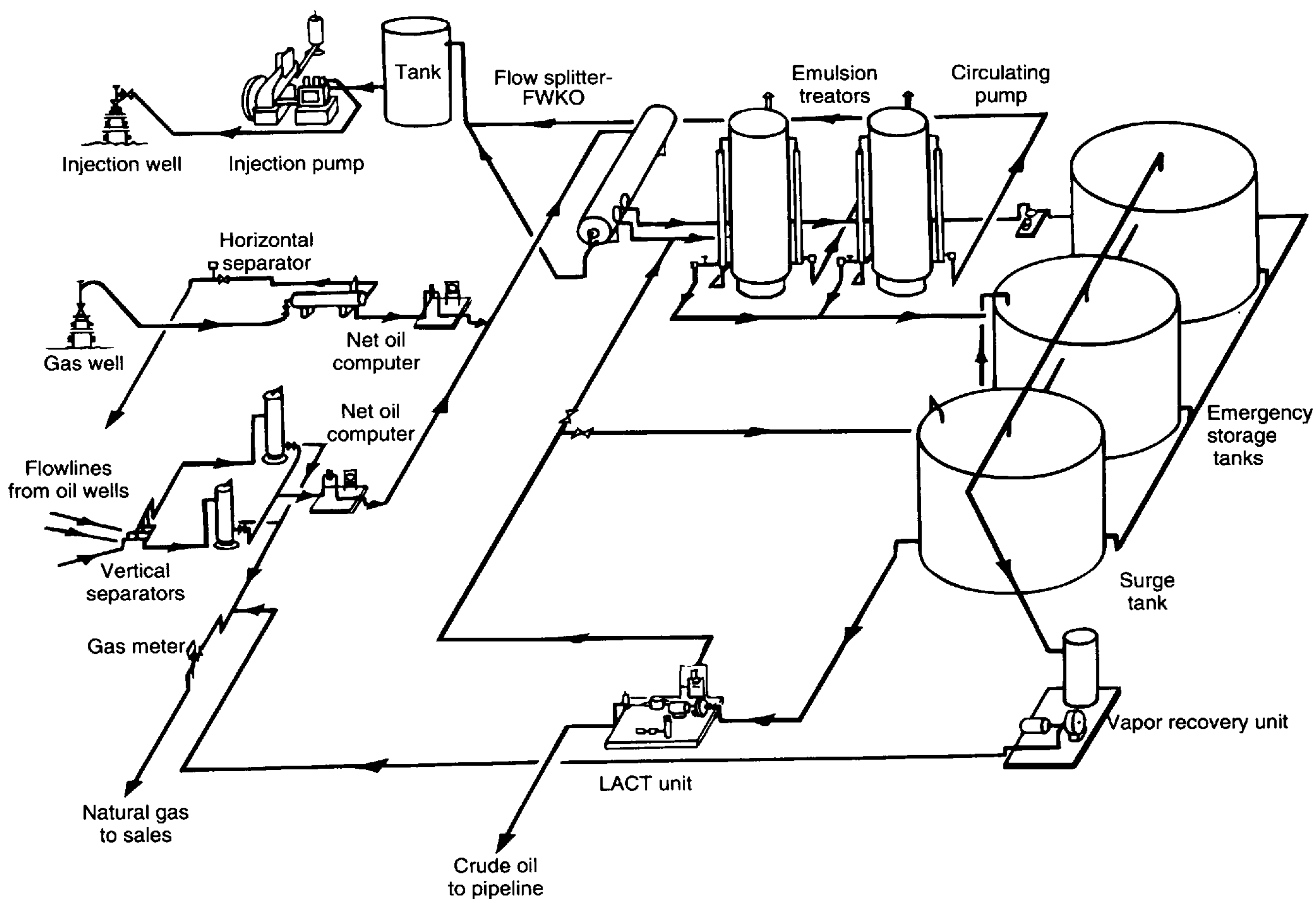

Figure 65—General Lease Service Installation

the treatment of the produced water and it can then be disposed of.

Instead of produced water being treated in a coalescer and flotation cell, a hydrocyclone may be used (see 7.9). Because hydrocyclones usually operate at pressures higher than coalescers, the water leaving the hydrocyclone may have an appreciable amount of dissolved gas. This water is normally directed through a degassing vessel which, because of its lower operating pressure, allows most of the dissolved gas to be released from solution. This has an effect similar to a flotation cell in that, as the bubbles of gas evolve and rise to the surface, they tend to cause the coalescence of any small oil droplets with which they have contact. The oil is skimmed from the surface and the remaining water is then disposed of.

Offshore, if water contains less than 29 parts per million (ppm) oil and grease, it can generally be permitted to be discharged directly into the ocean without further treatment. To ensure that this limit is met, produced water is generally treated to remove excess oil. This is often done by air flotation, a process of bubbling air through the water. As the tiny bubbles rise, they collect the oil droplets, enabling the oil to rise more quickly and efficiently to the surface. The collected oil is returned to the production process and the produced water is then discharged overboard.

Onshore disposal of produced water is more involved and usually requires the produced water to be reinjected into the producing formation where it originated, or be injected into some other suitable formation that will not result in the contamination of fresh water sources.

7.9 Hydrocyclones

Since the mid 1980s, hydrocyclones have found increasing applications in the separation of oil from water. Hydrocyclones utilize centrifugal force to effect this separation of fluids. The hydrocyclone consists of a long tube that is conical in shape (see Figure 67). The oily water is introduced tangentially into the large end of the cone, causing the flow to begin rotating. As the flow progresses toward the narrower end of this conical tube, the speed of rotation increases. The water, being heavier than the oil, moves to-

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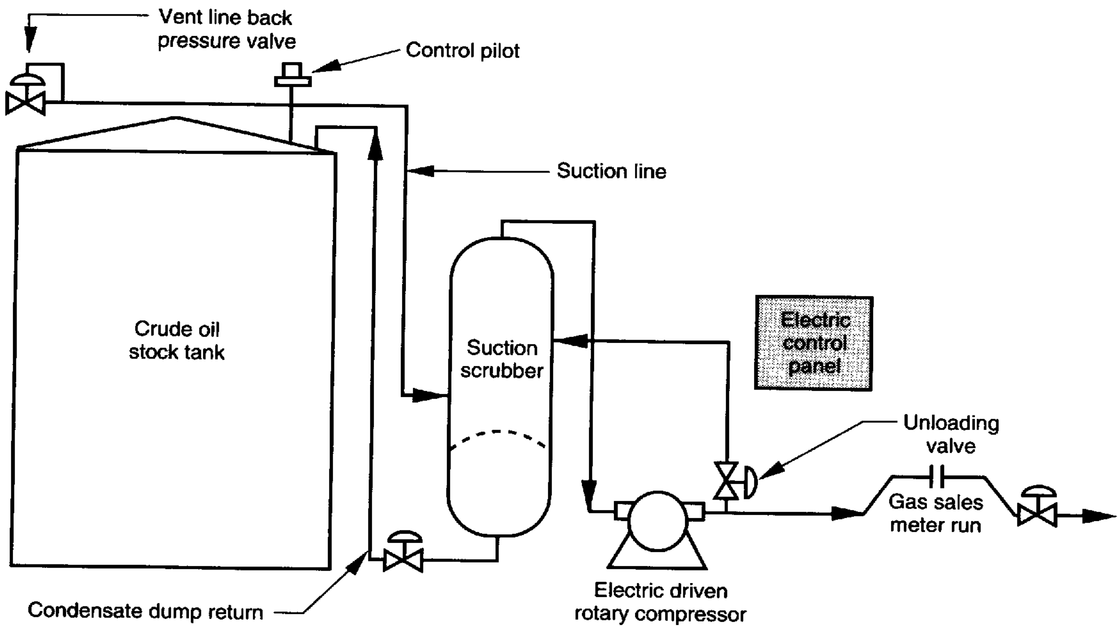

Figure 66—Typical Stock Tank Vapor Recover System

ward the wall of the tube, while oil is forced toward the center. This ultimately results in oil accumulating as a central core which can be removed axially at the large end of the cone. The water is discharged through the small end of the cone.

Several factors affect the efficiency of the separation of oil and water in the hydrocyclone. These include the specific gravity of the oil, the temperature of the oily water, the viscosity of the oil, and the pressure of the fluid at the inlet to the hydrocyclone. In general, the greater the inlet pressure the greater the pressure drop that can be developed between the inlet and outlet ports. The greater this pressure drop, the greater the speed of rotation and the greater the centrifugal force which will be developed to cause the oil and water to separate. Usually inlet pressures of 50 psi or higher are preferred.

Although many factors affect the degree of separation, under ideal conditions water discharged from the hydrocyclone may contain less than 15 ppm of oil, thus eliminating the need for additional processing of the water. As a result of their high separation efficiency, hydrocyclones are finding increasing applications in oil production. In addition, their compactness and relatively low weight, compared to conventional oil-water separation equipment, makes them appealing in offshore facilities where space is at a premium and loads must be kept to a minimum. Hydrocyclones are also being installed onshore particularly where large volumes of produced water are handled in fields with high water cuts.

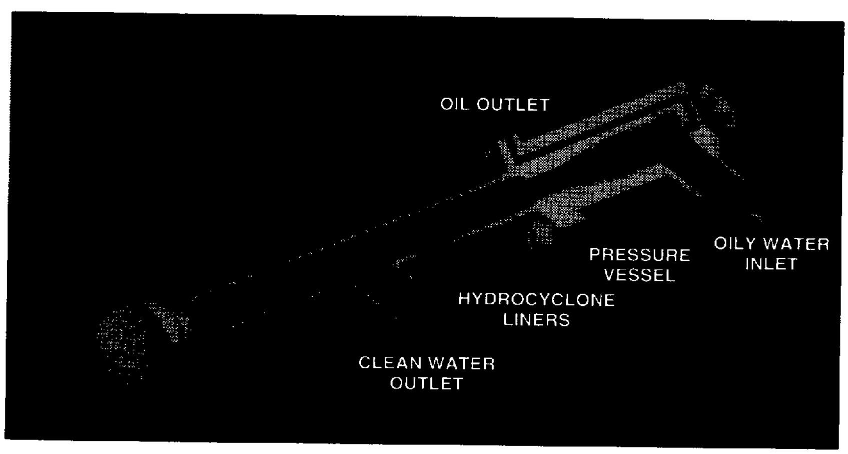

Figure 67—Hydrocyclone

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SECTION 8—GAUGING AND METERING PRODUCTION

8.1 Introduction

One of the most important duties of the lease operator is producing and measuring the proper amount of oil or gas from the wells on a lease, and seeing that proper credit is given for oil and gas delivered from the lease. In many cases, particularly where stripper wells are produced, as much oil or gas as possible is produced from each well. In some fields, oil or gas is produced from each well in accordance with allowables. These allowable rates are usually set each month by state regulatory agencies based upon current evidence concerning the market demand for oil or gas and the efficient rate of production for the particular field and wells. In the absence of regulations, the amount produced is determined by the individual producer.

For production control purposes, the volumes of oil, gas, and salt water produced by each lease are usually checked or measured by the lease operator or gauger during each 24-hour period. In any event, when a full tank of oil on a lease is delivered or run to a pipeline, tank car, or tank truck, the oil delivered is measured by gauging the height of oil in the tank before and after delivery is completed. The oil is tested to determine its gravity (density), because often the value of crude oil varies with gravity. Also, the temperature of the oil and its BS&W content are determined, so that the tank gauges can be converted into net barrels of oil delivered. Volumes are referred to at 60°F, the standard base temperature at which crude oil prices are posted.

8.2 Lease Tank Battery

It is at the lease tank battery that the oil and commingled gas produced by the wells on a lease are separated, measured, and tested. The oil is temporarily stored there, awaiting delivery to pipe line, truck, or other carrier. The older, manually-operated lease tank battery consists principally of a gas-oil separator, gun-barrel, heater-treater, two or more oil stock tanks, and gas-metering equipment. Because more than one well is usually produced through the main gas-oil separator, a test gas-oil separator and gas meter are often provided to enable separate periodic measurement of the production from each well for testing purposes. This also determines that each well produces its proper part of the total production from the lease. In some cases, an oil meter is used in place of a tank for well-testing purposes. Thus, oil production from all wells on a lease can be measured in the lease tank while one well is individually tested using an oil meter. Periodic well tests are often required by state regulations and are needed by the operator as a guide to maintain efficient operation of the wells and the underground oil reservoir.

8.3 Tank Battery Operation

After passing through the gas-oil separator, the gas usually is measured through an orifice meter, and the oil flows into one of the tanks where gauges of the height of oil in the tank are taken from time to time by the operator. The oil flow is usually directed into one tank of the lease battery until it is filled, after which the flow is switched to an empty tank.

The final gauging of a full tank is made by the pipeline gauger preparatory to running the oil from the tank into the pipeline. The closing gauge when the tank has been emptied and is sealed shut in preparation for another filling, is also taken by the pipeline gauger. It is the lease operator's responsibility to watch the gauging and testing of the oil by the pipeline gauger and to be sure that the measurements are correct. The lease operator in this transaction represents the producer or seller, and the pipeline gauger the transporter.

Similarly, it is often the duty of the lease operator to see that the metering equipment used to measure gas delivered off the lease is functioning and serviced properly, even though this may be the direct responsibility of other personnel or of the purchaser of the gas. Gas meter charts may be changed by the lease operator (Figure 68) who makes the proper notations and forwards them to the production office for reading and calculation of the gas volumes recorded. At times, lease operators sight read the gas meter charts to estimate the daily volume of gas produced by each lease. The gas purchaser usually supplies and maintains the gas sales metering equipment.

Figure 68—Changing gas meter charts is a routine function of the lease operator.

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When salt water is produced with the oil, the accumulated water must be drained from the lower levels of the gun barrel and stock tanks. This is usually done automatically by a siphon on the gun barrel, but may be done manually through the drain valve on the stock tanks. The volume of salt water produced during each 24-hour period may be measured by gauging before and after drawing off the water accumulated in the lower levels of the tanks. Sometimes it is necessary to transfer any oil emulsified with salt water from the bottom of a lease stock tank to a treater for removal of water or BS&W.

8.4 Tank Strapping

Before a tank battery is put in service, each tank is strapped, which means taking the measurements or dimensions of the tank and computing the volume of oil that can be contained in each interval of tank height. The capacity in barrels according to height of liquid in the tank is prepared in tabular form, known as a *tank table*. Common practice is to show the capacity for each 1/4 inch from the bottom to the top of the tank.

The strapping and preparation of the tank table for each tank is usually done by a third party not connected with the producer, pipeline, or oil purchaser.

8.5 Tank or Oil Gauging

To measure or gauge the level of oil in a tank, a steel tape with a plumb bob on the end is lowered into the tank until it just touches the tank bottom. The tape is then withdrawn and the highest point where oil wets the tape shows the level or height of oil in the tank. By referring this value to the tank table, the volume of oil (or oil and water) in the tank is determined. An automatic tank gauge has been used to some extent in past years. This device consists of a steel gauge line contained in a housing, with a float on the end of the line resting in the surface of the oil in the tank. The line extends up over the top of the tank and down the outside through a reading box. The end of the line is coiled and counterbalanced below the reading box, which is located at a convenient height for reading from the ground. The line running through the box is marked to show the height of oil in the tank, which can be read through a glass window in the box. This type of device can be modified to obtain a continuous recording of tank gauges.

8.6 Oil Measurement and Testing

Crude oil is bought and sold in the United States on a volume basis, with the barrel (42 standard gallons) as the unit of measurement. The volume must be corrected for BS&W. Volume also must be corrected to the standard base temperature of 60°F since the volume of oil as gauged in a tank increases with the temperature of the oil. In many cases, the value of crude oil increases with higher *API gravity*.

Thus, when the gauger representing the pipeline or other transporter proceeds to put a tank on the line, the first step is to determine the nature of the fluid below the pipeline connection and drain off through the drain valve any BS&W above this level in the tank. The top or opening gauge is then taken. The average temperature, gravity, and BS&W content of the oil in the tank must be measured. When the tank has been drained of oil to the level of the pipeline connection, a bottom, back, or closing gauge is taken. The lease operator representing the producer witnesses all of these gauges and measurements. This information, along with the names of the lease, producer, and transporter; the number of the tank, the date, and other necessary data are written on the pipeline run ticket, and both representatives sign the ticket. A sample run ticket is shown in Section 15. Such a ticket, when covering an actual transaction, is handled as carefully as a bank check.

8.7 Measurement and Testing Procedures

All procedures commonly used for measuring, sampling, and testing crude oil in the United States are passed on by the API Committee on Petroleum Measurement Standards.

8.7.1 TEMPERATURE MEASUREMENT

The temperature of the oil in a lease stock tank is ordinarily close to that of the air around the tank, except (a) while and shortly after the oil is produced when it may retain some of the elevated temperature of the subsurface reservoir; and (b) when the oil is heated in a treater to separate it from salt water or BS&W. In such cases, the temperature of the oil may be 10°F to 20°F above air temperature. The temperature of oil in a tank is usually taken with a special thermometer which is lowered into the oil on a line and then withdrawn to observe the reading (Figure 69).

Corrections of oil volumes measured at temperatures other than the standard of 60°F are made in accordance with tables published by the American Society for Testing Materials (ASTM D1250) and the Institute of Petroleum (IP 200).

8.7.2 GRAVITY AND BS&W CONTENT

To determine BS&W content and the API gravity of oil in tanks, samples of the oil are taken from the tank for testing. The samples are taken either (a) with a *thief,* which is a container that can be lowered on a line or stick into the tank from the top through a hatch and is equipped so that it can be filled at any level in the tank; or (b) by means of *sample cocks* installed at various levels in the shell of the tank and through which samples can be withdrawn. Thiefs and sample cocks are also used to determine whether there is excessive BS&W near the level of the pipeline connection to a lease stock tank, which is usually about 12 inches above the bottom of the tank. Most pipelines require that all oil higher

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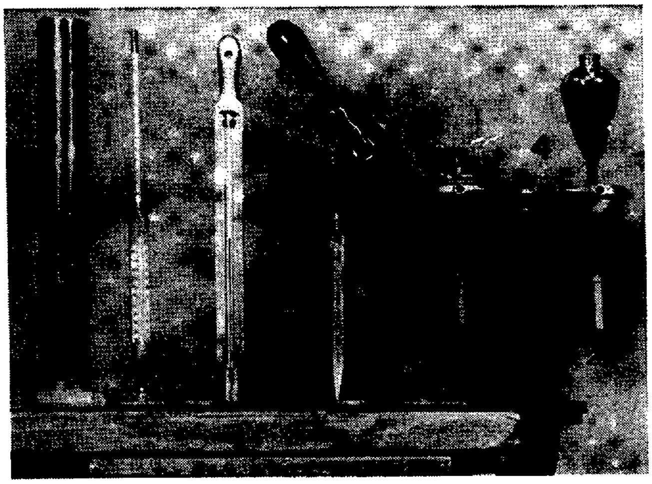

Figure 69—These are some of the gauger's tools: (1) Hydrometer and graduate for measuring API gravity of oil. (2) Thermometer for measuring temperature of oil in tanks. (3) Tank-gauging line for measuring height of oil in tanks. (4) Centrifuge or "shake-out machine" for measuring BS&W content of crude oil.

than 4 inches below the bottom of the pipeline connection must be acceptable. Buyers of crude oil have varying requirements regarding the cleanliness of crude oil, but the maximum BS&W content in most areas is 1.0 percent.

The BS&W content of the samples is determined by a centrifuge or shake-out test, and the glass container in which the test is made is graduated so that the percentages of BS&W can be read directly.

The API gravity of the oil is measured by a hydrometer graduated to give a direct reading which is then corrected to the standard temperature of 60°F.

8.8 Standardized and Semi-Automatic Tank Batteries

Most operators use a fairly well standardized lease tank battery with respect to type, layout, and size of equipment and fittings employed. This simplifies the installation and operation, serves to eliminate hazards to tank battery operation, and helps to avoid conditions and practices that otherwise might lead to waste.

Steps have been taken toward making the operation of older tank batteries more automatic. This is being done to further improve the efficiency and accuracy of the operations and minimize the hazards. To relieve operators of certain routine duties such as switching and topping out tanks, tank batteries are now often being equipped with (a) overflow lines connecting tanks near their top levels in order to prevent overfilling any one tank; (b) filling valves which close when the tank becomes full and diverts the stream to the next tank; and (c) electrical, mechanical, or air-operated devices and valves that switch tanks and shut in wells when all tanks are full.

The normal lease tank battery now consists of a pressure heater-treater, a run tank, a bad oil tank, an automatic custody transfer unit, and a test unit. The test unit consists of a vessel that separates gas, oil or emulsion, and free water into three phases; a gas meter; a gross liquid meter; and a device that determines net oil. Many leases also have tank vapor recovery units. A production gas-oil separator is not normally required because the pressure heater-treater contains a gas separator.

8.9 Automatic Custody Transfer

The use of fully automatic equipment is called *lease automatic custody transfer* (LACT). Figure 70 is a schematic layout of a multi-LACT system. An automatic custody transfer (ACT) installation (Figure 71) provides for the unattended transfer of oil or gas from the lease to the pipeline. The unit meets requirements for accuracy and dependability as it takes samples, records temperatures, determines quality and net volume, eliminates gas (where necessary), recirculates bad oil for another treatment, keeps a record for producing and accounting purposes, and shuts down and sounds an alarm when something goes wrong. Surge tanks are used for protection against irregular flow. The LACT unit actually delivers directly to the pipeline as soon as fluids have been separated. Compressors may be connected with the surge tanks to recover gas and stabilize oil to materially improve overall vapor recovery. Where applicable, the advantages include a reduction in lease storage (which might mean less evaporation loss, as well as less investment in stored oil) and increased operating efficiency and control.

The producer usually supplies the LACT unit. This unit is calibrated by the pipeline periodically and is maintained by the pipeline or producer. Each unit of oil that passes through the LACT unit is sampled, and these samples are stored on the unit. These samples are held under pressure and the sample container shielded from the sun to prevent excessive weathering. Weathering decreases the API gravity of oil, usually decreasing the selling price.

8.10 Gas Measurement

The most commonly used method for measurement of gas is the orifice meter. This is a differential measurement device actuated either by mercury float or—a more recent development—liquid filled bellows. It has been widely accepted by the industry for measuring gas volumes.

Orifice measurement of gas is covered in the API *Manual of Measurement Standards,* Chapter 14.3 "Orifice Metering of Natural Gas, 1978." (American Gas Association Gas Measurement Committee—AGA—Report No. 3; ANSI/API 2530).

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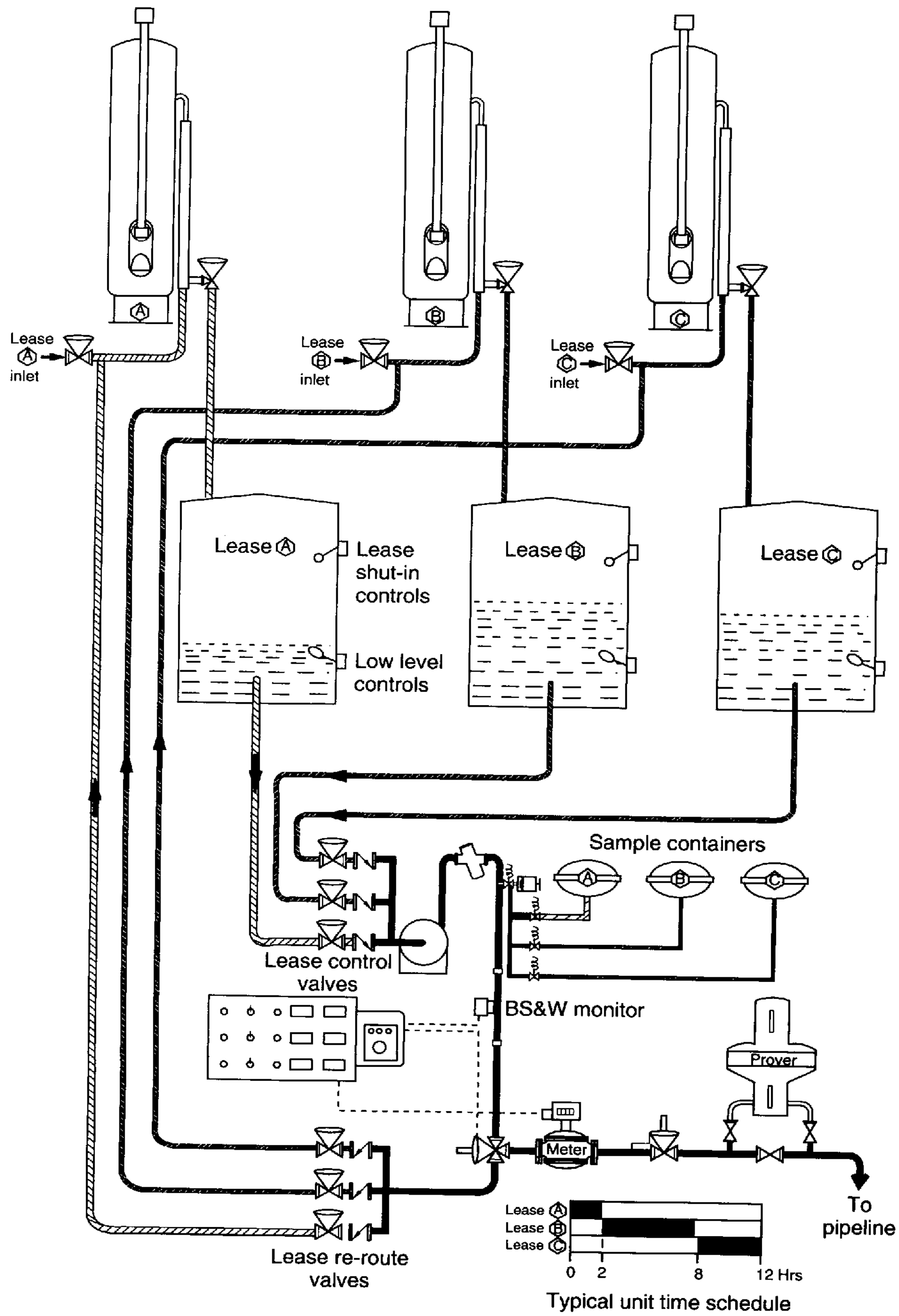

Figure 70—Flow Diagram of a Multi-lease Automatic Custody Transfer System

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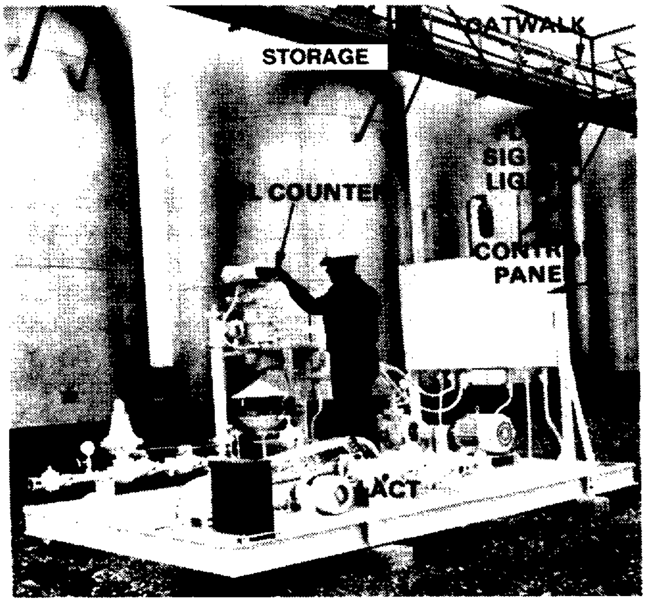

Figure 71—Automatic custody transfer unit where oil is measured for sale and transfer to the pipeline.

The orifice meter in conjunction with its primary devices—tube section, orifice plate, and pressure taps—when installed carefully and when using factors within the prescribed tolerances, will obtain an overall accuracy of measurement within ±2 percent.

An orifice meter installation consists of a static pressure and differential pressure recording gauge connected to an orifice flange or orifice fitting by suitable piping. The orifice meter tube (meter run) consists of upstream and downstream sections of pipe whose size and tolerance have been determined through calculation and conform with specifications set forth in AGA Report No. 3—ANSI/API 2530.

The orifice plate is centralized in the line by the flanges or within the fitting in a plane 90 degrees to the direction of flow. Bore, circumference, edge, and tolerance should meet all specifications as set forth in AGA Report No. 3—ANSI/API 2530.

A record of gas flow through the orifice meter is registered on meter charts or stored in gas flow computers.

Other types of gas meters have application in certain situations. These include the positive displacement meter (typical residential), turbine flow meter, and vortex shedding flowmeter.

8.11 Computers in Producing Operations

Field operating people plan and organize the work; maintain, repair, and troubleshoot; and solve problems to keep equipment functioning. However, computers are used in many modern operations to control and monitor oil, gas, and water production through the field communications system of wire and radio. Electronic controls operate the ACT units, automatic well test systems, the flow of wells, storage, use of fail-safe devices, sensors, valves, time clocks, and the alarm devices (see Figure 72). They also collect and record production information such as flow rates, malfunctions, liquid levels, pressure, temperature, fire detection, and flow control equipment. Computers perform the routine work and provide 24-hour surveillance of operations.

This equipment is operated and maintained by a team composed of electricians, mechanics, computer technicians, and production equipment specialists.

8.12 Programmable Logic Controllers and Distributed Control Systems

Programmable logic controllers (PLC) and distributed control systems (DCS) may be used to provide automatic, day-to-day control of oil field production systems. The PLC and DCS are electronic developments that have occurred in recent years. They are an outgrowth of the tremendous advances that have been made in computer technology.

The PLC and DCS provide means of automatically measuring and recording the values of process variables such as levels, pressures, temperatures, and flow rates. They also provide a means of starting and stopping equipment, opening and closing valves, and taking corrective action as determined by the control program in response to fluctuations in the process variables. As part of their control function, they

Figure 72—The master station controls and monitors operations through a communication system of satellites and remote control panels connected to the end devices.

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can keep track of previous measurements, indicate trends in any changes in these measurements, and use these trends to predict future problems or make appropriate changes in the process variables so that the process continues to function within normal operating limits.

When originally developed, PLCs were used in small, relatively simple control applications, while DCSs were used in larger, more complex operations such as chemical plants and refineries. In recent years, however, as PLCs have become more powerful in their capabilities and DCSs have become more diverse in cost and size, this demarcation in their application has become less distinct.

PLCs can be used instead of electro-mechanical (electric relay) panels and pneumatic panels for control purposes. Changing the electro-mechanical control panels often requires extensive modifications; it may be cheaper to replace the panel. To change the way a PLC controls a piece of equipment or process, it is only necessary to reprogram it. In addition to this versatility, PLCs are relatively inexpensive and reliable and have much greater capabilities.

With the enormous expansion taking place in the field of electronic communications and the great strides being made in computer technology, it is safe to say that PLCs, DCSs, and other means of automatic control and data acquisition will play an increasingly important role in oil and gas production.

8.13 Supervisory Control and Data Acquisition (SCADA) Systems

Supervisory control and data acquisition systems (SCADA) systems provide a means of monitoring and controlling production operations from a central location. Advances in communication and control technology have made SCADA systems an increasingly attractive option for operating remote oil and gas fields. With a SCADA system, many routine activities can be conducted without someone having to be physically present at the well or production facility. An operator at a central control location can monitor field operating variables such as flow rates, pressures, and temperatures; can start and stop equipment; open and close valves; and adjust production rates as needed. SCADA systems are used in the monitoring and control of remote oil and gas fields both onshore and offshore, and it is likely that they will continue to find increasing use in oil and gas production.

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SECTION 9—OFFSHORE PRODUCTION AND STRUCTURES

9.1 Introduction

One segment of the oil and gas industry that has shown remarkable growth and technological advancement in recent years is offshore operations. Since this type of activity began by gradually extending onshore fields or trends into adjacent shallow waters, there are conflicting claims as to where and when the first true offshore well was drilled. Louisiana, California, and Texas are the primary areas of the United States where such activities were under way before World War II.

Early efforts in drilling wells offshore employed conventional land drilling rigs that were located on adjacent shores, artificially constructed islands, or wharf platforms (usually wooden) in shallow water. Later, barge-mounted rigs were used to develop fields in shallow water, with production piped to facilities located onshore nearby (Figure 73). All of these methods are still used to some degree in certain near-shore areas, but far more specialized equipment has been developed to accommodate drilling and producing oil and gas wells in open water throughout many parts of the world.

As offshore oil and gas development moved into progressively deeper waters, bottom-supported steel platforms designed to withstand hurricane-force wind and waves, or even moving ice sheets, also were developed. These platforms became key elements in each of the two basic development schemes employed to date. Structures designed for the prevailing local conditions are now in use from the tropics to the North Sea and offshore Alaska, and in water depths to more than 1000 feet.

In one type of offshore development, wells are drilled by mobile drilling rigs, of which there are several types. These wells are usually on small protective structures, often called jackets, as shown in Figure 74. In a few instances, the wellheads are actually at the sea floor (underwater completions) and no part of the well is visible at the surface. Jacket development is generally limited to water depths less than 200 feet, while underwater completions may be made at much greater depths. In either case, these remote wells produce through flowlines on the sea floor to a central gathering platform. These large structures house personnel accommodations, production facilities, and sometimes limited oil storage. From such platforms the oil and gas are usually transported to shore by pipeline, or the oil may be loaded into barges or tankers.

Platform drilling, another offshore development method, is often used in shallow water and is the predominant method for water depths from 200 to about 1000 feet. In this case, wells are drilled from and protected by the same structure on which the production facilities are subsequently installed. Such structures are often called *self-contained*

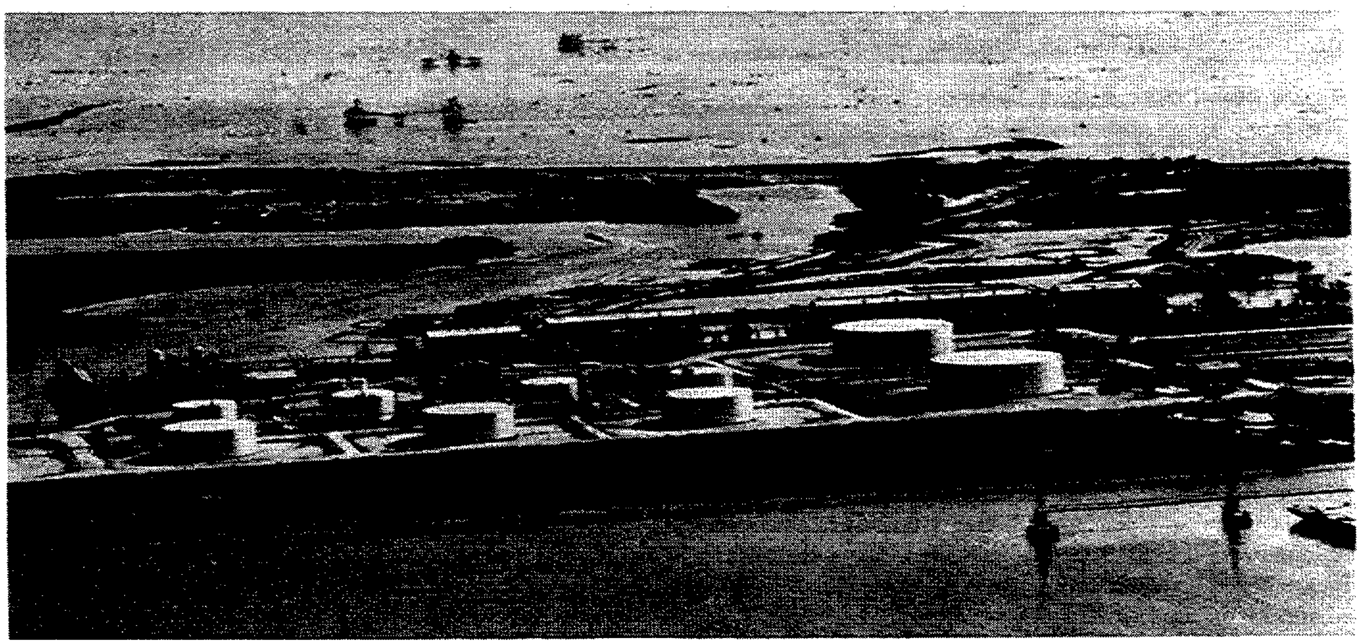

Figure 73—A field where development extends from the shoreline into deep ocean water. Some of the closest wells produce directly to shore, while others in the distance produce to gathering platforms (see Figure 74). This minimizes the transfer lines required. All production is subsequently handled by the main facilities onshore (foreground).

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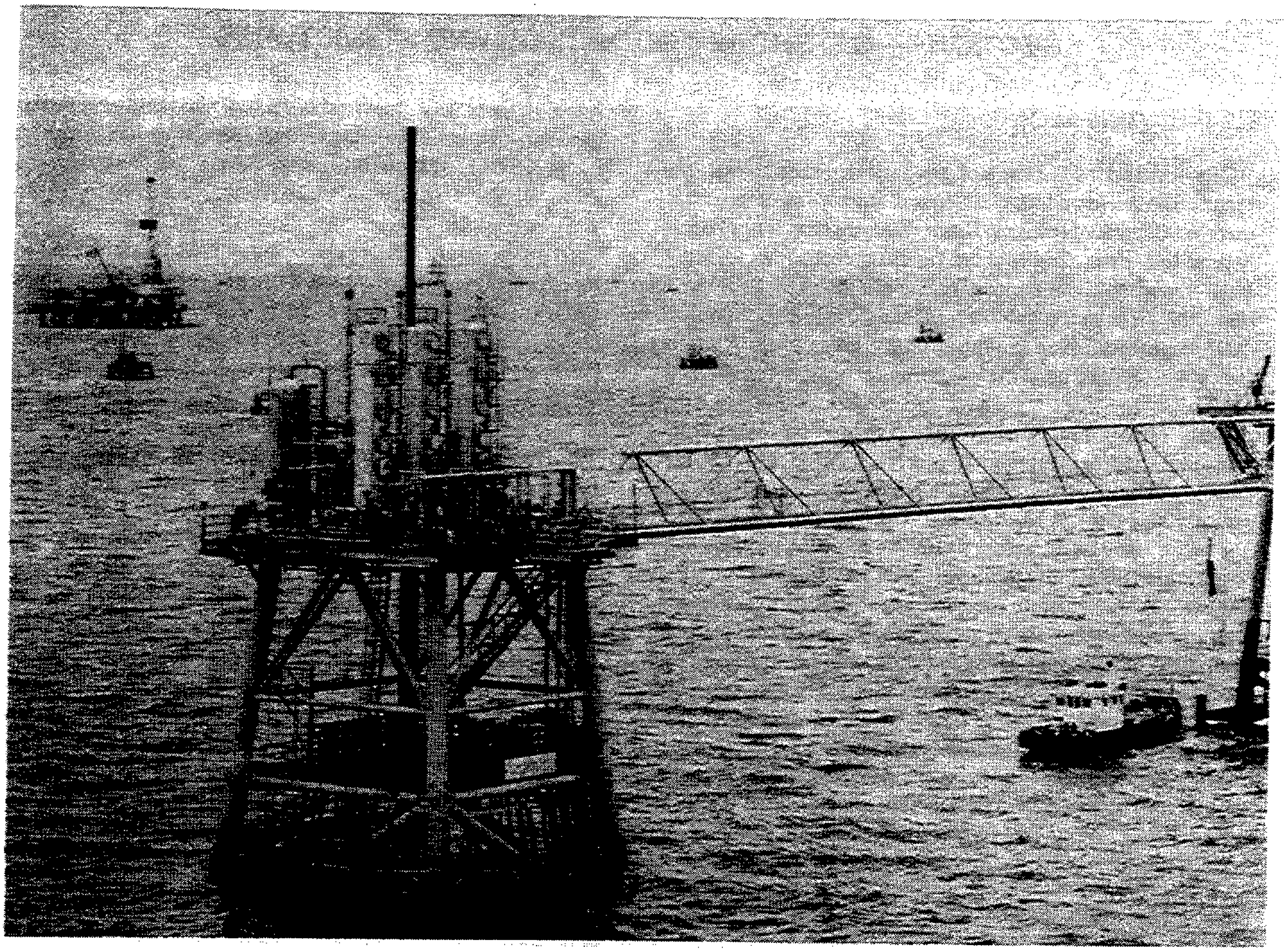

Figure 74—Offshore Well Jackets, Central Gathering Platform, and Mobile Rig
The many small structures each house from one to four wells, which produce through flowlines to the central gathering platform in the foreground. One transfer line each for oil and gas then carry production ashore. The wells were drilled by a mobile rig, as seen in the upper left.

platforms. Figure 75 shows a platform containing production facilities from which more than 60 wells were drilled. The well conductor casings can be seen in rows under the center of the platform, and the wellheads are under the deck on which the workover rig is located.

Production facilities that are used to produce, separate, and treat oil, gas, and water offshore are basically identical to those used onshore. The major difference is that the equipment is ingeniously packaged, often by stacking in layers, to fit in the very limited space available on offshore platforms. Figure 76 shows a production platform complex in the Gulf of Mexico off the Louisiana coast.

Some of the larger offshore fields have been developed by drilling from several large platforms. In such instances, it may be practical to handle production from all the structures through facilities on just one platform rather than for each to be fully self-contained. Figure 77 shows such a complex. The interconnecting walkways (bridges) are primarily for the convenience and safety of the production operators, to avoid transferring between platforms by boat. Typically such complexes are found in shallower water (generally less than 200 feet deep).

Remarkable progress in offshore construction, drilling, and production technology has been made during the last 30 years, and the pace is still accelerating. The industry, which saw most of its development in the Gulf of Mexico off the coast of Louisiana until the mid-1960s, is now flourishing on continental shelves throughout the world. Wells have been successfully drilled in thousands of feet of water using floating drilling rigs, and the technology to complete and operate such wells is developing rapidly. Completely new concepts for offshore platforms in thousands of feet of water

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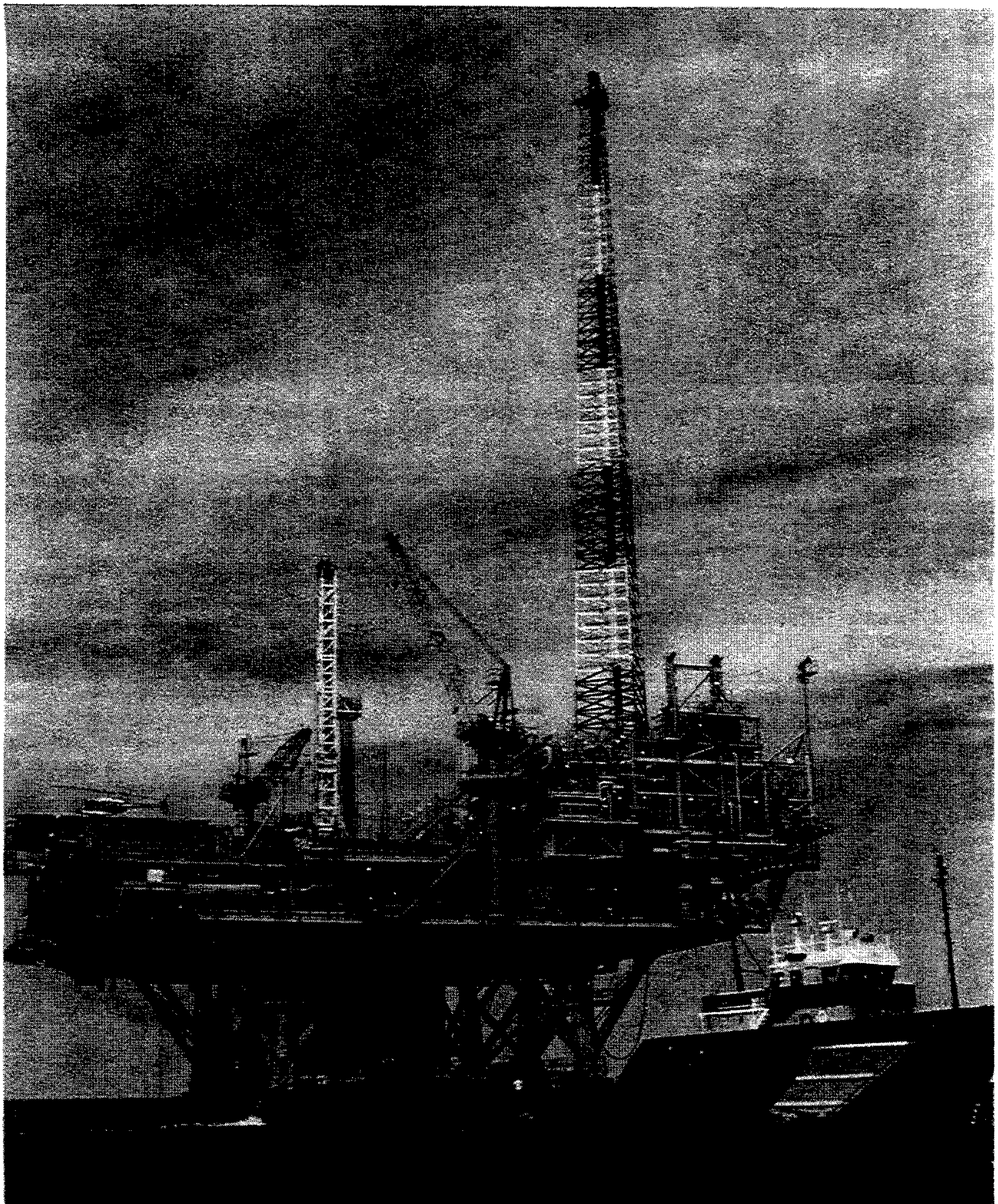

Figure 75—Offshore Self-contained Platform

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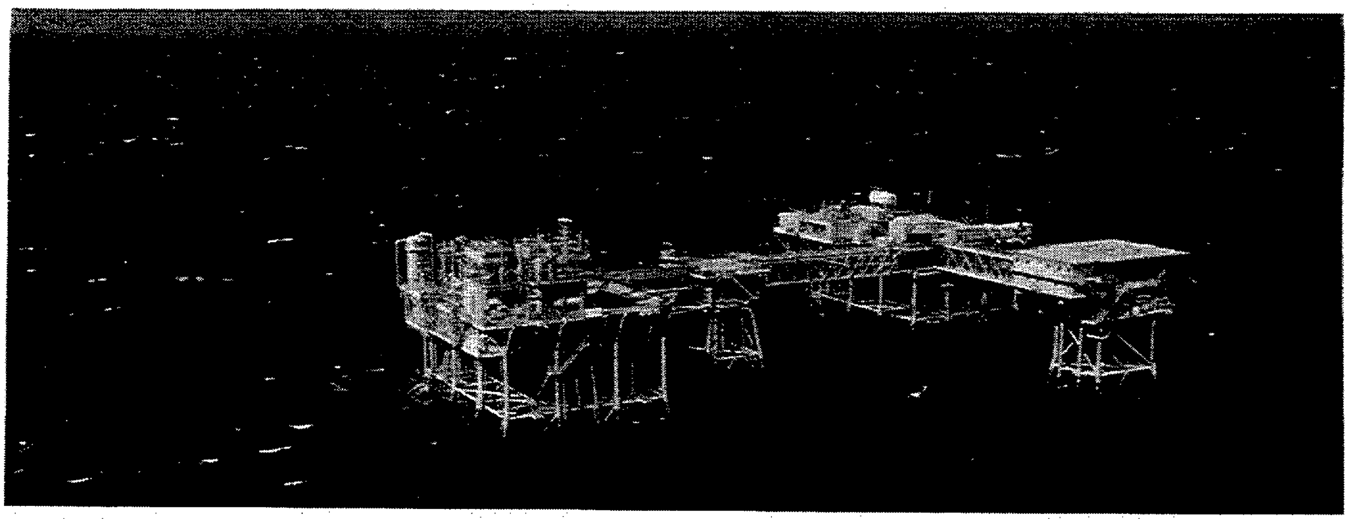

Figure 76—Large Offshore Production Complex (Note helicopter pad and crew's quarters on the right.)

also have been unveiled. Offshore oil and gas development throughout the world promises to be the most rapidly changing part of an always active and advancing industry. Some of these alternative concepts are described in 9.2 through 9.4.

9.2 Alternate Offshore Production Systems

Conventional platforms are essentially rigid structures which are pinned to the sea floor using piles. The weight of the structure and the facilities installed thereon is supported by the structure which transfers these loads into the sea floor via piling. Such structures typically have an economic limit in the range of 1200 to 1400 feet of water in environments such as the Gulf of Mexico. In harsher environments, the economic water depth limit may be even less. Beyond these depths other types of production systems become more attractive economically.

9.2.1 SUBSEA TEMPLATES

When deepwater prospects are located fairly close to shallower water, it may be economically feasible to develop the deepwater prospects using subsea completions and process the produced fluids on a floating facility or on a shallow-water platform. Often a multi-well template will be installed on the sea floor and the subsea wells will be drilled through the well slots provided by this template. Such templates frequently include well manifold systems which allow the production from the wells to be commingled at the template. Pipelines may then convey the produced fluids

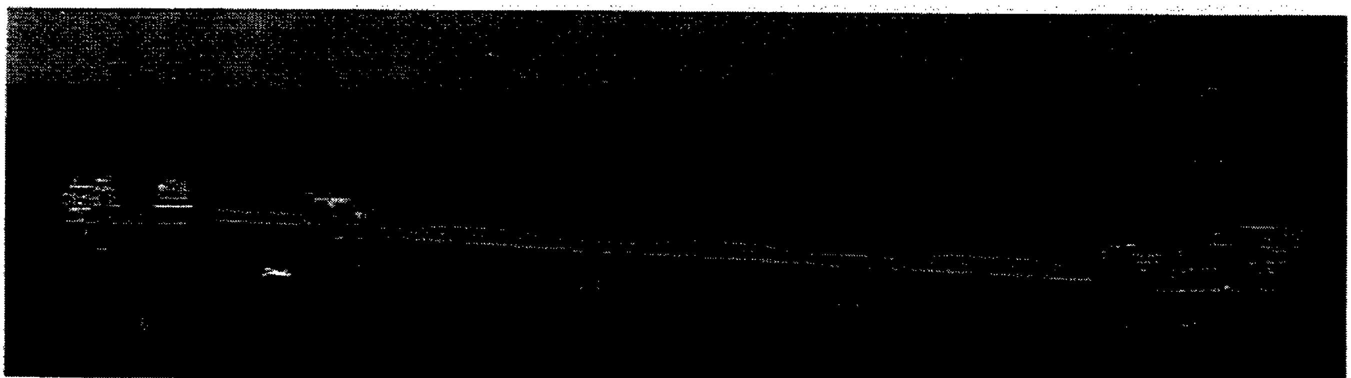

Figure 77— Three Offshore Platforms Operated as One Complex
Although there are wells on all three platforms, the platform at extreme left handles all production, including the platform to the right where drilling is still in progress.

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from these manifolds to the shallow water platform. The wells are controlled by means of a subsea control system which is operated from the platform.

9.2.2 TENSION LEG PLATFORMS

Beyond the depths where conventional platforms can be used, tension leg platforms (TLPs) may find application. TLPs are floating facilities that are anchored to the sea floor with vertical tendons installed at the corners of the structure. Tension is applied to the tendons by deballasting the structure after the tendons are installed. The tension, provided by the buoyancy of the structure, minimizes the motion caused by wave action.

Tension leg wellhead platforms (TLWPs) have been proposed to provide minimum facilities in deep water, with the produced fluids being processed on a separate facility such as a shallow-water platform.

Wells drilled from TLPs are usually completed with their tubing extending back to the platform. This permits direct access to the tubing for control of production rates and workover operations. The primary limitations of the TLP are those imposed by the amount of buoyancy that can be developed to provide tension in tendons and support the weight of the required equipment.

9.2.3 SEMI-SUBMERSIBLES

Semi-submersible vessels have found application as floating production facilities. Most of these systems have utilized drilling semi-submersibles which have been converted for the purpose. The semi-submersible, while a floating platform, differs from the TLP especially in the design of its mooring system. While the TLP utilizes vertical mooring tendons, a semi-submersible platform uses a conventional catenary mooring system. In general, semi-submersibles will exhibit more motion than a TLP but, when compared to a single-hull vessel such as a tanker or a barge, their motion is dampened considerably by their deep ballasted hulls and the comparatively small area exposed to wave action.

In converting a drilling semi-submersible for use as a floating production facility, the drilling rig may or may not be removed, depending on whether drilling and workover capabilities need to be retained, and whether the load carrying capability of the semi-submersible can accommodate both the weight of the drilling rig and the processing equipment.

Subsea completions are generally used when semi-submersibles are utilized to accommodate production facilities. The oil and gas may be conveyed to the semi-submersible through individual flowlines or through a specially designed production riser. Widely spaced subsea completions or template wells (see 9.2.1) may be used with semi-submersibles which are utilized as floating production systems. Sometimes, only preliminary processing of the oil and gas occurs on the semi-submersible, with final separation and dehydration of the oil and gas accomplished on a platform in shallow water or at facilities located onshore.

In general, the conversion of a drilling semi-submersible to a floating production facility constitutes a major modification. In some cases, the cost of conversion may approach that of a purpose-built vessel. The cost of conversion therefore must be carefully analyzed in selecting the best alternative for development.

9.3 Floating Production and Storage Facilities

In areas which are remote from shore and where an infrastructure of subsea pipelines and onshore production facilities does not exist, floating storage may be an alternative. Although tankers most often have been converted for this application, purpose-built storage units also have been used. An example of such a unit is the Brent Spar Buoy (see Figure 78) which was built for storing oil from the Brent Field in the North Sea.

When tankers are converted for permanent use as oil storage facilities, they usually are modified by permanently attaching a mooring buoy which incorporates a special fluid swivel. This buoy, which is attached to one of the tanker's ends, allows the tanker to be permanently moored at the location and the swivel permits the tanker to weathervane around the buoy without interrupting the flow of oil to the tanker. Permanently attaching such a buoy to a tanker involves a significant amount of modification to the ship. When tankers are thus converted, a means of unloading is required. This is usually accomplished by the shuttle (transport) tanker attaching a mooring hawser to the opposite end of the storage tanker from the buoy. The oil is transferred by means of a floating hose connected between the two ships. Generally the shuttle tanker will keep its engine and propeller turning slowly so as to keep the mooring line taught and thereby prevent the two ships from touching. Sometimes oil transfer may take place by means of a separate loading buoy to which the shuttle tanker can be temporarily moored. In mild environments the shuttle tanker may come alongside and tie up directly to the permanently moored tanker.

Such an installation is known as a floating storage and offloading facility (FSO) (see Figure 79). If all or some separation and treating of the oil takes place on board the permanently moored vessel, it is then known as a floating production storage and off-loading facility (FPSO) (see Figure 80). In some cases, subsea wells may be produced directly from an FPSO.

In the case of FSOs and FPSOs, some of the produced gas may be used for fuel. The remainder of the gas may be reinjected into wells or, more commonly, flared at either the platform or the floating facility or both.

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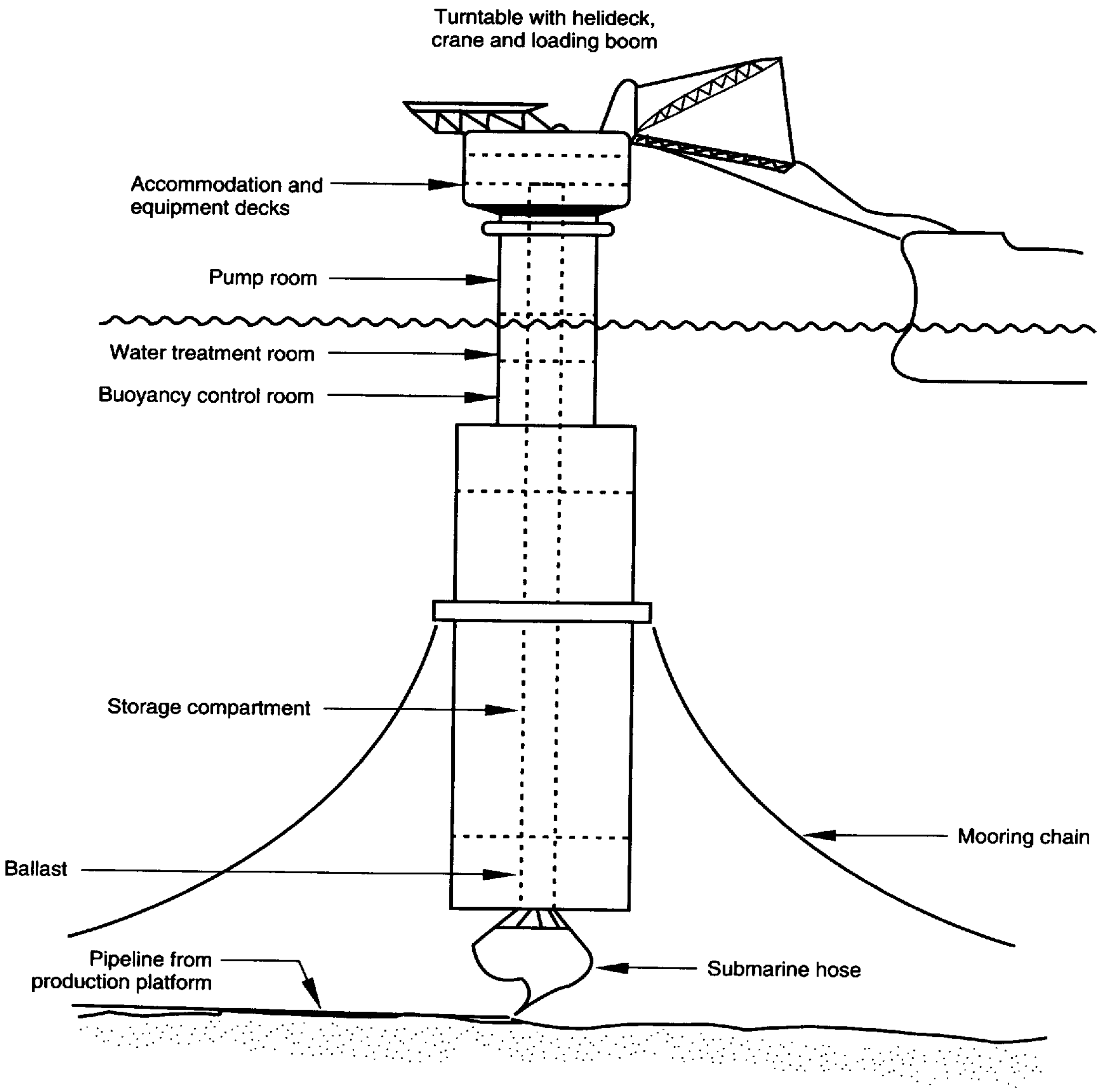

Figure 78—Bent Spar Buoy

9.4 Mobile Offshore Production Units (MOPUs)

Jackup drilling units can often be used as production platforms. When modified and used in this manner they are often referred to as MOPUs (as opposed to MODUs, or mobile offshore drilling units). When converted to a MOPU, the drilling rig may be left on the unit or may be removed, depending on several factors including the MOPU's proximity to the producing wells. Other factors include whether or not the drilling of additional wells is anticipated, and whether or not the jackup can accommodate both the drilling rig and the production equipment that will be required.

For more than 30 years, jackup drilling units have been converted to MOPUs and have been used in areas as widely different as the Persian (Arabian) Gulf and the North Sea. By far the greatest number of applications are in relatively shallow, mild or moderate environments where the choice of suitable candidates for conversion will be much wider. The advantages of converting jackups to MOPUs include relatively short conversion times and the ability to use the MOPU elsewhere when fields with short production lives are depleted.

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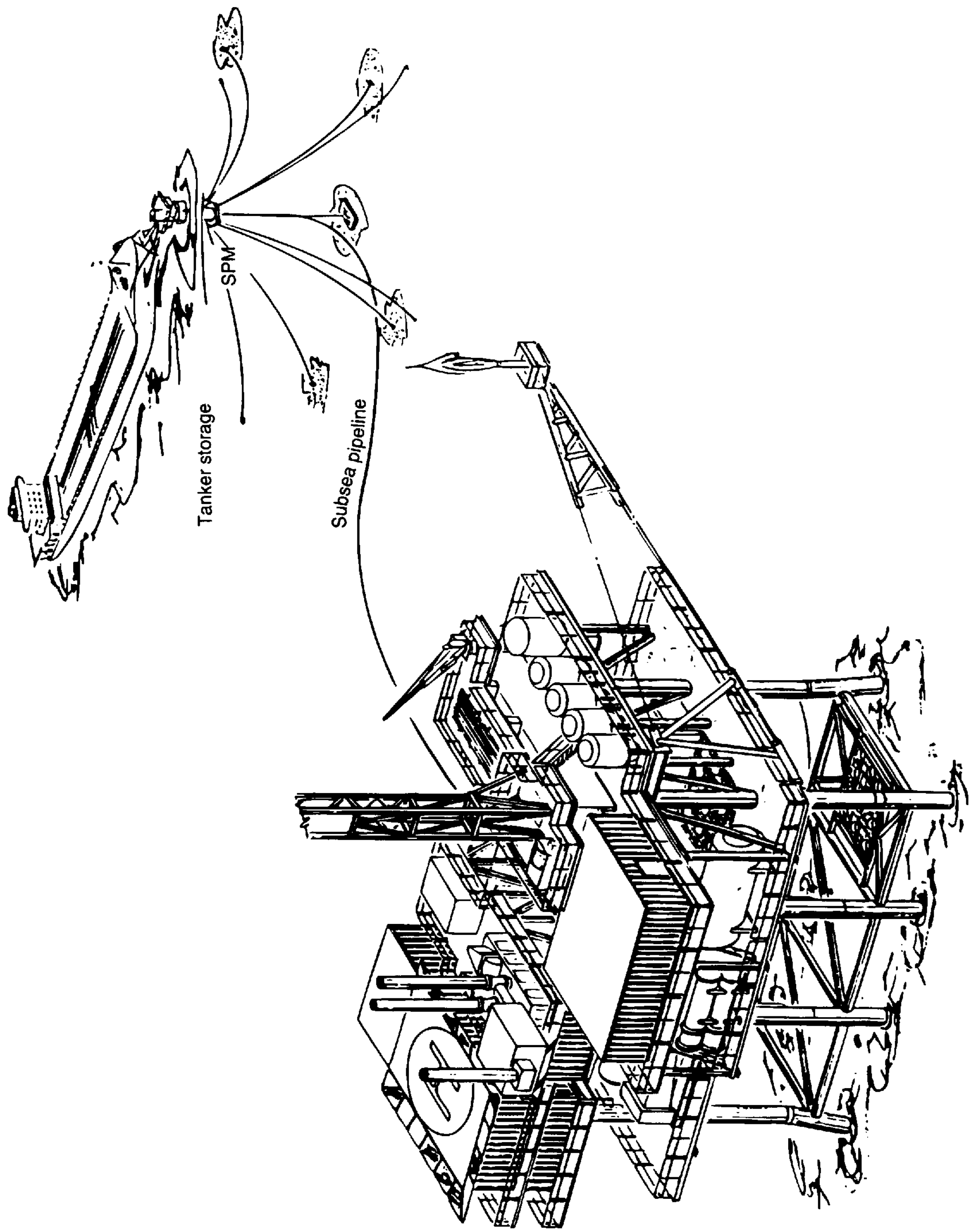

Figure 79—Floating Storage and Off-loading Facility (FSO)

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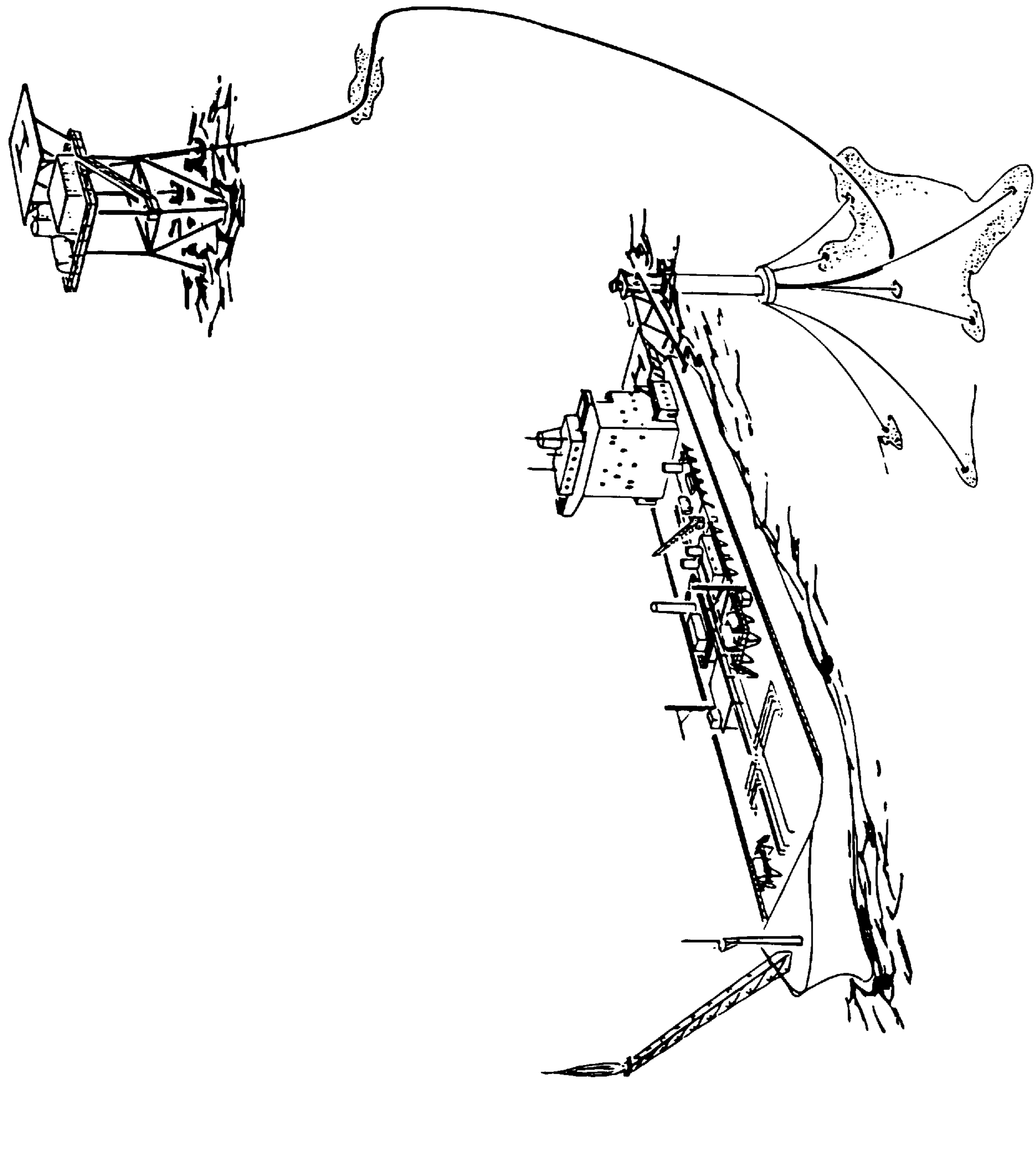

Figure 80—Floating Production Storage and Off-loading Facility (FPSO)

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9.5 Subsea Pipelines

As oil and gas producing wells were drilled offshore, it became necessary to lay subsea pipelines to convey the oil and gas to shore. Soon the design, fabrication, and installation of subsea pipelines became a specialty in its own right.

Subsea pipelines may be installed by a variety of methods. While rigid in short lengths, pipelines in long lengths are quite flexible, and virtually all methods of subsea pipeline installation make use of this fact. The most common installation method uses a pipe-laying barge. Short sections of pipe, usually around 40 feet in length, are welded together and lowered to the sea floor by means of a *stinger.* A stinger is a structural truss attached to the stern of the barge. It supports the pipe between the barge and the sea floor so that the pipe does not buckle during the laying process. Stingers may extend to the sea floor in shallow water or in water from 200 to 300 feet deep (see Figure 81). In deep water, a stinger supports the upper portions of the pipe, while pipe tension prevents buckling of the lower portion (see Figure 82).

Subsea lines may be fabricated onshore and towed along the sea floor to their intended location. This method is known as the *bottom tow* method of pipeline installation (see Figure 83).

The *off bottom tow* installation method utilizes pieces of chain as ballast, in conjunction with acoustical release

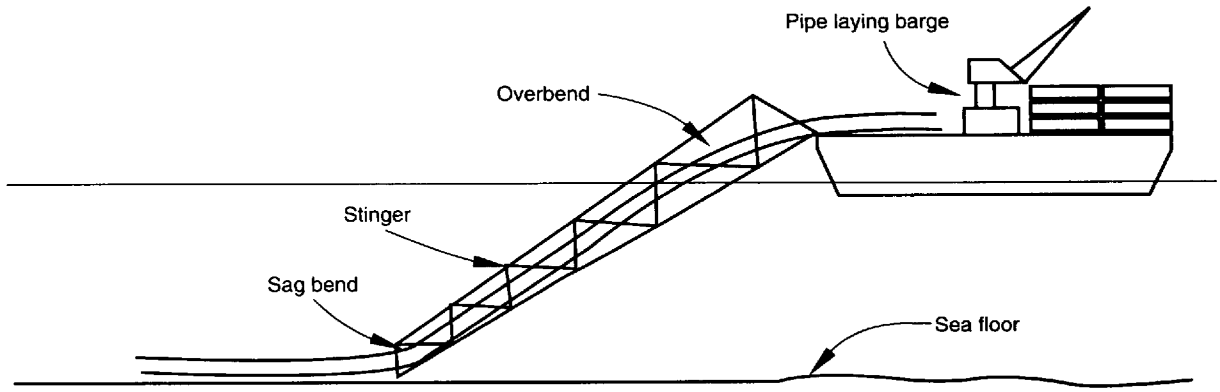

Figure 81—Pipe Laying Barge – Shallow Water

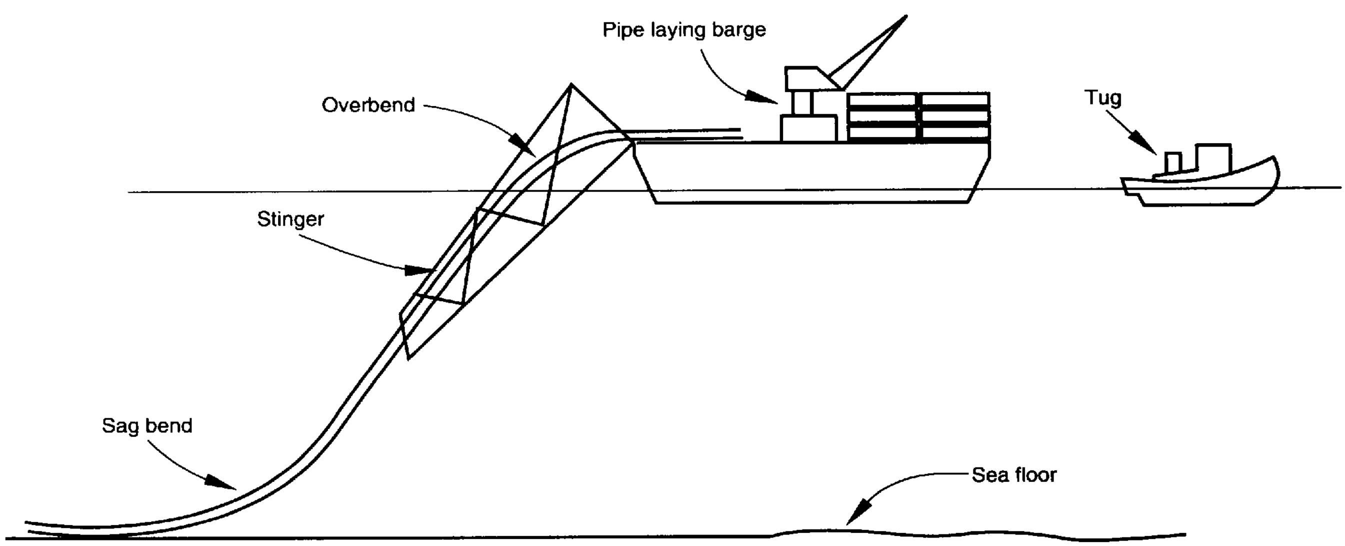

Figure 82—Pipe Laying Barge – Deeper Water

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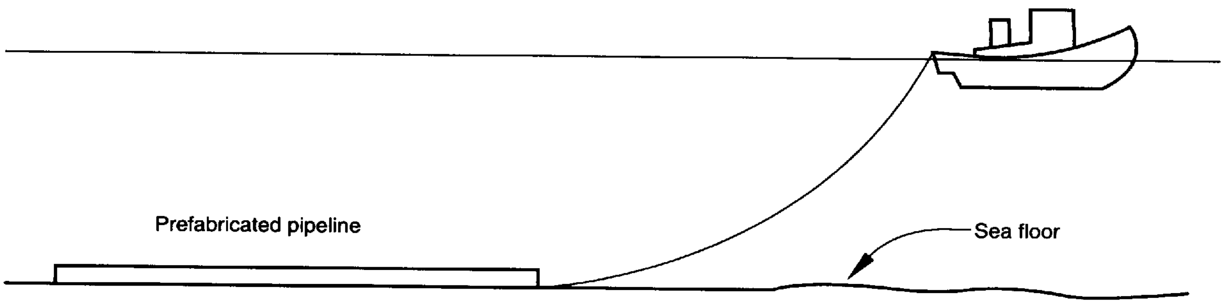

Figure 83—Bottom Tow Method of Pipelaying

buoys, to allow the pipe to be supported above the sea floor while towing. This minimizes the risk of collision between the pipe and objects on the sea bottom. When the pipe is in place, the buoys are released using an acoustical signal and the pipe comes to rest on the sea floor (see Figure 84).

Reel barges are an alternative method of installation. As the pipe is welded together, it is wound on a large reel. During installation, the pipe is unwound from the reel as the reel barge moves along the intended pipeline route (see Figure 85). Pipe laying with the reel method is restricted to pipe of 8-inch diameter or less.

In very deep water, the J-lay method may be used (see Figure 86). As the joints of pipe are welded together, the pipeline is lowered vertically to the sea floor. Tension applied to the pipe prevents buckling as the pipe makes the transition from the vertical to the horizontal position during the pipe laying process.

In recent years, flexible pipe has gained popularity in subsea installations. This pipe is constructed of alternate layers of synthetic material and metal (usually stainless steel). It is classified as a pipe rather than a hose because pressure ratings up to several thousand psi are available. Typically, the diameter of flexible pipe used is 10 inches or less, with the smaller diameter, higher pressure flexible pipe used mostly for subsea flowlines. Flexible pipe is generally wound on reels and installed using a transportable reel system temporarily installed on the stern of a work boat, or from a reel ship specially designed for the purpose.

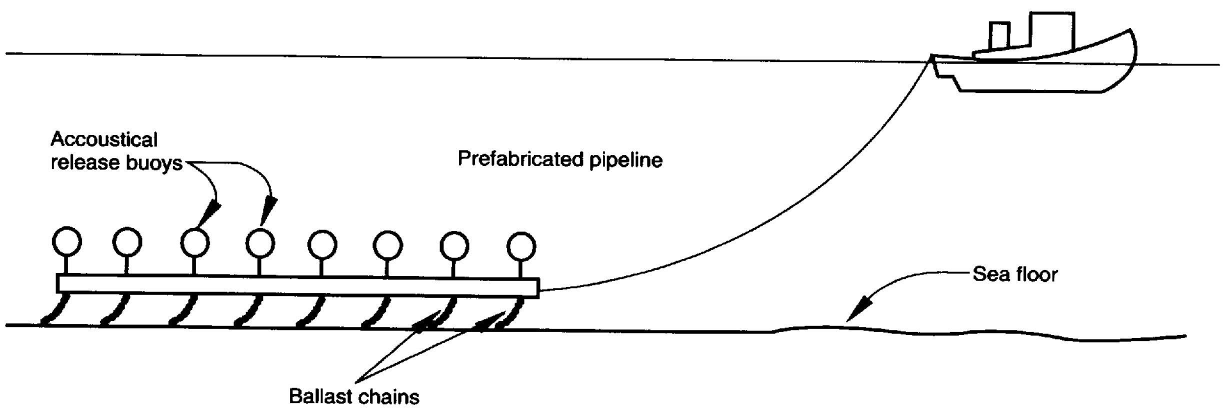

Figure 84—Off-Bottom Tow Method of Pipelaying

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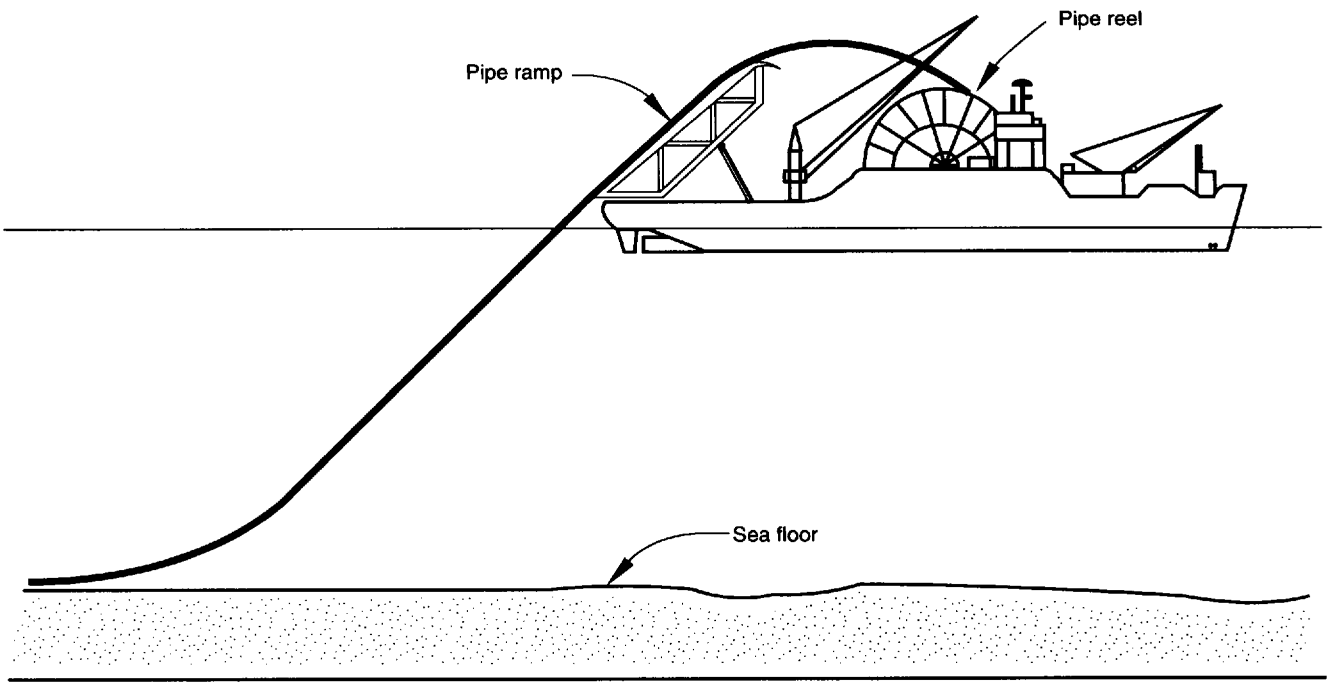

Figure 85—Installing Subsea Pipeline Using the Reel Laying Method

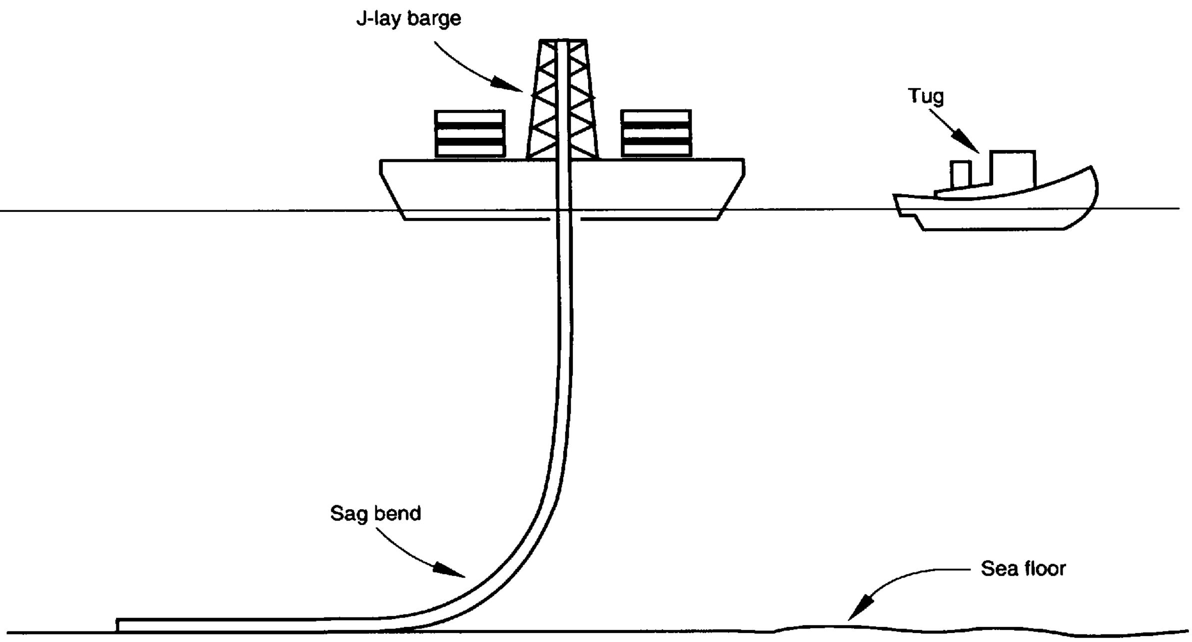

Figure 86—J-Lay Method

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SECTION 10—SPECIAL PROBLEMS

10.1 Introduction

Some of the toughest problems associated with oil and gas production result directly from impurities produced with the hydrocarbons. Substances such as water, carbon dioxide, hydrogen sulfide, and oxygen tend to corrode the metal equipment with which they come in contact. Hydrogen sulfide can weaken steel with no noticeable change in appearance before failure occurs. It is also dangerous to people and animals. Most impurities are very difficult and costly to neutralize or remove from oil and gas, yet they must be dealt with to protect equipment and to make the hydrocarbons usable.

Oil and water passing through restrictions such as pumps, tubing, or chokes can become thoroughly mixed in the form of very small drops which do not readily separate from each other. This type of mixture is referred to as an emulsion, and is undesirable because more than approximately 1 percent of water in the oil is not suitable for sale to pipelines and refineries.

Waters produced from oil and gas wells quite often contain dissolved materials which leave a deposit called *scale* in tubing or in surface equipment. The scale deposit is usually troublesome and difficult to remove, but left unchecked can totally plug equipment.

Finally, water produced with oil and gas is often much greater than the volume of oil produced. This water must be disposed of in a manner that will neither damage land nor pollute fresh water supplies. Even minute quantities of oil in the water can make its disposal most difficult.

One major producing problem results from certain hydrocarbon compounds collectively called *paraffin.* Paraffin is a sticky, waxy material which can form a thick deposit that plugs well tubing and surface piping.

10.2 Corrosion

Corrosion is one of the most costly troubles encountered by the oil industry, and in general terms is classed as either external or internal. Figures 87 through 90 demonstrate the corrosion damage that can occur without effective preventive measures. External corrosion is deterioration of the outer surfaces of equipment and piping caused by the exposure to air and moisture, or to stray electrical currents when the metal is surrounded by water or moist soil. Internal corrosion occurs within the piping or equipment as a result of corrodents in the fluids being handled. Erosion caused by high velocity movement of produced fluids and impurities can significantly contribute to internal corrosion.

Figure 87—Tubing Destroyed by Internal Corrosion

Figure 88—Internally Corroded Line Pipe

As many oil fields have grown older, more and more water has been produced. Progressively deeper drilling has resulted in more wells which produce some carbon dioxide. Changing operations with more pumping wells, more vapor recovery systems, and more drains and pumps have increased the chances for oxygen to enter production handling systems. These and many other factors have caused increasing internal corrosion problems. Thus, in recent years, increasingly more attention has been directed toward preventing corrosion.

Research has led to the discovery of many products called inhibitors, which can reduce corrosion rates by putting a protective film on steel. However, because of the many different conditions in various producing areas, no one product or group of products can prevent all corrosion problems.

In previous sections, well completion equipment, gathering systems, and storage systems have been described. Because corrosion may occur in any or all parts of these systems, inhibitors must be introduced into the fluid stream in the well itself. This often can be accomplished by using one of several different methods. After the inhibitor has been pumped into the wells, it is then produced back with the well fluids to protect both the well and surface equipment. In

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Figure 89—Valve made inoperable by external corrosion.

some cases, solid inhibitors, which slowly dissolve into the produced fluids, are placed downhole to accomplish the same results.

Concrete coatings have been used for many years to combat both internal and external corrosion. More extensive work has been done to develop plastics for protective coatings, and plastic-coated pipes, tanks, and other equipment are being widely used in oil and gas production. As a direct substitute for steel, most plastics do not have the strength or other desirable properties to make their use possible in many places where metal is now used. However, in some low-pressure systems, plastic pipe and other plastic items are being used extensively.

Much work is also being done to develop steel alloys which, because of their composition, naturally resist the effects of corrosive materials. This development has provided steels which are used many places in oil field equipment. However, the cost of some alloys limits their use to very specialized situations.

Some corrosion, usually resulting in pitting, is caused by stray electrical currents. When steel pipelines, tanks, casing strings, or the structural members of an offshore platform are surrounded by water or moist soil, electro-chemical cells similar to those in an automobile battery can develop. The resulting electrical current flow can cause tiny particles to move from the steel into the water or soil, eventually causing pits or holes in the steel.

To minimize this kind of problem, it is necessary to reduce or reverse the direction of current flow. Protective coatings are used to help insulate the steel surfaces, but the most effective protection is usually provided by inducing currents which flow to the steel instead of from it. This type of preservation for steel is called *cathodic protection.*

10.3 Emulsion Treating

There are several methods used to treat the oil and water mixtures known as emulsions. The simplest method is to allow the emulsion to stand for a long time so that the water can settle out because of its greater density. This method is not always successful because the emulsions quite often do not separate even after standing a very long time. Other means must then be used to speed the process.

Common methods of emulsion treating involve the use of chemicals or heat, or both. The treatment which is selected is determined by the characteristics of the emulsion and the costs of other methods. The treatment is normally done with a heater, or heater-treater, as shown in Figure 91 (also see Section 7.) Heat is supplied by a burner which uses either gas or fuel oil, and the chemicals used are injected in small quantities by pumps. A great variety of chemicals is used for this pur-

Figure 90—Severely corroded equalizer tube from gas-lift valve.

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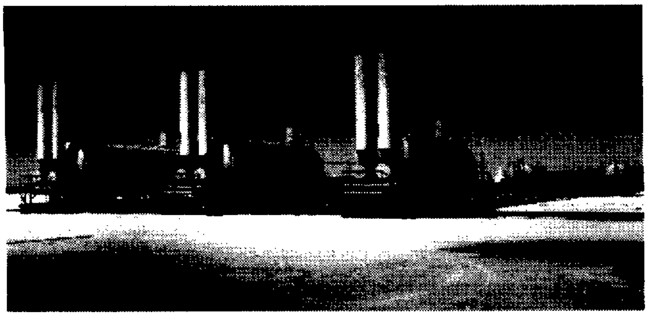

Figure 91—Emulsions are processed through some variation of heater-treaters like these.

pose, since no one material has proven effective for all emulsions. After being treated, the separated liquids are drawn off, with the oil going to the stock tanks and the water going to the disposal system.

10.4 Scale Formation

Perhaps the most familiar examples of scale are those which form in cooking vessels, hot-water heaters, and automobile cooling systems. Similar scale deposits can form in oil well piping and equipment, slowing down flow of fluids and hampering the operation of equipment.

Scale is a mineral deposit usually formed on surfaces in contact with water. Some common scales associated with oil field brines are calcium sulfate, barium sulfate, and calcium carbonate. Other precipitates are found along with these three deposits. Scale in producing wells sometimes begins in the producing formation before the scale-forming fluids reach the wellbore.

Scale creates serious problems in producing wells, injection wells, waste disposal wells, and plant water systems. Scale may restrict and completely plug off production in the formation, in the tubing, or in flow lines and equipment at the surface. Treatment down the tubing-casing annulus protects downhole equipment, but may not be effective at the face of the formation. Scale deposition can be attributed to such factors as pressure drops, mixture of incompatible waters, changes in physical or chemical environment, or temperature changes encountered by the well fluids.

Some scale deposits can be prevented by adding chemical agents to the produced fluids to prevent the formation of solids, or to prevent the solids that are formed from sticking to the surfaces of pipe or equipment. In many cases, however, it is not possible to apply this method because of the way the oil or gas well was completed. In such cases, the downhole scale can sometimes be removed by dissolving it with a strong acid solution. This method is not always successful because some forms of scale do not easily dissolve in acid and the pipes must be cleaned with scrapers or other mechanical means.

10.5 Naturally Occurring Radioactive Material (NORM)

Some scales which are deposited by produced water may be radioactive to one degree or another. Over the last few years this potential hazard has been recognized. Accordingly, procedures have been developed for the safe handling and disposal of this material (see Section 17).

10.6 Water Disposal

Extreme care must be exercised in handling and disposing of produced water because of possible damage to land areas and the possibility of polluting lakes, streams, or subsurface reservoirs which provide water for drinking as well as for irrigating purposes. State and federal regulations provide serious penalties for polluting.

Onshore, produced water is usually injected into wells which conduct it to underground saltwater sands. Sometimes the water can be returned to the same formation from which the oil is produced. This kind of water injection also helps to increase oil recovery. Offshore, the produced water can usually be disposed of into the seawater provided it does not harm marine life.

10.7 Paraffin Problems

Paraffin was briefly described in 10.1. This material varies in character, but in general it is a waxy substance that is difficult to remove and can cause serious or complete obstruction to flow. The main cause of paraffin deposits is the cooling of the oil and gas stream as it flows from the producing formation to the storage facilities at the surface.

Efforts to prevent the formation of paraffin in the well have been only modestly successful. Paraffin inhibitors work in some areas, and plastic-coated tubing sometimes retards its deposition. In general though, paraffin is allowed to deposit on the tubing walls and is periodically removed before serious problems result.

Paraffin removal may be accomplished by pumping chemicals to dissolve it, pumping hot oil that melts it, or by scraping the tubing with mechanical devices run in the well on wirelines or installed on the rods in pumping wells. Loosened paraffin is then produced from the well. Paraffin in lines and facilities on the surface is usually controlled with the use of scrapers, solvents, or heat.

10.8 Asphaltenes

Asphaltenes, though chemically different from paraffins, produce similar operating problems when deposited in tubing or flowlines. As the name implies, these compounds resemble asphalt or pitch. It is difficult to control their deposition and they are difficult to remove by either chemical or mechanical means.

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10.9 Hydrogen Sulfide

The presence of hydrogen sulfide gas in produced petroleum fluids is an especially difficult problem because it is potentially damaging to equipment and potentially dangerous to people and animals. Fortunately, it is found in only a small percentage of the producing fields in the nation.

At very low and nontoxic concentrations, hydrogen sulfide has an offensive odor similar to that of rotten eggs. Hence, natural gas which contains hydrogen sulfide is commonly called *sour gas.* At higher and more lethal concentrations, however, hydrogen sulfide gas kills the sense of smell rapidly, burns the eyes and throat, and can cause death.

When hydrogen sulfide and water are produced with petroleum, chemical reactions take place which result in corrosion of steel tubular goods and oil field equipment. In addition, hydrogen sulfide may infiltrate and attack the crystalline matrix of the steel, creating conditions which can lead to weakening and failure of the steel in certain cases. This failure, which may occur in a short period of time and is often evidenced by cracks in the steel, is called hydrogen embrittlement. A variety of special alloy metals, protective coatings, and inhibitors may be used separately or in combination to prevent damage to wells and facilities exposed to hydrogen sulfide.

To protect people and the environment, special efforts are required to confine gases containing hydrogen sulfide. Monitoring equipment may be needed which senses the presence of hydrogen sulfide and sounds alarms and shuts in wells and facilities in the event of a leak. Oil field personnel who regularly work around facilities which contain hydrogen sulfide receive special training in personal safety and have access to or carry emergency safety equipment.

To enhance the safety of operations involving hydrogen sulfide, API has developed the following recommended practices:

a. API RP 49: *Recommended Practices for Drilling and Drill Stem Testing of Wells Containing Hydrogen Sulfide.*
b. API RP 55: *Recommended Practices for Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide.*

These recommended practices should be consulted when appropriate.

Gas must be cleansed of hydrogen sulfide before it is sold. This frequently involves absorbing the hydrogen sulfide from the gas and processing it to obtain elemental sulfur, which is then sold.

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SECTION 11—ENHANCED RECOVERY

11.1 Introduction

Substantial quantities of oil will normally remain in the reservoir at depletion if only the primary production processes discussed in Section 1 are utilized. While gas recovery is frequently high, special measures are sometimes required to optimize recovery of gas and gas liquids. Capability to improve recovery has grown greatly as better technology and understanding of reservoir behavior have been developed, and the search for even more successful production processes is continually being pursued. Economics are highly important, also, since all recovery improvement measures are costly. Enhanced recovery will be used in this booklet to describe all efforts to increase ultimate production of oil and gas from a reservoir, and this terminology will be considered to encompass other nomenclature in common usage, such as pressure maintenance and secondary and tertiary recovery.

All enhanced recovery techniques include methods for supplementing natural reservoir forces and energy, or otherwise increasing ultimate recovery from a reservoir. Such techniques include water injection, gas injection, gas cycling, and miscible, chemical, and thermal processes. To optimize the production program for a reservoir, timing of enhanced recovery efforts is an important consideration. In many instances, enhanced recovery is begun almost the day production starts, while in other cases, projects are not started until the middle or latter stages of primary production. Timing is most heavily influenced by available technology, economics, and the need in many cases to carefully analyze reservoir performance under primary production before designing the enhanced recovery program.

11.2 Water Injection

By far the most widely applied enhanced recovery technique involves injection of water into the oil reservoir. Selected wells are chosen for injection and the water moves through the reservoir pushing oil to producing wells (Figure 92). Virtually without exception, this displacement of oil by water improves recovery in solution drive reservoirs, and frequently increases ultimate production from gas cap drive reservoirs. Figure 93 shows a waterflood in which each oil well is surrounded by four water injection wells, which are at the four corners of a square (as shown by arrows). This is only one of many injection patterns which might be used.

Water can sometimes be injected into an underground formation by gravity, but in most cases pumps are needed to inject at the rate desired (Figure 94). The water which is injected is obtained either from wells that produce water along with the oil, or from water supply wells drilled for that purpose (Figure 95).

Water injected into formations must meet certain requirements. Principally, injected water must be clear and stable, and must not react with the water in the formation where it is being injected to form scale or other undesirable compounds. It also must not be severely corrosive and must be free of materials that may plug the formation. The cost of working over a well after plugging may be many times the cost of preventing plugging by properly treating the water. Water treatment may include one or more of the following processes: deaerating, softening, filtering, stabilizing, testing, and chemical treating to adjust the composition, inhibit corrosion, or prevent growth of bacteria.

Since water is frequently less viscous than the oil it is pushing through the reservoir, there is a tendency for the water to bypass and leave some oil unrecovered. To maximize the volume of reservoir rock that is swept by water, a thickening agent, or polymer, is sometimes added to the injected water. Because the polymer is very costly, a bank or slug of thickened water is normally injected, followed by the injection of unthickened water.

11.3 Gas Injection

The practice of injecting or returning a part or all of the gas produced with oil has long been an important part of oil producing operations. The main purposes of injecting gas are (a) to prevent depletion of the main source of reservoir energy in gas cap drive reservoirs, (b) to create a gas cap drive to replace a less efficient recovery mechanism (such as solution drive), and (c) to prevent oil movement into the gas cap of strong-water drive or combination drive reservoirs. Injection of gas requires the use of compressors to raise the pressure of the gas so it will enter the formation.

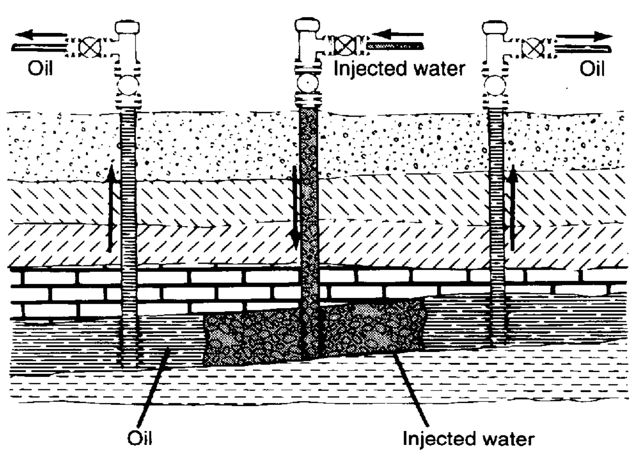

Figure 92—Water Injection

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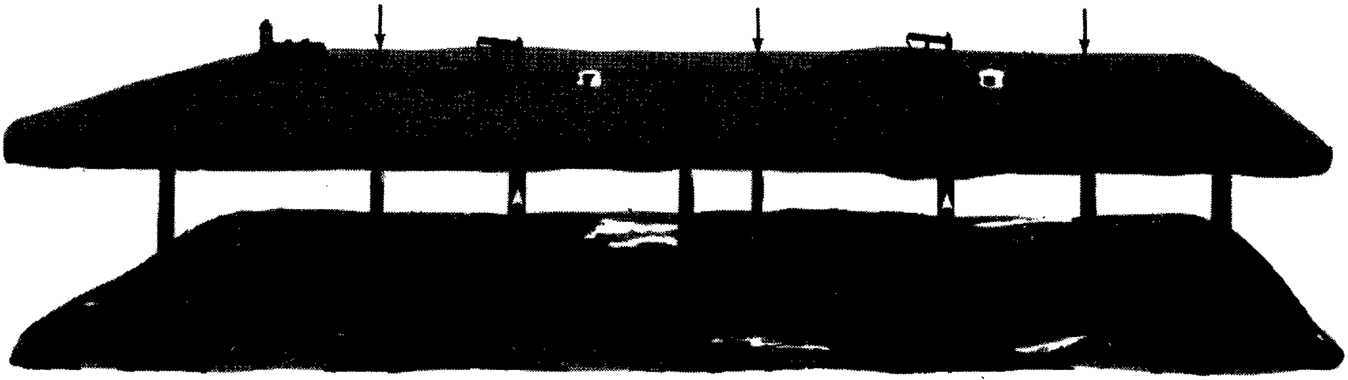

Figure 93—Waterflood

11.4 Miscible and Chemical Processes

Oil and water do not readily mix with each other and, in many cases, neither do oil and gas. This immiscibility contributes greatly to oil droplets resisting displacement, being bypassed by the water or gas, and being left unrecovered in the reservoir rock pores. Extensive research and field testing have been done to develop substances and techniques which will create miscibility between the reservoir oil and displacing fluids. Many factors bear upon the ability to achieve and maintain miscibility, including the composition of the oil, the natural water in the reservoir rock, the rock itself, and the injected fluids. Other factors are reservoir temperature and pressure, and the surface facilities and processes used to prepare and inject substances. Thus, each process must be designed to meet the conditions existing in a particular reservoir. Due to the extremely high costs of preparing compounds that are miscible with oil, a slug or bank is frequently injected which is miscible with both oil and either gas or salt water. This allows the slug to push the oil and water, or the gas to push the slug (Figure 96). Some of the substances used to achieve miscible conditions in the reservoir include high-pressure gas, enriched gas, surfactants, solvents, and alkaline materials.

High-pressure gas drive involves injection of a gas such as natural gas, carbon dioxide, or nitrogen under conditions of high reservoir pressure (3,000 psi or greater). If the pressure, temperature, gas composition, and oil composition are favorable, a mixable zone will be created and almost complete displacement of the reservoir oil will occur in that part of the formation swept by the injected gas. The injected gas may at times be mixed with water, or an injected gas bank may be propelled by a second gas or water bank.

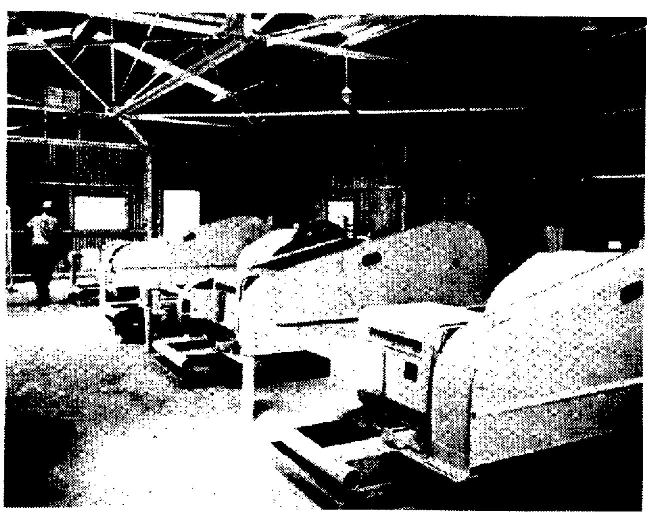

Figure 94—Water Injection Pump Station

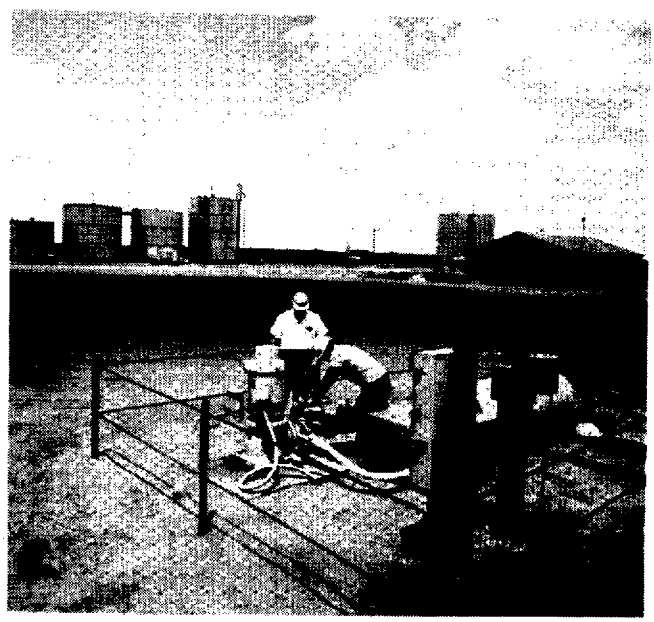

Figure 95—Water Supply Well

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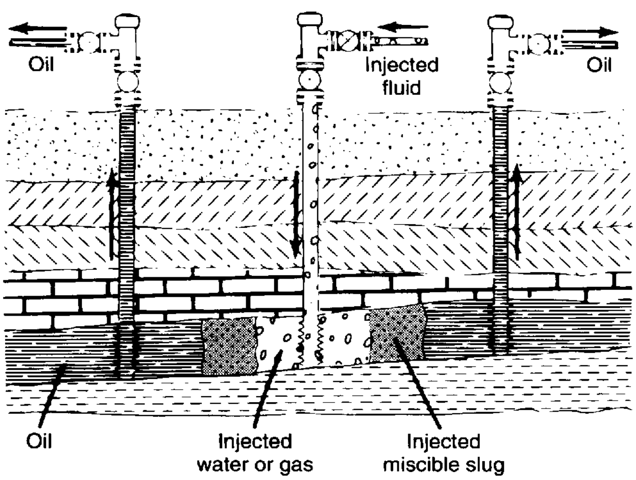

Figure 96—Miscible Recovery

Enriched gas drive entails injecting a gas enriched with ethane, propane, butane, or a combination of these substances, into the reservoir. As this gas contacts the reservoir oil, some of its components condense into a liquid that is soluble in oil. This liquid increases the oil volume and reduces its viscosity, thereby improving its flow properties. The swollen oil becomes mixed with the injected gas and moves to the producing wells to increase recovery.

Surface active agents, or surfactants, act at the surface between water and oil to reduce the forces which cause oil and water to reject one another. Ordinary soap is a surfactant, but it is ineffective under reservoir conditions. Specially designed surfactants for enhanced recovery projects can be made from naturally occurring organic materials or from petroleum derivatives. An injected surfactant bank might be followed by a polymer-thickened water bank, which might then be followed by salt water.

Injection of a slug of solvent which mixes with both oil and the displacing fluid is known as solvent flooding. Some solvents which have been used are light hydrocarbon compounds that mix with oil and a displacing gas and alcohols which have a high degree of solubility with both oil and water.

Certain crude oils possess an acid characteristic and will mix with a carefully designed alkaline substance to form a surfactant in the reservoir. A bank of the alkaline mixture is injected and followed by water, with which it is also miscible. Efforts to overcome the problem of immiscibility will continue and new processes will evolve and be developed in the future.

11.5 Thermal Processes

Thermal recovery techniques include the injection of heated water or steam. Also, certain projects involve burning a portion of the oil in the reservoir. These processes are designed to provide (or supplement) the reservoir drive mechanism and heat the oil, thereby reducing its viscosity and improving its flow characteristics. The great majority of thermal projects (although this is not exclusively the case) involve heavy, viscous crudes found at shallow depths where natural reservoir temperatures are not high and reservoir pressures are low.

Steam or heated water flooding are similar in concept to water flooding. Steam gives up much of its heat to the reservoir as it condenses to water and produces a steam driven bank of hot water. In place burning involves injecting air or oxygen into a well and igniting the reservoir oil. A portion of the oil which could not otherwise be produced is burned, creating heat and a driving bank of steam and combustion gases. Needless to say, thermal processes pose extraordinary challenges for surface equipment, injection wells, producing wells, and handling of produced fluids.

11.6 Gas Reservoirs

Many fluids which exist as gases in the reservoir contain hydrocarbon components which separate out as liquids when brought to the surface where pressure and temperature are reduced. In the case of a gas cap drive oil reservoir, it is desirable to leave the gas in the reservoir as an energy source until the oil is depleted. To permit earlier recovery of the gas liquids, however, gas production can be initiated, the liquids separated and sold, and the dry gas returned to supply reservoir energy for oil recovery. This process is called *gas cycling.* Gas cycling may increase the ultimate recovery of gas liquids, for in some instances these liquids will condense in the reservoir (and a portion may become unrecoverable) as pressure is reduced with production. Gas cycling maintains reservoir pressure while recovering these liquids, and may be attractive to apply in some gas caps as well as some gas reservoirs that are not associated with oil columns.

Strong water drives in gas reservoirs can lead to water influx into the reservoir as gas is produced, as well as entrapment of gas bubbles at high pressure in the water-invaded region. Enhanced recovery steps that may be taken include (a) production of gas at rates significantly above the rate of water influx, and (b) production of water from wells located around the periphery of the reservoir. Also, projects have been undertaken in old gas reservoirs completely invaded by water to reduce the pressure by producing water at high rates, allowing the gas to expand and percolate to the top of the structure where it can be produced.

11.7 Injection System Operation

Most enhanced recovery activities require the injection of a fluid, or a series of fluids, and proper operation of the injection system is extremely important. A complete water injection system will include a water knockout, separator,

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heater-treater, skimming tank, filters, backwash tank, backwash pump, injection pumps, chemical pumps, a power supply, and automatic control equipment. A simplified flow diagram showing some of this equipment is depicted in Figure 97. Because there are several things that can happen to water-treating and injection systems, close attention of an operator is needed if they are to work well. The following list includes many of the checks that must be made on the treating system:

a. Check water-oil separating equipment to make certain the water is oil-free.

b. Backwash filters regularly.

c. Note any changes in filter inlet and outlet pressures as evidence of decreased filter efficiency, particularly just before and after back washing.

d. Check automatic and manual safety shutdown equipment regularly.

e. Maintain proper chemical feed, if used.

f. Check volume of water going through the plant and to individual wells. Make necessary adjustments.

g. Regularly check wells to be sure that only clear water is being injected.

h. Check pressure held on vessels in closed systems. Air must be kept out of the closed system to keep water from becoming corrosive, and to prevent the formation of solids which would plug the subsurface formation.

i. Report immediately any failures of oil-water separation equipment, controls, pumps, chemical feeders, vessels, piping, or meters so that repairs or necessary changes can be made without delay.

Regardless of the system used, good operation depends upon proper attention to details. This is even more important when the injection of complex polymers, solvents, or surfactants are required to achieve the desired enhanced recovery.

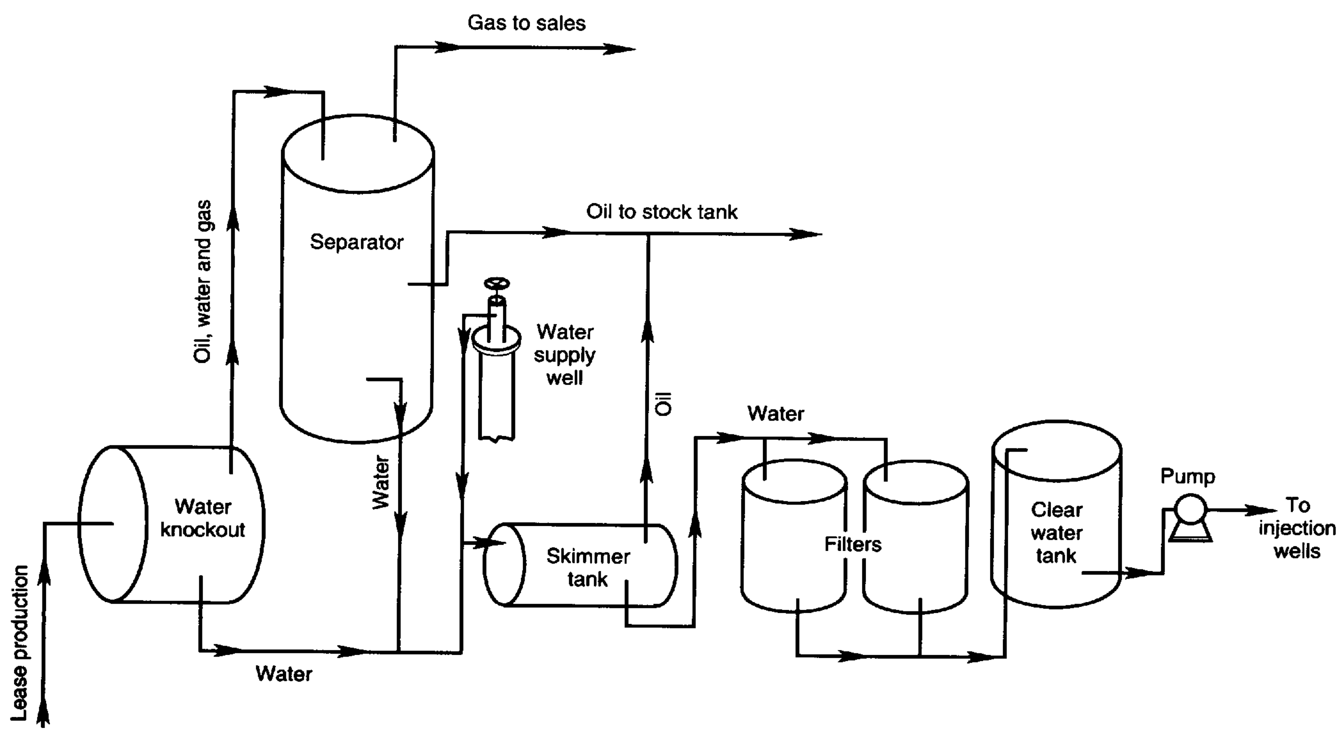

Figure 97—Diagram of a Water Injection System

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SECTION 12—PRODUCTION PERSONNEL

12.1 Introduction

When drilling of the well has been completed, the vital job of moving the oil and gas from the well to the purchaser falls to the production department. Although some oil or gas may have been produced during completion testing, production personnel make the well and its equipment a permanent part of an oil field.

This complex job involves the installation, operation, maintenance, repair, and replacement of production equipment. Other activities include well remedial work, well testing, and routine servicing of wells. Some of the field operating personnel are lease operators, roustabouts (maintenance personnel), repairmen, and technicians. The field supervisors may be known as foremen and superintendents. The engineering, geological, accounting, computing, and administrative personnel complete the basic team of specialists required in modern operations. However, vital assistance also is often provided by experts in communications, transportation, and other support functions.

In most cases oil and gas production is an around-the-clock job. Even though much of the work is done during daylight, oil and gas are being produced at all hours of the day and night. It is the job of production people to keep the wells producing, regardless of weather and all other obstacles.

12.2 Lease Operator

When oil or gas from a well is being sold to a transportation company or pipeline, the lease operator (Figure 98) is directly responsible for obtaining accurate records of the amount of oil sold. Thus the lease operator acts as the company's representative in the sale or transfer of gas or oil from the company to the buyer. Some companies have special gaugers to handle this transfer. Others use automatic custody transfer units. The lease operator produces the wells and must sometimes treat the oil so that it meets pipeline specifications. A continuous well performance surveillance is conducted. Allowables, where applicable, must be followed. Wells must be produced so that damage to the well and the reservoir do not occur. The lease operator performs minor maintenance jobs on wellheads, tank batteries, pumping units, engines, or other production equipment. Major repairs are usually done by company or contract crews comprised of specialists in mechanical repair, electronics and electricity, welding, instrumentation, oil and gas measurement, and other skills.

12.3 Maintenance Personnel

Each crew of roustabouts (Figure 99) is directed by a head roustabout or a gang pusher. It is the head roustabout's job to oversee the work of the roustabouts, to be sure the needed tools and equipment are at the working site, and generally to carry out the instructions of the production foreman on whose lease the work is being done. The head roustabout not only takes responsibility for completion of the given job, but also is responsible for the field training and safety of the crew.

12.4 Production Foreman

Coordination of all work on the lease or leases is in the hands of the production foreman. It is the foreman's job to

Figure 98—Lease Operator

Figure 99—Roustabout Crew

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Figure 100—Production Foreman and Maintenance Personnel

supervise lease operators, to direct the work of roustabout gangs and any specialists required, and to determine what work is needed, in what order it is needed, and how it should be done. This individual is an important representative of the management of the company and is responsible for seeing that approved company practices are employed in all work. The production foreman often supervises the completion of new wells; oversees the installation of production, treating, and storage equipment; and directs well servicing and recompletion work (Figure 100).

12.5 Field Superintendent

General supervision of all activities in a field, area, or district are under the control of a field superintendent. It is a superintendent's job to supervise and coordinate drilling and production activities and to control production in accordance with regulations and company policy. All of the field employees are under the superintendent's general direction. Plans for drilling and workover operations, tank battery plans and construction, and other general supervisory and operating activities are carried out by personnel under the control of the field superintendent (Figure 101).

12.6 Engineering Technician

The engineering technician (Figure 102) is a skilled specialist who installs and maintains the instruments and control devices, electrical or electronic, related to field operations. Engineering technicians may also work on designing and troubleshooting artificial lift equipment and on resolving problems associated with (a) major pieces of machinery, (b) enhanced recovery projects or (c) corrosion protection equipment. As a team member of the production group, the engineering technician works closely with the engineering group, computer personnel, and the field foreman to eliminate chronic malfunctions and resolve specific problems.

12.7 Petroleum Engineer

The petroleum engineer (Figure 103) applies basic physical and engineering principles to the development, recovery, and field processing of petroleum. There is a wide variety of types of work in which the petroleum engineer may be involved, such as drilling and completing wells, managing the recovery programs of underground reservoirs, and reducing the cost of oil and gas recovery. In addition, the engineer may work in research, evaluation, and finance, as well as producing property management.

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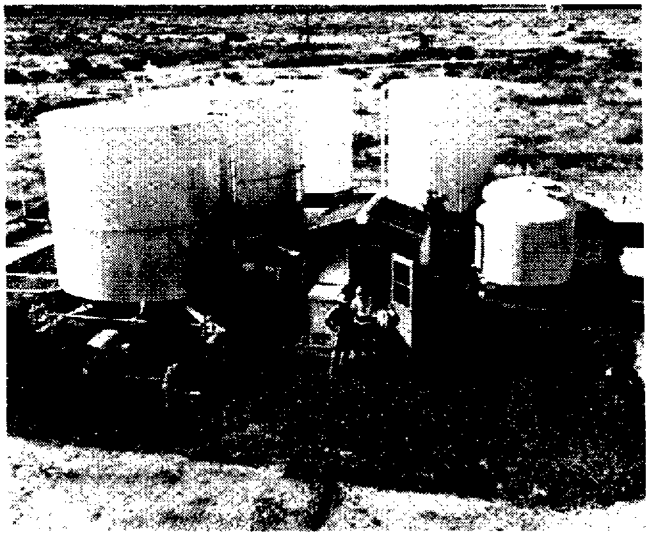

Figure 101—Head Roustabout, Foreman and Superintendent

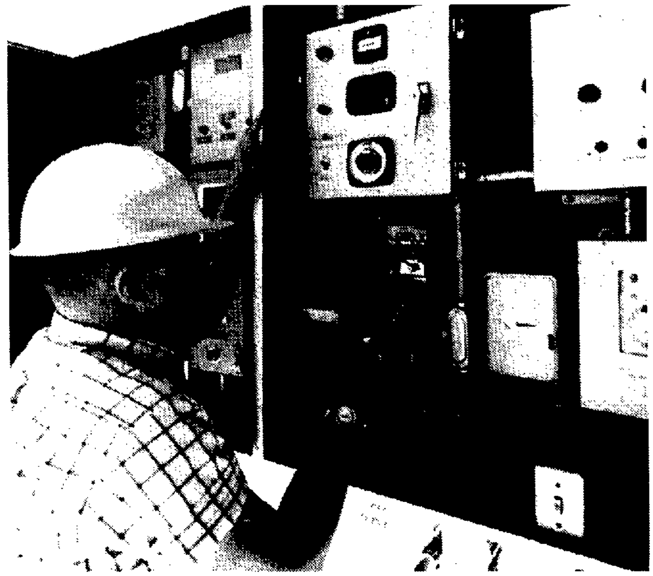

Figure 102—Engineering Technician

Figure 103—Petroleum Engineer

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SECTION 13—TOOLS AND EQUIPMENT

The figures in this section show some of the types of tools and equipment used in operating and maintaining oil and gas production facilities. The items include small hand tools, large power driven equipment, computers, and highly specialized mechanical and electronic instruments. Most of these implements are used in both onshore and offshore operations.

Figure 104 shows a truck used for crew and equipment transportation, safety and support equipment, and a wide assortment of basic tools. Items of this sort have been traditionally used in routine oil field maintenance for many years.

An electronic analyzer which is used to evaluate the condition of engines, compressors, and other types of large, rotating equipment is shown in Figure 105. Such instruments can offer distinct advantages, such as rapid inspection with the equipment operating normally compared to costly shutdown and dismantling for visual inspection. Even more important is the capability for early detection and correction of conditions which could lead to massive mechanical failure.

Figure 106 shows a production operator at a remote terminal connected to a computer. The computer continuously analyzes, displays, and records information received from sensors on a number of producing wells and the associated production handling and processing equipment. This enables one individual to monitor and control a number of widespread operations, perhaps miles apart, from a central location.

An instrument called a dynamometer (Figure 107) can be used to analyze the performance of rod pumping units. The dynamometer measures the loads on the polished rod and produces a record of the forces on the rod pump system at each point during the pump cycle. From study of this record, many well, pump, and rod string problems can be detected. Dynamometers in widespread use are either mechanical or

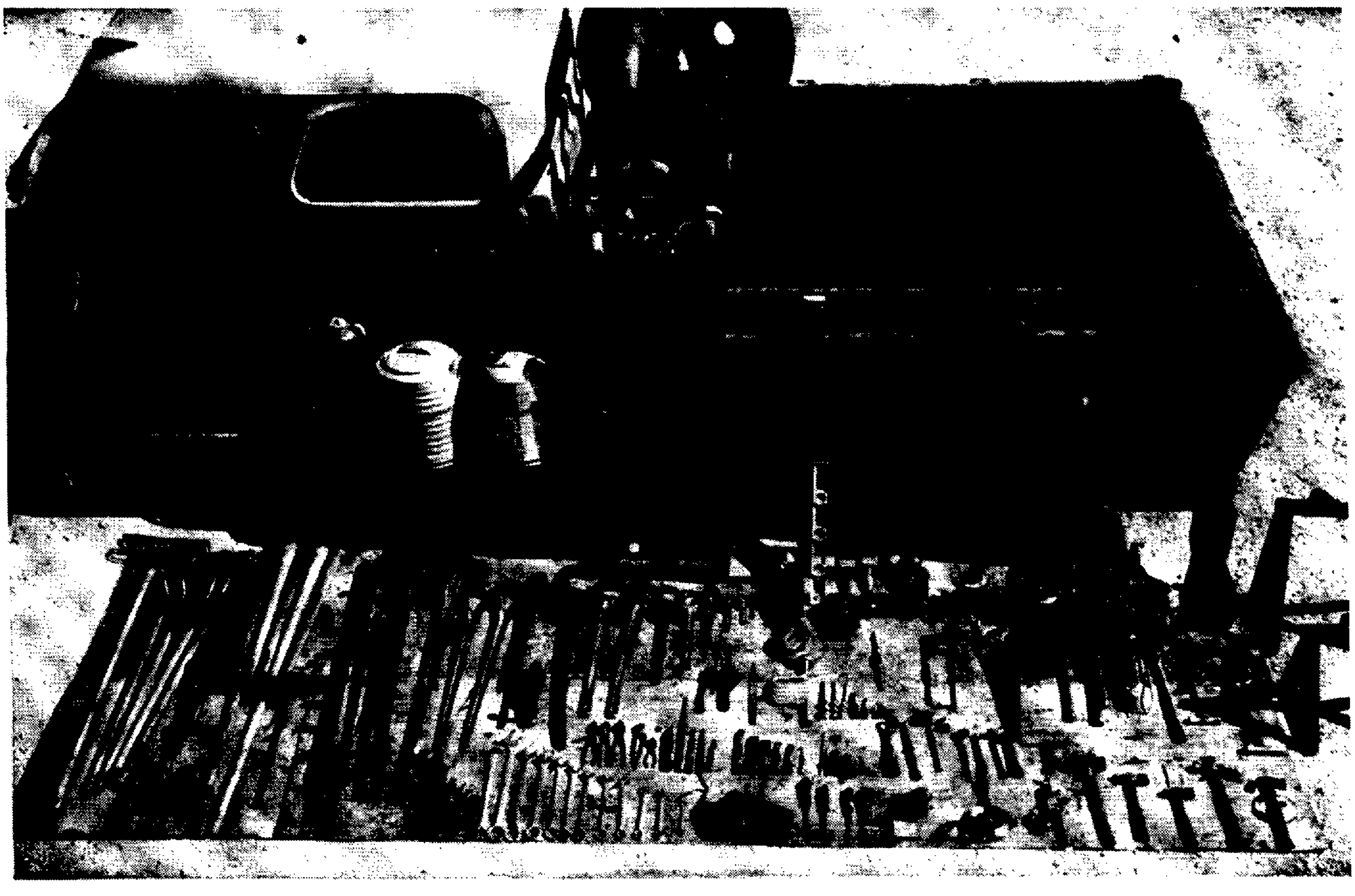

Figure 104—This is a six-passenger truck used for transportation of tools and employees to and from work on a producing lease. All the tools carried on the truck are shown.

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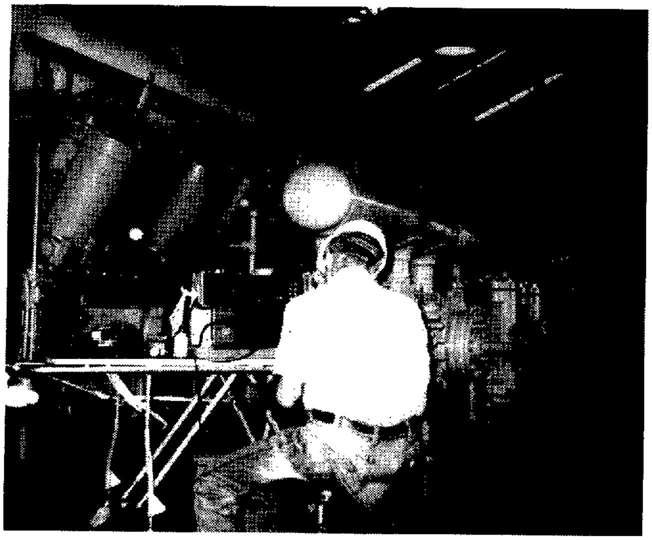
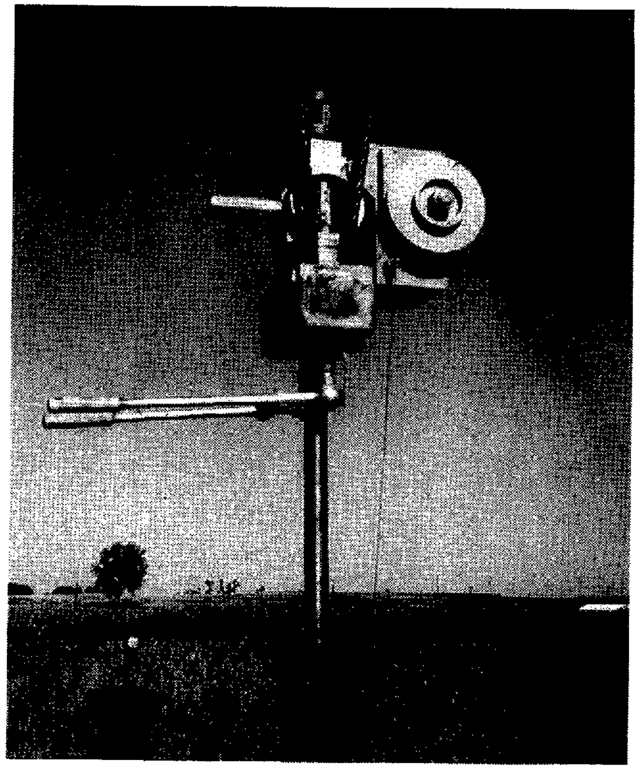


Figure 105—Technician evaluating large compressor with electronic analyzer.

electronic. Because of their ease of use, the electronic instruments have become increasingly popular in recent years.

While basic hand tools and other mechanical devices continue to be important in oil and gas operations, the most dramatic advancements in recent years have been in the areas of powered or automated devices. The availability of small, portable computers and other electronic gear for field use has greatly expanded the capabilities of operating and maintenance personnel.

Figure 106—Operator at remote computer terminal.



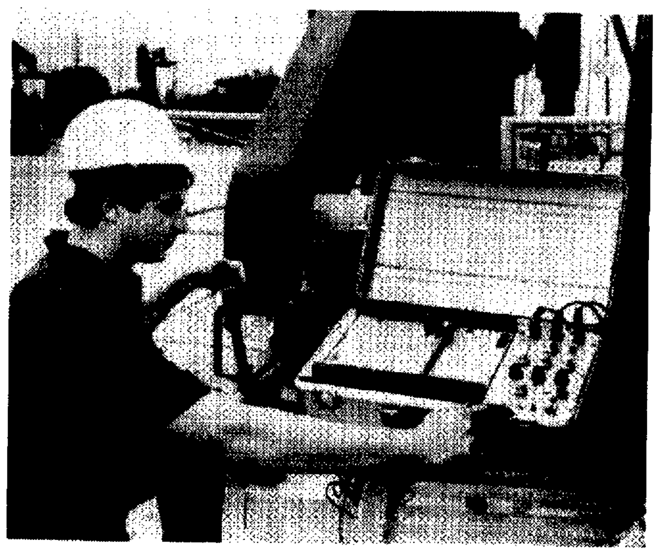


Figure 107—Mechanical (107a, upper and electronic (107b, lower) dynamometers.

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SECTION 14—PIPE, VALVES, AND FITTINGS

The most widely used means of moving produced oil, gas, and water from wells to treating or storage facilities is through short pipelines, commonly called flowlines or transfer lines. Long-distance pipelines, often called transmission lines, are used extensively to transport oil, gas, and petroleum products to refineries, market areas, or terminals. Within a production facility, fluids are virtually always moved through piping. To provide for these and numerous other transportation needs, many types, sizes, and strengths of pipe are used. Most pipe for this purpose is made of steel because of its high strength and moderate cost. Pipe made of other materials (plastic, stainless steel, or fiberglass) is used for specific applications such as highly corrosive fluids.

The steel pipe used for transporting oil and gas is manufactured in sections or joints normally ranging from around 10 feet (for small sizes) to more than 40 feet in length (for larger diameter sizes). To form a pipeline, these sections must be securely connected together. This is generally done by welding, which effectively joins the individual sections into one solid unit. In some situations, such as where sections of piping must be periodically removed for inspection or maintenance work, flanges welded to the respective pipe ends are bolted together. In this flange-and-bolt connection, a steel ring or flexible gasket is compressed between the flanges to provide a leak-free seal.

Threaded connections, where sections of pipe are screwed together, were once used extensively for pipelines and interconnecting piping. Threaded connections are now used chiefly for small piping or under conditions where the heat from welding cannot be tolerated. Figure 108 shows examples of welded, flanged, and threaded connections.

Many types of pipe fittings are required to accommodate the almost limitless array of piping configurations needed in hydrocarbon transportation and processing. Some of the most common are elbows (or ells) used for changes of direction; tees or crosses for joining two or more lines; swages or reducers for changing the line size; and flanges which are welded onto piping so that it can be bolted to another section of piping or to other equipment. Figure 108 shows these types of fittings.

In order to regulate the movement of oil or gas through pipelines or other piping, many different control devices are required. One of the most basic of these is the valve, which is primarily used to shut off or block flow through a line when appropriate. However, some valves are designed to withstand great pressure, some to open or close very quickly, some to withstand many cycles of opening and closing, others to allow flow in one direction only, and yet others to open and close according to pressure in the line. Some valves are manually operated, while others are mechanized to open or close automatically. Thus, the term *valve* is used in reference to many sizes and shapes of devices which may serve the same basic function but in different ways and under different conditions.

Other commonly used equipment includes meters to measure the volume of fluid moving through the line, regulators to control pressure, and relief devices to permit escape of all or part of the fluid should excessive pressure develop. These and some of the additional equipment used in the complex networks of piping which handle oil, gas, and water are shown in Figure 109 through 111.

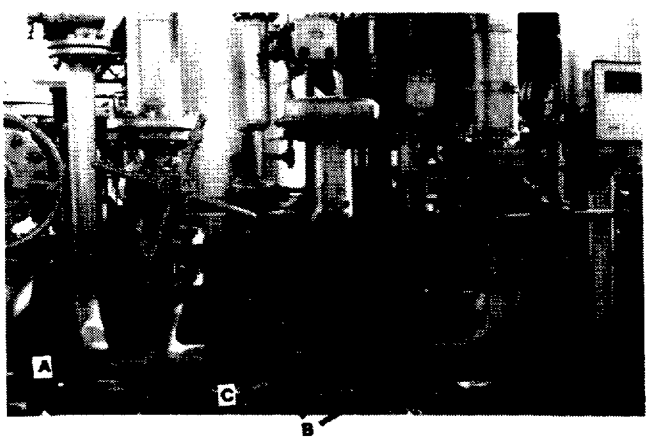

Figure 108—Large welded (A) and flanged piping (B) (foreground); small threaded connections (C) (background). Large flow control valve in center is pneumatically controlled by the operator installed on top of the valve.

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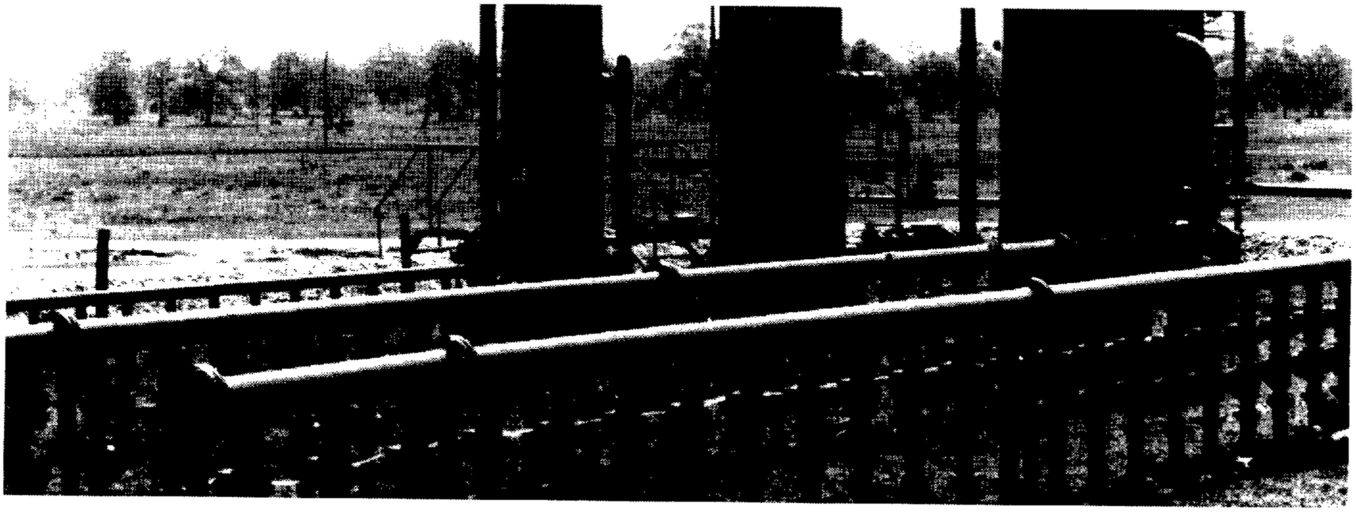

Figure 109—Well flowlines coming into a production header. Riser from each flowline contains a union, check valve and gate valve.

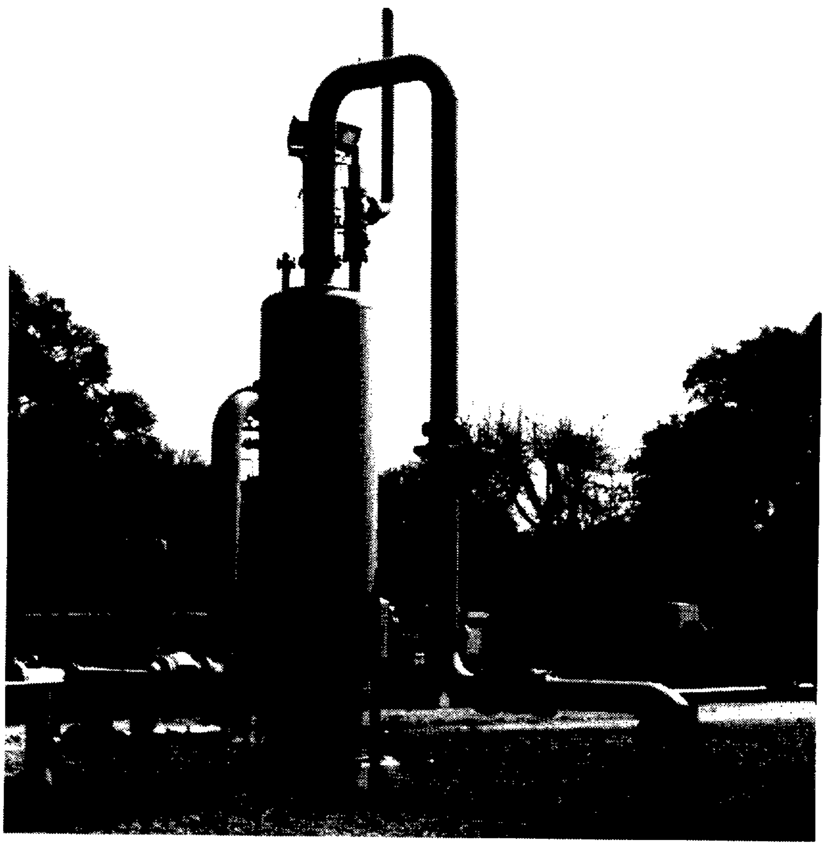

Figure 110—Pressure relief valve on top of vertical vessel. Large piping contains a number of flanged and welded ells.

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Figure 111—Small pipes, valves and fittings connect gas meter to meter run. Flanged device at lower left contains orifice plate; fitting above permits plate installation and removal.

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SECTION 15—REPORTS AND RECORDS

15.1 Introduction

As in any business, it is necessary to make and keep reports and records of oil and gas lease operations for operating, accounting, legal, and historical purposes. Each company adopts procedures to fit its organization and problems, which include meeting the requirements imposed by state and federal regulations and taxation. It is the duty of the management to establish organizational procedures whereby the lease operator or gauger prepares basic records and reports from which most of the additional office paper work is done. It is therefore important that they be accurate. Although these basic reports may vary with different companies, in general the reports made on the lease are concerned with (a) production of oil, gas, and salt water and their delivery from the lease, (b) individual well tests and the producing status of each well, (c) operations and maintenance of lease equipment, (d) amounts of supplies used, and (e) reports of unusual happenings, such as losses resulting from fire, storm, theft, and accidents.

15.2 Oil Production Report

In most cases, a daily well and lease oil production report is required, although weekly and even monthly reports are sometimes used (see gauge report in Figure 112). The lease operator usually determines the amount of oil in storage on the lease by daily gauging at approximately the same hour each day. These gross production figures can be corrected for temperature and BS&W content, if necessary, after the operator makes the needed tests. The daily production is listed on a daily production report, along with the amount of all oil deliveries from the lease during the preceding 24 hours. This report is sent or taken by the operator to a district or central production office. In certain instances, the lease is automated and the production report is prepared by computer at a central production office.

15.3 Pipeline Run Tickets

The pipeline oil run ticket or report is perhaps the most important record made on the lease because it becomes the

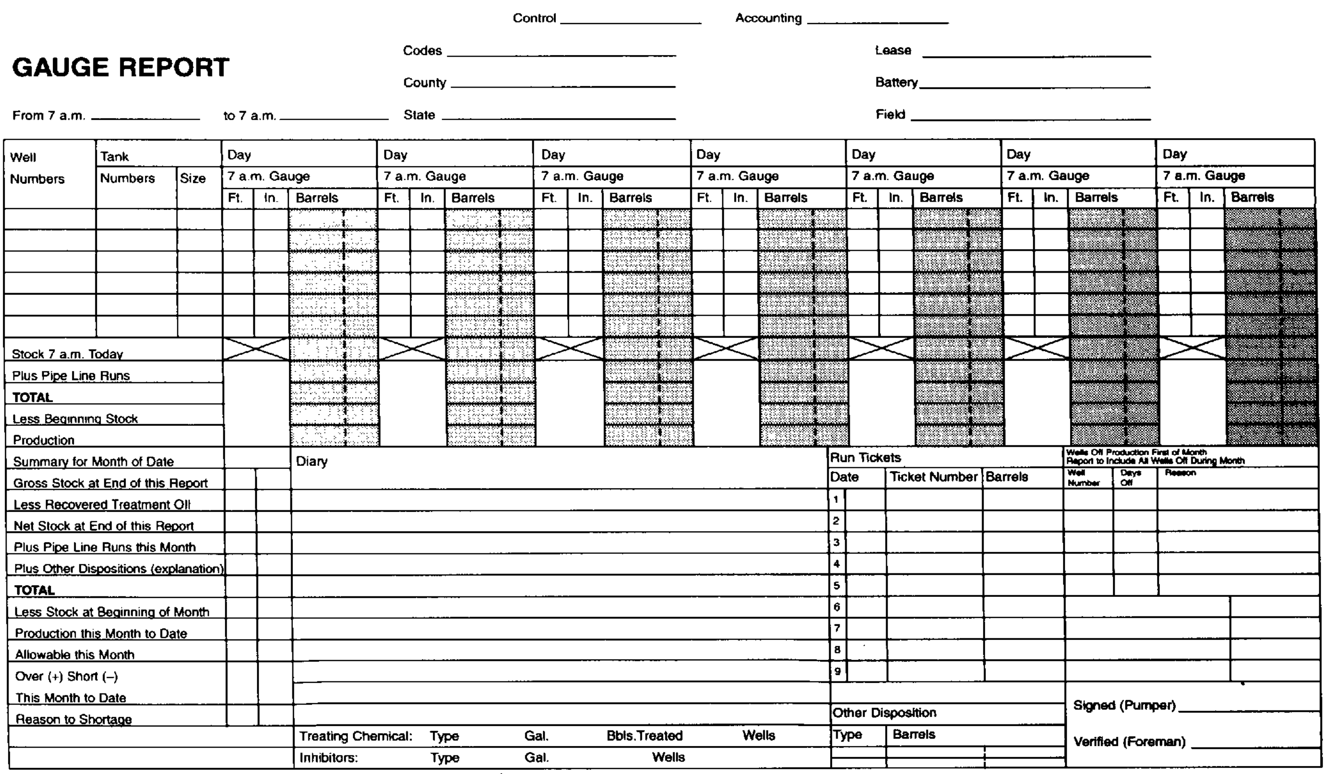

Figure 112—Gauge Report

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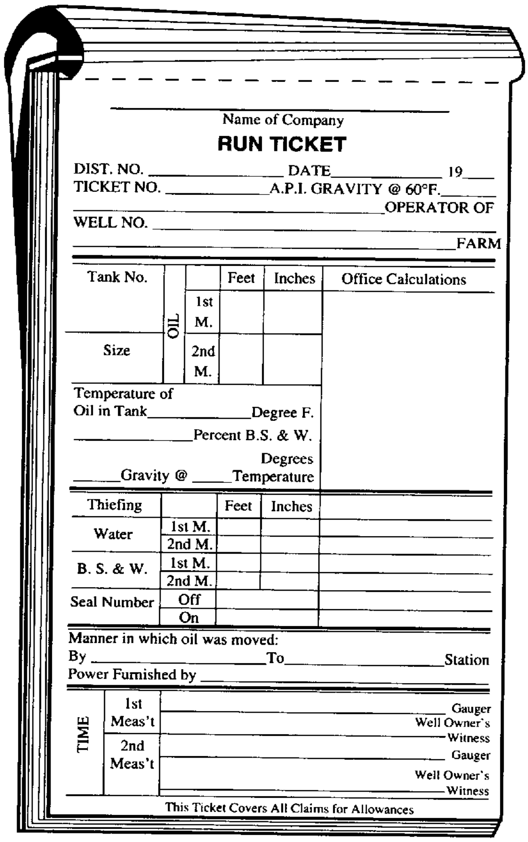
Name of Company
RUN TICKET
DIST. NO. ______ DATE ______ 19__
TICKET NO. ______ A.P.I. GRAVITY @ 60°F. ______
______ OPERATOR OF
WELL NO. ______
______ FARM

Tank No.			Feet	Inches	Office Calculations
	OIL	1st M.			
Size		2nd M.			

Temperature of Oil in Tank ______ Degree F.
______ Percent B.S. & W.
______ Gravity @ ______ Degrees Temperature

Thiefing		Feet	Inches	
Water	1st M.			
	2nd M.			
B. S. & W.	1st M.			
	2nd M.			
Seal Number	Off			
	On			

Manner in which oil was moved:
By ______ To ______ Station
Power Furnished by ______

TIME	1st Meas't	______ Gauger ______ Well Owner's Witness
	2nd Meas't	______ Gauger ______ Well Owner's Witness

This Ticket Covers All Claims for Allowances

Figure 113—A sample Run Ticket

basis for all payments to the producer, royalty owners, and to others for oil produced and delivered from the lease. A conventional, manually produced ticket is shown in Figure 113. Most pipeline run tickets today, however, are computer generated. The automatic metering system which produces the ticket is compensated for pressure, temperature, and often density. Accuracy is usually in the range of ±0.1 percent. If allowable oil production is assigned to a lease or well by state regulations, the oil allowables and storage figures are balanced against pipeline oil runs for production regulation purposes, after corrections for temperature and BS&W have been made.

Most state and federal regulations require monthly production reports, and these are prepared in the field or central office using the basic data taken from the lease operator's daily oil production report. If allowable production and actual production do not exactly balance, the lease operator is advised by the district office of the amount of the unbalance, so that future production can be adjusted to allowable production. Most states having oil conservation and regulation laws permit certain differences or tolerances between allowable and actual production of the well or lease during the month. This is necessary because it is impossible to produce an exact volume of oil from a well in any given period due to well production variations.

15.4 Gas Meter Charts

Gas volumes delivered from a lease and produced during well tests are usually measured through orifice meters. These volumes are reported by sending the meter charts to district or central offices for reading and calculation. The lease operator or meter man is responsible for seeing that the meter location, orifice size, date, and period covered by the chart are accurately shown on the chart. These meter charts, after reading and calculation, are used to determine the payments due for gas delivered from the lease in the same general manner that pipeline run tickets are the basis for the payments due on oil.

Although meter charts are still used in gas flow measurements, it is now common for gas flow computers to be used. These electronic devices are used in conjunction with standard orifice plates and orifice fittings. They may be powered either by the electricity available at the lease or by solar cells and storage batteries. Flow computers can be connected to a remote terminal unit (RTU) and the information transmitted by radio, or the information can be stored in the flow computer and manually downloaded periodically.

15.5 Well Test Records

Routine tests for production records may require only a minimum amount of data, such as periodic fluid-rate measurements. On the other hand, special tests for equipment evaluation, well evaluation, reservoir evaluation, and state or federal regulatory requirements are most detailed. As a result, a large amount of data may be required. The amount and type of data will vary due to the particular regulatory requirements, and will depend somewhat upon company policies if needed for evaluation purposes. A list of common well test data provided by field personnel is shown in Table 1.

Records may be made on separate well test report forms, or may be posted on the daily production report. These records show the exact status and production of each well at the time a test is made, and serve as a basis for subsequent reports to show the status and production of the lease and field as a whole. *Status* is used here to mean whether the well is flowing, pumping, on gas lift, shut in, or dead. The production tests indicate how much oil, gas, and salt water are produced by each well, and this information is used to determine proper well operating practices and as a guide to servicing well work. These tests are either reported manually by the lease operator or handled automatically through the use of a computerized system to provide printouts of well test data.

An example of regulatory well test reporting is shown in Figure 114. The Railroad Commission of Texas (RRC) Form W-10, Oil Well Status Report, is computer-generated for regular reporting with updates made on the printed form.

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Table 1—Common Well Test Data

Fluid Measurements:	Gas rate for all streams, MCF per day or MMCF per day Oil or condensate rate, barrels per day Water rate, barrels per day Oil or condensate gravity, API gravity @ 60°F
Pressure Measurements (PSIG):	Flowing wellhead pressure Shut-in wellhead pressure Flowing bottomhole pressure (frequently calculated) Shut-in bottomhole pressure (frequently calculated) Casing pressure when flowing through tubing (state whether or not casing is packed off)
Temperature Measurements (°F):	Bottomhole temperature Wellhead temperature Stock tank liquid temperature
Choke Size:	Inches
Separation Conditions:	Number of separators Separator pressures and temperatures Atmospheric temperature Stabilizer pressure and inlet and outlet temperatures
Time Data (Minutes, Hours, or Days):	Duration of flowing test Length of time on test choke size before test period begins Shut-in time for pressure measurement

15.6 Equipment, Service, and Supply Reports

The need for reports on the operation and maintenance of lease equipment depends upon the kind of machinery used on the lease and whether there is equipment on the lease whose performance is being studied from an engineering standpoint. Reports for offshore platforms, for instance, include records on subsurface safety devices, and may also record wave and weather data. In most cases, important information on the performance of engines, compressors, oil-treating devices, pumping units, and other equipment is found in the operation reports. This information is used as a basis for selecting the most serviceable and economical equipment for other leases.

Most situations call for making reports on operating supplies used on the lease. Included are such things as oil treating materials, lubricants, and oil or gas used for fuel. The service or results obtained by the various makes or kinds of similar supplies can be compared from such reports to guide future buying. Also, the data are used in cost accounting and control of lease operations.

Although many of the basic records and reports made by the lease operator are required by law enforcement authorities having responsibilities for enforcing conservation rules or taxation laws, it is apparent that the reports are of great importance and value to the producer's operating, accounting, and technical groups. For example, through study of reports or individual well production tests, well status reports, and lease production history, geologic and engineering groups are able to recommend the best operating procedures and methods to obtain maximum oil and gas recoveries under the most economic operating conditions.

15.7 Environmental Records and Reports

Numerous records and reports are required under various environmental regulations. Daily operating conditions are monitored on injection wells to ensure that wells are being operated in compliance with permit requirements. These might include monitoring of pressure, volume injected, and collection of other similar data. Additionally, records of testing results must be kept to ensure that the well continues to meet stringent regulatory requirements for mechanical integrity.

Spills that might be a threat to the human health and the environment must be reported by phone as soon as possible after they are discovered. Written reports must also follow within specified time limits (usually 15 days).

Waste disposal is documented by maintaining records of wastes that are managed onsite as well as records of waste shipped offsite. These records include the volume and content of the various waste streams, who transported the material, and where it was shipped for disposal or other management.

In addition to these records and reports, many environmental permits require that certain data be maintained on the operation, maintenance, and emissions or discharges of pollutants from the site.

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RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

[PRINTED FORM]

[DISTRICT ____________]

Operator
Address

[[RETEST]]

Test Period
Due Date

Effective
Date

FORM W-10
(Eff. 3/80)

OIL WELL STATUS REPORT

Page

				PRODUCING WELLS						NON-PRODUCING WELLS					RRC USE ONLY
						PRODUCING WELLS									
FIELD NAME LEASE NAME	LEASE NUMBER		WELL NUMBER	F FLOWING P PUMPING G GAS LIFT	DATE TESTED MO./DAY/YR.	OIL BBLS	WATER BBLS	GAS MCF	GAS OIL RATIO CU FT/BL.	SHUT IN	EXC. SWR 14B	INJECTION	SALT WATER DISPOSAL	PLUGGED & ABANDONED	EFFECTIVE DATE
						■									
						■									
						■									
						■									
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CERTIFICATE

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

Signature ____________________

Date ____________________ Title ____________________

Telephone No. ____________ ____________
Area Code Number

Figure 114—Railroad Commission of Texas Form W-10, Oil Well Status Report

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SECTION 16—STATE AND FEDERAL OIL AND GAS REGULATIONS

16.1 Introduction

The development and production of oil and gas in the United States is regulated by state and federal laws, as well as by rules established by state and federal regulatory agencies under such laws. In addition to the state and national laws which define property and the rights of the property owners, most of the producing states have passed legislation for preventing above ground and underground waste in drilling and production operations. A number of lawsuits and court opinions have generally upheld the oil and gas conservation laws and rules, and have actively encouraged conservation in the production of oil and gas.

The conservation of these natural resources rests, for the most part, with the regulatory agencies within the states. The protection of the environment is treated by regulations of the U.S. Environmental Protection Agency (EPA) or an EPA-qualified state agency. Federal regulations governing federal land use and leasing (both onshore and offshore), offshore pollution liability, transportation, the safety and health of the employee in the workplace, as well as the emergency cleanup of large oil spills, also are in place and enforced. Similarly, the inadvertent discharge of oil on or into the navigable waters of the United States requires prompt reporting to EPA, the appropriate state agencies, and the Coast Guard.

16.2 Commission or Board Regulations

The oil and gas laws passed by the states vary widely. The laws of some states contain provisions for conservation; in other states the laws create a conservation commission or board which administers and applies the conservation laws.

The conservation laws of most states are intended to prohibit above ground or underground waste and provide for the protection and equitable adjustment of the rights of producers or owners with respect to the crude oil or natural gas in an oil reservoir or field. For these purposes the regulations (a) allocate production between fields in the state to the total market demand, (b) allocate production among the leases in a field, (c) govern the drilling and abandonment of wells and the development and production of properties, (d) prescribe rules for the transportation and storage of oil and gas within the state and, (e) regulate subsurface injection wells as well as production waste disposal to prevent pollution.

16.3 Relation Between Regulation and Conservation

The conservation or the prevention of underground waste (or loss of recovery) of oil or gas usually requires regulation of the production rates of the wells and fields. The prevention of above ground waste also requires adjusting production of oil and gas to the total actual or reasonable market demand. In addition, it requires the control of storage of oil in surface tanks to a working minimum to avoid waste and pollution, danger from fires and explosions, and evaporation and shrinkage.

Even though the United States imports varying percentages of the oil it needs each day, it is important that the reservoirs in this country be produced efficiently.

16.4 Commission or Board Procedure

The commission or board, acting under the authority of state laws, usually holds hearings for developing or adopting appropriate rules or regulations for drilling, producing, and abandoning oil and gas properties. At these hearings, testimony and recommendations may be made by all interested parties, including operators, landowners, royalty owners, and the general public. Hearings may be called at the request of any of such interested parties.

Regulations adopted as a result of such hearings are subject to change to meet new situations, and to keep up with changes in technical knowledge and progress. Technical knowledge of oil and gas reservoirs had its real development beginning in the late 1920s and early 1930s. As this knowledge increased, it became obvious that many of the old production practices and regulations were wasteful and did not adequately control pollution. Because of this, most of the state laws and regulations have been adopted or changed since that time.

Commission or board regulations set procedures and requirements needed for calling and holding hearings. In recent years, the many commissions and boards have held thousands of hearings to gather operating and technical information for determining proper rates of production for reservoirs, proper well spacing, permissible gas-oil ratios, and methods of conserving and using casinghead gas.

State and federal agencies work together to assume administration and enforcement of regulations.

16.5 Reports Required

In addition to information supplied at hearings, the operators of oil and gas properties are required to file reports with federal and state agencies. These reports provide a check on the operator's compliance with the regulations, and also furnish data for determining taxes on oil and gas production sold. Monthly reports are required on the volumes of oil, gas, and water produced and on subsurface water disposal from each lease and from each offshore facility.

Other reports are required on individual wells to show the gas-oil ratio, water production, bottomhole pressure, and producing ability. Through the hearings and reports, the boards and commissions keep up with the growth and advance in technical knowledge and operating methods, and

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are able to use this knowledge in the proper administration of their duties.

16.6 Interstate Compact

Because of the variety of operating and regulatory problems existing between the states, some interchange of ideas and information among their regulatory agencies was considered desirable. This resulted in the formation of the Interstate Oil & Gas Compact Commission, which is an association of the governors and their representatives of the interested oil and gas producing states. The organization was approved by the Congress of the United States on August 27, 1935.

The Compact Commission usually meets twice a year to discuss common problems and to pass on and publish its findings, and the recommendations of its several committees. Its work is purely advisory, but has been very helpful to individual member states, particularly to those states that have the problem of writing laws and regulations to deal properly with their conservation problems when oil and gas development first begins.

16.7 MMS Control of Federal Lands

Because the federal government is a royalty owner in both onshore and outer continental shelf (OCS) leases, its interests in these properties are under the jurisdiction of the U.S. Department of Interior (DOI) and more specifically the Minerals Management Service (MMS). (DOI also acts on behalf of certain Indian Land interests when necessary.) MMS is charged with monitoring gas and oil production from federal leases, and their revenues and operating practices. Consequently, the producer, transporter, and refiner of oil from federal leases must comply with the special reporting and auditing procedures of this agency.

16.8 Federal Hot Oil Act

The Federal Connally Act (also called the Hot Oil Law) makes it illegal to transport oil, produced in violation of state laws or regulations, across state lines. This federal law has helped to make state oil conservation laws effective by preventing an escape through movement of the hot oil to another state before the offense is detected.

16.9 Other Laws and Regulations

It is impossible to discuss the details of the many additional state and federal laws and regulations here. They are designed to protect the rights and interests of individuals, oil operators, and the general public.

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SECTION 17—ENVIRONMENTAL, HEALTH, AND SAFETY CONCERNS

17.1 Introduction

In the process of producing oil or gas, other impurities, naturally present in the earth, also are produced. Unfortunately, little can be done to eliminate or minimize the amounts of these materials. Therefore, once at the surface, they must be removed from the product and properly managed to protect human health and the environment. In fact, the separation and treatment processes discussed in Section 7 are specifically designed to remove these inherent impurities.

However, as these impurities are removed, they generate wastes that must be disposed of properly and air pollutants that must be minimized. Almost any activity at an oil or gas production facility is impacted by one or more environmental regulations directed at this protection.

Numerous environmental agencies have regulations that affect the production processes. EPA is the federal regulatory agency for environmental protection. States also have environmental regulatory agencies with rules that must be followed. Additionally, oil and gas operations that are located on government land also will have to comply with regulations from the Bureau of Land Management (BLM); those on Indian lands will deal with the individual Indian Nations and the Bureau of Indian Affairs. Offshore facilities must comply with MMS regulations. However, for environmental concerns, EPA and applicable state agencies are the primary regulatory agencies. EPA regulations can be found in Title 40 of the *Code of Federal Regulations* (40 CFR).

Similarly, health and safety are also a concern because of the operations and chemicals used in oil and gas production. The Occupational Safety and Health Administration (OSHA) is the federal regulatory agency for health and safety issues. However, states also may have requirements. OSHA requirements range from safe design of equipment to including safety guards on equipment to protective clothing for workers. OSHA standards can be found in the regulations under Title 29 of the *Code of Federal Regulations* (29 CFR).

While a detailed review of all the environmental and health and safety regulations is beyond the scope of this document, it is appropriate to discuss some of the major requirements. This section provides a brief overview of the various federal environmental, health, and safety regulations. Keep in mind that state requirements may be different. Indeed, they may be more stringent than the federal requirements. Companies must ensure compliance with all applicable regulations.

17.2 Environmental Requirements

This section presents some of the general requirements for individual regulatory programs. However, there are some general requirements that exist regardless of the regulation. For example, many of the regulations require that permits be obtained before some activities can be conducted. These permits dictate certain conditions with which the facility must comply.

Documentation of compliance is a very important part of dealing with the environmental regulations. Many of the regulations discussed in this section require that routine reports be submitted to the agency demonstrating environmental compliance. Additionally, accidental releases of materials into the environment must be reported to various local, state, and federal groups.

If the facility is out of compliance with the regulations or with the permit conditions, the agency has enforcement provisions that allow for fines and penalties. Violations of some regulatory provisions can result in fines of up to $25,000 per day per violation, or jail terms, or both. Obviously, compliance with the various regulations is an important part of each company's operations.

■ The *Safe Drinking Water Act (SDWA)* is designed to ensure protection of the drinking water supplies. The SDWA requirements that most affect oil and gas production operations are the *Underground Injection Control (UIC)* provisions. The greatest volume of waste generated at production sites is produced water. Since produced water is often saline, onshore operations usually dispose of this water by reinjection into deep wells. Whether for disposal or enhanced recovery (see Section 11) these wells must be designed, constructed, and operated in compliance with the UIC requirements.

■ The *Resource Conservation and Recovery Act (RCRA)* regulates the management and disposal of wastes. Some wastes generated at exploration and production (E & P) sites are considered hazardous while others are exempt from the stringent regulations adopted under RCRA for hazardous wastes. Exempt wastes include those that are produced from primary field production and processing operations. Produced water, drilling fluids, and drill cuttings make up the greatest volume of wastes generated at Exploration and Production sites. These, along with certain other wastes generated in primary field operations, are among those considered exempt from the hazardous waste regulations.

Hazardous wastes are defined in the RCRA regulations. These might be wastes that are specifically listed in the regulations or wastes that meet certain criteria based upon laboratory testing or general knowledge. Although typical Exploration and Production operations generate relatively small amounts of hazardous waste, proper management and disposal of such wastes is important. Strict rules must be followed, and the management and disposal of the wastes documented.

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Regardless of the regulatory status of a waste, proper management is crucial to ensure compliance with the regulations and to minimize potential clean up liabilities in the future.

■ *Naturally Occurring Radioactive Material (NORM)* is a waste not yet regulated on the federal level, but has become such a concern in oil and gas operations that it bears a brief discussion. As the name implies, it is radioactive material that exists naturally in the oil and gas producing formations. It is present mostly in scales that form when salts precipitate out of the produced water. Several oil-producing states have implemented NORM regulations that dictate how this waste must be stored and disposed of.

■ The *Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA),* commonly known as Superfund, regulates the clean up of sites and the reporting of certain releases of hazardous substances to the environment. Generally, site clean up is required under this program when hazardous substances pose a significant threat to human health and the environment. Parties operating the site or contributing waste to the site often perform the clean up. Most companies attempt to avoid involvement in potential problem sites by auditing the facilities that receive their wastes to ensure that these waste management facilities are operating in compliance with applicable laws and regulations.

CERCLA, along with its amendments, the *Superfund Amendments and Reauthorization Act (SARA)* contains provisions for reporting certain releases of specific substances. Each of these regulatory requirements includes lists of substances considered hazardous by the EPA. In addition to these reporting requirements for episodic releases, there are routine reports that must be made under SARA Title III—the *Emergency Planning and Community Right-to-Know Act (EPCRA).* This portion of SARA requires that companies report the presence of certain chemicals at their sites to help the surrounding community to plan for an emergency situation.

■ The *Clean Water Act (CWA)* controls the pollutants that are allowed into surface waters. Under the *National Pollutant Discharge Elimination System (NPDES)* portion of this law, direct discharges of wastewater into surface waters must be permitted and must meet certain quality requirements. Onshore operations and produced water from offshore platforms are regulated under this program. Likewise, storm water falling on the production facilities (both onshore and offshore) has the potential to become contaminated with oil or other contaminants that might be present. Some oil and gas facilities have been required to obtain storm water discharge permits for contaminated storm water.

Another set of regulations under the CWA which impacts oil and gas operations are the *Spill Prevention Control and Countermeasures (SPCC)* requirements. These requirements, along with the *Oil Pollution Act (OPA) of 1990* regulate oil spill prevention and response. The SPCC program requires that facilities storing oil above set quantities have an SPCC plan that provides detailed information on how the facilities are designed and operated to minimize the likelihood of an oil spill. Certain minimum standards are set in the regulations. OPA 90 mandates national emergency planning, increases limits of liability for oil spills, revises the measure of damage of natural resources, establishes a fund for clean up costs, increases financial responsibility requirements for offshore facilities, addresses prevention and removal, and sets up a research and development program. Emphasis on spill planning is indicated by the need for facilities to develop a plan to handle a worst case discharge of oil which has the potential to reach water.

■ The *Clean Air Act (CAA)* enforces strict requirements for emission of pollutants into the air. Several activities at production sites are potential sources for these emissions, such as vapors from storage tanks and other equipment. The CAA requires certain controls on the amount of pollutants emitted, and permits for specific emission points. As amended in 1990, the CAA imposes greater controls on air emissions from all types of industries, including Exploration and Production operations. The Amendments focus much attention on the control of volatile organic compounds (VOCs), many of which are generated in the production of oil and gas. Controls also will be required to reduce emissions of hazardous air pollutants (for example, H_2S). Many sites must obtain air permits for their emissions.

■ The *National Environmental Policy Act (NEPA)* requires detailed environmental reviews, in the form of environmental assessments or environmental impact statements, for major federal actions undertaken or permitted by agencies of the federal government when those actions may significantly affect the quality of the human environment.

■ The *Federal Land Policy and Management Act (FLPMA)* established comprehensive land use guidelines for BLM on how to manage public lands under its jurisdiction. Production operations located on BLM lands must comply with additional restrictions placed on the operations by BLM. Additionally, BLM must be notified in the event potentially harmful releases.

■ The *Endangered Species Act (ESA)* is designed to protect endangered or threatened species or their critical habitat from proposed activities. Determinations are made as to whether or not a production project will adversely impact a threatened or endangered species. If a species may be adversely impacted, the project may be halted or certain restrictions placed upon it to protect the species. For example, operations may be limited to certain times of the year so as to not interfere with the endangered species' mating season.

■ The *Toxic Substance Control Act (TSCA)* was enacted to identify effects of chemical substances in the work place and

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in the environment, and contains several reporting provisions. One requirement is to record employee and consumer complaints of any significant adverse reactions of which they notify the employer. The company must keep records of any alleged significant adverse reactions to human health or the environment caused by handling a chemical substance. Sec. 8(e) reports to EPA may have to be made in accordance with EPA guidance on "substantial risk" to health or the environment.

■ The *Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA)* provides for the registration and use of pesticides and similar products intended to eliminate or control rodents, insects, weeds, microorganisms, and other living pests.

■ The *Coastal Zone Management Act (CZMA)* established national policy to preserve, protect, develop, and restore or enhance the U.S. coastal zone. The 1990 amendment has new requirements for states to develop programs on a variety of coastal issues including pollution run-off.

17.3 Health and Safety Requirements

Unlike the environmental regulations that might fall under a variety of federal laws, the health and safety requirements that impact industry are all part of the *Occupational Safety and Health Act (OSHAct).* This law gives OSHA authority to set and enforce standards to ensure the health and safety of employees. Below is a discussion of some of the major safety and health provisions that impact oil and gas operations.

■ The *Hazard Communication Standard* requires that employees be informed of hazards they might encounter in the work place. Commonly referred to as HazCom, this standard is designed to ensure that employees have all the information necessary to ensure proper and safe handling of hazardous chemicals. It requires that employers keep Material Safety Data Sheets (MSDS) on all hazardous chemicals purchased for use at the facility. The MSDSs provide specific hazard information about the product along with precautions to take when handling the chemical. The MSDSs must be readily available to employees and proper labeling must be done. Employers must explain these potential hazards to employees and meet the OSHA training requirements.

Employers are required to ensure that proper personal protective equipment (PPE) is available to employees. Basic PPE that might be required at most work sites includes safety glasses, hard hats, gloves, and safety shoes. However, more protective equipment, such as respirators, may be required in certain situations such as where hydrogen sulfide is present. There may be training requirements as well.

■ Confined spaces (such as tanks or small pits) can present a special hazard to those who enter them for inspection or maintenance. Harmful vapors from the materials stored in the confined space can cause injury or death to unsuspecting workers. The *Confined Space Entry* requirements ensure that workers who might enter such areas are properly trained to recognize a confined space and take precautions before entering it. Untrained personnel are forbidden from working in confined spaces.

■ In addition to potential health hazards which might be caused by the chemicals present at production sites, OSHA also is concerned with protection from physical hazards. For example, all pumps and motors that have exposed rotating shafts, flywheels, or belts must be guarded to prevent employee injury. Equipment is carefully designed and installed to avoid situations where employees might slip, trip, or fall. Guard rails and hand rails are used where falls might occur.

■ Elevated noise levels can result in hearing impairment. Therefore, adequate precautions to prevent employee overexposure to noise must be taken. This includes a hearing conservation program which identifies areas of excessive noise and provides for hearing protection, audiometric testing, engineering controls, and employee training.

■ A lock-out/tag-out program is required for protection from hazards due to electricity and other forms of energy. This program provides for certain procedures to be followed to ensure that any powered system is inoperable before maintenance is conducted. For example, pump maintenance must be done utilizing lock-out/tag-out procedures.

■ Fires and explosions as well as other emergency situations can present a special danger to employees. Employees who might be expected to respond to an emergency at the site must be trained under the *Hazardous Waste Operations and Emergency Response (HAZWOPER)* requirements. These regulations require that emergency responders receive a minimum of 8 or 24 hours of training, depending upon their particular role in an emergency.

■ In 1992 a new regulation, *Process Safety Management (PSM) of Highly Hazardous Chemicals,* was put into effect to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable, or explosive chemicals. OSHA is responsible for administering this regulation, which applies to all facilities onshore and to state waters that are normally occupied and contain the regulated substances in at least threshold amounts. This regulation is designated as 29 *Code of Federal Regulations* Part 1910.119.

Facilities covered by this regulation are required to have a comprehensive management program to ensure that the requirements of this regulation are met and that the employees are fully involved in the development and implementation of the process safety management program.

The process safety management program consists of a number of elements including employee participation, process safety information, hazards analysis, operating procedures, training, mechanical integrity, contractor safety, management of change, and others which are deemed necessary to ensure the safe operations of the facility. The regula-

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tion applies to chemical plants, refineries, and gas plants, as well as production facilities. It does not apply to drilling or well servicing operations. OSHA enforces the regulations through its regional and local offices which are located throughout the United States.

In keeping with the intent of the process safety management regulation set forth in 29 CFR 1910.119, API developed and in May 1993 published *Recommended Practices for Development of a Safety and Environmental Management Program for Outer Continental Shelf (OCS) Operations and Facilities* (API Recommended Practice 75). This recommended practice was developed with the participation of MMS and applies to all facilities on the OCS. State waters extend to a distance of three miles offshore. The OCS comprises the waters beyond this three-mile limit over which the federal government has jurisdiction.

API Recommended Practice 75 is similar to OSHA 1910.119 in that it utilizes a management system to meet the objectives set forth in the recommended practice. The individual elements of this system are similar to those of PSM. Despite its similarities to PSM, there are some important differences. API Recommended Practice 75 does not define threshold quantities of hazardous materials. However, it applies to all oil, gas, and sulphur production on the OCS. Thus, every facility from the largest production platforms to single well structures is included. Drilling and well servicing activities, which are excluded from the OSHA regulation, are included in API Recommended Practice 75. Further, API Recommended Practice 75 is also designated as an environmental management program, where protection of the environment is included along with the safety of the worker. The most significant difference, perhaps, is that while OSHA PSM is mandatory for facilities covered by the regulation, API Recommended Practice 75 is still voluntary. Most major and independent oil companies with operations on the OCS are developing and implementing programs to comply with API Recommended Practice 75.

There are many health and safety standards that impact the way oil and gas production companies do their business. OSHA regulations impact how a facility is designed and operated to ensure the protection of the workers. Detailed records are kept on incidents to help companies assess what caused the problem and how they can ensure that there is no recurrence.

17.4 Summary

There are numerous environmental, health, and safety regulations that impact the oil and gas exploration and production industry. Those discussed in this section are some that have the greatest impact. Additional details may be obtained by consulting the regulations found in the *Code of Federal Regulations* (Title 40 for environmental, Title 29 for health and safety). API also has published many other documents that provide more detail on what companies must do to comply with various environmental laws and regulations.

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SECTION 18—ECONOMIC CONSIDERATIONS

18.1 Introduction

The petroleum business is capital intensive; very large sums of money are required to acquire exploratory acreage and to find, develop, and produce oil and gas. In addition, it is a very high-risk business. No matter how much is invested in the undertaking or how deep the well goes, there is not the slightest guarantee that an exploratory well will find any oil or gas. Historically, only 1 of every 6 wildcat wells drilled in search of new fields has produced any oil or gas. The rest have been dry holes. Only about 2 of every 100 of these exploratory wells will discover a field of 1 or more million barrels of crude oil reserves or 6 or more billion cubic feet of gas reserves. These relatively small quantities are the minimum amounts necessary for the discovery to be considered significant in size.

High risk also is frequently associated with initial field development and transportation system expenditures. This is especially true when large investments in platforms, facilities, pipelines, and marine terminals must be made before the size and producibility of the reserve can be verified through development drilling and actual production experience. These risky conditions are particularly prevalent in offshore areas, the Arctic, and other remote and harsh environments.

Thus, those statistically few successful ventures must provide an adequate return on investment to shareholders or private company owners, plus cover the cost of unsuccessful undertakings, if a company is to stay in business.

Large investment requirements continue to occur over the 20-year or more producing life of a field. Ultimate investment may exceed that required for initial development by several fold. These outlays are necessary for such things as artificial lift, enhanced recovery, saltwater treating and disposal, and gas gathering, compression, and conditioning.

18.2 Ultimate Recovery

An oil or gas field is usually at its maximum capability to produce right after initial development is completed. While such things as artificial lift or enhanced recovery may create some peaks in the production rate with time, a general decline in oil and gas producibility occurs from discovery to abandonment. As a field ages, many factors tend to increase operating costs: water production may increase, old wells need more repair and maintenance, low-pressure gas may require more compression, and artificial lift requirements may increase. When expenses and declining production cause a well or a field to be unprofitable, it is usually abandoned. Thus, in a very real sense, ultimate recovery is governed by economics. The lower the capital and operating costs, the longer a field can be produced and the greater the ultimate recovery of oil and gas will be.

Most of the costs controlled by the oil company are related to the activities covered in this book. Other major costs are under government control and take the forms of taxation and regulation.

18.3 State Taxes

All states where the petroleum industry operates derive tax revenues from oil and gas activities. The taxation takes different forms in different states, but the main components are (a) income tax, (b) property or ad valorem tax, (c) severance tax (a tax on the value of oil and gas removed or severed from the lease) and (d) regulation taxes. Oil and gas taxes are a substantial source of state revenue in most of the major producing states. In recent years some state governments, pressed to meet growing budgetary needs, have increasingly turned to oil and gas taxation in attempts to solve their fiscal problems.

18.4 Federal Government Taxes and Price Controls

Seeing that the nation would become ever more dependent upon oil and gas as efficient, versatile and economical fuels, the U.S. Congress as early as 1913 recognized that discovered oil and gas were valuable capital resources which should not be taxed as the capital value was exhausted. After several refinements in the law were made, this taxation principle in 1926 took the form of a percentage depletion. Percentage depletion was a tax deduction granted to oil and gas producers and to producers in other extractive industries—those that take some 200 minerals and other raw materials from the earth.

Percentage depletion, as it applies to oil and gas, has been a key to making low-cost energy readily available in the United States. It has contributed greatly toward giving the American consumer access to large quantities of economical energy supplies, which have been essential to achieving an unprecedented standard of living.

The encouragement that was historically provided by the Congress to find and develop oil and gas has been substantially eroded since about 1970. The original depletion allowance was set at 27.5 percent of the gross income of each individual producing property, but not to exceed 50 percent of the net income from that same property before allowance for depletion. The rate of depletion was reduced to 22 percent in 1969.

Oil depletion was lost entirely for integrated companies (those that explore for, produce, transport, refine, and sell oil and gas) with the passage of the Tax Reduction Act of 1975. Under the provisions of that act, depletion on oil has been scaled down with time to the point that benefits also have

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been greatly reduced for non-integrated companies. Further, depletion on gas has been eliminated entirely or substantially reduced for most gas producers.

Federal price controls on oil and natural gas have seriously limited the funds available for reinvestment in new exploration and production ventures. Regulation of producer prices on gas sold into interstate commerce began in 1954, and controls were expanded to affect all gas production by the Natural Gas Policy Act of 1978. Complex oil price controls also were imposed from 1971 to 1981. When these were finally removed in 1981, the Congress already had in place a windfall profit tax. This tax diverted from 30 to 70 percent of the revenue added by oil price decontrol into the federal Treasury. It should be noted, however, that some categories of gas were exempt from price controls and some oil is exempt from the windfall profit tax. The windfall profit tax and price controls on gas were completely removed during the 1980s.

18.5 Other Government Activities

The federal government and certain states which hold large amounts of public lands have in recent years attempted to increase their oil and gas income through novel leasing and royalty agreements. A variety of sliding scale royalty, net profit sharing, and bonus bid combinations have been initiated. The thinking behind these activities appears to be that somehow government can increase its share of oil and gas income without reducing ultimate recovery, and without taking any of the risks or incurring any drilling and producing costs. To the extent that these measures are used, funds for new exploration and development will be reduced in the short term and, over the longer term, both production volumes and government income from petroleum will also likely be reduced.

State and federal regulations have added considerably to the cost of finding and producing oil and gas in the United States.

18.6 What It All Means

The lower the costs, the more oil and gas can be found, produced, and delivered to the consumer at reasonable prices. Higher costs, from whatever source, lessen funds available for new exploration, as well as hasten abandonment and reduce ultimate production from existing fields. Costs have gone up as easy to find fields have been produced, and more difficult geological and operating environments have been challenged.

Ample evidence exists to demonstrate that oil and gas drilling and producing activities respond to economic stimuli, and that the vast majority of profit is reinvested in additional oil and gas ventures. An industry unencumbered by unnecessary regulation and control will discover and produce the maximum quantities of oil and gas in the United States.

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SECTION 19—FUTURE TRENDS

19.1 Introduction

The future of oil and gas production likely will unfold a story of an industry constantly striving to expand its horizons at the leading edge of exciting technology. The passion to hunt for the unknown, to try what never before has been done, and to seek fortunes in oil have led to the highly sophisticated oil and gas business we have today. The challenges exist for such progress to continue, and there is every reason to believe they will be met.

The major frontiers now include deepwater and offshore areas prone to severe storms, extremely great well depths, ice environments, more difficult enhanced recovery techniques (see Section 11), and exploration for harder-to-find petroleum traps.

In the past, a combination of technology limits and economics dictated that the easy-to-find oil and gas—very shallow deposits and possible petroleum traps indicated by ground surface features—would be discovered first. Now that more than a century of exploration has passed, only the more difficult and obscure prospects remain to be found. Great potential for future discovery exists, but advanced geological and geophysical interpretations, aided by modern computer analysis, are required to identify promising prospects. These techniques are being refined to the point that an indication of hydrocarbons may be possible in a few instances. However, at this time drilling remains as the only sure way to know if oil and gas are present.

Fixed offshore platforms have been employed to produce in water depths up to about 1,000 feet. Exploratory drilling from floating vessels has occurred in much deeper waters, and prospects are known to exist under waters 6,000 to 9,000 feet deep or deeper. New kinds of producing structures, such as the guyed (or compliant) tower and TLPs, have the potential for greatly extending water depth capability. For extremely deep waters, several concepts appear feasible that call for drilling from floating vessels and placing wellheads and production facilities on the sea floor; subsea pipelines will carry production to floating storage or to fixed structures in shallower water (see Figure 115). Underwater wellheads already have been successfully applied in the Gulf of Mexico and several other areas around the world. Massive structures which are held on the ocean floor by gravity have been used in the unusually stormy waters of the North Sea. This technology may be utilized or serve as a building block in developing production structures for rough U.S. waters.

Efforts to drill ever deeper wells will continue. Drilling to below 20,000 feet is common now and wells have been drilled to depths below 30,000 feet. Conditions are being encountered that involve reservoir temperatures above 400°F and pressures above 20,000 psi. Some of these reservoirs contain gases with significant percentages of highly corrosive substances, hydrogen sulfide, and carbon dioxide. These temperatures, pressures, and gas compositions strain the limits of drilling, tubular goods, and production equipment technology. The problems, however, are being overcome and even deeper drilling is expected in the future.

New environmental challenges are presented to the oil driller and producer in the Arctic and sub-Arctic regions of Alaska. Operations in bitter cold and protection of the delicate tundra have been accomplished in the giant Prudhoe Bay field. Protection against the continually moving ice offshore presents an added difficulty. Rapidly moving winter ice in the Cook Inlet has been successfully withstood for many years by a variety of platforms. Man-made gravel islands have been used for shallow-water drilling in the U.S. and Canadian Beaufort Sea (see Figure 116). A variety of designs to break up or divert advancing ice are under consideration for deeper water operations in the Beaufort, Chukchi, and Bering Seas and in the Hope Basin, all offshore of Alaska.

Some recent and evolving technological developments are of particular interest and may indicate the trends which will develop in the future. These are discussed in 19.2 through 19.6.

19.2 Multiphase Pumps

Multiphase pumps are a recent concept that promises to have increasing impact in oil production. As their name implies, these devices can pump oil, water, and gas simultaneously. They may use either electric or hydraulic power and are likely to find application both onshore and offshore. Their use would allow produced fluids to be pumped from deep-water subsea completions to production facilities in

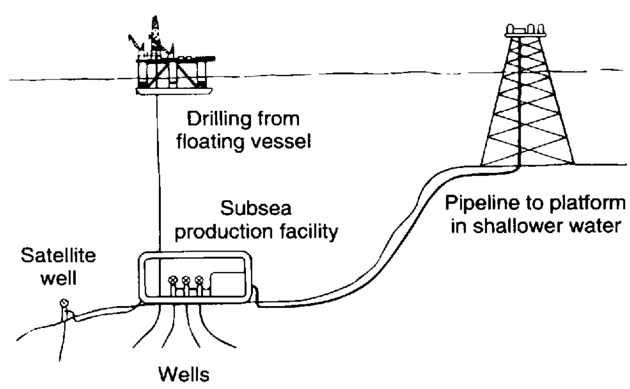

Figure 115—Conceptual Drawing of a Subsea Production Facility

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shallow water, thereby eliminating the high cost of surface facilities in deep water. Various manufacturers are continuing development efforts to perfect their designs.

19.3 Horizontal Trees

In wells that utilize conventional trees, the tubing is suspended from the tubing hanger which sits in a specially prepared profile within the wellhead assembly. After the tubing is installed in the well, the tree is then installed on the wellhead. In the case of subsea completions which utilize conventional subsea trees, workover operations require the use of a special workover riser and are limited to operations that can be conducted through the tubing.

Horizontal trees are a recent development that promises to simplify workover operations, particularly in subsea wells. Unlike conventional trees described above, horizontal trees are installed on the wellhead first and the tubing hanger is landed on a profile within the tree. All valves are external to the body of the tree, and the top of the tree is equipped with a profile that accepts a standard drilling BOP. Thus, all workover operations can be conducted through a conventional drilling riser and BOP stack, and are not restricted to only those which can be conducted through a conventional workover riser much smaller in diameter. As a result, the need to utilize the conventional workover riser is eliminated, the need to remove the tree for workover purposes is greatly reduced, the tubing can be pulled without disconnecting the flow line and control system, and workover operations are simplified.

Primarily because of these advantages, horizontal trees are expected to find increasing application in subsea completions. It is also likely that they will find increasing acceptance in surface applications both offshore and onshore. A simplified representation is shown in Figure 117.

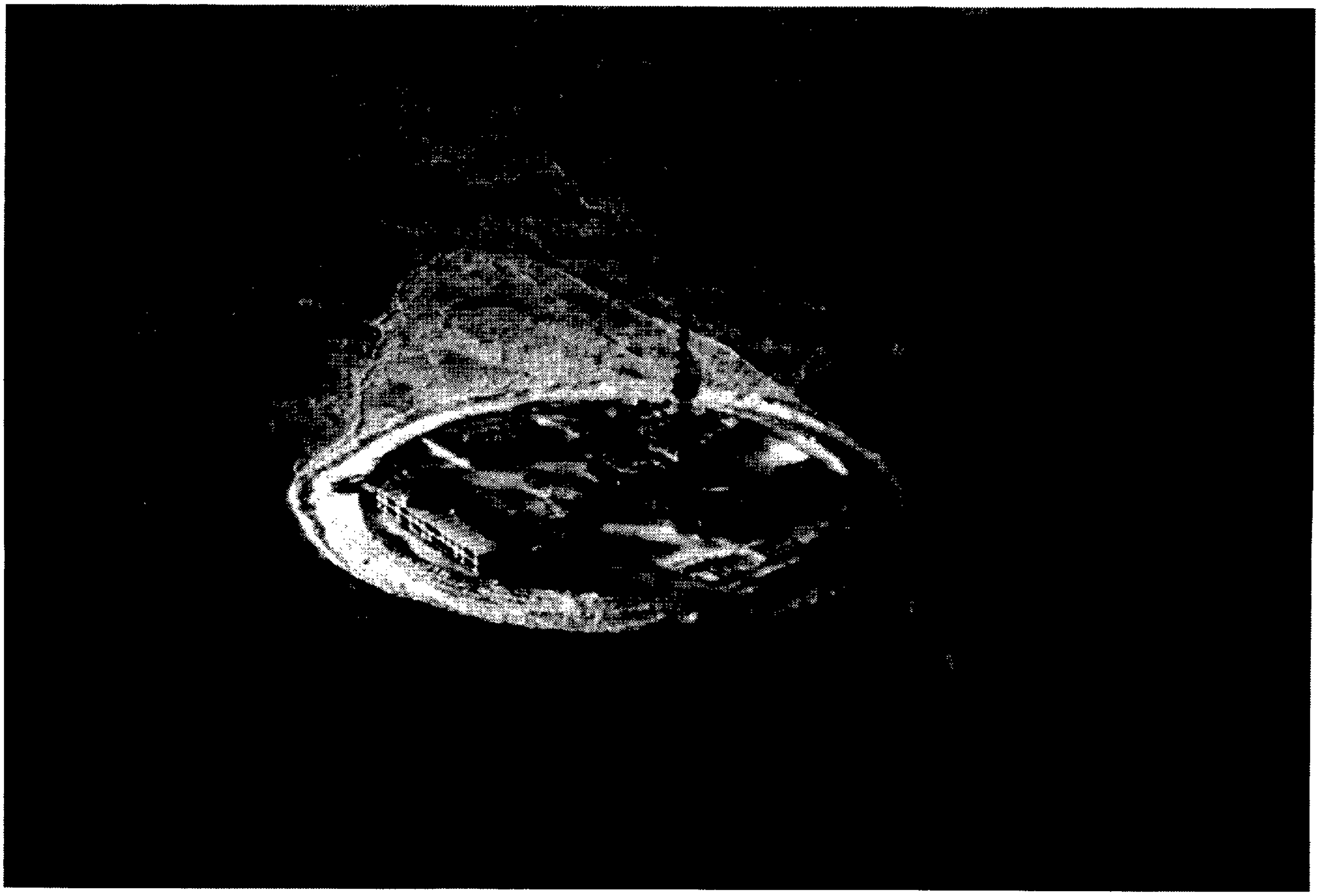

Figure 116—Manmade gravel island in U.S. Beaufort Sea during ice break-up season.

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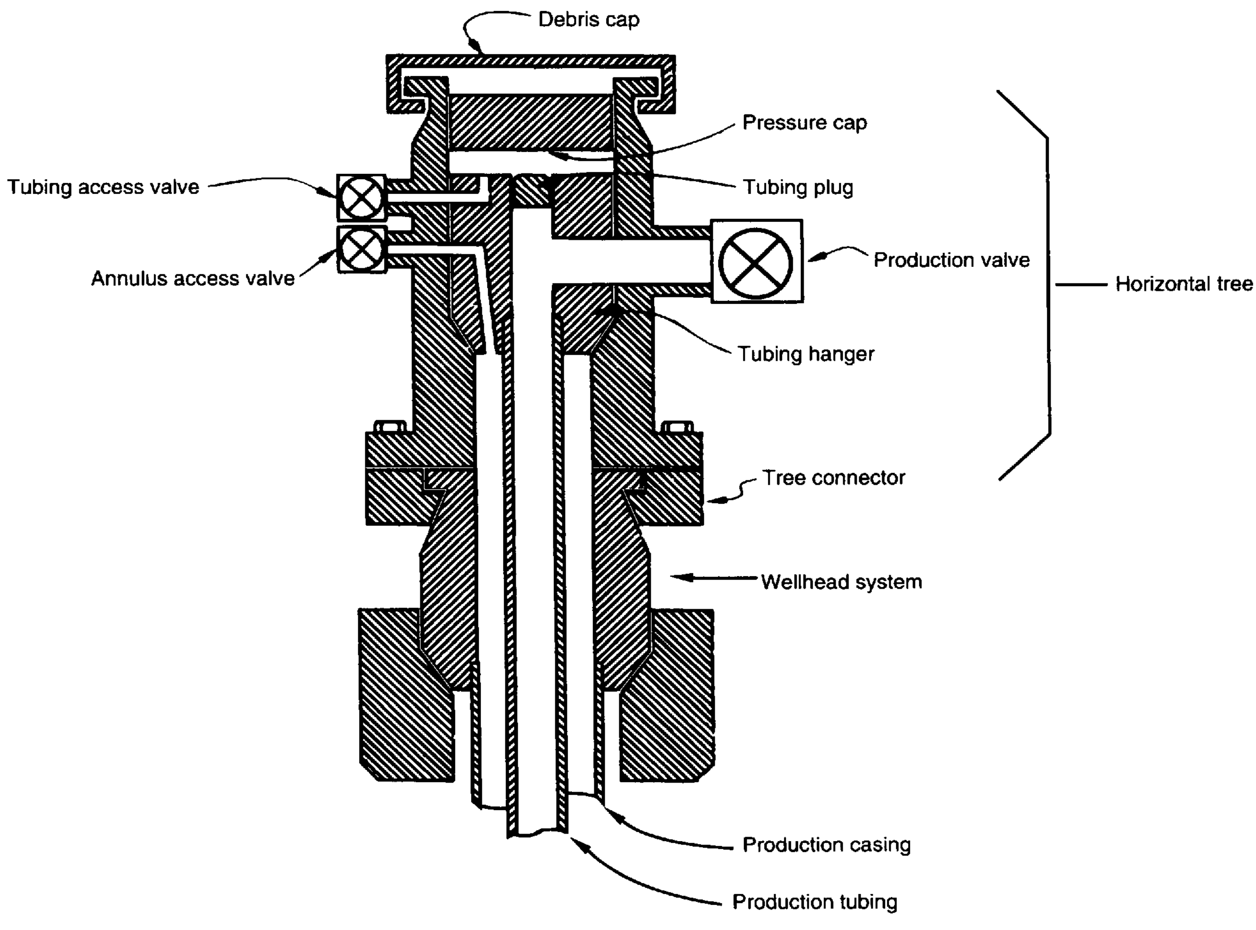

Figure 117—Simplified Diagrammatic Representation of a Horizontal Tree

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19.4 Horizontal Drilling

In recent years, horizontal drilling has enjoyed widespread application both onshore and offshore. Horizontal drilling is a natural outgrowth of directional drilling which was originally developed to allow wells to be drilled to targets not directly beneath their surface location. As directional drilling technology improved, it became feasible to extend the well bore horizontally over hundreds or even thousands of feet. This can greatly increase the length of the productive interval in the well. Horizontal drilling is particularly beneficial when the producing formation is relatively thin or when the permeability is low.

So much success has been realized in the development of this technology that it is now often economical to drill to bottom hole targets that were once considered uneconomical or physically impossible to reach from a given surface location. While economics justify horizontal drilling in many offshore wells, it may also be economically attractive onshore where reservoir conditions dictate. For example, the resurgence in drilling and production activity in the Austin Chalk in central Texas which occurred in the early 1990s was attributable, in large measure, to the technical and economic success of horizontal drilling. The Austin Chalk formation in many areas has low permeability. Much of the oil and gas occurs within, or migrates through, natural fractures in the reservoir rock. Horizontal drilling which intersected such fractures resulted in wells with greatly enhanced production rates, making the drilling of these wells economically attractive.

19.5 Downhole Well Splitters

A recent innovation allows two well bores to be drilled using a single string of conductor and surface casing. This may be attractive offshore where the number of conductor strings that can be accommodated is always limited. Starting at the bottom of the surface casing, each well bore is directionally drilled to its respective subsurface target. Each well is completed and produced independently, and may be serviced and worked over individually without the other well having to be shut in.

19.6 Multiphase Metering

Good reservoir management requires the regular testing of wells so that reservoir performance can be monitored and appropriate corrective action can be taken. Traditionally this has required that the production from each well be directed through a test separator so that the oil, gas, and water produced can be measured separately.

Wells in deep water that are remote from production facilities make such well testing difficult. As a result of the continued trend to develop fields in deep water, a significant effort was started in the mid-1980s to develop a multiphase meter that could measure the individual components of oil, water, and gas in a well stream without having to utilize a separator. Development has progressed and today such meters are capable of accuracies which are acceptable for well test purposes. Development of multiphase meters is continuing in the United States and other countries.

A continuous evolution of technology to conquer new frontiers has always occurred through the efforts of people in the business of drilling for and producing oil and gas; there is every expectation that these activities will be pursued with even greater vigor in the years ahead.

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APPENDIX A—GLOSSARY

The following is a list of words and phrases used in the oil and gas production industry. Some of the words in the list are considered slang—others common—and their usage as applied to the production of oil and gas often differs from normal usage. Only the most common words used in the industry, and those undefined or incompletely defined in this book are given here. The definitions are those of widest applicability, since the meaning may vary from work area to work area. The list is not to be considered all-inclusive, nor as covering all local variations in word meaning.

abandon: To cease efforts to produce oil or gas from a well, and to plug a depleted formation and salvage all material and equipment.

absorption: To soak up as a sponge takes water.

acidizing: The treatment of formations with hydrochloric or other acids in order to increase production or injection.

adsorption: The attraction exhibited by the surface of a solid for a liquid or a gas when they are in contact.

allowable: The amount of oil or gas that a well is authorized by the slate regulatory agency to produce during a given period.

API: American Petroleum Institute.

API gravity: The standard adopted by API for measuring the density of a liquid, expressed in degrees.

back off: To unscrew one threaded piece (such as a section of pipe) from another.

back up: To hold one section of an object, such as a pipe or a nut, while another is being screwed into or out of it. A back-up wrench refers to any wrench being used to hold the pipe or bolt.

bad oil: Oil not acceptable for delivery to the pipeline purchaser because BS&W levels are too high; oil requiring additional treating.

baffles: Plates or obstructions built into a tank or other vessel to change the direction of fluid flow.

ball and seat: Parts of the valves in a plunger oil well pump.

basic sediment and water (BS&W): The water and other extraneous material present in crude oil.

batch: A definite amount of oil, mud, chemicals, cement, or other material in a treatment or operation.

battery (tank battery): The production handling equipment on the lease.

B/D: The abbreviation for barrels per day. Other related abbreviations are:

- **BPD:** barrels per day.
- **BOPD:** barrels of oil per day.
- **BWPD:** barrels of water per day.
- **BLPD:** barrels of liquid per day.

beam: The walking beam of a pumping unit.

beam well: A well whose fluid is being lifted by rods and pump-actuated by a beam pumping unit.

bean: A type of choke used to regulate the flow of fluid from a well. Different sizes of beans are used for different producing rates.

bell hole: A bell-shaped hole dug beneath a pipeline to provide room for use of tools by workers.

bird cage: To flatten and spread the strands of a cable or wire rope. Also, the slatted or mesh-enclosed cage used to hoist workmen from crew boats to offshore platforms.

blank liner: A liner without perforations or slots.

blank off: To close off by sealing or plugging.

bleed: To drain off liquid or gas, generally slowly, through a valve called a bleeder. To bleed down, or bleed off, means to slowly release the pressure of a well or of pressurized equipment.

bleeder valve: A small valve on a pipeline, pump, or tank from which samples are drawn or to vent air or oil; sample valve.

blind: To close a line to prevent flow.

blind flange (blank flange): A solid disc used to dead end a companion flange.

blowout: An uncontrolled flow of gas, oil, or other fluids from a well.

blowout preventer (BOP): The equipment installed at the wellhead for the purpose of controlling pressures in the annular space between the casing and drill pipe (or tubing) during drilling, completion, and certain workover operations.

boilerhouse: To make up or fake a report without actually doing the work.

boll weevil: Any inexperienced worker.

bonnet: The part of a valve that packs off and encloses the valve stem.

boot: A tall section of large-size pipe used as a surge column on a vessel.

bottom-hole: The lowest or deepest part of a well.

bottom water: Water occurring below the oil and gas in a production formation.

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bowl: A device that fits in the rotary table or wellhead to hold the wedges or slips that support a string of drill pipe, casing, or tubing while tripping in or out of the hole.

bradenhead gas: See casinghead gas.

break out: To unscrew one section of pipe from another section.

brine: Water that has a large quantity of salt, especially sodium chloride, dissolved in it. Salt water.

bring in a well: To complete a well and put it on production.

British thermal unit (BTU): A measure of the heating value of a fuel.

bubble cap: A metal cap designed with openings to cause the upward-flowing gas bubbles in a gas-processing tower to intimately contact downward flowing liquids, causing some of the gas to condense to liquid. Bubble caps are mounted on a perforated-steel bubble-cap tray.

buck up: To tighten a threaded connection.

bump a well (bump down): To lower a sucker-rod string on a pumping unit so that the pump hits bottom on the downstroke.

cage: The part of a pump valve which holds the ball to limit its movement.

cased hole: A wellbore in which casing has been run.

casinghead gas: Associated and dissolved gas produced with crude oil; oil well gas.

casing pressure: Pressure measured at a wellhead casing outlet.

casing string: The pipe run in a well, for example: surface string, and intermediate string, and production string.

cathead: A spool-shaped attachment on a winch around which rope is wound for hoisting and pulling.

catline: A hoisting or pulling line operated from a cathead.

cat walk: A narrow walkway.

cellar: A hole dug, usually before drilling a deep well, to allow working space for the casinghead equipment.

centrifuge: A shake-out or grind-out machine. Samples of oil are placed in the machine and whirled at high speed to settle out sediment. BS&W content can be determined in this manner.

chase threads: To straighten and clean threads of any kind.

cheater: A length of pipe used to increase the leverage of a wrench.

check valve: A valve which permits flow in one direction only.

choke: A type of orifice installed for the purpose of restricting and controlling flow.

Christmas tree: The assembly of valves, pipes, and fittings used to control flow of oil and gas from the well.

clip: A U-bolt or similar device used to fasten parts of a wire cable together.

closed in: A well capable of producing oil or gas, but temporarily shut in.

collar: Usually refers to a coupling used to join two lengths of pipe.

come-along: A stretching or tightening device.

come out of the hole: To pull drill pipe, tubing, wireline tools, and so forth, out of the well.

computer production control (CPC): An operation wherein field conditions and activities (well testing, lease production, equipment operational and safety status, and so forth) are monitored or controlled automatically by a computer system.

condensate: Hydrocarbons which are in the gaseous state under reservoir conditions but which become liquid either in passage up the hole or in the surface equipment.

connection: The joining of two lengths of pipe.

control panel: Switches and devices to start, stop, measure, monitor, or signal what is taking place.

coupon: A small metal strip which is exposed to corrosive systems for the purpose of determining the nature and severity of corrosion.

crater: To fail. To cave in.

crooked hole: A wellbore which has inadvertently deviated from the vertical.

crude oil: A mixture of hydrocarbons that exists in the liquid phase in the underground reservoir and remains liquid at atmospheric pressure after passing through surface separating facilities.

cut oil: Oil that contains water, usually in the form of an emulsion. Also called wet oil.

D & P platform: A drilling and production platform. Such an offshore platform is a large structure with room to drill and complete a number of wells.

deadman: A substantial timber or plug of concrete buried in the earth to which a guy wire or line is attached for bracing a mast or tower. Also a land-side mooring device used with lines and cables when docking a vessel.

dead oil: Crude oil containing essentially no dissolved gas when it is produced.

dead well: A well which has ceased to produce oil or gas, either temporarily or permanently.

debug: To detect, locate, and correct malfunctions in a computer, instrumentation, or other system.

depletion drive: See solution gas drive.

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demulsifier: A chemical used to break down crude oil/ water emulsions so the water may be removed from the oil.

density: The weight of a substance per unit of volume. For instance, the density of a drilling mud may be described as 10 pounds per gallon or 15 pounds per cubic foot.

development well: A well drilled in a proven field for the purpose of completing the desired spacing pattern of production.

discovery well: An exploratory well that encounters a new and previously untapped petroleum deposit. A successful wildcat well.

disposal well: A well through which water (usually salt water) is returned to subsurface formations.

dissolved gas: Natural gas which is in solution with crude oil in the reservoir.

dissolved-gas drive: See solution-gas drive.

doghouse: A small house used for keeping lease records, changing clothes, or any other use around a lease.

dogleg: A term applied to a sharp change of direction in a wellbore or ditch. Applied also to the permanent bending of wire rope or pipe.

dolomite: A type of sedimentary rock similar to limestone but rich in magnesium carbonate. Some times dolomite is found as the reservoir rock for petroleum.

dope: A viscous material used on casing or tubing threads as a lubricant, and to prevent corrosion; a tar base coating for pipelines to prevent corrosion.

doubles: Drill pipe and tubing pulled from the well two joints at a time. The two joints make a stand of pipe that is set back and racked in the derrick. Three-joint stands are called thribbles; fours are fourbles.

doughnut: A ring of wedges that supports a string of pipe or a threaded, tapered ring used for the same purpose.

downcomer: A tube that conducts liquids downward in a vessel (as an absorber, a stripper, or heater-treater).

downhole: A term to describe tools, equipment, and instruments used in the wellbore. For example, a downhole tool is used in the wellbore. Also, conditions or techniques applying to the wellbore.

drawdown: The difference between the static and the flowing buttonhole pressures. The distance between the static level and the pumping level of the fluid in the annulus of a pumping well.

dress: To sharpen or repair items of equipment (as drilling bits, tools, or sucker rod pumps) in order to make them ready for reuse.

drip: The small quantities of liquid hydrocarbons which sometimes condense in a natural gas line. Also the equipment installed on a gas line to remove liquids.

dry gas: Natural gas that is produced without liquid hydrocarbons. Also gas that has been dehydrated to remove water (pipeline gas).

dry hole: Any exploratory or development well that does not produce oil or gas in commercial quantities.

dump valve: The discharge valve through which oil and water are discharged from separators or treaters.

dynamometer: The dynamometer records the variation in load on the polished rod as the rod string reciprocates in sucker-rod pumping.

effective permeability: The permeability of a rock to a fluid when the rock is not 100 percent saturated with the fluid. See permeability.

effective porosity: The percentage of the bulk volume of a rock sample that is composed of interconnected pore spaces, allowing the passage of fluids through the sample. See porosity.

emulsion: A mixture of crude oil and formation water Generally requires time and heat, chemicals (called demulsifiers or emulsion breakers), or electricity to separate the water from the oil.

entrained gas: Gas suspended in bubbles in a stream of liquid such as water or oil.

entrained liquids: Mist-size liquid droplets occurring in a gas stream. Special designed separators, with a mist extractor, are used to remove the liquid from the gas stream.

expansion loop: A bend placed in a line to absorb line movement or line crawl due to expansion and contraction of the pipe.

exploratory well: See wildcat well.

fail safe: Said of equipment or a system so constructed that, in the event of failure or malfunction of any part of the system, devices are automatically activated to stabilize or secure the safety of the operation.

fatigue: Failure of a metal under repeated loading.

female connection: A pipe or rod coupling with the threads on the inside.

field: An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although at times it may refer to both the surface and the underground productive formations.

field facility: An installation designed for one or more specific field processing units—scrubbers, absorbers, drip points, compressors, single or multiple stage separation units, low temperature separators, and other types of separation and recovery equipment. Also see battery.

fire wall: A dike built around oil tanks, oil pumps, and other oil handling equipment to contain any oil which may

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be accidentally discharged from the equipment. It also serves to block the spread of a fire or give protection for a period of time while emergency action is taken.

fishing: The effort to recover tools, cable, pipe, or other objects from the wellbore which have become lost in the well accidentally. Many special and ingeniously designed fishing tools are used to recover objects lost downhole. The object being sought downhole by the fishing tools is referred to as the fish.

fittings: The small pipes and valves that are used to make up a system of piping.

five-spot: Four input or injection wells located in a square pattern with the production well in the center. See injection pattern.

flange up: To finish a job.

float: A long, flat-bed semi-trailer.

flow by heads (heading): Intermittent flow from a well.

flow chart: A record of the flow rate made by a recording meter.

flow line: The surface pipe through which oil travels from the well to the field processing facility.

flow string: The string of casing or tubing through which fluids from a well flow to the surface.

flowing pressure: The pressure at the wellhead of a flowing well.

flowing well: A well which produces without any means of artificial lift.

fluid: A substance that flows. Both liquids and gases are fluids. In common oil field usage, however, the term fluid refers to liquids.

fluid injection: Injection of gases or liquids into a reservoir to force oil toward and into producing wells.

fluid level: The distance from the surface to the top of the liquid in the tubing or casing in a well. The static fluid level is taken when the well is not producing and after it has stabilized.

flush production: The high initial rate of flow from a good well.

formation damage: The reduction of permeability in a reservoir rock arising from the invasion of drilling fluid and treating fluids into the section adjacent to the wellbore. Often called skin damage.

formation pressure: The pressure exerted by formation fluids, recorded in the hole at the level of the formation, with the well shut in.

fracturing: Application of hydraulic pressure to the reservoir formation to create fractures through which oil or gas may move to the wellbore.

frozen up: Said of equipment of which the components do not operate freely.

gauging nipple: A small section of pipe in the top of a tank through which a tank may be gauged.

gas anchor: A device for the buttonhole separation of oil and gas in a pumping well. It serves to prevent gas lock by minimizing gas entry into the pump.

gas cap: The portion of an oil-producing reservoir occupied by free gas.

gas-cap drive: The drive energy supplied naturally by the expansion of gas in a cap overlying the oil in a reservoir.

gas injection: Natural gas injected under high pressure into a producing reservoir through an input or injection well as part of an enhanced recovery operation.

gas lift: The raising, or lifting, of liquid from a well by means of injecting gas into the liquid.

gas-oil ratio (GOR): The number of cubic feet of gas produced with a barrel of oil.

gas-liquid ratio (GLR): The number of cubic feet of gas produced with a barrel of liquid. (Usually water and oil.)

gas plant products: Liquids recovered from natural gas in a gas processing plant and, in some situations, from field facilities. See natural gas liquids.

gas processing plant (gas plant): A facility designed (a) to achieve the recovery of natural gas liquids from the stream of natural gas which may or may not have been processed through lease separators and field facilities, and (b) to control the quality of the natural gas to be marketed.

gas regulator: A device for controlling the pressure of gas flowing in a pipeline.

gas sand: A porous sandstone reservoir which contains natural gas.

gas well: A well capable of producing natural gas.

gathering lines: The flow lines which run from several wells to a central lease or plant facility.

geology: The scientific study of the origin, history, and structure of the earth as recorded in rocks. A person trained in geology is a geologist. A petroleum geologist is primarily concerned with sedimentary rocks where most of the world's oil has been found.

gin-pole truck: A truck equipped with a pair of poles and hoisting equipment for use in lifting heavy machinery around a lease.

gone to water: Describes a well in which oil production has decreased and water production has greatly increased.

gradient, pressure: Pressure change with depth, expressed in psi per foot.

gradient, temperature: Temperature change with depth, expressed in °F per 100 feet.

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gravity-API: See API gravity.

gravity-specific: Density expressed as the ratio of the weight of a volume of substance to the weight of an equal volume of another standard substance. In the case of liquids and solids, the standard is fresh water, In the case of natural gas or other gaseous material, the standard is air.

gravity drainage: The movement of the oil in the reservoir toward the wellbore due to the force of gravity.

grind out: See shake out.

gunk: The collection of dirt, paraffin, oil, mill scale, rust, and other debris that is cleaned out of a pipeline when a scraper or a pig is put through the line.

guy wire: A rope or cable used to steady a mast or pole.

hand: Practically anyone who works in the oil industry, but especially applied to those who work in the field.

handy: A connection that can be unscrewed by hand.

hang the rods: To pull the rods out of the well and hang them in the derrick.

hard hat: Molded plastic hat worn in the field for protection.

headache: A warning cry given by a fellow worker when anything is accidentally dropped or falls from overhead toward another worker.

heat (a connection): To loosen a collar or other threaded connection by striking it with a hammer, Also, warm (a connection) or whip (a connection).

hold-down: A mechanical arrangement to prevent the upward movement of certain pieces of equipment installed in a well.

hole: The wellbore.

holiday: A gap or void in the coating of a pipe or in paint on a metal surface.

hot oil: Oil production in violation of state regulations or transported interstate in violation of federal regulations.

hot-oil treatment (to hot oil): A treatment using heated oil to melt and remove accumulated paraffin from the tubing, annulus, flow lines, or production equipment.

hot tapping: Making repairs or modifications on a tank, pipeline, or other installation without shutting down operations.

hydrocarbon: A compound consisting of molecules of hydrogen and carbon. Petroleum is a mixture of many hydrocarbons.

hydro-test (hydrostatic testing): To apply hydraulic pressure (usually with water) in order to find leaks in tubing, lines, piping, vessels, and equipment.

***in situ* combustion:** The setting afire of some portion of the oil in a reservoir in order (a) that the gases produced by combustion will drive oil ahead of them to the producing wells and (b) to heat the oil so it will flow more readily.

initial potential (IP): The initial capacity of a well to produce.

injected gas: High pressure gas injected into a formation to maintain or restore reservoir pressure or otherwise enhance recovery. Also, gas injected for gas-lift.

injection pattern: The spacing and pattern of wells in an enhanced recovery project. The more common injection patterns include line drive, five spot, seven spot, nine spot, and peripheral.

injection pump: A pump that (a) injects chemicals into a flow-line system for the purpose of treating emulsions or corrosion and (b) injects liquids under ground for disposal or to enhance recovery.

input well: A well that is used for injecting fluids into an underground stratum.

insulated flange: A flange that contains insulating material to separate the metal parts.

intermitter: A device for regulating the production of a gas-lift well whereby the well produces for short periods of time and is then closed in. This action is repeated several times a day.

intermediate casing string: The casing set in a cell after the surface casing. Also called protection casing.

jack board: A device used to support the end of a length of pipe while another length is being screwed on.

joint: A length of pipe, casing, or tubing, usually from 20 to 30 feet long.

junk: Metal debris lost in a hole. Junk may be a lost bit, milled pieces of pipe, wrenches, or any relatively small object that must be fished out of the hole.

junk basket: A fishing tool run in the well when it is necessary to retrieve small parts or lost tools.

kick-off: To bring a well into production.

kill a well: To stop a well from producing so that surface connections may be removed for well servicing or workover. It is usually accomplished by circulating water or mud to load the hole and render it incapable of flowing.

knockout: A kind of tank or vessel used to separate water from oil. A free water knockout (FWKO).

lay barge: A shallow-draft, barge-like vessel used in the construction and laying of underwater pipelines in swampy areas and to offshore platforms.

laying down tubing: Pulling tubing from the well and laying it on a pipe rack. Similar terms apply to drill pipe and rods.

lean gas: Natural gas containing little or no liquefiable hydrocarbons.

lease: (1) A legal document that conveys to an operator the right to drill for oil and gas (2) The tract of land, on which a

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lease has been obtained, where the producing wells and production equipment are located.

lease automatic custody transfer (LACT or ACT): The measurement and transfer of oil from the producer's tanks to the oil purchaser's pipeline on an automatic basis without a representative of either having to be present.

lifting costs: The costs of producing oil from a well or a lease.

limestone: A type of sedimentary rock rich in calcium carbonate. Limestone sometimes serves as a reservoir rock for petroleum.

location: The place at which a well is to be or has been drilled.

long string (casing): See production casing.

long string (tubing): In a dual completed well, the tubing string to the deepest zone.

lubricator: A specially fabricated length of pipe that is usually temporarily placed above a valve on top of the Christmas tree. Lubricators are used to run special tools, usually on a wireline, into a producing well without having to kill the well.

macaroni string: A string of tubing of very small diameter.

make a hand: To become a good worker.

make it up: To screw a pipe or threaded connection tight by the use of a wrench.

make up: To assemble and join parts to form a complete unit, as to make up a string of tubing. To screw together two threaded pieces.

male connection: A pipe or rod coupling with the threads on the outside.

manifold: An accessory system of valves and piping to a main piping system (or other conductors) that serves to divide a flow into several parts, to combine several flows into one, or to reroute a flow to any one of several possible destinations.

marginal well: A low producing rate well that is approaching depletion to the extent that any profit from its continued production is doubtful.

marsh buggy: A tractor-like vehicle whose wheels are fitted with extra large rubber tires for use in swamps.

master valve: A large valve located on the Christmas tree used to shut in a well.

MCF: The abbreviation for 1,000 cubic feet (usually applied to natural gas).

measuring tank: A calibrated tank that automatically measures the volume of liquid run in and then released. Measuring tanks are used in LACT systems and may also be referred to as metering tanks or dump tanks.

meter chart: A circular chart which records the differential and static pressures. See orifice meter.

migration: The movement of oil from the area in which it has formed to a reservoir rock where it can accumulate.

miscible flood: An oil recovery process which involves the injection of a fluid which mixes readily with the oil, followed by a displacing fluid.

mist extractor: A metallic element used to remove moisture of condensable hydrocarbons from a gas stream in an oil and gas separator or scrubber.

MMCF: The abbreviation of 1,000,000 cubic feet; a common unit of measurement of large quantities of gas.

mosquito bill: A tube mounted at the bottom of a sucker rod pump and inside a gas anchor to provide a conduit for well fluids into the pump. See gas anchor.

mud: The liquid that is circulated through the wellbore during rotary drilling and workover operations.

multiple completion: A well equipped to produce oil or gas separately from more than one reservoir.

natural gas: A mixture of hydrocarbons and varying quantities of non-hydrocarbons that exists either in the gaseous phase or in solution with crude oil in natural underground reservoirs.

natural gas liquids: Those portions of reservoir gas which are liquefied at the surface in separators, field facilities, or gas processing plants. Plant products are also known as liquefied petroleum gas (LPG).

natural gas plant: See gas processing plant.

needle valve: A valve used on small, high-pressure piping where accurate control of small amounts of liquid or gas is desired. Also used with pressure gauges.

net-oil computer: A combination of electronic and mechanical devices that automatically determines the amount of oil in a water and oil emulsion.

nipple: A pipe fitting that is usually threaded on both ends and is less than 12 inches in length.

nipple up: To assemble a system of pipe, valves, and nipples as in a Christmas tree.

nominations: The amount of oil or gas a purchaser expects to take from a field as reported to a state regulatory agency.

non-associated gas: Natural gas which is in reservoirs that do not contain significant quantities of crude oil.

non-operator: A working-interest owner other than the one designated as operator of the property.

off production: A well when it is shut in or temporarily not able to produce.

offset well: Well drilled near another one.

offshore: That geographic area which lies seaward of the coastline.

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oil—petroleum—gas: A fluid or gas composed of hydrocarbons.

oil and gas separator: An item of production equipment used to separate the liquid components of the well stream from the gaseous components.

oil country tubular goods: Oil-well casing, tubing, and drill pipe.

oil field: See field.

oil operator (operator): An individual or company engaged in the business of finding and producing oil and gas.

oil patch: A colloquial expression for an oil field. If one goes to an oil field, then one goes to the oil patch.

oil sand: A sandstone reservoir that yields oil.

oil string: See production casing.

oil well: A well completed fort he production of rude oil from at least one oil zone or reservoir.

on the beam: A well being pumped by a beam pumping unit.

on the line: A tank when it is being emptied into a pipeline.

on the pump: A well that is not capable of flowing and is produced by means of a pump.

open hole: Uncased portion of a well.

orifice meter: An instrument commonly used to measure the flow of fluid (usually gas) in a pipe.

overproduced: A well that has produced more than its allowable.

packer: An expandable plug-like device for sealing off the annular space between the well's tubing and the casing.

P&A: The abbreviation for plugged and abandoned. See plug and abandon.

paraffin: Heavier paraffin-base hydrocarbons often form a wax-like substance called paraffin. Paraffin may accumulate on the walls of tubing, flow lines, and other production equipment, thus restricting the flow of well fluids to the extent that it must be removed. See hot-oil treatment.

pay out: The recovery from production of the costs of drilling, completing, and equipping a well.

pay sand: The producing formation, or that formation which represents the objective of drilling. Also referred to as pay.

permeability (of a reservoir rock): The ability of a rock to transmit fluid through the pore spaces; a key influence on the rate of flow, movement, and drainage of the fluid. There is no necessary relation between porosity and permeability. A rock may be highly porous and yet impermeable if there is no communication between pores. A highly porous sand is usually highly permeable. See effective permeability.

petroleum: Oil or gas obtained from the rocks of the earth by drilling down into a reservoir rock and piping them to the surface. See hydrocarbon.

petroleum rock: Sandstone, limestone, dolomite, fractured shale, and other porous rock formations where accumulations of oil and gas may be found.

pig: A device inserted in a pipeline for the purpose of sweeping the line clean of water, rust, or other foreign matter. Also known as go-devil.

pig a line: To run or put a pig or scraper through a pipeline.

pig iron: Any piece of oilfield equipment made of iron or steel.

pinch a valve: Closing a valve part way to reduce the flow of liquid or gas through a line.

pipeline gas: Gas which meets gas pipeline purchaser specifications.

pipeline oil: Clean oil. Crude oil whose BS&W content is low enough to make the oil acceptable for transport or pipeline shipment.

plug and abandon (plugged and abandoned) (P&A): Expressions referring to the act of placing plugs in a depleted well or dry hole, then abandoning it. See abandon.

plug back: To shut off a lower formation in a wellbore.

plunger lift: A method of lifting oil using a swab or free piston propelled by compressed gas from the lower end of the tubing string to the surface.

pop-off valve (pop valve): See pressure-relief valve.

pony rod: A sucker rod made in short lengths of 2 feet to 8 feet.

porosity (of a reservoir rock): The percentage that the volume of the pore space bears to the total bulk volume. The pore space determines the amount of space available for storage of fluids. See effective porosity.

positive-displacement meter (PD meter): A mechanical, fluid-measuring device that measures by filling and emptying chambers of a specific volume.

potential test: A test which indicates the maximum rate at which a well can produce.

power rating: Rating given by a manufacturer of an engine operating at its most efficient output.

power tools: Equipment operated hydraulically or by compressed air for making up and breaking out drill pipe, casing, tubing, rods, nuts, and so forth.

pressure drawdown: The reduction in a well's buttonhole pressure. See drawdown.

pressure gauge: An instrument for measuring fluid pressure.

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pressure gradient: See gradient, pressure.

pressure maintenance: Maintaining reservoir pressure by injecting fluid, normally water or gas, or both.

pressure regulator: A device for maintaining pressure in a line, downstream from the device.

pressure-relief valve: A valve that opens at a preset pressure to relieve excessive pressures within a vessel or line; also called a relief valve, safety valve, or pop valve.

primary recovery: The amount of oil or gas produced from a reservoir by the .eservoir's natural sources of energy. This includes gas-cap drive, dissolved-gas drive, water drive, or any combination of these.

prime mover: The electric motor, internal combustion engine, or other source of power for the machinery being operated.

production: The yield of an oil or gas well. Also that branch of the petroleum industry that has to do with bringing the well fluids to the surface and separating them, and with storing, gauging, and otherwise preparing the product for the pipeline.

production casing (production string): The last string of casing set in a well; the casing string set to the top or through the producing formation and inside of which is usually suspended the tubing string. Also called the oil string or long string.

producing platform: An offshore structure accommodating a number of producing wells. Also see well platform.

production platform (processing platform): An offshore structure providing a central processing and disposition point for fluids produced from wells on adjacent producing and well platforms. The treated oil and gas is moved to shore through submarine pipelines. Produced water is generally disposed of within the field.

productivity test: A test of a well's ability to produce under specified conditions.

proration: A system of allocating the amount of oil or gas a well or field is allowed to produce within a given period by a regulatory agency.

protection casing: A string of casing set to protect a section of the hole and to permit drilling to continue to a greater depth. Sometimes called intermediate casing.

prover: A device used to calibrate meters used in measuring oil.

psi: Pounds per square inch.

psia: Pounds per square inch absolute; pressure measurement which takes atmospheric pressure into consideration.

psig: Pounds per square inch gauge (as observed on a gauge).

pull a well: To remove rods or tubing from a well.

pulling unit (pulling machine): A portable, truck-mounted mast equipped with winch, wirelines, and sheaves, used for pulling rods or well workover.

pump: A device used to increase the pressure of or move liquids, Types of pumps include: sucker rod, reciprocating, centrifugal, rotary, gear, and jet.

pumped off: A pump when fluid is not entering the pump intake.

put on pump: To install an artificial lift pumping system to produce a well.

pup joint: A joint of pipe or tubing shorter than standard length.

put a well on: To start a well flowing or pumping.

rabbit: A device that is put through casing or tubing before it is run to make certain it is the proper size inside and outside. A drift mandrel.

rack pipe: To stand pipe in the derrick when coming out of the hole or to stack pipe on a pipe rack.

recompletion operations: To perform operations to change producing formations in an existing well.

relief valve: See pressure-relief valve.

remote control station: A centrally located station containing equipment to control and regulate operations in one or more fields.

reservoir: A subsurface porous and permeable rock body that contains oil, gas, or both.

reservoir pressure: The pressure at the face of the producing formation when the well is shut in.

reworking a well (remedial operations): To restore production from an existing formation when it has fallen off substantially or ceased altogether. See workover.

rig: The derrick, draw works, and attendant surface equipment of a drilling or workover unit.

riser: A pipe through which liquid travels upward.

rock a well: To alternately bleed pressure from the casing and then from the tubing of a dead well until the well will flow on its own.

round-trip: To pull out and subsequently run back into the hole a string of drill pipe, tubing, or sucker rods Also termed trip.

royalty interest: The fraction of the oil and gas retained by the mineral rights owner under the lease agreement.

run: The amount of crude oil sold and transferred to the pipeline by the producer.

run a tank: To transfer oil from a stock tank into a pipeline.

run in: To go into the hole with tubing or drill pipe.

run ticket: A record of oil transferred from the producer's storage tank to the pipeline. This is the basic legal instrument by which the lease operator is paid for oil produced and sold.

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running tool: Specialized tools used to run equipment in a well, such as a wireline running tool for installing retrievable gas lift valves. Various tubing running tools also are used.

safety hat: See hard hat.

safety valve: See pressure-relief valve.

saltwater disposal: The method and system for the disposal of salt water produced with crude oil. A typical system is composed of collection centers and disposal wells in which treated salt water is injected into a suitable formation.

sand: A loose material most commonly composed of small quartz grains formed from the disintegration of preexisting rocks. Also see sandstone.

sand consolidation: Any one of several methods by which loose, unconsolidated grains of a producing formation are caused to adhere together in order to prevent a well from producing sand yet still allow oil or gas to be produced.

sand control: Any method by which large amounts of sand are prevented from entering the wellbore. Methods include: gravel pack, screen liner, and sand consolidation.

sanded up: Clogged by sand entering the wellbore.

sandstone: A compacted sedimentary rock composed of the minerals quartz or feldspar Sandstone is a common rock in which petroleum and water accumulate.

scraper: A device used to clean deposits of paraffin from tubing or flow lines. See pig.

scrubber: A vessel through which gas is passed to remove liquid and foreign matter.

sedimentary rock: A rock composed of materials that were transported to their present position by wind or water. Sandstone, shale, and limestone are sedimentary rocks.

separator: A pressure vessel used for the purpose of separating gas from crude oil and water.

service well: A non-producing well used for injecting liquid or gas into the reservoir for enhanced recovery. Also a salt-water disposal well or a water supply well.

shake out: To spin a sample of oil at high speed to determine its BS&W content. Also called grind out.

shale: A fine-grained sedimentary rock composed of silt and clay sized particles. The most frequently occurring sedimentary rock.

short string: In a dual well, the tubing string for the shallower zone.

shrinkage: A decrease in oil volume caused by the vaporization of solution gas from the oil as pressure is reduced.

shut in: To close valves on a well so that it stops producing; a well on which the valves are closed.

shut-in pressure: Pressure as recorded at the wellhead when the valves are closed and the well is shut in.

sinker bar: A heavy weight or bar run with a wireline tool to add weight so that the tool will lower properly into the well.

skimmer tank: A produced water processing tank designed to skim oil from the surface of the water.

slips: Wedge-shaped pieces of metal with teeth or other gripping elements, used to prevent pipe from slipping down into the hole or for otherwise holding pipe in place. Packers and other downhole equipment are secured in position by means of slips that engage the pipe as a result of action performed at the surface.

sour crude oil (sour crude): An oil containing free sulphur or other sulphur compounds whose total sulphur content is in excess of 1 percent.

sour gas: Natural gas containing hydrogen sulfide.

spacing: Distance between wells producing from the same reservoir (usually expressed in terms of acres, for example, 10-acre spacing).

spear: A fishing tool designed to go inside pipe that is lost in a well to obtain a friction grip and permit recovery of the pipe.

stab: To guide the end of a pipe into a coupling when making up a connection.

stabilized: A well is considered stabilized when, in the case of a flowing well, the rate of production through a given size of choke remains constant, or, in the case of a pumping well, when the fluid column within the well remains constant in height.

stage separation: An operation whereby well fluids are separated into component liquids and gases by passing consecutively through two or more separators. The operating pressure of each succeeding separator is lower than the one preceding it.

standing valve: A fixed ball and seat valve situated at the tower end of the barrel of a sucker-rod pump. The standing valve and its cage do not move as does the traveling valve.

stands: Connected points of pipe racked in the derrick when making a trip.

static fluid level: The level to which fluid rises in a well when the well is shut in.

static pressure: The force exerted by a fluid at rest and confined within a tank, line, or well as measured by a gauge.

stimulation: The descriptive term used for several processes to enlarge old channels, or create new ones, in the producing formation of a well, for example, acidizing or fracturing.

stock tank: A lease tank into which a well's production is run.

strap: To measure and record the dimensions of oil tanks for the purpose of preparing a tank table to accurately determine the volume of oil in a tank at any measured depth.

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string: Refers to the casing, tubing, or drill pipe in its entirety.

strip a well: To pull rods and tubing from a well at the same time. Tubing must be stripped over the rods one joint at a time.

strip chart: In lieu of the circular chart for recording gas flow through an orifice meter, strip charts are sometimes used.

stripper: A well nearing depletion that produces a very small amount of oil or gas.

structure: An underground geological feature capable of forming a reservoir for oil and gas.

stuck pipe: Refers to pipe or tubing inadvertently stuck in the hole.

stuffing box: A packing gland; a chamber or box to hold packing material around a moving pump rod, valve stem, or wireline to prevent the escape of gas or liquid.

sub: A short length of tubing containing a special tool to be used downhole; a short pipe adapter.

subsurface safety valve: A safety device installed in the well's tubing below the surface to automatically shut the well in when predetermined flow rate, pressure, or other conditions are reached.

surface casing: The first string of casing to be set in a well. Its principal purpose is to protect fresh water sands.

surge tank: A vessel on a flow line whose function is to receive and cushion sudden rises or surges in the stream of liquid.

swab: A rubber-faced device, which closely fits the inside of tubing, that is pulled through the tubing to lift fluid from the well. Also to pull such a device through the tubing.

swabbing: Operation of a swab on a wire line (swab line) to bring well fluids to the surface when the well does not flow naturally. This is a temporary operation to determine whether or not the well can be made to flow or if artificial lift is needed.

sweet: Oil or gas when it contains no sour impurities.

swing check: A type of check valve.

tail chain: The short length of chain, with a hook attached, on the end of a winch line.

tail gas (residue gas): Gas from a processing unit after extraction of liquids.

tail out rods: To pull the bottom end of a sucker rod away from a well when laying rods down.

tail pipe: Pipe run in a well below a packer.

take a strain on: To begin to pull on a load.

tally: To measure and record the length of pipe or tubing.

tank battery: See battery.

tank dike: See fire wall.

tank table: A table giving the barrels of fluid contained in a storage tank corresponding to the linear measurement on a gauge line. See strapping.

tap: A threaded opening in a line or vessel in which a gauge or valve may be installed. Also, a notched tool used to cut inside threads.

tattletale: A device on an instrument control panel to indicate the cause of a system shutdown or alarm signal.

telemetry: A system for the electronic transmission of oil field data.

temperature bomb: An instrument lowered into a well to record downhole temperature.

thief: A metal cylinder with a spring-actuated closing device that is lowered into a tank to obtain samples of oil at any given depth.

thief hatch: An opening in the top of a tank large enough to admit a thief and other oil-sampling equipment.

thread protector: A device screwed onto pipe threads to protect the threads from damage when not in use.

tight formation: A formation of relatively low permeability.

top out: To finish filling a tank.

total depth (T.D.): The maximum depth reached in a well.

transducer: An instrumentation device for converting a signal from one form to another. A pressure transducer.

trap (geologic): An arrangement of rock strata or structures that halts the migration of oil and gas and causes them to accumulate.

trip: See round-trip.

tubing anchor: A downhole, packer-like device run in a string of tubing that grips the wall of the casing to prevent up and down movement of the lower section of tubing as the well is pumped by a rod pump.

tubing head: The top of the string of tubing with control and flow valves attached.

tubing job: The pulling and running of tubing.

unit operator: The company designated to operate unitized properties

unitization: Unitization is the process whereby the owners of adjoining properties pool their reserves and form a single unit for the operation of the properties by only one of the owners. The production from the unit is then divided on the basis established in the unit agreement. The purpose of such agreement is to produce the reserves more efficiently, increasing the recovery for every participant. Important where enhanced recovery is anticipated.

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up-dip well: A well located high on the structure.

upset tubing: Tubing that is upset is made with a thicker wall and larger outside diameter on both ends of a joint to compensate for cutting the threads.

vapor recovery unit: A facility for collecting stock or storage tank vapors to prevent their loss to the atmosphere.

vent: A connection in a vessel, line, or pump to permit the escape of air or gas.

viscosity: A measure of how easily a liquid will pour or flow.

warm up (a connection): See heat (a connection).

water-coning: The upward encroachment of water into a well due to pressure draw down from production.

water drive: The reservoir-drive mechanism whereby oil is produced by the expansion of the underlying water, which forces the oil into the wellbore.

water flooding: One method of enhanced recovery in which water is injected into an oil reservoir to force additional oil out of the reservoir rock and into the well bores of producing wells.

water well: A well drilled to (a) obtain a fresh water supply to support drilling and production operations, or (b) obtain a water supply to be used in connection with an enhanced recovery program.

waterflood kick: The first indication of increased oil production as the result of a waterflood project.

weathered crude: Crude oil which has lost an appreciable quantity of its entrained gas due to evaporation during storage.

well: A hole drilled in the earth for the purpose of finding or producing crude oil or natural gas. Also see service well.

well permit: The authorization to drill a well issued by a governmental regulatory agency.

well platform: An offshore structure with a platform above the surface of the water that supports the producing well's surface controls and flow piping.

well servicing: The maintenance work performed on an oil or gas well to improve or maintain the production from a formation already producing in the well. Usually, it involves repairs to the pump, rods, gas-lift valves, tubing packers, and so forth.

wellhead: The equipment used to maintain surface control of a well.

wet gas: Natural gas containing significant amounts of liquefiable hydrocarbons.

wet job: Pulling tubing full of oil or water.

wildcat well: A well drilled in previously unexplored areas. Also rank wildcat.

winch: A machine used for pulling or hoisting by winding rope or cable around a power-driven drum or spool.

wireline tools: Special tools or equipment made to be lowered into and retrieved from the well on a wireline (small-diameter steel cable), for example, packers, swabs, gas lift valves, or measuring devices.

wireline truck (wireline unit): A service vehicle or unit on which the spool of wireline is mounted for use in downhole wireline work.

work boat: A boat or self-propelled barge used to carry supplies, tools, and equipment to a job site offshore.

working interest: The operating interest under an oil and gas lease.

working pressure: The pressure at which a system or item of equipment is designed to operate.

workover: Operations on a producing well to restore or increase production. A workover may be done to wash out sand, acidize, hydraulically fracture, mechanically repair, or for other reasons. See reworking a well.

zone: Describes a unique interval which has one or more distinguishing characteristics, such as lithology, porosity, or saturation.

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