# Introduction to Production Operations in Oilfield

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# Introduction to Production Operations

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# Chapter 1

# Aspects of H.C Reservoir

# Chapter 1 Contents

## Chapter 1

# Aspects of H.C Reservoir

## 1.1 GEOLOGY OF RESERVOIR ROCKS

### 1.1.1 Origin of Sedimentary Rocks

Even that occurred millions of years ago are still occurring today, one has only look at the seashores and the deep sea sediments to see how rock was deposited during geological time. This sequence of events has enabled geologists to accurately define the historical passage of time, as seen within the rocks on the earth's surface, and as brought up in cores from the thousands of wells drilled on the planet's surface.

It was about 4,500 million years ago that the surface of the earth began to solidify out of the condensed molten rock. From then, volcanic activity slowly mudded the surface of the plant until sufficient solidification had occurred to enable other processes to take over the formation of solid material on the surface.

Wind was responsible for picking up surface material and transporting it to other places. In so doing, it caused erosion of grains against each other to make fines material.

The wind transported the material to “bowl areas" where deserts began to form. Alternatively, the wind-born fines were blow out to sea and settled as a continuous film of dust like material over the sea bottom surrounding the land.

In the deserts the extremes of temperature, together with the erosion of wind blown material slowly attacked the bedrock and caused additional fines and breakdown of solidified crystalline rocks, this rock debris then become available for further movement and deposition in other areas.

All this happened millions of years ago, but is still happening today in the large desert areas of the world. For example in North Africa , wind and temperature are slowly changing, with uncontrollable certainty, the coastlines and inland areas of Libya, Tunisia and other surrounding parts of the Sahara desert. The dust grains being deposited today will be the consolidated rock of tomorrow, geologically speaking.

There are other forces at work to provide the vast sedimentary basins of geological history. Rivers and glaciers gouge vast grooves out of solid rock across with them flow. The rivers rapidly transport solids to the sea where they are deposited as gigantic deltaic fans of material. Alternatively, the river may transport material into inland basins where again thick sediments begin to build-up.

Glaciers have left their mark over vast areas of the Northern and Southern Hemisphere. Even today large masses of debris are being slowly transferred from higher places to lower places.

Gravity has been ever present; from the moment the first galactic elements spun together to eventually condense into the bodies of our solar system. We see gravity now irrevocably transferring material to lower basins, be it above or below sea level. If it were not for the continual earth movements and upheavals that heave been actively changing the shape of this plant, then earth would by now be virtually flat. Indeed, in areas where little activity occurs in the form mountain building mechanisms, it is easy to see that already the geomorphology, or shape of the land, is heading towards pleasant rolling lowlands.

However, one of the greatest eroding mechanisms that exist is the sea itself. Covering two thirds of our plant's surface it has steadily been attacking the land masses and carrying the broken rock particles back out to sea, where it has deposited them, along with all the other debris brought to it by rivers, winds and glaciers.

### 1.1.2 Fines to Solids (Diagenesis)

The transported, broken down material has slowly built up in basins of the deserts, courses of bygone rivers, or beneath sea beds. There are other mechanisms, such as volcanic lava outflows and injected molten rocks, but these are not of great interest to the oil industry certainly insofar as source rocks and oil field reservoirs are concerned.

The fine material compacts and the surrounding fluid material are in water or air is slowly squeezed out as the grains are buried deeper. Pressure and increasing temperature with depth may even change the shape of the sedimentary debris, such that the spaces between the grains decrease with the changing grain shapes.

Diagenesis now begins to occur, that is the changes from individual rock detritus grains into solid rock. No longer do the grains act individually, as the grains of sand in an egg timer or running through our fingers on the sea shore. Instead heat, pressure and interstitial fluids now cause them to come together to form a solid rock. What were once individual eroded grains of rock have now remolded to from potential oil reservoir rock.

Associated with diagnosis is the continual movement of fluids through the spaces or pores between the grains. Generally this fluid is water containing dissolved salts in different concentrations. Clearly, if the grains of the rock are laid down on the sea bed, then the water initially associated with the grains is the sea water itself, and the grains at that time are water wet. As the sediments sink under the overlying sediments, the properties of the associated waters tend to change.

This is partly because the dissolved salts within the water have undergone chemical reaction either with the sediments or have precipitated out as cementing material associated with diagnosis.

Thus rock originally laid down underwater tends to be water wet. That is water is in direct contact the rock grains. Occasionally a reservoir rock is termed “oil-wet”– where oil is the fluid in direct contact with the rock grains. It can be easily seen that a rock originally laid down under desert conditions, or wind blow "Aeolian" conditions, is unlikely to have sea water or even surface waters directly associated with the grains. Under such contortions it is easy to envisage that oil could be the first liquid to come in direct contact with the rock. This is not the only way, however, that a normally "water wet rock" could become "oil wet".

## 1.1.3 Rock Types

So far, we have discussed the main methods of depositions of inorganic sedimentary rock. The grains that have gone to makeup this rock have originated by abrasion, decomposition, leaching, erosion or other atmospheric contribution. The rock of origin or parent rock may have been other sedimentary rocks or volcanic or crystalline rock; the strict geological term for such sedimentary beds is the "Clastic Rock ".

### 1.1.3.1 Clastic Rocks

Clastic rocks result from the build-up, via deposition of fragments spilt from existing rocks by the progress of weathering and erosion.

### 1.1.3.2 Non-clastic Rocks

So far we have not discussed the second most important rock types, the non-clastic Rocks. They are classified on their chemical composition, and may be broadly classified as ***limestones***. They cover the rocks which originate generally by precipitation from salt saturated sea and inland waters. The more common non-clastic rocks are the carbonates dolomites, silicates, carbonaceous rock, ferruginous, and evaporate rock.

## 1.1.4 Origin of Oil

Although oil as we find it today has not yet been satisfactorily simulated in the laboratory, there is now a fair understanding of the mechanisms involved.

For the past 600 million years the sea had been abundant with marine lift. The micro-organisms found today existed extensively, if in different from, throughout geological time. These minute organisms contain large amounts of body fasts. When dead, they drop to the sea bed and are steadily buried, where their body cells rupture and the organic material is liberated.

Over million of years this vast amount of organic material, under the influences of pressure and perhaps temperature, was slowly converted into the oil we fined today. The source rock from which the oil originated is quite often far apart from the rock in which the oil collects. Even at thousands of feet in depth, oil floats in water. The oil probably migrated away as a slowly moving “fog” of hydrocarbon disseminated throughout the fluids in the pores of the rocks, and moved upwards until trapped in reservoir structures.

All the main types of sedimentary rock can provide storage space for hydrocarbons, depending on their physical characteristics. Ninety nine percent of all hydrocarbons are found in sedimentary rock, and thus a basic understanding of their means of origin, and what they now are, is essential to the Petroleum Engineer.

## 1.2 OIL RESERVOIR STRUCTURES

There are three basic requirements for an oil reservoir:

1. Cap Rock
2. Permeable Structure
3. Hydrocarbon Source

The cap rock generally is an impermeable layer, or isolating barrier, which prevents the easy flow fluids. Beneath or against this layer, oil may accumulate in the pores between the grains in permeable rock.

There are many potentially good reservoir traps, but the pore space is filled entirely with water. The simple reason for this is that subsurface fluid movement has not brought about any influx of oil. A source rock, where oil has originally formed, is essential, before migration can occur into an oil trap. Migration may actually be prevented by a cap rock and under such conditions the oil accumulates in-situ, and thus source rock also becomes the reservoir rock.

As already mentioned, oil once formed will tend to move, either by compaction and pressure squeezing, movement of surrounding rock waters, or simply by fluid density difference .

Generally the movement is upwards until it becomes trapped under a cap rock. The simplest and most common type of trap is the anticlinal or dome trap (**Figure 1.1**).

The anticlinal shape of the filed can be formed from a number of causes. Earth movements, due to compression forces can cause a corrugated effect in the earth’s sediments. Perfect examples of such structures are the numerous North West - South East running anticlines in Iran at the northern end of the Arabian Gulf.

The movement of salt, or other rocks, which can act as fluid under pressure can also result in an up welling of shallower rocks. These domes thus formed tend to be quite circular and are ideal traps for migrating oil. A number of North Sea fields were formed by such a mechanism.

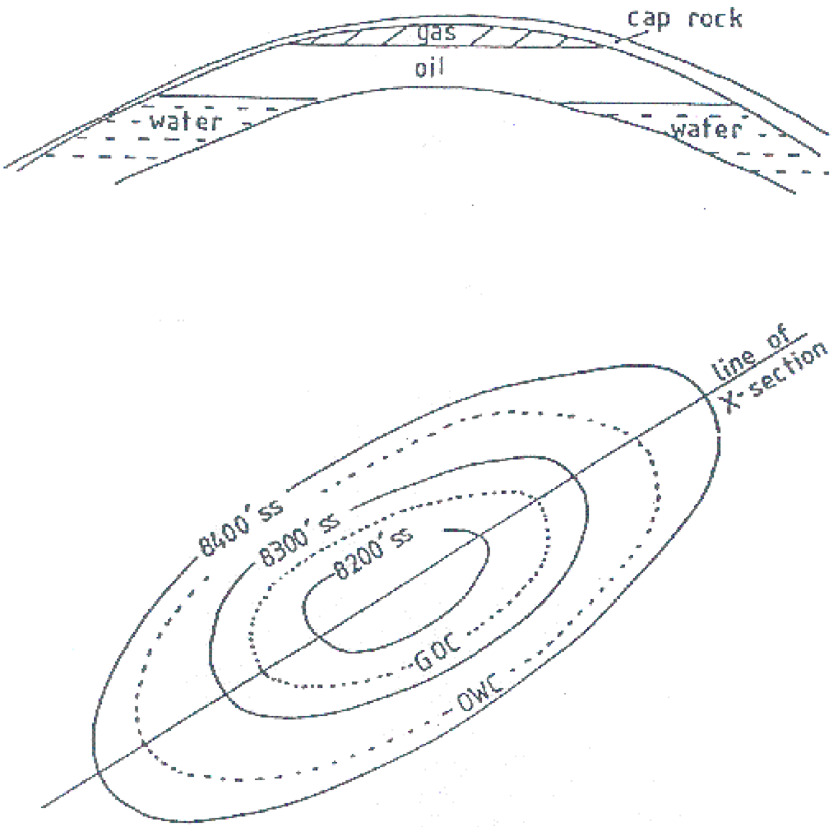
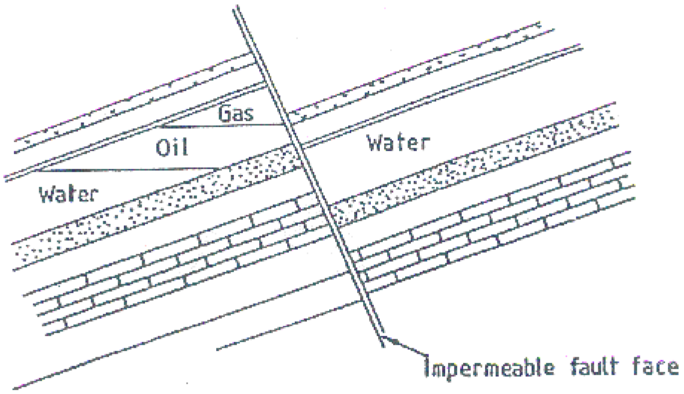


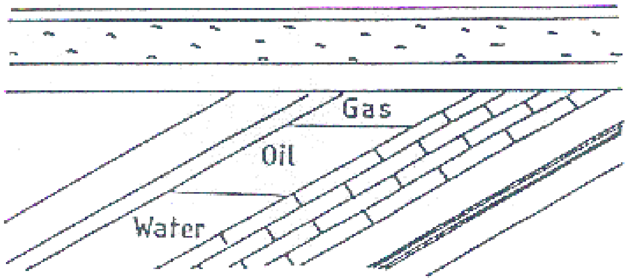
**Figure 1.1 Typical Anticlinal Oilfield Trap**

**Figure 1.2** shows typical cross sections of other oilfield structures. Faulting often results in the intrusion into the fault face of secondary cementing materials, which are impermeable. This face then offers an ideal layer against which hydrocarbons can accumulate. Unconformities brought about by the erosion of a tilled rock sequence, followed by the covering of horizontal impermeable sediments, also offer an ideal trap.

Often accumulations result from a combination of these and other traps. Simple permeability variations within the same reservoir rock can sometimes be potential reservoirs. Trap combinations increase the complexity of discovering and producing oil reservoirs.



A. Trap Fault



B. Unconformity Trap

Figure 1.2 Common Oil Traps

# 1.3 PARAMETERS CONTROLLING FLUID FLOW

Because of the very natural of deposition of rock and its very variable origin, every cubic inch of every reservoir can be different. This heterogeneity continually causes problems in the prediction of reservoir performance. There are, however, one or two basic characteristics which are measured by one means or another, either on a micro or macro scale. Each has its advantage, even though micro and macro results can be very different.

This section deals briefly with the two main characteristics which must be known before oil recovery or water flooding predictions can be made.

## 1.3.1 Porosity

The porosity is a measurement of the amount of pore space in a rock of know total rock volume which is not composed of solid mineral (**Figure 1.3**), and is denoted by the Greek symbol ø.

There are three common types of porosity; effective, non-effective (or isolated) and total porosity. The effective porosity is the percentage of the total volume of pores that are interconnected, thus sometimes called interconnected porosity. The non-effective porosity is of little interest to the petroleum engineer as it represents the volume of the pores which are not connected, and therefore cannot allow fluid flow. Generally, the non-effective porosity is about 5 % or less of the total porosity. The total porosity is the sum of the effective and non-effective porosity.

If a porosity value is applied to a reservoir rock it refers to the effective porosity.

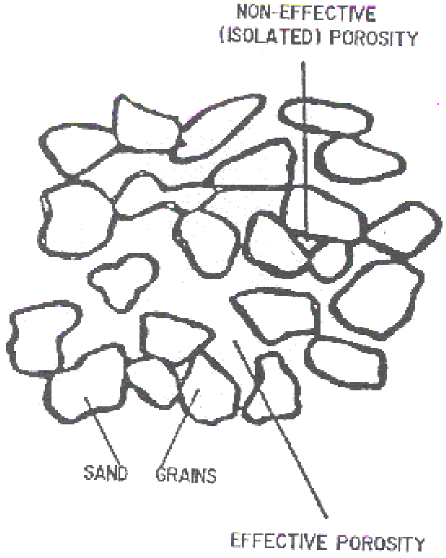


**Figure 1.3 Rock Characteristics**

$$\textbf{Total Porosity} = \frac{\textbf{Void Space}}{\textbf{Bulk Volume}} \%$$

## 1.3.2 Permeability

Permeability is a measure of the ability of fluid to flow through a rock. It is theoretically a measure of a rock property only and fluid which flows through the interconnecting pores. A fluid will only flow when the pressure in one part of formation is higher than another.

Henry Darcy , Studying the flow of water through unconsolidated sand filter beds , found that the flow increased in proportion to the pressure difference , but also depended on the “ thickness “ or viscosity of the fluid. Permeability is given the symbol "k" and **Figure 1.4** describes its derivation.

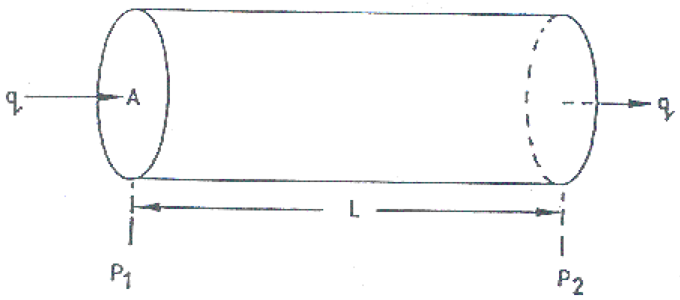


**Figure 1.4 Permeability**

$$K = \frac{q \times L \times \mu}{A(P1\_P2)} \quad \textbf{(Darcy Equation)}$$

Where:

K = Permeability – Darcies
q = Volumetric flow rate – ml/sec
L = Length of rock – cm
$\mu$ = Fluid viscosity – centipoises
A = Cross sectional area of the rock–$cm^2$
$P_1 - P_2$ = Pressure drop across length L– atmospheres

Permeability is measured in Darcies, although reservoir values are normally expressed in thousandths of a Darcy, and the unit is called the millidarcy (md). Values for typical reservoirs rang between 5-500 mds, with occasionally higher permeabilities.

So often in oil reservoirs more than one type of fluid is present. Thus, when one fluid only is present the value is known as the ***specific permeability***. If the rock is water wet (often occupying about 20% of the pore space) and oil flows through the rock, then the oil permeability is known as the ***effective permeability*** "k" of oil. These two permeabilities are combined as a ratio to provide a ***relative permeability***.

$$\mathbf{k_r o} = \frac{\mathbf{k_o}}{\mathbf{k}} = \frac{\textbf{Effective permeability of oil}}{\textbf{Specific permeability}}$$

One must remember that the specific permeability should be independent of the fluid used.

The above relationship can be similarly defined for gas and water. Further, we can see that the relative permeability can vary from zero at low saturations to unity at 100% saturation. The relationship enables us to construct relative permeability curves to provide information about fluid flow in reservoirs when different fluids are displacing others – ( say water displacing oil ) – **see Figure 1.5**.

Referring to **Figure 1.5**, the wetting phase has zero, or very low, permeability below about 20% and this value is the irreducible water saturation. As the water saturation increases, the oil permeability is drastically reduced, and at about 50 % water saturation the total permeability is only about one third of the specific permeability. Above about 80% water saturation the oil phase is virtually immovable.

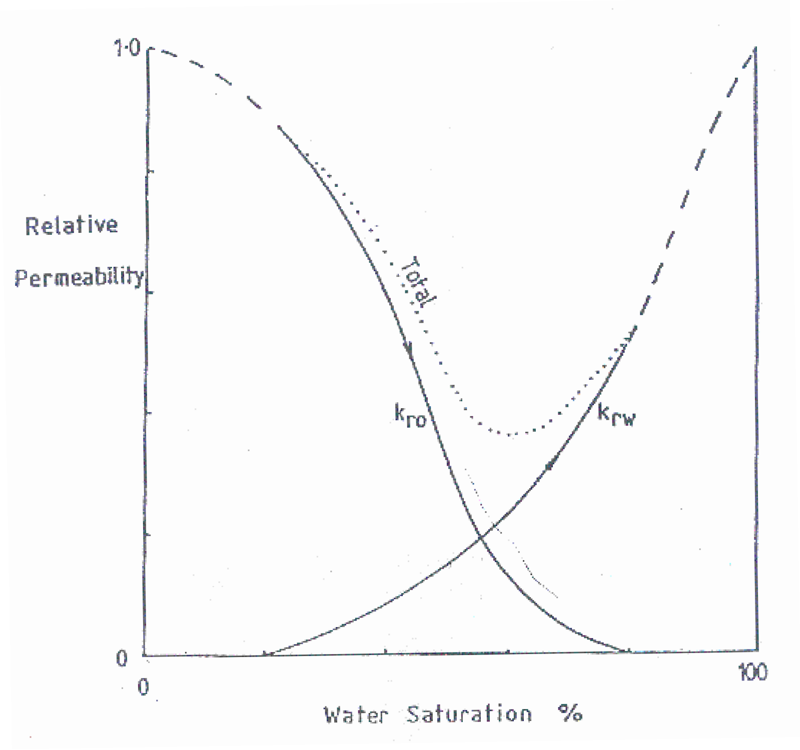


**Figure 1.5 Oil/Water Relative Permeability**

**Figure 1.6 A&B** indicates graphically how the relative permeability curves are developed during a waterflood. Initially approximately 20% immobile water is present and the oil produces as dry oil at a production well (**Figure 1.6A**). As the water saturation increases, the water permeability begins to rise and oil and water will be produced. Water need not fill a pore channel to form a continuous path, and thus the water does not tend to block off large oil filled pores at the lower saturations. At higher saturations (**Figure 1.6B**) the oil phase forms insular globules and the oil flow virtually ceases.

It is important to understand that the relative permeability curves are not unique function of fluid saturation, but depend also on the distribution of the fluid. Gas- oil relative permeability curves can depend on how the gas is formed in the rock pores. Similarly the wettability of rock, and also the direction of saturation change, will affect water distribution and hence the relative permeability to oil in an oil / water system.

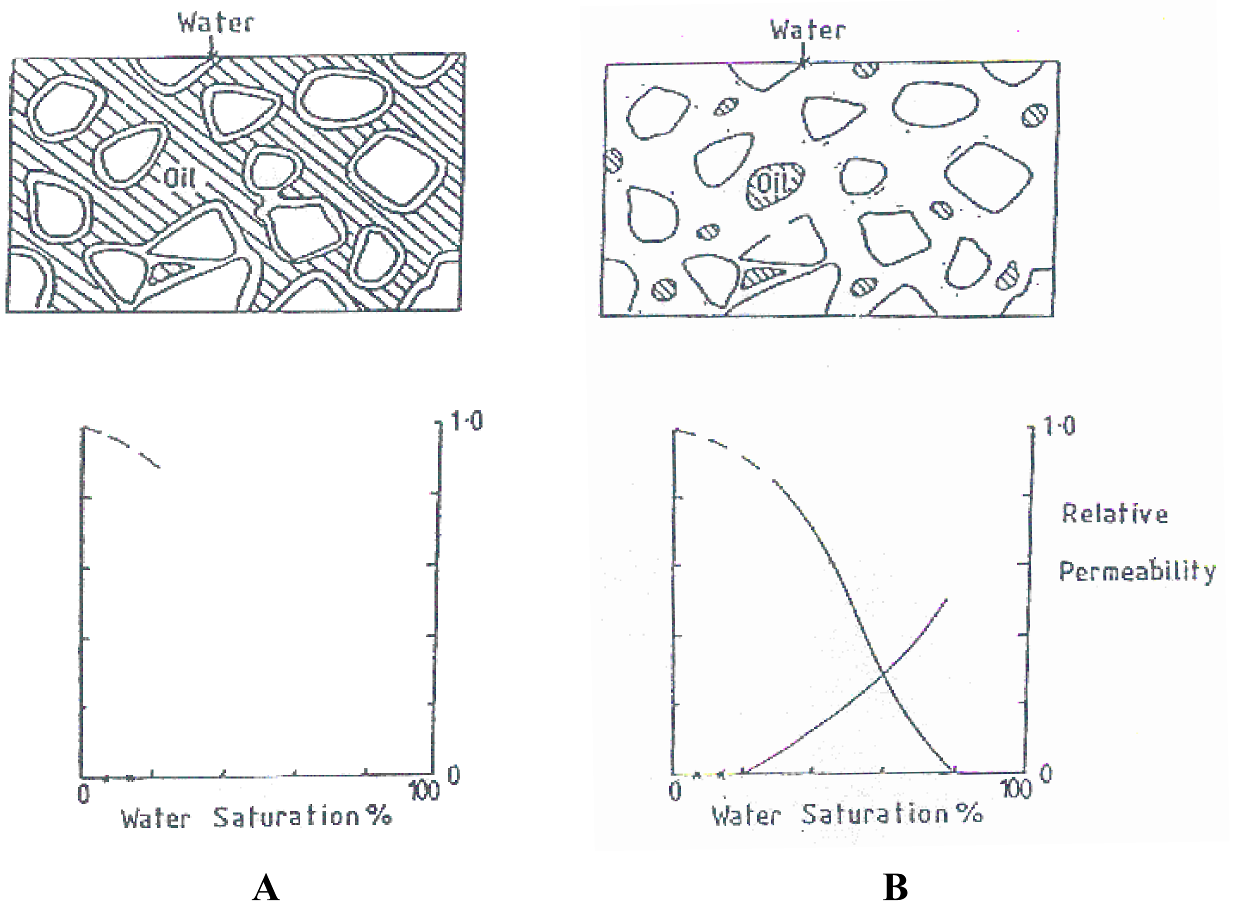


Figure 1.6 Development of Fluid Displacement during Water Injection

**Permeability Problems**

The reservoir engineer's lift would be a great deal easier if all reservoirs were homogeneous. Unfortunately, this is almost never the case. Nearly all reservoirs have ranges of permeabilities. This makes the decision for water quality requirements and management of the injection flood front all the harder.

Water break-though at producers very often occurs because of the more permeable streaks allowing rapid water front movement. If the permeable streak is at the top of a formation there is a good chance that gravity segregation will assist a fairly uniform front. However, if the permeable zones are near the bottom of the formation, them a non-uniform flood front is likely, and break – through may well be premature.

Consequently, the completion and control of the injection well profile is very important. Some operators may prefer not to perforate a high permeability channel. This may work if vertical permeability is poor, but if this is not the case, then water is likely to rapidly find its way into the high permeability zones. Other attempts at control are cementation squeezing of the high permeability channels, or polymer / Chemical control. Unfortunately, no definite remedy is available. Every field has to be looked at on its merits, and even then, very often no satisfactory answer will be found.

## 1.4 RESERVOIR DRIVE MECHANISMS

For movement of fluid through a reservoir rock, there must be a pressure differential across the length of a rock face. This pressure differential can be brought about artificially, or can occur naturally, without any man- made interference.

Around a well-bore, when a well is allowed to flow, there tends to be a reduction in pressure as fluids flow into the production tubulars. If the reservoir pressure, resulting from the height of the fluid column, rock compression and reservoir fluid movement, is greater than the pressure required to support the fluid column in the well-bore, then the fluid should flow naturally from the wellhead.

As fluids are produced from the reservoir, a number of factors will influence the remaining reservoir pressure as it being to decrease.

If the reservoir is entirely enclosed on all sides by an impermeable rock, then the reservoir pressure is rapidly deleted purely by fluid expansion, and equilibrium conditions will be rapidly obtained, with minimum amount of natural fluid production.

If, on the other hand, there is a natural water drive, the produced fluids are rapidly replaced, and the reservoir pressure need hardly decrease.

Thirdly, an artificial waterflood may be introduced at another well. This water serves not only to maintain reservoir pressure, but also help sweep the hydrocarbons towards the producer.

The physical properties of the rock will also control the fluid flow. All reservoirs are heterogeneous and permeability alters both horizontally and vertically. However, because of the method of horizontal deposition of the same type of rock at the same geological time, beds over a lateral area tend to have similar permeabilities. Because of this deposition, there are almost certain to be high permeability and low permeability layers, varying in thickness.

The changing properties of the different layers may cause a variety of problems to the downhole production engineer. A high permeability layer is likely to produce more fluids, more rapidly than a low permeability layer. At the same time, however, the more productive layer is likely to accept more injected water or natural aquifer water. This will cause water break through at the producing well , often while vast amounts of oil still exist within the tighter layers .This water break through brings into the producing well heavier fluids , which in turn cause a heavier producing column, more back pressure on the production formation and an eventual killing of natural production .

The production engineer has to get round these problems as best he can either by attempting to control the injection fluid flood front by careful perforation of different producing zones, or by chemical control.

Almost unquestionably a natural water drive is the most effective, and eventually likely to produce maximum oil recovery. This unfortunately, is rarely more than about 40% of the total oil-in-place in the reservoir Different drive mechanisms will control the overall recovery. These drives are now briefly discussed.

## 1.4.1 Natural Water Drive

In permeable rock, over geological time, fluids are continually moving. These waters may be continually replaced from nearby surface out – cropping rock layers, where surface run off water enters the rock and seeps into the aquifers (artesian water drive). Alternatively they may be moved through the deeper aquifer rocks by overlying compaction or earth movements.

Since oil floats on water, when the water comes into contact with the hydrocarbons, it will tend to support the oil column pressure rise from beneath the complete surface of the oil water contact (OWC). Consequently , as oil is produced , the OWC will move up remaining near horizontal (depending on reservoir characteristics already discussed) and the overall recovery of the oil , and its displacement from the reservoir pores will be high (**Figure 1.7**).

The natural water drive meanwhile will tend to maintain the overall reservoir pressure, which may not drop more than 30%, or so, of the original pressure. SO long as gas does not come out of solution during this pressure drop, the overall recovery from a reservoir undergoing natural water drive may be as high as. 40–45% of oil-in-place

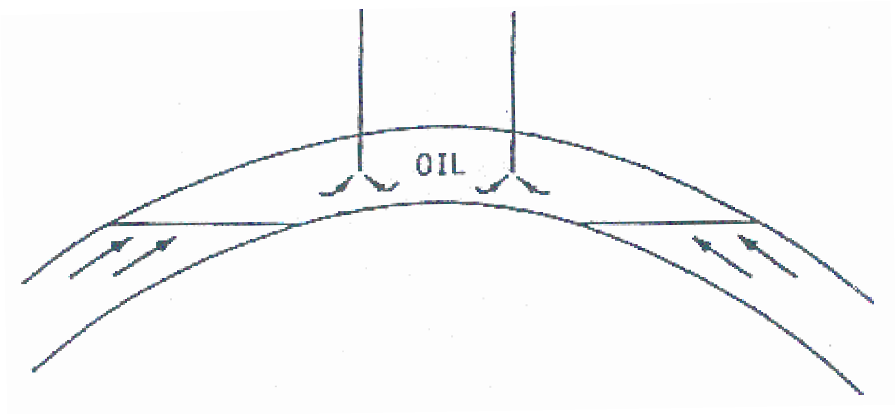


**Figure 1.7 Natural Water Drive**

## 1.4.2 Dissolved Gas Drive

If on other hand there is no natural water drive to help maintain reservoir pressure and efficiently help flood the oil from the reservoir pores, then other mechanisms occur naturally which help produce the oil.

Most oil accumulations have, or did have, gas dissolved in solution with the oil. This gas will come out of solution when the reservoir pressure decreases - in much the same way that a bottle of carbonated water will release carbon dioxide, with a certain amount of forming when the pressure is released.

At the production well the pressure will rapidly decrease, until the saturation pressure is the pressure at which gas will start coming out of solution. It is sometimes referred to as the bubble point pressure. Form that time the amount of liquid oil that is produced is very low, due to the relative permeability effects of the gas and oil.

The oil will tend to be isolated in large pockets, while the gas forms a continuous gas passage to the production well bore. This gas path is fed by more gas breaking out of solution away from the well bore and further isolating more oil.

Consequently, the reservoir pressure drops quickly related to the amount of oil produced (**Figure 1.8**) and total production will rarely exceed 20% the initial oil – in place. At the same time, the ratio of gas produced to oil (GOR) increases rapidly and the value of the fluids produced at the wellhead is severely diminished.

Such a natural dissolved gas drive is very uneconomical, and should be avoided if at all possible. The most commonly used method of avoiding this problem to carry out an artificial water flood at a very early stage. If sufficient water is injected, related to the total fluid off-take, then the saturation pressure may never be reached, and theoretically the reservoir should behave in a very similar manner to that of the natural water drive recovery mechanism.

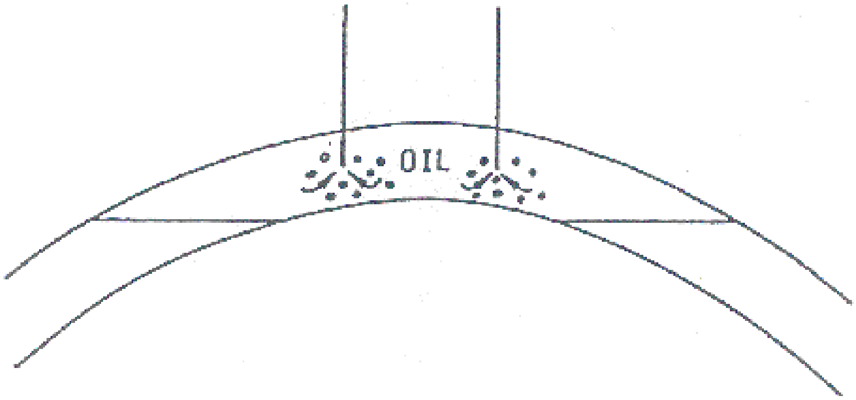


**Figure 1.8 Natural Dissolved Gas Drive**

### 1.4.3 Gas Cap Drive

It is not uncommon for a hydrocarbon accumulation to be associated with a gas cap, **Figure 1.9**. This in itself will present completion problems. Gas coning into the upper perforation tends to be a more common problem than water coning up to the bottom perforation. Both however, should be prevented if at all possible.

Under a gas cap drive the gas tends to expand downwards as the oil is extracted and the reservoir pressure decreases. If the vertical permeability was uniform across the field and there were no high or low permeability streaks, then the gas oil contact (GOC) would remain reasonably level, except at the well bores. As such, a reasonable oil sweep might be expected. However, gas having a very low viscosity in relation to oil will tend to finger rapidly, and oil is quickly left behind and becomes unrecoverable.

**Figure 1.9** shows that the total recovery under a gas cap drive tends to be about midway between a natural dissolved gas drive and a natural water drive. Eventually, of course, gas control will breakdown, and gas will either come down or break out of solution around the well bore. This will then cause a high GOR and the rapid loss in reservoir pressure for precious little extra oil recovery.

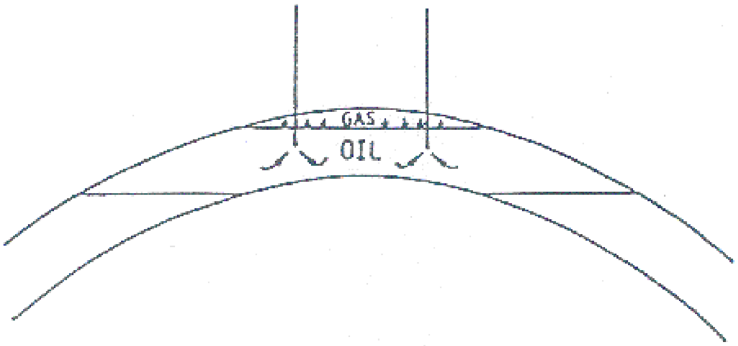


Figure 1.9 Gas Cap Drive

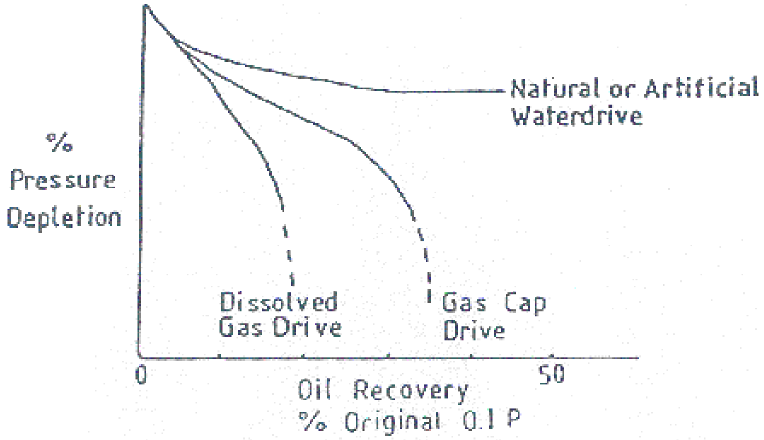


Figure 1.10 Drive Mechanism Pressure Trends

### 1.4.4 Combination Drive and Water Injection

Rarely will just one reservoir drive mechanism occur alone. It is not unusual to have a reservoir where all three natural mechanisms could. The decision to inject water is nowadays often taken at a very early stage, after reservoir engineers have evaluated the performance of a reservoir from a few early well tests.

Clearly if a reservoir can be kept above the bubble point even around a well bore, then the overall recovery can be improved and the economics of development perhaps justified .Sometimes, engineers will allow a reservoir to produce naturally under a dissolved gas drive until the pressure has dropped considerably, but not down to the bubble point. With a lower pressure, the power requirements to injected water are probably decreased.

A natural water drive, to a greater or lesser extent, tends to be present in most reservoirs. If to a lesser extent, then an artificial drive may be installed to support the flood. If the natural water flood is limited because of poor vertical permeability across the OWC, then there is of ten a need to injected at, or just above, the OWC? If, however, there is simply not the water pressure beneath to support the intended oil off take, then water is generally injected just below the OWC. As a rule of thumb, if the aquifer support volume is 40 times that of the oil reservoir volume, then natural water drive may be effective, assuming other characteristics are suitable.

### 1.4.5 Flood Patterns

The flood pattern defines the location and injection interval determined for each particular oilfield. The type of pattern chosen is based on careful reservoir engineering evaluation, often using complex models that will predict the overall reservoir performance and expected oil recovery over the producing life of the field.

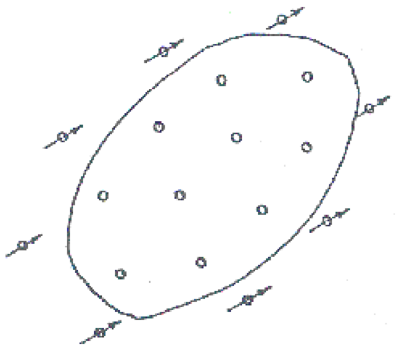
One of the most basic decisions required for a waterflood project, is whether to inject above or below the OWC. This decision, besides being based on overall recovery efficiency, must take into consideration the rock properties. Very often, because of diagenesis, the pore sizes and cement type will differ across the OWC. Once oil has migrated into a trap from its source rock, there is still a high chance that aquifer water beneath the oil will carry on moving, the salinity slowly changes and interaction between rock and interstitial fluids continue. This consequent can cause the formation of clays beneath the OWC, and / or reduction in pore sizes by additional cementation. Indeed, there is case where the permeability beneath the OWC has been reduced so much that no pressure support is contributed by the associated aquifer. Under such conditions but would provide no worthwhile recovery anyway, because of lack of communication.

The pattern flood configurations used by operators are numerous, ranging from the straight forward line floods through spot configuration floods, to peripheral and even unplanned floods. Some of the more common are now briefly discussed.

### 1.4.5.1 Peripheral Flood

This flood type is common in a dome accumulation, where water is injected around the outside of an oil deposit, and down-dip. The decision to inject above or below the OWC will have to be made. Very often as down –dip producers water out they are re-completed as water injectors.

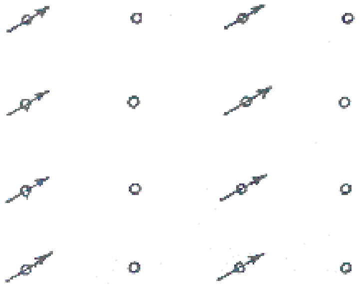
In the case of offshore fields, the peripheral flood often means that he water injection wells are the most deviated. This will, of course, cause inherent problems with drilling and logging, all of which must be taken into account in the planning stage.



Oil recovery by peripheral flooding is often very good. In fact, the Secondary recovery process is tending to support or replace a natural rise in the OWC as the oil is extracted from the up –dip areas of the dome.

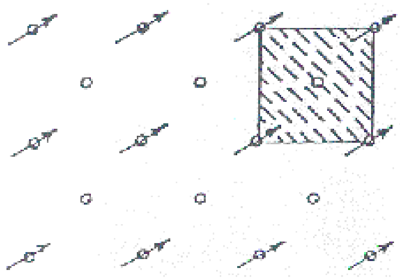
### 1.4.5.2 Line Drive

Figure below shows the line drive configuration. This pattern is often adopted in fairly flat thin homogenous sands. Water is injected into the oil zones and displaces oil laterally in a line flood front towards the producers. As long as the basic required reservoir parameters, already mentioned, are present then the process is reasonably efficient. However, if there is a high permeability streak then premature breakthrough may occur causing difficulty in achieving efficient recovery and requiring complex completion controls.



### 1.4.5.3 Five-Spot

This pattern is very often adopted for a pilot trial, before drilling the necessary infill injection wells to carry out a total 5- spot field flood. Sometimes an operator may prefer to inject to one well with 4 surrounding producers, as a pilot trial. This configuration is called an inverted 5- spot, where the four surrounding producers all gain advantage from the one injector.



A well laid out 5-spot pattern very often produces a good recovery, and the field is efficiently produced. The disadvantage can be that the increased plateau production period related to the water flood is fairly short lived before water breakthrough (depending on the proximity of injector to producer) and of ten results in the requirement for the early initiation of artificial lift.

# Chapter 2

# Petroleum Reservoirs

# ***Chapter 2 Contents***

## Chapter 2

# Petroleum Reservoirs

A petroleum reservoir is a trap containing gas, oil, and water in varying proportions. These fluids are contained in the pore spaces of rock formation among the grains of sandstones or in the cavities of carbonates. The pores spaces are interconnected so that the fluids can move through the reservoir. The porous formations have to be cut off on all sides, above and below, in such a way that the only escape for the fluids will be through a well-bore drilled into the reservoir.

## 2.1 PHYSICAL CHARACTERISTICS

In order to have a producing oil reservoir, the following conditions must exist:

1. There must be a body of rock having sufficient porosity to contain the reservoir fluids and permeability to permit their movement.
2. The rocks must contain oil or gas in commercial quantities.
3. There must be some natural driving force within the reservoir, usually gas or water.

Special attention should be given to the natural driving force. Oil in itself does not have such force or energy, it cannot move itself. Only the energy stored in the reservoir in the form of gas or water under pressure can move the oil to the well. When this energy has been spent, only the slow method of gravity drainage remains to get the oil to a well-bore. Gravity does not always work to move oil in the right direction to reach a well.

## 2.2 RESERVOIR PRESSURE

The fluids in the pores of a reservoir rock are under a certain degree of pressure, generally called reservoir pressure or formation pressure. A normal reservoir pressure at the oil-water contact approximates very closely the hydrostatic pressure of a column of saltwater to that depth. The hydrostatic pressure gradient varies somewhat, depending upon the amount of dissolved salts in the average water for a given area. For fresh water it is 0.433 psi/ft of depth, but for water containing 80,000 ppm of dissolved salts (Gulf Coast) the pressure gradient is approximately 0.465 psi/ft. However, normal fully marine water is about 35,000 ppm dissolved salts, and hence approximately 0.446 psi/ft. Reservoirs can contain fluids under abnormal pressures up to as high as 1.00 psi/ft of depth.

Abnormal pressures may develop in isolated reservoirs as a result of compaction of the surrounding shales by the weight of the overburden. During this process water is expelled from the shale into any zone of lower pressure. This may be into wholly confined sandstone which does not compact as much as the shale; consequently, its contained water is under a lower pressure than that in the shale. Ultimately, a state of equilibrium can be reached when no further water can be expelled into the sandstone, and its fluid pressure will then approximate that of the shale.

Since compaction of sandstones is related to the pressure of the pore fluid as well as to the pressure exerted by the overburden, it follows that abnormally pressured sandstones are partly supported by the fluid pressure and partly by grain-to-grain contact. Consequently, when the abnormal pressure is reduced by production, compaction of the reservoir bed immediately begins to occur. Subsurface compaction can cause serious problems not only because of collapse of casing in wells, but also because it is reflected at the surface by subsidence. Such occurrences result in very expensive landfill and well repair costs. It has also been demonstrated that there can be a direct relationship between subsidence and the amount of liquid withdrawn. Thus some permanent reduction of porosity and permeability results from permitting abnormal reservoir pressures to decline, and this may adversely affect the rate of production and possibly the ultimate recovery.

## 2.3 OIL FIELD FLUIDS

The distribution of fluids will be different for each pool, depending on:

- Source rock
- Reservoir rock
- Porosity
- Permeability
- Relative permeability of reservoir fluids
- Relative densities
- Hydrodynamics of the reservoir
- Migration variables (lithology, temperature, etc.)

By definition, a fluid is any substance that will flow. Oil, water and gas are all fluids by this definition. Oil and water are liquids as well as fluids, but gas is a fluid though not a liquid.

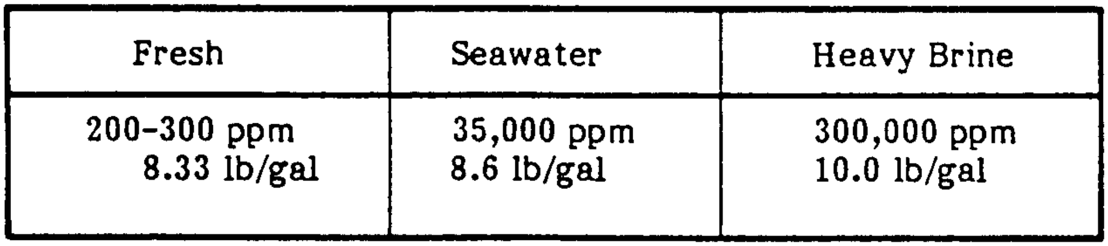
### 2.3.1 Reservoir Water

Many oil reservoirs are composed of sediments which were deposited on the floor of seas and oceans; consequently, these sedimentary beds were originally saturated with saltwater. Part of this water was displaced in the process of the formation of oil accumulations. That which remained in the formation has been given the name of connate interstitial water, "connate" from the Latin meaning "born with" and "interstitial" because the water is found in the interstices, or pores, of the formation. By common usage this term has been shortened to "connate water" and always means the water in the formation when development of the reservoir was started. Connate water determinations (Sw) using core samples are expressed as a percentage of the volume occurring in the pore spaces of the reservoir. Swi (irreducible connate water saturation) is the fraction of pore space which may be retained as non-movable wetting phase even though oil and gas may be flowing in the same pore spaces under the influence of relatively large pressure gradients. In addition to the connate water distributed throughout the pay section with the oil and gas, nearly all petroleum reservoirs have water-bearing formations down-dip from the pay-zones. All the pore spaces of such formations are filled with water. It is this volume of "free" water which supplies the energy for the "water drive" in some reservoirs. With this "water drive mechanism," as some hydrocarbons are liberated via the well-bore the water rushes into the vacated pore spaces, increasing in volume and pushing more hydrocarbons to the surface.

The character of reservoir water is determined by

- Water saturation
- Concentration of dissolved solids
- Composition of dissolved solids

Water saturation (Sw) is determined directly by core analysis or indirectly from bore-hole logging tools. Concentrations of dissolved solids are analyzed directly by use of a hydrometer and indirectly with a resistivity tool to measure the resistivity of water (Rw). Resistivity of water in the interstitial pore space is a measure of all ions and is therefore an indirect measure of dissolved solids. Density increases with increased dissolved solids **Table 2.1**.



| Fresh | Seawater | Heavy Brine |
|---|---|---|
| 200-300 ppm<br>8.33 lb/gal | 35,000 ppm<br>8.6 lb/gal | 300,000 ppm<br>10.0 lb/gal |

**Table 2.1 Dissolved Solids (Concentrations)**

Dissolved solid composition can only be analyzed using water directly from the well. As all brines have similar ionic analyses even though the total concentrations may differ greatly, it suggests they are all diluted forms of the same original water, i.e., seawater.

The oil-water contact is always transitional and may be from two feet to several hundred feet thick.

## 2.3.2 Reservoir Oil and Gas

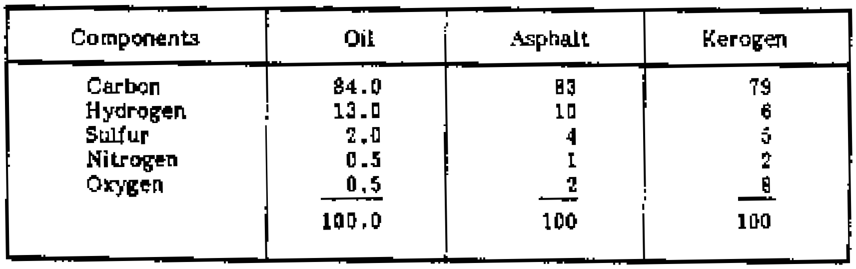
The relationship between oil and gas in the reservoir depends upon the degree to which the oil is saturated with gas, i.e., the amount of "dissolved gas" contained in the liquid oil. Natural gas is always associated with oil (yet oil is not always associated with gas), and the energy supplied by gas under formation hydrostatic pressure is probably the most valuable drive in the withdrawal of oil from reservoirs.

Gas is associated with oil and water in reservoirs in two principle ways, as "solution gas" and "free gas" in gas caps. Given suitable conditions of pressure and temperature, natural gas will "stay in solution" in oil in a reservoir. High pressure and low temperature are favorable conditions for keeping gas in solution. When the oil is brought to the surface and the pressure relieved (as in a separator), the gas comes out of solution.

Free gas tends to accumulate in the highest structural part of a reservoir and form a gas cap. As long as there is free gas in a reservoir gas cap, the oil in the reservoir will remain saturated with gas in solution. Having gas in solution lowers the viscosity of the oil, making it easier to move to the well-bore.

## 2.3.3 Composition of Petroleum

Petroleum is basically composed of carbon and hydrogen with minor amounts of sulfur, nitrogen and oxygen (**Table 2.2**). An increase in minor elements decreases the value of crude.



| Components | Oil | Asphalt | Kerogen |
|---|---|---|---|
| Carbon | 84.0 | 83 | 79 |
| Hydrogen | 13.0 | 10 | 6 |
| Sulfur | 2.0 | 4 | 5 |
| Nitrogen | 0.5 | 1 | 2 |
| Oxygen | 0.5 | 2 | 8 |
|  | 100.0 | 100 | 100 |

**Table 2.2 Chemical Composition of Oil, Asphalt and kerogen**

Hydrocarbons (compounds of carbon and hydrogen only) make up over 90 percent of most crude oils. The hydrocarbons in crude oils vary in molecular size and molecular type (**Table 2.3**).

| Molecular Size | Weight % |
|---|---|
| Gasoline ($C_4$-$C_{10}$) | 31 |
| Kerosene ($C_{11}$-$C_{12}$) | 10 |
| Gas Oil ($C_{13}$-$C_{20}$) | 15 |
| Lubricating Oil ($C_{20}$-$C_{40}$) | 20 |
| Residuum ($>C_{40}$) | 24 |
| | 100 |
| **Molecular Type** | |
| Paraffins | 30 |
| Naphthenes | 49 |
| Aromatics | 15 |
| Asphaltics | 6 |
| | 100 |

**Figure 2.3 Composition of a Typical Crude Oil**

## 2.3.4 Source of Petroleum

Petroleum originates from a small fraction of the organic matter deposited in sedimentary basins. Most of this organic matter is the remains of plants and animals that lived in the sea, and the rest is land-delivered organic matter carried in by rivers and continental runoff, or by winds. Living organisms are composed of carbohydrates, proteins, and lipids (fats) and lignin in varying amounts. These compounds are degraded by micro-organisms into the monomer sugars, fatty acids, etc. These immediately condense into nitrogenous and humus complexes, progenitors of kerogen. Some hydrocarbons are deposited in the sediments, but most form from thermal alteration at depth. Lipids are closest to petroleum in composition among the major life substances (**Table 2.4**).

| Substance | Elemental Composition in Weight (%) | | | | |
|---|---|---|---|---|---|
| | C | H | O | S | N |
| Carbohydrates | 44 | 6 | 50.0 | --- | --- |
| Lignin | 63 | 5 | 31.0 | 0.1 | 0.3 |
| Proteins | 53 | 7 | 22.0 | 2.0 | 16.0 |
| Lipids | 80 | 10 | 10.0 | --- | --- |
| Petroleum | 82-87 | 12-15 | 0.1-2.0 | 0.1-5.0 | 0.2 |

**Table 2.4 Average Chemical Composition of Natural Substances**

Petroleum contains traces of several substances that could have come only from living things. Examples of these are:

- Porphyrins related to hemin and chlorophyll
- Optically active compounds (compounds that will rotate the plane of a ray of polarized light)
- Structures related to cholesterol, carotene and terpenes
- A predominance of odd-numbered paraffin chains

Carbon isotope data suggests that the lipids of plants are an important source of petroleum.

Normal (straight chain) paraffins in crude oil sometimes show a predominance of odd-numbered chain lengths. This odd-numbered chain length has a biochemical origin and tends to predominate in the high molecular weight ranges in oils derived from continental or near-shore organic matter and in the low ranges for marine organic matter.

## 2.3.5 Origin of Gases

The following discussion presents generally accepted theories for the origin of gases. Methane is formed by bacterial decay of organic material; it is a major product of the diagenesis of coal and is given off by all forms of organic matter during diagenesis. It is the most common hydrocarbon in subsurface waters and is an end product of petroleum metamorphism. When heated, the kerogen in shales from gas-producing areas gives off much greater quantities of methane as compared to the kerogen of shales from oil-producing areas.

Hydrogen sulfide originates from the reduction of sulfate in the sediments and from sulfur compounds in petroleum and kerogen. Carbon dioxide is from the decarboxylation of organic matter, and from $HCO_3$ and $CaCO_3$. Nitrogen is from the nitrogen in organic matter and from trapped air. Helium is from the radioactive decay of uranium and thorium. During the oil genesis and coalification process, the order of generation is generally nitrogen, $CO_2$ and methane.

## 2.3.6 Occurrence of Petroleum

Only about 2 percent of the organic matter dispersed in fine-grained rocks becomes petroleum, and only about 0.5 percent of that ends up as a commercial reservoir accumulation. This emphasizes the inefficiency of the origin, migration and accumulation process.

The ratio of dispersed hydrocarbons to reservoired hydrocarbons is about 200 to 1 on a worldwide basis, partly because the volume of potential reservoir rock is small compared to total sediments in the earth's crust. Within prospective parts of oil-forming basins, the ratio generally varies between 10 and 100.

Petroleum is found from the Precambrian to the Pleistocene, but it is increasingly abundant in younger sediments for several reasons, such as:

- Older oilfields are increasingly destroyed over geologic time
- An increase in continental margins and restricted basins occurred when the continents split during the Jurassic.

## 2.3.7 Factors Which May Affect Crude Oil Gravity

The following factors are all interrelated in too complex a manner to take each as being more than a rough generalization. Formation temperature and pressure seem to be very influential. If they are high, gravity is usually high. Also note the concept of maturity, old oils, which tend to be paraffinic, are more stable and tend to have higher gravity.

- ***Geological age (maturity):*** Older rocks tend to have higher gravity, but many tertiary rocks have API°40 + (e.g., the North Sea); and many Paleozoic rocks have API°20 -.

- ***Depth of burial:*** Deeper reservoir, higher gravity. Deepest wells tend to produce gas.

- ***Basinal position:*** Gradient from high at the center to low at the edges.

- ***Tectonism:*** High gravities are more common in regions of high stress.

- ***Lithology:*** No apparent relationships.

- ***Salinity:*** Marine source tends to higher gravity than fresh/brackish; may be due to basinal position.

- ***Sulfur content:*** This is high in low-gravity crudes. Main variations are regional, e.g., Middle East crudes are high in sulfur, Nigerian and Libyan crudes are low.

# 2.4 BASIC HYDROCARBON NOMENCLATURE

Petroleum is composed of two elements, hydrogen and carbon, Joined together in compound called hydrocarbons. Two simple ways of looking at these hydrocarbons is by ratio and by weight.

The average ratio of hydrogen to carbon in petroleum hydrocarbons is 2 to 1. This means that although specific compounds may vary, crude have about two atoms of hydrogen for every atom of carbon.

A single carbon atom weights 12 times as much as a hydrogen atom. Thus, despite the 2 to 1 ratio of hydrogen to carbon in 100 pounds (45 Kilograms) of crude oil, roughly 84 pounds (38 kilograms) will be carbon and 14 (6 Kilograms) will be hydrogen. The remaining 2 pounds (1 kilogram) are various impurities and must be greatly reduced because they are harmful to the environment and corrosive to both refining equipment and the machinery in which products must ultimately be used. These impurities include sulfur (0 – 3 lb.), Nitrogen (0 – 1 lb.), oxygen (0 – 0.5 lb.), and Chlorine. Nickel, vanadium, iron, copper, and other metals in traces so small they are measured in parts per million or parts per billion.

## 2.4.1 Classification of Hydrocarbons

There are so many different hydrocarbon compounds in crude oil that scientists can only guess at the exact number. Estimates range from 20,000 to 5,000,000 somewhere between 50,000 and 1,000,000 is a reasonable guess, with so many compounds, it's necessary to have systematic ways to classify them into manageable groupings. The two basic systems used are by carbon number and by molecular structure.

***Carbon Numbers***

The simplest classification is by carbon number. This is based on the number of carbon atoms found in a given hydrocarbon molecule. For example, methane ($CH_4$) has one carbon atom per molecule and is $C_1$. Ethane ($C_2H_6$) and Ethylene ($C_2H_4$), through different compounds with different properties, are both classified $C_2$'s.

The carbon number is important because it indicates the physical state of the compound. Basically, the higher the carbon number (i.e., the more carbon atoms per molecule), the higher the boiling point, the greater the viscosity (the rate at which it will flow through a small opening) and the higher the density (weight per volume).

Compounds from $C_1$ to $C_4$ are gases at room temperature. Those from $C_5$ to $C_{17}$ are liquids, through some $C_{17}$'s may be solid. And those from $C_{17}$ to $C_{40}$ are solids. These solids are not like steel or concrete, but more like wax. They can be penetrated with a sharp instrument, but they won't pour or flow unless heated.

**$C_1$ (Methane)** is used as a fuel in the refinery in addition it can sold and transported by liquefying it by lowering its temperature to –255ºF(–159ºC). This reduces its volume by a factor of 1000 and there by simplifies transportation.

**$C_2$ (Ethane)** is used as a refinery fuel; $C_2$ Ethylene is used in making polyethylene and other plastics.

**$C_3$'s (Propane and Propylene)** are used in plastics manufacture; propane can also be liquefied for sale as LPG (Liquefied Petroleum Gas).

**$C_4$'s (Butane and Butylenes)**, the largest gas molecule at room temperatures, can be combined to from $C_8$'s (liquids) for use in gasoline. $C_4$'s can also be added directly to gasoline to increase vapor pressure for better starts on cold mornings.

**Materials from $C_5$ to $C_{12}$** are used directly in gasoline manufacture

**Materials from $C_{13}$ to $C_{17}$** are used as fuels and lubricants.

**Materials from $C_{17}$ to $C_{40}$** are used for heavy fuels and asphalts. They are also used as charge stocks for refinery processes that break them down into smaller compounds with lower carbon numbers (the $C_5$ to $C_{12}$ liquids) for use in Gasoline.

### ***Molecular Structure***

A second, more complicated way to classify hydrocarbon compounds is by their molecular structure, the actual arrangement of the carbon and hydrogen atoms.

These atoms can combine in a number of ways to satisfy valence requirements. For convenience, these are separated into "families" or homologous series, each of which is given a name.

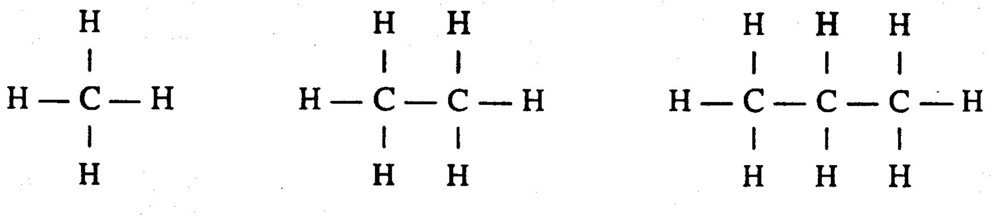
Every atom has the capacity to combine with a given number of other atoms; this is its valence number. The valence of hydrogen, for instance, is 1. One way of looking at that is to say it has a “hand” that can join with a “hand” from another atom to from a valance bond. Carbon has valence of 4 which means that each carbon atom can combine with four other atoms.

The carbon atoms can link together to form "chains" or "rings." Crude oil and natural gas mixtures consist primarily of "straight chain" hydrocarbon molecules, the bulk of which are paraffins.

## 2.4.2 Paraffin Series Formula: $C_nH_{2n+2}$

Paraffins, also called ***alkanes***, were named when early chemists through these compounds were relatively inactive.

Hydrocarbons in this series are ***saturated*** compounds - all four carbon bonds are connected either to another carbon atom or a hydrogen atom, with one such atom for each bond



**Methane** **Ethane** **Propane**

Notice that, all names end in ***-ane,*** the ending used for the paraffin series. In each case, the number of hydrogen atoms is two times the number of carbon atoms plus two more for the ends of the chain.

The paraffin hydrocarbons are the most stable of the lot because all valence bonds are fully satisfied as indicated by the single line linkage. Most reactions involve the replacement of hydrogen atoms with other atoms; the carbon linkage remains stable.

Each successive molecule in the paraffin series is created by adding a carbon and two hydrogens to the previous molecule. The incremental change in relative molecular weight is thus fourteen. Long chains containing scores of carbon atoms in series may be formed. However, the only ones normally identified by name contain ten or less carbons (**Table 2.5**).

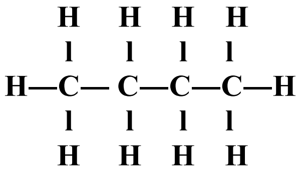
| Name | Formula | Mol. Wt. | Name | Formula | Mol. Wt. |
|---|---|---|---|---|---|
| Methane | $CH_4$ | 16 | Hexane | $C_6H_{14}$ | 86 |
| Ethane | $C_2H_6$ | 30 | Heptane | $C_7H_{16}$ | 100 |
| Propane | $C_3H_8$ | 44 | Octane | $C_8H_{18}$ | 114 |
| Butane | $C_4H_{10}$ | 58 | Nonane | $C_9H_{20}$ | 128 |
| Pentane | $C_5H_{12}$ | 72 | Decane | $C_{10}H_{22}$ | 142 |

**Table 2.5 Paraffin Hydrocarbons Series**

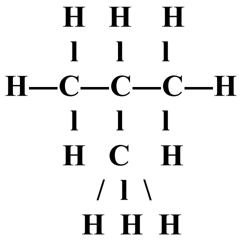
In referring to a given paraffin hydrocarbon, the abbreviation $C_3$ for propane, $C_4$ for butane, etc. may be used. Statements like "propanes plus fraction ($C_3^+$)" refer to a mixture composed of propane and larger atoms.

***Paraffin isomers***: When the paraffin series molecule contains four or more carbon atoms there are different ways these can be connected without affecting the formula. Compounds which have the same chemical formula but a different atomic structure are called isomers. They possess different physical and chemical properties.

There are only two isomers of butane. In the structural diagram shown below for i-butane we could draw the carbon atom below instead of above the carbon chain. But, this would be just a "mirror image" of the molecule as drawn. It is the same molecule with the same properties. The adjective "normal" is used to designate a molecule wherein all of the carbon atoms are in a straight line. An "isomer" has the same formula but a different arrangement of the carbon atoms. In an analysis, these are often abbreviated as "n" and "i" respectively.



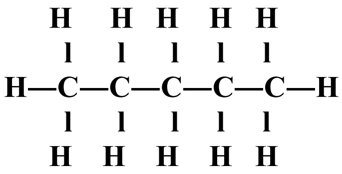
**Normal-butane**
**(n- $C_4H_{10}$)**



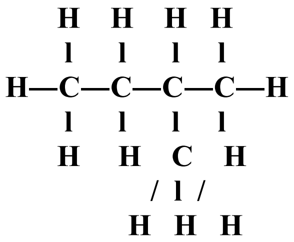
**Iso-butane**
**(i- $C_4H_{10}$)**

Even though these two compounds consist of the same number of carbon and hydrogen atoms they differ chemically and have different boiling points, densities, and refractive indices. Most important from our point of view is that the simple, straight chain paraffin has a much lower octane than the more compact, branched isoparaffins.

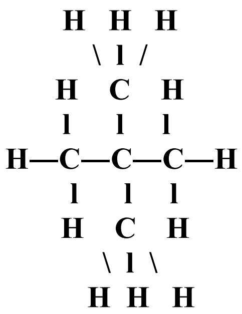
As the carbon number increases, the number of possible permutations (isoparaffins) increases astronomically. There are three combinations for pentanes ($C_5H_{12}$), (normal pentane) and two isopentane (called, by convention, isopentane and neopentane).



**Normal-pentane**



**Iso-pentane**



**Neo-pentane**

Similarly, there are 9 possible combinations for the $C_7$ paraffin, heptanes, 355 for $C_{12}$ and 62, 491, 178, 805, 132 combinations for $C_{40}$.

An important thing to remember is that no matter how complicated or how simple, all Paraffins have the same ratio of two hydrogen atoms for every carbon atom, plus two more hydrogen, one at each end of the chain to fill the remaining valences.

Chemists express this as $C_nH_{2n+2}$, the formula for all Paraffins shown at the beginning of this section. If we have a two carbon atom paraffin, then n=2, thus there will be 2 x 2 + 2 = 6 atoms of hydrogen. $C_2H_6$ is, of course, ethane. You might try going back and checking one or two of the other Paraffins diagrammed above against the formula.

A final point to remember is that the valence bonds of Paraffins are saturated with hydrogen. That is, every carbon atom is holding as much hydrogen as it can; every valence not needed to link it to another carbon atom is linked to a hydrogen atom.

### 2.4.3 Olefin or Ethylene Series (Alkenes) Formula: $C_nH_{2n}$

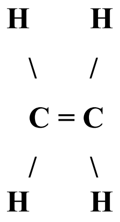
Olefins are the second type of hydrocarbon important to us. Olefins are not found naturally in crude oil, but are the product of the refining process.

The olefin group of compounds is a simple straight chain series in which all the names end in -***ene***. Ethylene (ethene) $C_2H_4$ is the simplest molecule in the series.

Hydrocarbons in this series combine easily with other atoms like chlorine and bromine, without the replacement of a hydrogen atom. Since they are so reactive, they are called ***unsaturated hydrocarbons.***

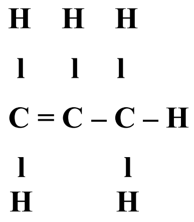
Unlike the paraffins, the maximum bonding capacity of the carbon atom is not fully satisfied by hydrogen or carbon atoms. Two adjacent carbon atoms form a "temporary" bond (in the absence of other available atoms) to meet bonding requirements fixed by valence. It is a necessary but unstable alliance. The structural formula for the olefins uses a double line to indicate the double carbon-carbon linkage, the most reactive point in the molecule.

What distinguishes olefins from Paraffins is that olefins are unsaturated. $C_2$ paraffin, ethane, was saturated because it contained six hydrogen atoms. If we remove two of the hydrogen's and bend the two vacated carbon valence bonds around to join with each other, we create a double bond or unsaturated bond. The resulting compound is ethylene, the $C_2$ olefin.



**$C_2H_4$**

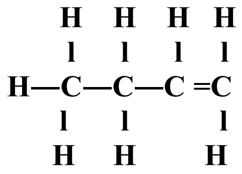
**Ethylene (Ethene)**



**$C_3H_6$**

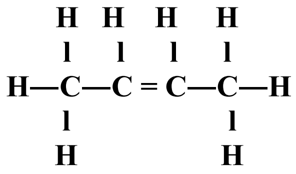
**Propylene (Propene)**

With four or more carbon atoms, isomers also may result from the position of the double bond as well as the arrangement of the carbon atoms.



**$CH_3CH_2CH=CH_2$**

**1-Butene**



**$CH_3CH=CHCH_3$**

**2-Butene**

These molecules possess many different properties. They may furthermore react at the double bond or be split into two molecules at the double bond to form compounds with different characteristics.

Because of the double bond, all olefins contain exactly twice as many hydrogen atoms as carbon atoms. So the chemical formula for all olefins is $C_nH_{2n}$. Propylene and butylenes are the $C_3$ and $C_4$ olefins respectively.

This double bond is also a kind of liability, because it makes olefins less stable than Paraffins. Valence bonds are normally 120 digress apart in three dimensional space. By "bending" the valences around to make them into a double bond, we've created a certain amount of "springiness" in the bond. As a result, when olefins are exposed to sunlight or oxidizing agents, these bonds are prone to springing back and combining readily with other compounds, causing the olefin to lose their double bond.

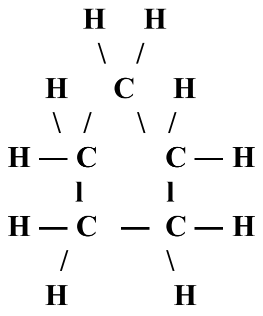
## 2.4.4 Naphthene Series Formula: $C_nH_{2n}$

Naphthenes, the third type of hydrocarbon, have the same ratio of two hydrogen atoms per carbon atom as do olefins. But they are more like Paraffins because they are saturated compounds.

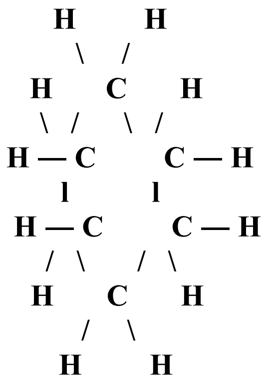
The naphthene series has a ring structure but is saturated. Naphthenes may be found in most crude oils but are seldom shown in routine analyses. Being saturated molecules, they are not very reactive. Cyclohexane is a common member of this series. Its structural formula is $C_6H_{12}$.

Cyclohexane is similar to benzene except that it is saturated. On chromatographic analysis it occurs between n-hexane and n-heptane. Cyclopentane ($C_5H_{10}$) also occurs. On chromatographic analysis it occurs between n-pentane and n-hexane.

It's as though we took a straight $C_5$ to $C_6$ paraffin chain, removed the hydrogen atom from each end, and then bent it around to join the valence of the first carbon atom with the last.



**Cyclopentane ($C_5H_{10}$)**



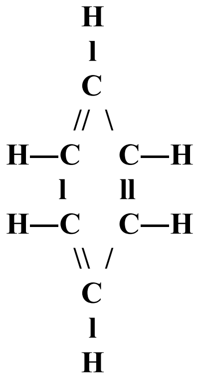
**Cyclohexane ($C_6H_{12}$)**

This distinctive ring shape is why naphthenes are also called cycloparaffins. The two naphthenes above, cyclopentane and cyclohexane, are the basic of all naphthenes, all naphthenes are formed by adding to either a cyclopentane or cyclohexane ring.

## 2.4.5 Aromatic (Benzene) Series Formula: $C_nH_{2n-6}$

Aromatics get their name from the fact that the earliest known members of this class had very strong smells.

Aromatic is the word used to describe an unsaturated hydrocarbon molecule where the carbon atoms form a ring, a cyclic compound. ***Benzene,*** the parent compound of this series, has the structural formula of $C_6H_6$.



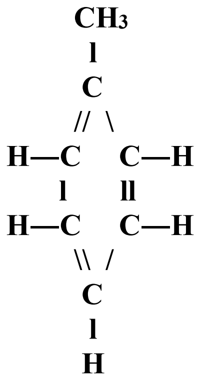
**Benzene ($C_6H_6$)**

Like the naphthenes, benzene has a cyclic structure called a benzene ring. But unlike the naphthenes, the benzene ring has double bonds.

Since the aromatics are ***unsaturated,*** they react readily. They may be oxidized to form organic acids. They also promote foaming and other operational problems in the production and handling of crude oil and natural gas.

Most petroleum contains only a trace of aromatics. Some contain significant amounts. Any analysis of crude oil and natural gas should include aromatics. Even small amounts can influence physical behavior and affect design.

All the aromatics are formed by adding carbons and their associated hydrogen to the benzene ring creating extra branches and even, additional rings. By adding a carbon and two hydrogens, for instance, we get toluene, the only $C_7$ aromatic.



**Toluene ($C_7H_8$)**

## 2.5 PARAFFIN HYDROCARBON COMPOUNDS

In the production, gathering, conditioning, and processing of natural gas and its associated liquids, the primary concern is the behavior of the paraffin series hydrocarbons with 10 or less carbon atoms ($C_1$ –$C_{10}$). This concern includes nitrogen and water and contaminants in the gas, such as sulfur compounds.

Paraffin hydrocarbons are less reactive with other materials than many hydrocarbons, but it must be remembered that they have been in contact with the chemicals present in the reservoir rock for many millions of years. They are also conditioned by use of alcohols, glycols, and amines in which they are soluble and with which they react to some degree.

### 2.5.1 Radicals

A radical represents a group of atoms that act as a single unit in the formation of many common compounds.

***Alkyl Radical:*** At least the simpler paraffins often react by replacing one hydrogen with some other radical or element. This alkyl radical has the formula:

| | | | | |
|---|---|---|---|---|
| $C_nH_{2n+1}$ | : | $(CH_3)$, | $(C_2H_5)$, | $(C_3H_7)$ |
| | | Methyl | ethyl | propyl |

The parenthesis indicates the radical group. The alkyl radical normally has a valence of +1.

In many cases the alkyl radical is indicated by the symbol "R." The formula for methanol is $CH_3$ OH; for ethanol it is $C_2H_5OH$. Both may be written as ROH. When "R" is used, one cannot identify the specific alkyl radical. It is used only to show general reaction characteristics.

***Hydroxyl Radical,*** (OH). This combination occurs in many common compounds. It combines with hydrogen to form water - H (OH) or $H_2O$; with metallic salts like sodium, calcium and magnesium to form hydroxides (bases, caustics); and with alkyl radicals to form alcohols, such as methanol, ethanol, etc.

***($SO_4$), ($CO_3$).*** If radicals like these combine with hydrogen, an acid is formed. When combined with metallic salts like sodium, calcium, and magnesium, a salt is formed (which occurs commonly in water systems). The scale formed in water systems is caused by precipitation of salts like these. The common names for some common radicals of this type are:

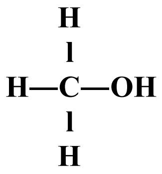
$SO_4$ - sulfate
$SO_3$ - sulfite
$CO_3$ - carbonate
$HCO_3$ - bicarbonate

Each of the radicals has a valence found from the valence of its elements. The hydroxyl radical has a valence of minus one and is sometimes written as $(OH)^{-1}$.

It therefore combines in proportions fixed by this valence:
$H(OH)$, $NaOH$, $Mg(OH)_2$ - so that the sum of plus and minus valences equals zero.

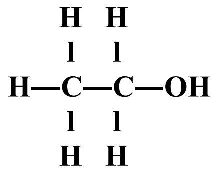
## 2.5.2 Alcohols

The common alcohols are formed from the addition of a single hydroxyl radical to an alkyl radical. The name of the alcohol ends in "ol," or the name of the alkyl radical is followed by the word "alcohol."



$$\begin{array}{ccccc} & & H & & \\ & & | & & \\ H & - & C & - & OH \\ & & | & & \\ & & H & & \end{array}$$

**$CH_3OH$**
**Methanol**
**(methyl alcohol)**



$$\begin{array}{ccccccc} & & H & & H & & \\ & & | & & | & & \\ H & - & C & - & C & - & OH \\ & & | & & | & & \\ & & H & & H & & \end{array}$$

**$C_2H_5OH$**
**Ethanol**
**(ethyl alcohol)**

Both $C_2H_5OH$ and $CH_3OH$ could be written as ROH in denoting the general reaction of an alcohol.

## 2.5.3 Mercaptans

Compounds with the general formula RSH are known as mercaptans. They may be regarded as sulfur alcohols since the formula is the same if you replace the oxygen atom in the (OH) radical by a sulfur atom.

Formulas for typical mercaptans are:
$CH_3SH$ - methyl mercaptan
$C_2H_5SH$ - ethyl mercaptan

## 2.5.4 Other Carbon-Sulfur Compounds

There are several other carbon-sulfur compounds present in sour petroleum fluids. Some are:

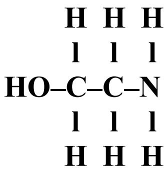
Carbonyl sulfide - COS
Carbon disulfide - $CS_2$
Thiophene - an unsaturated compound having the formula:

$$H_2C = CH - S - HC = CH_2$$

Sulfur is a very reactive element that combines chemically with many other elements and compounds. Its compounds react with carbon steel to form sulfides and oxides of iron. Many compounds polymerize and form the "sludge" so common in sour petroleum systems. This sludge is often very corrosive and should be removed by filtration.

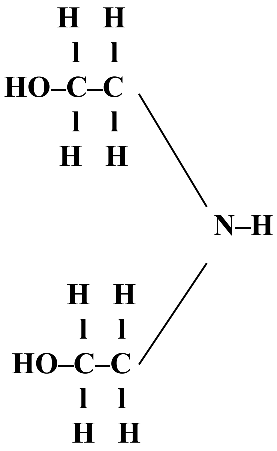
## 2.5.5 Organic Nitrogen Compounds - Amines

There are a number of common organic compounds formed by the reaction of organic materials with ammonia ($NH_3$). In this basic reaction one or more hydrogen atoms are replaced by an organic radical. The word "amine" is used commonly to denote this type of compound. There are a large number of amines used in the chemical industry.



**$HOCH_2CH_2NH_2$**

**Monoethanolamine**



**$(HOCH_2CH_2)_2NH$**

**Diethanolamine (DEA)**

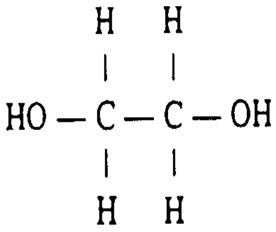
The alkanolamines are commonly used for treating sour gases and liquids, particularly monoethanolamine and diethanolamine. As the names indicate, the alkanolamines may be considered a combination of an alcohol and ammonia.

Notice that the only difference in the above compounds is how many hydrogen atoms of ammonia are replaced by the radical ($C_2H_4OH$), ethanol minus one hydrogen atom.

## 2.5.6 Glycols

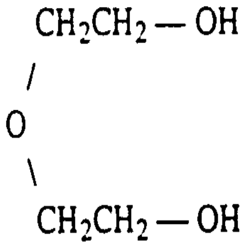
The glycols are a family of chemicals, sometimes called diols. They may be regarded as complex alcohols since they contain alkyl and hydroxyl radicals. The glycols used for dehydration are based on the ethyl radical.

As with most compounds containing hydroxyl groups, the glycols react readily with other compounds and elements. In DEG and TEG the oxygen atom also is very reactive.



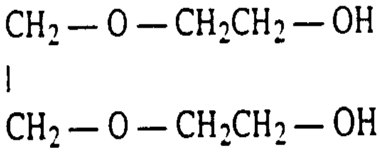
$$\begin{array}{ccccccc} & & H & & H & & \\ & & | & & | & & \\ HO & - & C & - & C & - & OH \\ & & | & & | & & \\ & & H & & H & & \end{array}$$

**Ethylene Glycol (EG)**



$$\begin{array}{l} \quad CH_2CH_2-OH \\ / \\ O \\ \backslash \\ \quad CH_2CH_2-OH \end{array}$$

**Diethylene Glycol (DEG)**



$$\begin{array}{l} CH_2-O-CH_2CH_2-OH \\ | \\ CH_2-O-CH_2CH_2-OH \end{array}$$

**Triethylene Glycol (TEG)**

## 2.6 IMPURITIES ASSOCIATED WITH HYDROCARBONS

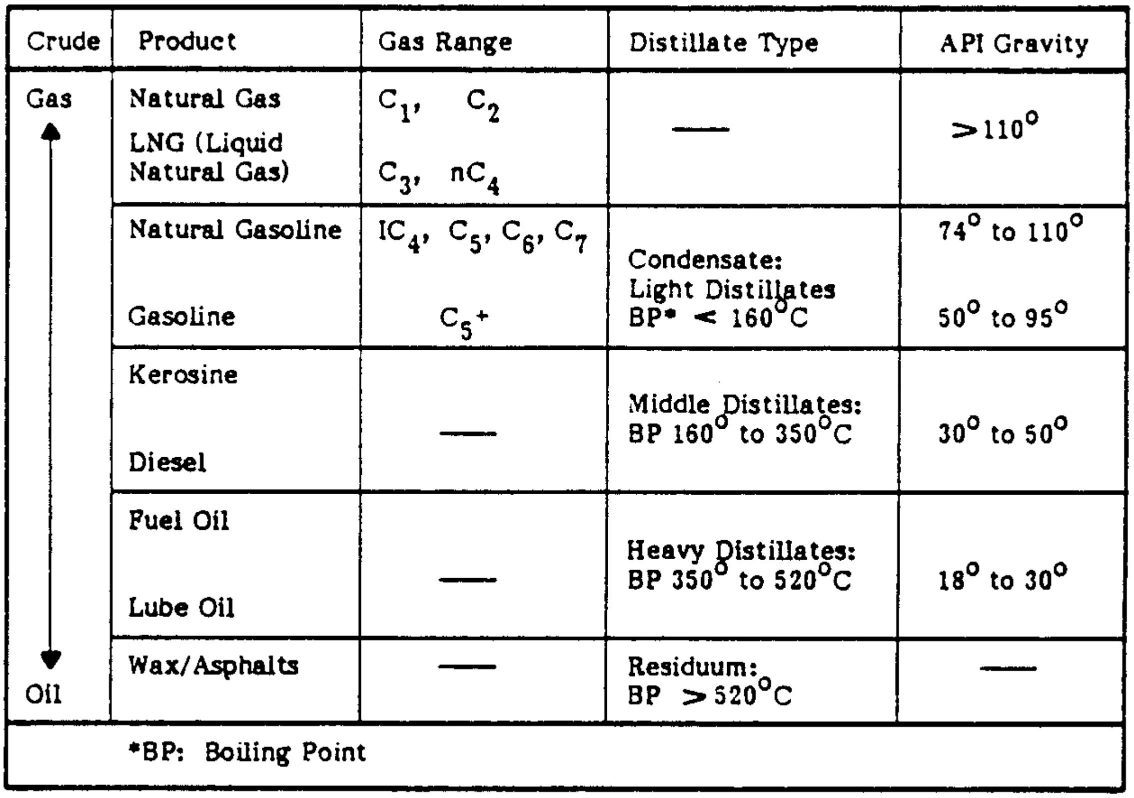
Impurities occur as free molecules or as atoms attached to the larger hydrocarbon molecules, the so-called non-hydrocarbon compounds. When free, they can in most cases be detected with special equipment (**Table 2.6**).

| Impurity | Equipment Available to Measure Impurity |
|---|---|
| Sulfur | $H_2S$ Detector |
| Nitrogen | All Gas/Nitrogen Detector |
| $CO_2$ | TC Chromatograph |
| Helium | TC Chromatograph |
| Oxygen | All Gas Detector |
| Water | Salinity Check<br>(AgNO3 Titration) |
| Salt | |
| Ash | — |

Table 2.6 Impurities Associated with Hydrocarbons

## 2.7 PRODUCTS FROM CRUDE OIL

The products from crude oil, their gas ranges and their gravity are included in **Table 2.7 and 2.8.**



| Crude | Product | Gas Range | Distillate Type | API Gravity |
|---|---|---|---|---|
| Gas ↑ | Natural Gas | $C_1$, $C_2$ | — | >110° |
| | LNG (Liquid Natural Gas) | $C_3$, $nC_4$ | | |
| | Natural Gasoline | $IC_4$, $C_5$, $C_6$, $C_7$ | Condensate: Light Distillates BP* < 160°C | 74° to 110° |
| | Gasoline | $C_5^+$ | | 50° to 95° |
| | Kerosine<br>Diesel | — | Middle Distillates: BP 160° to 350°C | 30° to 50° |
| | Fuel Oil<br>Lube Oil | — | Heavy Distillates: BP 350° to 520°C | 18° to 30° |
| ↓ Oil | Wax/Asphalts | — | Residuum: BP >520°C | — |
| | *BP: Boiling Point | | | |

Table 2.7 Products from crude oil

The process of distillation and cracking is extremely complex and extensive. A brief table showing different important products and fractions are as:-

| Fractions Obtained by Distillation | Final products Obtained by Re-distillation and Further Treatment |
|---|---|
| Hydrocarbon gases | Natural gas, bottled fuel gas |
| Petroleum ether | Solvents, paint thinners, cleaners |
| Gasoline | Motor fuels, solvents, toluene for explosives etc. |
| Kerosene | Illuminating oil, diesel fuel, gas absorption oils |
| Fuel oil | Heating fuels, diesel fuel, cracking stock, naphthenic acid which may be converted to lubricating oil additives paint driers, fungicides, etc. |
| Lubricating oil | Lubricants of all kinds, medicinal |
| Stock | Oil, transformer oil, wad, hydraulic oil, detergents and wetting agents, rust preventatives, waterproofing compounds |
| Residue | Wood preservatives, roofing compounds and shingle saturants, road oils paving asphalt, insulating asphalt coke. |

**Table 2.8 Usage of Petroleum Products**

# Chapter 3

# Introduction to Exploration and Drilling

# Chapter 3 Contents

### Chapter 3

# Introduction to Exploration and Drilling

## 3.1 EXPLORATION METHODS

### 3.1.1 Geological Methods

**Surface, subsurface geology and remote sensing**
Oil has been often found in subsurface tarps (anticlines). These traps were first recognized by their sometimes distinctive features, so surface geological maps can be helpful.

Surface mapping and photogeology, i.e., aerial photos and photogrammetric "stereo pairs" using Earth Resources Satellite (ERSAT) scans, are used extensively for lithological and structural determinations. Another type of surface exploration is agrochemical prospecting, a recent technique based on the supposition that some hydrocarbons in an oil accumulation migrate vertically to the surface directly over the oilfield.

Subsurface geology becomes advanced of surface geological either from drilled wells, outcrops, and geophysical data which help identify the possible presence of oil and gas.

### 3.1.2 Geophysical Methods

The geophysical branch of the exploration is primarily concern with defining subsurface geological features through the use measuring the physical properties of rocks.

In petroleum exploration the three main methods are:

- Seismic : Studies the elastic characteristics of rocks.
- Magnetic : Studies the magnetic properties of rocks
- Gravity : Studies the density properties of rocks.

By 1920 it was obvious that anticlinal folding was only one of a number of geological factors controlling oil and gas accumulation and that much could not be determined from surface mapping alone. The seismic method, the most important in today's predrilling exploration, uses the transit time of sound waves (the time required for a sound pulse to travel a fixed distance between a transmitter and reciever) generated by an explosion. These transit times depend on the nature of the rocks penetrated, particularly their density. The transit time measured is for a wave reflected from a

surface in the subsurface (**Figure 3.1**). Under favorable conditions geologic beds may be mapped quite accurately to create subsurface contour maps of structure and possible reservoir locations.

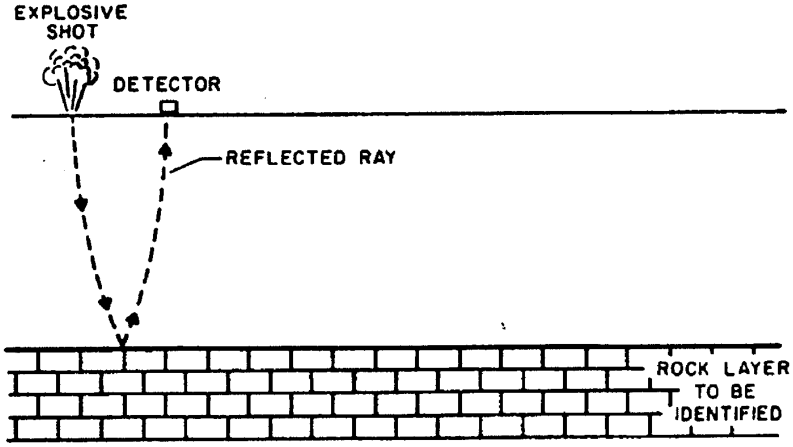


**Figure 3.1 Reflected Seismic Waves**

### 3.1.3 Geochemical Techniques

The geochemistry is the study of the chemical properties of rocks, and petroleum. This study will lead to determine qualitatively and quantitatively the potential of the source rock to generate oil and gas. Geochemistry, also, studies the thermal maturation of the source rock, and correlates petroleum of different reservoirs.

### 3.1.4 Seismic Surveys

The significant features of a conventional land operation are depicted in **Figure 3.2**. For clarity of representation, only with a limited number of seismicray paths are shown, but it should be noted that for each seismmeter there is a corresponding reflecting point at each reflecting surface as well as at least one retracted ray path.

A wide variety of specialized instruments and equipment has been developed for particular operations, such as swamp, sand, shallow water, and open water.

The basic seismic field instrumentation can be considered as the seismometers, the seismic amplifiers, and the magnetic tape recording system. It is not uncommon for operators to have strong opinions concerning all three. During the early history of seismic exploration, instruments were not commercially available. Each operator set up a shop to design and build his own instruments and equipment, and this background and "Organization in being" often influence present day thought. However, the field of modem seismic instrumentation manufacture is now highly competitive, and instrumentation with any desired performance characteristics is available commercially.

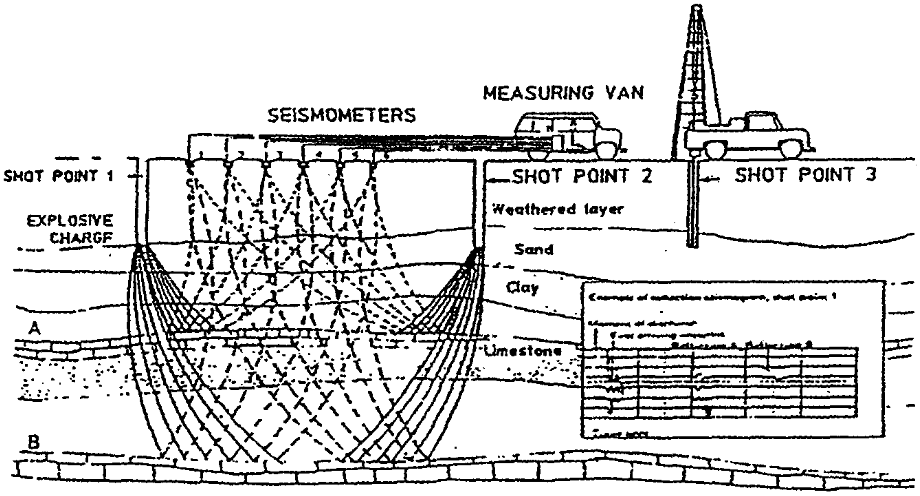


**Figure 3.2 Seismic Data Acquisition**

Geochemical prospecting as a direct indicator of oil has had limited success because hydrocarbons do not migrate directly upward from an accumulation. Migration occurs along faulted and fractured zones and through more permeable beds such as glacial drift or continental deposits. Water in sands overlying accumulations can redirect any upward migration. Consequently, surface indications may be useful in defining oil, gas or barren regions, but they cannot pinpoint an accumulation.

Seeps and natural asphalts give surface evidence of oil or gas that has migrated from its original accumulation. Outcrops, if not weathered, contain traces of hydrocarbons that are indicative of the oil potential of the sediment.

## 3.2 TRAPS

Once the hydrocarbons have been generated and expelled from the source rock, migration is a continuous process, regardless of whether they are, moving through a reservoir rock or through a fracture system. Obviously, then, a barrier or trap is needed to impede this migration in order to get an accumulation.

A trap is produced by a set of geological conditions which cause oil and gas to be retained in a porous reservoir or at least allowed to escape at a negligible rate. Shales and evaporates make good seals, although any un-fractured rock that has a displacement leakage pressure higher than that of the hydrocarbon accumulation will seal a trap.

Most traps are not filled to their structural or stratigraphic spill point. A spill point is illustrated by the successive diagrams in **Figure 3.3**. Note in Stage 1 the stratification of gas, oil and water above the trap spill point. In Stage 2, hydrocarbons fill the trap to the spill point; oil is spilling out and migrating farther up-dip. In Stage 3, the trap is filled with gas. Gas moving from below enters the trap, but a like volume spills out at the same time; oil bypasses the trap entirely. Incomplete filling of a trap is more likely the result of the seal not sustaining the greater hydrocarbon column pressure rather than being the result of insufficient oil and gas to fill the trap (**Figure 3.3**). For this reason, traps often may be filled to capacity and yet have water levels far above the spill point.

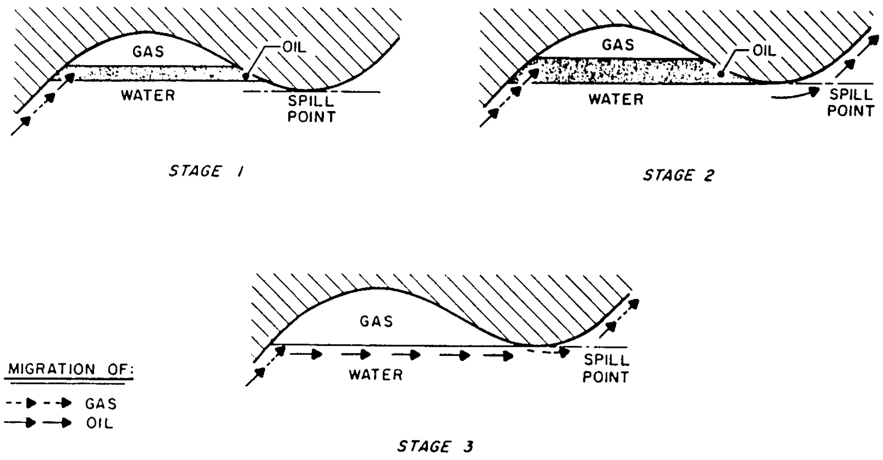


**Figure 3.3 Spill Point of a Hydrocarbon Trap**

Traps for oil and gas under hydrostatic conditions have two general forms: the trapping factor is either (1) an arched upper surface or (2) an up-dip termination of the reservoir. **Figure 3.4** shows some of the simpler forms.

Traps for hydrocarbons under hydrostatic conditions (liquid at rest) are of structural or stratigraphic origin, either alone or in combination, and have horizontal gas-water or oil-water contacts. Hydrodynamic (moving liquid) traps may also occur in different structural environments, but they are characterized by inclined gas-or oil-water contacts.

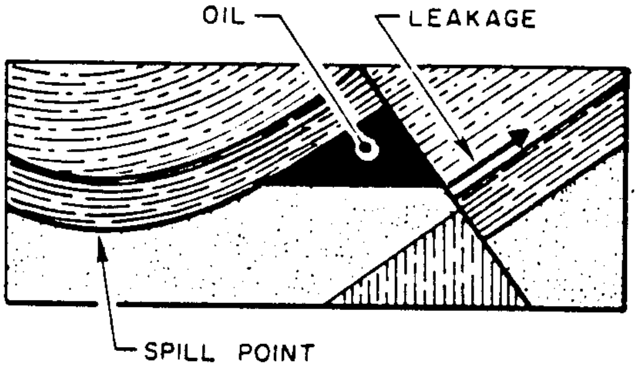


Figure 3.4 Fault Trap Leakages

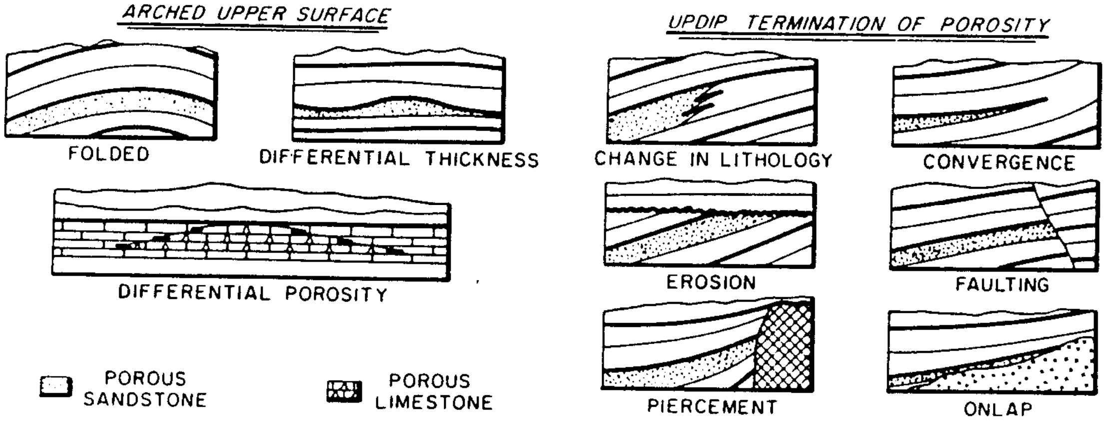


Figure 3.5 Basic Reservoir Traps

## 3.2.1 Anticlinal Traps

These vary widely in shape and size. However, they all have a common characteristic in that a gas-water or oil-water contact completely surrounds an accumulation of hydrocarbons. The structure generally extends through a considerable thickness of formation so that traps are formed in all the potential reservoir rocks affected. The culminations of the various hydrocarbon accumulations will be offset if the anticline is asymmetric (not uniformly shaped) so that a shallow accumulation may not overlie a deeper one even though it is on the same structure. An example of this can be seen in the anticlinal traps associated with rotational faults (discussed under Fault Traps).

## 3.2.2 Fault Traps

These traps depend upon the effectiveness of the seal at the fault. The seal may be the result of placing different types of formations side by side (for example, shale against sand), or it may be caused by impermeable material called gouge within the fault zone itself. The simple fault trap may occur where structural contours provide closure against a single fault. However, in other structural configurations, such as a monocline, two or even three faults may be required to form a trap. In fault trap accumulations, the oil-water contact closes against the fault or faults and is not continuous as in the case of anticlinal traps. Fault trap accumulations tend to be elongated and parallel to the fault trend.

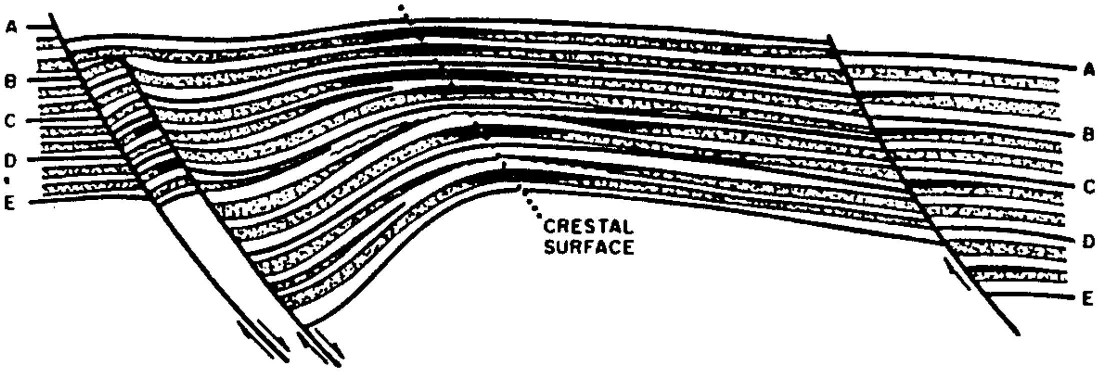


**Figure 3.6 Potential Hydrocarbon Traps Associated with Rotational Faults**

Many kinds of traps are associated with curved rotational faults; (**Figure 3.6**). Accumulations tend to be along the faults and are found in fault traps and anticlinal traps in a complex pattern. An understanding of the nature of these traps is most important for their efficient development.

Traps associated with thrust faults may be either fault traps as in the lower sands or anticlinal as in the uppermost sand (as illustrated in **Figure 3.7**). Accumulations in such traps usually tend to be elongated and parallel to the direction of thrust; they may be quite long but relatively narrow. Thrust traps are often compound.

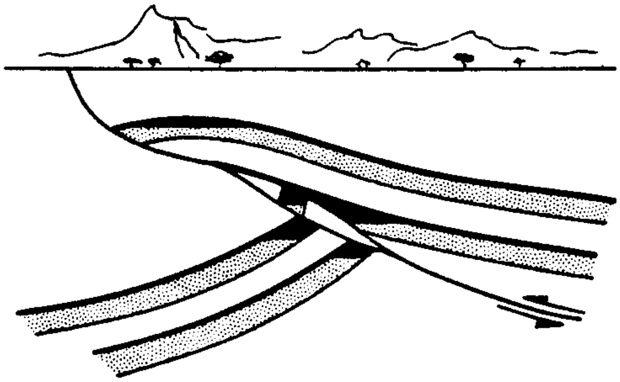


Figure 3.7 Thrust Traps

The intrusion of underlying material (usually salt) into overlying strata often forms a variety of traps, both structural and stratigraphic. **Figure 3.8** illustrates three types of traps. Piercement may be more or less circular, or long and narrow. The salt and associated material forms an efficient up-dip seal. Hydrocarbon accumulations in the peripheral traps around a salt plug may not be continuous. Oil accumulations are usually broken into segments in smaller traps formed by modifying faults or structural closure against the plug. This discontinuous nature of oil accumulations in piercement traps is detrimental to development operations because it cannot be predicted and thus increases the risk of dry holes.

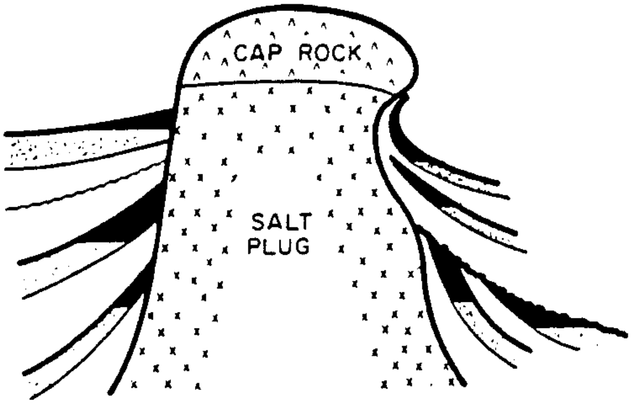


Figure 1.1.8 Piercement Traps Associated with a Salt Dome

## 3.2.3 Stratigraphic Traps

These result from lateral change that prevents continued migration of hydrocarbons in a potential reservoir bed. Many are directly related to their environment of deposition, but others, particularly carbonates, are caused by later changes such as dolomitization. Many large oil and gas fields are associated with this type of trap. The East Texas Field accumulation occurs in the truncated edge of the Woodbine Sand below an unconformity sealed by the Austin Chalk as shown in **Figure 3.9.**

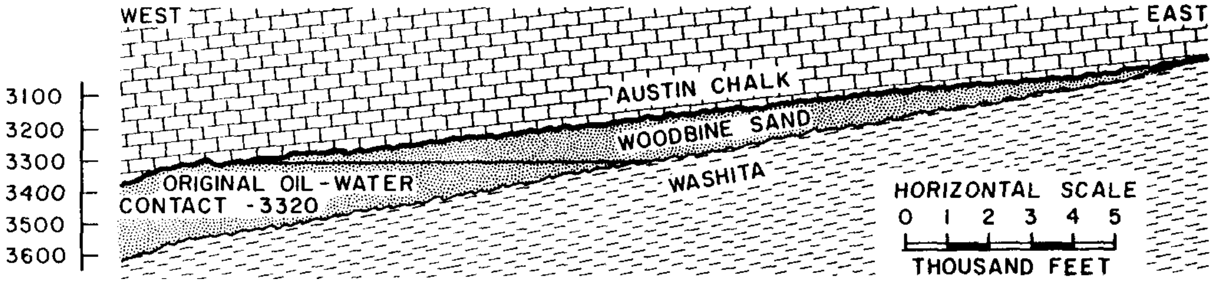


**Figure 3.9 Cross-Section of Pinch-out Trap between Unconformities, East Texas Field**

## 3.2.4 Lenticular Traps

These pinch out or change permeability on all sides. Lenticular traps are fairly common in carbonate rocks, usually occurring in the upper part of reef carbonate buildups.

# 3.3 DRILLING

Once exploration techniques have indicated the location of a potential petroleum reservoir, the drilling phase, the complex process of drilling a hole from the surface to the reservoir, begins.

Although the process of drilling can be complex, its goal rather simple: to make a small hole in the earth, often measuring no more than few inches diameter.

Drilling forms the final test of the exploratory stage and the first step of the Production stage. It is only drilling into the potential oil bearing rock structures that the presence of oil can be finally determined.

## 3.3.1 Rotary Drilling

Rotary drilling represented one of the petroleum industry's greatest technical breakthroughs. This drilling method reduced drilling time and complexity and permitted a great deal of control over well-bore size, depth, and orientation.

### Drilling string

**Figure 3.10** is a pictorial representation of the rotary drilling process. A drill bit is threaded onto a string of pipe called the ***drill string***. The first few joints of pipe above the bit are usually drill collars, very heavy pieces of pipe. The bit and drill string are lowered to the bottom of a well. Then the drill string is turned at the surface, causing the entire drill string and the bit to rotate.

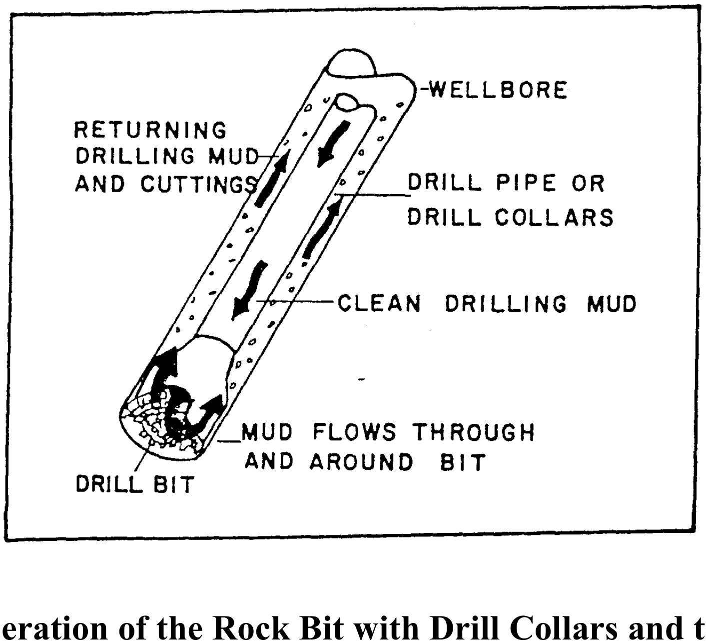


**Figure 3.10 Operation of the Rock Bit with Drill Collars and the Mud System**

The weight of the drill collars forces the bit against the bottom of the well with great pressure. When the drill string and bit are rotated, the teeth of the bit break the subsurface rock into small pieces called cuttings.

## Drilling Mud (Drilling fluid)

Drilling mud, a liquid mixture of water and / or oil, clay, weighting material and various chemicals, is pumped down the drill string from the surface. The mud passes through and around the hollow drill bit and returns to the surface in the space between the drill string and the well-bore. The mud carries the cuttings from the well-bore to the surface, where the cuttings are removed and discarded.

Returning mud is directed into a series of screens pits or tanks which allow cuttings and other solids to settle out of the mud. The clean liquid mud is then pumped back to the drill string by mud pumps. Thus, the mud is constantly circulating into the well to the mud pits, and back to the well.

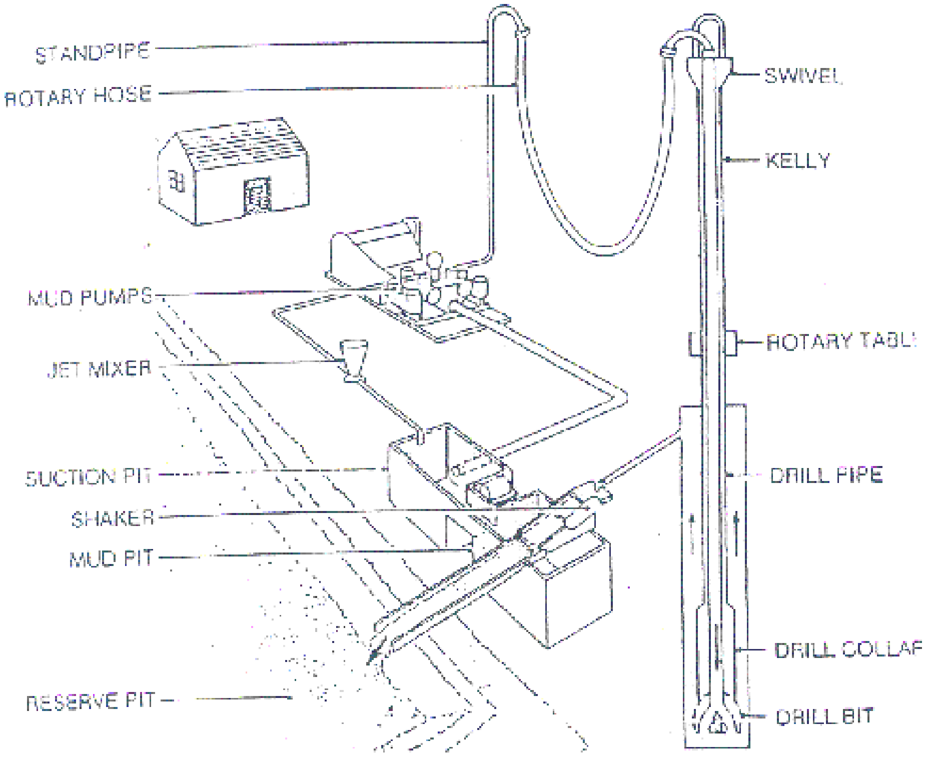


**Figure 3.11 Drilling fluid circulation system**

To remove cuttings from a well-bore, mud must circulate down the well and back to the surface. As the drill bit passes through some formations, the mud pump pressure and the hydrostatic head of the mud are sufficient to inject the mud into these formations. Since the cuttings cannot flow, they are left in the well-bore while the mud

leaves the well-bore. This condition is referred to as ***"lost circulation"*** because the mud no longer returns to the surface and cuttings are left in the well-bore. In such conditions, lost circulation materials are added to the drilling mud to prevent its escape from the well-bore. **Figure 3.12** illustrates lost circulation.

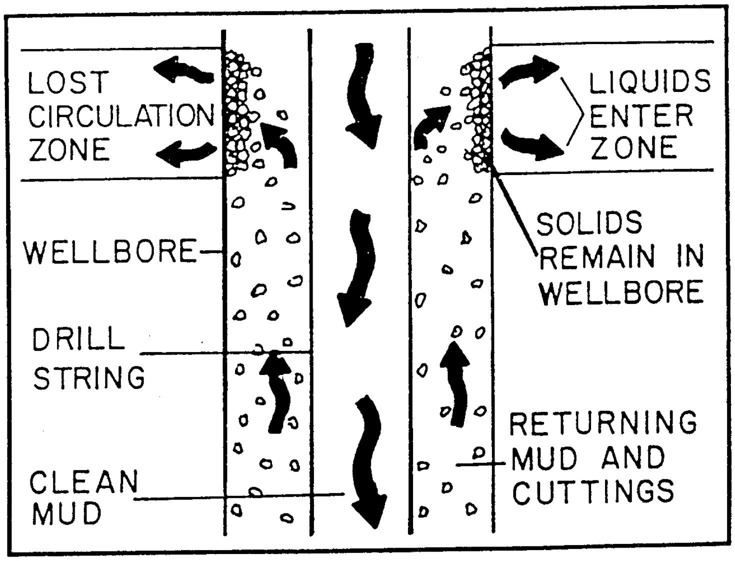


**Figure 3.12 Lost Circulation Zones Accept Drilling Liquids, but the Solids Remain in the Well-bore**

Even under normal circulation conditions, a certain amount of drilling mud enters a formation. When this occurs, liquid in the mud enters a porous formation while solid materials in the mud remain pasted to the sides of the well-bore. The solid materials left in the well-bore are referred to as the ***"mud-cake"***. The liquids that enter the formation are called the ***"mud filtrate"***. Both the mud-cake and filtrate are important considerations when completion procedures are begun after a well has been drilled.

## The tri-cone drill bit

The tri-cone drill bit, or rock bit, is a piece of mechanical equipment. Usually consist of three equally spaced toothed wheels mounted on a head so that as the head rotated the wheels also rotate against the rock, each tooth chipping away a small piece of rock. The drill pipe immediately above the drill bit is much heavier than normal drill pipe and is referred to as a drill collar. The drill collar is heavy enough to force the teeth of the drill into the rock. As drilling proceeds, more lengths of drill pipe are added under the Kelly.

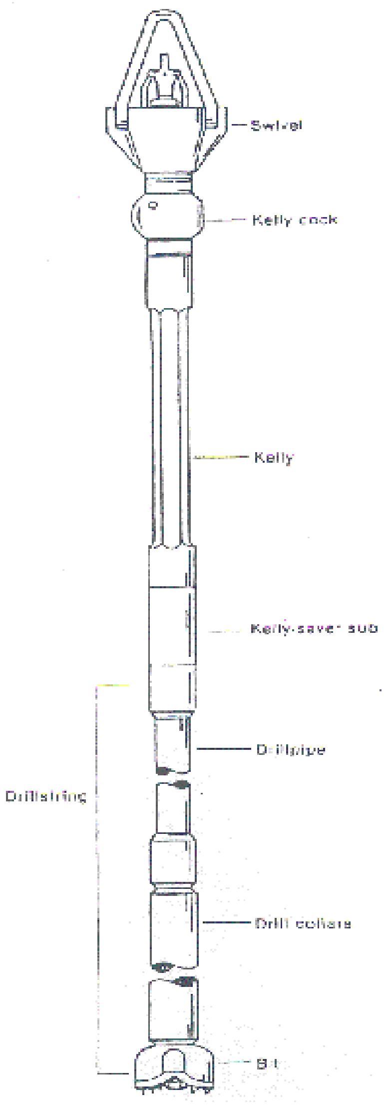


**Figure 3.13**

As the bit rotates these cones rotate (over bearings). The bit's teeth are on the cones, and as the cones rotate, these teeth, made of very hard steel or hard metal such as tungsten carbide, break and grind against the rock. **Figure 3.14** is a photograph of a standard rock bit.

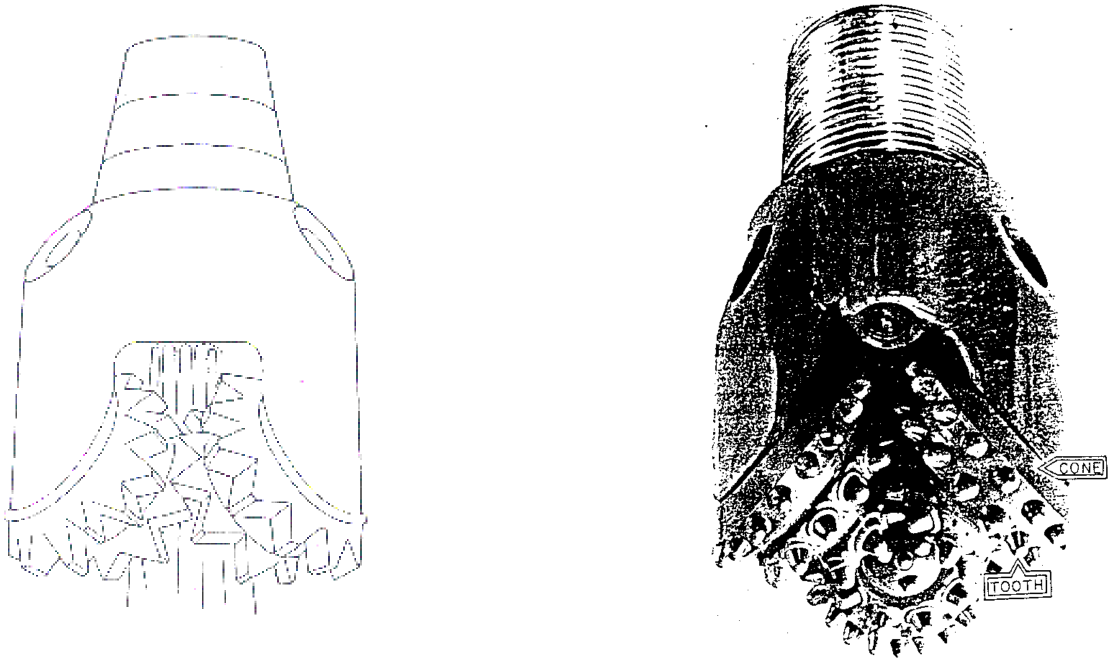


Figure 3.14 Standard Rock Bit

Other bits have industrial diamonds imbedded in the surface of the cones. Diamond bits are used in very hard rock formations. However, after continued use, the diamonds wear or break off. When a diamond drill bit becomes dull, it must be removed and discarded.

## 3.3.2 Drilling Rig Components

**Figure 3.15** shows a schematic view of a drilling rig and the associated equipment and facilities. **The derrick** is used to support the drill string and to allow raising and lowering of the string. **The traveling block** is an arrangement of pulleys in which cables are run through the crown block to the draw-works.

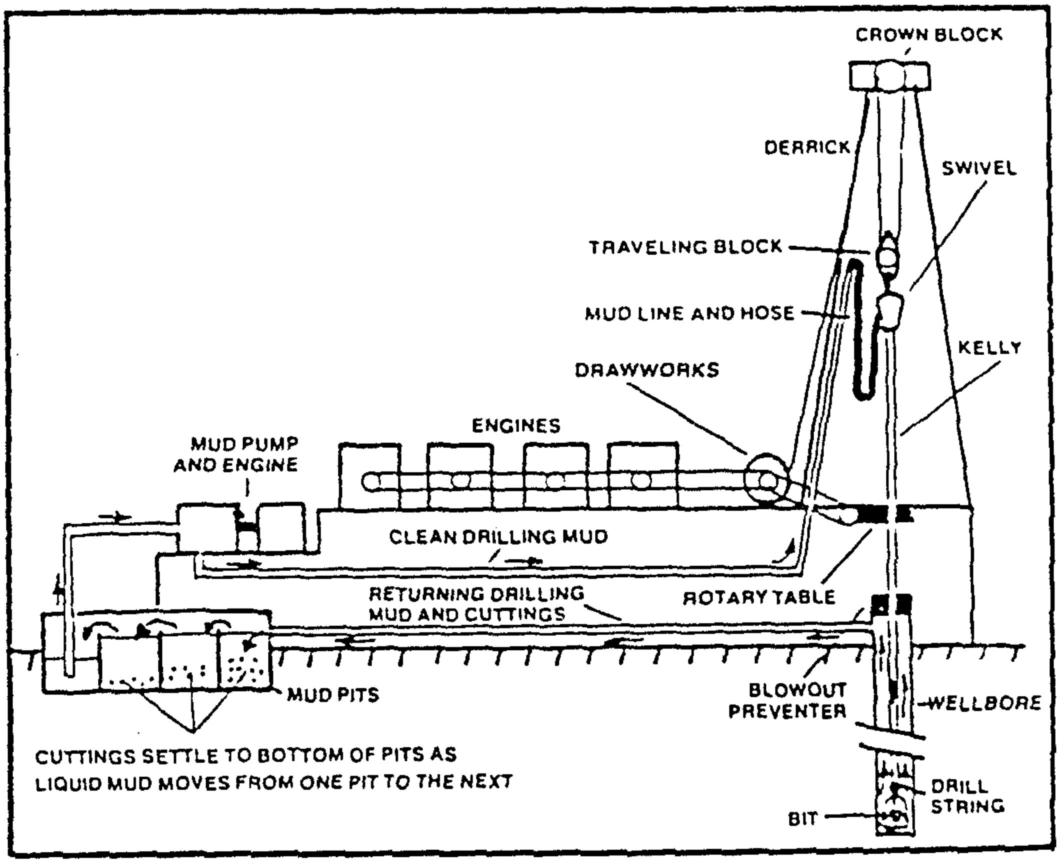


**Figure 3.15 Drilling Rig**

The drill string is attached to a square or hexagonal-shaped piece of pipe called the **kelly**. The kelly is attached to the **swivel**, which is supported by the traveling block. The swivel is attached the mud-line, a flexible hose which allows mud to be pumped down the drill string.

The kelly passes through a similarly shaped opening in the kelly drive table, or **rotary drive bushing**, which rotates the drill string. **The diesel**, LPG, gas or electric engines which operate the draw-works also can be used to power the kelly drive table.

### 3.3.3 Surface and Intermediate Casing Strings

As a well is drilled, the bit passes through a number of formations before a potential reservoir is reached. It is important that some of these formations be protected against invasion by mud filtrate or they may interfere with later drilling activities.

A great deal of the world's drinking water supply comes from shallow, fresh-water aquifers. These aquifers often occur within a few hundred feet of the earth's surface. Obviously, it would not be desirable to allow mud filtrate to enter these aquifers if they supply water used for human consumption or irrigation. Thus a string of pipe called surface casing is placed in a well-bore and cemented in place after the drill bit has passed through the formation.

**Figure 3.16** illustrates the use of surface casing. After the well has been drilled through the formation, usually with fresh water as the circulating medium, the drill string and bit are removed. A string made up of several joints of large-diameter pipe is lowered into the well-bore until it rests' on the bottom of the hole. Then cement mixed with water in a thin liquid form is pumped down the casing and allowed to circulate up to the surface in the area between the casing and the well-bore. When the cement hardens, the cement and casing form a complete seal against contamination of the aquifer by future drilling operations. Casing that has been cemented in place will remain in the well permanently.

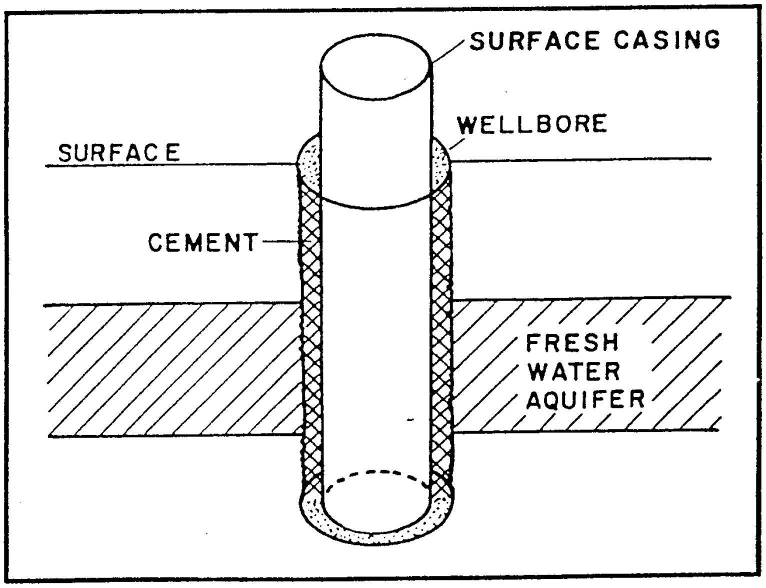


**Figure 3.16 Surface Casing is Used to Isolate Shallow Water Zones**

Drilling operations resume once the casing is in place. Since some cement is usually left in the casing, the drill bit will first have to remove this cement. Also, since the casing is smaller than the original well-bore, a smaller-size drill bit must be used for continued drilling.

After surface casing is set and drilling operations continue, the drill bit often passes through other formations that can interfere with drilling. Such formations might have very high porosity and permeability and could cause severe lost circulation problems. Other formations, such as unconsolidated clay and sand formations, can slough into the well-bore, fall on top of the bit, and wedge the bit in the well-bore. With unconsolidated clay and sand formations, one or more other casing strings, called intermediate casing strings, should be installed.

**Figure 3.17** pictures a well in which drilling has been resumed after setting both surface and intermediate casing strings. As each casing string is set, the drill bit size must be reduced.

In most wells surface casing is required to isolate aquifers and the soft earth near the surface. Intermediate casing is required in some areas, though not in all.

The decision to use surface and intermediate casing strings is often dictated by various reservoir and formation conditions. Most decisions regarding casing strings, casing sizes, setting depths, and cementing methods are governed by various regulations. Most state governments, have specific regulations governing casing usage.

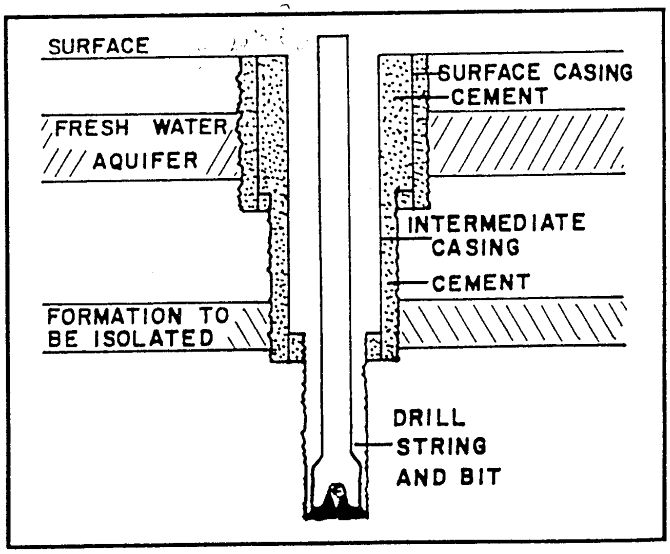


Figure 3.17 Several Casing Strings are required in Some Wells

## 3.3.4 Drilling Control

Drilling technology has advanced significantly since the early days of cable tool drilling. With modern techniques, it is possible to precisely control hole size, depth, and direction.

Seldom do drill strings create a perfectly straight hole. More often, a well-bore takes a path resembling a corkscrew. **Figure 3.18** shows an exaggerated view of what might be considered an average well-bore. Curved holes can create problems when production activities begin.

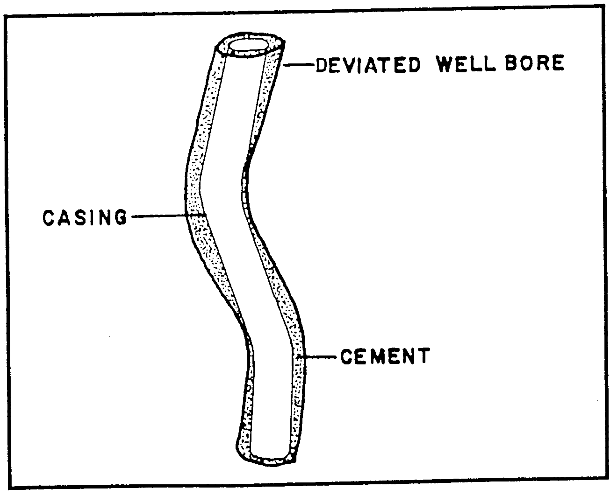


**Figure 3.18 Seldom are Well-bores Drilled without some Deviation which Affects the Casing Design**

Sometimes the drill bit encounters a change from very hard rock to soft rock, or vice versa. When that happens, it is possible for the bit to travel at an angle away from the intended path, as shown in exaggerated form in **Figure 3.19**.

Where wells are drilled in populated areas, it is not possible to place a drilling rig directly over the intended location of a well. Thus, a well-bore may be intentionally angled from the surface as shown in **Figure 3.20**. Well-bore direction can be controlled to a surprisingly accurate degree. By careful control of weight on the bit, rotation speed, selection of bit types, and use of some specialized tools, it is possible to intentionally change the path of a well-bore.

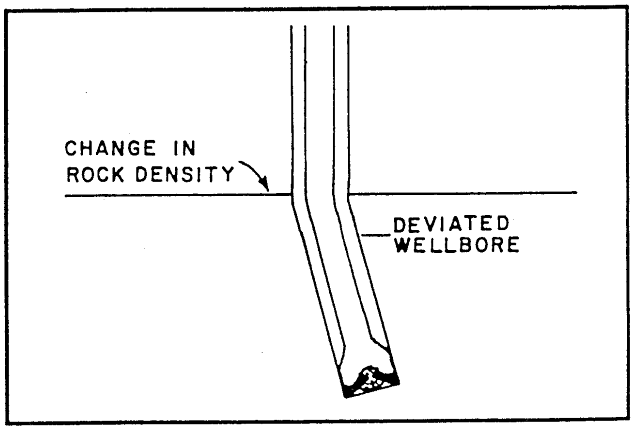


**Figure 3.19 A Change in Rock Density can Cause the Bit to Change Direction of Travel**

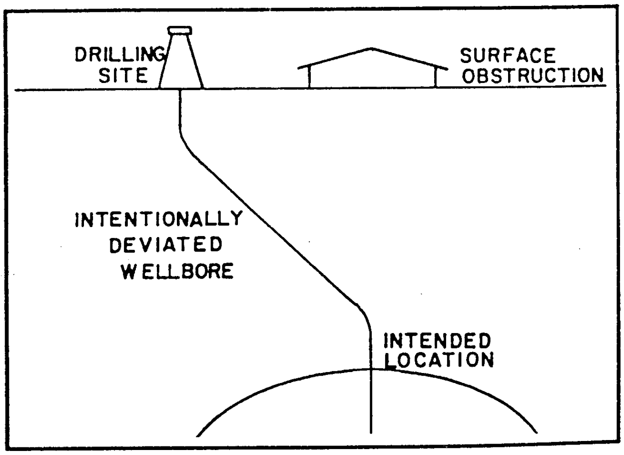


**Figure 3.20 Population Centers and Terrain Features Require that a Well-bore be Deviated Intentionally**

Some well-bores encounter soft formations which would be washed out by the action of drilling mud. Such large-diameter sections could interfere with later operations. However, by careful control of mud consistency, weight, and pressure, it is possible to avoid such problems.

Depth measurement is often surprisingly difficult. Because of deviations in well-bore direction and stretch of the drill string, depth measurements may be in error by several feet. To maintain precise depth measurement, it is necessary to use other data such as orientation and direction.

# Chapter 4

# Well Completion

# ***Chapter 4 Contents***

## 4.1 From Bottom Hole to Well Head

4.1.1 Casing
4.1.2 Packers

## 4.2 Completion

4.2.1 The functions of well completions
4.2.2 Completion Methods
4.2.3 Different Types of well Completions
42.4 Different Types of Wells
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### Chapter 4

# Well Completion

## 4.1 FROM BOTTOM HOLE TO WELL HEAD

It is an arduous task to tap oil and gas from underground reservoirs, as is the flow of hydrocarbons in the reservoirs.

Hydrocarbons that are formed in the earth's strata (**Figure 4.1**) migrate from one part to another till it reaches a point where it can migrate no further. An impermeable barrier like shale may restrict the flow and trap the hydrocarbons. These traps or reserves that contain the structures are also known as Reservoir or Traps or simply Sands. An oilfield structure may contain several layered zones, and the one which actually contains the hydrocarbons in commercial quantity are known as the Pay Zone or the Pay Structure.

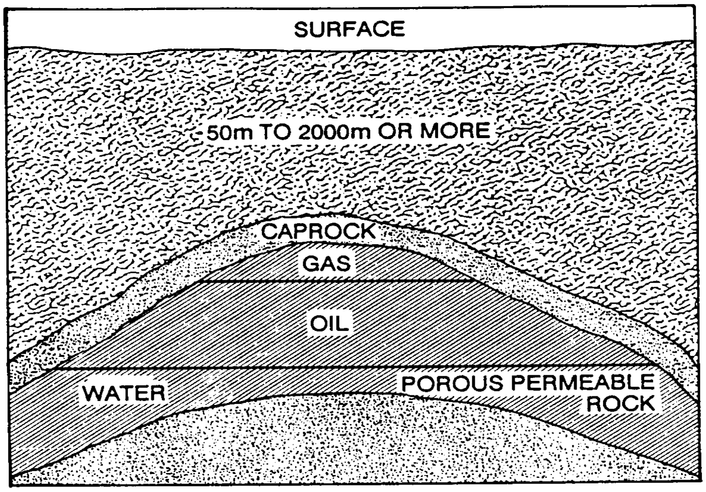

**Figure 4.1 Undistributed Strata**

Once a pay structure is determined and tested, commercial drilling is started in a particular area known to be producing commercial quantity of oil and gas. Once the well is drilled, it is Cased Cemented. Production Tubings are then inserted along with the well head equipments like Tubing Hangers and Christmas Trees. Packers are set to isolate the casing tubing annulus. Tubing and casing are perforated in the pay zone. Well is cleaned of the drilling mud and the completion fluid and made ready for start up of primary production phase.

### 4.1.1 Casing

The act of casing means to line the hole with steel and is done to prevent the hole collapsing. See **Figure 4.2**, it is usually done at intervals; first with large casing for the first 200-500 feet (60-150 meters) and then progressively smaller casing down to the bottom of the hole. As casing proceeds, the next drilling phase has to be carried out working through the casing. Thus a smaller drill bit must be used each time. Casing is cemented in position by squeezing the cement down the inside and up the outside, forcing cement into the formation and space between the casing and the hole. After the first casing stage, a blow-out preventor is fitted. The drill string works through the blow-out preventor and should unexpectedly high pressure be encountered, the blow-out preventor will shut, closing off the hole. It is in effect a very strong type of gate valve, usually hydraulically operated which pinches the drill pipe and closes off the hole.

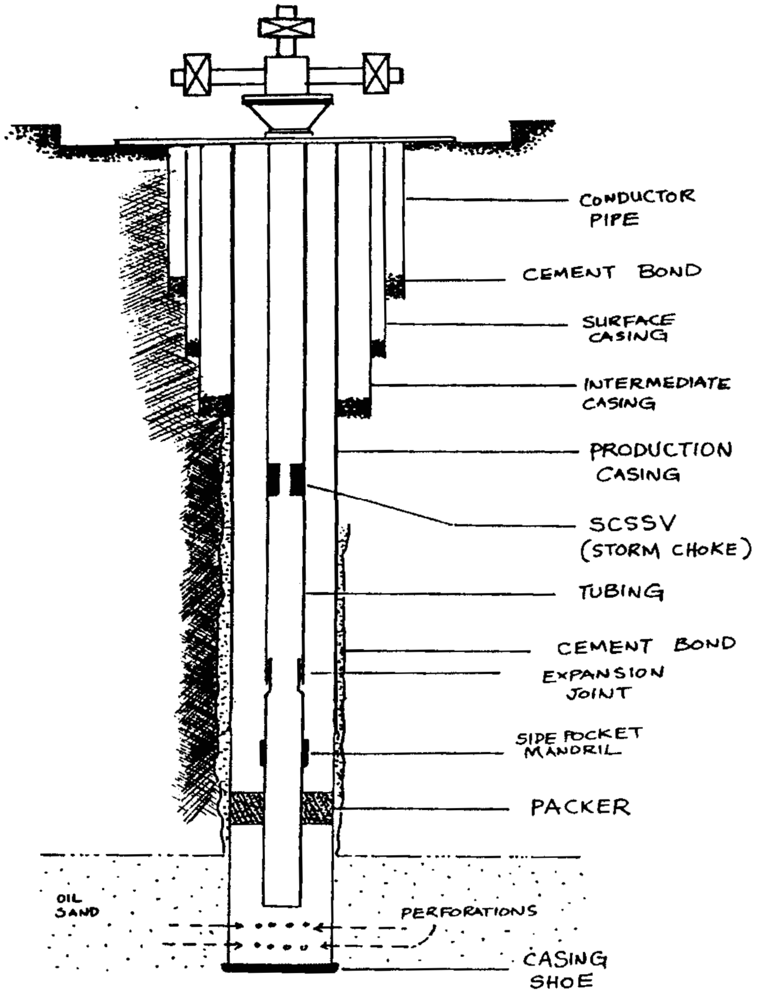

Figure 4.2 Typical Well Casing

Casings are provided to prevent loose soil or formation from caving in and blocking the hole.
The primary functions of a casing may be summarized as:

- Prevention of caving of hole.
- Prevention of contamination of upper fresh water sands.
- Exclusion of water from the producing formation.
- Confining production to well bore.
- Facilitating installation of subsurface equipments.

Tubing is the length of pipe which runs all the way down up to the pay zone, just above the perforations or sometimes across the pay zones (in which case one has to perforate the tubing as well). The well fluid actually flows through this conduit, into the well head. The energy for the flow of well fluid is either supplied by:

a. The pressure difference between the flowing bottom hole pressure “pwf” and the well head pressure “pwh” or

b. If the reservoir energy has depleted or the well is water logged so that the hydrostatic head in the tubing is so high that reservoir fluid cannot flow naturally, then the energy for lifting is provided by artificial methods like electrical semi submersible pumps or sucker rod pumps or gas lifting.

Tubings come in various sizes ranging from 1.315” to 4-1/2”.
Selection of the tubing is made on the basis of the reservoir potential. The most common sizes that are in use these days are 2.3/8”, 2.7/8” and 3.1/2”

## 4.1.2 Packers

The annulus between the tubing and the production casing is sealed by means of a Production Packer, to prevent the movement of fluids due to a pressure differential above and below the sealing point.

### 4.1.2.1 The Packer Requirements:

a. It should be connected to the tubing.

b. Its OD should be sufficiently less than the ID of the casing to provide clearance for running in the hole.

c. It must be designed so that when it is in the proper position, some surface control can be used to cause it to seal off the annulus between the tubing and casing.

In addition to contributing to efficient production operations, the packer relieves the casing of high well pressures. This is important because the casing, being of larger diameter than the tubing and having thinner walls, is usually more susceptible to high pressure damage than the tubing.

Many packer applications are temporary. Packers are used during cementing, fracturing and testing operations, but the tool is retrieved when the servicing job is completed. These types of packers are called "Retrievable packers: because they are designed for easy recovery, the other major packer application in permanent well completions. These packers are known as "Permanent Completion Packers" and are designed to be left in the well over a long period of time.

### 4.1.2.2 Types of Packers

Depending on the retrievability, packers can be of two types:

a. Retrievable type, one which can be retrieved.

b. Permanent Completion packer- one which cannot be retrieved and has to be drilled through for a workover job at a later stage.

### 4.1.2.3 Basic Operation

A packer can be set by:

a. Applying weight or compression (mechanical or hydraulic)

b. By rotational tubing movement or rotation.

c. By tension.

# 4.2 COMPLETION

This is the act of completing the well at the bottom. Depending on the type of reservoir formation encountered, completions as shown in **Figure 4.3** may be just an open uncased or a cased hole through the formation, in which case perforation of the casing is necessary. There are many types of completion, each specified to cope with certain formation problems.

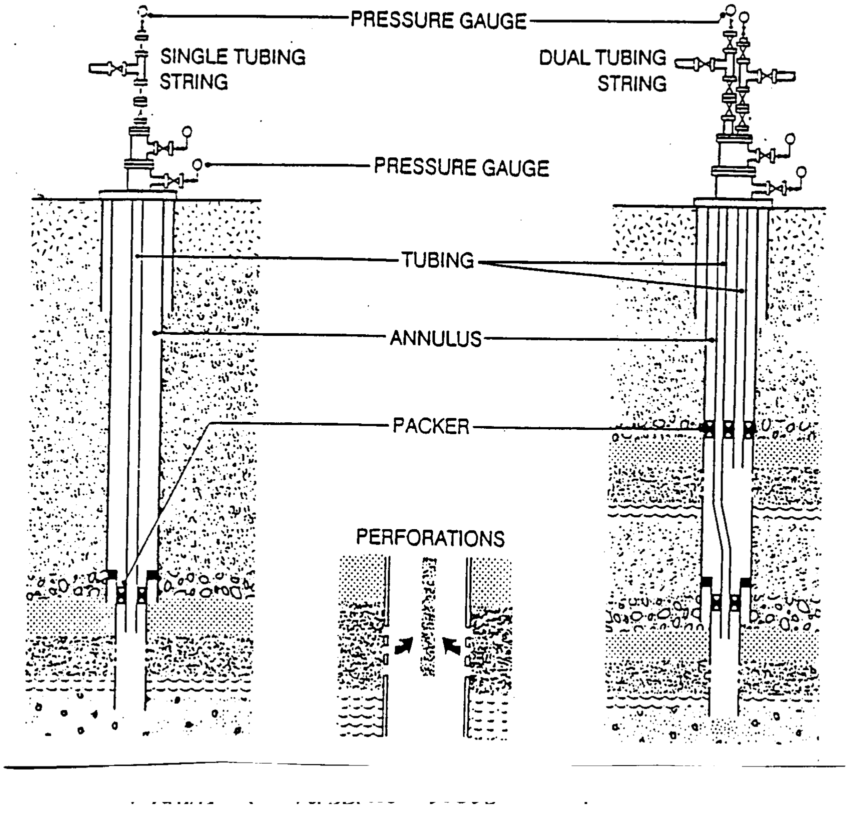

Figure 4.3 Typical Well Completion

## 4.2.1 The functions of well completions

The function of well completions is allowing different operations through the completion such as:

- Bottom-hole pressure survey.
- Circulation rate.
- Production zone selection.
- Artificial lift.
- To provide the optimum production through the proper selection of production tubing.

## 4.2.2 Completion Methods

After the well is drilled, it must be completed and prepared for production. The "completion methods," refers to those processes where by the well is prepared to produce oil or gas. A number of different types of completion methods are used today. The more common methods are described below.

### 4.2.2.1 Open-Hole Completions

This less common method is often used when setting a permanent casing string through the producing zone is not necessary. An open hole completion involves drilling down to the top of the producing zone, setting casing, and cementing it in place just above the pay zone (**Figure 4.4**). The well is drilled into the producing zone with a smaller bit, and an open hole or uncased section is left for the oil and gas to flow into he well. This technique can only be used in good, competent formation rock, or excessive cave-ins will result. An open-hole completion is often used to prevent mud and cement damage to the producing zone.

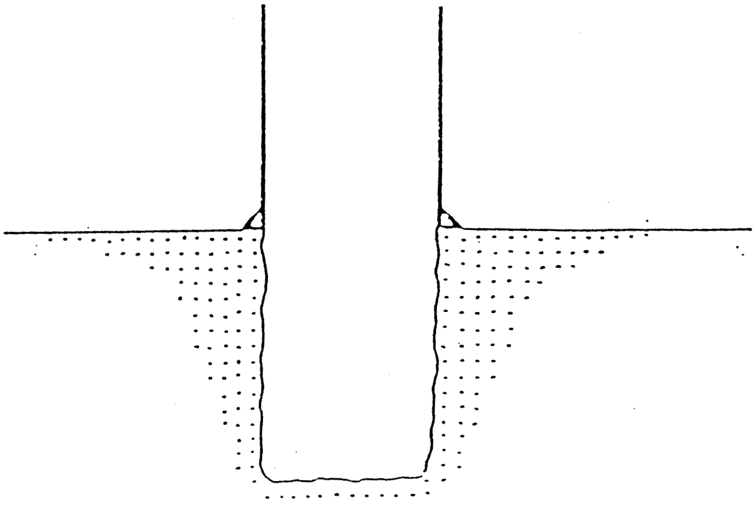

**Figure 4.4 Open-Hole Completion**

### 4.2.2.2 Cased-Hole Completions

The most common type of completion today is the cased-hole completion. The finals string of casing, called the production casing or the long string, is inserted through the production zone and cemented. The casing serves several purposes; it keeps the formation from caving into the well-bore; it provides a permanent vehicle for the transmission oil or gas to the surface; and it isolates the producing zone from the other zone in the well. The latter prevents foreign fluids of other zones from migrating into the producing formation.

When the casing is set and cemented in place, the well is then perforated. To perforate a well, a device is lowered on a wireline into the well and used to shoot holes through the steel casing and cement into formation. **Figure 4.5** illustrates the technique known as jet perforating. A small high-explosive charge is lowered into the well and used to shoot a series of small holes into the formation. These holes or perforations are shot into the casing adjacent to that part of the formation containing the oil or gas. The perforations allow the oil and gas to flow through the steel casing, into the well-bore, and up to the surface.

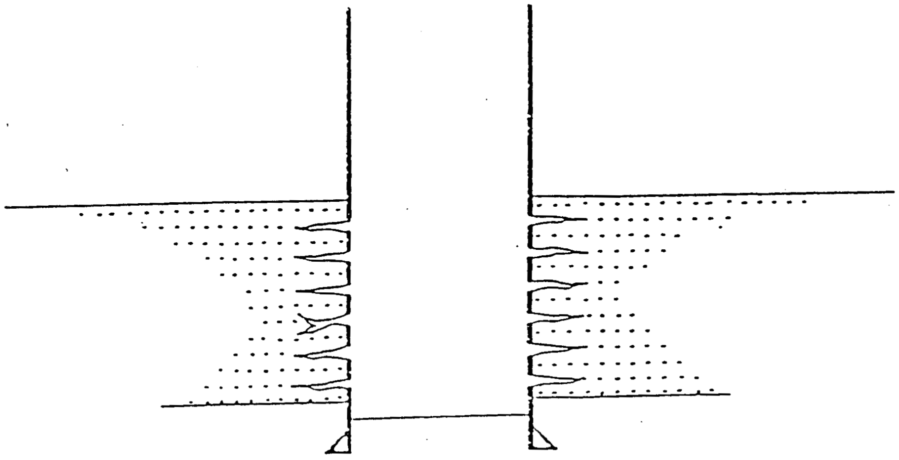

**Figure 4.5 Perforated Casing Completetion**

### 4.2.2.3 Slotted Liner Completion

This completion method is common. As with open-hole completion, the well is drilled to the top of the producing zone, then casing is set and cemented in place. After the well is drilled into the pay zone, **a slotted linear** is run into the well and connected to the production casing by a liner hanger (**Figure 4.6**). The slotted liner is used to keep the rock from caving in and closing off the bottom of the well. The technique is not very successful in soft rock, which tends to break up into fine particles it allows an entire section of rock to produce into the well without having to case and cement the zone.

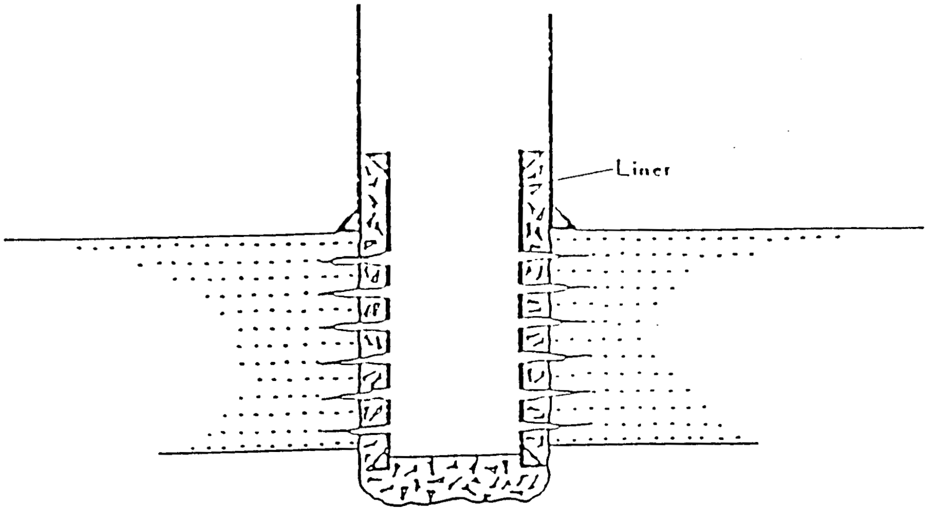

**Figure 4.6 Perforated liner Completion**

### 4.2.2.4 Completion Requiring Sand Control

In areas where formations often are very soft, causing loose formation material to be carried into the well with the oil and gas. These types of formations are often called **unconsolidated sands.** Problems can result, because the sand which flows into the well with the oil and gas plugs the borehole and can cause problems at the surface. Several techniques can help prevent or control the production of sand from such wells. **Gravel packing** and **sand consolidation** are two of the most common.

One method of **gravel packing** is shown in **Figure 4.7**. This technique consists in drilling through the unconsolidated formation, setting and cementing the casing, and perforating the casing, as in normal cased-hole completion. Some of the soft formation behind the perforations is washed out to form a cavity behind the casing. A gravel pack is then placed in the well. This usually consists of coarse sand, similar to that used on construction sites, which is pumped down the casing and out into the cavity behind the perforations. It acts as a filter to help keep the unconsolidated sand in the producing formation away from the well-bore. A screen and liner (**Figure 4.8**) is set down into the gravel pack, when the gravel is placed in the well. The openings in the screen are small enough to prevent the gravel pack from coming through, but the oil and gas can flow through the gravel pack and the screen into the well. Because the gravel pack is held in place by the screen, and the producing formation is held in place by the gravel pack, this method filters out the sand and allows the oil or gas to be produced.

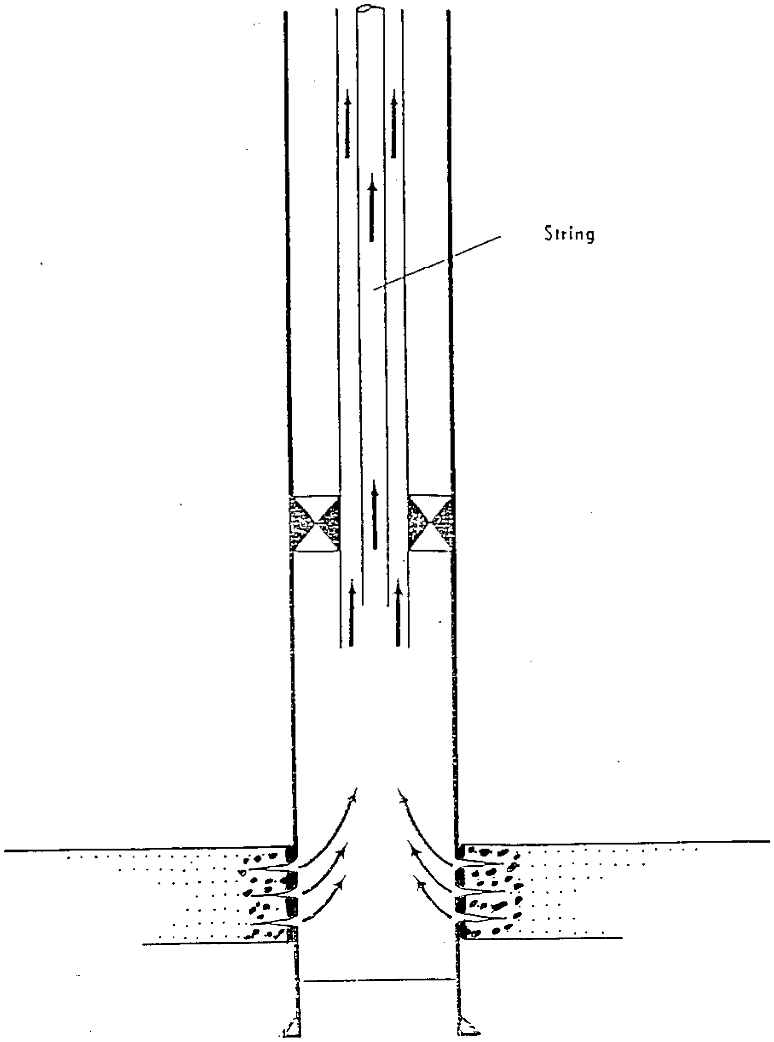

**Figure 4.7 Single Completion with gravel packing**

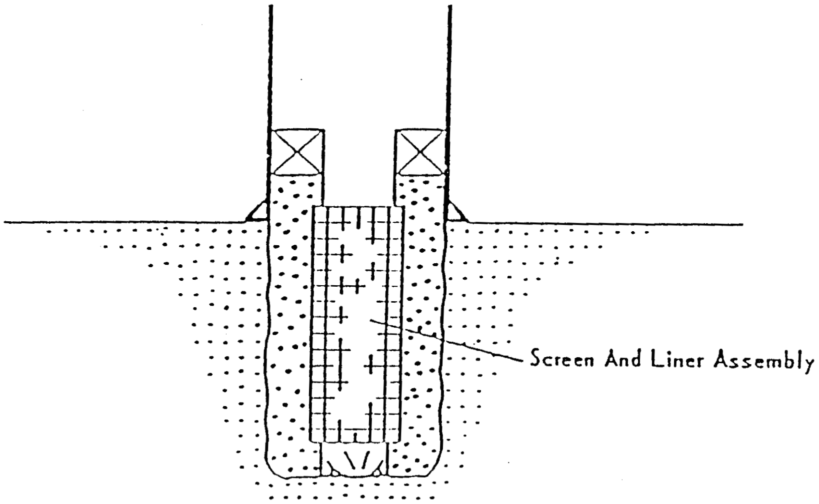

**Figure 4.8 Screen and Liner Completion**

## 4.2.3 Different Types of well Completions

### A. Producing Wells

- Single completion to provide production from one zone.
- Dual completion to allow production from zones (**Figure 4.9**).

### B. Artificial Lift

- Beam pump completion.
- Gas lift completion.

## 4.2.4 Different Types of Wells

### A. Producer Wells

a. Oil producer well.
b. Gas producer well.
c. Water producer well.

### B. Injection Wells

a. Gas injection wells.
b. Water injection wells.

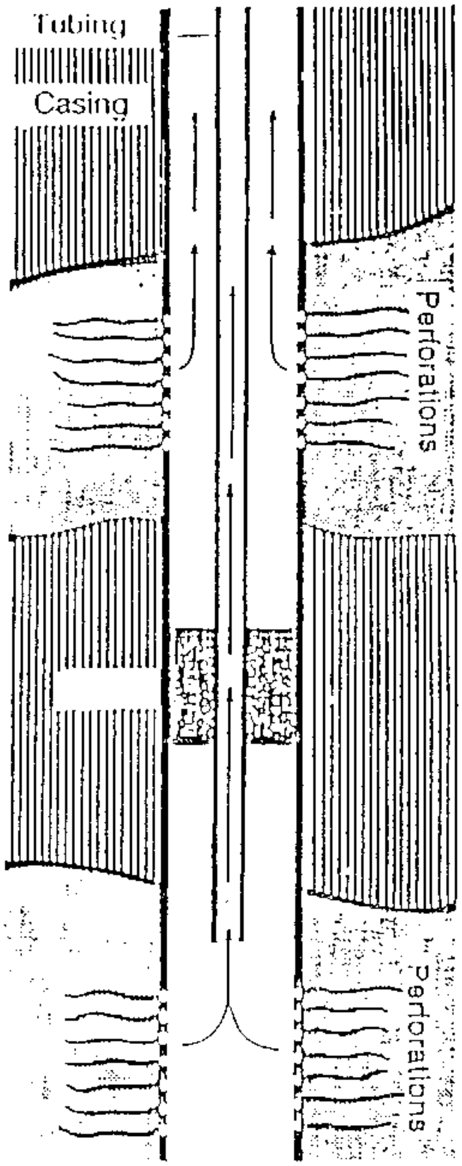

Figure 4.9 Completion of a Well to Prduce from two different Formations (Dual Prduced)

## 4.2.5 Different Types of Production

A. **Natural Flow:** The reservoir pressure is sufficient to flow the fluid the reservoir to the surface.

B. **Artificial Lift:** As the reservoir pressure declines to where it can no l overcome the hydrostatic head of the well, some artificial method to l fluid up to the surface is required, such as:

- Beam pump.
- Electrical Submersible Pump (ESP).
- Jet pump.
- Gas lift.
- Hydraulic pump.

# Chapter 5

# Wellhead, Flow Line and Inlet Manifold

# Chapter 5 Contents

### Chapter 1

# Wellhead, Flow Line and Inlet Manifold

## 5.1 WELLHEAD AND FLOW CONTROL EQUIPMENT

### 5.1.1 Flowing Wells

A flowing well may be defined as any well which has sufficient pressure in the reservoir rock to cause the oil or gas to flow to the surface through the well bore. Flowing wells have always been considered ideal, because they require relatively little equipment or expense to bring the oil to the surface. Such wells are common in both offshore operations, and are typical of large oil fields, where sufficient pressure exists in the rock to force the oil to the surface.

The equipment commonly used in a flowing well consists of tubing and a wellhead. The casing has been inserted through the pay zone and set in place. It has been perforated to provide a flow path for the oil or gas to follow from the reservoir rock into the well bore. A smaller string of pipe, called tubing, is inserted inside the casing and suspended from the surface by the wellhead.

This tubing is not cemented in place, as is the casing, but serves as a conduit inside the casing for most oil and gas production from a well to the surface. It is smaller than the casing, usually being no more than two or three inches in diameter.

This tubing is usually used as a flow path instead of the casing, because the tubing is considered expendable and can be retrieved, if necessary, from the well. The tubing can be easily replaced if it becomes damaged by corrosion or the force of fluids flowing through it. On the other hand, the casing, which has been cemented in the ground, is a permanent fixture and cannot tolerate excessive abuse or wear.

At the top of the tubing, on the surface of the ground, is a **wellhead**. This is often called the "Christmas tree", because a large wellhead with many valves resembles a tree with many ornaments hanging from it.

## 5.1.2 Wellheads

The wellhead and Christmas tree are the equipment used to maintain surface control of the flow of fluids from the well. A wellhead provides a safe and adequate means for supporting and attaching blowout control equipment curing drilling and later it provides sealing between casing strings and a connection for Christmas tree.

The Christmas tree controls the flow or fluids from the well, and it also provides an additional opening into the well which may be utilized for fracturing, circulating fluids, producing the well, and other emergency or miscellaneous uses that eight arise during the life of the well.

There is a wide variance in the complexity of wellhead equipment depending upon the intended service requirements, particularly regarding pressure requirements- For purposes of clarification, wellheads and trees used with pressures in excess of 1000 psi are considered to be high-pressure types.

### 5.1.2.1 High-Pressure Wellhead

**Standard Wellhead Assemblies:** Good engineering practice specifies that wellheads and trees be manufactured and made of materials in accordance with API Standard 6E, now designated 6A. Standard high-pressure flanged casing heads, in most cases, are at least 3000 psi working pressure. The size was selected because (1) most. blowout preventers are 3000 psi working pressure or higher and will therefore fit the 3000 psi flanged heads with a minimum of flanged adapters; (2) the difference in cost between most 2000 and 3000 psi working pressure flanged heads is small; (3) it reduces inventory on wellheads and parts. Another factor which has entered the picture is the possible use of stimulation methods that will require surface pressures in excess of 2000 psi.

### 5.1.2.2 Low Pressure Wellhead

During recent years, the use of low-pressure heads became more prevalent because of an increased drilling effort in low-pressure areas and the doubtful economics of using a piece of equipment too large and more expensive than justifiably required. This head may also be used as a casing head on tubing less completion. The top flange fits low-pressure, 6-inch preventors. It also incorporates a low-price threaded hanger.

These are representative types that are commonly used; however, there are numerous others available that will be satisfactory providing that steel is used in the construction and that they are purchased from reliable manufactures.

### 5.1.2.3 Wellhead Equipment

Wellheads vary in size, strength, configuration, depending on well conditions. For example, a wellhead could consist of several heavy fittings, with certain parts designed to hold very high pressures. Such a wellhead would be used on a high-pressure gas well. On the other hand, it could be just a simple assembly designed mainly to support tubing in the well-say, in cases where pressure and production are low. However, it is possible to say that a typical wellhead is made up of a casing head, tubing head, and Christmas tree (Figure 5.1). Bear in mind, though, that there is a lot of variation in wellhead design and installation.

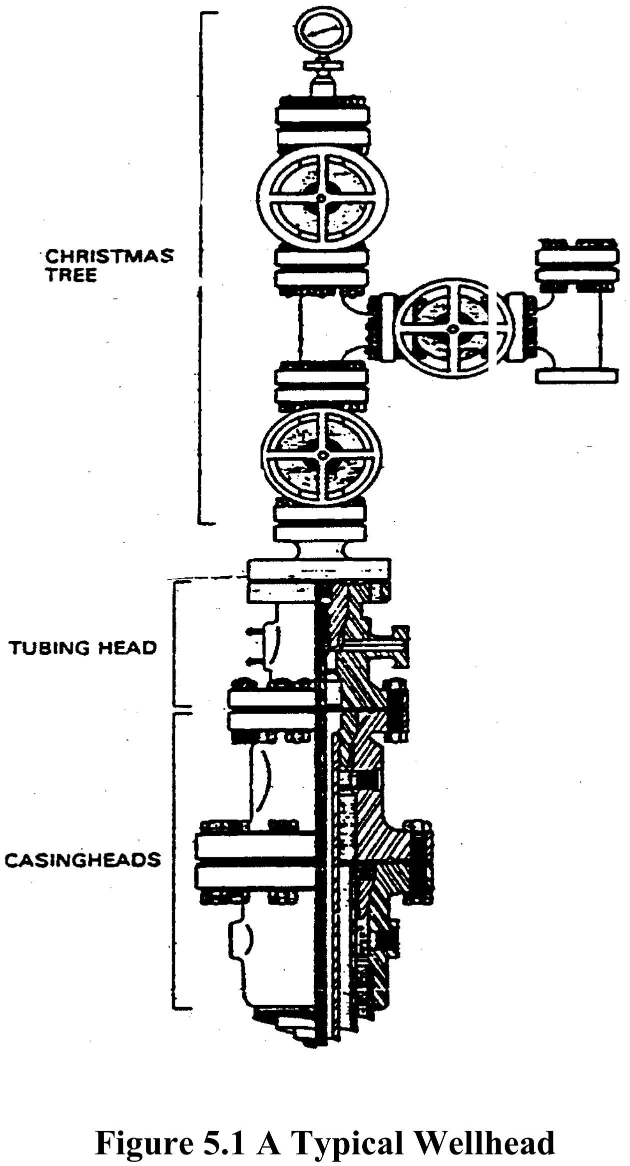

Figure 5.1 A Typical Wellhead

Well head equipment is a term used to describe, in general, equipment attached to the top of the tubular materials used in a well to support the string, provide seals between strings and control production from the well.

Sizing, grades, designs, dimensions and quality of all well head equipments are determined by the American Petroleum Institute (API).

Based on the allowable cold-working pressures well head equipments of the following grades generally used.

| Max cold-working Pressure, psi | Hydrostatic Test Pressure |
|---|---|
| 960 | 1440 |
| 2000 | 4000 |
| 3000 | 6000 |
| 5000 | 10000 |
| 10000 | 15000 |
| 15000 | 22500 |

So a 15000 psi Christmas tree means that the maximum operating pressure to which the tree should be subjected is 15000 psi even though the test pressure of the tree had been 22500 psi.

## A. Casing Heads

The casing head as shown in Figure 5.2 is a unit or housing attached to the top end of the surface pipe to provide a means for supporting the next string of casing, and sealing the annular space between the two strings of casing. It is composed of a casing hanger bowl to receive the casing hanger necessary to support the next string of casing, a top flange for attaching blow out preventors, other intermediate casing heads or tubing heads and lower connections.

Casing heads are available with or without lock screws in the flange. Lock screws are normally used only to hold the casing hanger down against pressures which may occur during nipple up operations or when casing-string weights are light enough to require a hold down to seal.

Regardless, the casing head provides for the use of gripping devices, or hangers, to help support the weight of the casing.

Casing heads also have sealing elements or packers to prevent the flow of fluids within the head and to the atmosphere. Openings are provided for bleeding off pressure that may collect in or between casing strings.

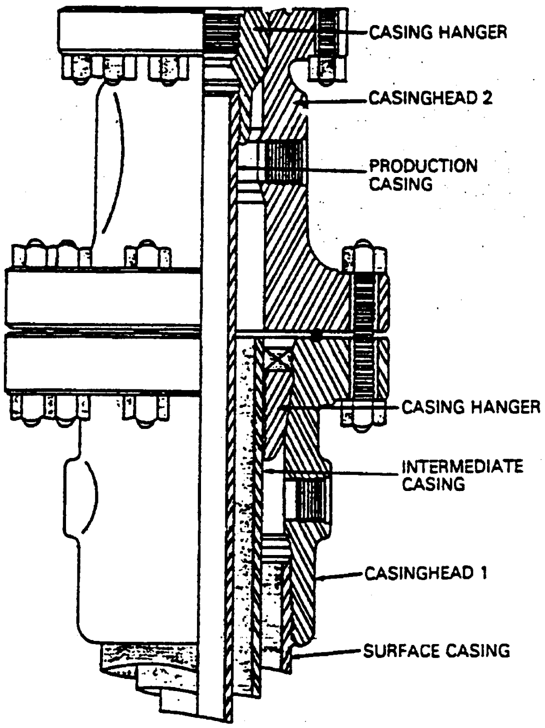

Figure 5.2 Casing Head

## Casing Hangers

A casing hanger is a device which sits in the bowl of the casing head or an intermediate casing head to suspend the next smaller casing string securely and provide a seal between the suspended casing and the casing-head bowl.

## Intermediate Casing

An intermediate casing is a spool-type unit or housing attached to the top flange of the underlying casing head to provide means of supporting the next smaller casing string and sealing the annular space between the two casing strings. It is composed of flange within an internal casing-hanger bowl.

The lower flange of an intermediate casing is counter bored with a recess to accommodate a removable bit guide, or a bit guide and a secondary-seal assembly, the purpose of the bit guide is to protect the top end of the intermediate casing string from damage by bits and tools going in the hole. By using a secondary seal, well fluids are confined to the body of the intermediate casing head and not allowed to contact the ring gasket or the pack-off on the casing hanger below. If the well fluids are corrosive, use of a dependable secondary seal is particularly important to protect the ring gasket.

## B. Tubing Head

A tubing head is shown in Figure 5.3 is a spool-type unit or housing attached to the top flange on the casing head to provide a support for the tubing string and seal the annular space between the tubing string and production casing string. It also provides access to the casing tubing annulus through side outlets. It is composed of a lower flange, one or two outlets, and a top flange with an internal tubing hanger bowl.

Tubing heads are generally two types:

a. With flanged bottom and flanged top.
b. Threaded bottom (usually screwed directly on the production casing string) and flanged top.

Like intermediate casing heads, the tubing head is constructed much in the same manner that a recess is provided to accommodate a bit guide or, a bit guide and secondary seal.

The top flange of a tubing head must be equipped with an internal bowl of the proper design to receive the required tubing hanger. Lock screws must be included in the top flange to hold the tubing hanger in place when manipulating the tubing under pressure.

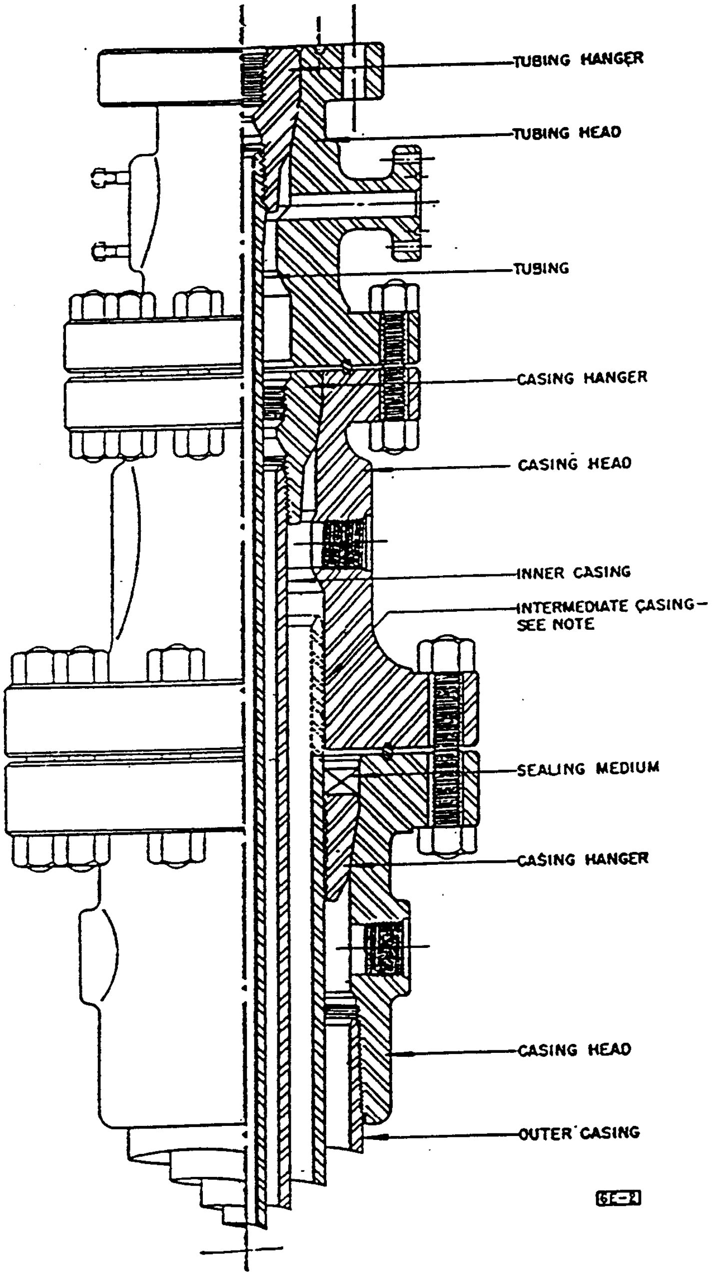

Figure 5.3 Tubing Head

## C. Christmas Tree

A Christmas tree as shown in Figure 5.4 is an assembly of valves and fittings used to control production and provide access to the producing tubing string. It includes all equipment above the tubing-head top flange. Many variations in arrangement of these fittings are available to satisfy the needs of any particular application.

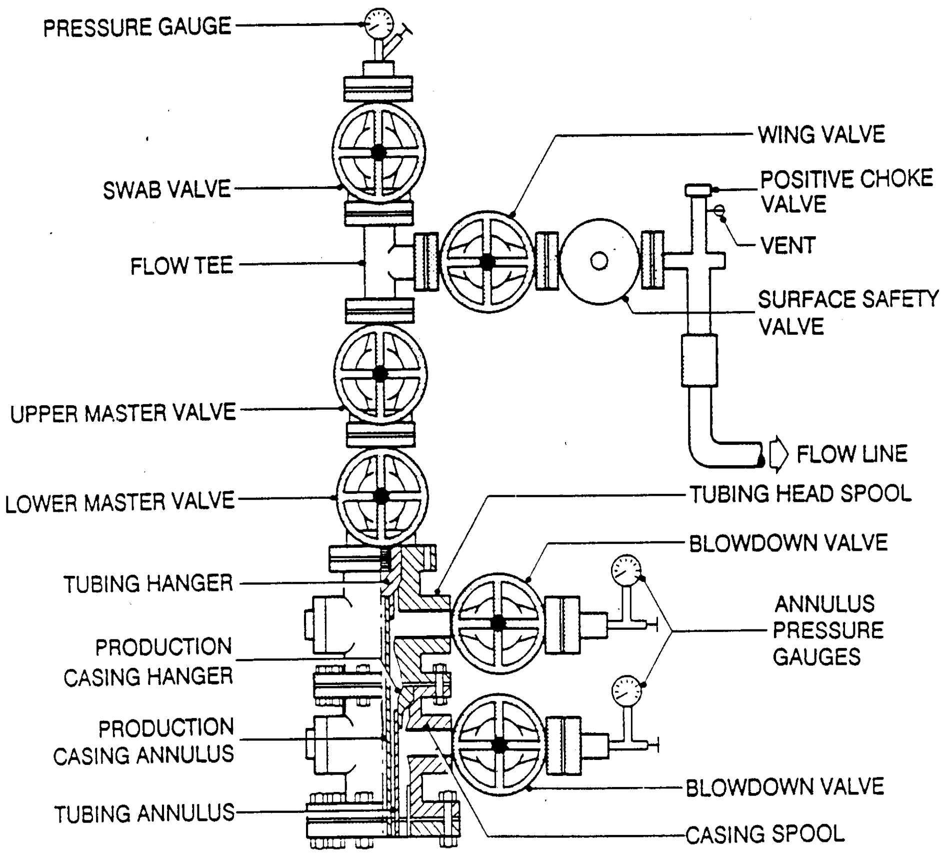

Figure 5.4 Typical Single Christmas Tree

## 5.1.3 Christmas Trees Assembly

All Christmas trees assemblies should be assembled, pressure tested to hydrostatic test pressure, and checked with a drift mandrel to assure full opening before installation.

The components of Christmas tree as shown in Figure 5.4 are:

- Lower master valve.
- Upper master valve.
- Wing valve.
- Swab valve.
- Safety valves.
- Check valve.
- Treetop adapter.
- Tubing pressure gauge.
- Casing pressure gauge.

### 5.1.3.1 Lower Master Valve

This is a manual gate valve fitted at the bottom of a Christmas tree which should be operated as seldom as is possible; e.g., only for very long periods of shutdown or for servicing of the next downstream valve. When it is operated the next valve downstream should always be closed. These two instructions are necessary to prevent wear of the tubing master valve. If it does wear then the well must be plugged before it can be serviced. To prevent excessive wear of the valve it should never be in a partially open position when the oil is following.

### 5.1.3.2 Upper Master Valve

This is used to open up or shut-in the well and for wire line operations. In order to reduce wear on this valve to an absolute minimum it is always opened first when opening up a well and shut last when shutting down a well. The upper master valve is equipped with a pressure controlled actuator being held in position by a high / low pressure pilot. The pilot receives impulses from downstream of the adjustable choke valve. If the pilot registers a high or low pressure the upper master valve will automatically shut, shutting in the well.

#### 5.1.3.3 Wing Valve

This is a manual gate valve which is used for normal well closing –in and opening-up oil production. It therefore gets the most wear. If it has been closed for some time the operator should be aware that on its upstream side there will be full static wellhead pressure, probably with a pocket of separated gas. To prevent the storm choke from closing, the wing valve must be opened very slowly. If there is gas its movement through the valve will have a distinctive sound. This sound will change when the oil reaches the valve. The expanding gas may cause a temporary frost at the valve and downstream from it. The wing valve should never be in a partially open position when the oil is flowing.

#### 5.1.3.4 Swab Valve

This is a manual gate valve which is opened to allow oil pressure through the top adaptor for reading pressure or taking samples. It also allows the wire line crew vertical access for operation inside the tubing string; e.g. work on the storm choke, or plugging the tubing string.

#### 5.1.3.5 Safety Valves

These valves operate automatically to close-in the well when the flow line pressure goes above or below set limits. Thus, it protects the flow line if the wellhead pressure goes too high and protects the well if the flow line pressure goes too low.

There are four general types in use:

- Safomatic.
- Manumatic.
- Baker Submersible.
- Cameron Type FC.

#### 5.1.3.6 Check Valve

This prevents any reverse flow from the line into the well. It has a hinged flap which lifts to permit normal flow, but closes to prevent reverse flow. Although fitted to many older installations, it is only necessary in dual completion, single flow line completions and is being removed from other types.

#### 5.1.3.7 Top Adaptor

The top adaptor is a fitting on top of the swab valve with a threaded connection of reduced size to accommodate a small needle valve. This needle valve is used for taking a sample or reading pressure. Caution is essential when opening it because of the very high static pressure which can be present in the wellhead manifold, especially when there is no flow to line.

#### 5.1.3.8 Tubing Pressure Gauge

Usually fitted to the treetop adaptor, the tubing pressure gauge measures pressure in the production tubing.

#### 5.1.3.9 Casing Pressure Gauge

Measures pressure in the tubing annulus.

### 5.1.4 Flow Control

Equipment for surface control of the flow of fluids from producing wells includes

1. Chokes,
2. Safety valves that close either by high or low flow line pressure or by remote signal, and
3. Pressure regulators.

#### 5.1.4.1 Chokes

#### Definition and Usage

A choke is a device which is installed in a flow stream to control the flow rate of produced well fluids. Some of the reasons for controlling producing rates are:

1. Government-regulated (prorated) production,

2. Prevention of possible formation damage such as water coning, and

3. Reduction of flowing pressure to permit the use of lower working pressure lines and equipment.

#### Types of Chokes

The two main classifications of chokes are:

1. Positive or fixed
2. Adjustable.

Adjustable chokes utilize a variable orifice which is controlled by hand wheel or handle. Positive chokes have a fixed orifice dimension which may be replaceable. The bodies of both types of chokes are L-shaped. End connections can be fully flanged, fully threaded, or a combination flanged – threaded design. The major parts of a choke are:

1. Body
2. Removable flow bean
3. Plug or cap for servicing flow bean of fixed chokes
4. Stem of adjustable chokes, and
5. Bonnet for servicing internal parts of adjustable chokes

The choice of the use of positive versus adjustable chokes quite often is determined by operating experience in a particular area.

## A. Positive Choke

### The Multiple Orifice Valve (Willis Choke)

This valve as shown in Figure 5.5 contains the choke and enables its opening diameter to be adjusted without interrupting the flow from the well. The choke consists of two porcelain disc (back disc and front disc) enclose in a seat. One disc is held stationary whilst the other is rotated to an intermediate position to control flow. This choke is less resistant to erosion so is not used on “sandy” wells.

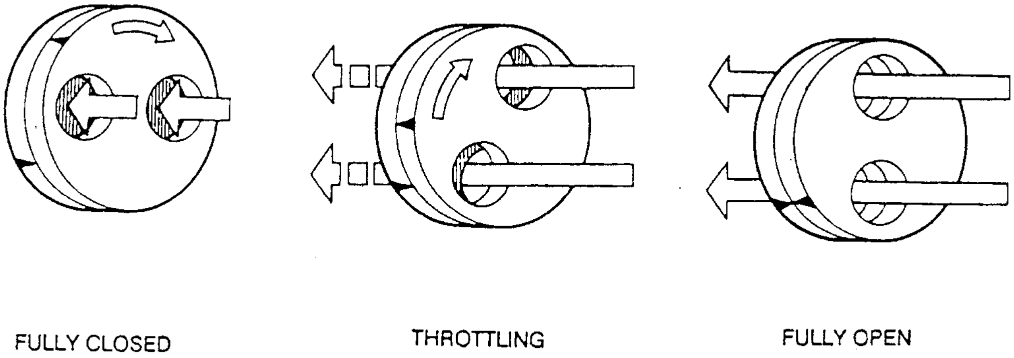

**Figure 5.5 Willis Choke**

### The Rotary Choke

This type of choke (Figure 5.6) uses an indexing disc with six different size replaceable beans to give fixed rates of flow. The beans are chosen to suit the productive capacity of the well. One of the beans can be a blank in order to obtain a positive shut-off of the well when necessary.

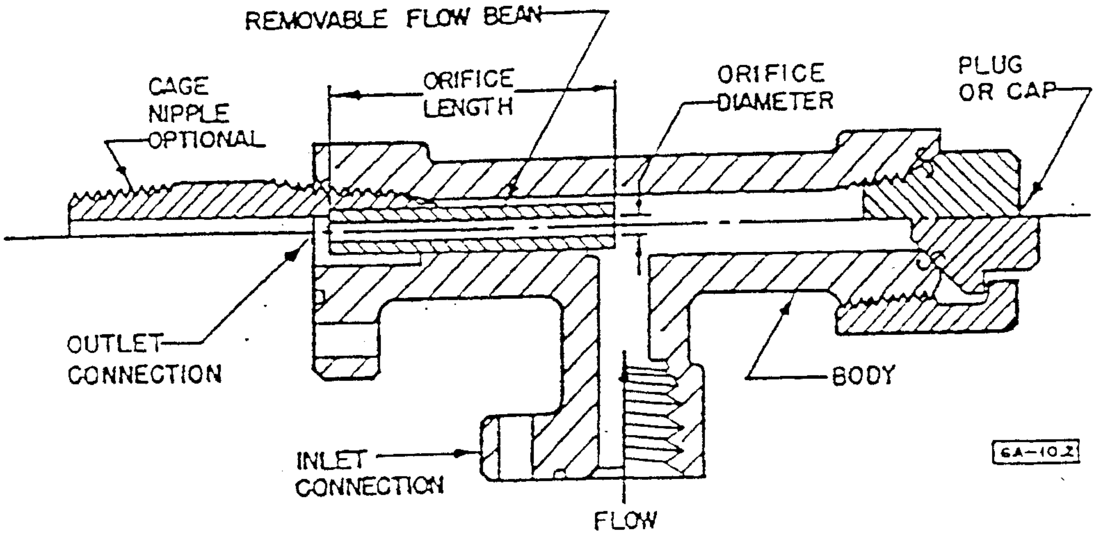

Figure 5.6 Positive Choke

## Advantages of Positive Chokes

Utilization of this type of choke is advantageous under the following operating conditions:

1. Fairly constant flew rates
2. Adequate (both technically and amount) labor supply
3. Erosive and/or corrosive effects or the produced fluids are minimal, and
4. Adequate stock of various sizes of flow beans.

## Disadvantages of Positive Chokes

Some of the disadvantages of fixed chokes are:

1. Inability to adjust flow rates without removing the choke from service
2. Could require stocking of many sizes or flow beans, and.
3. Frequent flow bean changes to maintain the desired flow rates.

## B. Adjustable Choke with Changeable Bean

This type of choke is shown in Figure 5.7 and is similar in construction to a needle valve. It contains two beans, the master bean and a changeable or probation bean. Further adjustment is made using a hand wheel operated stem which terminates in a needle valve.

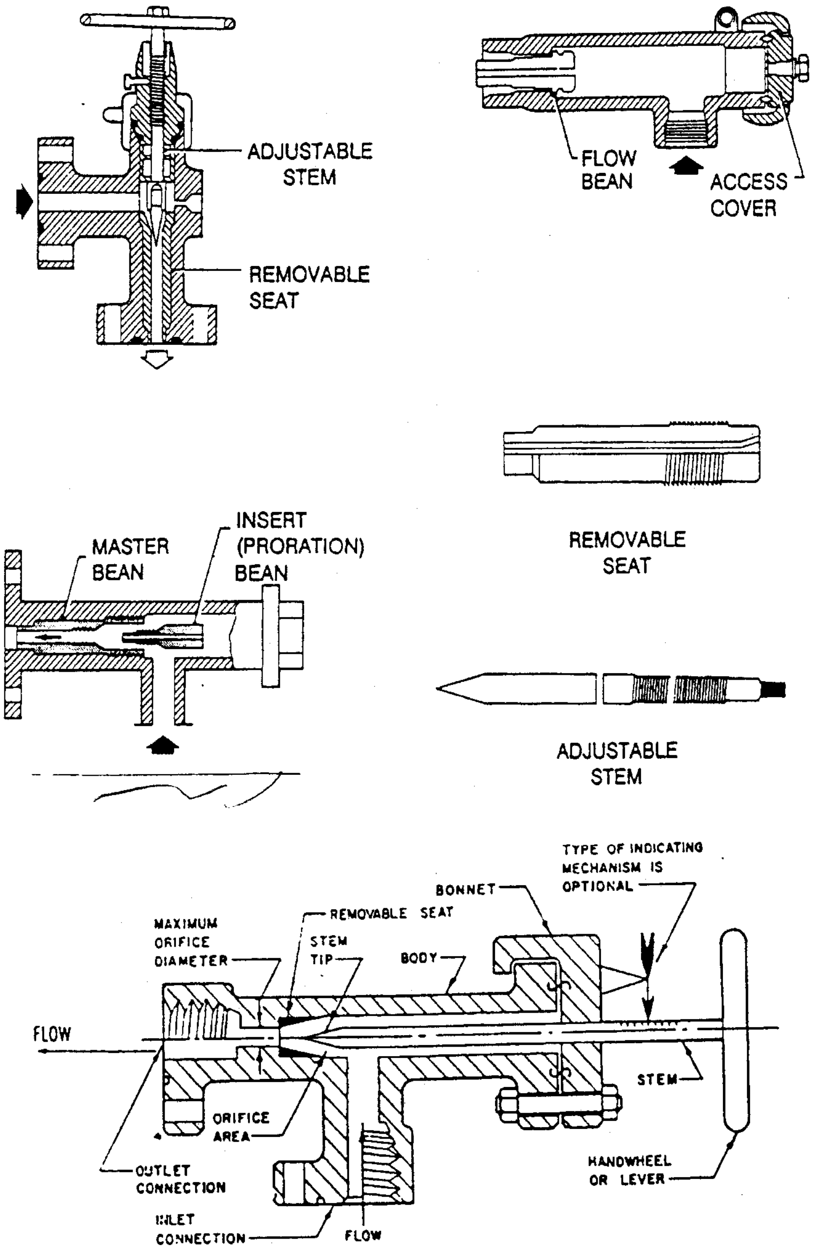

Figure 5.7 Adjustable Choke

## Adjustable Choke Usage

Adjustable chokes are seldom used for well flow regulation in areas of sand production because it quickly erodes the needle valve point and seat. However, they are used frequently in other areas and almost universally in water flood "injection wells where the fluid injected is free of abrasive materials. This type of choke is of particular advantage during the initial production and testing of a well. Discrepancies in sizing can be corrected without taking the choke out of service. Variable orifice chokes are more economical than the fixed type where producing rates change often.

### Factors that cause production changes are:

1. Market demand.

2. Make-up requirements when other wells are shut-in for various reasons such as remedial work, mechanical failures, etc. This is especially important during periods of peak demand.

3. Changing reservoir and fluid characteristics such as increased free water production, increased gas-oil ratio, declining bottom-hole pressure, etc.

4. Erosion and/or corrosion of the flow bean or choke body will change the orifice diameter, which will increase the producing rate above the desired amount. This correction can be made without removing the choke from service, whereas a positive choke would require a new flow bean of the correct size.

### The advantages of using an adjustable choke are:

1. Sizing errors can be corrected without changing the orifice.

2. Allows standardization of orifices with a single size or a few sizes which are applicable over a wide range of flow rates.

3. Provides an adjustment range during erosion and/or corrosion attack of the orifice area.

**The limitations of the adjustable choke are listed below:**

1. Initial costs are approximately 50% more than a positive choke for the same application.

2. It is not designed to provide a full shut off; as a gate valve for example. Since this is true in most applications, the fixed orifice choke is as good as the adjustable in this manner. A valve which provides full slut-off must be installed upstream and downstream of both types of chokes for servicing.

3. Impingement of produced fluids on the stem of this type of choke may cause adjustment problems. This can happen if sand is produced. Normally, the stem and stem tip are of an exotic metal construction such as stainless steel, K-monel, Stellite, etc, which increases costs.

4. Production of fluids carrying solid particles such as sand or granite wash may erode the more expensive adjustable choke body and internal parts just as rapidly as the positive type. This is a case where the less expensive choke is more economical than the other.

### 5.1.4.2 Choke Selection and Sizing.

Operating experience is the main consideration in selection and sizing of chokes for an existing well or field trial and error methods are normally involved in designing the most economical size and type. Manufacturer's representatives can be an important source of design data. Information obtained from other operating companies with similar producing conditions is also helpful.

The following is a list of some of the core important factors in sizing a choke:

1. Pressure. Wellhead shut-in pressure determines the rated pressure of the choke. Inlet and outlet choke pressures for specific fluids are necessary parameters which must be known before a design can be initiated.

2. Produced fluid volumes. Gas-oil ratio, water cut, and knowledge of specific gravities of each fluid are the other factors which affect choke sizing.

3. Less important, but some of the factors which should be considered, are sand production, paraffin problem, corrosion, hydrate formation, flowing temperatures, etc.

### 5.1.4.3 Flow Rate Calculation

**Note:** "rate" means anything per unit time. So a time factor (T) is in second, hour, day or even a year (annum) will always appear in the denominator.

| Unit | | FACTOR | | Unit |
|---|---|---|---|---|
| $M^3$ per hour ($M^3$/ hr) | × | 151 | = | Bbl per day (Bbl/ day) |
| $M^3$ per hour ($M^3$/hr) | × | 847.6 | = | Cu ft per day (Cu ft/day) |
| Gal per min (GPM) | × | 5.420 | = | Bbl per hr (Bbl/hr) |
| MM Cu ft per day<br>(MM Cu ft/d) | × | 1180 | = | $M^3$ per hr ($M^3$/hr) |

At this point it is worth noting that oil rate is often mentioned in bbls/day as well as metric tons/day. The former is on volumetric basis while the latter is on weight basis, where the density or specific gravity of the fluid in question comes into play. So the two units must not be confused. For accurate conversion from bbls to metric tons, one must know the specific gravity of the liquid and proceed in the following manner:

**Example:** Let's say a particular well produces at the rate of 1000 bbls/day. What should be the yield per year expressed in thousand metric tons, when oil gravity is 0.834?

$$1000 \text{ bbls/day} = 1000 \times 5.615 \ \frac{\text{Cu ft}}{\text{Day}} \qquad (1 \text{ bbl} = 5.615 \text{ Cu ft})$$

$$= \frac{1000 \times 5.615}{35.351} \times \frac{M^3}{\text{Day}} \qquad (1 \ M^3 = 35.315 \text{ Cu ft})$$

$$= \frac{1000 \times 5.615}{35.351} \times 365 \ M^3/\text{ annum} \qquad (365 \text{ days} = 1 \text{ yr})$$

$$= 58034.12 \ M^3/\text{ annum.}$$

Now 1 $M^3$ of 5.00 Sp. Gr. liquid weight 1 Metric ton
So, 1 $M^3$ of 0.834 Sp. Gr. liquid weights 0.834 metric tons.

$$58034.12 \ M^3/\text{ annum} = 48400.456 \text{ metric tons/annum}$$
$$= 48.4 \text{ MT/annum} \qquad (\ M = 10^3)$$

So the well will yield 48.4 MT/ annum of 0.834 gravity crude.

However, for Quick Calculations, which is approximate, one can use the factor:
1 bbl/day = 50 metric tons pr year.

## 5.1.5 Well Control (Protection)

### 5.1.5.1 Safety Controls

Reason for use of Safety Controls Automatic is to shut-in equipment for producing oil and gas wells and can be installed down hole and/or on the well head. This safety equipment is necessary if it is desired to automatically shut off well flow in case of a blowout and/or fire. In addition to the extreme costs involved in controlling a blowout, such disasters can:

5. Damage the producing reservoir,
2. Destroy surface equipment and surrounding property, and
3. Imperil the safety of company personnel or other individuals.
4. Another important economic consideration is the lost production until normal operations are restored.

Blowouts of "wild" wells can result from surface equipment failures or sabotage. Examples of incidents causing surface equipment failures are:

1. Sand-laden fluid eroding a hole in a choke or flow tee,
2. Flow line or sales line break,
3. Separator or treater malfunction, or
4. Wellhead failure as a result of being struck by a truck (on shore) or a boat or anchor (offshore).

**Types of Well Safety Valves.**

Two main classifications of well shut-in valves are:

1. Down hole or tubing safety valves, and
2. Surface valves.

These valves are controlled directly by sensing pressure or can be hydraulically (remote) controlled.

Use of High-Low pressure surface safety valves. High or low pressure safety valves generally installed at the Christmas tree are used to shut-in flowing wells automatically when the flowline pressure increases or decreases beyond predetermined limits. For example, well flow lines in offshore location frequently are damaged or broken by shell dredges or dragging boat anchors. The resulting drop in flowline pressure closes the automatic valve at the tree. Similarly, a blockage in the flowline resulting from paraffin or freezing hydrates my build up flowline pressure in excess of a predetermined limit and shut in the well, thus protecting flow lines, separation, and treating equipment.

Consideration should be given to using this type of valves at the following locations and conditions.

1. Isolated localities visited infrequently.
2. Populated areas.
3. Remote locations requiring automatic control.

#### 5.1.5.2 Surface Control Devices

These valves operate automatically to close-in the well in the cases of emergency and as a mean of well flow line and facilities protection against system failure.

#### A- Safomatic SSV

This valve blocks the oil flow by releasing a steel ball into the flow stream. Oil pressure moves the ball against a seat and holds it there until it is reset manually. The flow line pressure is monitored internally by springs incorporated inside the valve.

#### B- Manumatic

This valve uses a gate to block the oil flow. The gate is moved by a pneumatically pressurized actuator controlled by pilots who are continuously monitoring the flow line pressure. After a closure the gate will automatically re-open if the flow line pressure returns to normal. A hand wheel is incorporated for manual operation.

#### C- Surface Controlled-Surface Safety Valve (SC-SSV)

This is a gate-SSV operated hydromatically by a flow line high & low-pressure pilots sensing pressures from the flow line and surface hydraulic control unit which is pneumatically gas operated. This surface hydraulic control unit is operating both SSV & SSSV if well is completed with down hole SC-SSSV.

Direct controlled tubing safety valves close in predetermined conditions and they do not offer protection until these conditions exist.

### 5.1.5.3 Subsurface Control Devices

Mainly two types of subsurface control devices are used in an oil well.

a. Surface controlled subsurface safety valve or SCSSSV.
b. Removable tubing safety valve or a storm chokes.

#### 5.1.5.3.1 Surface Controlled Subsurface Safety Valve (SCSSSV)

A SCSSSV or simply SSSV is a fully opening safety device for installation in the tubing string below the surface.

**The purpose of this type of safety valve**
To shut off flow through the tubing in the following cases:

1. Surface pressure vary above or below predetermined limits because of surface equipments damage
2. A flow line break,
3. Excessive flow line pressure,
4. A fire or emergency shut down in the installation or actuation of high gas, or
5. H2S alarm in the installation.

The valve may also be closed manually with a surface control, hence the name.

The device consists of a tubular housing, made up as a part of the tubing string which contains a spring-operated, pressure controlled **rotating ball** or **flapper** type valve.

#### A. Flapper type SCSSSV (AFPC application)

The flapper is pushed open by means of a telescopic flow tube which in turn is pushed down by applying hydraulic pressure through a 1/8” or 1/4 “ tube from the surface. The absence of hydraulic pressure causes the flow tube to be retrieved at its normal position due to spring action, snapping the flapper shut against the tubing bore, thereby preventing flow,. In order to keep the SCSSSV continuously open, it s therefore necessary to keep the hydraulic line continuously charged by the hydraulic fluid (Figure5.8).

In case of an emergency, the logic circuit automatically bleeds of the hydraulic pressure, thereby snapping the valve close. In order to open the valve, it is first necessary to equalize the valve from either side. The bottom of the flapper would assume well shut in pressure after some time after closure of SCSSSV. So an equivalent amount of pressure has to be exerted atop the flapper by depressurizing the well, filling it up with water (up to the top of SCSSV flapper) and then pressuring it by using high pressure pumps. Once the well is equalized, hydraulic pressure is applied through the servo line, and the valve is opened.

Care should be taken while applying hydraulic pressure. It should not be increased suddenly, lest the flow tube slips and damages the safety valve permanently.

### B. Tubing-Retrievable, Ball-Type SC-SSSV

The Ball Type Tubing Retrievable Valves (Figure 5.9) are normally closed valves held open by hydraulic pressure. Upon loss of the hydraulic pressure, the large springs alone are designed to lift the hydrostatic head of the hydraulic fluid and to mechanically rotate the ball into its closed position, regardless of tubing pressure.

Valves operate on a hydraulic-piston principle. To open the valve, it is recommended that pressure (equal to or greater than well static pressure) be applied to the tubing to equalize across the ball before hydraulic control pressure is applied to open the valve. Further application of the pressure forces the piston to rotate the ball into an open position.

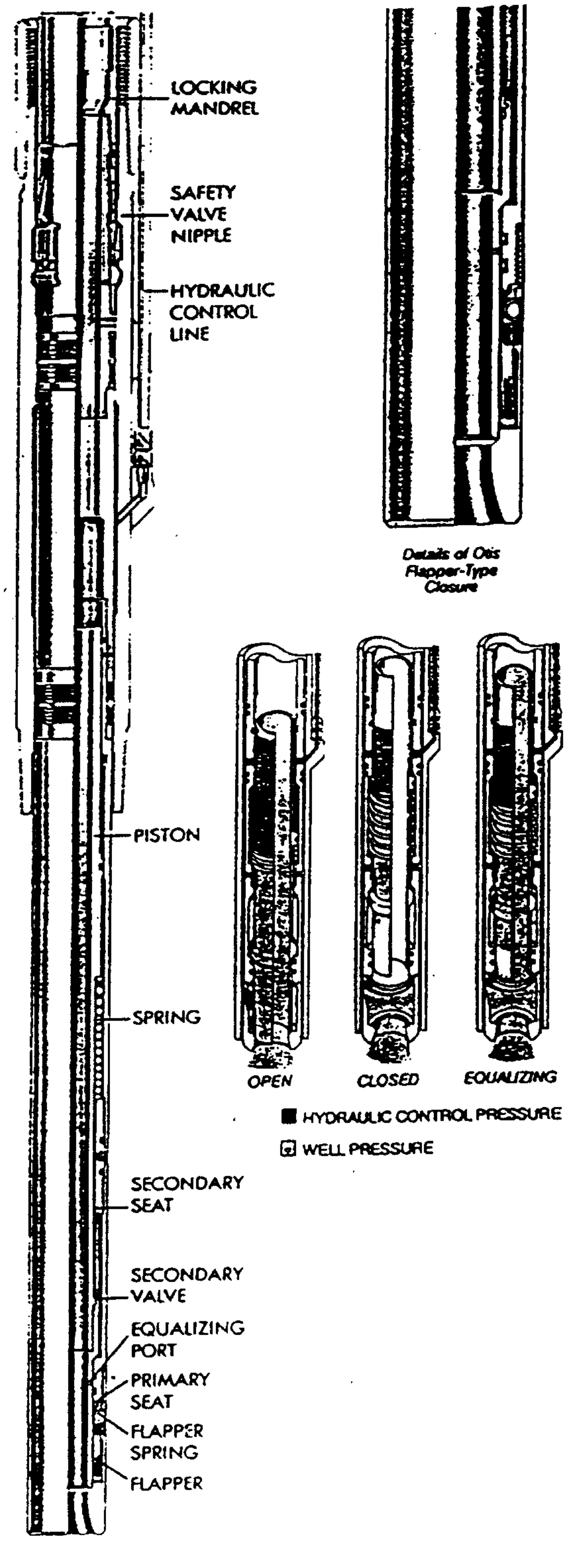

Figure 5.8 Flapper type SCSSV's

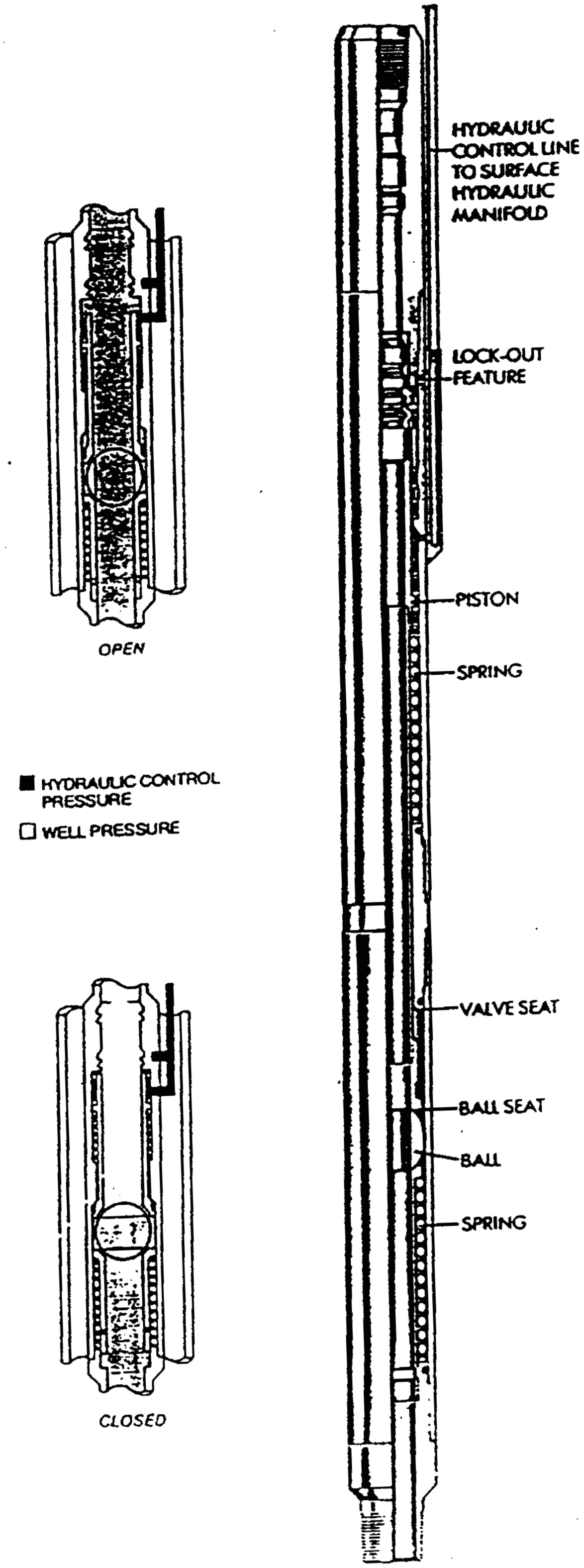

Fig ing Retrievable, Ball Type SC-SSSV

### 5.1.5.3.2 Removable Tubing Safety Valve (Storm Choke)

The SCSSSV is an integral part of the tubing. So to remove it one has to remove the tubing, i.e. deploy a work over rig. Storm choke, however, is a safety valve, located inside the tubing, which can be removed and replaced by wire line operations.

The storm choke is a safety valve (Figure 5.10) fitted inside the tubing at a depth of 1000m. Its function is it close automatically if there is an abnormally high flow of oil through the wellhead above. Once it has closed it will not re-open automatically, but must be re-opened by the use of special wire line equipment. This is a complicated and expensive operation which is carried out by a trained wire line crew. The conditions which will close the storm choke occur when there is a burst at the wellhead or in the flow line. Such a burst will cause the oil to flow out of the well very rapidly, with an equally rapid drop in pressure. It is this rapid pressure drop which triggers the storm choke, in fact any rapid pressure drop can trigger it, for instance, quick and careless opening of wellhead valves by an operator. For this reason care and attention are essential on all wellhead operations.

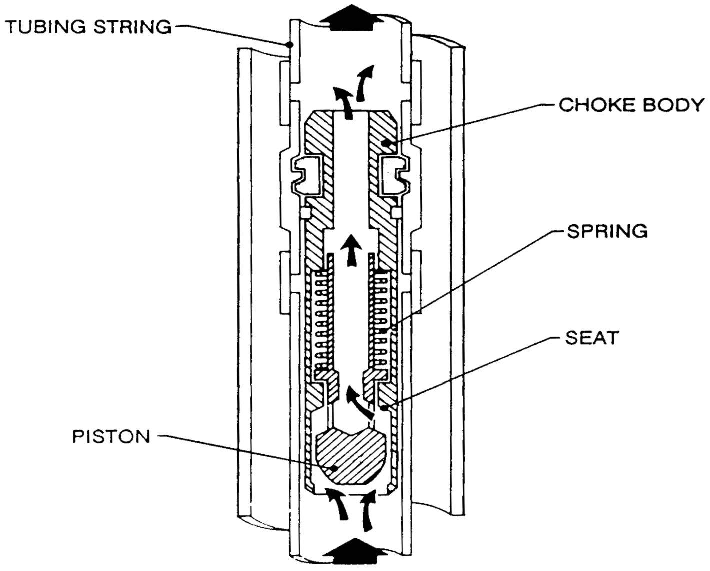

Figure 5.10 Storm Choke

# 5.2 FLOW LINES

## 5.2.1 Introduction

The flow line connects the wellhead to the flow station. A gate valve or a ball valve is fitted in the line near to the wellhead for isolation purpose. At the flow station the line enters the arrival manifold through another isolating valve.

Where the line crosses roads, railways, etc. it is buried at a safe depth, otherwise it is laid at ground level on concrete or metal supports. Whenever possible its routs is chosen with regard to access for servicing, so that instead of taking a straight line from well to flow station it will follow public roads and company service roads. In more remote areas the line cuts through open country which has been purchased and cleared by the company. For both safety and access a clearance of up to 15m is provided to each side. Laying the line on the surface gives rise to problems of damage and rust. Because of these an operator’s duties include inspection tours along the line routes.

Although it is only a pipe laid across the ground and has no moving parts, the flow line is as vital as any other item of plant. It should not be regarded as just another piece of pipe. There are several factors which affect its design and dimensions. Two of them are, the flow rate and properties of the fluid. The thickness depends on the working pressure of the fluid and on the strength of the steel from which the pipe is manufactured. The pipe is usually 6 inches outside or 4 inches outside diameter, depending on its length. Information on this is found in standard tables and recommendations.

## 5.2.2 Pressure Losses

Fluid moving through a pipe loses energy because of friction between the fluid and the pipe wall. This causes a reduction of pressure along the pipe. The degree of reduction depends on; the flow rate, the line length, the line diameter, the fluid viscosity, the quantities of the fluid and the gas-oil ratio. Thus the arrival manifold pressure will always be lower than the wellhead manifold pressure. The difference should be reasonably consistent from day to day; a wide variation should be investigated and reported.

If the flow stops then there will be no friction loss and the pressure should equalize along the whole length of the line, except for differences in head if the pipe rises and falls along its routs. If a difference does appear during static conditions it could be an indication of a leak or blockage and should be investigated and reported.

# 5.3 INLET MANIFOLDS

## 5.3.1 Introduction

### Definition

Manifolds, as applied here, are the means by which the production from several wells are combined before being routed to production equipment, such as an oil and gas separator, or, if the gas-oil ratio is quite low, to a treater or storage tanks. In other cases the manifold must isolate the stream from one well from the other well streams and send it to a test separator. The term header, when used in connection with a manifold, refers to a pipe conduit passing through the manifold which, through appropriate valving and connections, can accept fluid from any one of several inlets to the header.

### Manifold

Manifolds vary in complexity depending on many factors, but a standard manifold might include the following:

1. Production header,
2. Test header, and the
3. Necessary valves for operation.

A typical manifold including these items is shown in Figure 5.15. If wells of appreciably different flowing pressure were routed into a manifold, it would probably be necessary to segregate the wells into two or more streams. In this case the production header would be expanded to include ***high pressure*** and ***low pressure*** production headers. Other installations could require segregation on a different basis for example, wetness or dryness (water content) of the oil produced. Should there be a requirement to blow-down the flow lines from the individual wells to a pit, a blow down header would also be included in the manifold.

## 5.3.2 Manifold Headers and Their Functions (Figure 5.11)

### 5.3.2.1 High-Pressure Header

This header will take production from the individual wells coming into the manifold that fall into the high-pressure category and route the combined flow to production equipment, probably an oil and gas separator. The kind of production coming into the header will determine the valving necessary on the individual wells upstream or the header. In most all cases a check valve will be required on each flow line; also an isolating valve of some description. This header must be sized so that the flow velocity stays within the prescribed limits. A grade and wall thickness of pipe must be chosen that will safely withstand the maximum pressure to which the header will be subjected.

### 5.3.2.2 Low-Pressure Header

This header will take production from the low-pressure wells and route the combined stream to the production equipment. This equipment naturally will not be the same as used to process the oil from the high-pressure header-otherwise there would be no need for separate headers. Depending on the relative amount of production, this header may be larger or smaller than the high-pressure header. For the same amount of production and the same gas-oil ratio, this line would have to be larger than the high-pressure header to maintain velocities within prescribed limits. Valving and piping would normally be the same as for the high-pressure header except for size and working pressure.

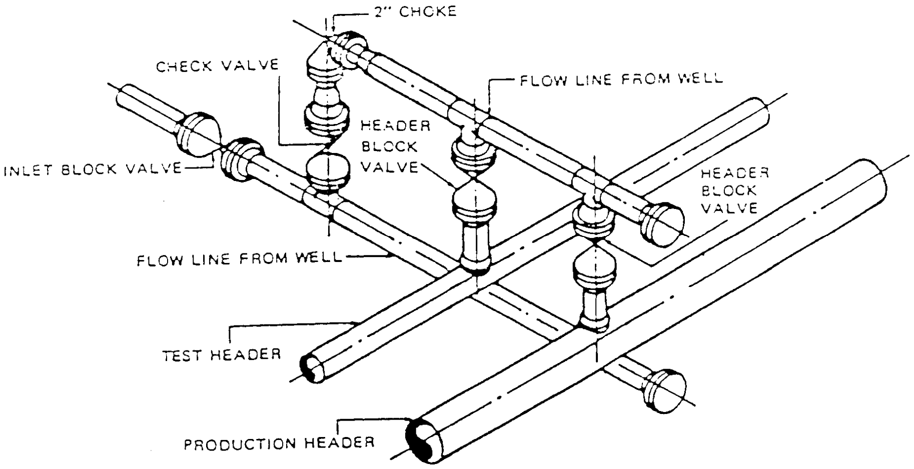

Figure 5.11 Basic Elements of a Manifold

### 5.3.2.3 Blow down Header

A blow-down header would be necessary if blowing down the flow lines from the individual wells at the manifold is a requirement. This may be necessary if nominal amounts of paraffin, sand, salt or other material is likely to precipitate in the flow lines from the wells. Heavy amounts of accumulation might require the inclusion of equipment for "pigging" wire lines, etc. About the only auxiliary equipment necessary for this head would be a valve from the individual well flow line to the header. Since high velocities will likely be encountered when wells are "blown" through this header, it is quite important that sturdy hold-downs be supplied to prevent movement and/or vibration.

### 5.3.2.4 Test Header

Testing of the individual wells on a periodic basis is usually necessary. This will require a test header that enables one well at a time to be turned into the header and routed to the test equipment.

### 5.3.2.5 Shutdown Valves

A shutdown valve is fitted, on each outlet from the inlet manifold as follows:

- Located on the LP bulk line at the outlet from the LP bulk header. When shut it cuts off the flow of crude oil to the downstream process train system components.

- Located on the HP bulk line at the outlet from the HP bulk header. When shut it cuts off the flow of crude oil to the downstream process train system components.

- Located on the high flow test separator inlet from the high flow test header when shut it cuts off the flow of crude oil to the high flow separator.

- The bulk arrival takes all inputs collectively to the bulk separator. The test arrival manifold takes one input individually to the test separator.

## 5.3.3 Inlet Manifold Components (Figure 5.11)

### 5.3.3.1 Isolating Valves (BV'S)

The two isolating valves are manually operated ball-block valves. These are fitted one on each of the two branch pipes which connect the flow line to the bulk and test manifolds.

In usual operations, one branch is open and the other is closed, thus the flow line is connected to the bulk manifold or to the test manifold. When re-directing the flow from one to the other, an operator should be aware that incorrect valve sequencing could block the oil flow and cause the line pressure to rise high enough to trigger an automatic closure at the wellhead (SSV). To avoid this, open the closed valve before closing the open valve and turn both of them evenly, slowly and simultaneously.

### 5.3.3.2 Check Valve

The check valve is one way/none return-valve serves to prevent back flow opposite to the normal flow direction for a number of reasons in a given system.

### 5.3.3.3 Chemical Injection point

This enables injection of emulsifiers into the oil stream at a point which will ensure adequate mixing before separation begins. Only one or two points are in use at any one time in a multi-input flow line group.

### 5.3.3.4 Instruments

A pressure gauge and a temperature indicator are fitted for routine conditions checks.

### 5.3.3.5 Safety Relief Valve

Each manifold, header and each collector line is fitted with a separate relief valve. Each SRV is preset at a specific pressure to function when this high pressure limit is reached. The discharge is piped to the burning pit or flash drum and will continue as long as the high pressure exists. When normal pressure is restored the valve will be kept closed automatically.

# Chapter 6

# Gas Liquid Separation

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## Chapter 6

# Gas Liquid Separation

## 6.1 INTRODUCTION

In an oilfield separation system the substances to be separated are oil, water and gas. The difference in this case is density.

Before we go on to consider the oilfield separation process in more detail, let's look at the components to be separated.

**Crude Oil** this is a complex mixture of hydrocarbons produced from the reservoir in liquid form. Its density usually ranges from around 40 lb/cu ft, to 55 lb/cu ft.

**Natural Gas -** which is associated with an oil accumulation may be termed **free gas** or **dissolved gas.**

- **A- Free Gas** is a hydrocarbon mixture which exists in a gaseous state at reservoir conditions of temperature and pressure. It remains as a gas when it is produced under normal conditions.
- **B- Dissolved Gas** is dissolved in the oil at a certain temperature and pressure. If the pressure is ft reduced and/or the temperature is increased, the dissolved gas may be liberated from the oil. When this occurs the gas assumes the characteristics of free gas.

The density of the gas depends upon the pressure at which it is confined. At 750 psi a typical hydrocarbon gas may have a density of 2.25 lb/cu ft. However, at atmospheric pressure the density of that same gas may only be 0.1 lb/cu ft.

There is a relationship between the volumes of gas and oil produced from a reservoir. This relationship is known as the **Gas Oil Ratio (G.O.R.).**

G.O.R. is defined as the volume of gas produced per unit volume of oil production. The usual oilfield units for this ratio are standard cubic feet per barrel (scf/bbl).

**Water** produced with oil or gas may be in the form of liquid or vapour. The liquid water may also be in the form of free water or it may be emulsified in the oil. Other units in the Petroleum Processing Technology Series will deal with the problems of oilfield emulsions and water vapour in gas. In this unit we will just concern ourselves with the separation of free water from the oil and gas.

Produced water is usually salty and has a density somewhat higher than that of sea water. Typical oilfield water may have a density of 67 lb/cu ft.

If the three reservoir fluids of oil, water and gas were to be placed in a closed container and allowed to stand, separation would occur.

The water, being the densest of the fluids, would sink to the bottom of the container. The oil would float on top of the water. Finally, gas, the least dense component, would occupy the space on top of the oil.

This then is the basis of oilfield separation.

However, reservoir fluids are being continuously produced and must be continuously separated. This takes place in one or more pressure vessels which are designed to achieve optimum separation as a continuous process.

## 6.2 SEPARATION PROCESS

The process can be described as:

- Three phase separation, or
- Two phase separation

The phases referred to are oil, water and gas. In two phase separation, gas is removed from total liquid (oil plus water). In three phase separation, however, in addition to the removal of gas from liquids, the oil and water are separated from each other.

**Figure 6.1** shows the difference between 2 and 3 phase separation in a very simplistic way.

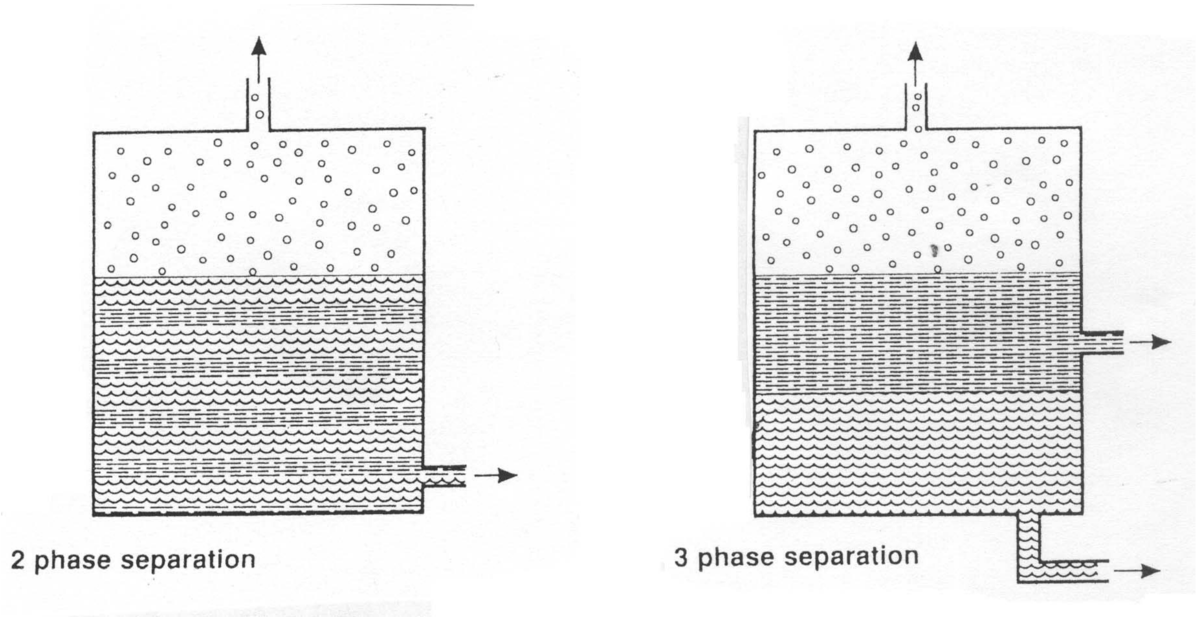


**Figure 6.1 The Difference between 2 & 3 Phase Separation in a Very Simple Way**

## 6.3 PRINCIPLES OF SEPARATION

The objective of ideal separation is to separate the hydrocarbon stream into liquid-free gas and gas-free-liquid.

Ideally, the gas and liquid reach a state of equilibrium at the existing conditions of Pressure and Temperature within the vessel.

Two factors are necessary for separators to function:

1- The fluids to be separated must be insoluble in each other.
2- One fluid must be lighter than the other.

Separations depend upon the effect of gravity to separate fluids. If they are soluble in each other, no separation is possible with gravity alone. For example, a mixture of distillate and crude oil will not separate in a vessel because they dissolve in each other. They must be segregated in the distillation process.

### 6.6.1 Gravity Separation

Since a separation depends upon gravity to separate the fluids, the ease with which two fluids can be separated depends upon the difference in the density or weight per unit volume of the fluids.

In the process of separating gas from liquid (**Figure 6.2**), there are two separation stages:

1- Separate liquid mist from the gas phase.
2- Separate gas in the form of foam from the liquid phase.

Droplets of liquid mist will settle out from gas, provided:

- The gas remains in the separator long enough for mist to drop out.
- The flow of the gas through the separator is slow enough that no turbulence occurs, which will keep the gas stream stirred up so that the liquid has no chance to drop out.

The difference in density between the gas and liquid will determine the maximum flow rate of gas that will allow the liquid to settle out. For example, mist will drop out of gas at 52 bars (750 psi) pressure as long as the gas is moving less than 31cm/sec (1 ft/sec). In other words, the separator has to be large enough so that the gas travels from the inlet nozzle to the outlet nozzle at a rate of 31 cm/sec (1 ft/sec), or less.

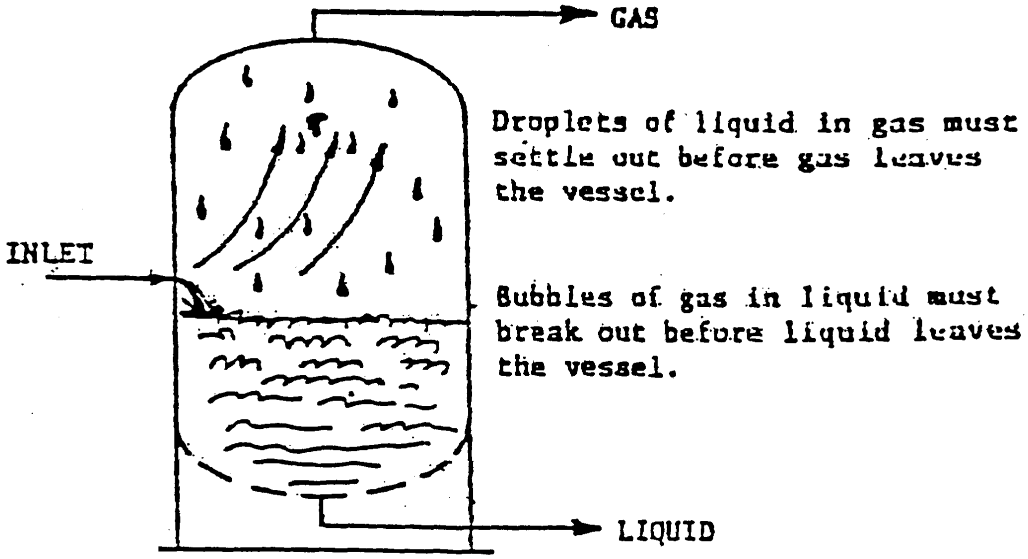


Figure 6.2 Separation Process

It has been stated that gas at 52 bars (750 psi0 weighs about 0.036 kg/l (2.25 lb/cu.ft), whereas it weighs only 0.0016 Kg/l (0.10 lb/cu.ft) at 1 bar (15 psi). Since its density is lower at 1 bar (15 psi), the oil droplets will settle out faster because there is greater difference in density between the low-pressure gas and oil.

Consequently, the gas can flow faster in the separator. In fact, it can flow at 1.52 m/sec (5 ft/sec) and not interfere with the liquid droplets as they settle out. Gas bubbles in the liquid will break out in most oilfield applications in 30 to 60 seconds. Consequently the separator is design so that the liquid remains in the vessel for 30 to 60 seconds. The length of time that the liquid remains in the vessel is called its **residence time.**

## 6.6.2 Separation System Problems

There are many problems that confuse the separation process as follows:

- Slugs of liquid.
- Dust.
- Oil fogs.
- Mists.

Therefore, it is necessary to carry out additional separation to remove them from the incoming stream.

**Dust:** causes erosion of compressor intake valves and plugging of small orifices in various controlling and process equipment.

**Oil fogs and mists:** Create environmentally and process equipment problems because they contaminate lubricants, chemical and desiccants.

These are common problems in natural gas pipelines, compressor stations, conditioning equipment, and control systems.

## 6.6.3 Factors Affecting Separation

The factors that affect the operation and separation between the oil and gas phases in a separator are:

- Fluid stream composition.
- Operating pressure.
- Operating temperature.

Changes in any one of these factors on a given fluid stream will change the amount of gas and oil leaving the separator.

Foaming and emulsion will also affect the capacity of separation in a separator. Foam must be broken to obtain a good gas-oil separation. It takes time (length) to breakout physically; chemical like silicon compounds may be used.

## Effect of factors that cause separation

| *Separation factor* | *Effect of factor* |
|---|---|
| 1. Difference in weight of fluid. | Separation is easier when weight difference is greater. |
| 2. Residence time in separator. | Separation is better with more time. |
| 6. Coalescing surface area. | Separation is better with more area. |
| 4. Centrifugal action. | Separation is better at higher velocity. |
| 5. Presence of solids. | Makes separation more difficult. |

Separation of oil and gas is a critical field processing operation and becomes a part of the gas processing necessary properly to condition the gas properly.

## 6.4 PHASES OF SEPARATION

The total process within the separator can be broken down into 4 parts which we will follow now (**Figure 6.3**).

### 6.4.1 Primary Separation

As the reservoir fluids enter the vessel an initial separation of gas and liquid takes place. This happens because of:

- a reduction in velocity
- a reduction in pressure
- a change in flow direction

***The velocity*** of the inlet stream is reduced as the fluids flow from a relatively small diameter pipeline into the large volume separator.

***The pressure*** is reduced by maintaining a controlled pressure on the vessel lower than that of the inlet stream.

***The change in flow direction*** is accomplished by placing some form of deflector at the inlet to the separator.

### 6.4.2 Secondary Separation

After the initial separation, gas will flow towards the outlet of the vessel. However, it will still contain a certain amount of liquid in the form of droplets. In the secondary separation process these liquid droplets are removed from the gas stream.

Liquid droplets which are suspended in the gas stream will tend to fall or 'settle' towards the bottom of the vessel. This is simply due to the force of gravity.

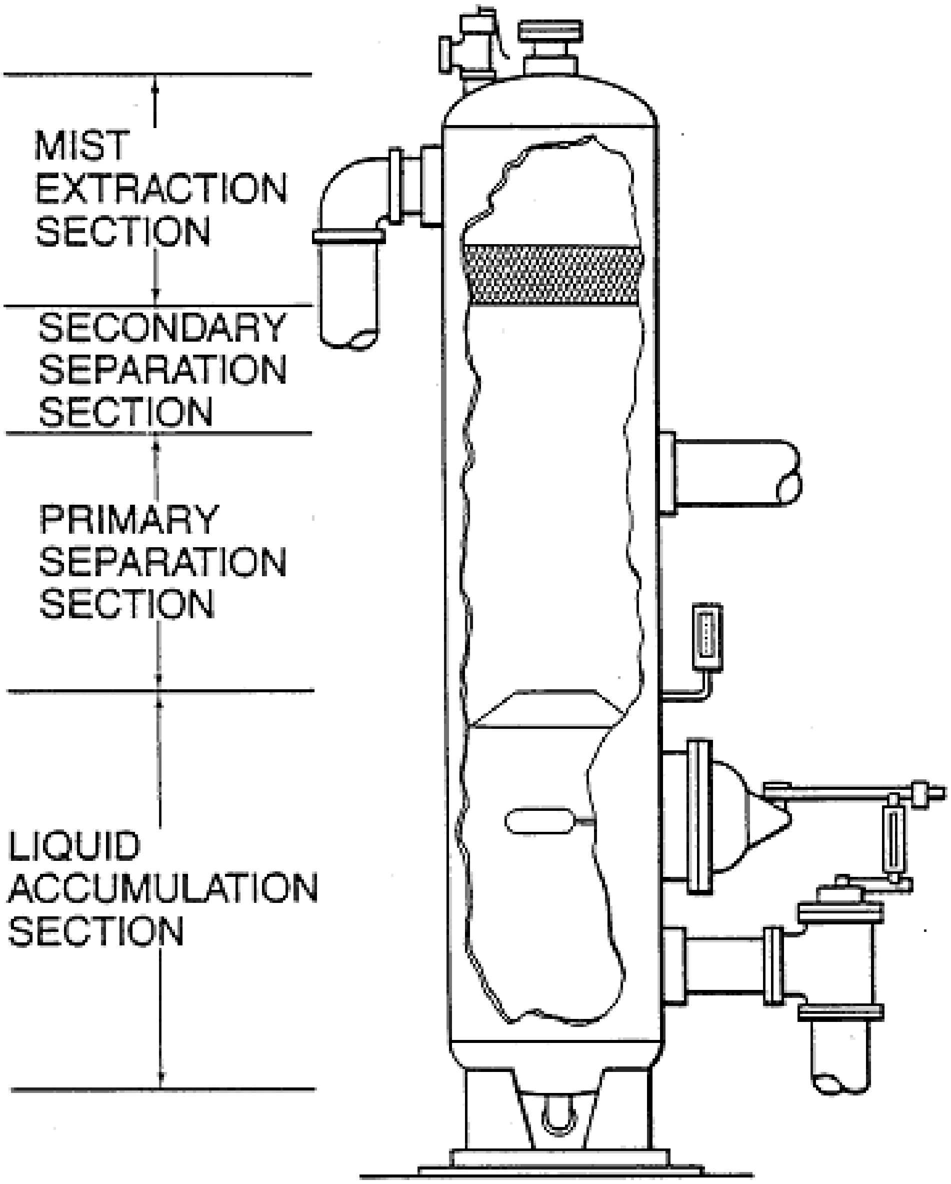


**Figure 6.3 Separator Sections**

The ease with which the droplets will settle out of the gas stream and fall into the liquid accumulation section of the separator depends on a number of factors. These include:

- The size of the droplets.
- The density of the liquid droplet compared to the density of the gas.
- The velocity at which the gas stream is traveling through the separator.
- The turbulence which exists in the flowing gas stream.

Of these factors:

- The difference in density between oil and gas and the droplet size will be determined by the composition of the well stream.

- The velocity of the gas stream is determined by the size of the separator and its throughput.

- Turbulence can be reduced by having devices called **straightening vanes** (**Figure 6.4**) built into the separator to make the gas flow more streamlined.

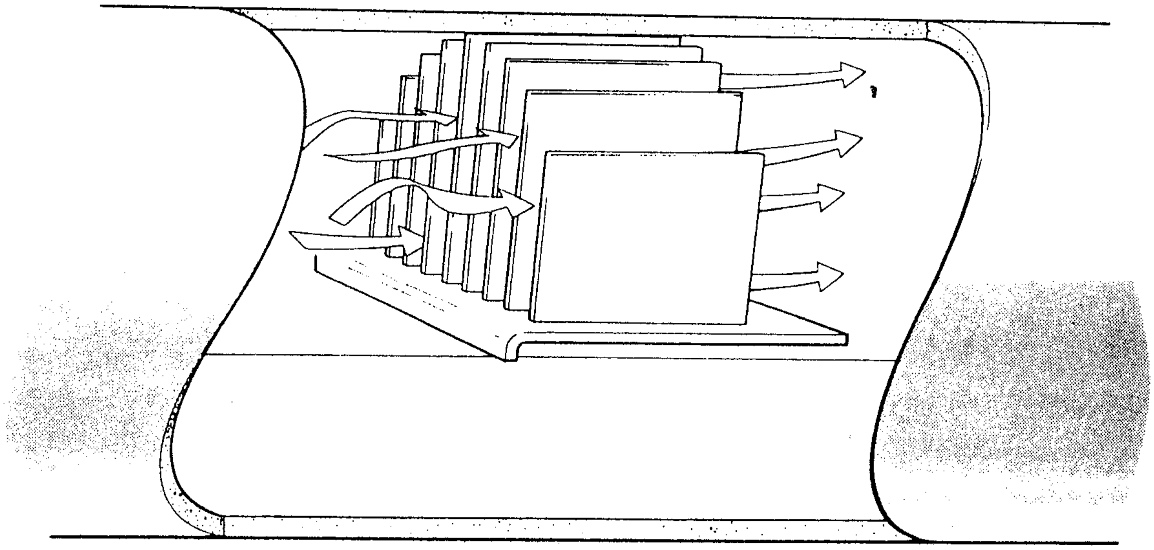


**Figure 6.4 A Typical Set of Straightening Vanes inside a Vessel**

## 6.4.3 Mist Extraction

The secondary separation of liquid droplets from the gas by gravity settling will not usually remove very small particles. These particles tend to remain in the gas stream in the form of a mist. In order that the gas leaving a separator as free as possible room liquid, a final **mist extraction** section is built into the vessel.

Mist extraction is accomplished using either an **impingement** or a **centrifugal force** mechanism.

## 6.4.4 Liquid Accumulation Section

The lowermost section of a separator is where the liquids from the other three sections accumulate before being discharged from the vessel. Initially, this liquid will have gas bubbles entrained within it which must be removed.

Just as liquid droplets tend to fall through a gas stream, gas bubbles tend to rise to the surface of liquids due to density differences.

The time required for the bubbles to reach the surface and re-enter the gas stream will vary. However, for most oilfield applications it will occur in one to four minutes. This means that the liquids must stay in the vessel for this period of time, which is known as the **retention time.**

If the separator is of a sufficiently large capacity, this will ensure that the reservoir fluids stay in the vessel for the required retention time.

You will remember that a 3 phase separation process not only removes gas from liquid, as we have just seen, but also separates oil and water.

This, in effect, adds a fifth part to the total process within the separator.

## 6.4.5 Oil and Water Separation Section

Oil and water do not mix. If these liquids are left long enough in a vessel, separation will occur and the oil will float on top of the water.

Oil and water will separate faster than gas will be liberated from the oil. So, if the separator is large enough to allow efficient gas separation, then the retention time required for oil and water separation will be exceeded.

# 6.5 TERMINOLOGY AND APPLICATIONS:

## 6.5.1 Vessels Terminology

The term "oil and gas separator", in oil field terminology, designates a pressure vessel used for the purpose of separating well fluids into gaseous and liquid components. A separating vessel may be referred to in the following ways:

1. Oil and gas separator
2. Separator
6. Stage separator
4. Trap
5. Knock-out (vessel, drums, and trap)
   Water knockout
   Liquid knockout
6. Flash chamber (trap, vessel)
7. Expansion vessel (separator)
8. Scrubber (gas scrubber)
9. Filter (gas filter).

## 6.5.2 Separator Application

To size and design a separator, certain data and information must be known. There must be data about the process fluids and operating conditions. You need to know the service that the separator is to perform and the performance requirements. Often it is helpful to know something about the system into which the unit will fit. Special construction and design specifications, if applicable, must be followed. Then all that information must be interpreted to select the best design and to correctly size it. Often design data is incomplete and assumptions must be made. Information about type of service and the relationship to the whole system can be useful in making better assumptions.

There are also a whole range of different separator designs which can be used or adapted to fit each need. There are vertical and horizontal designs, longitudinal or cross flow, an assortment of mist extractor types and designs with and without slug catching sections.

## Separators

Are mechanical devices used for primary separation to remove and collect liquid from natural gas, which is normally accomplished with the aid of centrifugal force.

The terms **oil and gas separator, separator, stage separator, and trap** all refer to a conventional oil and gas separator. These separating vessels are normally used near the wellhead, manifold, or tank battery to separate the fluids produced from oil and gas wells into oil and gas or liquid and gas. They must be capable of handling "slugs" or "heads" of well fluids.

## Production Separator

Also called "bulk separator" or "primary separator", is used to separate one or more combined well streams at a well site, gathering center, plant or offshore platform. It can be two or three-phase. "Primary" separation indicates it is the first process of separation the produced fluids have encountered. If located in a plant, the production separator might be very large and handle the production from a whole field. In large plants, several production separators are often used in parallel.

## Test Separator

Is usually, connected parallel to a production separator. It is normally sized to handle one well at a time. Individual wells can be segregated from the main production stream at the well manifold and processed through the test separator where the separated phases are then measured. The products are then recombined with the main stream products.

## Knockout (vessel, drum, trap)

Knockout is used to remove only water from the well fluid or all liquid oil plus water from gas. In the case of a water knockout the gas and liquid petroleum are discharged together and the water is separated and discharged from the bottom of the vessel.

A liquid knockout is used to remove all liquid, oil plus water, from the gas. The water and liquid hydrocarbons are discharged together from the bottom of the vessel and the gas is discharged from the top.

## Flash Chamber (Separator, Drum)

This is a two-phase vessel used as a subsequent stage of separation to process the liquid hydrocarbons flashed from a primary separator. The name is applied to the vessel used as a second stage separator on a cold separation unit. The vessel is usually of low pressure design-not more than 125 psig working pressure. It rarely differs from the conventional low pressure separator.

The secondary purpose is degassing liquid before it enters another process. An example is in an electrostatic coalescer or desalter where no free gas can be tolerated, the fluid is first degassed in a flash separator which is elevated above the coalescer so that once degassed the fluid will remain gas-free.

## Expansion Vessel

This name applied to the vessel into which gas is expanded for a cold separation application. It also is referred to as a cold separator or a low temperature separator. The vessel differs considerably from the normal separator since it is designed primarily to handle and melt gas hydrates that are formed by expansion cooling. In cold separation applications where a hydrate preventative is used, the design may be very close to that of normal separator. The usual working pressure of this vessel is in the range of 1000 to 1500 psig.

## Filter (Dust Scrubber)

Where liquid is present to a fair degree in a gas stream, the conventional oil and gas separator will remove any solid particles in the stream. The liquid acts to trap the solids in the mist extractor (or coalescer) and other sections of the separator. It then serves as a medium to flow solids out of the vessel.

When gas is dry, there are still solid particles present to interfere with some phases of gas transmission and distribution. The vessel designed to remove these solids is called a filter or dust scrubber.

The filter normally uses a dry filter pack to trap undesirable particles. These filter packs require periodic removal for changing or cleaning.

## Scrubber

Scrubbers are usually two-phase, vertical vessels. The scrubber is NOT used as a primary separation means at a well, and are recommended only for:

1. Secondary operation to remove carryover fluids from process equipment such as the absorber and the Liquid Dust Scrubber.

2. Gas line separation downstream from separator and where flowlines are not long.

3. Very high GOR flow streams that is, to "scrub" small amounts of liquid from a gas stream.

4. Flare scrubbers or vent scrubbers are placed in gas outlet streams from production separators to remove any residual liquids left or any condensates that may have formed in the line, prior to flaring or venting.

5. Suction and discharge scrubbers are placed upstream and downstream of gas compressors.

6. Fuel gas scrubbers remove residual liquid from gas just prior to its use as a fuel.

7. Pipeline scrubbers remove condensate from gas streams flowing through long pipelines.

**Slug Catcher**

Or surge drum is a separator designed to separate bulk liquid-gas flow streams which are surging or slugging. The slug catcher may be also serving as a production separator, in which case better separation is required. Properly designed it should smooth out the intermittent flow.

**Metering Separators**

Separator featuring calibrated liquid chambers are used for metering in either 3-phase or ordinary 2-phase operation. These vessels register the number of dumps of the calibrated volume of oil and water and are applicable where individual well tests are desire or where continuous or frequent data are necessary.

**Accumulators**

Condensed overhead vapors from distillation columns collect in vessels called accumulators. These Keep the tower functioning smoothly and prevent tower fluctuation from down stream equipment. Hence surge residence time is the basic design factor in designing vessels for this type of service.

## 6.6 STAGE SEPARATION

The purpose of stage separation is to reduce the pressure on the reservoir liquids a little at time, in steps, or stages, so that a more stable stock tank liquid will result. Petroleum liquids at high pressure usually contain large quantities of liquefied propanes, butanes, and pentanes, which will vaporize or flash as the pressure is reduced. This flashing can cause substantial reduction in stock tank liquid recovery, depending on well stream composition, pressure, temperature, and other factors. For example, if a volatile condensate at 1,500 psig were discharged directly into an atmospheric storage tank, most of it would vaporize immediately, leaving very little liquid in the tank.

In many circumstances it may be possible to do this. However, imagine a situation where the pressure of the reservoir fluids at the wellhead is 2 500 psi and the gas oil ratio is 2 000 scf/bbl.

If separation is to yield stabilized oil and gas at atmospheric pressure, then the separator may need to be extremely large. With a throughput of, say, 75 000 bbl/day of oil, the separator must be capable of handling all that oil plus 150 000 000 cu ft of gas. The pressure would also have to be reduced in one go, from wellhead conditions to atmospheric conditions.

The ideal method of separation, to attain maximum liquid recovery, would be that of differential liberation of gas by means of a steady decrease in pressure from that existing in the reservoir to that existing in the storage tanks. With each tiny decrease in pressure, the gas evolved would immediately be removed from the liquid. However, to carry out this differential process would require an infinite number of separation stages, obviously an impractical solution. A close approach to differential liberation can be made by using three or more series-connected stages of separation, in each of which flash vaporization takes place. In this manner, the maximum economical amount of liquid can be recovered.

When ideal separation has been accomplished, the, gas and liquids have reached a **state of equilibrium** at the temperature and pressure within the vessel. In other words, at these conditions of temperature and pressure, no further separation would take place.

In most oilfield applications the goal is to **stabilize** the crude oil for shipment at pressures at or near to atmospheric, this means that the separator would have to be operated at this pressure.

In order to achieve optimum separation in such a case the process would be carried out in a number of separator vessels working in series. Each separator would operate at a lower pressure than its predecessor. This process is known as **stage separation.** At each stage the gas which is liberated and separated is removed and the liquid passes to the next vessel in the sequence.

Stage separation is a process in which gaseous and liquid hydrocarbons are separated into vapor and liquid phases by two or more equilibrium flashes at consecutively lower pressures. Two-stage separation involves one separator and a storage tank (**Figure 6.5**). Three-stage separation requires two separators and a storage tank. Four-stage separation requires three separators and a storage tank. The tank is always counted as the final stage of vapor-liquid separation because the final equilibrium flash occurs in the tank.

The series of vessels used in a stage separation process is known as a **train** of separators. The number of vessels in a train varies, but usually ranges from two to four. We can refer therefore to a two, three or four stage separation train.

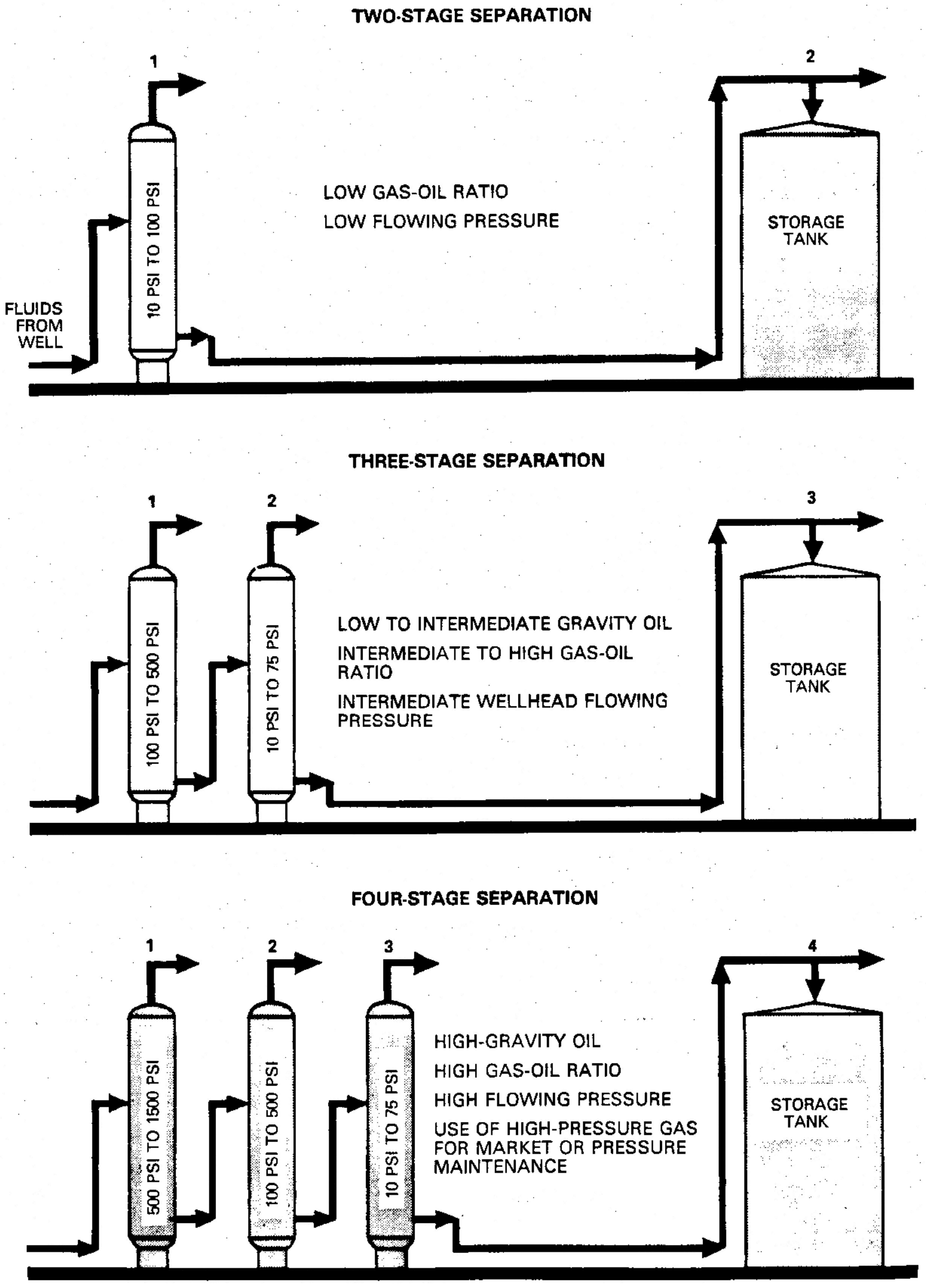


**Figure 6.5 Stage Separation Flow Diagrams**

# 6.7 CLASSIFICATION OF SEPARATORS

Separators are classified into two ways:

1. The shape of the vessel.
2. The number of the fluids to be separated.

## 6.7.1 The Vessel Shape

Separators are commonly manufactured in three basic shapes:

1. Horizontal Separator
2. Vertical Separator
6. Spherical Separator

## A. Horizontal Separators:

The horizontal separator (**Figures 6.6, 6.7, 6.8 and 6.9**) is designed for processing well stream. The large liquid surface area provides for efficient removal of gas from the liquid. This type of vessel has a large interface area between the liquid and the gas phases. Thus, adding more separation when the gas capacity is a design criterion, the horizontal vessel is more economical in high pressure separators due to increased wall thickness required with large diameters and, in general, recommended for use with low gas-oil ratio fluid streams unless additional factors dictate otherwise. However, the liquid level control replacement is more critical than that in vertical separator.

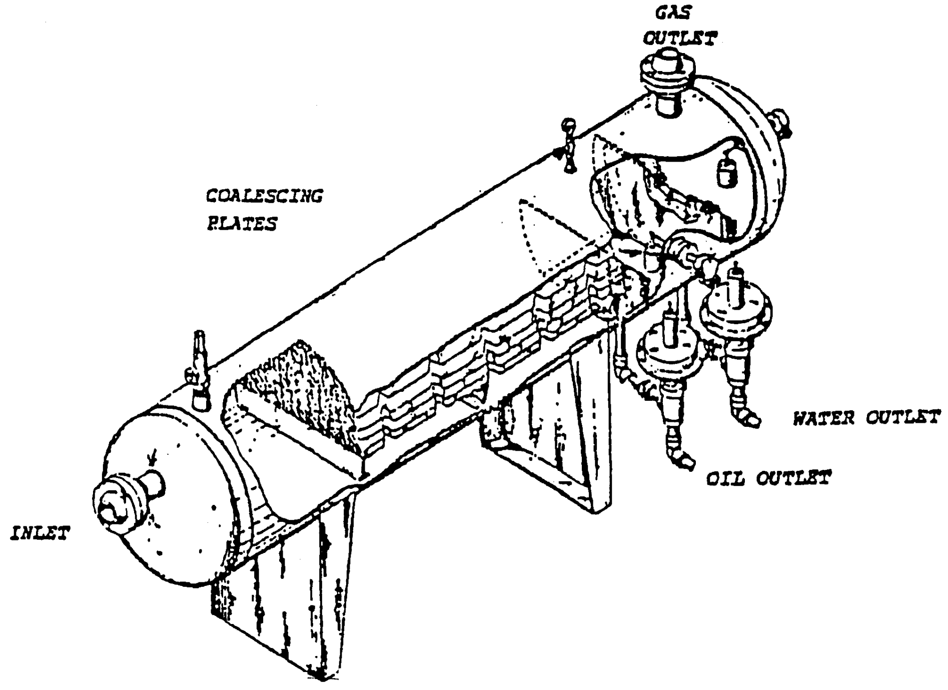


**Figure 6.6 Three-Phase Horizontal Separator**

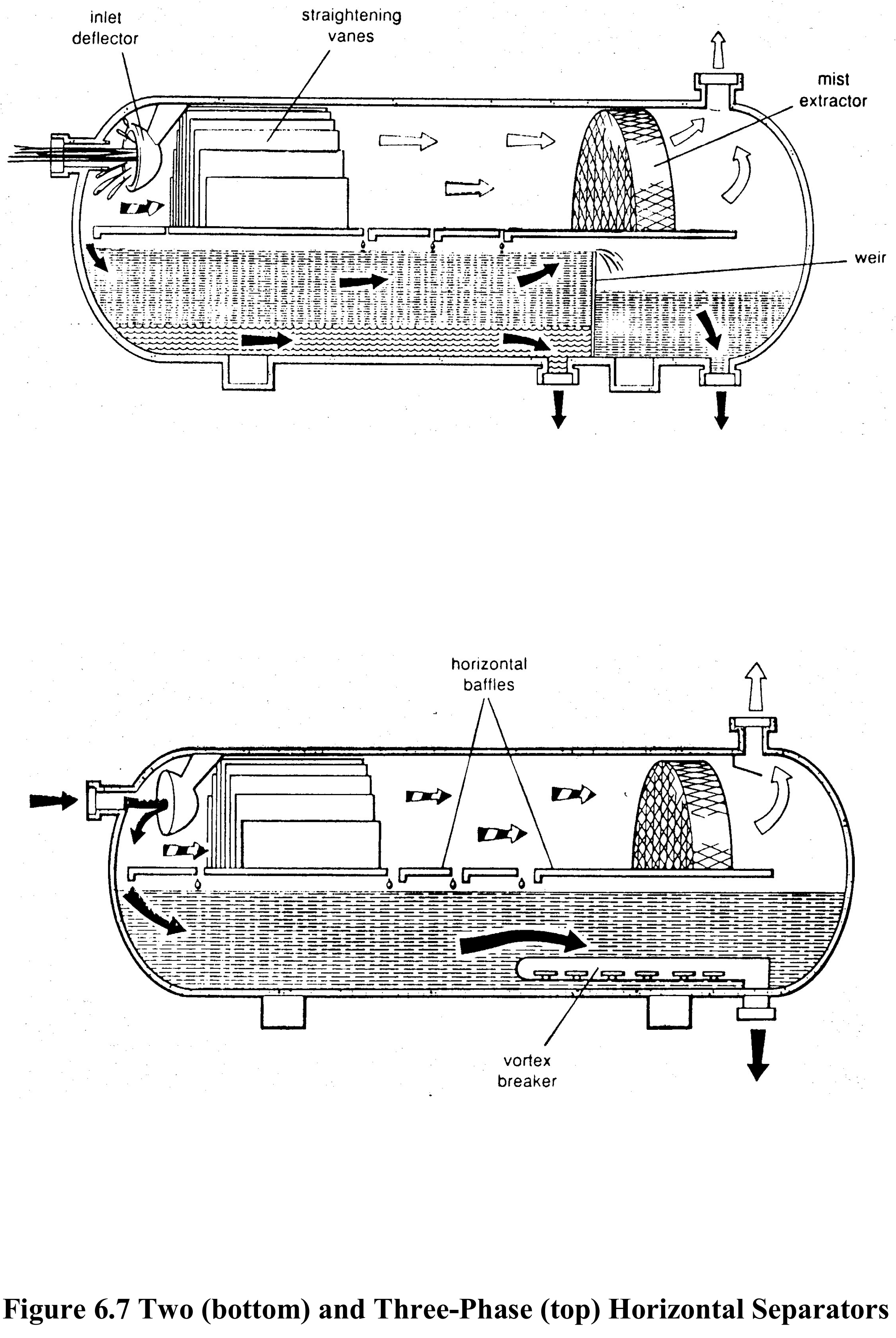
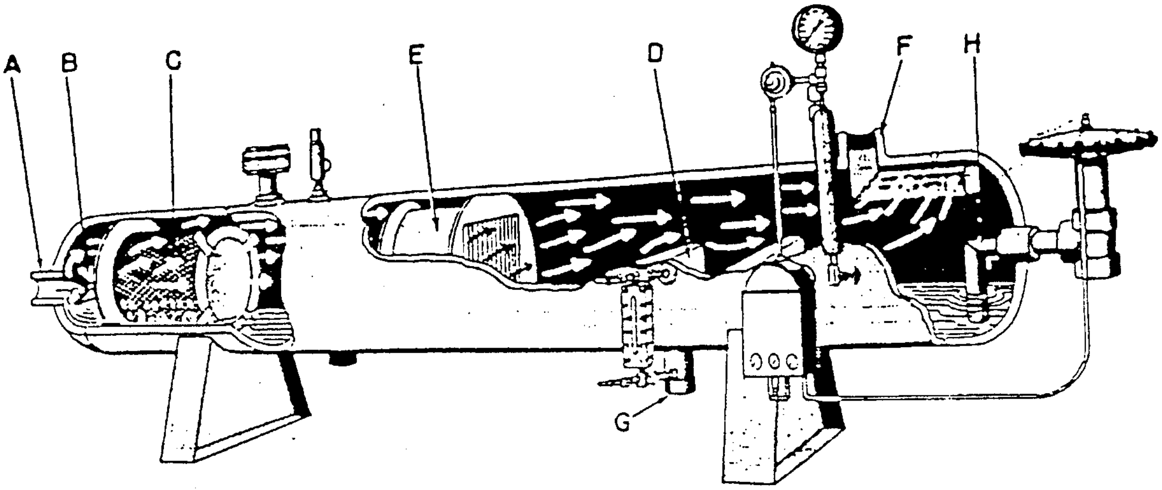


Figure 6.7 Two (bottom) and Three-Phase (top) Horizontal Separators

## Operation of Single Barrel Separator:

The oil and gas mixture enters at (A) (**Figure 6.8**) and hits an angle baffle (B) where the direction of flow is changed. Here the heavier liquids fall to the bottom of the tank while the gas and spray rise. This wet gas passes into a chamber (C) where small drops gather into larger drops and fall into the liquid at the bottom of the tank.

The partly dried gas goes through a final element where the last liquid particles of smallest size are removed from the gas by a mist extractor (E) generally similar to the scrubber dome. The dried gas then goes through the top portion of the tank and into the gas outlet (F). The liquid from which the gas has been removed moves along the bottom of the tank past the plates (D) to the oil outlet (H). The plates act as baffles to keep waves from forming in the liquids.



**A- Oil and Gas Inlet**
**B- Impact Angle**
**C- De-Foaming Element**
**D- Wave Breaker and Selector Plate**
**E- Mist Extractor**
**F- Gas Outlet**
**G-Drain**
**H-Oil Outlet**

**Figure 6.8 Single Barrel Horizontal Separator**

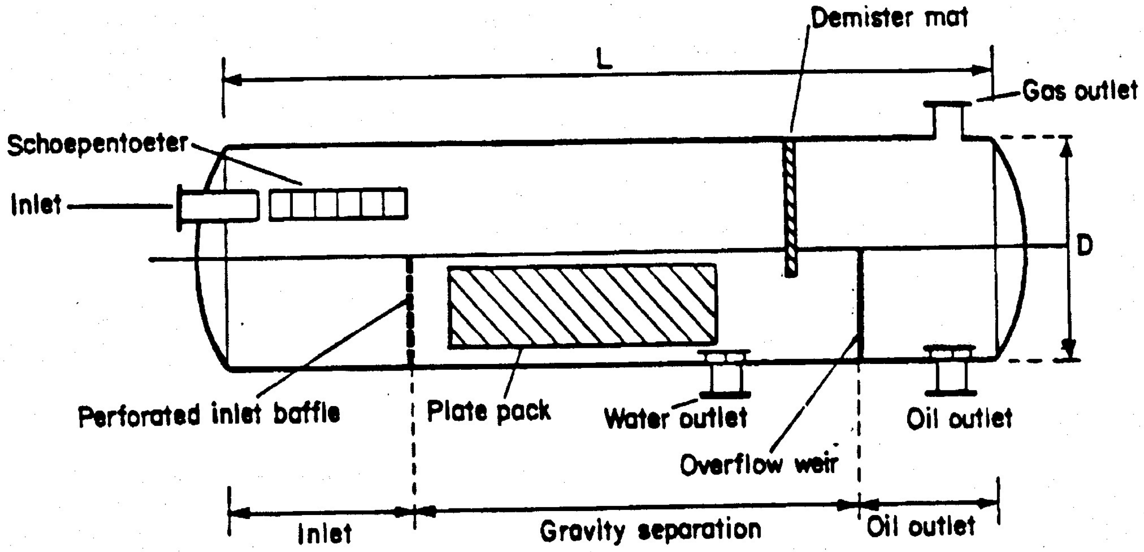


Figure 6.9 Typical Horizontal Three-Phase Separator with parallel plates

## Advantages of Horizontal Separators:

1. For a given oil and gas capacity, the horizontal usually will be cheaper than a vertical.
2. A horizontal configuration will be more adaptable to skid – mounting and on-skid piping.
3. For a given size, more area is available for settling in the liquid phase. Thus, the horizontal conforms to three phase operation better than does a vertical.
4. If heating coils or sand jets are required, horizontal configuration is more adaptable.
5. Foamy crudes are processed more effectively in a horizontal than in a vertical. The greater surface area between the gas and liquid phases is an asset in allowing free passage of collapsed foam to the liquid section of the separator. In fact, if the crude is more than slightly foamy, this feature alone generally will dictate use of a horizontal vessel.

## Disadvantages of Horizontal Separators:

1. Horizontal separator normally have less liquid surge capacity than a vertical of comparable oil and gas capacity, and.
2. Liquid level control is more critical than with a vertical type.

## B. Vertical Separators:

This type (**Figure 6.10, 6.11, and 6.12**) is capable of handling large slugs of liquid without carryover to the gas outlet and is best suited for well streams with low liquid content and high gas volume. The action of level control is not critical.

Due to the greater vertical distance between the liquid level and the gas outlet, there is less tendency to re-vaporize the liquid into the gas phase. Vertical type is most often used on fluid streams having considerably less liquid than gas (gas – oil ratio is high)

**Advantages of Vertical Separators:**

1. Liquid level and control not as critical as for horizontal;
2. Easier and cheaper to design for surge capacity;
3. With certain designs, more extraneous material (for example, sand, mud, and corrosion products) can be handled; and
4. Usually easier to clean.
5. Requires less space to install (e.g. offshore applications)

**Disadvantages of Vertical Separators**:

1. More expensive,
2. Does not adapt to skid-mounted assemblies as well as do horizontals in most case, and
3. Requires a larger diameter for the same gas capacity.

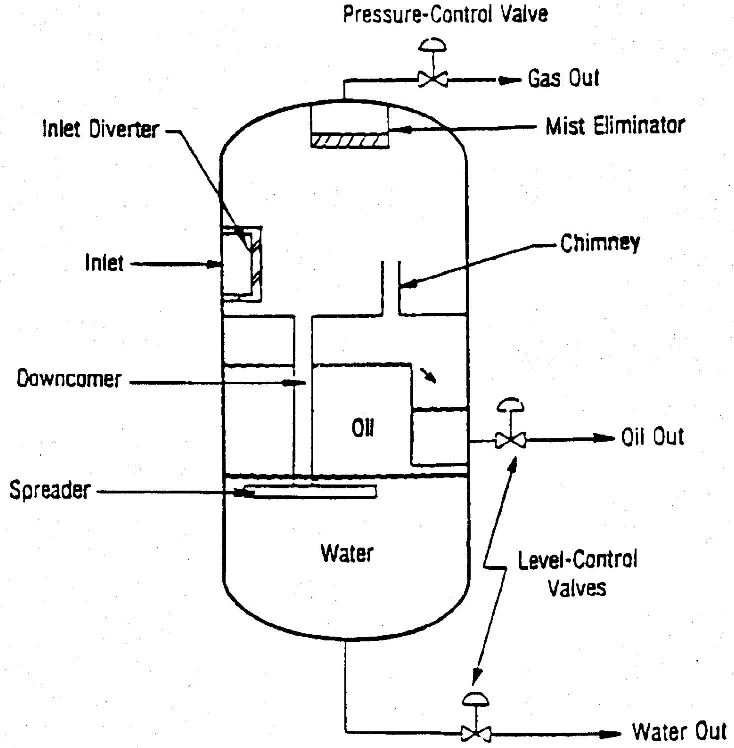


**Figure 6.10 Typical Vertical Three-Phase Separator with parallel plates**

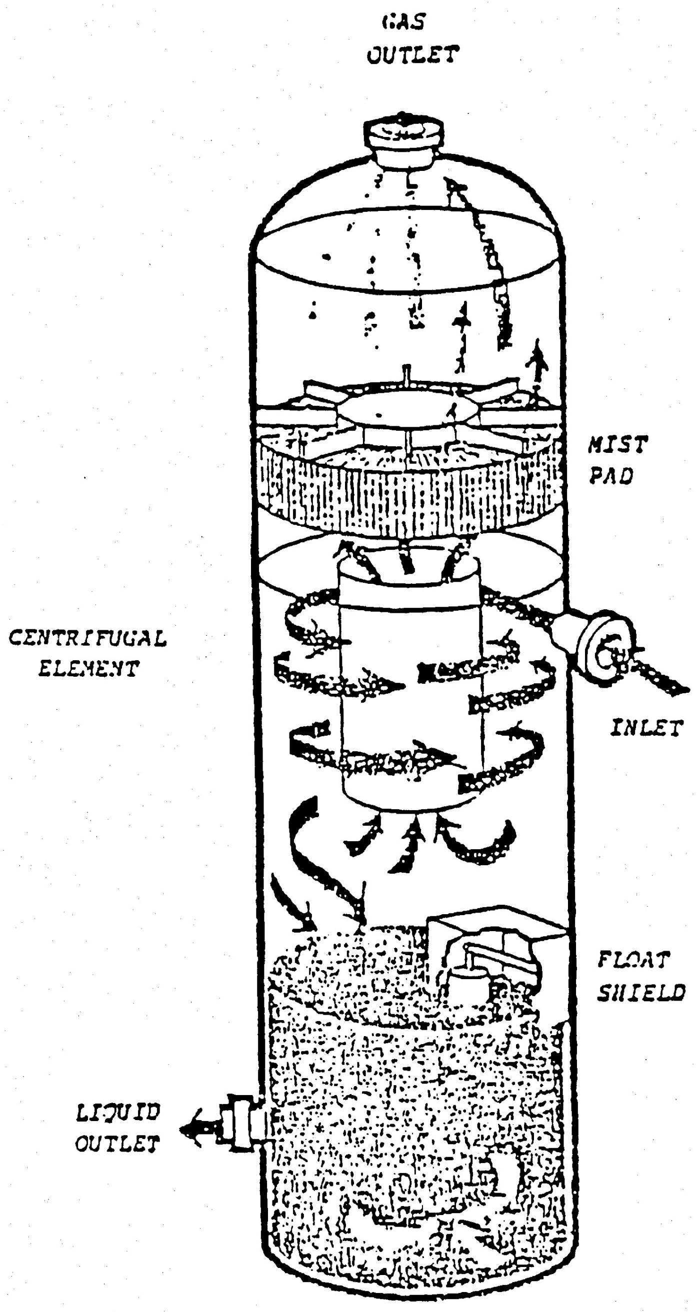


Figure 6.11 Two-Phase Vertical Separator

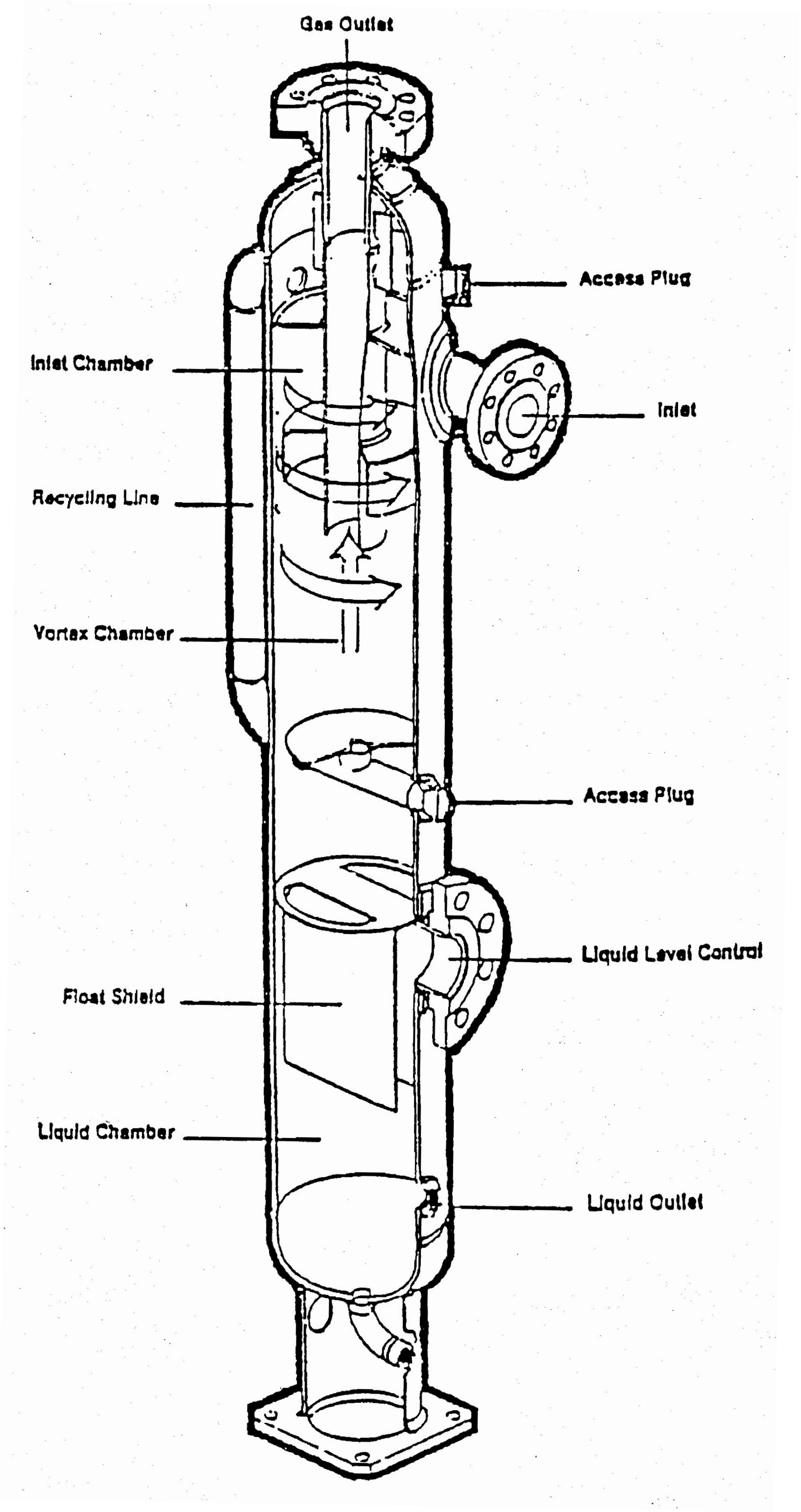


Figure 6.12 Two-Phase Vertical Separator

## C. Spherical Separators:

These types of separators (**Figure 6.13**) are compact vessels arrangement and provide good gas separation. However, they have very limited surge space and liquid settling section.

When a well stream can contain excess mud or sand and are subjected to surging foamy components, the spherical separator is not economical. The liquid level control is very critical.

These Separators are not as popular today because of their limitations.
However, they are still used in small scale operations.

### Operation

Figure 6.13 illustrates the principles of the spherical separator. The well stream enters the top of the separator and the liquids spread thinly over the hemispherical baffle and accumulate in the lower part of the vessel. Gas proceeds along the same initial path between the hemispherical baffle and the separator shell. At the lower edge of the baffle, the gas passes into the chamber of the separator and rises through the mist extractor. Gas leaves the separator through the upturned outlet which emerges from the bottom center of the vessel. The rising liquid activates a float or level controller to operate the oil valve on the dump line from the separator.

**Advantages of Spherical Separators:** Its compactness

1. Ease of skid mounting
2. Excellent gas separation capacity per dollar, and
3. Its cleanout and drain features are better than those of a vertical separator.

**Disadvantages of Spherical Separators:**

1. Is not economical for large gas capacities, and
2. Its surge capacity is limited.

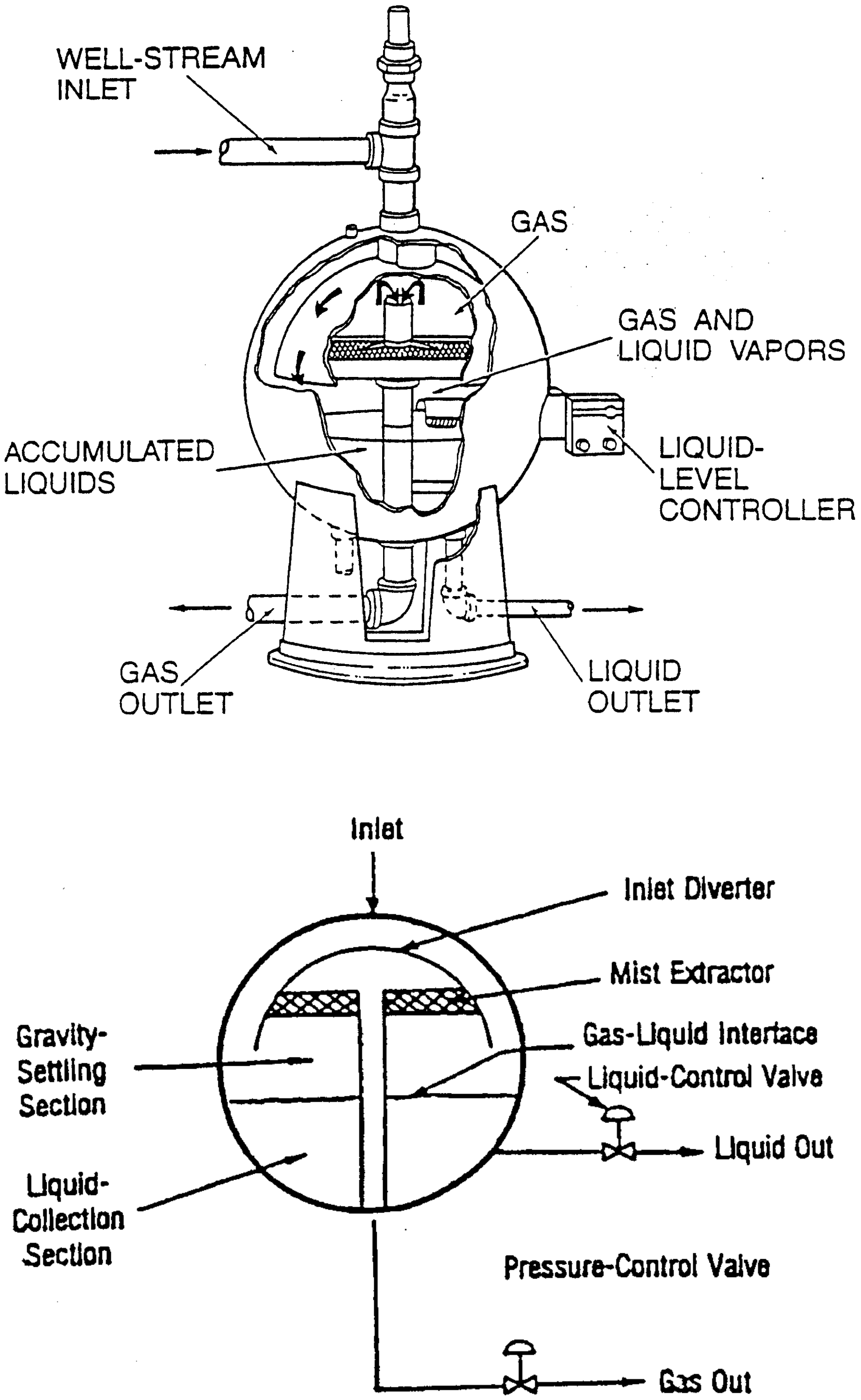


**Figure 6.13 Spherical Separator**

The designation of high or low gas-oil ratio is rather arbitrary. The following are specific instances in which high or low GOR's usually occur:

**Low Gas-Oil Ratio**

- Oil well streams.
- Flash tanks in dehydration, and sweetening plants.
- Fractionator's reflux accumulators.

**High Gas-Oil Ratio**

- Gas well streams.
- Gas pipeline scrubbers.
- Compressor suction scrubbers
- Fuel gas scrubbers.

The terms Flash Tank, Accumulator and Scrubber are commonly used for specific applications of separators. The vessels are gas-liquid separators.

## 6.7.2 The Number of Fluids to be Separated

Normally, fluids to be separated are either in two or three phases. If there are two fluids, such as gas and liquid, the separator to be used is a two -phase separator, may be horizontal or vertical type. If three fluids are separated, such as, gas oil and water, the vessel to be used is a three-phase separator. The number of phases refers to the number of streams that leave the vessel, and not the number of phases that are in the inlet stream. For example, well stream test separator frequently has gas, oil and water but only the liquid and gas are separated in the vessel, and flow to another separator where the oil and water are separated. Consequently, a two-phase separator is one which the inlet stream is divided into two fluids and a three-phase separator will have three products.

Some well streams contain sand or either solid particles which are removed in a separator. Special internal devices are provided to collect and dispose of solid materials. They are not considered another phase in the classification of the vessel.

### A- Two-Phase Separators

The flow in horizontal or vertical separators is similar. The well stream enters the inlet side and strikes a baffle. Forward motion is stopped temporarily with the heavy liquids falling to the bottom of the vessel.

Gas and liquid spray continue through straightening vanes, which cause liquid drops to form and drop intro the accumulation section.

As in **Figures 6.11 & 6.12** flow in a centrifugal separator is somewhat different than that in conventional types. The vessels are usually vertical and depend on centrifugal action to separate the fluids. The inlet stream is directed to flow around the wall of the vessel in swirling motion. The heavier liquid moves to the outside, and droplets collect on the wall and fall to the bottom. The lighter of the fluids collects in the middle of the vessel and flows up the outlet pipe.

## B- Three-Phase Separators

This type handles gas plus two immiscible liquid phases. The two liquid phases might be oil and water, glycol and oil, etc. The potential application of three phase separators occurs where space is a major consideration.

The designation of high or low gas-oil ratio is rather arbitrary. The following are specific instances in which high or low GOR's usually occur:

**Low Gas-Oil Ratio**

- Oil well streams.
- Flash tanks in dehydration, and sweetening plants.
- Fractionator's reflux accumulators.

**High Gas-Oil Ratio**

- Gas well streams.
- Gas pipeline scrubbers.
- Compressor suction scrubbers
- Fuel gas scrubbers.

The terms Flash Tank, Accumulator and Scrubber are commonly used for specific applications of separators. The vessels are gas-liquid separators.

## 6.8 SEPARATOR INTERNALS

Production equipment involving the separation of oil and gas usually has a wide variety of mechanical devices that should be present in some of all separators, regardless of the overall shape or configuration of the vessel. These mechanical devices improve the separator's efficiency and simplify its operation. The most commonly used devices are:

- **Inlet configuration**
- **Intermediate configuration**
- **Outlet configuration**
-

### 6.8.1 Inlet Configurations

In **horizontal separators** the internal configuration can take many shapes. The most commonly used are:

- **Structural channel iron**
- **Angle iron**
- **Cyclone**
- **Flat plates**
- **Dished heads**
- **Schopentoeter**

The latter three shapes have been considered optimum for certain applications. These shapes are used in gas-liquid separators in front of the inlet nozzle of the vessel, which serve two purposes:

1. To aid in the separation of entrained gas from the liquid.
2. To divert the fluid flow downstream.

In **vertical separators,** there is a centrifugal inlet device, it causes the primary separation of the liquid and gas to take place. Here, the incoming stream is subject to a centrifugal force as much as 500 times the force of gravity. This action stops the horizontal motion of the liquid droplets together, where they will fall to the bottom in the settling section.

## Inlet Diverters

There are many types of inlet diverters. **Figure 6.14** shows two basic types of devices that are commonly used. The first is a deflector baffle. This can be a spherical dish, flat plate, angle iron, cone, or just about anything that will accomplish a rapid change in direction and velocity of the fluids. The rapid change of the fluid velocity disengages the liquids from the gas due to kinetic energy differences. At the same velocity, the higher density liquid possesses more kinetic energy and therefore does not change direction or velocity as easily as the gas. Thus, the gas tends to flow around the diverter while the liquid strikes the diverter and then falls to the bottom of the vessel. The design of the deflector is governed principally by the structural support required to resist the impact-momentum load. The advantage of using devices such as a half-sphere or cone is that they create fewer disturbances than plates or angle iron, cutting down on re-entrainment or emulsifying problems.

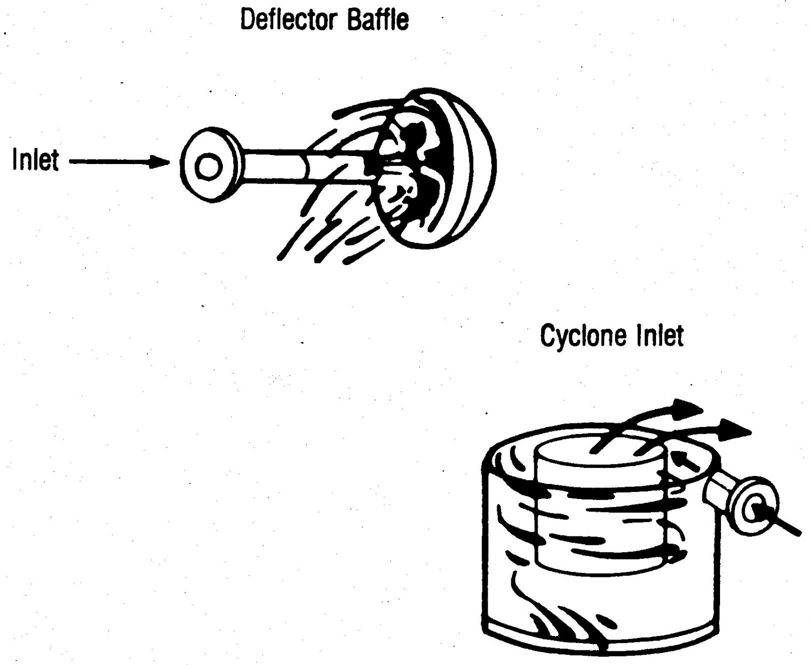


**Figure 6.14 Two Basic Types of Inlet Diverters**

The second device shown in **Figure 6.14** is a cyclone inlet that uses centrifugal force to disengage the oil and gas. This inlet can have a cyclonic chimney, as shown, or may use a tangential fluid race around the walls. These devices are proprietary but generally use an inlet nozzle sufficient to create a fluid velocity of about 20 ft/s (6.096 m/s) around a chimney whose diameter is no larger than two-thirds that of the vessel diameter.

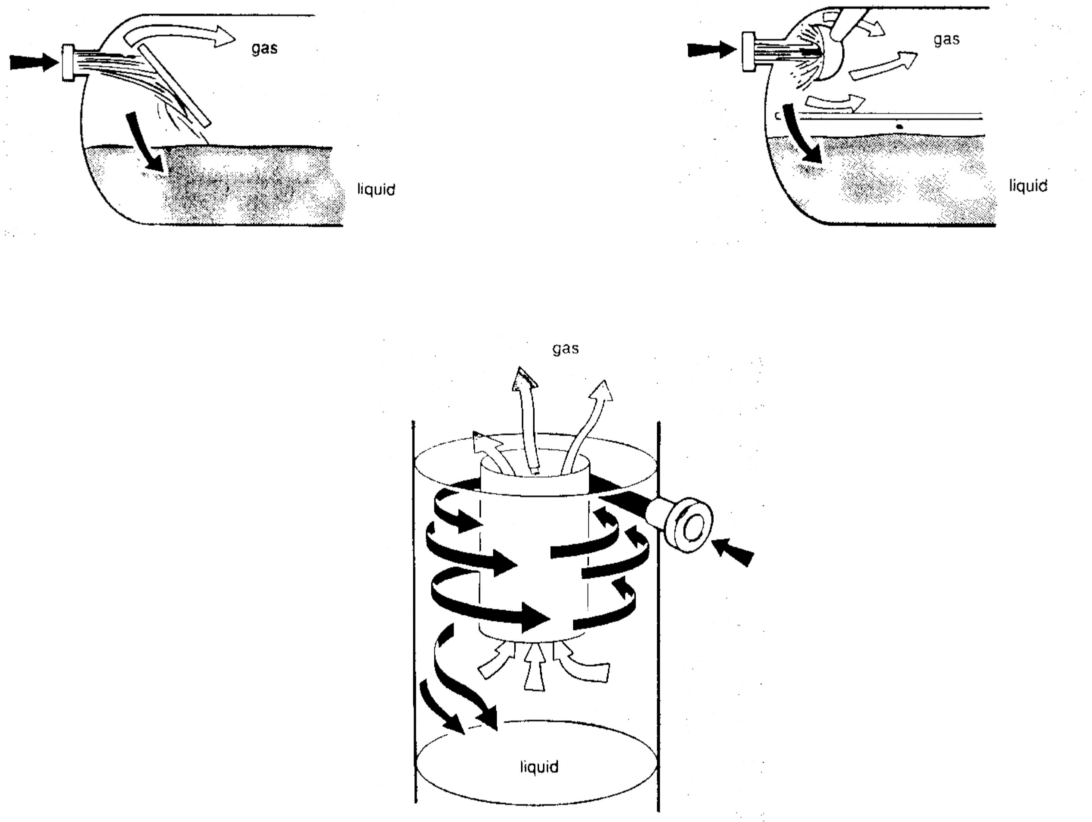


**Figure 6.15 Inlet Diverter Types**

## Schoepentoeter

The Schoepentoeter (vane-type) is a Shell-proprietary inlet device and is commonly used for introducing gas/ liquid mixtures into a vessel or column

It is used to absorb the initial momentum as the well fluid enters the separator. It tends to deflect the direction of flow causing gas to rise and free liquid to drop that the flow encounters. A drop in velocity as well as reduction in pressure.

**Figure 6.16** shows schematically the typical outline of a Schoepentoter in a vertical vessel together with its design parameters (for simplicity not all the vanes are shown).

The geometry of the Schoepentoter is largely standardised so that the choice of dimensions to be made by the designer is limited to the following:

- The number of vanes per side $n_v$.
- The vane angle, a which is 8 degrees o less.
- The length of the straight part of the vanes, $L_v$ , which shall be 75, 100, 150 or 200 mm. The choice of $L_v$ is also used to fix the vane spacing.
- The radius of the vanes, $R_v$, which shall be 50 or 100 mm.

With a Schoepentoeter, it is normal to specify a protruded nozzle, although this is not essential.

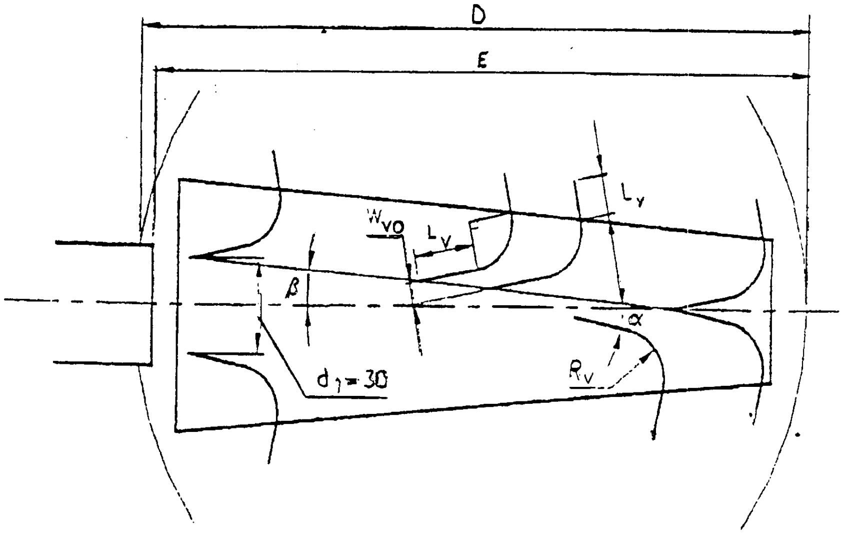


**Figure 6.16 Schematic Outline of the Schoepentoeter**

a = vane angle, angle made by straight part of vanes with centre line.
B = edge angle, angle made by edge of the row of vanes with centre line.
D = vessel inside diameter, mm.
$d_1$ = inlet nozzle inner diameter, mm
E = available space, mm.
$L_v$ = length of straight part of vanes (normally 75, 100, 150 or 200 mm)
$N_v$ = number of vanes per side.
$R_v$ = vane radius, mm (normally 50 or 100 mm)
t = vane material thickness, mm (normally 3 mm, but typically 5 mm for heavy duty, e.g. slugs)
$W_{vo}$ = width of vane entrance opening, mm.

## 6.8.2 Intermediate configuration

The most commonly used of these intermediate devices are:

- **Wave Breaker**
- **Coalescing plates**
- **Straightening vanes**
- **Weir**
- **Horizontal baffles**
- **Defoaming Plates**

**Wave Breakers**
In large horizontal vessels, wave breakers may be used to limit wave propagation in the vessel. The waves may result from surges of liquid entering the vessel. The wave breakers consist of plates perpendicular to the flow located at the liquid level. On floating or compliant structures where internal waves may be caused by the motion of the foundation, wave breakers may also be required parallel to the flow direction. The wave actions in the vessel must be minimized so level controls, level switches, and weirs may perform properly.

**Stilling Wells**
Even where wave breakers are not needed, it may be beneficial to install a stilling well around any internal floats for level control. The stilling well is a slotted pipe which protects the float from currents, waves, etc., which could cause it to sense an incorrect level.

**Coalescing Plates**
It is possible to use various plate or pipe coalescer designs to aid in the coalescing of oil droplets in the water and water droplets in the oil. Recent tests using C. E. Natco's Performax plates indicate that some savings in vessel size are possible. Because of potential plugging problems, it is recommended that coalescers only be used to extend the capabilities of existing three-phase separators or where there are severe space limitations.

**Horizontal Baffles**
These are used in large gas liquid separators to prevent waves in the liquid phase.

**Weir**
It is a dam-like structure, which is controlling the liquid level and keeps it at a given level. Maybe one or two weirs are used in one separator, where one maintains the oil level and the other the water level.

## Straightening vanes

These are used to separate liquid mist from gas and used where hydrate or paraffins are present. They are used when hydrate or paraffins prevent the use of pads.

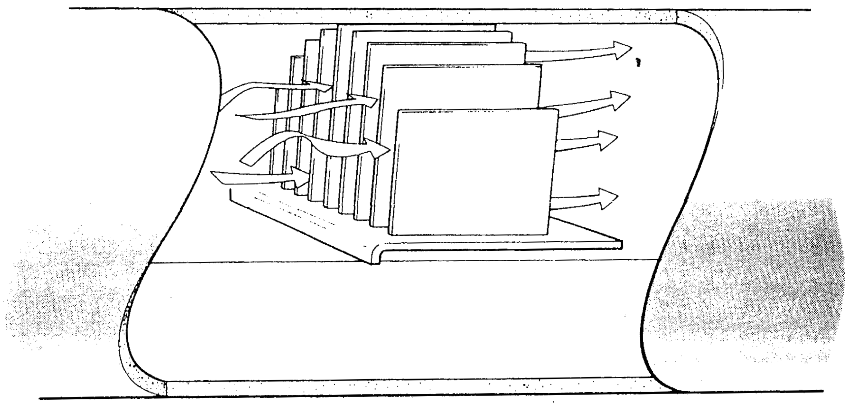


Figure 6.17 Straightening vanes

## Defoaming Plates

Foam at the interface may occur when gas bubbles are liberated from the liquid. This foam can be stabilized with the addition of chemicals at the inlet. Many times a more effective solution is to force the foam to pass through a series of inclined parallel plates or tubes as shown in Figure 6.18 so as to aid in coalescence of the bubbles.

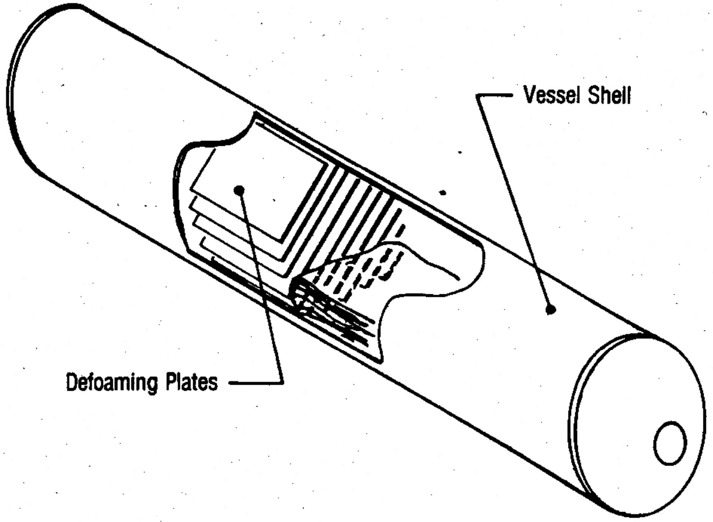


Figure 6.18 A Schematic of Defoaming Plates

## Sand Jets and Drains

In horizontal three-phase separators, one concern is the accumulation of sand and solids at the bottom of the vessel. If allowed to build up, these solids upset the separator operations by taking up vessel volume. Generally, the solids settle to the bottom and become well packed.

To remove the solids, sand drains are opened in a controlled manner, and then high-pressure fluid, usually produced water, is pumped through the jets to agitate the solids and flush them down the drains. The sand jets are normally designed with a 20 ft/s jet tip velocity and aimed in such a manner to give good coverage of the vessel bottom.

To prevent the settled sand from clogging the sand drains, sand pans or sand troughs are used to cover the outlets. These are inverted troughs with slotted side openings.

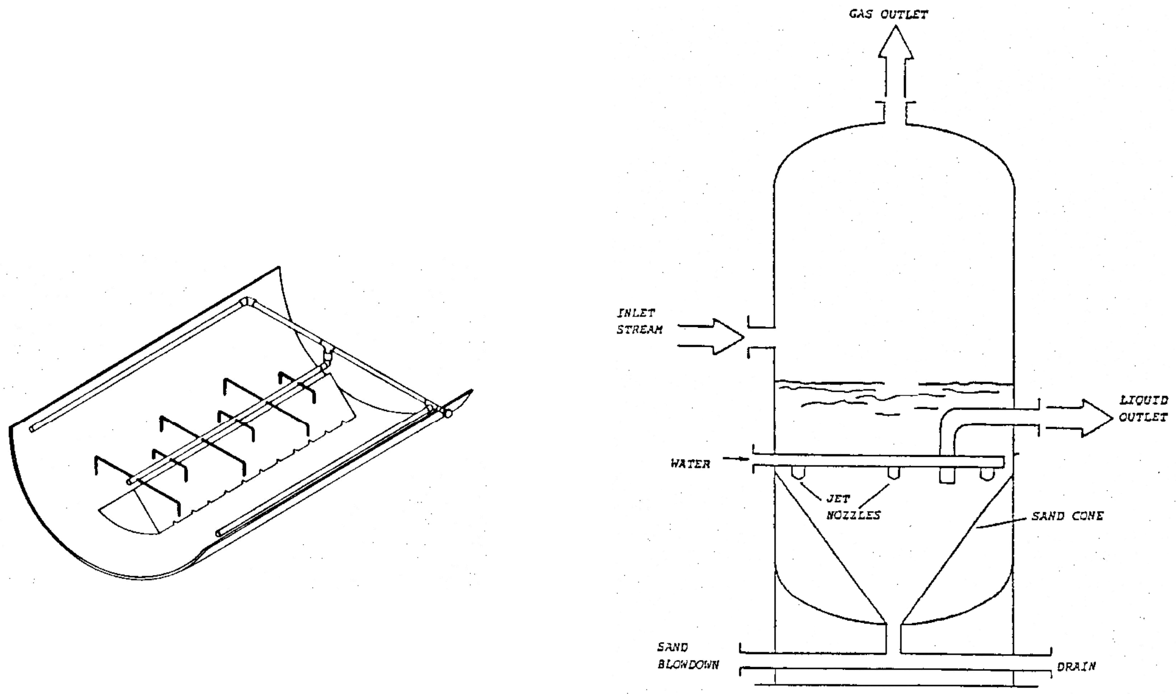


**Figure 6.19 Sand Jets and Piping Inside Horizontal and Vertical Separator. Triangular Cover Prevents Plugging of Drains.**

## 6.8.3 Outlet Configuration

These mechanical outlet devices are sometimes used in horizontal and vertical separators, and the most commonly used are the following.

**Mist pad or extractor**

Most frequently used in gas-liquid separators and normally located near the gas outlet that will coalesce small particles (mist) of liquid that will not settle out by gravity. It breaks oil-water emulsion to help in segregating the two liquids. Not used where hydrate or paraffin may be present.

The most common mist extraction device is the **knitted wire mesh** pad which is an impingement mechanism. (**Figure 6.20**)

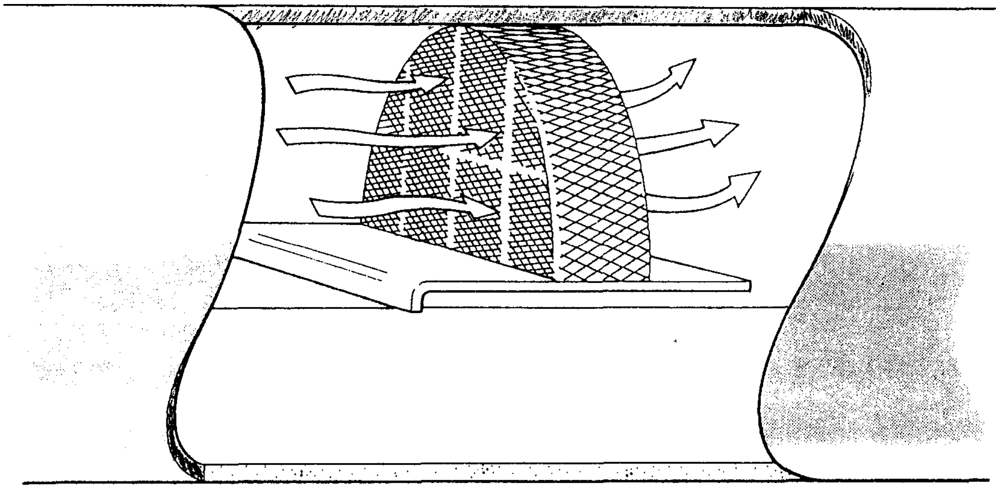


**Figure 6.20 A knitted Wire Mesh Pad**

This type of mist extractor is placed near to the gas outlet from the vessel. As the gas containing the very small droplets flows past the wire mesh, the gas turns to flow round the strands of wire. The droplets, however, tend to continue in a straight line so they will strike the wire strands and stick to them. As more droplets stick to the wire, a film of liquid forms which slowly moves to the lowest point on the wire. At this point the liquid accumulates to form a drop. When the drop is large enough it will break away from the surface where it has collected. From there it will fall down to the liquid accumulation section of the separator under the influence of gravity.

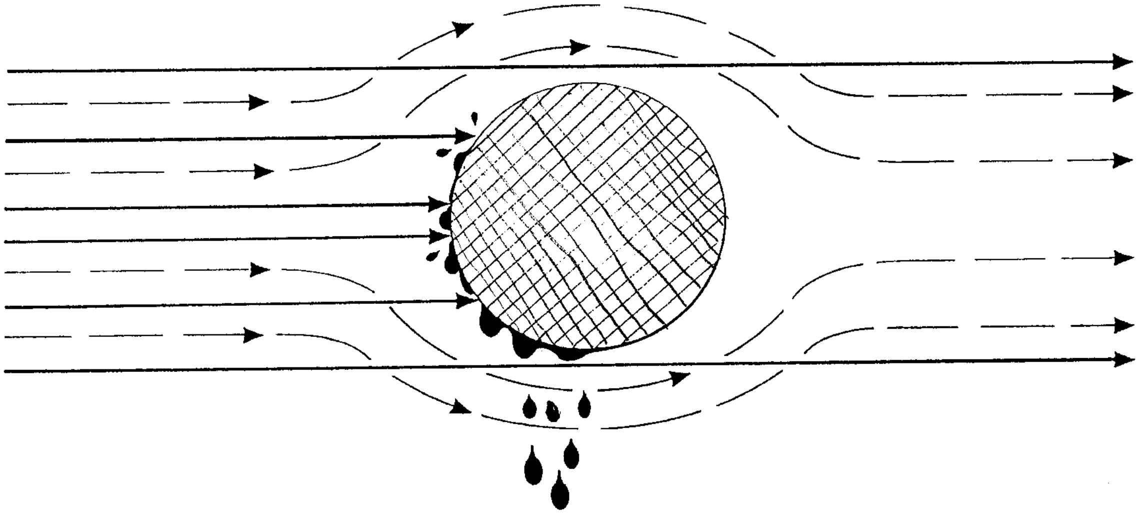


Figure 6.21 The Action of a Knitted Wire Mesh Pad

The use of centrifugal force for mist extraction is usually confined to vessels where the gas flow is vertically upwards. If the gas stream containing liquid mist is made to flow in a circular motion, centrifugal force throws the liquid particles outwards. This causes the particles to impinge on the walls of the vessel or container. Here the small droplets will coalesce into larger droplets until they are large enough to gravitate to the liquid accumulation section.

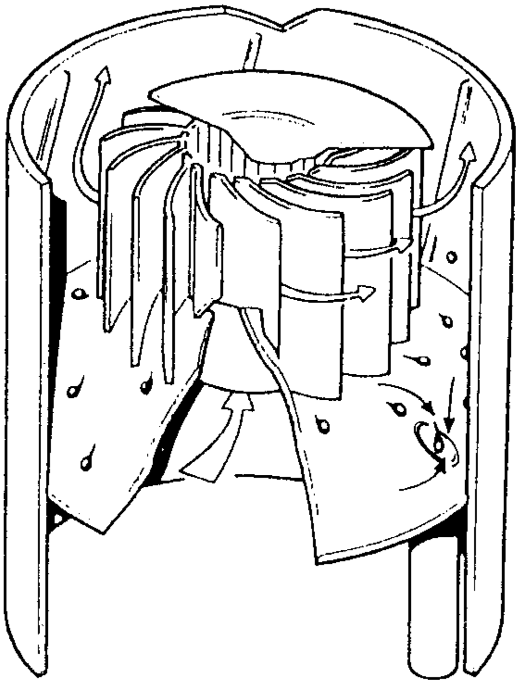


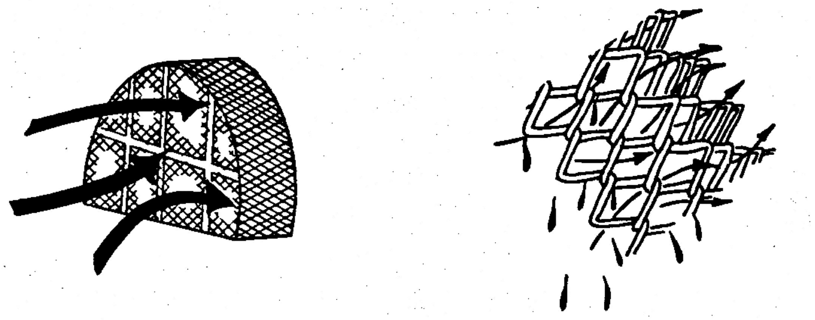
Figure 2.22 A Centrifugal Force Type Mist Extractor

In centrifugal extraction, a continual change in gas flow direction at high velocities is required for small particle removal. This results in relatively large pressure drops across the extractor, which may limit its application.

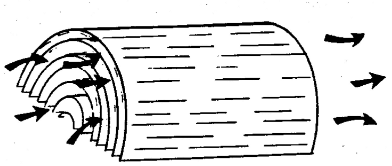
The stainless steel woven wire mesh mist-eliminator of thickness 10 – 20 cm (4-8 inch) is considered to be the most efficient type. It is held in place by a sturdy grid which prevents it from being swept out or torn by a sudden surge of gas, and has been proven by removing up to 99.5% or ore of the entrained liquids from the gas stream.

This type offers the greatest area for the collection of liquid droplets per unit volume as compared to vane type.

**Figures (6.23 and 6.24)** show two of the most common mist-extraction devices; wire-mesh pads, and vans. Wire-mesh pads are made of finely woven mats of stainless steel wire wrapped into a tightly packed cylinder. The liquid droplets impinge on the matted wires and coalesce. The effectiveness of wire mesh depends largely on the gas being in the proper velocity range. If the velocities are low, the vapor just drifts through the mesh pad without the droplets impinging and coalescing. Alternately high velocity gas can strip the liquid droplets from the wire mesh and carry the droplets out the gas outlet.



**Weir-Mish Pads**



**Arch Plates**

**Figure 6.23 Schematic of Two Types of Mist Extractors**

Vane-type mist extractors force the gas flow to be laminar between parallel plates, which contain directional changes. Droplets impinge on the plate surface where they coalesce and fall to a liquid-collection area where they are routed to the liquid-collection section of the vessel. Vane-type mist extractors are sized by their manufacturers to assure both laminar flow and a certain minimum pressure drop.

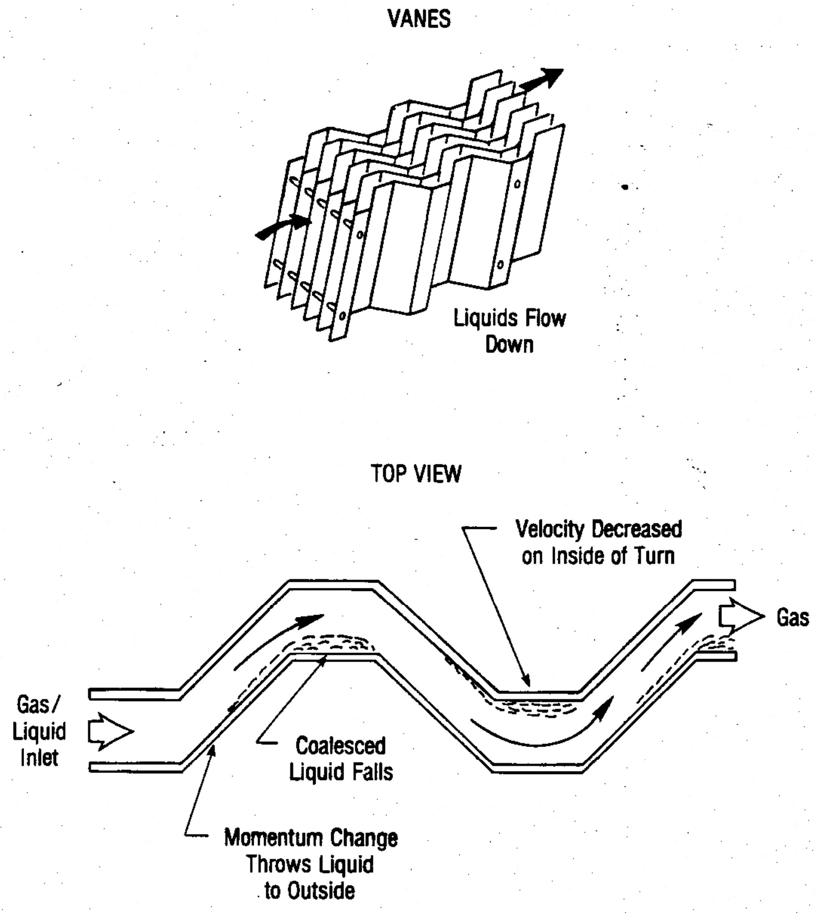


Figure 6.24 A Common Mist Extraction Device using Vanes

Some separators have centrifugal mist extractors which cause the liquid drops to be separated by centrifugal force. These can be more efficient than either wire mesh or vanes and are the least susceptible to plugging. However, they are not in common use in production operations because their removal efficiencies are sensitive to small changes in flow. In addition they require relatively larger pressure drops to create the centrifugal force.

The selection of a type of mist extractor involves a typical cost benefit analysis. Wire mesh pads are the cheapest; however, mesh pads are the most susceptible to plugging with paraffins, gas hydrates, etc. With age, mesh pads also tend to deteriorate and release wires and/or chunks of the pad to the gas stream. This can be extremely damaging to downstream equipment such as compressors. Vane units, on the other hand, are more expensive. Typically, vane units are less susceptible to plugging and deterioration than mesh pads. The selection of a type of mist extractor is affected by the fluid characteristics, the system requirements, and the cost.

It is recommended that the sizing of mist extractors should be left to the manufacturer. No specific sizing technique has been identified for mist extractors and therefore no method is presented in this manual. Experience indicates that if the gravity-settling section is designed to remove liquid droplets of 500 micron or smaller diameter, there will be sufficient space to install a mist extractor.

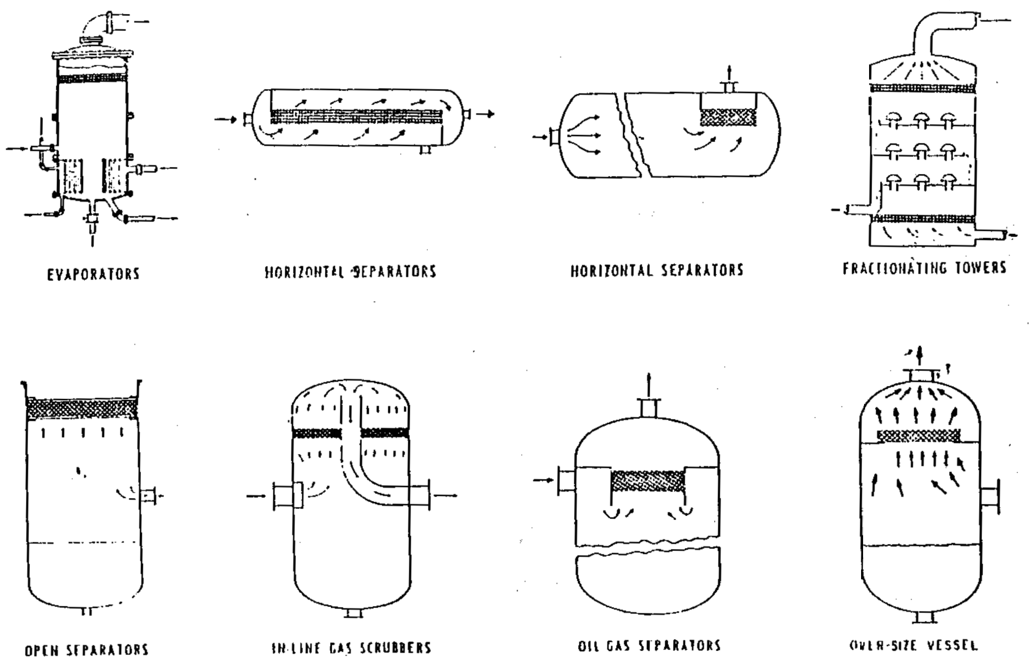
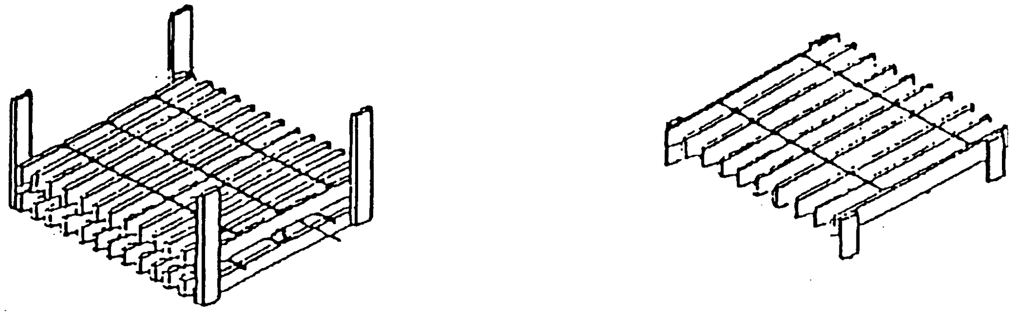


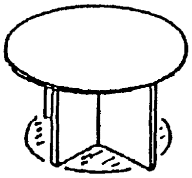
Figure 6.25 Mist Extractors in Various Types Vessels

## Vortex Breakers

The liquid outlet should be equipped with anti-vortex devices to prevent a vortex from forming, and gas from going out with the liquid. Several types are shown in **Figures 6.26 & 6.27**.

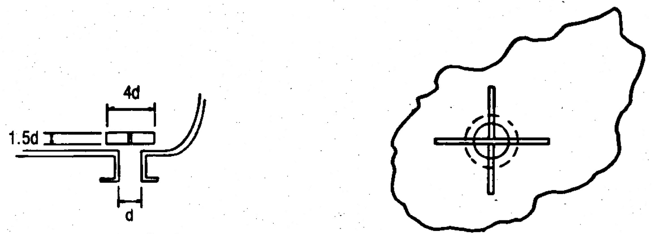


**Gas Vortex Breaker** **Liquid Vortex Breaker**



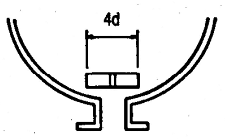
**Liquid Vortex Breaker**

Figure 6.26 Outlet Vortex Breaker



Longitudinal Section

Plan



Cross Section

Figure 6.27 Three Views of Typical Vortex Breaker

# 6.9 OPERATING PROBLEMS

Some of the major problems encountered in the operation of oil and gas separators are due to foam, paraffin, sand, emulsions and slugging.

## 6.9.1 Foamy Crudes

This is caused when the oil fails to release the gas quickly enough as it passes through the vessel, and a layer of oily bubbles forms on top of the liquid surface.

Another major cause of foam is impurities other than water in the crude oil that are impractical to remove before the stream reaches the separator. Foam presents no problem within a separator if the internal design assures that the rate of foam breakup is faster (or at least equal to) the rate of buildup.

The level control displacer on the oil side of the weir is designed to operate in a liquid. It cannot float in foam.

When the float sinks in the foam it indicates a false low level to the level controller and the oil outlet valve will close. This can result in the carry-over of liquids with the gas stream and a possible shutdown of the gas facilities downstream.

### The problem

Foaming in a separating vessel is a threefold problem and may be outlined as follows:

1. Mechanical control of liquid level is aggravated because any control device must deal with essentially three instead of two phases.

2. Foam has a large volume-to-weight ratio. Therefore, it occupies more than its appropriate share of vessel space, which would otherwise be available to allow minimum gas and oil velocities.

3. In an uncontrolled foam bank, it becomes impossible to remove separated gas or degassed oil from the vessel without entraining some of the foamy material in either the liquid or gas.

Information concerning the general characteristics of foam within separators is of little value, since the vessels contain no windows or ports to inspect the interior. However, information on characteristics of foaming liquids may be compared with respect to known oil-gas separation results and predictions within given vessels can be derived.

To stop this happening, anti-foam agents are often injected into the inlet stream to prevent foaming.

## Use of a Foam Comparator

Comparison of foaming tendencies of a known oil to new one about which no operational information is known can be made on the basis of observations in a foam comparator. The results provide comparison of the relative foam problem, which may be expected with the new oil as weighed against the known oil production. Then a related amount of adjustment can be made in the design parameters, as compared to those found satisfactory for the known case.

It should be noted that the amount of foam varies with pressure levels between which gas is liberated and also with the characteristics of the liquid at separator conditions. Therefore, comparators do not take into account all function of foam formation. Though no measure of quantitative foaming effect can be taken into account, qualitative comparisons of two different crude or two conditions of one crude are most valuable in separator application decisions. In some cases, the effects of temperature may be found to be quite spectacular and frequently is overlooked in the design of separators for foaming conditions. The influence of this effect can be evaluated by use of a foam comparator.

Results of a foam comparator test will allow a manufacturer to design the internals of the separator to most efficiently process the foam by breaking it into its gaseous and liquid phases before it leaves the separator.

## Depressants

Foam depressants are available that often will do a good job in increeasing the capacity of a given separator. However, in sizing a separator to handle a particular crude, the use of an effective depressant should not be assumed as charateristics of the crude and the foam may change during the life of the field. Sufficient capacity should be provided in the separator to handle the anticipated production without use of a foam depressant inhibitor. Once in operation, use of a foam depressant may allow more throughput than the design capacity. This is valuable in expansion programs. To anticipate this effect, it is a good idea to oversize lines and valves entering and leaving a separator.

## 6.9.2 Paraffin

Separator operation can be adversely affected by an accumulation of paraffin. Mist extractors, in particular, are prone to malfunction by accumulations of paraffin. Where it is determined that paraffin is an actual or potential problem, use of a type of mist extractor prone to plugging should be avoided; and manways, handholes and nozzles shoud be provided to allow steam, solvent or other type of cleaning of the separator internals.

## 6.9.3 Sand

Sand can be very troublesome in separators. These difficulties are evidenced mainly by cut-out of valve trim, plugging of separator internals and accumulation in the bottom of equipment. Special hard trim can minimize effects of sand on the valve. Accumulations of sand can be alleviated by the inclusion of jets for injection of water, steam or possibly a side stream of the production periodically into the bottom of the vessel.

Plugging of separator intermals is a problem that must be given considerable consideration in the design of the separator. A design that will promote good separation and have a minimum of traps for sand accumulation may be difficult to attain. The design that provides the best mechanism for separating the gas and oil phases probably will provide areas for sand accumulation. A practical balance of these factors is the best solution, and the experience of a separator manufacturer is invaluble in providing a workable solution to the problem.

## 6.9.4 Emulsions

A common operating problem is that caused by the water and oil forming an emulsion.

This is a mixture of two immiscible liquids where one of the liquids is dispersed throughout the other in the form of very small droplets. In the oilfield, the dispersed liquid is usually the water.

An emulsion may be classed as 'tight' or 'loose'. Milk is a tight emulsion. It is a mixture of butter fats and water and it cannot be easily broken.

Salad dressing is a loose emulsion. It is a mixture of oil and vinegar. When you shake the bottle an emulsion forms and the small globules of oil and vinegar can be seen with the naked eye. If you let the bottle stand for a few minutes the emulsion will break down and the oil will begin to float on the top of the vinegar.

If emulsions are found in a separation process they may be tight or loose. The type will depend, for example, on the nature of the oil being produced and the amount of water present.

If a stable emulsion has been formed betwwen the oil and water phases upstream of the separator or in the vessel, separation of these phases is not practical. The combined water and oil stream must be removed from the separator and routed to other equipmnt for separation into two phases. This separation usually can be accomplished in a conventional treater.

When emulsion tendencies are present, the settling time required to achieve an acceptable separation of oil and water may be longer than that required to adequatly clean the gas in any vessel configuration. In this case, it will be necessary to remove the water and oil phases from the vessel and route them to another separator for further processing. Frequently, it is possible to appreciably lower the settling time necessary for water-oil separation by application of heat in the liquid section of the separator.

Over a period of time an accumulation of emulsified material and /or other impurities usually will form at the interface of the water and oil phases. In addition to adverse effects on the liquid level control, this occurrence will also decrease the liquid settling time in the separator with a resultant decrease in water-oil separation efficiency,however, in some cases, the emulsion can be treated in the separator itself. This involves the injection of a chemical into the well fluids. This chemical, which is called a **demulsifier,** helps to break down the emulsion and allows the separator to do its job.

## 6.9.5 Slugging

Slugging occurs when, for some reason or another, there is an intermittent, rather than a constant, flow of well fluids into the separator. In some instances the flow may cease altogether for a few seconds and then a **slug** will arrive.

This intermittent flow can cause rapid fluctuations in separator levels and pressures. The controllers react to these changes by rapidly opening and closing their respective valves in an attempt to bring the situation under control. In severe cases the control system may become unstable resulting in a shutdown.

# Chapter 7

# Crude Oil Dehydration

# Chapter 7 Contents

## Chapter 7

# Crude Oil Dehydration

## 7.1 INTRODUCTION

Rarely is clean oil, ready for sale into a pipeline, produced from an oil well. Generally, what comes out of the well is a mixture of oil, water, gas, and even sand or solid materiel. Foreign material, such as water and sand must be separated from the oil and gas before they can be sold. This process is known as oil treating or oil dehydration in which water is removed from the oil. The amount of this foreign material is referred to as the BS&W, or basic sediment and water, content of the oil. Normally, the BS&W content must be less than 0.5 % vol. before the oil will be acceptable for sale into a pipeline. Some type of treating involving special equipment is usually necessary to remove these contaminant materials from the oil or gas.

Oil treating requires knowledge of emulsions. Oil-water emulsions (**Figure 7.1**) are common in the oil field and need specialized treating before the oil can be cleaned. A water-in-oil emulsion consists of water drops suspended in an oil solution. Conversely, all oil-in-water emulsion consists of oil drops suspended in water. These tiny droplets often will not separate because the finely dispersed droplets are not large enough to coalesce and form into separate oil and water components. A good example of all emulsion is homogenized milk. In homogenized milk, cream has been emulsified or finely dispersed, into the milk so it will not separate out, the same type of thing often happens to oil and water as production occurs from reservoir. The oil and water become mixed together and form an emulsion to the extent that the water or oil will not easily separate.

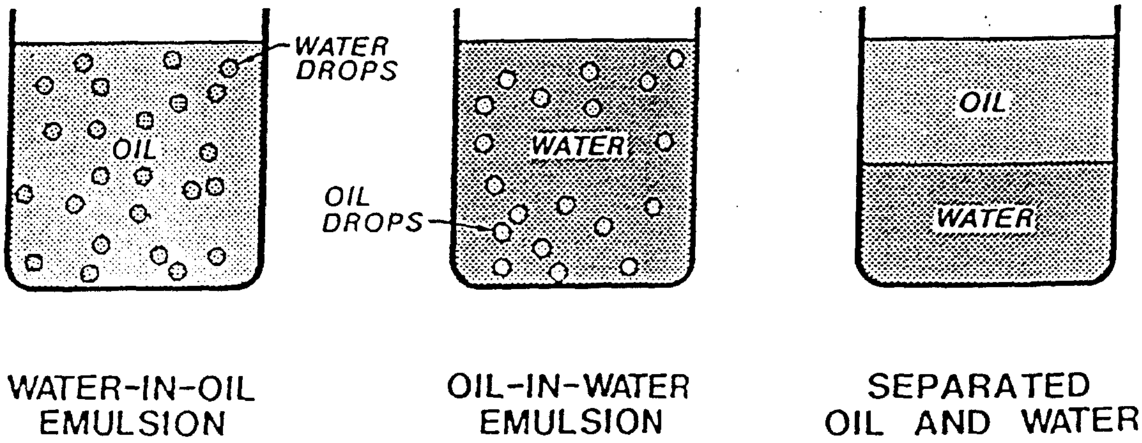


Figure 7.1 Oil - Water Emulsion

**The objective** is to separate the oil from the water, or to break the emulsion. Generally, the emulsion must be heated and some emulsion breaking chemical added to accomplish this. It has been found that, if all emulsion is warmed or heated, the emulsified fluids separate. In the following sections, we will look at some of the equipment that is used to separate or demulsify oil and water mixtures. Many different types of oil treating equipment are used in the oil field.

The majority of oil production treatment is done by Heater Treaters. For onshore applications where space is available, large tanks called Gunbarrels or Wash tanks are also used. The space limitations of offshore applications dictate the use of heater treaters or electrostatic treaters.

Chemical treating to deactivate emulsifiers may be required, but the choice and concentration of chemical can only be determined in the field.

## 7.2 EMULSIONS

Some water produced with oil readily separates from the oil and is referred to as free water. On the other hand, some water produced is mixed in such a way with the oil that treating is necessary to separate them. Such a combination of oil and water is called an emulsion.

In an emulsion one of the liquids is spread out, or dispersed, throughout the other in the form of small droplets, in oil field emulsions, water is usually dispersed in oil and is referred to as a water-in-oil emulsion. When the opposite happens, oil-in-water emulsion is formed. Emulsions may be tight (difficult to break) or loose (easy to break) depending on the type and amount of emulsifying agent present.

In order for an emulsion to exist, it is necessary to have:

1. Two mutually immiscible liquids.
2. An emulsifying agent, and
3. Sufficient agitation to disperse the discontinuous phase into the continuous phase.

In oil production, oil and water are the two mutually immiscible liquids. An emulsifying agent in the form of small solid particles, paraffins; asphaltenes, etc., is almost always present in the formation fluids and sufficient agitation always occurs as fluid makes its way into the wellbore, up the tubing, and through the surface choke.

As the well fluids churn their way up the hole, agitation is provided by a downhole pump, gas lift valves, or tubing restrictions; the turbulence caused by the pressure drop across the choke is the primary source of agitation for emulsion formation. Since the installation of a choke to control the flow rate of the produced well fluids is necessary in most installations, elimination of the causes of emulsion formation is not ordinarily a solution to the problem.

The degree of agitation and the nature and amount of emulsifying agent determine the stability of the emulsion. Some stable emulsions may take weeks or months to separate if left alone in a tank with no treating. Other unstable emulsions may separate into relatively pure oil and water phases in just a, matter of minutes.

Normal oilfield emulsions consist of an oil-continuous or external phase, and a water dispersed or internal phase. In some isolated cases, where there are high water cuts, it is possible to form reverse emulsions with water as the continuous phase and oil droplets as the internal phase. Complex emulsions have been reported in low gravity, viscous crudes. These mixed emulsions contain a water external phase and have an internal water phase in the dispersed oil. The vast majority of oil treating systems deal with normal emulsions.

**Figure 7.2** shows normal oil in water emulsion. The small water droplets exist within the oil-continuous phase. **Figure 7.3** shows a close-up of a skin (monomolecular film) of emulsifying agent surrounding water drop and **Figure 7.4** shows two drops touching, but being prevented from coalescing due to the film of emulsifying agent around each drop.

When thinking about emulsion stability it may be helpful to realize that in a pure oil and pure water mixture without an emulsifying agent, no amount of agitation will create an emulsion. If the pure oil and water are mixed and placed in a container, they quickly separate. The natural state is for the immiscible liquids to establish the least contact or smallest surface area. The water dispersed in the oil will form spherical drops. Smaller drops will coalesce into larger drops and this will create a smaller interface area for a given volume. If no emulsifier is present the droplets will eventually settle to the bottom causing the smallest interface area. This type of mixture is a true dispersion.

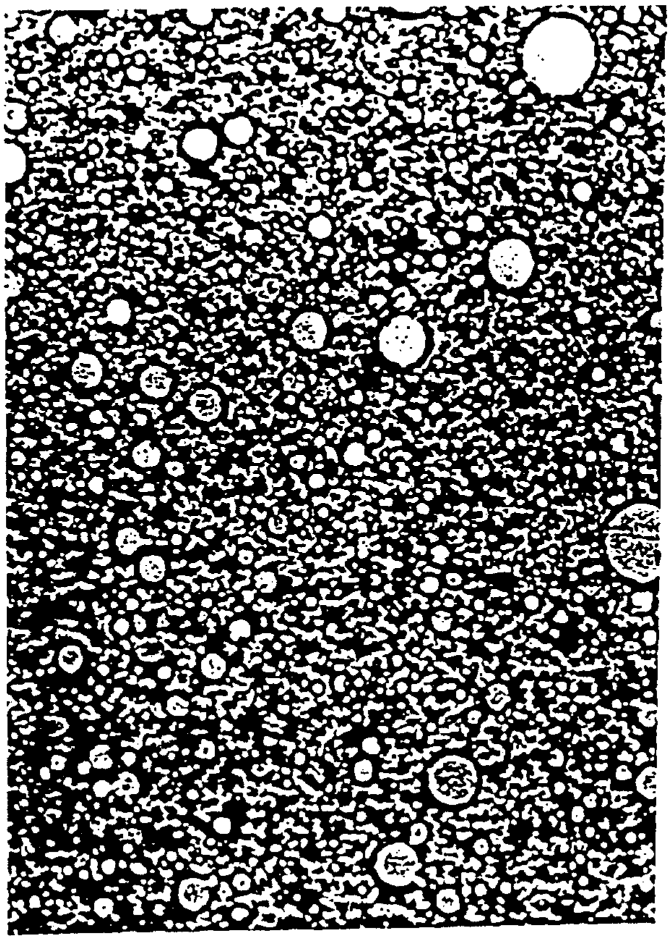


Figure 7.2 Photomicrograph of an Oil - in -Water Emulsion

Figure 7.3 Photomicrograph Showing a Close-up View of the Emulsifying Agent Skin Surrounding a Water Droplet

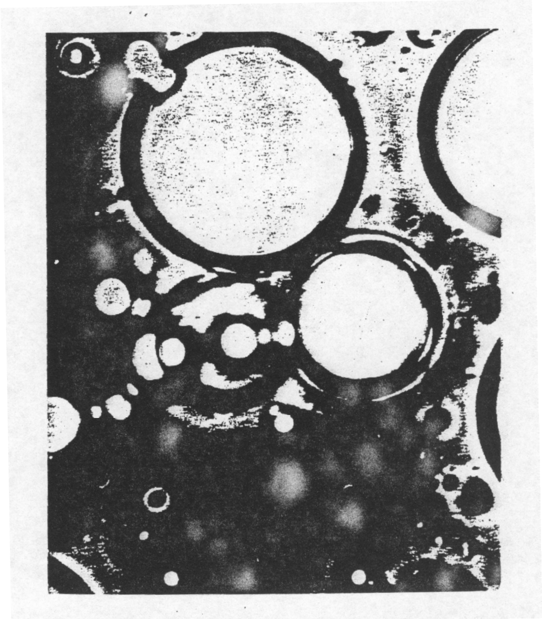


Figure 7.4 Photomicrograph Showing two Droplets Touching but Unable to Coalesce because of the Emulsifying Agent Skin Surrounding the Droplets

## 7.2.1 Emulsion Terminology

### 7.2.1.1 Standard or Regular Emulsion

When individual water droplets are dispersed in a continuous surrounding body of crude oil, the emulsion is known as a regular or standard emulsion. This is the type of emulsion most commonly encountered in the oil fields of the world, and fortunately it is also the easier of the two basic emulsion types to break down, so the water can be separated from the oil.

### 7.2.1.2 Reversed or Inverted Emulsion

When individual oil droplets are dispersed in a continuous water phase, the emulsion is described as reversed or inverted. Reversed emulsions are not common; they usually are found only where the amount of water in the total liquid stream greatly exceeds that of the oil, such as when a water-drive field has almost "watered out".

### 7.2.1.3 Unstable or Loose Emulsion

An emulsion is described as unstable or loose if the water droplets vary considerably in size and if most of the water droplets are relatively large in size.

### 7.2.1.4 Stable or Tight Emulsion

If the water droplets will not settle out of the oil because of their small size and surface tension, then some form of treatment is required and the emulsion is described as stable or tight.

## 7.3 EMULSIFYING AGENTS

An emulsifying agent is a substance that promotes the formation and stability for emulsion. This is accomplished by the emulsifying agent collecting in the surface of water droplets and forming a tough film which keeps the droplets from joining.

Emulsifying agents commonly found in oil field emulsions include asphalt, resins, paraffins, and oil soluble organic acids. Different emulsifying agents occur naturally in different reservoirs.

An emulsifying agent in the system is a material which has a surface-active behavior. Some element in the emulsifier has a preference for the oil, and other elements are more attracted to the water. An emulsifier will tend to be insoluble in one of the liquid phases. It thus concentrates at the interface. There are several ways emulsifiers work to change a dispersion into an emulsion. The action of the emulsifier can be visualized as one or more of the following:

1. It decreases the interfacial tension of the water droplet, thus causing smaller droplets to form. The smaller droplets take longer time to coalesce into larger droplets which would settle quickly.

2. It forms a viscous coating on the droplets which keeps them from coalescing into larger droplets when they collide. Since coalescence is prevented, it takes longer time for the small droplets, which are caused by the agitation the system has experienced, to settle out.

3. The emulsifiers may be polar molecules which align themselves in such manner as to cause an electrical charge on the surface of the droplets. Since like electrical charges cause repulsion, it is necessary for two droplets to collide with sufficient force to overcome this repulsion before coalescence can occur.

Naturally occurring surface-active materials normally found in crude oil serve as emulsifiers. Paraffins, resins, organic acids and bases, metallic salts, colloidal salts and clay and aspartames (a general term for material with chemical compositions containing sulfur, nitrogen, and oxygen) are common emulsifiers in oilfields. Workover fluids and drilling mud are also sources of emulsifying agents.

The type and amount of emulsifying agent has an immense effect on the stability of the emulsion. It has been shown that the temperature history of the emulsion is also important as it affects the formation of paraffins and asphaltenes. The speed of migration of the emulsifying agent to the oil water interface and the behavior in terms of the strength of the interface bond are important factors. An emulsion treated soon after agitation or after the creation of paraffins and asphaltenes can be less stable and easier to treat if the migration of the emulsifier is incomplete. In aged emulsion may become more difficult to treat because the emulsifying agents have migrated to the oil/water interface. Normally, the lower the crude viscosity and the lighter the crude, the more rapid the aging process.

In order to break an emulsion, the film must be neutralized or destroyed by using treatment methods. Treating is usually done in the field using various types of equipment (free-water knockouts, separators, heater treaters, electrostatic treaters, etc.) and by adding chemicals to the emulsion immediately after it is produced.

## 7.4 DEMULSIFIERS

Chemical demulsifiers sold under various trade names such as Tretolite, Visco, Braksit, etc., are highly useful aids to resolution of emulsions. Demulsifiers act to neutralize the effect of emulsifying agents. Typically they are surface-active agents and thus, their excessive use can decrease the surface tension of water droplets and actually create more stable emulsions. Also, demulsifiers for water-in-oil emulsions tend to promote oil-in-water emulsions; therefore, excessive chemical use may cause water-treating problems.

There are four important actions required of a demulsifier.

1. Strong attraction to the oil/water interface.
2. Flocculation.
3. Coalescence.
4. Solid wetting

When these actions are present they promote the separation of oil and water. The demulsifier must have the ability to migrate rapidly through the oil phase to the droplet interface, where it must compete with the more concentrated emulsifying agent. The demulsifier must have an attraction for droplets with a similar condition. In this way, large clusters of droplets gather which, under a microscope, appear like bunches of fish eggs. The oil will take on a bright appearance since small droplets are no longer present to scatter the light rays.

At this point, the emulsifier film is still continuous. If the emulsifier is weak, the flocculation force may be enough to cause coalescence. This is not true in most cases and the demulsifier must therefore neutralize the emulsifier and promote a rupture of the droplet-interface film. This is the opener which causes coalescence. With the emulsion in a flocculated condition, the film rupture results in rapid growth of water drop size.

The manner in which the demulsifier neutralizes the emulsifier depends upon the type of emulsifiers. Iron sulfides, clays and drilling mud's can be water-wet causing them to leave the interface and be diffused into the water droplet. Paraffins and asphaltenes could be dissolved or altered to make their films less viscous so they will flow out of the way oil collision or could be made oil-wet so they will be dispersed in the oil.

It would be unusual if one chemical structure could produce all four desirable actions. A blend of compounds is therefore used to achieve the right balance of activity.

The demulsifiers selection should be made with the process system in mind. If the treating process is a settling tank, a relatively slow-acting compound can be applied with good results. On the other hand, if the system is an electro- chemical-process where some of the flocculation and coalescing action is accomplished by the electric field, there is need for a quick-acting compound, but not one which must complete the droplet building action.

As field conditions change, the chemical requirements can change. If the process is modified for example, very low rates oil electrostatic units the chemical requirement can change. Seasonal changes bring paraffin-induced emulsion problems. Workovers contribute to solid and acid/base contents which alters emulsion stability. So, no matter how satisfactory a demulsifier is at one point in time, it can not be assumed that it will always be satisfactory over the life of the field.

## 7.5 CRUDE OIL TREATING (Emulsion Treating)

### 7.5.1 Information Needed Prior to Process Selection

Treating processes and equipment for individual leases should not be selected until the physical characteristics of the oil and water have been determined and a study of the effect of available chemicals on the emulsions has been made. It is equally important that an estimate be made of the volumes of fluid that are to be handled. The gravity, viscosity, and pour point of the oil are important for determining if heating will be necessary. The water should be considered from corrosion and scaling standpoint.

Successful treating of a crude oil emulsion is normally carried out in three stages:

a. Destabilization of emulsions
b. Coalescence of small droplets of the dispersed phase (water) into large droplets
c. Settling out of large droplets and separation of the two phases.

### 7.5.2 Destabilization of Emulsions

To destabilize an emulsion it is necessary to deactivate or delocalize the emulsifying agent so that the droplets coalesce upon collision.
Stable emulsions are broken down by:

a. Chemical demulsifying.
b. Heat treatment.
c. Electrical coalescence.

### 7.5.2.1 Chemical demulsifying

The main approach for treating stable emulsions is the injection of a chemical demulsifier. Chemical treatment is most effective when added prior to the formation of an emulsion. This also allows the chemicals time to work on an emulsion while the oil is in transit to the terminal. Most oilfield emulsions, chemically treated in the field, will have been broken on arrival at the terminal. The processes taking place in most of the mechanical dehydration equipment in use at terminals, (such as heater-treaters, coalescers, and wash tanks), are enhanced by the additional injection of a chemical demulsifier in the oil-flow to these equipments.

These chemical demulsifiers are surface active agents which diffuse through the oil phase of the emulsion to the oil- water interface where they deactivate the emulsifying compounds. The stabilized films around the dispersed phase droplets are thus weakened and colliding droplets are able to merge into larger ones. A demulsifier also removes skin strengthening solids from the surface by dispersing them into one of the separate liquids.

**How Chemicals Break Emulsions:**

The purpose of treating chemicals is to induce coalescence, so that the oil and water will separate rapidly. The action of the chemical is to act on and destroy or rupture the tough film surrounding the water droplets. Practically all modern emulsion treating chemicals are more soluble in oil than in water, with the exception of a few chemicals made for oil-in-water or "reverse" emulsions. These latter are essentially water-soluble.

### 7.5.2.2 Heat treatment

The introduction of heat into an emulsion is beneficial in its treatment in several ways:

a. It increases the solubility of the emulsifying agent in the oil and the dispersion of it into the oil phase away from the interface.
b. It enables the demulsifier to reach the surface of the droplet and speeds up the reaction of the demulsifier.
c. It reduces the viscosity of the oil and allows faster coalescence and settling of the water droplets.
d. It adds energy to the system causing movement of the water droplets by increasing the Brownian motion.
e. It causes expansion of the droplet which helps to rupture the surrounding film.

When heat alone is not enough to resolve an emulsion, the assistance of a chemical demulsifier is required. Some emulsions do not resolve even at a temperature of 90 °C without the aid of a chemical demulsifier.

Heat must be applied only as needed because too much heat will waste energy (fuel) and cause greater wear on the equipment. Also, excessive heat can cook off the lighter ends of crude oil which will change the oil's gravity and result in lost revenue.

It must be remembered, however, that heat vaporizes the light ends of the oil and, unless these are conserved, will reduce API gravity and volume.

#### 7.5.2.3 Electrical Coalescence

Electrostatic coalescence is a separation process that employs an intense electrical field to enforce collisions between small droplets. The resulting larger drops are readily separated by gravity. The technique can be applied to any dispersion with an insulating continuous phase and a difference in the dielectric constant of both the continuous and dispersed phases. When these types of dispersion are subjected to an electric field, the dispersed phase can experience several types of electric force. Droplets that acquire a net charge will start to move in the direction of the field; furthermore dipoles can be induced (charge separation in a single droplet) leading to droplets being attracted towards each other. The total result is accelerated movement and increased frequency of collisions. The electrical forces attainable are two or three orders of magnitude higher than gravitational forces.

### 7.5.3 Gravity Separation of Oil/Water Emulsions (Settling)

Water and oil are separated by virtue of their different densities. Dispersed phase droplets will settle out of the continuous phase (oil droplets rising, water droplets falling), and while the emulsion is destabilized, the droplets will coalesce to form a distinct layer which can be recovered. For laminar flow conditions, an unhindered dispersed phase droplet will achieve a constant velocity when the force due to density difference is equal to the resistance to motion of the fluid in which it is moving. This velocity can be calculated using Stokes' law:

$$V_T = \frac{gd^2}{18\eta}(\rho_w - \rho_o) \qquad (1)$$

Where:

$V_T$ = Terminal settling velocity of droplet, in m/s
$g$ = Acceleration due to gravity, in m/s$^2$
$d$ = Diameter of droplet, in m
$\eta$ = Dynamic viscosity of the continuous phase, in Pa .s
$\rho_w$ = Density of water, in kg/m$^3$
$\rho_o$ = Density of oil, in kg/m$^3$.

The following factors have the greatest influence on settling velocities:

**g: Acceleration due to gravity.**

Gravity is the driving force. This force can be increased using cyclones or centrifuges although their use is uncommon in the oil field practice.

**$(\rho_{w} - \rho_{o})$, $\eta$: Density difference and viscosity.**

Large density differences between oil and water and low continuous phase viscosities are favorable for fast separation (settling). Generally speaking, the heavier the crude the greater its viscosity and the lower the oil-water density difference. Consequently, heavy crudes are much more difficult to dehydrate than light crudes. Heat treatment can be used to accelerate the dehydration of heavy crude as an increase in temperature will result in a decrease in viscosity (**Figure 7.5**).

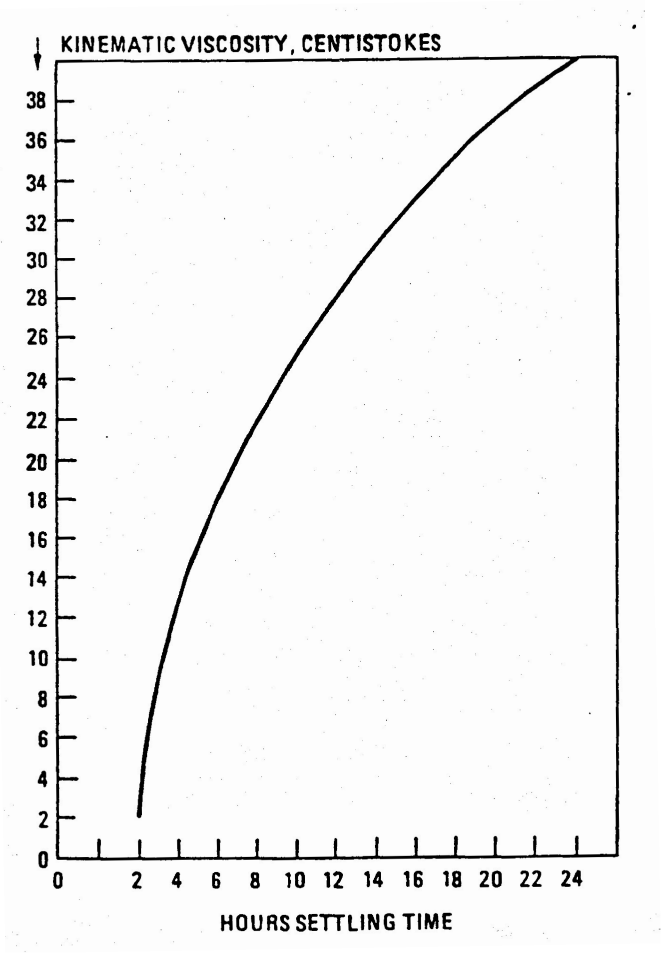


**Figure 7.5 Approximate Time / Viscosity Curve**

### d: Droplet size

The terminal settling velocity increases with the square of the droplet diameter. Therefore, it is desirable to have relatively large dispersed phase droplets, which can be achieved by either minimizing the degree of mixing or by promoting coalescence (**Figure 7.6**).

In summary, the type of treatment to apply on a particular crude oil depends entirely on the type of oil and the circumstances under which emulsions are formed.

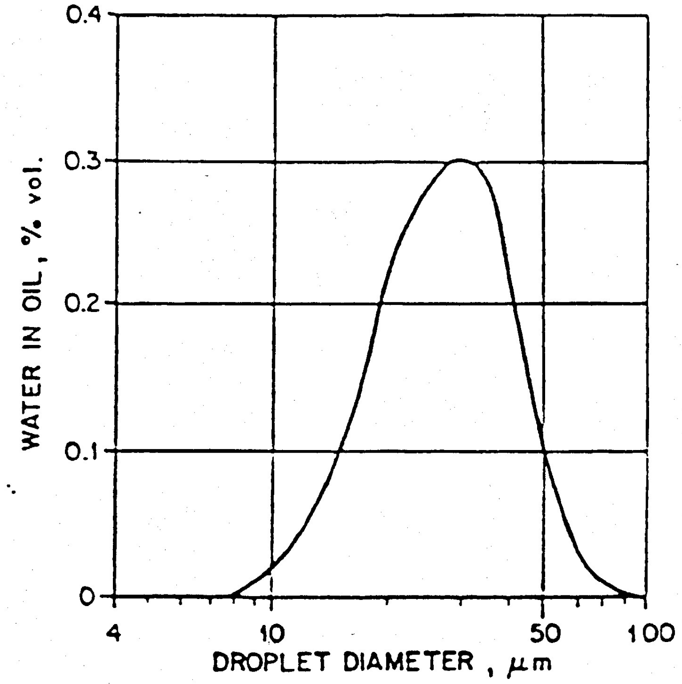


**Figure 7.6 Droplets Size Distribution Curve**

# 7.6 FACTORS THAT AFFECT TREATING

## 7.6.1 Gravity Separation

Most commonly used oil-treating equipment relies on the forces of gravity to create the separation between the water droplets and the oil-continuous phase. Because the water droplets are heavier than the volume of oil they displace, they have a downward gravitational force exerted upon them. This is resisted by a drag force caused by their downward movement through the oil. When the two forces are equal, a constant velocity is reached which can be computed from Stoke's Law as

$$V_t = \frac{1.8 \times 10^{\,6} (\Delta SG) dm^2}{\mu} \qquad (2)$$

**Where:**

$V_t$ = Terminal-settling velocity of the droplet, ft/s

$d_m$ = Droplet diameter, microns

$\Delta SG$ = Difference in the specific gravity relative to water of the droplet and the continuous phase

$\mu$ = Viscosity (absolute) of the continuous phase, cp

This is another form of the Stoke's law already shown in the previous section.

Several conclusions can be drawn from this simple equation.

1. The larger the size of a water droplet, the larger the square of its diameter, and thus, the greater its downward velocity. That is, the bigger the droplet size, the less time it lakes for the droplet to drop to the bottom of the vessel and thus, the easier it is to treat the oil.

2. The greater the difference in density between the water droplet and the oil phase, the greater the downward velocity. That is, the lighter the oil, the easier it is to treat the emulsion.

3. The higher the temperature, the lower the viscosity of the oil, and thus, the greater the downward velocity. That is it is easier to treat the oil at high temperatures than at low temperatures. However, care must be exercised to ensure that gas breakout does not occur in the coalescing-section due to the elevated temperatures. Gas rising to the liquid surface will carry water droplets with it.

## 7.6.2 Coalescence

The process of coalescence in oil treating systems is time dependent, in dispersions of two immiscible liquids, immediate coalescence seldom occurs when two droplets collide. If the droplet pair is exposed to turbulent pressure fluctuations, and the kinetic energy of the oscillations induced in the coalescing droplet pair is larger than the energy of adhesion between them, the contact will be broken before coalescence is completed.

## 7.6.3 Viscosity

The viscosity of the oil-continuous phase is extremely important in sizing a treater. Equations (1&2) are used for determining the settling velocity of a water droplet includes the oil viscosity. As the oil viscosity increases, the settling velocity of a given droplet decreases. This requires that the treater size be increased.

The oil viscosity also affects coalescence of the water droplets. As the oil viscosity increases there is more resistance to random motion of the water droplets. Therefore, the droplets do not move as fast. This decreases the energy and the frequency of the collisions. Thus, it is more difficult to grow large water droplets. A treater for this application must be designed to remove smaller water droplets. The diameter of the droplet is squared in equations (1&2), so the settling velocity is reduced by the square of the diameter reduction. Again, increasing the oil viscosity requires the treater size to be increased.

By far the best situation is to have oil viscosity versus temperature data for a particular oil to be treated. Alternately, data from other wells in the same field can usually be used without a significant error. This viscosity versus temperature data may be plotted on special ASTM graph paper. Such plots are usually a straight line, unless the oil has a high cloud point. The viscosity may then be predicted at any other temperature.

With virtually any crude oil the viscosity change with temperature can excellent guide to minimum crude processing temperatures. An ASTM chart of the viscosity versus temperature is useful to detect the paraffin formation or cloud point of the crude as shown in **Figure 7.7A**. This normally establishes a minimum temperature for the treating process. There are examples of 30° API crude and higher which have pour points of 80 to 90° F.

In the absence of any data, **Figure 7.7B** may be used to estimate oil viscosities. **Figure 7.7** plots kinematic viscosity in centistokes versus temperature in degrees Celsius. To obtain the oil viscosity in centipoises at a particular temperature in degrees Fahrenheit the following conversions are required:

$$T\ (^{o}C) = (5/9)\ [T\ (^{o}F) - 32] \qquad (3)$$

$$\mu = \nu\ (SG) \qquad (4)$$

**Where:**

$T$ = Temperature, ºC
$\nu$ = kinematics viscosity, c s
$\mu$ = Absolute viscosity, c p

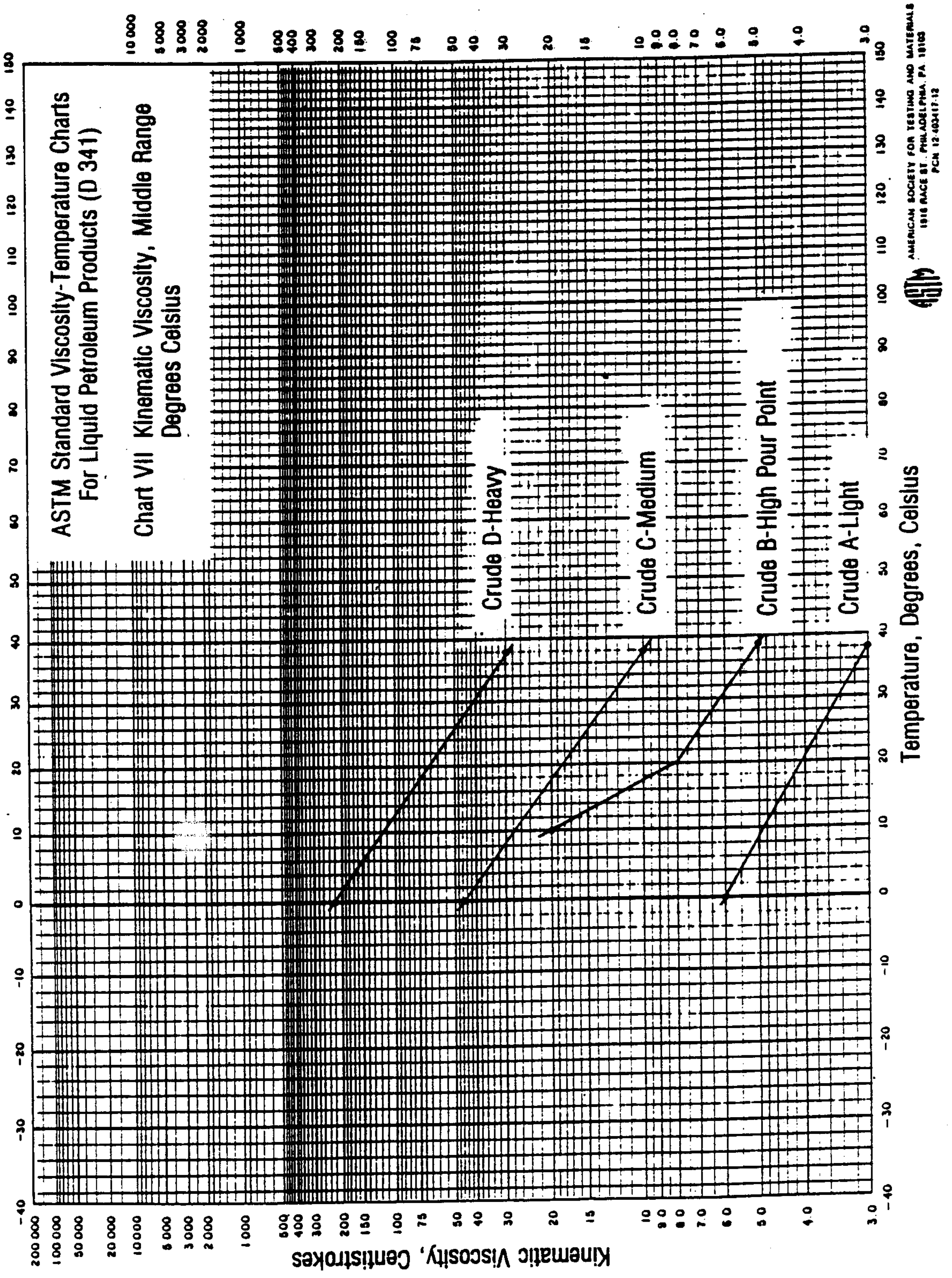


Figure 7.7A Viscosity-Temperature Chart

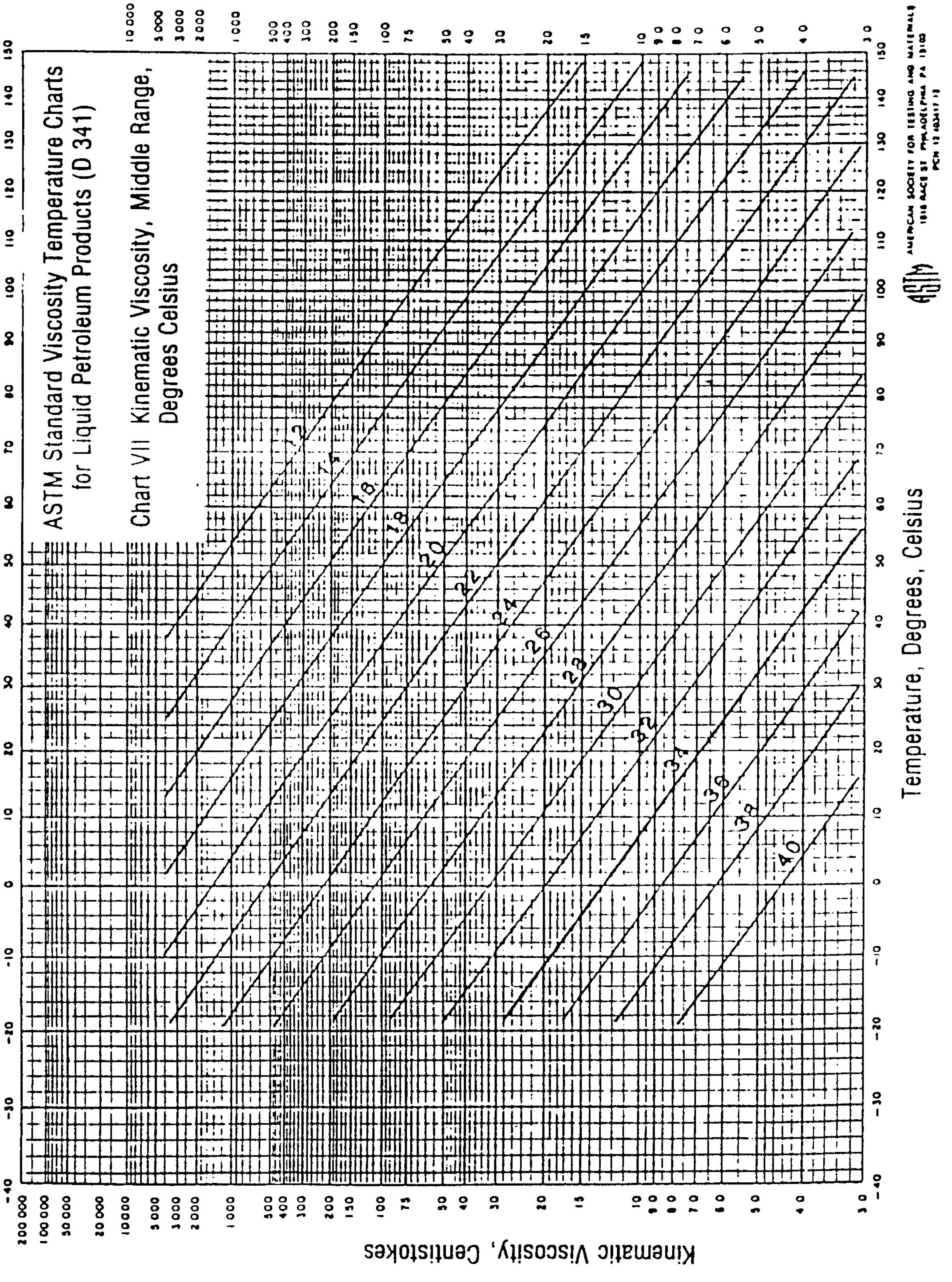


Figure 7.7B Viscosity-Temperature Chart

## 7.6.4 Temperature Effects

Adding heat to the incoming oil/water, stream is the traditional method of treating oil. The addition of heat reduces the viscosity of the oil phase allowing more rapid settling velocities in accordance with equation (1&2). For some emulsifying agents such as paraffins, the addition of heat will deactivate the emulsifier by increasing its solubility in the oil phase. Treating temperatures normally range from 100° (38 ºC) to 160° F (71 ºC). In treating of heavy crudes, the temperature may be as high as 300° F (149 ºC).

Adding heat, however, can cause a significant loss of the lower boiling point hydrocarbons (light ends). This results in shrinkage of the oil, or loss of volume. The hydrocarbon molecules leaving the oil phase may be used as fuel, vented, or compressed and sold with the gas. Even if they are sold with the gas, there will probably be a net loss in income realized by converting liquid volume into gas volume. **Figure 7.8** shows the amount of shrinkage which may be expected

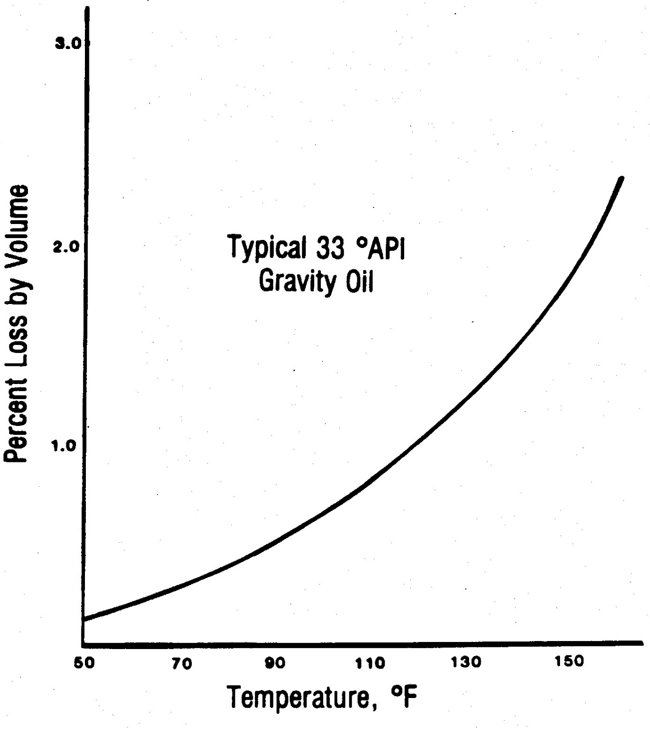


**Figure 7.8 Percent loss by Volume as a Function of Temperature**

Increasing the temperature at which final treating occurs has the disadvantage of making the stock crude oil heavier and thus decreasing its value. Because the light ends are boiled off, the remaining liquid has a lower API gravity. **Figure 7.9** shows the API gravity loss for a typical crude oil.

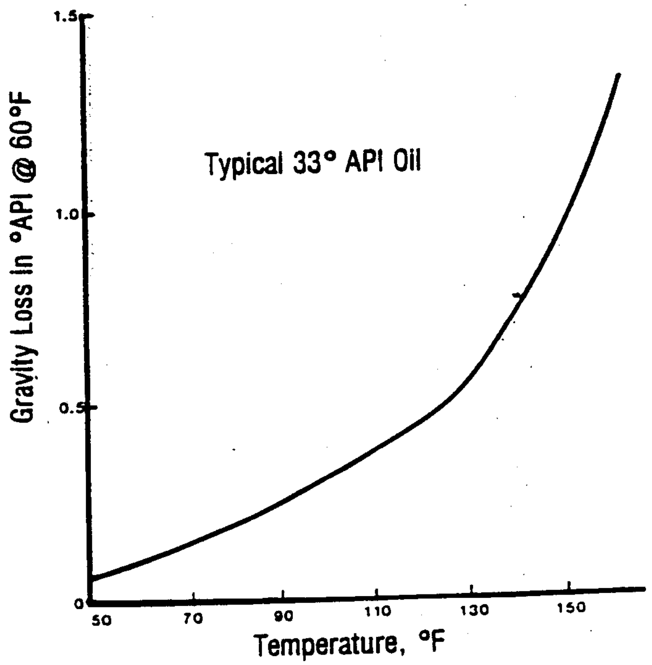


**Figure 7.9 API Gravity Loss as a Function of Temperature**

Increasing the temperature lowers the specific gravity of both the oil to be treated and the water which must be separated from it in the treater. However, depending on the properties of the crude, it may either increase or decrease the difference in specific gravity. In most cases, if the treating temperature is less than 200 ºF (93 ºC) specific gravity with temperature can be neglected.

Finally, it takes fuel to provide heat and the cost of fuel must be considered. Thus, while heat may be needed to adequately treat the crude, the less heat which is used the better separation.

If properly and wisely done, heating an emulsion can have great beneficial effect on water separation. However, if a satisfactory rate of water removal can be achieved at the minimum temperature delivered into a process, there may be no reason to suffer the economic penalties associated with adding heat.

## 7.6.5 Heat Input Requirements

The heat input and thus, the fuel required for treating, depends on the temperature rise, amount of water in the oil, and flow-rate. It requires about twice much energy to heat water as it does to heat oil. For this reason, it is beneficial to separate any free water from the emulsion to be treated with either a free water knockout located upstream of the treater or an inlet free-water knockout section in the treater.

Assuming that the free water has been separated from the emulsion and the water remaining is less than 10 percent of the oil; the required heat input for an insulated vessel can be approximated from:

$$\mathbf{q = 15Q_O\, \Delta T\, [0.5\, (SG)_O + (SG)_W\, W_C / (100 - W_C)]} \qquad \mathbf{(5)}$$

**Where:**

$q$ = heat input, Btu / hr

$Q_O$ = oil flow-rate, BOPD

$\Delta T$ = temperature difference

$(SG)_O$ = oil specific gravity relative to water

$(SG)_W$ = water specific gravity

$W_C$ = inlet percent water cut, percent

## 7.6.6 Water Droplet Size and Retention Time

The droplet diameter is the most important parameter in determining water-settling velocities since this term is squared in equations (1&2). A small increase in droplet diameter will create a much larger increase in the settling velocity. Thus, in sizing treating equipment, it is necessary to predict a droplet diameter which must be separated from the oil to meet a desired BS & W specification.

It would be extremely rare to have laboratory data of droplet coalescence for a given system. While it may be possible to predict the droplet size at the inlet to the treater, the shearing that occurs at the inlet nozzle and diverter and the coalescence that occurs at the oil/water interface cannot be determined. The treater represents a dynamic process which cannot be adequately simulated by static laboratory tests.

Qualitatively we would expect droplet size to increase with retention time in the coalescing section, and with heat input which excites the system leading to more collisions of small droplets. Droplet size could be expected to decrease with oil viscosity, which inhibits the movement of the particles and decreases the force of the collisions oil/water interface zone is where nearly all of the coalescence occurs.

Except for providing some minimal time for initial coalescence to occur, increasing retention time in a crude oil treating system may not be very cost effective. Consequently, one would not expect retention time to have a significant impact on the droplet diameter.

The effect of temperature on droplet size distribution is small. The temperature does, however; have a large effect on the oil viscosity. Since temperature and retention time have relatively small effects, an empirical relationship can be proposed relating droplet size distribution to oil viscosity alone. This relationship assumes sufficient retention time has been provided so initial coalescence can occur. Typically, retention times vary from 10 to 30 minutes, but values outside this range are not uncommon.

If the water-droplet-size distribution in the oil to be treated was known, it would be possible to predict the size of droplets which must be removed to assure that only a limited amount of water remains in the treated oil. Therefore, a relationship exists between the design BS & W content of the treated oil and the droplet-size that must be removed for a set, droplet-size distribution, since the droplet size distribution is function of viscosity stated above, the droplet size to be removed is related to both the required BS & W and the oil viscosity.

The water droplet diameter should not exceed 250 microns.

## 7.6.7 Coalescing Media

It is possible to use a coalescing media to promote coalescence of the water droplets. These media provide a large surface area upon which water droplets can collect. The most common coalescing media is wood shavings or excelsior which is referred to as a hay section. The wood excelsior is tightly packed to create an obstruction to the flow of the small water droplets and promote random collisions of these droplets for coalescence. When the droplets are large enough, they fall out of the flow stream by gravity.

It is possible that the use of a hay section will low lower treating temperatures. However, these media have a tendency to clog with time and are difficult to remove. They are no longer in common use.

## 7.7 EQUIPMENT USED IN OIL/WATER SEPARATION

Because of the tendency for water to form an emulsion with crude oil, the removal of water from crude oil often requires additional processing beyond normal three-phase separation of the free water. Crude-oil-treating equipment is designed to break emulsions by coalescing the water droplets and then use gravity settling to separate the oil and water. Treaters typically use one or more of the following to promote coalescence of the water droplets:

- Free Water Knockouts (FWKO)
- Wash Tanks
    - Gunbarrel Tanks (wash tanks)
    - Concentric Wash Tank
- Horizontal Flow Treater
- Heater Treaters
    - Vertical Treater
    - Horizontal Treater
- Electrostatic Treater

### 7.7.1 Free Water Knockouts (FWKO)

Oil, water, and gas are being produced as a mixture from the well. They are first sent into a free-water knockout, where any water that would readily and freely separate from the oil is extracted and sent into a saltwater disposal system. Any free gas which separates out of the mixture is drawn off as a separate side stream from this vessel. This gas will either be used as fuel or sold. The remaining oil and water emulsion leave the free-water knockout and is transferred to the heater.

If a substantial amount of water is associated with the crude oil (say 30 to 70% vol.) the majority (free water) will separate quickly, typically in less than 10 minutes. Free water knock out can be carried out in pressure vessels (see **Figure 7.10).**

Utilization of small prefabricated pressure vessels means that offshore installation is sometimes acceptable, in which case significant reductions in pumping loads and often heating loads can be realized.

Final treating of the oil separated by FWKO's can be carried out in conventional wash tanks / batch tanks / heater treaters.

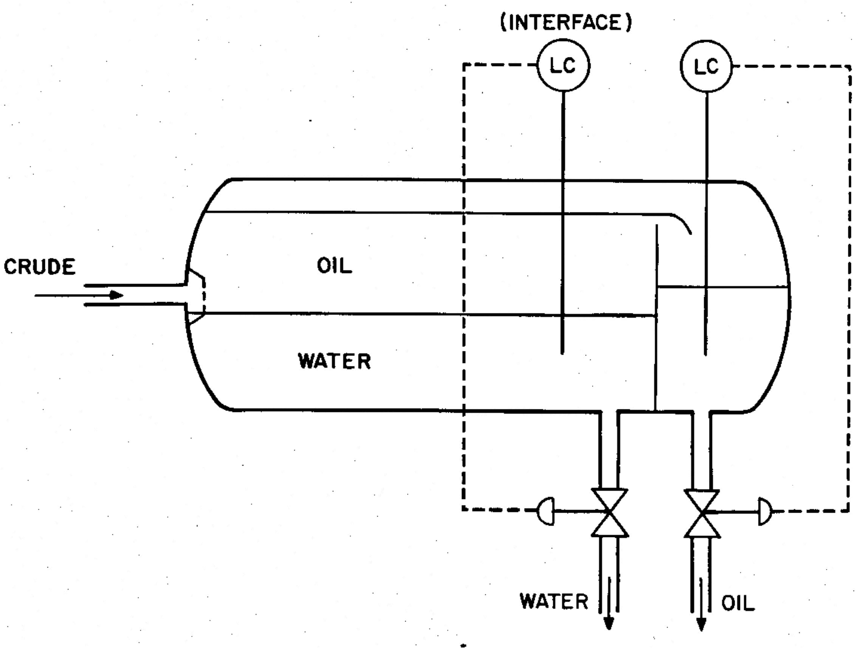


Figure 7.10 Horizontal Free Water Knockouts

### 7.7.2 Heater Treaters

Heater treaters, also called emulsion treaters, are common devices used throughout the world to separate oil and water emulsions. The heater treater is similar to a free water knockout, but the treater has heating capability with the inclusion of' fire tubes. The fire tubes extend horizontally into the vessel, natural gas or oil burns inside the fire tubes and creates heat, which passes through the fire tubes and into the emulsion. The combustion of the gas within the fire tubes is used to heat the oil and water emulsion entering the vessel and passing around the outside of the tubes. As the oil and water mixture grows hotter, the emulsion breaks or separates and forms into clean oil and clean water.

The water is removed from the bottom of the heater treater and sent to the water disposal system. The clean oil is drawn off the centre of the vessel and sent to the oil storage tanks for sale. Again, level control devices are used to regulate the drainage of water and oil from the vessel. All natural gas which occurs in the oil-water emulsion exits at the top of the heater treater. This gas, together with any gas produced from the free water knockout of other vessels, can subsequently be used as a fuel for the heater.

#### 7.7.2.1 Vertical Heater Treaters

The most common type of single-well onshore treater is the vertical treater shown in **Figure 7.11**. Vertical treaters are recommended where sand or other solid sediments are considered a potential problem.

Flow enters the top of the treater into a-gas-separation section. Care must be exercised to size this section so that it has adequate dimensions to separate the gas from the inlet flow. If the treater is located downstream of a separator, this chamber can be very small. The gas-separation section should have an inlet diverter and a mist eliminator. (see Two-Phase Separators).

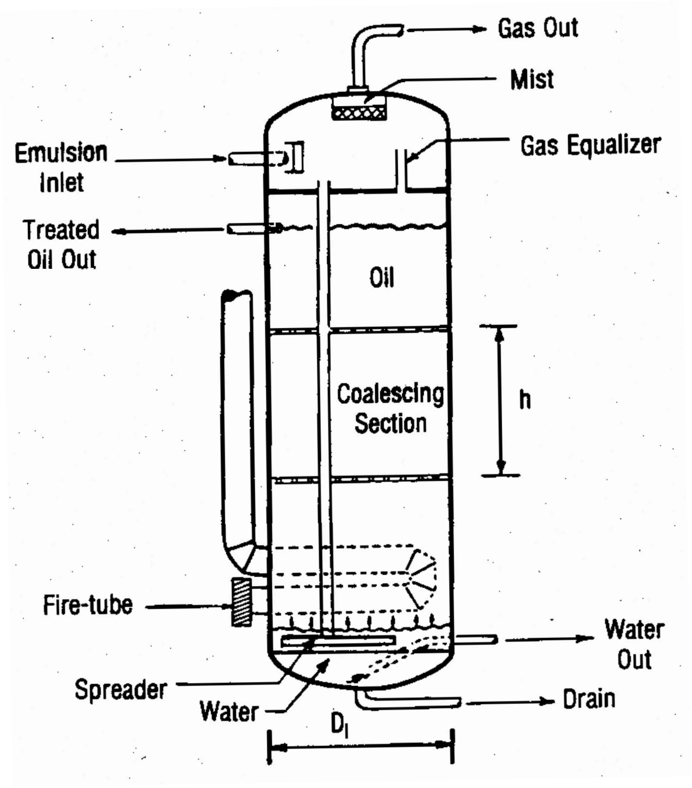


**Figure 7.11 Simplified Schematic of a Vertical Heater Treater**

The liquids flow through a downcomer to the base of the treater, which serves as a free-water knockout section. If the treater is located downstream of a free-water knockout, this bottom section can be very small. If the total well-stream is to be treated, this section should be sized to allow the free water to settle out. This will minimize the amount of fuel gas needed to heat the liquid stream rising through the heating section. The end of the downcomer should be below the oil/water interface to "water wash" the oil being treated. This will facilitate the coalescence of water droplets in the oil (see Three-Phase Separators).

The oil and emulsion rises over the heater fire-tubes to a coalescing section, where sufficient retention time is provided to allow the small water droplets in the oil-continuous phase to coalesce and settle to the bottom. Treated oil flows out the oil outlet.

Any gas flashed from the oil due to heating flows through the equalizing line to the gas space above. The gas liberated when crude oil is heated may create a problem in the treating equipment if the equipment is not adequately designed. In vertical heater-treaters, the gas rises through the coalescing section. If a great deal of gas is liberated, it can create enough turbulence and disturbance to inhibit coalescence. Perhaps more important is the fact that the small gas bubbles have an attraction for surface-active material and hence for the water droplets. Thus, they have a tendency to keep water droplets from settling and may even cause them to carry-over to the oil outlet. Standard vertical treaters are available in 20 to 27 ft. heights. These heights have been selected to provide sufficient static liquid head to prevent vaporization of the oil.

Oil level is maintained by pneumatic or lever-operated dump valves. The oil/water interface is controlled by an adjustable external water leg or an interface controller.

#### 7.7.2.2 Horizontal Heater Treaters

For most multi-well situations, horizontal treaters are normally required. **Figure 7.12** shows a typical design of a horizontal treater.

Flow enters the front section of the treater where gas is flashed. The liquid falls around the outside of the fire-tubes to the vicinity of the oil/water interface, where the liquid is water washed and the free water is separated. For low GOR crudes, blanket gas may be required to maintain gas pressure. The oil emulsion rises past the fire tubes absorbing heat and is skimmed into the oil-surge chamber. The oil/water interface in this section of the vessel is controlled by an interface level controller which operates a dump valve for the free water.

The oil and emulsion flows through a spreader into the back (coalescing) section of the vessel which is liquid packed. The spreader distributes the flow evenly throughout the length of this section. Treated oil is collected at the top through a collection device sized to maintain uniform vertical flow of the oil. Coalescing water droplets fall countercurrent to the rising oil-continuous phase. The oil/water interface is maintained by a level controller and dump valve for this section of the vessel. A level control in the oil-surge chamber operates a dump valve on the oil-outlet line, thus, regulating the flow of oil out the top of the vessel in order to maintain a liquid-packed condition.

The inlet section must be sized to handle settling of the free water and heating of the oil. The coalescing section must be sized to provide adequate retention time for coalescence to take place and to allow the coalescing water droplets to settle downward, countercurrent to the upward flow of the oil.

The usual oilfield horizontal heater-treater overcomes the gas liberation problem by coming to equilibrium in the heating section before introducing the emulsion to the settling-coalescing section. Some large crude-processing systems use a fluid-packed, pump-through system which keeps the crude at pressures well above the bubble point. Top-mounted degassing separators above electrostatic coalescers have been used in some installations.

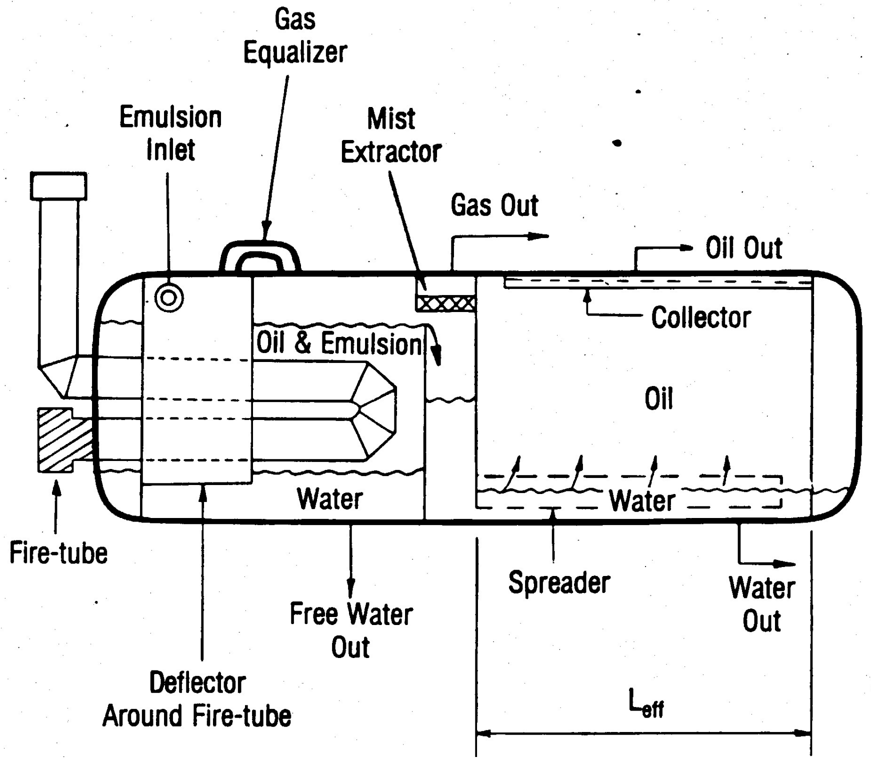


Figure 7.12 Simplified Schematic of a Horizontal Treater

## 7.7.3 Electrostatic Heater Treaters

Coalescing of the small water drops dispersed in the crude can be accomplished by subjecting the water-in-oil emulsion to a high voltage electrical field. When a nonconductive liquid (oil) containing a dispersed conductive liquid (water) is subjected to an electrostatic field, the conductive particles or droplets are caused to combine by one of three physical phenomena (**Figure 7.13**).

1. The droplets become polarized and tend to align themselves with the lines of electric force. In so doing, the positive and negative poles of the droplets are brought adjacent to each other. Electrical attraction brings the droplets together and causes them to coalesce.
2. Droplets are attracted to an electrode due to an induced charge. In an AC field, due to inertia, small droplets vibrate over a larger distance than larger droplets, thereby promoting coalescence. In a DC field the droplets tend to collect on the electrodes forming larger and larger drops until eventually they fall by gravity.
3. The electric field tends to distort and thus weaken the emulsifying film.

Whatever the actual mechanism, the electric field causes the droplets to move about rapidly, which greatly increases the chances of collision with another droplet. When droplets collide with the proper velocity, coalescence occurs.

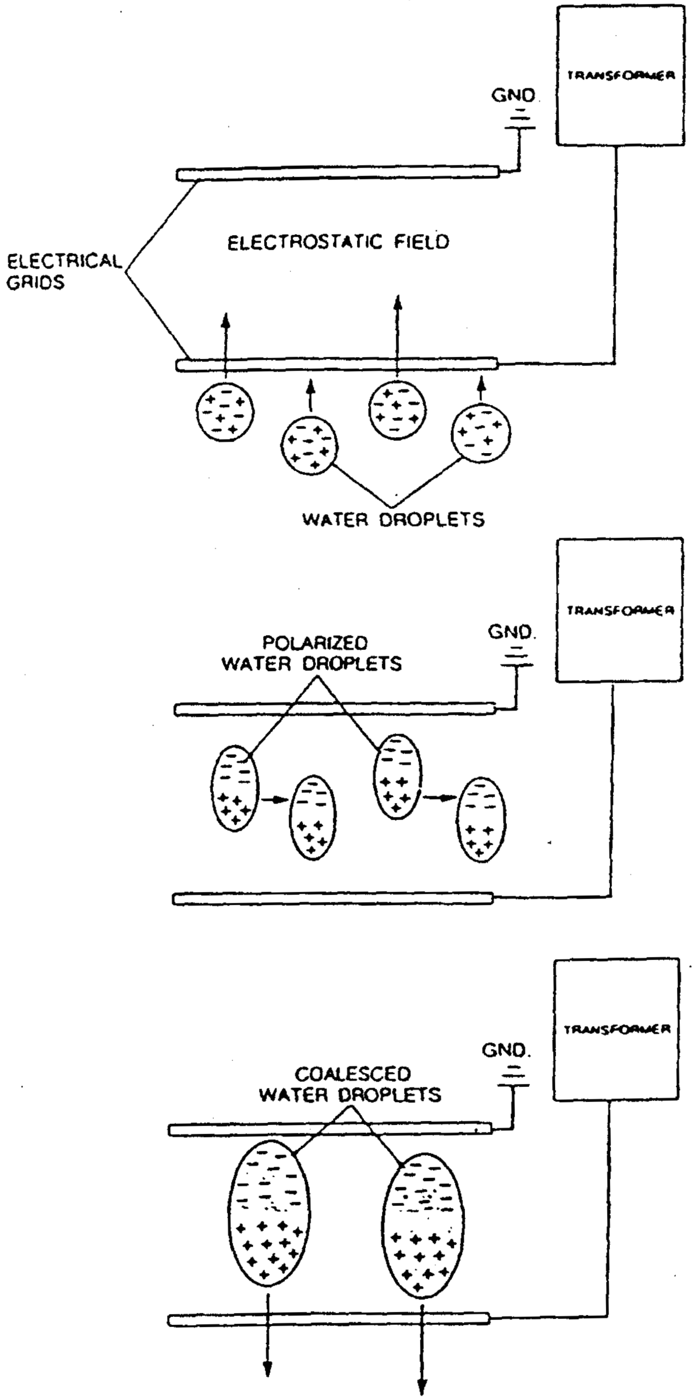


Figure 7.13 Electrostatic Treating

The most common type of electrostatic treater is similar in configuration to a horizontal treater as shown in **Figure 7.14**. Flow through the vessel is basically the same as a conventional horizontal heater treater, except that an electrostatic grid is included in the coalescing section. The electrostatic section contains two or more electrodes, one grounded to the vessel and the other suspended by insulators. An electrical system supplies an electric potential to the suspended electrode. The usual applied voltage ranges from 10,000 to 35,000 volts AC, and the power consumption is from 0.05 to 0.10 KVA/ft$^2$ of grid. Intensity of the electrostatic field is controlled by spacing of electrodes and applied voltage. Optimum field intensities vary with applications, but generally fall within the range of 1,000 to 4,000 volts per inch of separation. The use of an electric field is most effective whenever the fluid viscosity is less than 50 centipoises at separating temperatures, the specific gravity difference between the oil and water is greater than 0.001, and the electrical conductivity of the oil phase does not exceed 10$^{-6}$ mho/cm.

Electrical apparatus supplying potential to the electrodes consists of a system of step-up transformers (either single or three-phase) in which the primary side is connected to a low-voltage power source (208, 220, or 440 volt) and secondary windings are so designed that induced voltage will be of the desired magnitude.

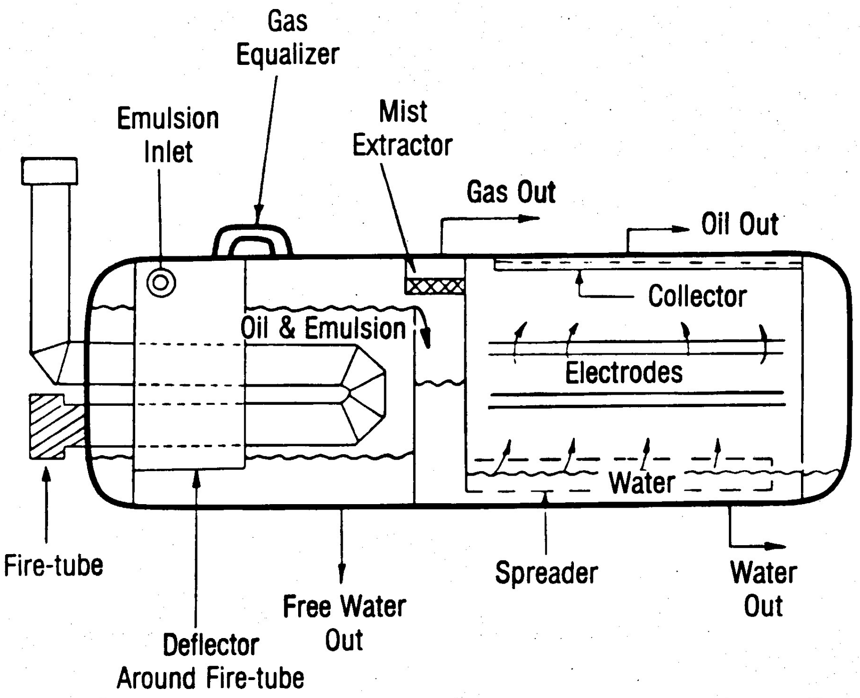


**Figure 7.14 Simplified Schematic of an Electrostatic Treater**

The vessel design must have good gas removal and distribution of the emulsion across the electrical grid. It is important to maintain the fluid in the liquid phase in an electrical-coalescing section. Any vapor in the electrode area will be saturated with water. These water saturated vapors, being highly conductive, will greatly increase the power consumption.

Similarly, it is important to prevent the water level from reaching the height of the electrodes. Produced water almost always contains some salts. These salts make the water a very good conductor of electric currents. Therefore, if the water contacts the electrodes it may short out the electrode grid or the transformer.

Time in the electrostatic field is controlled by electrode spacing and the vessel configuration. An electrostatic field exists throughout the body of the oil dielectric within the vessel, although most coalescing takes place in the more intense fields in the vicinity of the electrodes.

Loading rate is the major controlling factor in sizing vessels for coalescing units. Vessels generally are sized for a certain volume flow per unit time per square-foot of grid area. Since coalescence of droplets in an electric field is so dependent on the characteristics of the particular emulsion to be treated, it is unlikely that a general relationship of water droplet size to use in the settling equations can be developed. Therefore, sizing of grid area requires laboratory testing. In most practical applications, a rate of 25 to 100 barrels per day per square foot of grid area is needed.

Field experience tends to indicate that electrostatic treaters are efficient at reducing water content in the crude to the 0.2 to 0.5 percent levels. This makes them particularly attractive for desalting operations, which is discussed in the manual,

Desalting: However, for normal crude treating where 0.5 to 1.0 percent BS & W is acceptable, it is recommended that the vessel be sized as a horizontal heater-treater neglecting any contribution for the grids. By trial and error after installation, the electric grids may be able to allow treating to occur at lower temperatures

# Chapter 8

# Crude Oil refining

# Chapter 8 Contents

### Chapter 8

# Atmospheric Distillation

## 8.1 FUNDAMENTALS OF SEPARATION IN TOWERS

### 8.1.1 Distillation

Distillation is a separation process requires differences to be recognized and utilized. We separate many things by detecting a difference in a physical property, color, size, weight, shapes for example it also requires acting according to such information. Separation by distillation implies a difference in boiling points of two or more materials.

The components or compounds making up crude oil are numbered in thousands. Many of these components have similar physical properties including boiling points that may differ by only a few degrees. Therefore, it is difficult to separate some pure compounds from the complex mixture of components in crude oil by distillation alone. There are other methods of separation used in a refinery for example, extraction with a solvent, crystallization, and absorption. However distillation is the most common method. Fortunately, rarely need pure compounds and it is often enough to separate groups of compounds from each other by boiling range.

If crude oil were a final product, it would have just been a low-grade fuel struggling to establish itself against coal. If we separate the many compounds in crude oil into groups we find that these groups have characteristics that make them considerably more valuable than the whole crude oil.

Some of these groups are products some may be feedstock to other processing units where they are chemically changed into more valuable products. These products, in turn, are usually separated or purified by distillation.

### 8.1.2 Principles of Distillation

The basic principle of distillation is simple when a solution of tow or more components is boiled, the lighter component the one most volatile or the one with the greatest tendency to vaporize (vaporizes preferentially).

This results in the vapor above the liquid being relatively rich in the lighter, more volatile material. And the liquid is left with proportionately more of the less volatile or heavier liquid. Thus a separation, to some degree, has taken place. This process is shown in Figure 8.1.

A tow component mixture, comprising crosses and dots, is contained in a vessel. We Heat is add until the more volatile material, in this case the dots, start to vaporize. Now the vapor contains a higher proportion of dots than dose the original liquid.

It is important to note that equilibrium will be established. That is, at a given temperature and pressure there is an equilibrium in composition reached. By equilibrium we mean there is a given concentration as "dots" in the vapor and in the liquid depending upon the original concentration of each component in the liquid and their respective properties in relation to each other.

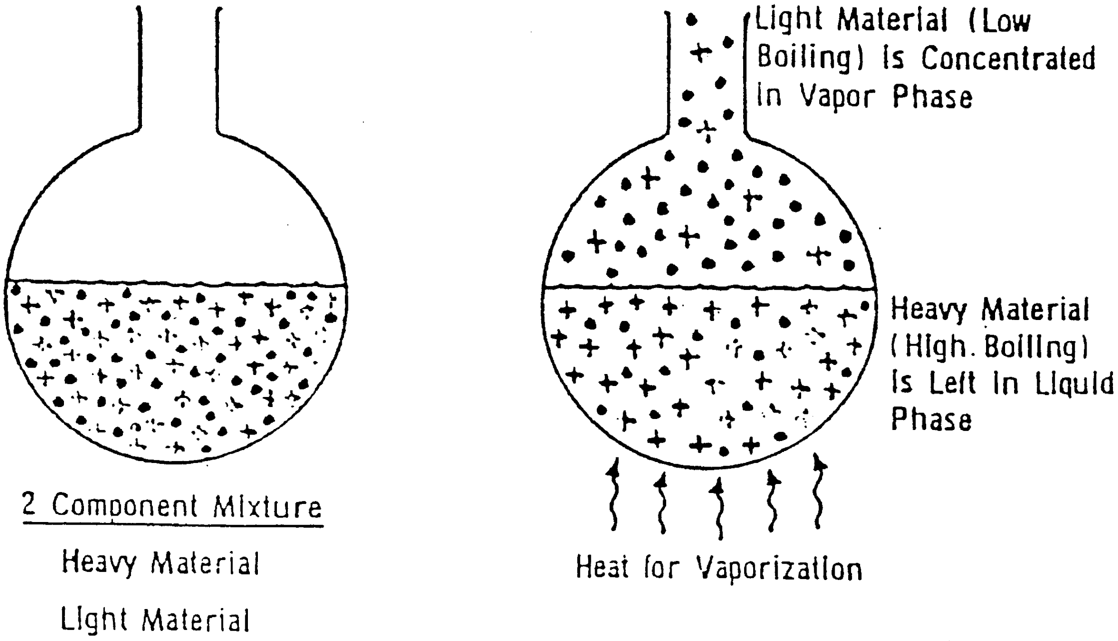


**Figure 8.1**

Now, let's develop this simple distillation concept into a practical operation as it is used in the refinery. First, let’s separate and remove the product see Figure 8.2.

By cooling the over head vapor, we condense and remove it from the original mixture. Thus to have made a partial separation, partial because you will note that there are a few "crosses" in the distillate product. This has occurred because at the temperature and pressure we are conducting the distillation; the heavier component still vaporizes to some extent. This is because the components of interest in a given distillation usually have fairly close boiling points

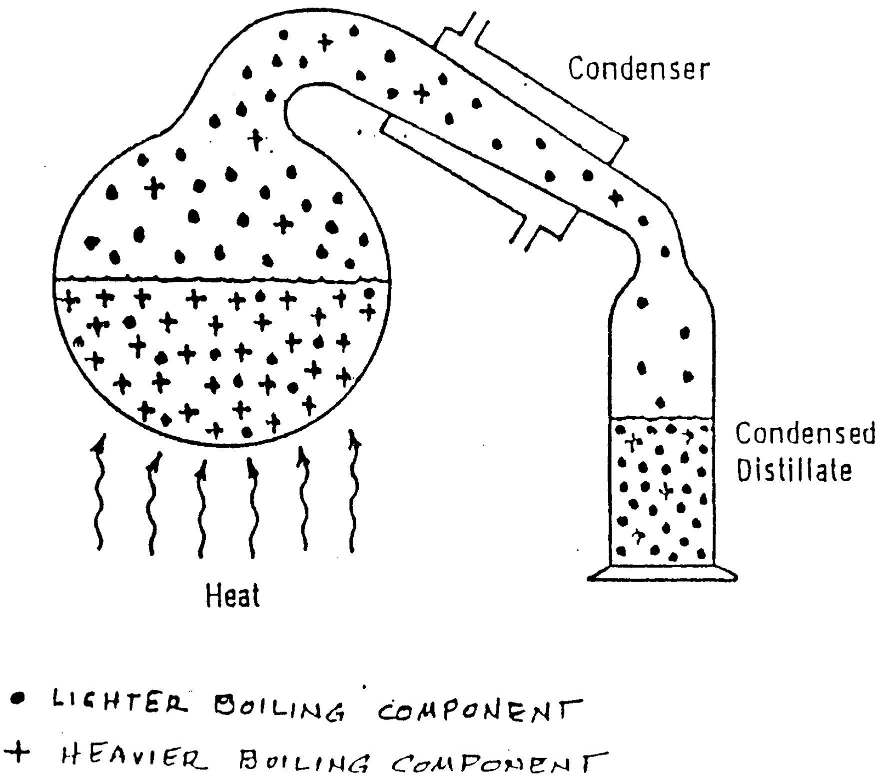


Figure 8.2 Simple Distillation

Therefore, to purify the distillate product, we may have to conduct a second distillation as shown in Figure 8.3. Obviously, we can continue to cascade these simple distillations until we achieve the desired purity of product.

The distillations depicted so far are those we call patch, and normally practical in the refinery, although it is done frequently in the laboratory. Let us make our distillation equipment look more like refinery pieces of equipment and let us make continuous instead of patch operation.

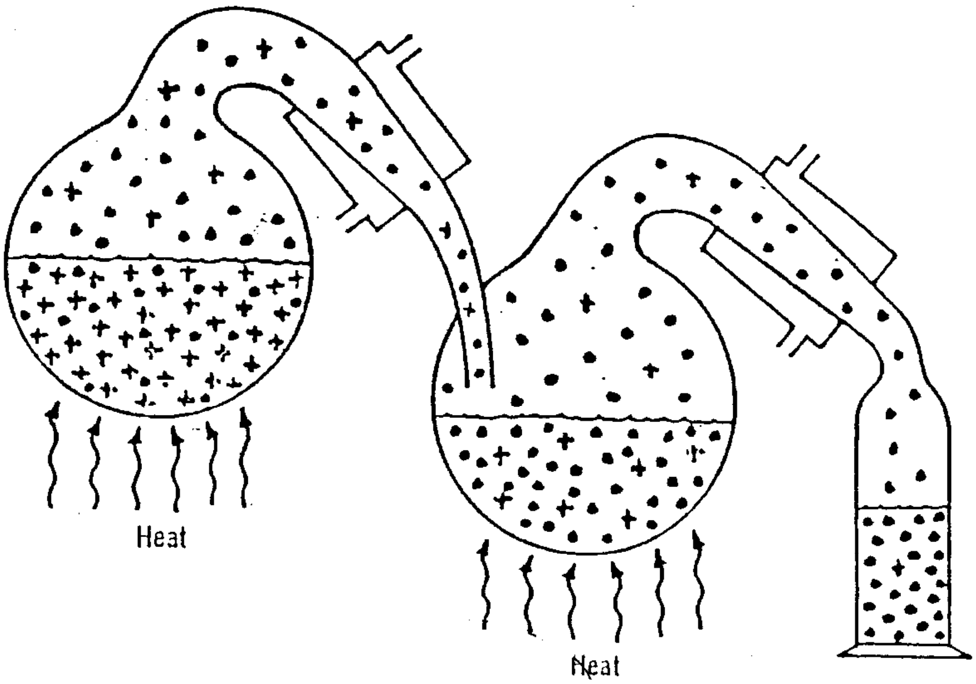


Figure 8.3 Stage Distillation

This is called Flash Vaporization. As shown in Figure 6.6. The liquid is pumped continuously through a heater and into a drum where the pressure is lower. The lighter material flashes instantly, vapor and liquid flow from the drum continuously. The same system is shown diagrammatically in the in the lower section of Figure. 6.4 Suppose we have 50% of the charge taken overhead. That is, we set the temperature and the pressure of the system in such a way that half the charge is boiled off. And further, suppose the resulting overhead product does not contain the desired concentration of the lighter product. As we have seen before, we can increase the purity by adding a stage of distillation.

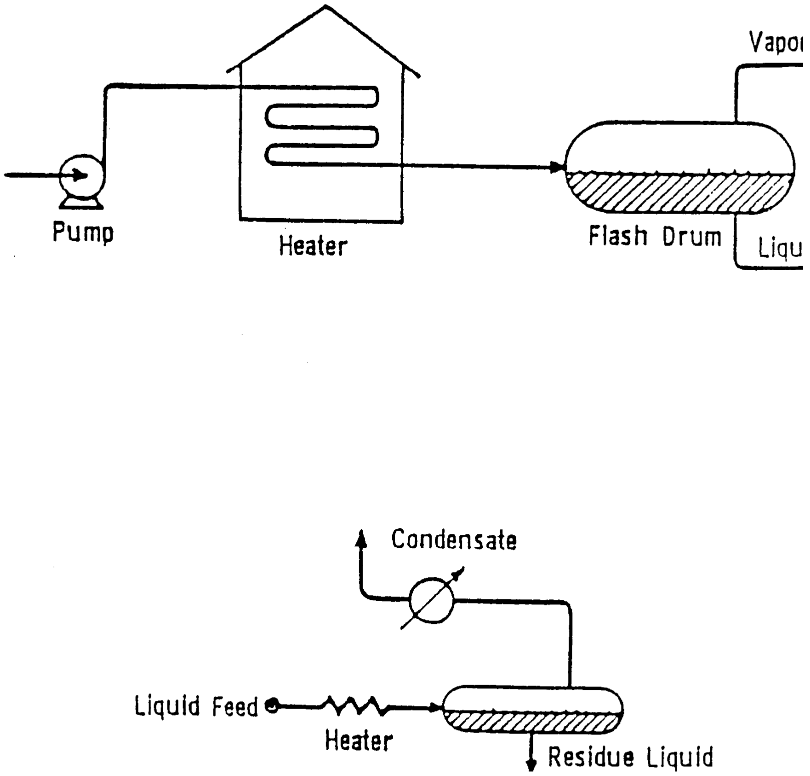


**Figure 8.4 Flash Vaporization**

Suppose we add two more stages of distillation as shown in Figure 8.5. Although this is accomplishing our goal of increasing the purity of the light friction, we are also making large amounts of the intermediate product, each of which contains the same light friction.

If we compare feeds to and products from two continues stages, we note that the liquid from the upper stage and the feed to the lower stage are similar in that both are leaner in the lighter component than is the feed to the upper stage. Therefore, we could combine each indeterminate product with the feed to the next lower stage. This would improve the yield of the light fraction and all the original feed would be recovered eventually in the overhead and bottom products.

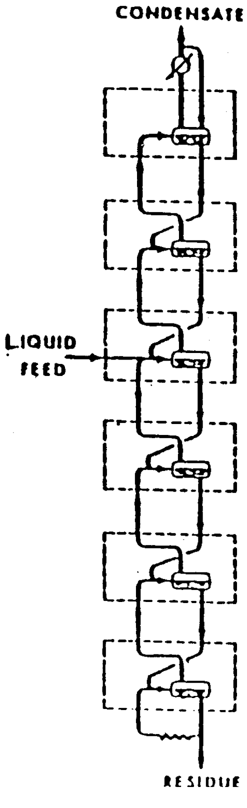


**Figure 8.5 Schematic Illustration of a Typical Distillation Operation**

An obvious simplification in equipment can be made if we allow the hot vapor from the stage above the next higher (the intermediate product). This eliminates the need for the intermediate condensers and heaters. Now we have the continuous, multi-stage distillation.

## Tower Sections

We have described staging for the purpose of concentrating the lighter component in the overhead. The same principles apply to concentrating the heavier component in the bottom product. The upper two stages are called **rectifying stages**. These below the feed are called **stripping stages**.

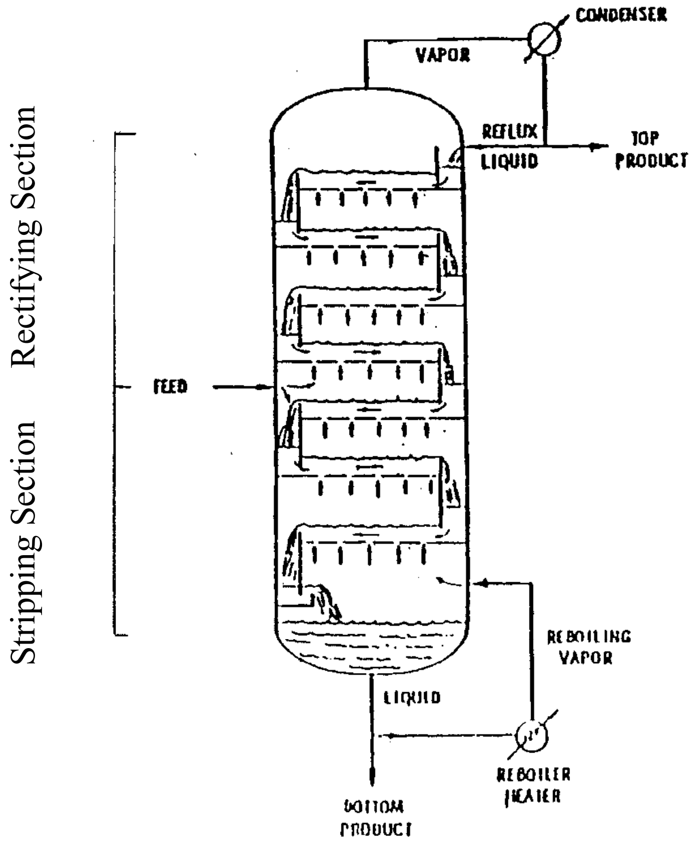


Figure 8.6 Distillation Tower With Cross – Flow Trays

The upper rectifying section increases the purity of the overhead product while the stripping section increases recovery of the overhead product. In many cases, the bottom product is the one of primary interest. For the bottom, or heavy, product the rectifying section improves purity.

## Equilibrium Stage:

We now have the concept of stages. Let us define the term "stage" and see how it is actually designed mechanically.

A stage, or more specifically, an equilibrium stage, is defined as any portion of the distillation column such that the liquid and vapor leaving it have composition similar in equilibrium with each other. By definition, then, a stage should be designed in such a way as to provide intimate contact, or mixing, of the rising vapor and the descending liquid. The concept of an equilibrium stage is converted to an actual mechanical separation tray by using an efficiency factor which is less than one and depends on the tray design (Figure 8.7)

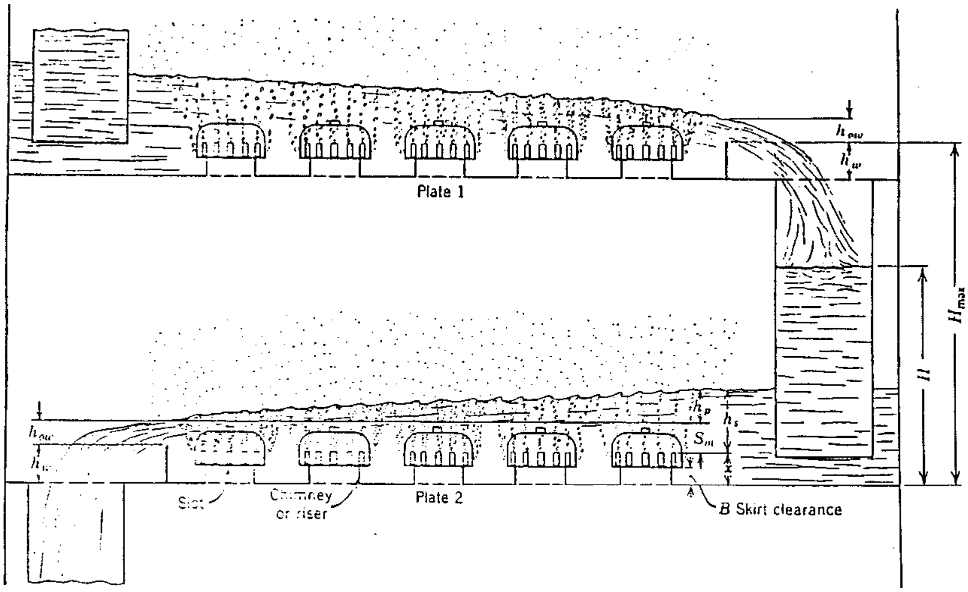


Figure 8.7 Equilibrium Stage (Tray) Liquid and Vapor Loading

The design of trays has taken many forms over the years. Some common ones are bubble cap trays, valve trays, sieve trays, uniflex trays and many others. Alternate designs include packing instead of trays. Various kinds of packing have used, some of which are pall rings, saddles and mesh. The type of column internal used depends on the application. The considerations being purity of feed, efficiency, capacity, reliability, pressure drop, liquid holdup and cost.

The column in Figure 6.6 is a simple binary column with seven trays. There is only one feed and two products, the overhead and bottoms. More complex columns may have several feed streams, entering the column at different points, and more than two products. We may draw products from the side of the column. As shown in Figure 6.8 there is reflux liquid and re boiling vapor returned to the column in addition to feed.

## 8.1.3 Reflux

The word reflux is defined as "flowing back". Applying it to distillation tower, reflux is the liquid flowing back down the tower from each successive stage.

### Kinds of Reflux (Figure 8.9)

### A. Cold Reflux

Cold reflux is defined as reflux that is supplied at temperature a little below that at the top of the tower. Each pound of this reflux removes a quantity of heat equal to the sum of its latent and sensible heat required to raise its temperature from reflux drum temperature to the temperature at the top of the tower. A constant quantity of reflux is recirculated from the reflux drum into the top of the tower. It is vaporized and condensed and then returns in like quantity to the reflux drum.

### B. Hot Reflux

It is the reflux that is admitted to the tower at the same temperature as that maintained at the top of the tower. It is capable of removing the latent heat because no difference in temperature is involved.

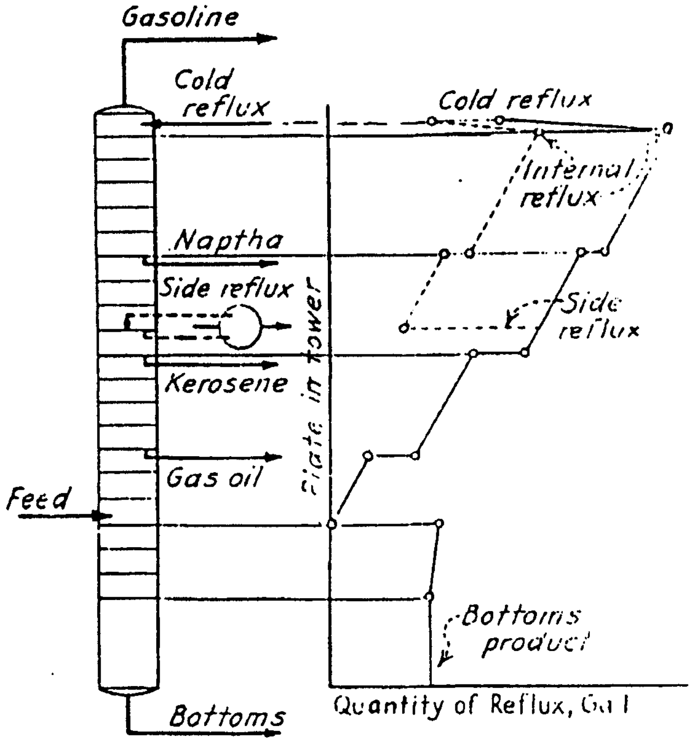


Figure 8.8 Relative Amount of Reflex or Overflow Liquid at Each Tray of Contact

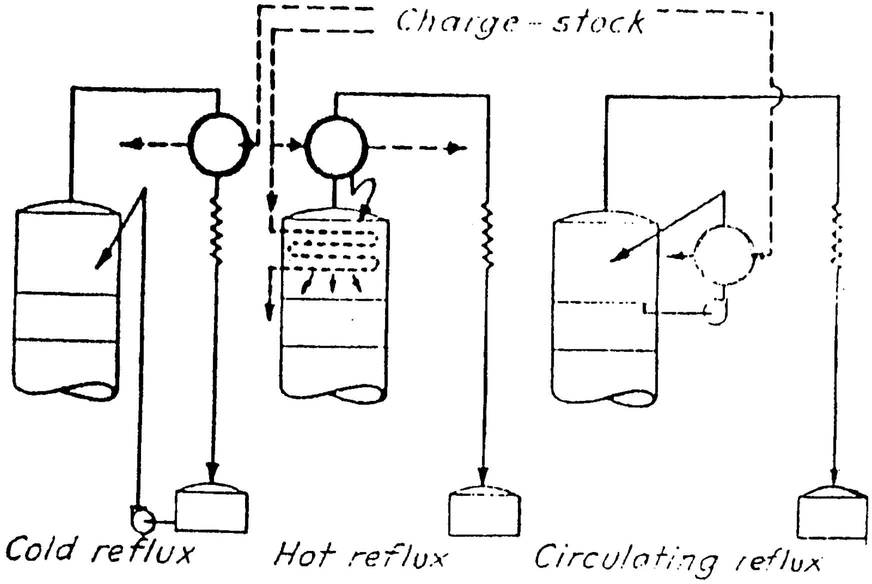


Figure 8.9 Methods of Removing Reflux Heat

## C. Internal Reflux

It is the reflux or the overflow from one plate to another in the tower, and may be called hot reflux because it is always substantially at its boiling point. It is also capable of removing the latent heat only because no difference in temperature is involved.

## D. Circulating Reflux

It is also able to remove only the sensible heat which is represented by its change in temperature as it circulates. The reflux is withdrawn and is returned to the tower after having been cooled.

## E. Side Reflux

This type of reflux (circulating reflux) may conveniently be used to remove heat at points below the top of the tower. If used in this manner, it tends to decrease the volume of vapor the tower handles.

## Reflux Ratio

It is defined as the amount of internal reflux divided by the amount of top product. Since internal hot reflux can be determined only by computation. Plant operators usually obtain the reflux ratio by dividing actual reflux by the top product. It is denoted by R which equals L/D.

## The Importance of Reflux Ratio

In general, increasing the reflux improves overhead purity and increases recovery of the bottom product. The number of stages required for a given separation will be dependent upon the reflux ratio used.

## Two points to consider

1. A minimum number of plates (stages) required at total reflux.

2. There is a minimum reflux ratio below which it is impossible to obtain the desired enrichment however many plates are used.

### Total Reflux

Total reflux is the conclusion when all the condensate is returned to the tower as reflux, no product is taken off and there is no feed.

At total reflux, the number of stages required for a given separation is the minimum at which it is theoretically possible to achieve the separation and total reflux is carried out at:

1. Towers start-up
2. The testing of the tower

### Minimum Reflux

At minimum reflux, the separation can only be achieved with an infinite number of stages. This sets the minimum possible reflux ratio for the specified separation.

### Optimum Reflux Ration

Practical reflux ratio will lie between the minimum for the specified separation and total reflux. The optimum value will be the one at which the specified separation is achieved at the lowest annual cost (steam or vapor). For many systems, the optimum value of reflux ratio will lie between 1: 2 to 1: 5 times the minimum reflux ratio.

## 8.1.4 Reboiling

In all our distillations discussed so far. We have added heat. Heat can be added in two ways. As we have seen, we add heat by means of the feed. We can also add heat by means of a reboiler.

The reboiler is a heat exchanger through which the bottom liquids circulate. Heat is transferred to the bottom materials which cause vaporization of the lighter components. This vapor travels up the column to provide the stripping action and the additional heat necessary to vaporize the down coming reflux.

# 8.2 CRUDE DISTILLATION

The purpose of crude oil distillation is primarily to split the crude into several distillate fractions of a certain boiling range. Sharpness of fractionation is of secondary importance. The number of trays used for crude distillation is very small compared to most other distillations. A crude distillation tower, producing 6 fractions has only 40 to 50 trays.

Crude can be separated into gasoline, naphtha, kerosene, diesel oil, gas oil, and other products, by distillation Figure 6.10 at atmospheric pressure. Distillation is an operation in which vapors rising through fractionating decks in a tower are intimately contacted with liquid descending across the decks so that higher boiling components are condensed, and concentrate at the bottom of the tower while the lighter ones are concentrated at the top or pass overhead. Crude is generally pumped to the unit directly from a storage tank, and it is important that charge tanks be drained completely free from water before charging to the unit. If water is entrained in the charge, it will vaporize in the exchangers and in the heater, and cause a high pressure drop through that equipment. If a slug of water should be charged to the unit, the quantity of steam generated by its vaporization is so much greater than the quantity of vapor obtained from the same volume of oil, that the decks in the fractionating column could be damaged. Water expands in volume 1600 times upon vaporization at 100ºC at atmospheric pressure.

## 8.2.1 Process Description (Figure 8.11)

### Heat Exchange

In order to reduce the cost of operating a crude unit as much heat as possible is recovered from the hot streams by heat exchanging them with the cold crude charge. The number of heat exchangers within the crude unit and cross heat exchange with other units will vary with unit design. A record should be kept of heat exchanger outlet temperatures so that fouling can be detected and possibly corrected before the capacity of the unit is affected.

### Crude Flashing

Desalted crude is heat exchanged against what ever other heat sources are available to recover maximum heat before crude is charged to the heater, which ultimately supplies all the heat required for operation of the crude unit.

The heat input is controlled by having the heater transfer temperature reset flow of fuel to the burners. The heater transfer temperature is merely a convenient control, and the actual temperature, which has no great significance, will vary from 325ºC to as high as 430ºC, depending on the type of crude and the pressure at the bottom of the fractionating tower. It is noteworthy that if the quantity of gasoline and kerosene in crude is reduced, the transfer temperature required for the same operation will be increased, even through the "lift" is less.

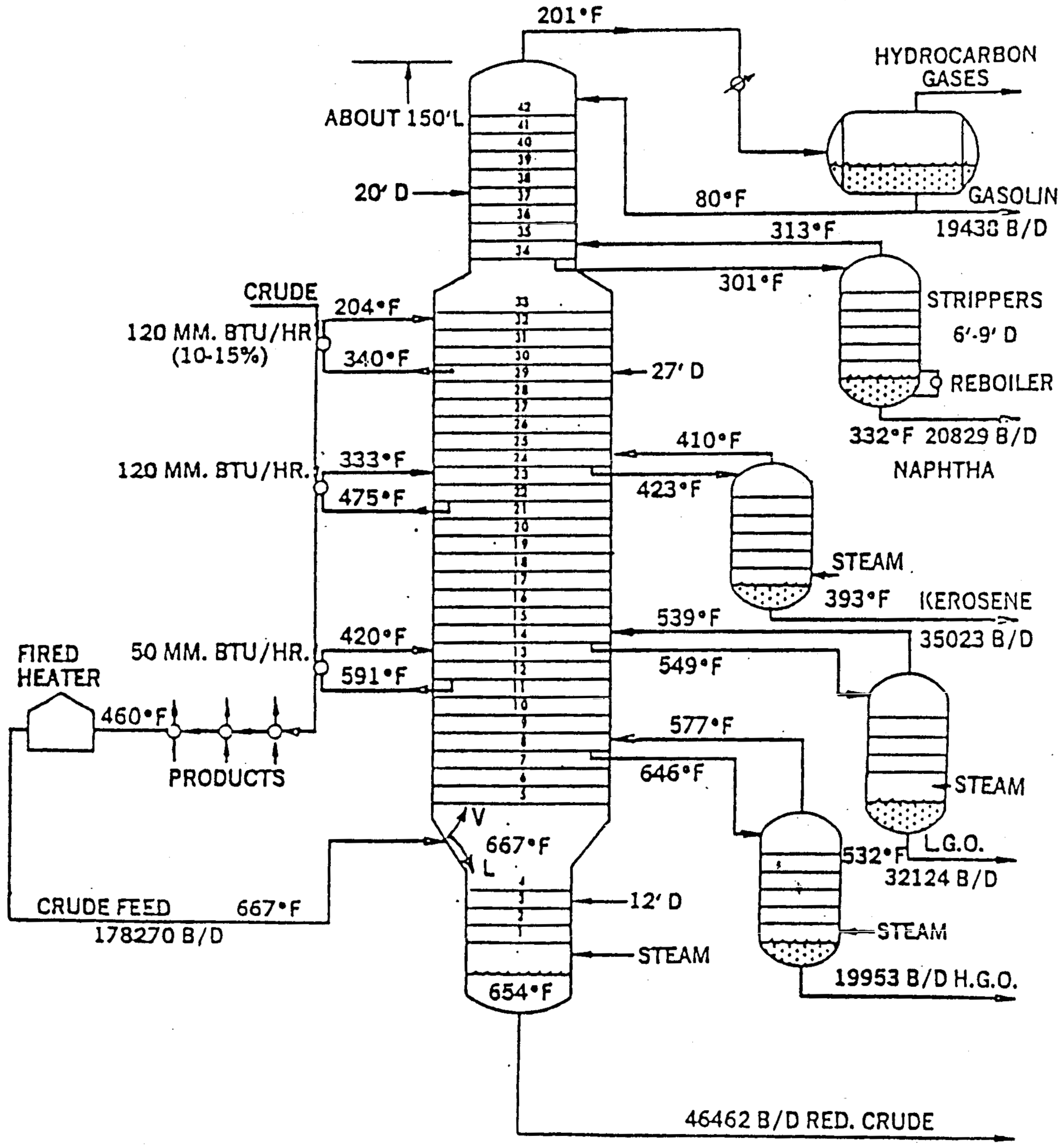


Figure 8.10 Atmospheric Crude Tower

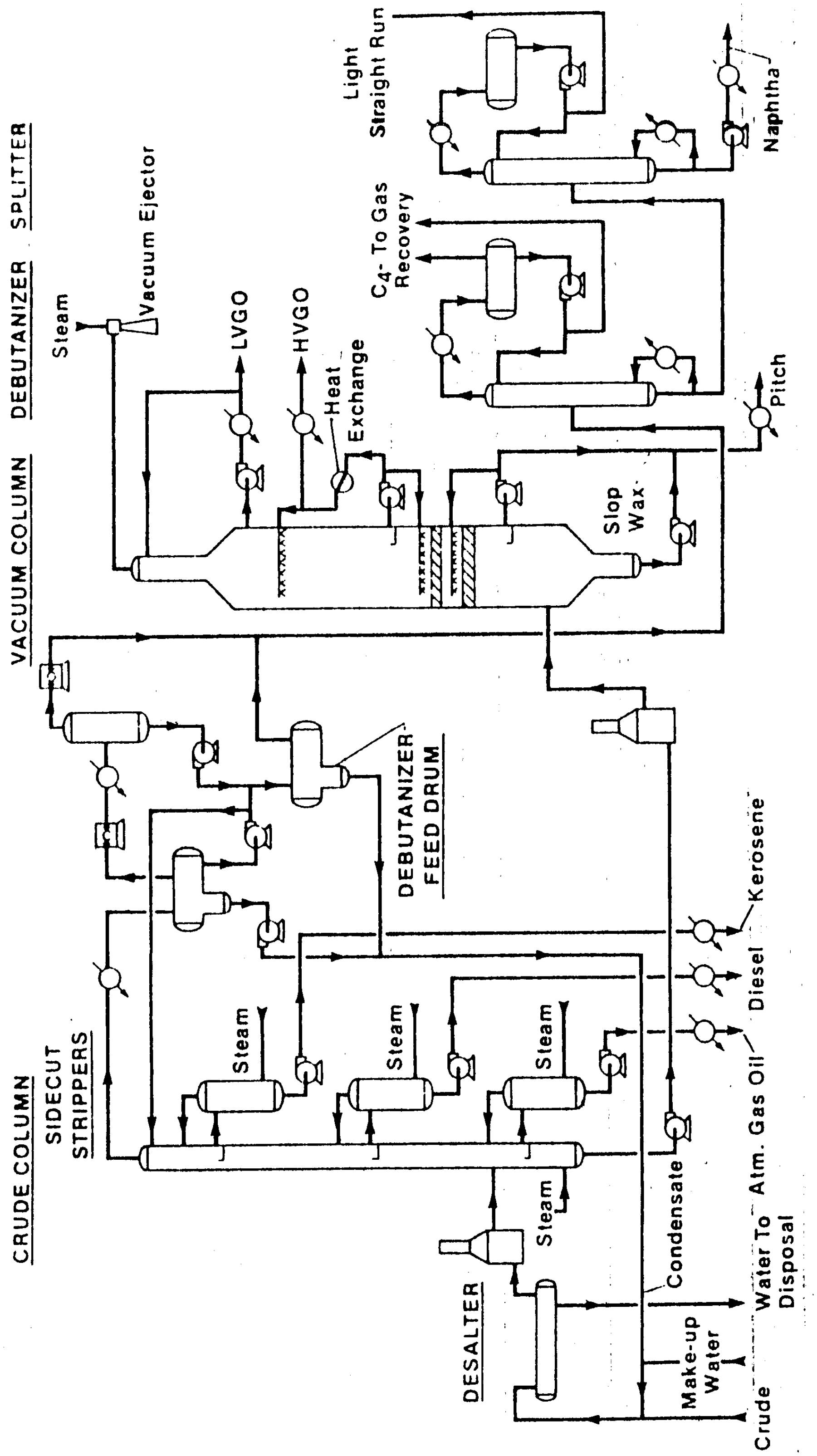


Figure 8.11 Crude and Vacuum Distillation Unit

Crude entering the flash zone of the fractionating column flashes into the vapor which rises up the column and the liquid residue which drops downwards. This flash is a very rough separation; the vapors contain appreciable quantities of heavy ends, which must be rejected downwards into reduced crude, while the liquid contains lighter products, which must be stripped out.

## Fractionation

Flashed vapors rise up the fractionating column Figure 6.10 counter – current to the internal reflux flowing down the column. The lightest product, which is generally gasoline passes overhead and is condensed in the overhead receiver. (Should the crude contain any non-condensable gas, it will leave the receiver as a gas, and can be recovered by other equipment, which should be operated to obtain the minimum flash zone pressure.) The temperature at the top of the fractionators is a good measure of the endpoint of the gasoline and this temperature is controlled by returning some of the condensed gasoline as reflux to the top of the column. Increasing the reflux rate lowers the top temperature and results in the net overhead product having a lower endpoint. The loss in net overhead product must be removed on the next lower draw try. This will decrease the initial boiling point of material from this tray. Increasing the heater transfer temperature increases the heat input and demands more reflux to maintain the same top temperature.

External reflux which is returned to the top of the fractionators passes downwards against the rising vapors. Lighter components of the reflux are revaporized and return to the top of the column while the heavier components in the rising vapors are condensed and return down the column. We have then an internal reflux stream flowing from, the top of the fractionators all the way back to the flash zone and becoming progressively heaver as it descends.

The products heaver than the net overhead are obtained by withdrawing portions of the internal reflux stream. The endpoint of a sidecut will depend on the quantity withdrawn. If the sidecut withdrawal rate is increased, the extra product is material which was formerly flowing down the fractionators as internal reflex. Since the internal reflux below the draw off is reduced, heavier vapors can now rise to that point and result in a heavier product. Changing the drawoff rate is the manner in which sidecuts are kept on end point specifications.

Temperature of the drawoff decks is a fair indication of the endpoint of the product drawn at that point and an experienced operator may vary his drawoff rate to hold a constant deck temperature and therefore a specification product.

The degree of fractionation between cuts is generally judged by measuring the number of degrees centigrade between the 95% point of the lighter product and the 5% point of the heaving product. (Some people use IBP and FBP but the IBP varies with stripping). The gap between gasoline and kerosene should be about 5ºC while between kerosene and light gas oil 3ºC is normal. Fractionation can be improved by increasing the reflux in the fractionators, which is done by raising the transfer temperature. There may be occasions when the internal reflux necessary to achieve satisfactory fractionation between the heaver products is so great that if it was supplied from the top of the fractionators the upper decks would flood. An "Intermediate Circulating Reflux" solves this problem. Some internal reflux is withdrawn, pumped through a cooler, or exchanger, and returned colder a few decks higher in the column. This cold oil return condenses extra vapors to liquid and increases the internal reflux below that point. If we wish to improve fractionation between the light and heavy gas oil, we would increases the heater transfer temperature, which would cause the top reflux to increases, then restore the top reflux to its former rate by increasing the circulating reflux rate. It is to be noted that even through the heater transfer temperature is increased, the extra heat is recovered by exchanger with crude, and as a result the heater duty wills only increases slightly.

Sometimes fractionators will be "pulled dry". That is to say, the rate at which a product is being withdrawn is greater than the quantity of internal reflux in the fractionators. All the internal reflux then flows to the stripper, the decks below the drawoff run dry, and therefore no fractionation takes place, while at the same time there is insufficient material to maintain the level in the stripper, and the product pump will tend to lose suction. It is necessary then to either lower the product withdrawal rate or to increases the internal reflux in the tower by raising the transfer temperature or by reducing the rate at which the next lightest product is being withdrawn.

## Product Stripping

The flashed residue in the bottom of the fractionators and the sidecut products have been in contact with lighter boiling vapors. These vapors must be removed to meet flash point specifications and to drive the light ends into lighter and more valuable products.

Steam, usually superheated steam, is used to strip these light ends. Generally only enough steam is used to meet a flash point specification. While further increases in the quantity of steam may raise the IBP of the product slightly, the only way to substantially increase the IBP of one product is to increases the yield of the next light product. (Provided, of course, the fractionators has enough internal reflux to make a good separation).

All the stripping steam is condensed in the overhead receiver and must be drained off. Refluxing water will upset the fractionators. If the endpoint of the overhead product is very low, water may not pass overhead, and will accumulate on the upper decks and cause the tower to flood.

## The effect of steam

Steam is frequently used in fractionating columns, strippers and sometimes in furnaces. If the quantity and temperature of the steam are known, its effect can be determined by calculating the partial pressure exerted by the steam. This partial pressure is then subtracted from the total system pressure (according to Dalton's law) and the calculations on the hydrocarbon equilibria etc. are carried out at resulting lower pressure. In other words steam has the same effect as lowering the pressure.

## Example

Let it be required to calculate the top temperature of a fractionating column when the top product, of which the composition is given below, contains in addition 4% by wt of steam. Total pressure at the top of the column is 20 psia.

| | lbs/hr. | Mol. wt. | Moles |
|---|---|---|---|
| $C_3$ | 200 | 44 | 4.55 |
| $iC_4$ | 300 | 58 | 5.17 |
| $nC_4$ | 500 | 58 | 8.62 |
| $iC_5$ | 200 | 72 | 2.78 |
| $nC_5$ | 1,000 | 72 | 13.89 |
| $C_6$-$C_9$ | 37,800 | 110 | 343.64 |
| | 40,000 | | 378.65 |
| $H_2O$ | 1,600 | 18 | 88.89 |

The mole percentage steam amounts to

$$\frac{88.89}{378.65 + 88.89} \times 100\% = 19.0\%$$

Consequently the steam partial pressure amounts to 19.0% of 20 psia = 3.80 psia and the hydrocarbon partial pressure equals, therefore, 20-3.80 = 16.20 psia. The conventional dew point calculation as described before is now carried out at a pressure of 16.20 psia, disregarding the steam.

When liquid water is present on the top tray of the column, its vapour pressure must be subtracted from the total pressure. In this case, however, the temperature must be known, and this has to be determined by trial and error.

### Example 2

**Data given:** Total pressure and temperature of a flashing system and the amount of hydrocarbon vapour to be flashed off per hour;

**Required;** Amount of steam needed for this operation.

By trial and error the pressure at which the amount of vapour flashed off at the given temperature is found from the flash equation.

From the relation:

$$\frac{\text{moles of oil vapour}}{\text{moles of oil vapour + moles steam}} = \frac{\text{partial pressure of oil vapour}}{\text{total pressure of system}}$$

The moles of steam can be found and consequently the required weight of steam determined.

### Desalting

Most crude contain traces of salt which can decompose in the heater to from hydrochloric acid and cause corrosion of the fractionator's overhead equipment. In order to remove the salt water is injected into the partially preheated crude and the stream is thoroughly mixed so that the water extracts practically all the salt from the oil. The mixture of oil and water is separated in a desalter, which is a large vessel in which may be accelerated by the addition of chemicals or by electrical devices. The salt laden water is automatically drained from the bottom of the desalter.

If the oil entering the desalter is not enough, it may be too viscous to permit proper mixing and complete separation of the water and the oil, and some of the water may be carried into the fractionators. If, on the other hand, the oil is too hot, some vaporization may occur, and the resulting turbulence can result in improper separation of oil and water. The desalter temperature is therefore quite critical, and normally a bypass is provided around at least one of the exchangers so that the temperature can be controlled. The optimum temperature depends upon the desalter pressure and the quantity of light material in the crude, but is normally about 120ºC ± 10ºC being lower for low pressure and light crudes. The average water injection rate is 5% of the charge.

Regular laboratory analyses will monitor the desalter performance, and the desalted crude should normally not contain more than one kilogram of salt per 1,000 barrels of feed.

Good desalter control is indicated by the chloride content of the overhead receiver water. This should be in the order of 10-30 ppm chlorides. If the desalter operation appears to be satisfactory but the chloride content in the overhead receiver water is greater than 30 ppm, then caustic should be injected at the rate of 1 to 3 lbs. Per 1000 barrels of charge to reduce the chloride content to the range of 10-30 ppm. Salting out will occur below 10 and severe corrosion above 30 ppm.

Another controlling factor on the overhead receiver water is pH. Thus should be controlled between pH 5 and 6.5. Ammonia injection into the tower top section can be used as a control for this.

## Product Disposal

All products are cooled before being sent to storage. Light products should be below 60ºC to reduce vapor losses in storage, but heavier products need not be as cold. If a product is being charged to another unit, there may be an advantage in sending it out hot.

A product must never leave a unit at over 100 ºC if there is any possibility of it entering a tank with water bottoms. The hot oil could readily boil the water and blow the roof off.

## 8.2.2 Product Specifications

The composition of a distillation product is determined by performing laboratory tests on samples of that product. These test results are then compared with product specifications or standards that have been set for the product. If the product is meeting specifications, column operations do not have to be adjusted. But, if the products are off-specification, a change in column operations must be made.

One can see that the control of the tower is a rather complicated simultaneous solution of material and heat balances. At each draw we must draw the quantity of material in the crude that boils within the specified boiling range. If we draw too much, or too little, the product above or below will have to shift by that amount, thereby possibly putting it off specification. To stay on specifications the material balance must be maintained; the quantity of each product in the crude must be withdrawn at that particular draw tray.

The second problem, the heat balance, must be solved so that the right product appears at the right tray with the proper degree of fractionation. The tower designers help with this problem by locating the draw trays according to the design crude and product slate. However, cruder vary, product requirements vary, and the refinery must manipulate the heat and material balance to draw the right amount of product, with the proper distillation range or other product specifications.

Specifications for typical products boiling ranges are shown in Figure 6.12. These products would come out of crude that has a crude assay TBP as shown in Figure 8.13.

### Initial Boiling Point (IBP)

The initial boiling point (IBP) of a petroleum product is that temperature at which the first drop of condensate is collected during a laboratory distillation test. In a mixture of hydrocarbons, the first molecules to vaporize are the light ones. So, the initial boiling-point test is used to check for light hydrocarbons that are present in a product. Suppose specifications on the bottom product call for an initial boiling point between 100-110 °F. Lab tests show an IBP of 95 °F. You know that light material boils at lower temperatures than heavy material. So, the bottom product in this example contains material that is too light.

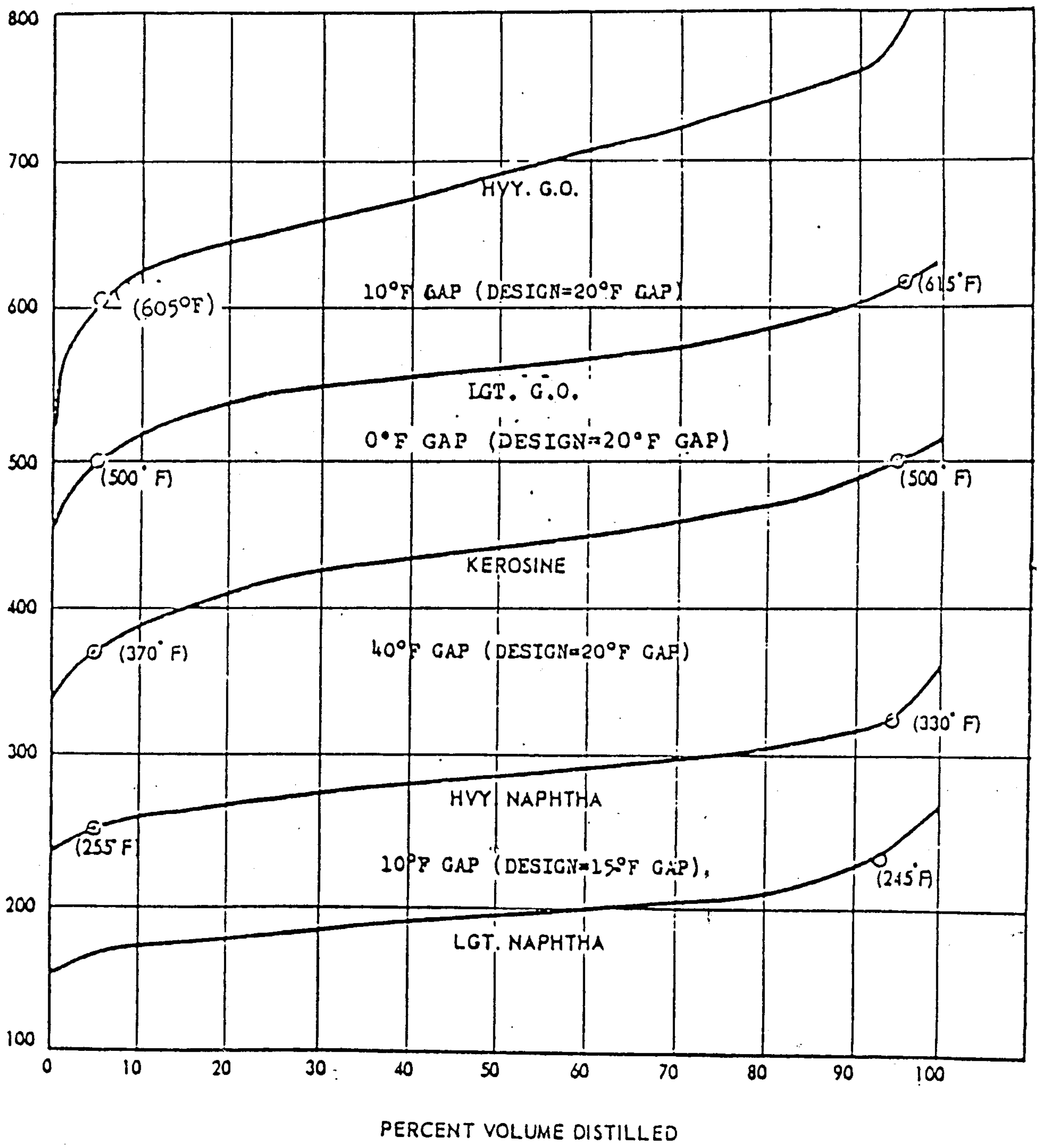


Figure 8.12 Acceptable Products / Crude Oil ATM. Tower

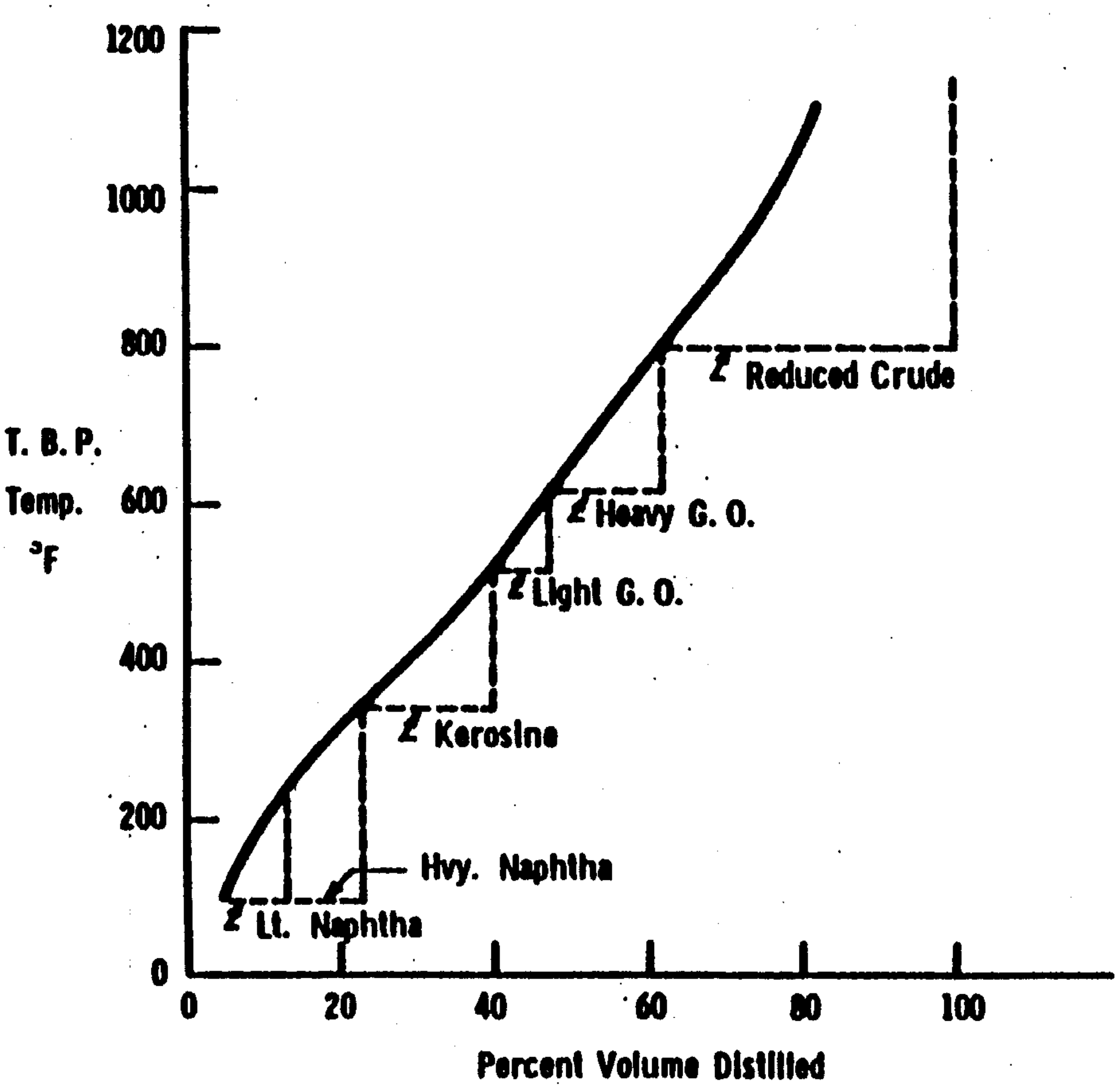


Figure 8.13 Typical Crude Oil Products

In order to raise the IBP of a product, we must make the product heavier. One way to raise the IBP of the bottom product is to strip some light components off with steam. Another way to raise the IBP is to increase the temperature of the feed or the reboiler temperature so more light components are vaporized.

## End Boiling Point (EP)

The end boiling point (EP) of a petroleum product is the highest temperature reached during a laboratory distillation test, or the temperature at which the last drop of liquid vaporizes during the test. In a mixture of hydrocarbons, the last molecules to vaporize are the heavy ones. So, the end boiling point or end point test is used to check for heavy hydrocarbons that are present in a product.

Specifications call for an overhead product with an EP between 150-160 °F. Lab results indicate an EP of 170 °F. You know that heavy material boils at higher temperatures than light material. So, the top product does not meet specifications because it contains material that is too heavy. In order to lower the EP of a product, we must make the product lighter. One way to reduce the EP of the top product is to decrease the feed or reboiler temperature so that fewer heavy components vaporize.

Another way to bring EP on-specification is to lower the top temperature by increasing the reflux rate.

## Flash Point

The temperature at which a petroleum product generates ignitable vapors is called the flash point. Light hydrocarbons tend to flash more easily than heavy hydrocarbons. A sample that contains traces of light hydrocarbons flashes at a lower temperature than a sample without these traces.

A side draw product carries flash point specifications of 125-130 °F. The lab test shows a flash point of 110 °F. The sample contains material that is too light. We can bring the product back to specification by decreasing the reflux rate, or by using more stripping steam, or by increasing the reboiler temperature.

## API Gravity

Another specification for petroleum products is API gravity. API gravity is used to designate the "heaviness" or "lightness" of products based on a scale in which 10° API gravity is the same weight as water. An oil that is exactly the same weight as water would be measured at 10 °API. Kerosene is measured at about 42° API. Gasoline, which is lighter than kerosene, is measured at about 60° API. The lighter the oil, the higher its API gravity

Suppose specifications call for a product with an API gravity of 30-35°. The product sample tests 28°. The product is too heavy.

## Colour

Petroleum products are often color tested in the lab. Light hydrocarbons are light colored while heavy hydrocarbons are dark in color. A light hydrocarbon product that is dark colored probably contains too many heavy molecules. Excessive vapor rates can cause small drops of liquid to become entrained in the vapor and be carried up the tower. Entrainment of heavy materials may contaminate the overhead product and make it too dark in color. Hydrocarbons will decompose and change color at very high temperatures. So, an off-color product may indicate that a tower is operating at too high a temperature.

# 8.3 CRUDE DISTILLATION OPERATION

Figure 6.10 shows a diagram of a crude distillation column. Before the feed enters this column, it is heated by a series of heat exchangers and a furnace. Next, the feed is introduced into the column on the feed tray. Most of the lighter fractions immediately vaporize, or flash and start rising up the tower. The heavier fractions remain in a liquid state and work their way to the bottom of the column. Any light components that remain in the liquid are removed with stripping steam.

In addition to overhead and bottom products, three other fractions are drawn from the side of the tower. Each of these fractions passes through a stripping column that uses steam to remove light components. Vapors from the stripping columns are reintroduced to the tower at a point above the draw-off tray.

## 8.3.1 Reflux Rate Changing

Vapors at the top of the tower are cooled and condensed to liquid. Part of this liquid is returned to the tower as cooling reflux. Let's consider the effect of making cut point changes in a crude unit by varying the reflux rate. Reflux as a "coolant" that removes heavy fractions by condensing them.

Suppose the reflux rate is increased from 1,000 to 1,200 barrels per hour, and the other tower operating conditions are held constant. This extra reflux flowing down the tower causes the temperature on each tray to decrease. Some of the heavier hydrocarbons in the upward flowing vapors will now condense and fall back down the tower. The heaviest components are condensed out of the vapors on each tray in the column. As a result, the fraction formed on each tray will be lighter. The extra reflux flowing down the tower reduces the temperature of the liquid at the bottom of the column. When the bottom temperature decreases, the amount of light material vaporized out of the liquid at the bottom of the tower is decreased. So the liquid at the bottom of the column becomes lighter. Since the amount of product drawn to the stripper columns remains constant, increasing the reflux rate causes more bottom product to be formed. Because fewer vapors are now going overhead, the amount of top product formed is decreased, or less. Lighter overhead, bottom, and side draw products are produced by increasing the reflux rate.

If we decrease the reflux rate from 1,000 barrels to 800 barrels, the cut point changes are reversed. The temperature on each of the trays increases, and a higher tower temperature mean heavier products. So overhead, bottom, and side draw products become heavier. The amount of overhead product produced increases and the amount of bottom product formed decreases.

## 8.3.2 Feed Temperature Changing

Now let's consider how changing the temperature of the feed affects cut point changes in the crude unit. Suppose we raise the temperature of the feed and hold the reflux rate and other tower variables constant. As the crude enters the column more of the feed is vaporized because of the higher temperature. Some of the heavy material that previously fell to the bottom of the tower is contained in these vapors. So the products formed above the feed tray become heavier. The increase in temperature causes the lightest materials in the liquid at the bottom of the tower to boil out, so the bottom product becomes heavier. Since more vapor goes overhead when the temperature of the feed is increased, the amount of top product formed increases. Because less liquid falls to the bottom of the column when the feed temperature increases, the amount of bottom product formed decreases. So heavier overhead, bottom and side draw products are produced by increasing the feed temperature.

If we reduce the temperature of the feed, the cut point changes will again reverse. Less heavy material is vaporized when the crude enters the column, so the top and side draw products become lighter. The material that no longer vaporizes is actually lighter than the liquid at the bottom of the column. When this material falls to the bottom of the column, the bottom product gets lighter. Lighter overhead, bottom, and side draw products are produced by decreasing the temperature of the feed. When the feed temperature is reduced, the amount of top product produced decreases and the amount of bottom product formed increases.

## 8.3.3 Side Product (Draw off) Rate Changing

Another way to change the cut point in a crude column is to vary the amount of liquid that is drawn to the stripper columns. Suppose we increase the kerosene draw by 100 barrels. When we open a stripper draw on the side of a crude unit less reflux flows to the trays below the draw-off tray. Reducing the amount of reflux going to the trays below the kerosene draw causes these trays to heat up. As the temperature on these trays increases more heavy material begins rising up the tower. Because the temperature of the vapors rising to the kerosene draw is higher, the draw-off tray temperature will also be higher. High temperatures produce heavy products, so increasing the kerosene draw makes this product heavier. The products formed below the kerosene draw also become heavier.

Now suppose we want to make the kerosene product heavier without changing the composition of the gas oil and reduced crude products. To do this we must increase the kerosene draw and at the same time not change the amount of reflux, or liquid on the gas oil tray and the trays below this point. We can do this by decreasing the gas oil draw at the same time the kerosene draw is increased. We draw less gas oil product to keep the same amount of reflux on the gas oil tray and the trays below this point. With the same amount of reflux on these trays, the temperature profile in this part of the tower does not change and the gas oil and reduced crude products do not change composition. So to make the kerosene product heavier without changing the composition of the gas oil and reduced crude products, the gas oil draw is decreased and the kerosene draw is increased.

Let's reverse the situation and look at what happens when the kerosene draw is decreased. Now the amount of reflux flowing to trays below the kerosene draw increases. An increase in reflux causes more heavy components to condense out of the rising vapors because the temperature on the trays falls. Low temperatures produce light products, so reducing the kerosene draw results in a lighter kerosene product. The products formed below the kerosene draw also become lighter.

Suppose we want a lighter kerosene product but do not want to change the composition of the gas oil and reduced crude products. Since there is more reflux flowing down to the gas oil tray, we will have to increase the gas oil draw. In this situation we are drawing more gas oil product to keep the same amount of reflux on the gas oil tray and the trays below this point. So to make the kerosene product lighter without changing the composition of the gas oil and reduced crude products, the gas oil draw is increased and the kerosene draw is decreased.

The composition of crude distillation products can be changed by varying the amount of liquid that is drawn to a stripping column. Opening a stripper draw makes this product and products formed below this point heavier. Closing a stripper draw makes this product and products below this tray lighter. To change the composition of a side draw product without affecting the composition of products below this point, you must adjust two stripper draws. The first stripper draw adjustment is made to change the composition of the product. The second adjustment keeps the composition of the other products from changing by maintaining the same amount of reflux, or liquid on these trays.

# 8.4 FRACTIONATOR CONTROL

The fractionator operates by using a controlled temperature gradient from top to bottom. The composition of the top product is fixed by its bubble point or dew point. The bottom product is controlled by its bubble point.

The fractionator always must operate so that the material and energy balances around it are satisfied on a steady-state basis. Any momentary upsets will be reflected by internal unstable operation which causes intolerable "upsets." Furthermore, it is a "sluggish" device. Liquid "hold-up time" is fairly large since flow rates are relatively low compared to its capacity. Therefore, an inherent time lag occurs when controlling at the tower extremities.

The fractionator must process that feed inlet rate, condition and composition that comes to it. Attempts will be made to control these but the success for this will vary. The fractionator control system must, therefore, be fairly flexible.

A demethanizer and/or deethanizer normally are used to remove noncondensibles that are prohibited in the salable products. The problem is to keep these noncondensibles from passing out the bottom (fairly easy) with only minimum loss of salable products out the top (more difficult). Therefore, the overhead product is the more critical of the two, although both are important.

Usually, a depropanizer and/or debutanizer is producing a commercial overhead product that must meet certain specifications. At this point (hopefully) no noncondensibles are in the system. In the usual situation the propane, butane or LPG mix are less valuable per unit volume than the heaviest product (natural gasoline, condensate, etc.). This latter product should contain all of the propane and butane that the sales specifications allow. Still...the most sensitive control problem is to keep the methane and ethane levels low (from previous fractionation) to meet vapor pressure specs and maintain the heavier ends at a concentration to satisfy weathering tests.

There are several rules that should be followed in fractionator control:

1. The lesser of the two streams should be manipulated (controlwise) to obtain the greatest sensitivity in product quality.
2. Separation should be manipulated to control the purity of the purest product; the material balance should be manipulated to control the quality of the less pure product.

Older control systems attempt to accomplish these functions by the use of pressure, temperature, level and flow controls on each stream independently. The next plateau was to recognize that these streams were not really independent and to address the interaction between them by means of control loops. The next level of sophistication is to add a chromatograph to sense directly those composition changes that are critical and transmit the proper signal to the controls. A simple analog system may be used to accomplish this. The final plateau is reached by "marrying" all of these to a computer which has been properly programmed. All streams being sensed feed their information into this computer or programmable logic controller which runs through a dynamic simulation and then tells the controls what to do.

A computer does not solve the control problem; it can only react within the limits imposed on it by its creator. It also represents an expensive control system.

As a guide in this endeavour, a series of control systems will be shown. These systems should be viewed as examples to illustrate the principles involved.

### 8.4.1 Feed Surge Control

Regardless of the process used to recover liquid, both flow rate and composition will vary to the first fractionator. A combination surge drum and vessel to flash-off a portion of the methane and ethane might be used ahead of this fractionator. The level must fluctuate in this vessel. One simple approach is to use a liquid level control with a long displacement type float. By setting it on 100-200 % proportional control, large level fluctuations will dampen out rate changes.

Figure 8.14 (A) to (D) show several possible arrangements. The pump would be eliminated in the first three if the tank is at a high enough pressure. If the tank is large, **(A)** could be used. A level indicator with level alarms would be required on the tank to guard against low and high levels. Method shown **(B)** would use the wide band (and maybe long float) with or without the pump. Method **(C)** is a further addition that might be necessary when the pressure on the accumulator is not constant. The LC resets the flow recording controller (FRC). In each of these systems, any pump used would have to be of the centrifugal type subject to back pressure control.

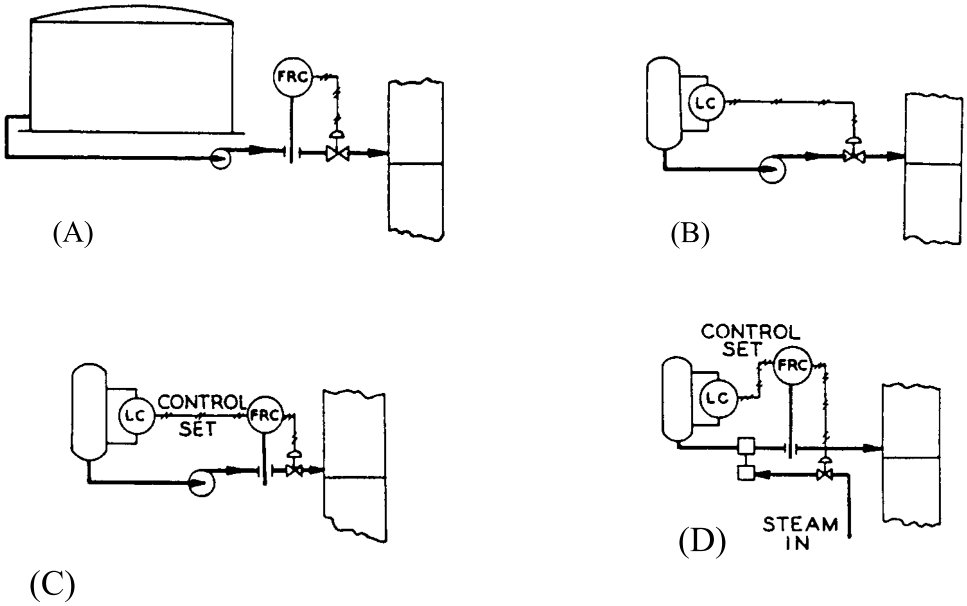


**Figure 8.14 Feed Surge Control**

Figure 8.14 (D) shows a steam pump layout. The level controller sets the control point for flow. The flow controller actuate; the valve on the steam line. Few steam pumps are now used, but this diagram illustrate; a simple interlock system.

## 8.4.2 Feed Temperature (Thermal Condition)

For efficient separation; it is usually desirable to have the feed at its bubble point when it enters the tower, unless the feed comes directly from some preceding distillation step, an outside source of heat is required.

Steam may be used to heat the feed, any change in feed temperature, a corrective adjustment to the supply of steam into the exchanger. To maintain feed temperature; usually a three mode controller is used. The use of a cascade loop (Figure 8.15) can provide superior temperature control.

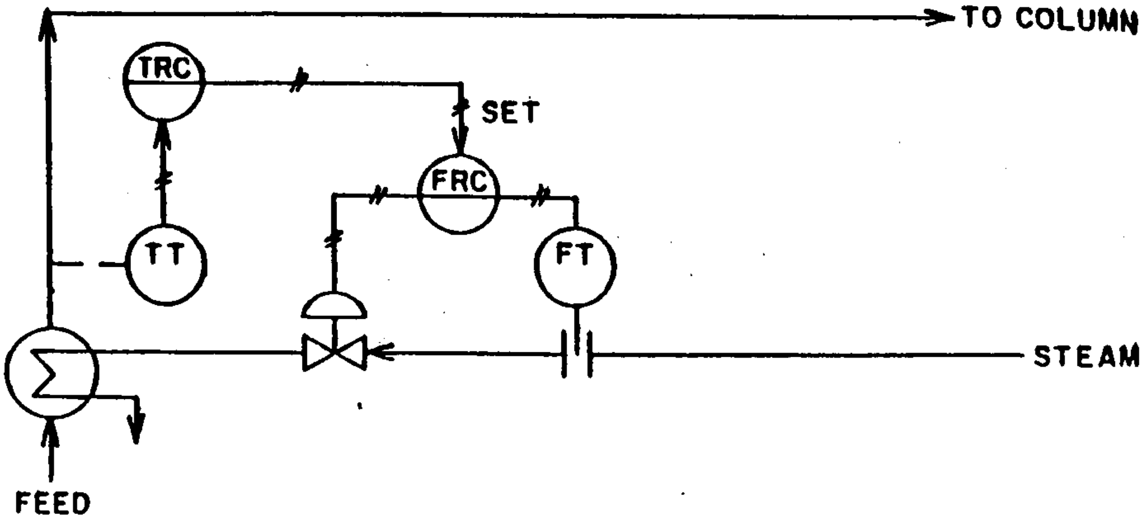


**Figure 8.15 Improved Column Feed Temperature Control**

Constant temperature feed does not necessarily mean constant feed composition (quality). If the feed composition varies, its bubble point varies. It is common practice to set the temperature control at a point which is equivalent to the bubble point of the heaviest feed.

### 8.4.3 Column Pressure Control

Regardless of the column control system, it must contain some provision for pressure control. Column pressure can be controlled by manipulating the material balance (rate of distillate product) or by manipulating the condensing temperature (bubble/dewpoint pressure of distillate). Figure 8.16 (A) to (E) show several arrangement.

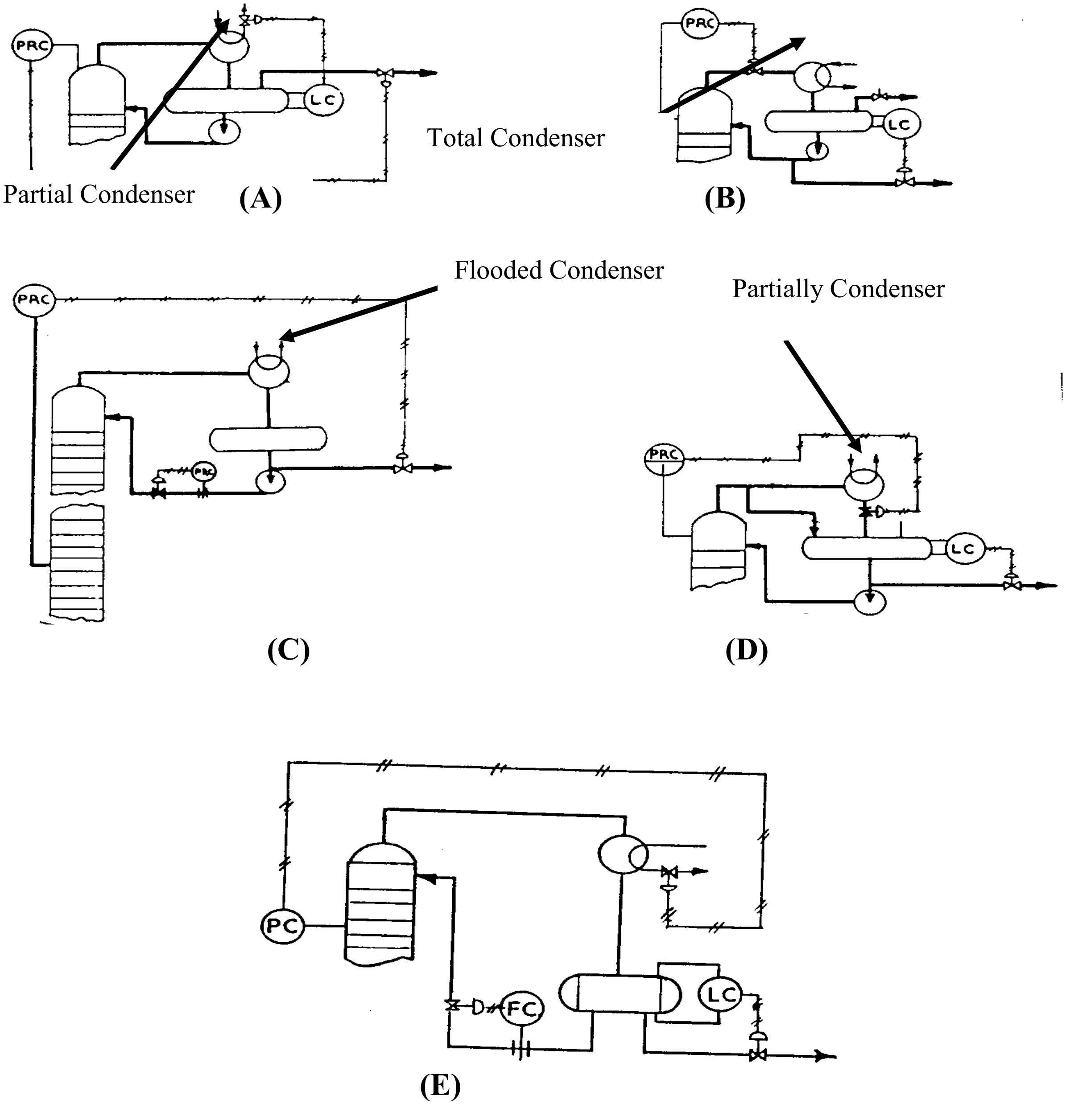


Figure 8.16 Column Pressure Control

Figure 8.16 (A) shows a simple back pressure control on the vapour from the partial condenser. In this case, only enough liquid is condensed to provide reflux. The pressure tap could be on the tower, as shown, or on the reflux accumulator. A proportional response plus reset might be used, although a narrow band proportional control alone could be adequate since pressure offsets are often not critical.

Figure 8.16 (B) shows a system for a total condenser that has proven suitable for a narrow boiling range product. The disadvantage is that a large control valve must be placed in the overhead line.

Figure 8.16 (C) shows a flooded condenser system for a total condenser. In this system the accumulator runs completely full of liquid and pressure is controlled by manipulating the heat transfer area in the condenser. This method is commonly used in NGL fractionators.

Figure 8.16 (D) is an example of one type of hot vapor bypass to control tower pressure. The condenser is partially flooded. The vapor bypass changes the surface temperature of the liquid in the accumulator, hence controlling tower pressure.

The temperature of the condensed product in the accumulator can also be controlled by controlling the cooling medium. This is shown schematically in Figure 6.16 (E) this method is not recommended if the cooling medium is cooling water as it induces fouling and scaling in the condenser. If the cooling medium is air, louvers or variable pitch for blades can be used to control air flow. Induced draft coolers are preferred because the tube bundle is not exposed to precipitation.

Most pressure control systems are based on manipulating the cooling rate at the condenser. If the condenser is allowed to operate without restriction, the column pressure will be as low as possible given the cooling medium and operating conditions. This is called "floating pressure control" and has the benefit of reducing the difficulty of separation, as relative volatilities tend to increase with decreasing pressure for most hydrocarbon separations.

With a total condenser, the rate of reflux would be controlled by a flow control set manually or representing a ratio to some stream.

### 8.4.4 Reboiler Control

Boil-up rate is controlled by setting the flow of heat to the reboiler. A flow controller is placed in the line carrying the heating medium to the reboiler.

The amount of lighter boiling material in the bottom product is determined by the set point of the steam rate controller, A setting which permits a greater amount of steam into the reboiler will cause more of the lighter material to be driven back into the column as vapors.

The rate of bottom product withdrawal is controlled by the level in the reboiler, Figure 8.17 shows a kettle type reboiler.

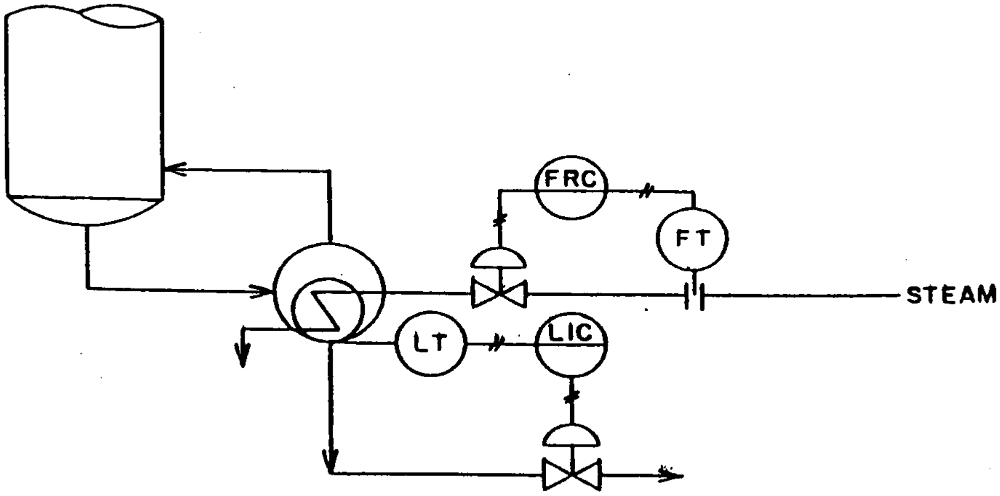


Figure 6.17 Kettle Reboiler Control

Other types include thermosyphon reboilers and forced-circulation reboilers. For them, the bottom product is withdrawn from the column (Figure 8.18)

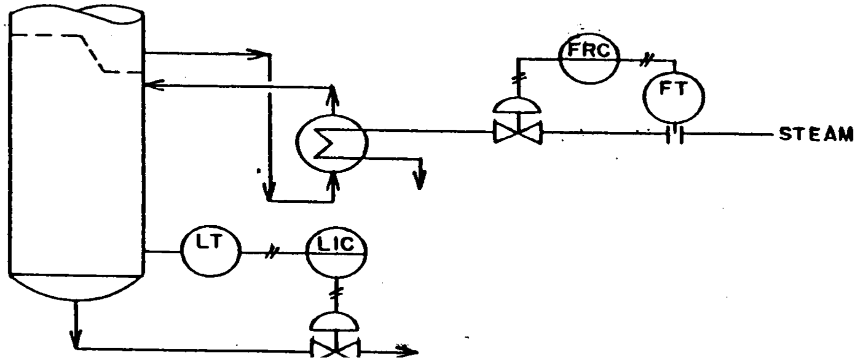


Figure 8.18 Thermosyphon Reboiler Control

## 8.4.5 Variable Feed Tower

Suppose the distillations product is to be fed into a second column. Then any inadvertent changes in the first column would be reflected in the quantity and composition of the feed to the second.

One way to iron out temperature variations caused by liquid level changes, in the first column, is to add flow controllers to the product lines with variable feed rates and compositions, cascade controls are justified. If the feed rate and composition are relatively constant, hand reset of the major control loop is sometimes adequate, in other cases the flow set point is continuously adjusted by the level controller in cascade arrangement Figure 8.19.

When composition of the bottom product is the important consideration, it is desirable to maintain a constant temperature in the lower section. This can be done by letting the temperature measurement set the control point of the reboiler steam supply as shown in Figure 8.20.

When compensation of the distillation product is the important consideration it is desirable to maintain a constant temperature in the upper section as shown in Figure 8.21.

Measuring temperature in a column usually requires that the sensing device be in the liquid on the tray. Heat transfer from a liquid medium to the sensing device is much greater than the heat transfer from a gas medium.

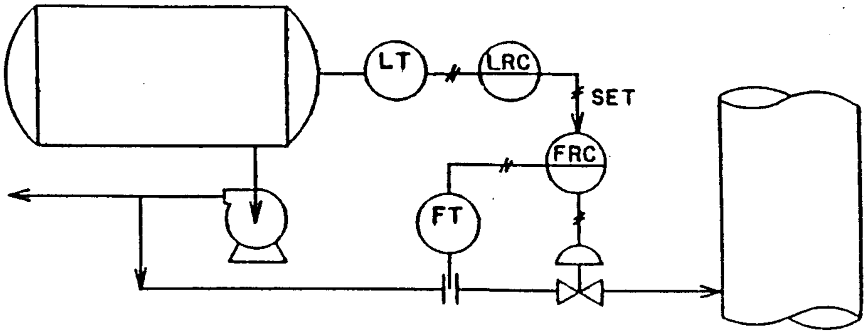


Figure 8.19 Cascade Control of Feed to Second Column

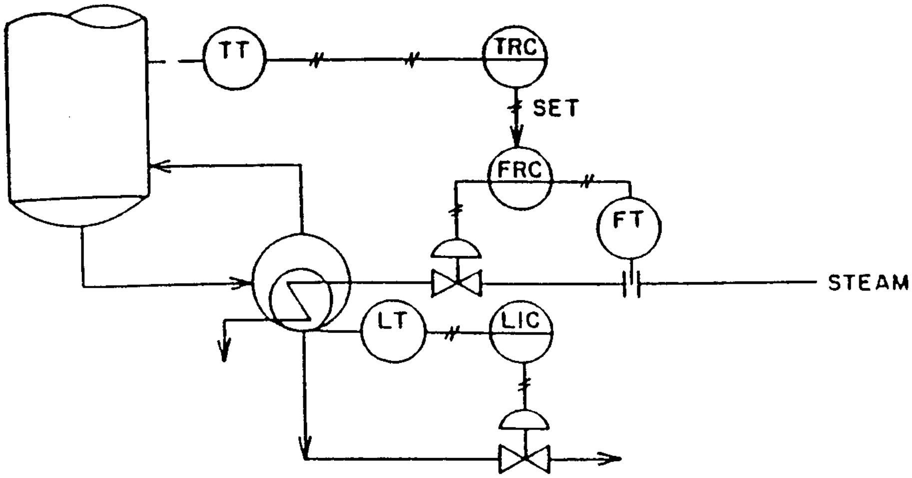


Figure 8.20 Temperature Cascaded Heat Addition to the Reboiler

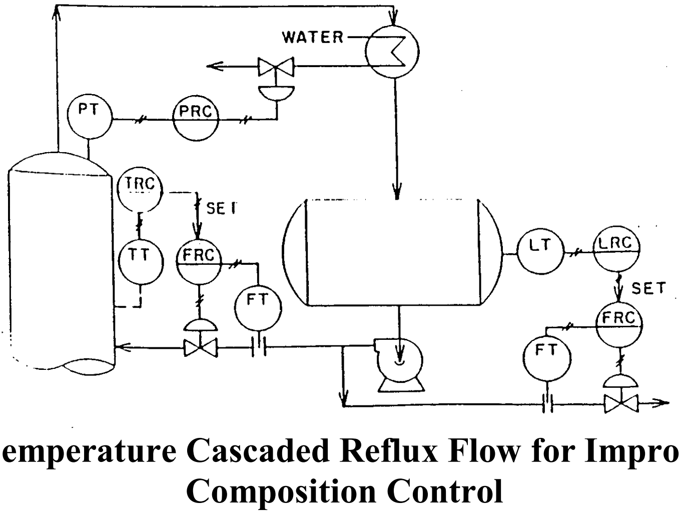


Figure 8.21 Temperature Cascaded Reflux Flow for Improved Overhead Composition Control

## 8.5 TROUBLESHOOTING OPERATING PROBLEMS

This part deals with common operating problems. It is not apropos to try to cover all problem situations. The following are discussed:

1. Flooding
2. Dry trays
3. Damaged trays
6. Water in a hydrocarbon column
5. Foaming
6. Condenser foggin

### 8.5.1 Flooding

**Design**

Flooding is a common operating problem. Companies naturally wish to obtain, maximum capacity out of fractionation equipment and thus often run routinely close to flooding conditions. New columns are typically designed for around 80% of flood. Clearly, the column needs some flexibility for varying operating conditions. Vendors, state that their modern methods for determining percentage of flood represent very closely the true 100% flood point The designer, therefore, shouldn't expect to design for 100% of flood and be able to accommodate variations In operating conditions. Designers recommend a percentage of flood of not more than 77% for vacuum towers or 82% for other services, except that for columns under 36" diameter, 65-75% is recommended.

**Downcomer Backup Flood**

If the downcomer backup for valve trays exceeds 40% of tray spacing for high vapor density systems (3.0 lbs/ft$^3$), 50% for medium vapor densities, and 60% for vapor densities under 1.0 Ibs/ft$^3$, flooding may occur prior to the rate calculated by jet flood. Another good rule of thumb is that the downcomer area should not be less than 10% of the column area, except at unusually low liquid rates. If a downcomer area of less than 10% of column area is used at low liquid rate, it should still be at least double the calculated minimum downcomer area.

### Tower Operations

The tower operator can quickly determine which type of flooding will tend to be the limiting one for a particular system. If a rigorous computer run is available for the anticipated or actual operation, the operator can quickly calculate the expected limiting column section. The operator can then provide DP cell recording for the entire column and limiting section (s). As mentioned previously, a DP cell is the best measure of internal traffic and flooding tendency.

Many plant nontechnical operators do not understand that high vapor rates as well as high liquid rates can cause down comer backup flooding. It is well to explain to the plant operators the mechanism of downcomer backup flooding and show them with a diagram how the head of liquid in the downcomer must balance the tray pressure drop. Then it can be explained how vapor flow is a major contributor to this pressure drop.

Flooding across a column section reflects itself in an increase in pressure drop and a decrease in temperature difference across the affected section. Product quality is also impaired, but it is hoped that the other indicators will allow correction of the situation before major change in product quality. When a column floods, the levels in the accumulator and bottom often change. It can occur that the accumulator fills with liquid carried over while the reboiler runs dry.

Also, in a flooded column, the pressure will often tend to fluctuate. This may help to differentiate between flooding and a high column bottom level, if the bottom level indicator reading is suspect. The high bottom level will give higher than normal pressure drop but often not the magnitude of pressure fluctuations associated with flooding.

Here is a tip for possible capacity Increase for towers with sloped downcomers. Usually, the tray vendor doesn't use the dead area next to the bottom part of the sloped downcomer as active area if the trays are multipass, since he would require a different design for alternate trays. This area could be used for additional vapor capacity in an existing column.

## 8.5.2 Dry Trays

This problem, as with flooding, also impairs product quality. No fractionation occurs in the dry section, so the temperature difference decreases. However, unlike flooding, the pressure drop decreases and stays very steady at the ultimate minimum value. This problem is usually easier to handle than flooding. The problem is caused by either insufficient liquid entering the section or too much liquid boiling away. The problem is solved by reversing the action that caused the dry trays.

Since the changes usually occur close to the source of the problem, the source can usually be quickly found with proper instrumentation. Too little reflux or too much sidestream withdrawal is two examples of insufficient liquid entering a section. Too hot a feed or too much reboilling are examples of excessive liquid boiloff.

## 8.5.3 Damaged Trays

### Effects

Trays can become damaged several ways. A pressure surge can cause damage. A slug of water entering a heavy hydrocarbon fractionator will produce copious amounts of vapor. The author is aware of one example where all the trays were blown out of a crude distillation column. If the bottom liquid level is allowed to reach the reboiler outlet line, the wave action can damage some bottom trays.

Whatever the cause of the tray damage, however, it is often hard to prove tray damage without column shutdown and inspection, especially if damage is slight. Besides poorer fractionation, a damaged tray section will experience a decrease in temperature difference because of the poorer fractionation. An increase in pressure difference may also result since the damage is often to downcomers or other liquid handling parts. However, a decrease in pressure difference could also occur.

### Bottom Level

Trays are particularly vulnerable to damage during shutdown and startup operations. Several good tips to minimize the possibility of tray damage during such periods are provided.

First it is important to avoid high bottoms liquid level as mentioned-previously. Initial design should provide sufficient spacing above and below the reboiler return vapor line. A distance equal to at least tray spacing above the line to the bottom tray or better tray spacing plus, say, 12" and a distance of at least tray spacing below the line to the high liquid level is absolutely necessary. Probably more tray problems occur in this area of the column than any other. In spite of good initial design, however, the bottoms liquid level needs to be watched closely during startup.

If a tower does become flooded in the bottom section, a common operator error is to try to pump the level out too quickly. This can easily damage trays by imposing a downward acting differential pressure produced by a large weight of liquid on top of the tray and a vapor apace immediately below the tray. To eliminate the flooding, it is better to lower feed rate and heat to the reboiler. It is important to be patient and avoid sudden change.

### Steam/Water Operations

Steam/water operations during shutdown have high potential for tray damage if not handled correctly. If a high level of water is built up in the tower and then quickly drained, as by pulling off a bottom manway, extensive tray damage can result, similar to pumping out hydrocarbons too fast during operation.

Steam and water added together to a tower can be a risky operation. If the water is added first at the top, for instance, and is raining down from the trays when steam is introduced, the steam can condense and impose a downward acting differential pressure. This can result in considerable damage. If steam and water must be added together, start the steam first. Then *slowly* add water, not to the point of condensing all the steam. When finished, the water is removed first. One vendor estimates that he sees about six instances of tray failure per year resulting from mishandled steam/water operations.

### Depressuring

Depressuring a tower too fast can also damage the trays by putting excessive vapor flow through them. A bottom relief valve on a pressure tower would make matters worse since the vapor flow would be forced across the trays in the wrong direction. The equivalent for a vacuum tower would be a top vent valve which would suck in inerts or air and again induce flow in the wrong direction. Such a top vent should not be designed too large.

### Phase Change

Overlooking change of phase during the design stage can also cause tray damage. An example is absorber liquid going to a lower pressure stripper and producing a two-phase mixture. In one case, the absorber stream entered the stripper in a line that was cited down onto the stripper tray. The two phase mixture beet out a section of trays. A $1/4$" protection plate was provided and this had a hole cut in it in two years.

## 8.5.4 Water in Hydrocarbon Column

Here small amounts of water are meant rather than large slugs which could damage the trays. Often the water will boil overhead and be drawn off in the overhead accumulator bootleg (water drawoff pot). However, if the column top temperature is too low, the water is prevented from coming overhead. This plus too hot a bottom temperature for water to remain a liquid will trap and accumulate water within the column. The water can often make the tower appear to be in flood.

Many columns have water removal trays designed into the column. Top or bottom temperatures may have to be changed to expel the water if the column isn't provided with water removal trays. In some instances, the water can be expelled by venting the column through the safety relief system.

It should be remembered that water present in a hydrocarbon system, being immiscible, will add its full vapor pressure to that of the hydrocarbons. The author once wondered why the pressure was so high on a certain overhead accumulator until he noticed the installed bootleg.

A small steady supply of water entering a column through solubility or entrainment can, in some cases, cause severe cycling at constant intervals during which time the water is expelled. After expulsion of water, the column lines out until enough is built up for another cycle.

Besides water, other extraneous substances can leak into a column with varied effects. One example was a column separating two components and using the light component as seal flush for the reboiler pump. When excessive lights leaked into the tower system, the bottoms product went off specification. It took a long time to solve the problem since at first the operators suspected loss of tray efficiency.

## 8.5.5 Foaming

The mechanism of foaming is little understood. During the design phase, foaming is provided for in both the tray downcomer and active areas. "System factors" are applied that derate the trays for foaming. Oil absorbers are listed as moderate foamers. Heavy oil mixed with light gases often tends to foam. The higher the pressure, the more foaming tendency, since the heavy oil will contain more dissolved gases at higher pressures. Liquids with low surface tension foam easily. Also, suspended solids will stabilize foam. Foaming is often not a problem when a stabilizer is not present.

No laboratory test has been developed to adequately predict foaming. Oil that doesn't foam in the laboratory or at low column pressure might well foam heavily at high column pressure. In general, aside from adding antifoam, there seems to be no better solution to foaming than providing adequate tray spacing, and column downcomer area. One designer solved a downcomer foaming problem by filling the downcomer with Raschig rings to provide coalescing area.

For troubleshooting suspected foam problems, vaporize samples of feed and bottoms to look for suspended solids. Also, one can look for the Tyndall effect as described in the section on condenser fogging.

In investigating foaming problems. It is helpful to have an estimate of foam density.

## 8.5.6 Condenser Fogging

Fogging occurs in a condenser when the mass transfer doesn't keep up with the heat transfer. The design must provide sufficient time for the mass transfer to occur. A higher temperature differential ($\Delta T$) with non-condensables present or a wide range of molecular weights can produce a fog. The high $\Delta T$ gives a high driving force for heat transfer. The driving force for mass transfer, however, is limited to the concentration driving force ($\Delta Y$) between the composition of the condensible component in the gas phase and the composition in equilibrium with the liquid at the tube wall temperature. The mass transfer driving force ($\Delta Y$) thus has a limit. The $\Delta T$ driving force can, under certain conditions, increase to the point where heat transfer completely outstrips mass transfer, which produces fogging.

**Nature of a Fog:** Fog, like smoke, is a colloid. Once a fog is formed, it is very difficult to knock down. It will go right through packed columns, mist eliminators, or other such devices. Special devices are required to overcome a fog, such as an electric precipitator with charged plates. This can overcome the zeta potential of the charged particles and make them coalesce.

A colloid fog will scatter a beam of light. This is called the "Tyndall Effect" and can be used as a troubleshooting tool.

## Review

1. Quality control over distillation products is maintained by setting specifications for these products.
2. An initial boiling point test identifies the presence of light hydrocarbons.
3. An end point test identifies heavy hydrocarbons.
4. The temperature at which a petroleum product generates ignitable vapors is called the flash point.
5. Light hydrocarbon products have relatively high API gravity readings.

   Reduced crude has a relatively low API gravity reading.
6. Cut point changes are made on distillation products by adjusting the heat balance inside a tower.
7. Whatever material enters a tower as feed leaves the tower as products.
8. You can increase the temperature in a crude column by increasing the feed temperature or decreasing the reflux rate.
9. A temperature increase means that products get heavier.
10. You can decrease the temperature in a crude column by decreasing the feed temperature or increasing the reflux rate.
11. A temperature decrease means that products get lighter.
12. When the tower temperature increases, the amount of overhead product produced increases and the amount of bottom product formed decreases.
13. When the tower temperature decreases, the amount of overhead product produced decreases and the amount of bottom product formed increases.
14. When we close a stripper draw on the side of a crude unit more reflux flows to the trays below the draw-off tray.

15. Closing a stripper draw makes this product and the products below this tray lighter.

16. To change the composition of one side draw product without affecting the composition of products below this point, you must close one stripper draw and open another.

17. The temperature on the top tray of a tower should be just high enough to completely vaporize the overhead product.

18. In order to store the overhead product in liquid form, the pressure in a condenser or accumulator must be slightly higher than the vapor pressure of the product at the temperature it is being stored.

19. The ideal temperature at the bottom of the tower is the temperature at which the vapor pressure of the bottom product is slightly below the operating pressure of the tower.

## 8.6 GLOSSARY

| | |
|---|---|
| **Distillation** | A process in which heat is used to separate a mixture of hydrocarbons into two or more relatively pure products (or fractions) by the difference in their respective boiling points or boiling ranges. When a mixture of hydrocarbons is heated, the light components are the first to boil and go into a vaporized state. These vapors are cooled and condensed to form a fraction that is enriched in light hydrocarbon molecules. The liquid that doesn't vaporize forms a heavy fraction. |
| **Hydrocarbon** | A molecule made up of hydrogen and carbon atoms. |
| **Physical Change** | A change that does not involve the breakdown or restructuring of a substance's molecules. |
| **Chemical Change** | A change that involves a chemical reaction in which a substance's molecules are rearranged. |
| **Sensible Heat** | Heat that actually increases the temperature of a substance. |
| **Latent Heat** | Heat that is added to vaporize a substance already at boiling temperature. |
| **Vapor Pressure** | Pressure exerted by the molecules in a liquid as they attempt to escape from a liquid to a vaporized state. |
| **Partial Pressure** | The amount of pressure exerted by each component in a mixture of gases. The total pressure inside a closed vessel is equal to the sum of the partial pressures exerted by each gas. |
| **Reflux** | A liquid formed by cooling and condensing overhead vapors from a distillation column. This liquid is returned to the tower to remove heat from hot, rising vapors that are contacted on each tray. The exchange between cool reflux and hot vapors keeps each tray in the tower operating at a slightly different temperature. |

| | |
|---|---|
| **Stripping Section** | The part of the column below the feed tray where light components are vaporized out of the liquid. |
| **Rectifying Section** | The part of the column above the feed tray where heavy components are condensed out of the vapors. |
| **Atmospheric Column** | A column that operates at or slightly above atmospheric pressure (16.7 PSI or above). |
| **Vacuum Column** | A column that operates under a partial vacuum (under 16.7 PSI). |
| **Tray** | A plate inside a distillation column where vapor-liquid contact takes place. Different types of hardware can be used to create this contact. |
| **Feed Tray** | The tray on which feed is introduced into the tower. |
| **Down comers** | Passageways for the downward flow of liquid through the tower. |
| **Initial Boiling Point** | The temperature at which the first drop of condensate falls from the condenser into the receiver in a laboratory distillation test. Abbreviated (IBP). |
| **End Boiling Point** | The highest temperature reached during a laboratory distillation test, or the temperature at which the last drop of liquid in the sample vaporizes during the test. Abbreviated as End Point (EP). |
| **Boiling Range** | The range of temperatures from a sample's initial boiling point to its end boiling point. A boiling range test identifies both light and heavy hydrocarbons over a product's entire boiling range. |
| **Flash Point** | The temperature at which a petroleum product generates ignitable vapors. |

| | |
|---|---|
| **API Gravity** | A measure of the "lightness" or "heaviness" of a product. An API gravity of 10° means that a product is exactly the same weight as water. Products that are heavier than water have API gravity less than 10°. Petroleum products that are lighter than water have an API gravity that is greater than 10°. |
| **Heat Balance** | All the heat that goes into a distillation column must be taken out. If we adjust the amount of heat put into a tower or the amount removed, the composition and quantity of the products that are formed will also change. |
| **Cut Point** | The product separation temperature that is used in a distillation column to obtain a product that contains the desired mixture of hydrocarbons. Altering the heat balance in a column to produce more or less of a particular product is called changing the cut point. |
| **Material Balance** | The input of material to a distillation column equals the output of material from that column. Whatever material enters a tower as feed leaves the tower as products. |
| **Process Variable** | A process condition that can change during the process operation. The four most common process variables are temperature, pressure, liquid level, and flow rate. |
| **Primary Element or Sensor** | A device that senses the condition of a process variable, or causes a change in the variable that makes a measurement possible. |
| **Control Loop** | A combination of instruments that works to keep a process variable at a set value. The instruments will vary according to the process being controlled. |
| **Measuring Means** | The instrument in a control loop that senses and measures the condition of a process variable and transmits this measurement. |

| | |
|---|---|
| **Controller** | The instrument in a control loop that continuously compares a measurement of the process variable with setpoint. The controller continuously transmits a signal to the final control element and adjusts this signal when necessary to make a process correction. |
| **Final Control Element** | The devices in a control loop that actually make process adjustments and corrections. In most process control situations, the final control element is a control valve coupled with an actuator. |
| **Setpoint** | The desired value for a process variable. |

# Chapter 9

# Conversion Processes

# *Chapter 9 Contents*

### Chapter 9

# Conversion Processes

## 9.1 INTRODUCTION

Conversion processes are chemical unit processes where components and compounds are subject to chemical reactions and new components and compounds, which extremely different from the original ones are produced.

The purpose of conversion processes is to increase the production of light distillates, intermediate distillates or both together by either breaking down of large hydrocarbon molecules such as straight run fuel oil (bottom product of atmospheric distillation columns), vacuum diesel oil and tar (side and bottom products of vacuum distillation column) into smaller molecules or combining small hydrocarbons molecules to larger molecules.

The breaking down of large hydrocarbon molecules into smaller molecules is usually known as "destructive processes", while combining small hydrocarbon molecules to larger molecules are known as "synthetic" processes on rebuilding hydrocarbon molecules. The most used "destructive" processes are cracking (thermal, catalytic, and hydrocracking) and reforming (thermal and catalytic reforming). The most used "synthetic" processes (rebuilding hydrocarbon molecules) are polymerization, alkylation and isomerization.

The above mentioned "conversion" processes are tools by means of which the petroleum refiner can adjust the quantity and quality of the products obtained from a given amount of crude oil to match the consumers' demands.

## 9.2 CATALYTIC REFORMER

Catalytic Reforming was introduced to the refining process to meet the increasing demands of high octane gasolines.

The octane rating of gasoline is increased by "reforming" the molecules into molecules which perform better in the gasoline engines:

- n-paraffins to iso-paraffins
- naphthenes to aromatics

Paraffinic hydrocarbons have the lowest octane number, while the aromatics have the highest.

The typical feedstocks going into catalytic reformers are:

1. Heavy straight-run naphthas (fractions boiling between 82-190 °C) and
2. Heavy hydrocracker naphthas.

These streams are composed of four major hydrocarbon groups: paraffins, olefins, naphthenes and aromatics (PONA).

For the case of heavy straight run naphtha as the feedstock, the PONA analysis before and after reforming is as follows:

| COMPONENT | FEED | PRODUCT |
|---|---|---|
| Paraffins | 45 - 55% | 30 - 50% |
| Olefins | 0 | 0 |
| Naphthenes | 30-40% | 5 -10% |
| Aromatics | 5 -10% | 45 -60% |

The paraffins and naphthenes undergo cyclization and isomerization to produce higher octane components. The product from the catalytic reformer is usually called "reformate". This is usually blended to straight run gasolines to produce higher octane gasolines.

## 9.2.1 Chemical Reactions in the Reforming Unit

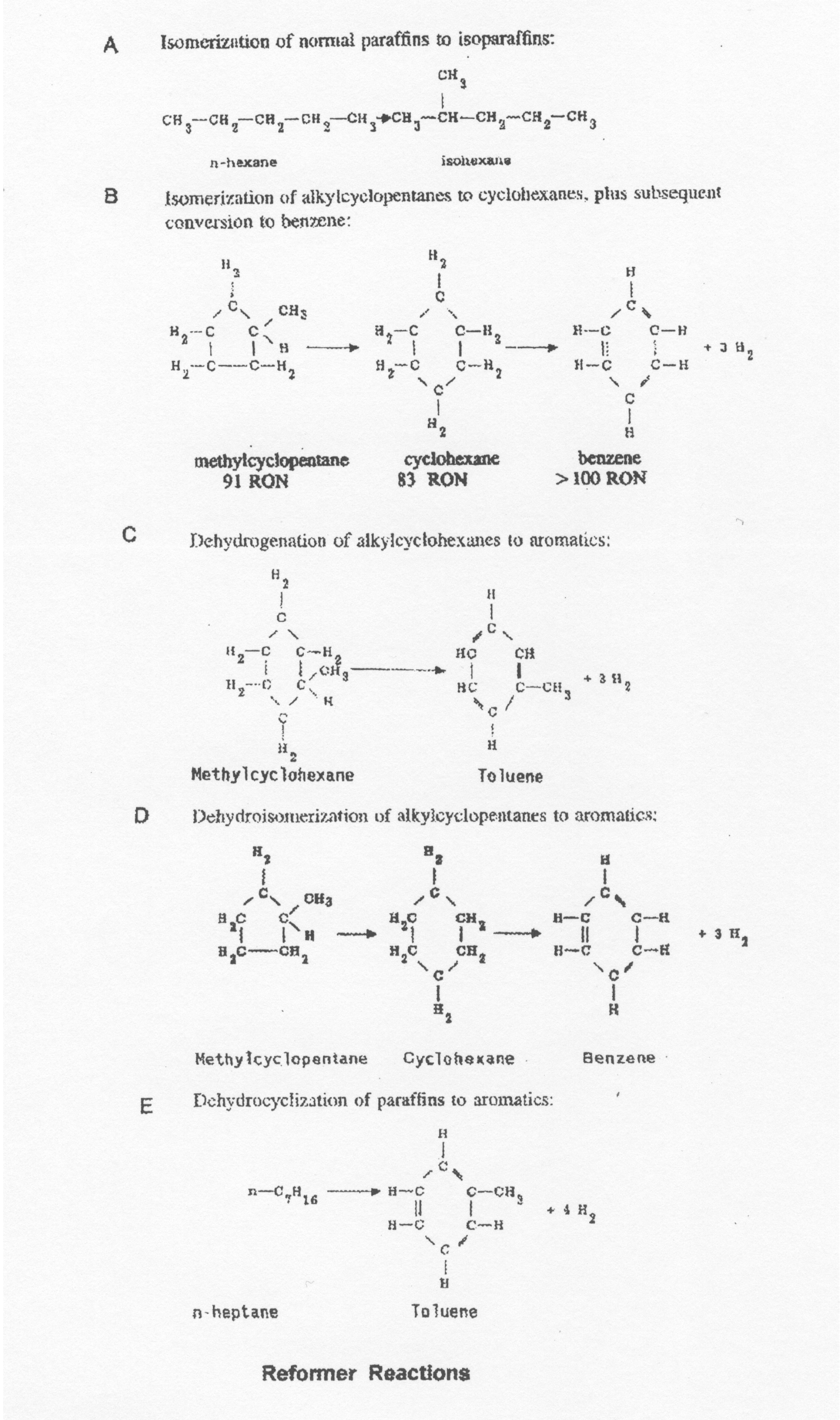
There are both desirable and undesirable reactions taking place in a reformer unit. Desirable reactions in a catalytic reformer all lead to the formation of aromatics and iso-paraffins as follows:

1. Paraffins are isomerized and to some extent converted to naphthenes. The naphthenes are subsequently converted to aromatics.
2. Olefins are saturated to for paraffins which then react as in 1.
3. Naphthenes are converted to aromatics.
4. Aromatics are left essentially unchanged.

Undesirable reactions in the reformer include:

1. Side chains on naphthenes and aromatics are broken off to form lighter gases.
2. Cracking of paraffins and naphthenes to lighter gases.

A very desirable by-product of the reformer is excess hydrogen, which is used in other units (hydrotreaters and hydrocrackers).



Reformer Reactions

## 9.2.2 Reformer Catalyst

The reforming units usually use a stationary bed of catalyst in a reactor vessel.
The feed is heated to a vapor state and passed down through the catalyst bed. The high temperatures and catalyst cause the chemical reactions go to completion.

The catalyst used in a reformer unit is usually a platinum material such as:
- platinum-iridium or
- platinum-rhenium

There have been several designs of reformer units in the refining industry, some of which have special trademarked names such as:

- Platformer **(licensed by UOP)**
- Powerformer **(licensed by Exxon)**
- Ultraformer **(licensed by SU Oil, Ind.)**
- Catalytic Reformer **(licensed by Engelhard)**
- Houdriforming and Iso-Plus Houdryforming **(licensed by Houdry)**
- Rheniforming **(licensed by Chevron)**

A reforming reactor unit is shown diagrammatically as shown in the Figure 9.1.

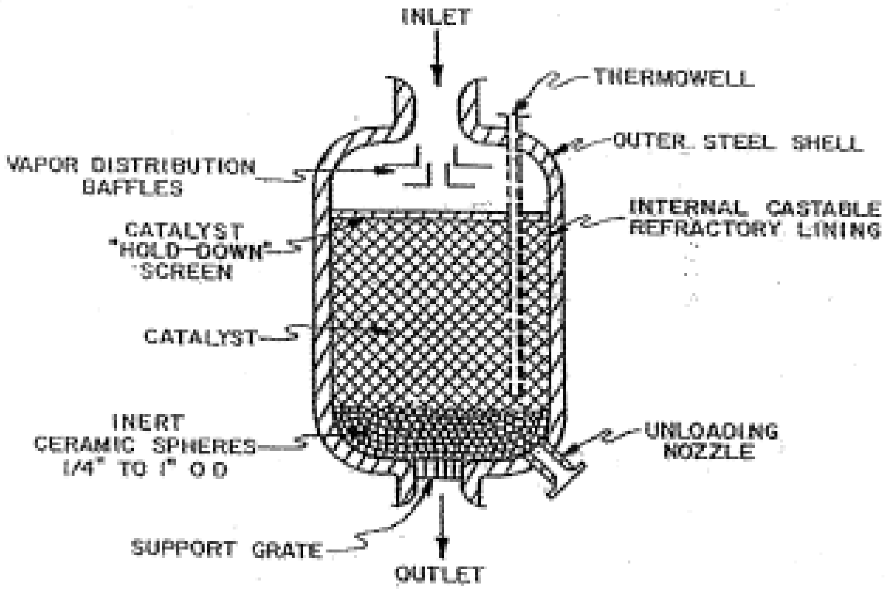


**Figure 9.1 Typical Fixed Bed Catalytic Reactor**

The catalyst beds are regenerated periodically (6 to 24 months) to get rid of the coke deposits that form on the catalyst surfaces.

The catalyst must be removed and a new bed purchased every two to four years, Reforming catalysts are very expensive.

In the reforming process, the higher the octane desired, the lower the yield and the more light ends (low boiling compounds) are created.

Depending on how the reformer catalysts are regenerated, reforming processes are classified into:

- semi-regenerative
- continuous
- cyclic

The semi-regenerative process is the most popular one of the three.

## 9.2.3 Semi-Regenerative Reforming process

In the semi-regenerative process (Figure 9.2), the pretreated feed and recycle hydrogen are heated to 498 –542 °C before entering the first reactor. In the first reactor, the major reaction is the dehydrogenation of naphthenes to aromatics (endothermic reaction) with a large drop in temperature. To maintain reaction rate, the gases are reheated before going to the second reactor. As the charge proceeds through the reactors, the reaction rates slows down and the reactors become larger and the reheat necessary becomes less.

There are 3 to 4 reactors in series, each having a heater upstream of it. There can be separate heaters or a single large heater with separate coils in it.

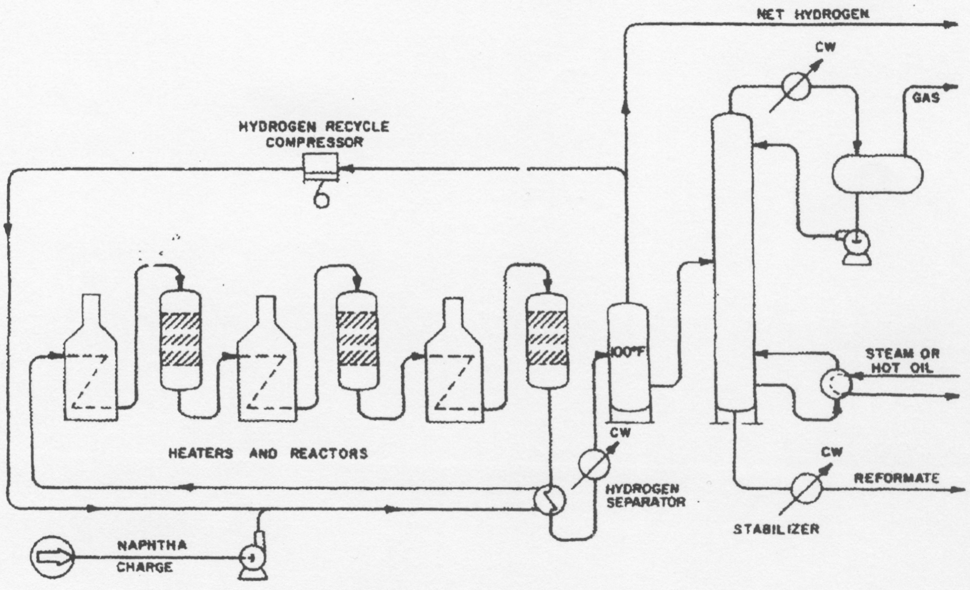
The gaseous products from the last heater are cooled and the products get condensed. The hydrogen rich gases are separated from the liquid stream which goes to a debutanizer tower (to be stabilized).

The hydrogen rich gas stream is split into hydrogen recycle stream and a net hydrogen by-product used for hydrotreating and hydrocracker operations or as fuel.

Operating pressures in the reformers range from 345 – 2415 kPa and the hydrogen charge ratios are in the range of 3 – 8 mol of Hydrogen per mol of feed.

## Feed Preparation

The active material in most catalytic reforming catalysts is platinum. Certain metals, hydrogen sulfide, ammonia, and organic and sulfur compounds will deactivate the catalyst. Feed pretreating, in the form of hydrotreating, is usually employed to remove these materials. The hydrotreater employs a cobalt-molybdenum catalyst to convert organic sulfur and nitrogen compounds to hydrogen sulfide and ammonia, which then are removed from the system with the unreacted hydrogen. The metals in the feed are retained by the hydrotreater catalyst. Hydrogen needed for the hydrotreater is obtained from the catalytic reformer. If the boiling range of the change stock must be changed, the feed is redistilled before being charged to the catalytic reformer.



Catalytic reforming, semiregenerative process.

**Figure 9.2 Semi-Regenerative Reforming process**

## 9.2.4 Catalytic Reforming Process Description (Continuous Process)

The equipment for the continuous process is designed to permit the removal and replacement of catalyst during normal operation. As a result, the catalyst can be regenerated continuously and maintained at a high activity. As coke lay down and thermodynamic equilibrium yields or reformate are both favored by low-pressure operation, the ability to maintain high catalyst activities by continuous catalyst regeneration is the major advantage of the continuous type of unit. This advantage has to be evaluated with respect to the higher capital costs and possible lower operating costs due to lower hydrogen recycle rates and pressures needed to keep coke lay down at an acceptable level.

The semi regenerative unit is at the other end of the spectrum and has the advantage of minimum capital costs. Regeneration requires the unit to be taken off-stream. Depending upon severity of operation, regeneration is required at intervals of 3 to 24 months. High hydrogen recycle rates and operating pressures are utilized to minimize coke lay down and consequent loss of catalyst activity.

The cyclic process is a compromise between these extremes and is characterized by having, a swing reactor in addition to those on-stream in which the catalyst can be regenerated without shutting the unit down. When the activity of the catalyst in one of the on-steam reactors drops below the desired level, this reactor is isolated from the system and replaced by the swing reactor. In the cyclic processes, regeneration is typically performed on a 24- or 48hour cycle. The catalyst in the replaced reactor is then regenerated by admitting hot air into the reactor to burn the carbon off the catalyst. After regeneration it is used to replace the next reactor needing regeneration. Because of these extra facilities, the cyclic processes are more expensive but offer the advantage of low-pressure operation and higher yield of reformate at the same severity.

The Platforming process can be obtained as a continuous, cyclic, or semi-regenerative operation and the other processes as either cyclic or semiregenerative. The Platforming, semiregenerative process is typical of reforming operations and will be described here.

A simplified process flow diagram of the Platforming process is given in Figure 9.3. The pretreated feed and recycle hydrogen are heated to 925 to 975 °F before entering the first reactor. In the first reactor, the major reaction is the dehydrogenation of naphthenes to aromatics and, as this is strongly endothermic, a large drop in temperature occurs. To maintain rate, the gases are reheated before being passed over the catalyst in the second reactor. As the charge proceeds through the reactors, the reaction rates decrease and the reactors become larger, and the reheat needed become less. Usually three reactors are sufficient to provide the desired degree of reaction and heaters are needed before each reactor to bring the mixture up to reaction temperature. In practice, either separate heaters can be used or one heater can contain several separate coils. The reaction mixture from the last reactor is cooled and the liquid products condensed. The hydrogen rich gases are separated from the liquid phase in a drum separator and the liquid from the separator is sent to fractionator to be debutanized.

The hydrogen-rich gas stream is split into hydrogen recycle stream and a net hydrogen by product which is used in hydrotreating or hydrocracking operations or as fuel.

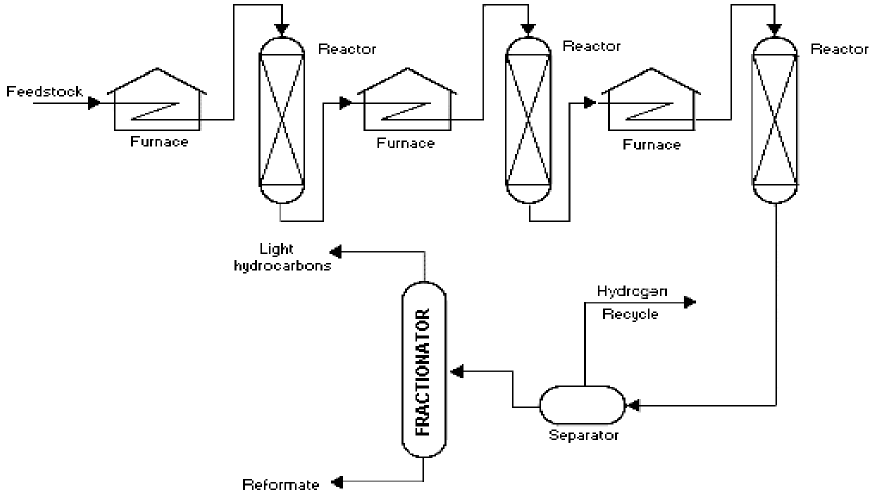


Figure 9.3 Platforming Unit

The reformer operating pressure and the hydrogen/feed ratio are compromises among obtaining maximum yields, long operating times between regenerations, and stable operation. It is usually necessary to operate at pressures from 200 to 500 psig and at hydrogen charge ratios of 4,000 to 8,000 scf/bbl fresh feed. Liquid hourly space velocities in the area of 2 to 3 are in general use.

## 9.2.5 Reforming Catalyst

All the reforming catalyst in general use today contains platinum supported on a silica or silica-aluminum base. In many cases rhenium is combined with platinum to form a more stable catalyst, which permits operation at lower pressures. Platinum is thought to serve as a catalytic site for hydrogenation and dehydrogenation reactions and chlorinated alumina provides an acid site for isomerization, cyclization, and hydrocracking reactions.

Reforming catalyst activity is a function of surface area, pore volume, and active platinum and chlorine content. Catalyst activity is reduced during operation by coke deposition and chloride loss. In a high pressure process, up to 200 barrels of charge can be processed per pound of catalyst before regeneration is needed. The activity of the catalyst can be restored by high temperature oxidation of the carbon followed by chlorination. This type of process is referred to as semiregenerative and able to operate for 6 to 24 month periods between regenerations.

The activity of the catalyst decreases during the on-stream period and the reaction temperature is increased as the catalyst ages to maintain the desired operating severity. Normally the catalyst can be regenerated at least three times before it has to be replaced and returned to the manufacturer for reclamation.

### Reactor Design

Reactors used for catalytic reforming vary in size and mechanical details, but all have basic features as shown on Figure 9.1. Very similar reactors are used also for hydrotreating, isomerization, and hydrocracking

## 9.3 CATALYTIC CRACKING

Catalytic cracking is the most important and widely used refinery process for converting heavy oil into more valuable gasoline and lighter products.

Catalytic cracking involves the breaking of large, low value molecules into smaller, high value molecules using high temperatures and catalyst.

The catalytic-cracking processes in use today can all be classified as either moving-bed or fluidized-bed units.

The thermofor catalytic-cracking process (TCC) is representative of the moving-bed units and the fluid catalytic cracker (FCC) of the fluidized-bed units.

The catalysts used in both processes are chemically similar and differ only in physical configuration.

The cracking process produces carbon (coke), which remains on the catalyst particle and rapidly lowers its activity.

To maintain the catalyst activity at a useful level, it is necessary to regenerate the catalyst by burning off this coke with air. As a result, the catalyst is continuously moved from reactor to regenerator and back to reactor.

The process flows (Figure 9.4) of both types of processes are similar. The hot oil feed is contacted with the catalyst in either the feed riser line or the reactor. As the cracking reaction progresses, the catalyst is progressively deactivated by the formation of coke on the surface of the catalyst. The catalyst and hydrocarbon vapors are separated mechanically and oil remaining on the catalyst is removed by steam stripping before the catalyst enters the regenerator. The oil vapors are taken overhead to a fractionation tower for separation into streams having the desired boiling ranges.

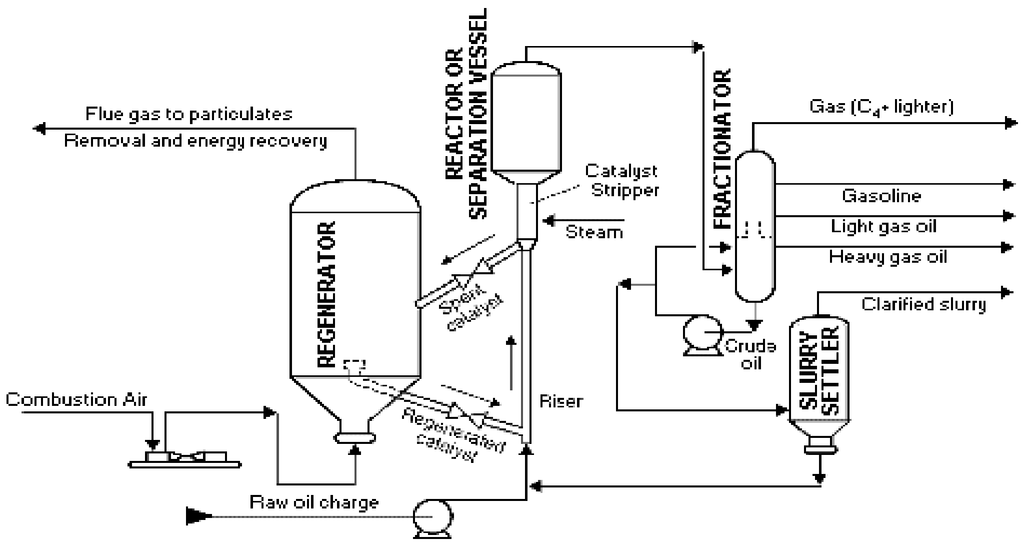


**Figure 9.4 Fluid Catalytic Cracking (FCC)**

The spent catalyst flows into the regenerator and is reactivated by burning off the coke deposits with air. Regenerator temperatures are carefully controlled to prevent catalyst deactivation by overheating. This is generally done by controlling the air flow to give a desired $CO_2$/CO ratio in the exit flue gases as the burning of CO to $CO_2$ does not remove coke from the catalyst but only produces excess heat.

Cyclone separators separate the flue gas and catalyst and the catalyst steam-stripped to remove adsorbed oxygen before the catalyst is contacted wit the oil feed.

## 9.3.1 Catalytic Cracking Reactions

a. High molecular weight paraffins are cracked to paraffins of low molecular weight and olefins.

Paraffins → Paraffins + Olefins

b. High molecular weight alkyl naphthenes are cracked to low molecular weight naphthenes and olefins.

Alkyl naphthenes → Naphthenes + Olefins

c. Alkyl aromatics are cracked according to the following equation:

Alkyl aromatics → Aromatics + Olefins

The products of the above mentioned reactions are subject to further cracking reactions which are simply summarized below:

Naphthenes → Aromatics + $H_2$
Olefins + $H_2$ → Paraffins
Olefins + Olefins + $H_2$ → Iso - paraffins
Olefins + Paraffins → Iso-paraffins
Iso-paraffins → Aromatics + $H_2$

Most of the above reactions products are in the range of gasoline ($C_5$ — $C_8$) which composed of high percentage of aromatics and iso-paraffins which have high octane number.

## 9.3.2 Catalytic Cracking Catalysts

Commercial cracking catalysts can be divided into three classes:

1. Acid-treated natural alumina silicates.
2. Amorphous synthetic silica-alumina combinations.
3. Crystalline synthetic silica-alumina catalysts called zeolites or molecular sieves.

Catalysts are handled in the form of (beads) or powder. Most catalysts used in commercial units today are either class (3) or mixtures of classes (2) and (3) catalysts.

The advantage of the zeolite catalysts over the natural and synthetic amorphous catalysts are:

1. Higher activity.
2. Higher gasoline yields at a given conversion.
3. Production of gasoline containing a larger percentage of paraffinic and aromatic hydrocarbons.
4. Lower coke yield (and therefore usually a larger throughput at a given conversion level).
5. Increased iso-butane production.
6. Ability to go to higher conversions per pass without over cracking.

The high activity of zeolitic cracking catalysts permits short residence time cracking and has resulted in many cracking units being adapted to riser cracking operations.

Basic nitrogen compounds, iron, nickel, vanadium and copper in the oil act as poisons to cracking catalysts.

### 9.3.3 Process Variables

In addition to the nature of the charges stock, the major operating variables affecting the conversion and product distribution are the cracking temperature, catalyst/oil ratio, space velocity, catalyst type and activity, and recycle ratio. For better understanding of the process, several terms should be defined.

***Activity:*** Ability to crack gas oil to lower boiling fractions.

***Catalyst/oil ratio*** = C/O = lb catalyst/lb feed.

***Conversion*** = $$100 \; \frac{(\text{Volume of feed — volume of cycle stock})}{\text{Volume of feed}}$$

***Cycle stock:*** Portion of catalytic- cracker effluent not converted to naphtha and lighter products (generally the material boiling above 430 °F).

***Efficiency*** = $$\frac{(\%\ \text{gasoline}) \times 100}{\%\ \text{conversion}}$$

***Recycle ratio*** = Volume recycle/volume fresh feed

***Selectivity:*** The ratio of the yield of desirable products to the yield of undesirable products (Coke and Gas).

***Space velocity:*** Space velocity may be defined on either a volume (LHVS) or a weight (WHSV) basis. In a fluidized-bed reactor, the LHSV has little meaning because it is difficult to establish the volume of the bed. The weight of the catalyst in the reactor can be easily determined or calculated from -the residence time and C/O ratio.

***LHSV***= liquid hour space velocity in volume feed / (volume catalyst) (hr).

***WHSV***= weight hour space velocity in lb feed / (lb catalyst) (hr). If it is the catalyst residence-time in hours, then WHSV = l/ (t) (C/O)

The general effects of the operating variables are the same for both the moving and fluidized-bed units but each type of unit has special limitations, which affect their importance. Within the limits of normal operations, increasing:

1. Reaction temperature.
2. Catalyst/oil ratio.
3. Catalyst activity

Feed for a catalytic cracker

- Straight run heavy gas oil (often called HAGO heavy atmospheric gas oil)
- Vacuum gas oils (HVGO and LVGO)

Feed to the cat reactor is at about 260-425°C. The hot catalyst in the reactor is at about 650 to 815°C and the reaction occurs at about 480-540°C.

When the molecules crack, there is a deficiency of hydrogen to fill the open spaces. This causes:

- Some coking (pure carbon molecules)
- Production of olefinic hydrocarbons: molecules such as ethylene, propylene and butylene.
- Large aromatics with side chains are broken where the side chain is attached.

The cracked product is separated from the catalyst and sent to a fractionator.

Coke on the catalyst must be burned off in a regenerator unit.

There are three main parts to a cat cracker system:

- Reactor (catalyst and hydrocarbon)
- Regenerator (catalyst and air)
- Fractionator (hydrocarbon separation)

# 9.4 HYDROCRACKING PROCESS

Hydrocracking process is one of the most versatile of all petroleum refining processes. Any fraction from naphtha to non-distillable can be processed, producing almost any desired product with a molecular weight lower than that of the charge stock At the same time, that hydrocracking takes place, sulfur, nitrogen, and oxygen are almost completely removed and olefins are saturated, thereby giving products that are a mixture of essentially pure paraffins, naphthenes and aromatics.

Hydrocracking is carried out at moderate temperatures and pressures over a fixed catalyst bed in which the fresh feed is cracked in hydrogen atmosphere.

Exact process conditions vary widely ending on the feedstock properties and the products desired. However, pressures usually range between 1500 and 3000 psig and temperature between 280 and 475 °C.

Following are some of the advantages of hydrocracking process:

1. Better balance of gasoline and distillate production.
2. Greater gasoline yield.
3. Improved gasoline pool octane quality and sensitivity.
4. Production of relatively high of isobutane in the butane fraction.

## 9.4.1 Hydrocracking Reactions

There are hundreds of simultaneous and complicated chemical reactions occurring during hydrocracking process. Main hydro cracking reactions are summarized as following:

(1) Cracking reactions:

$$\text{Paraffins, Naphthenes and aromatics of high molecular weight} \xrightarrow[\text{Cracking}]{\text{Heat, Catalyst}} \text{paraffins, naphthenes, aromatics of low molecular weight + olefins}$$

(2) Hydrogenation reactions:

$$\text{Olefins} + H_2 \xrightarrow[\text{(Saturation)}]{\text{Hydrogenation}} \text{Corresponding Paraffins + Heat}$$

(3) Isomerization reactions:

$$\text{Olefins+ low molecular weight paraffins} \xrightarrow[\text{Catalyst}]{H_2} \text{isoparaffins}$$

The above-mentioned reactions show that cracking and hydrogenation are complementary, for cracking provides olefins for hydrogenation, while hydrogenation in turn provides heat for cracking. The cracking reaction is endothermic and the hydrogenation reaction is exothermic. The reaction actually provides an excess of heat because the amount of heat released by the exothermic Hydrogenation reaction is much greater than the amount of heat consumed by the endothermic cracking reactions.

This surplus of heat causes the reactor temperature to increase and accelerate the reaction rate. Injecting cold hydrogen into the reactors to absorb the excess heat of reaction controls this.

## 9.4.2 Hydrocracking Catalysts

There is a number of hydrocracking catalysts available and the actual composition is tailored to the process, feed material, and the product desired. Most of the hydrocracking catalysts consist of crystalline mixture of silica-alumina with a small uniformly distributed amount of rare-earth metals. The Silica-alumina portion of the catalyst provides cracking activity while the rare-earth metals, encourage hydrogenation.

Almost, all hydrocracking catalyst use silica-alumina as the cracking base but the rare-earth metals vary according to the manufacturer. Those in most common use are Platinum (PE), Palladium (Pd), Nickel (Ni), and Tungsten (W).

## 9.4.3 Process Variables

### 9.4.3.1 Temperature

Reactor temperature is the primary means of conversion control at normal reactor conditions a 20 °F increase in temperature almost double the reaction rate but not affect the conversion level as much.

### 9.4.3.2 Reactor Pressure

The primary effect of reactor pressure is on its effects on the partial pressures of hydrogen and ammonia. Conversion increases with increasing hydrogen partial pressure and decreasing with increasing ammonia partial pressure. The hydrogen effect is greater, however, and the net effect of raising total partial pressure is to increase conversion.

### 9.4.3.3 Space Velocity

The volumetric space velocity is the ratio of liquid flow rate in barrels per hour to catalyst volume in barrels. The catalyst volume is constant; therefore the space velocity varies directly with feed rate. As the feed rate increases, the time of catalyst contact for each barrel of feed is decreased and conversion is lowered. In order to maintain conversion at the proper level when the feed rate is increased, it is necessary to increase the temperature.

### 9.4.3.4 Nitrogen Content

The organic nitrogen content of the feed is of great importance as the hydro-cracking catalyst is deactivated by contact with organic nitrogen compounds. An increase in organic nitrogen content of the feed causes a decrease in conversion.

### 9.4.3.5 Hydrogen Sulphide

Hydrocracking in the presence of a small amount of hydrogen sulphide normally produces a very low smoke point jet fuel. At high hydrogen sulphide levels corrosion of the equipment becomes important and the cracking activity of the catalyst is also affected adversely.

## 9.4.4 Fixed Bed Catalyst Process

There is a number of hydrocracking processes available for licensing. With the exception of the H-Oil and HY-C processes all hydrocracking processes in use today are fixed-bed catalytic processes with liquid down flow. The hydro cracking process may require either one or two stages, depending upon the process and the feedstocks used.

The process flows of most of the fixed-bed processes are similar and the Unicracking/JHC process will be described as a typical fixed-bed hydro cracking process.

The Unicracking/JHC process is a fixed-bed regenerative process employing a molecular-sieve catalyst impregnated with a rare-earth metal. The process employs cither single-stage (Figure 9.5) or two-stage (Figure 9.6) cracking with typical operating conditions ranging from 500 to 800 °F and from 1,000 to 2,000 psig. The temperature and pressure vary with the age of the catalyst, the product desired, and the properties of the feedstock.

The decision to use a single or two-stage system is dependent upon the size of the unit and the product desired. For most feedstocks the use of a single stage will permit the total conversion of the feed material to gasoline and lighter products by recycling the heavier material back to the reactor. The process flow for a two-stage reactor system is shown in Figure 9.6. If only one stage is used, the process flow is the same as for the second stage of the two-stage plant.

In a modem refinery, catalytic cracking and hydrocracking units work as a team. The catalytic cracker takes the more easily cracked paraffinic gas oils (from the atmospheric and vacuum towers) as feed. The hydrocracker, on the other hand, is capable to handle the more aromatic feedstocks (from the fractionators of the cat cracker and coking units), which are difficult to be processed in a cat cracker.

Hydrocrackers are excellent at helping to control the volumes of gasoline vs. diesel produced from a refinery. Thus a hydrocracking unit can be used to swing production to meet demand.

## The Process;

There are different hydrocracking processes, but the common units are fixed bed reactors filled with catalysts. Catalysts commonly employed are a mixture of crystalline silica-alumina with a small amount of rare earth metals (platinum, nickel, etc.) within the crystalline lattice. The silica-alumina (portion of the catalyst) causes the cracking reactions while the rare earth metals promote hydrogenation.

The fresh feed is mixed with makeup hydrogen and recycles gas (high in hydrogen content) and passed through a heater to the first reactor. The first stage reactor is operated at a sufficiently high temperature to convert 40 to 50 vol. % of the reactor effluent to material boiling below 400°F. The reactor effluent goes through heat exchangers to a high-pressure separator where the hydrogen rich gases are separated and recycled to the first stage for mixing both makeup hydrogen and fresh feed. The liquid product from the separator is sent to a distillation column where the gasoline and lighter fractions are taken overhead and the bottoms used as feed to the second stage reactor. If jet fuel or diesel fuel is one of the products desired, then the distillation column separation is made with the jet fuel or diesel fuel going overhead. The bottoms from the distillation column are mixed with recycle hydrogen and sent through a furnace to the second stage reactor. Here the temperature is maintained to bring the total conversion of the unconverted oil from the first stage and second stage recycles to 50 to 70 vol. % per pass. The second stage product is combined with the first stage product prior to fractionation.

Both the first and second stage reactors contain several beds of catalysts. The major reason for having separate beds is to provide locations for injecting cold recycled hydrogen into the reactors for temperature control. In addition, redistribution of the feed and hydrogen between the beds helps to maintain a more uniform utilization of the catalyst.

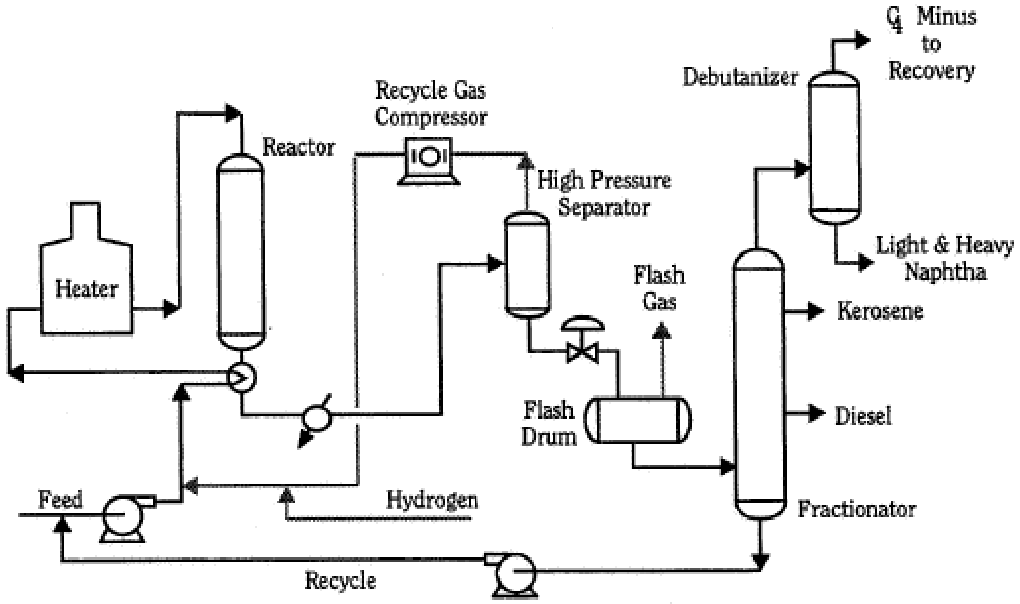


Figure 9.5 Single Stage Hydrocracking
(Once Through Operation)

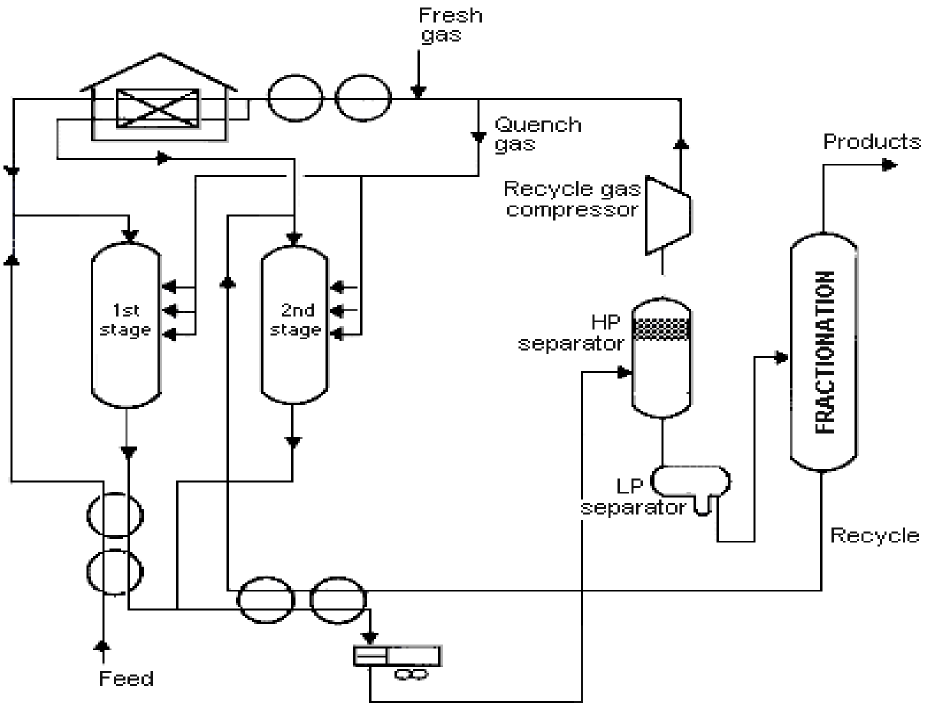


Figure 9.6 Schematic of a two-stage hydrocracking unit

| Process | Company |
|---|---|
| Isomax | Standard Oil Co. (Calif.) and UOP |
| Unicracking/JHC | Union Oil Co. and Esso Research and Engineering Co. |
| H-G hydrocracking | Gulf OH Co. and Houdry Process and Chemical Co. |
| Ultra cracking | Standard Oil C0. (Indiana) |
| Hy-C, H-Oil | Hydrocarbon Research, Inc, and Cities Service Research |
| Shell | Shell Development Co. |
| BASF-IFP hydrocracking | Badische Aniline and Soda Fabric, and Institute Francis Petrole |

Table 9.1 Hydrocracking Processes Available For License

### 9.4.5 Safety Considerations

Because this unit operates at very high pressures and temperatures, control of both hydrocarbon leaks and hydrogen releases is important to prevent fires. In some processes, care is needed to ensure that explosive concentrations of catalytic dust do not form during recharging. Inspection and testing of safety relief devices are important due to the very high pressures in this unit. Proper process control is needed to protect against plugging reactor beds. Unloading coked catalyst requires special precautions to prevent iron sulfide-induced fires. The coked catalyst should either be cooled to below 120° F before dumping, or be placed in nitrogen-inerted containers until cooled.

There is a potential for exposure to hydrocarbon gas and vapor emissions, hydrogen and hydrogen sulfide gas due to high-pressure leaks. Large quantities of carbon monoxide may be released during catalyst regeneration and changeover. Catalyst steam stripping and regeneration create waste streams containing sour water and ammonia.

### 9.4.6 Corrosion Considerations

Because of the operating temperatures and presence of hydrogen, the hydrogen sulfide content of the feedstock must be strictly controlled to a minimum to reduce the possibility of severe corrosion. Corrosion by wet carbon dioxide in areas of condensation also must be considered. When processing high-nitrogen feedstock, the ammonia and hydrogen sulfide form ammonium hydrosulfide (bisulfide), which causes serious corrosion at temperatures below the water dew point. Ammonium hydrosulfide is also present in sour water stripping.

## 9.5 THERMAL CRACKING

Thermal processing generally refers to those petroleum-refining processes, which change the molecular structure of hydrocarbons by application of heat without the use of catalysts. When thermal cracking process is based on cracking straight run fuel oil (bottom product of atmospheric distillation column) or vacuum diesel oil and tar (side and bottom streams of vacuum distillation column) under severe thermal conditions to produce desirable products e.g. gas oil, gasoline and coke, the process is called "delayed coking".

Visbreaking is another thermal cracking process used under mild thermal conditions to reduce the viscosity of straight run fuel oil without coke formation. The visbroken fuel oil is mainly used as fuel for furnaces.

## 9.5.1 Visbreaking

This is a mild thermal cracking operation used mainly to reduce the viscosity and pour points of vacuum reduced crudes. This process is often referred to as the poor man's cracker, because the cost of a visbreaker is quite less compared to catalytic cracking processes. By having a visbreaker process, a refinery can reduce the production of heavy fuel oil by 20 to 30 percent.

The main reactions that take place during visbreaking are:

1. Breaking off and cracking of side chains attached to cyclo-paraffins and aromatic rings.
2. Cracking of resinous materials to light hydrocarbons (mainly olefins).
3. Some cracking of naphthene rings (above 480 °C).

The amount of cracking in a visbreaker is limited, because too severe operation can make the resulting product unstable leading to formation of gummy materials by polymerization.

The product yield of a visbreaker for a sample of vacuum residue from Kuwaiti crude is shown below:

| | |
|---|---|
| • Butane and lighter products | 2.5 (wt %) |
| • $C_5$ – 180 °C naphtha | 5.9 (wt %) |
| • Gas oil, 320 °C EP | 13.5 (wt %) |
| • Tar | 78.1 (wt %) |

There are two types of visbreaker operations: coil and furnace cracking (Figure 9.6) and soaker cracking (Figure 9.7). Coil cracking uses higher furnace outlet temperatures (473 – 500 °C) and reaction times from one to three minutes, while soaker cracking uses lower furnace outlet temperatures (427 – 443 °C).

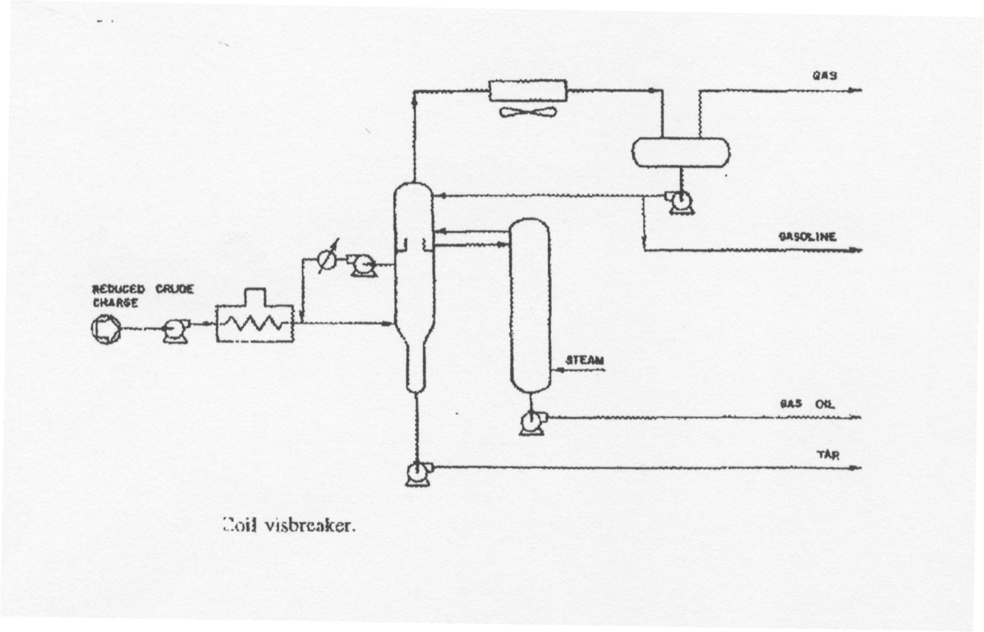


Figure 9.6 Coil Visbreaking

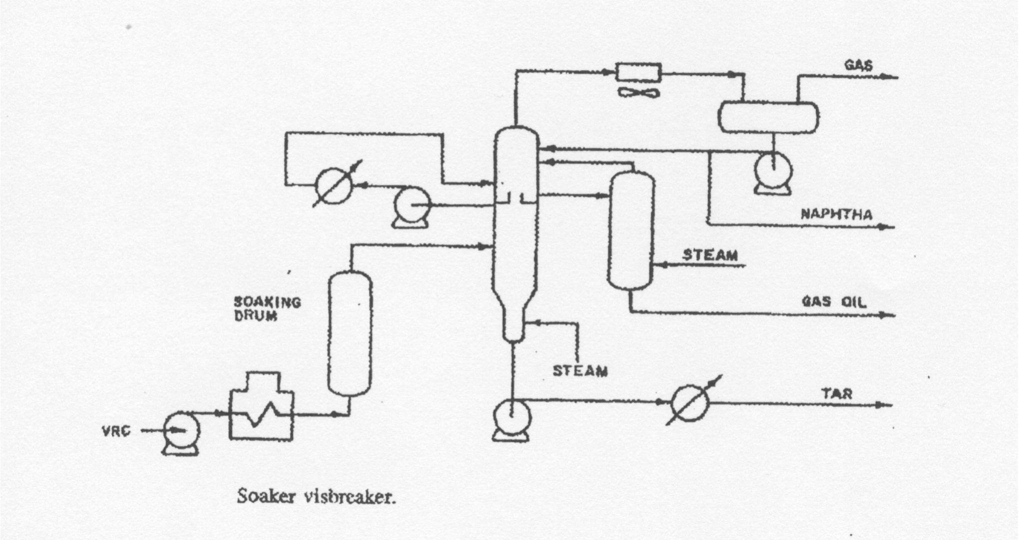


Figure 9.7 Soaker Visbreaking

## 9.5.2 Coking Processes

Coking units convert heavy feedstocks into a solid coke and lighter molecules. Processing of heavier crudes and lack of fuel oil market for heavy residual oil is forcing more utilization of cokers.

The feed to the coking unit is vacuum reduced crude and cat cracker fractionator bottoms of all the coking processes, **delayed coking** is the most popular one. **Fluid coking** and **Flexicoking** are two other common coking processes.

### 9.5.2.1 Delayed Coking

The name for this process comes from the process of heating the feed in a very high velocity stream. It reaches coking temperature without cracking. The cracking occurs in the next vessel, so the process is considered delayed coking.

Hot fresh liquid feed is charged to the fractionator tower above the bottom of the vapor zone. Liquids from the feed and molecules condensed from the vapor enter a furnace at a high velocity.

In the furnace the feed is heated to 500°C and enters the coke drum where the coking takes place. Heavy molecules crack to form light molecules and pure carbon coke solid. When the coke drum is nearly full, feed is switched to the next drum while the coke is removed from this one.

Light hydrocarbons (gas oil, naphtha and light ends) leave the top of the coke drum and enter the fractionator as a vapor stream. The vapor contacts the incoming feed, which cools the vapor and prevents further cracking.

The feed is heated and stripped of light ends.
Coke drum reaction vapor is cooled and heavy ends are condensed.
The fractionator separates the gas oils, naphtha and light ends.

The cokes formed in the delayed coking process are of different types (sponge coke, needle coke) and are used for graphite manufacture, electrodes, and other chemicals.

Typical yields from a delayed coker:

| | |
|---|---|
| • Coke | 45.76 (wt %) |
| • Gas (Butanes and lower) | 11.92 (wt %) |
| • Naphtha | 20.50 (wt %) |
| • Gas oil | 21.82 (wt %) |

### 9.5.2.2 Flexicoking and Fluid Coking

In the Flexicoking process, the feed (e.g. vacuum residue) is preheated to about 315-370 °C and sprayed into the reactor where it contacts a hot fluidized bed of coke particles (T = 510 to 540 °C ). These hot coke particles is recycled to the reactor from the coke heater at a rate sufficient to maintain the reactor bed temperature. The coke recycle from the heater thus provides sensible heat, heat of vaporization for the feed, and the endothermic heat for the cracking reactions.

The cracked vapor products pass through cyclone separators in the top of the reactor vessel (to separate the entrained coke particles), and are then quenched in the scrubber vessel located at the top of the vessel. Some of the high-boiling (> 495 °C) vapors are condensed in the scrubber and are recycled back to the reactor.

The balance of the cracked vapors flow to the coker fractionator where the various cuts are separated.

The coke produced by the cracking process is deposited as thin films onto the of the existing coke particles in the reactor fluidized bed. The coke is steam-stripped in the baffled section at the bottom part of the reactor to prevent reaction products, other than coke to leave the reactor.

The coke particles flow from the reactor to the heater where they are heated to about 593 °C. The coke heater is also a fluidized bed and its primary function is to transfer heat from the gasifier to the reactor.

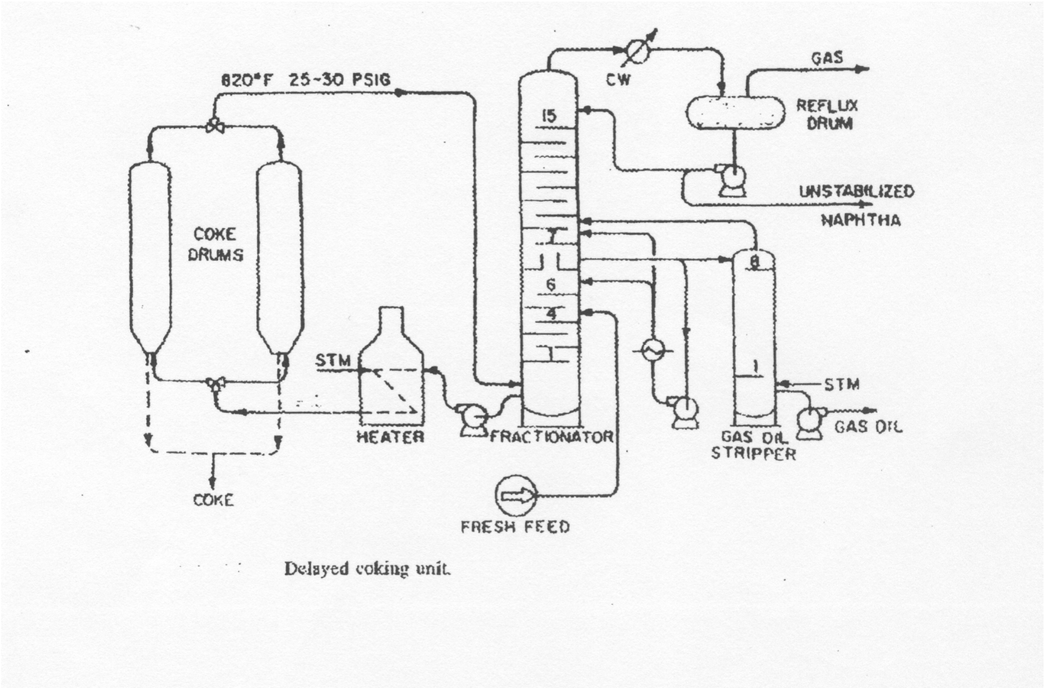
Some coke particles flow from the coke heater to a third fluidized bed (gasifier) where it is reacted with air and steam to produce a fuel gas product consisting of CO, $H_2$, $CO_2$, and $N_2$. Sulfur in the coke is converted mainly to $H_2S$ and nitrogen to $NH_3$. This gas flows from the top of the gasifier to the bottom of the heater where it fluidizes the heater bed and provides the heat needed in the reactor. The heat requirement is also supplemented by the recirculating hot coke particles from the gasifier to the heater. Approximately 60 to 90 % of the coke produced in the reactor is gasified in the gasifier.

### 9.5.2.3 Fluid coking

Fluid coking is a simplified version of the flexicoking process. In this process, only enough coke is burned to satisfy the heat requirements of the reactor and the feed preheat. Generally, this means burning 20 to 25 percent of the coke produced in the reactor. The balance of the coke is withdrawn from the burner vessel and is not gasified as in the flexicoker. As a result, only two fluid beds are used in a fluid coker a reactor and a burner (which replaces the heater).

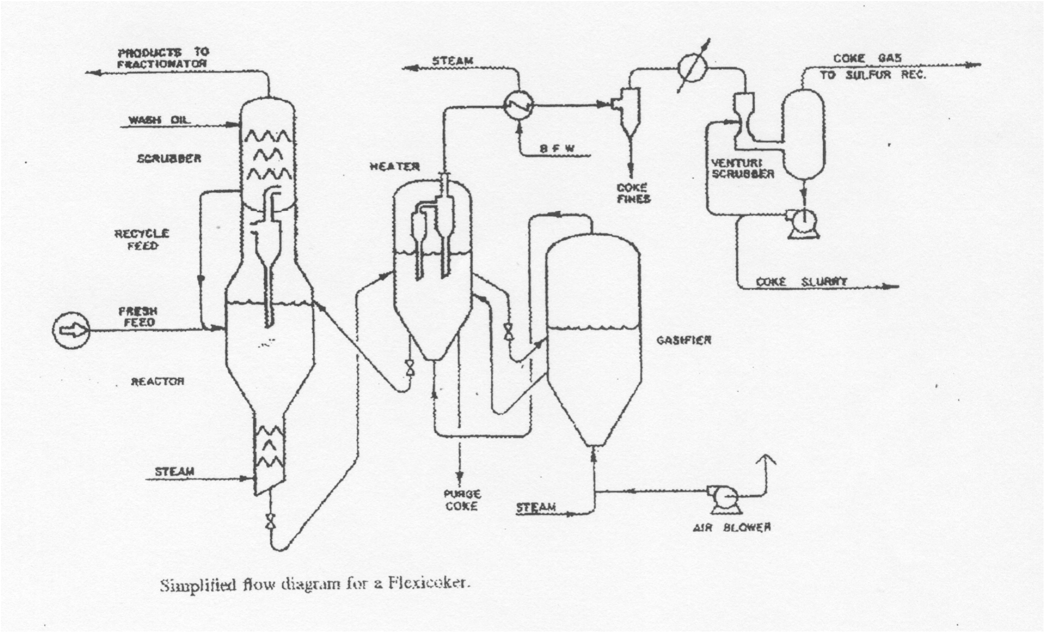
Typical yields of the two processes are as follows:

| | **Flexicoking (wt %)** | **Fluid Coking (wt %)** |
|---|---|---|
| **Gas** | 11.8 | 11.8 |
| **Light naphtha** | 1.9 | 1.9 |
| **Heavy naphtha** | 7.8 | 7.8 |
| **Gas oil** | 50.4 | 50.4 |
| **Gross coke** | 28.1 | 28.1 |
| **Total** | 100.0 | 100.0 |
| **Net coke** | 22.4 | 2.3 |



Delayed coking unit.

**Figure 9.8 Delayed Coking Unit**



Simplified flow diagram for a Flexicoker.

**Figure 9.9 Simplified Flow Diagram for a Flexicoker**

# 9.6 ISOMERIZATION

## 9.6.1 Introduction

The light straight run gasoline "LSR" ($C_5$-180 °F.) can have its octane number improved by the use of an isomerization process to convert normal paraffins in to their isomers. This results in a significant octane increase as n-pentane has an unleaded RON of 61.7 and isopentane has a rating of 92.3 in once-through isomerization the unleaded RON of LSR gasoline can be increased from 70-84.

## 9.6.2 Methods of Isomerization

There are two methods used to perform isomerization depending on the feedstock state.

a. **Vapor-Phase Isomerization Process**
   In this case feed stock in vapor state. This method is used for the isomerization of normal butane (n-$C_4$) to isobutene (i-butane), which is used as a feedstock for alkylation unit.

b. **Liquid Phase Isomerization Process**

### 9.6.2.1 Butane Isomerization Process

The isomerization reaction of paraffins and olefins have been known for a long lime, but the reaction was not considered to be important, until the higher octane number of branched chain hydrocarbon compared with the straight chain types was realized. The reaction become important when the reactivity of iso-butane for alkylate production was realized, and it was found that large quantities of normal butane were available.

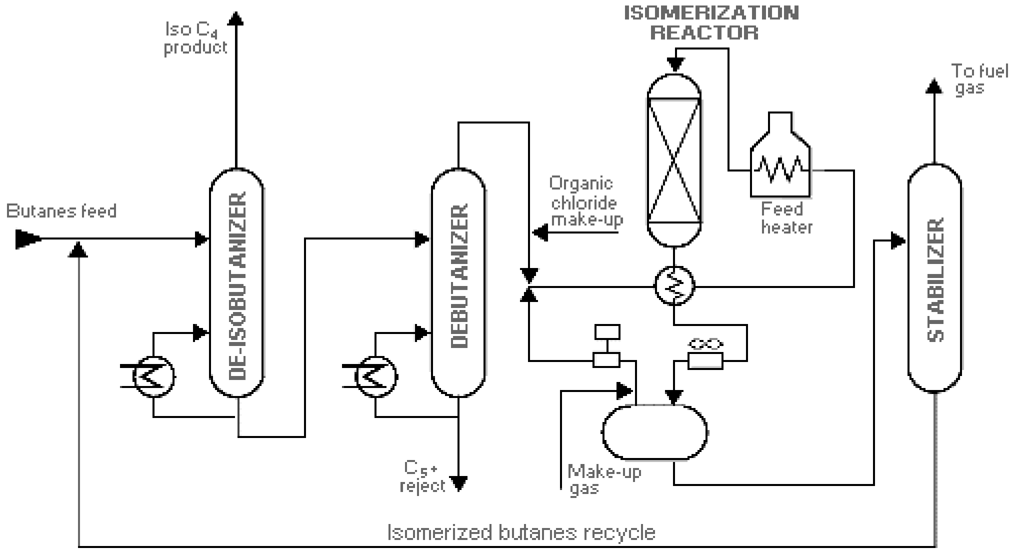


Figure 9.11 Butane Isomerization

The most efficient catalyst for isomerization of n-butane to iso butane is a mixture of aluminium chloride and hydrogen chloride. The reaction is carried out at about 200 °F and under a pressure of 150 to 500 psi. Under these conditions the butane is liquid and is passed in part, through an aluminium chloride saturator, in which it dissolves some catalyst for effecting conversion in the succeeding reactor, hydrogen chloride being introduced to promote the reaction. Sludge containing aluminium chloride and heavy hydrocarbons is withdrawn from the bottom of the reactor, whilst vapour containing light hydrocarbons, aluminium chloride and hydrogen chloride passes to an aluminium chloride fractionator, from which n-butane and aluminum chloride is withdrawn from the base and returned to the top of the reactor. The vapours containing iso-butane and some n-butane, and hydrogen chloride are condensed and passed to a hydrogen chloride stripping column, where the hydrogen chloride is removed and returned to the process. The hydrocarbons are then soda-washed, to remove any remaining acid, and finally fractionated to obtain the iso-butane.

### 9.6.2.2 Pentane Isomerization Process

Normal paraffins hydrocarbons heavier than butane can also be isomerized using a similar process and catalyst, other catalyst containing aluminium chloride are also used, e.g., aluminium chloride in antimony trichloride. The isomerization of Pentane-Hexane mixtures is practiced commercially, by introducing the hydrocarbons containing hydrogen into a mixture aluminium chloride and hydrocarbons. Temperatures of 220° to 250°F and pressure of 650 to 750 psi are normally used. The product is known as "isomerate" and must be fractionated to give the isomerized pentanes and hexanes.

As the molecular weight of the normal subject to isomerization is increased, there is a tendency for cracking of the molecules to occur with the formation of lower molecular weight iso-paraffins. There is also a tendency to form olefins, which Polymerize to large molecules than are desired.

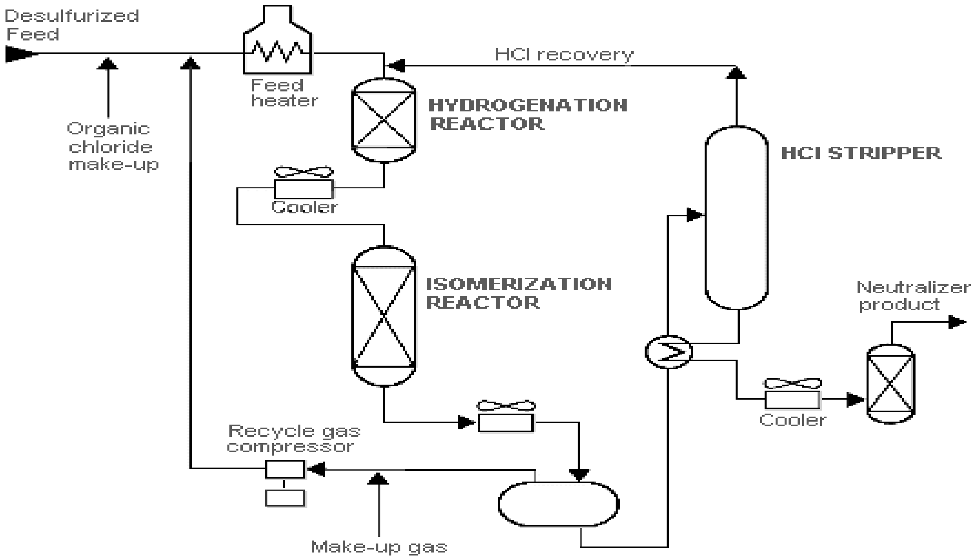


Figure 9.12 Pentane/Hexane Isomerization

# 9.7 ALKYLATION PROCESS

## 9.7.1 Introduction

Alkylation combines low-molecular-weight olefins (primarily a mixture of propylene and butylene) with isobutene in the presence of a catalyst, either sulfuric acid or hydrofluoric acid. The product is called alkylate and is composed of a mixture of high-octane, branched-chain paraffinic hydrocarbons. Alkylate is a premium blending stock because it has exceptional antiknock properties and is clean burning. The octane number of alkylate depends mainly upon the kind of olefins used and upon operating conditions.

## 9.7.2 Sulfuric Acid Alkylation Process

In cascade type sulfuric acid ($H_2SO_4$) alkylation units (Figure 9.13), the feedstock (propylene, butylene, amylene, and fresh isobutane) enters the reactor and contacts the concentrated sulfuric acid catalyst (in concentrations of 85% to 95% for good operation and to minimize corrosion). The reactor is divided into zones, with olefins fed through distributors to each zone, and the sulfuric acid and isobutanes flowing over baffles from zone to zone.

The reactor effluent is separated into hydrocarbon and acid phases in a settler, and the acid is returned to the reactor. The hydrocarbon phase is hot-water washed with caustic for pH control before being successively depropanized, deisobutanized, and debutanized. Alkylate obtained from the deisobutanizer can then go directly to motor-fuel blending or be rerun to produce aviation-grade blending stock. The isobutane is recycled to the feed.

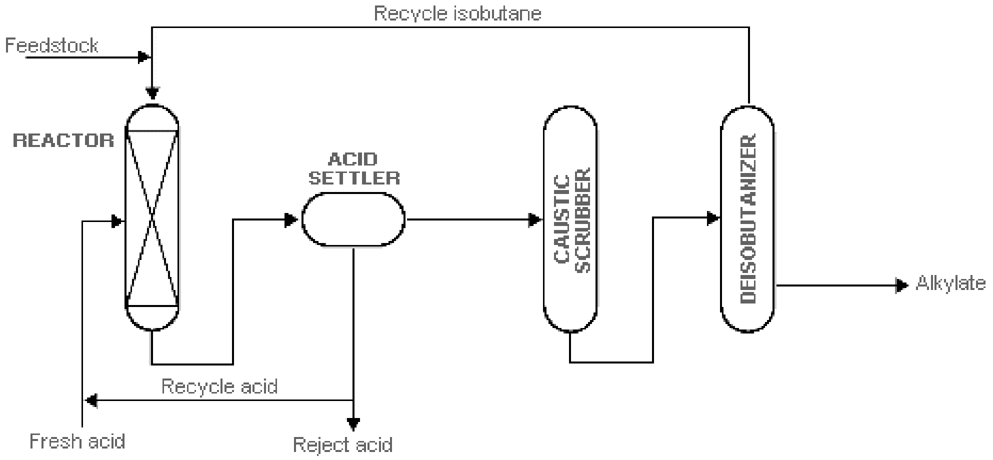


Figure 9.13 **Schematic of sulfuric acid alkylation process**

## 9.7.3 Hydrofluoric Acid Alkylation Process

Phillips and UOP are the two common types of hydrofluoric acid alkylation processes in use.

### 9.7.3.1 Phillips Process

In the Phillips process, olefin and isobutane feedstock are dried and fed to a combination reactor/settler system. Upon leaving the reaction zone, the reactor effluent flows to a settler (separating vessel) where the acid separates from the hydrocarbons. The acid layer at the bottom of the separating vessel is recycled. The top layer of hydrocarbons (hydrocarbon phase), consisting of propane, normal butane, alkylate, and excess (recycle) isobutane, is charged to the main fractionator, the bottom product of which is motor alkylate. The main fractionator overhead, consisting mainly of propane, isobutane, and HF, goes to a depropanizer. Propane with trace amount of HF goes to an HF stripper for HF removal and is then catalytically defluorinated, treated, and sent to storage. Isobutane is withdrawn from the main fractionator and recycled to the reactor/settler, and alkylate from the bottom of the main fractionator is sent to product blending.

### 9.7.3.2 UOP Process

The UOP process uses two reactors with separate settlers. Half of the dried feedstock is charged to the first reactor, along with recycle and makeup isobutane. The reactor effluent then goes to its settler, where the acid is recycled and the hydrocarbon charged to the second reactor. The other half of the feedstock also goes to the second reactor, with the settler acid being recycled and the hydrocarbons charged to the main fractionator. Subsequent processing is similar to the Phillips process. Overhead from the main fractionator goes to a depropanizer. Isobutane is recycled to the reaction zone and alkylate is sent to product blending.

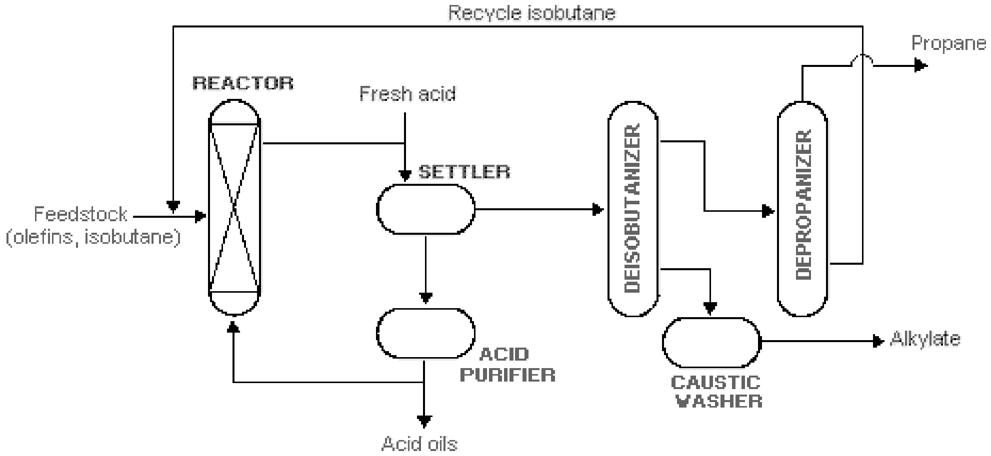
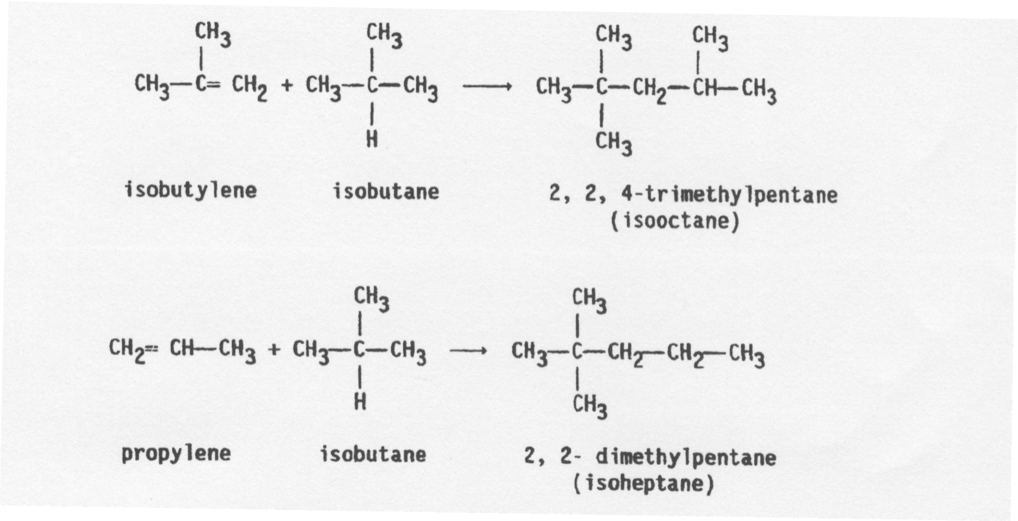


Figure 9.14 Schematic of hydrogen fluoride alkylation

Besides manufacturing plenty of high octane gasoline, a catalytic cracking unit also produces a large number of smaller molecules like propylene and butylene.

The "alky" plant takes 2 olefins, propylene and butylene and reacts them with isobutane to form an iso-paraffin called alkylate.



The total volume of materials entering the alkylation process is greater than the volume of products out. This is because larger molecules are produced from the smaller varieties.

The catalysts used in the Alkylation unit to facilitate the reactions are either:

- Sulphuric acid ($H_2SO_4$), or
- Hydroflouric acid (HF acid).

**Alkylate Product**

- Boiling range is controlled to gasoline specifications.
- The API gravity is about 70
- It is high in octane. MON 88-94, RON 94-99.
- Alkylate is blended with LSR Naphtha (gasoline) to produce higher octane gasoline.

### 9.7.4 Safety & Corrosion Considerations

Sulfuric acid and hydrofluoric acid are potentially hazardous chemicals. Loss of coolant water, which is needed to maintain process temperatures, could result in an upset. Precautions are necessary to ensure that equipment and materials that have been in contact with acid are handled carefully and are thoroughly cleaned before they leave the process area or refinery. Immersion wash vats are often provided for neutralization of equipment that has come into contact with hydrofluoric acid. Hydrofluoric acid units should be thoroughly drained and chemically cleaned prior to turnarounds and entry to remove all traces of iron fluoride and hydro-fluoric acid. Following shutdown, where water has been used the unit should be thoroughly dried before hydrofluoric acid is introduced.

Leaks, spills, or releases involving hydrofluoric acid or hydrocarbons containing hydrofluoric acid can be extremely hazardous. Care during delivery and unloading of acid is essential. Process unit containment by curbs, drainage, and isolation so that effluent can be neutralized before release to the sewer system is considered. Vents can be routed to soda-ash scrubbers to neutralize hydrogen fluoride gas or hydrofluoric acid vapors before release. Pressure on the cooling water and steam side of exchangers should be kept below the minimum pressure on the acid service side to prevent water contamination.

Some corrosion and fouling in sulfuric acid units may occur from the breakdown of sulfuric acid esters or where caustic is added for neutralization. These esters can be removed by fresh acid treating and hot-water washing. To prevent corrosion from hydrofluoric acid, the acid concentration inside the process unit should be maintained above 65% and moisture below 4%.

## 9.8 POLYMERIZATION

Polymerization in the petroleum industry is the process of converting light olefin gases including ethylene, propylene, and butylene into hydrocarbons of higher molecular weight and higher octane number that can be used as gasoline blending stocks. Polymerization combines two or more identical olefin molecules to form a single molecule with the same elements in the same proportions as the original molecules. Polymerization may be accomplished thermally or in the presence of a catalyst at lower temperatures.

### 9.8.1 The Process

The olefin feedstock is pretreated to remove sulfur and other undesirable compounds. In the catalytic process the feedstock is either passed over a solid phosphoric acid catalyst or comes in contact with liquid phosphoric acid, where an exothermic polymeric reaction occurs. This reaction requires cooling water and the injection of cold feedstock into the reactor to control temperatures between 300 and 450 °F at pressures from 200 psi to 1,200 psi. The reaction products leaving the reactor are sent to stabilization and/or fractionator systems to separate saturated and unreacted gases from the polymer gasoline product.

Polymerization is used in the petroleum industry to indicate the production of gasoline components, hence the term "polymer" gasoline. Furthermore, it is not essential that only one type of monomer be involved. If unlike olefin molecules are combined, the process is referred to as "copolymerization." Polymerization in the true sense of the word is normally prevented, and all attempts are made to terminate the reaction at the dimer or trimer (three monomers joined together) stage. However, in the petrochemical section of a refinery, polymerization, which results in the production of, for instance, polyethylene, is allowed to proceed until materials of the required high molecular weight have been produced.

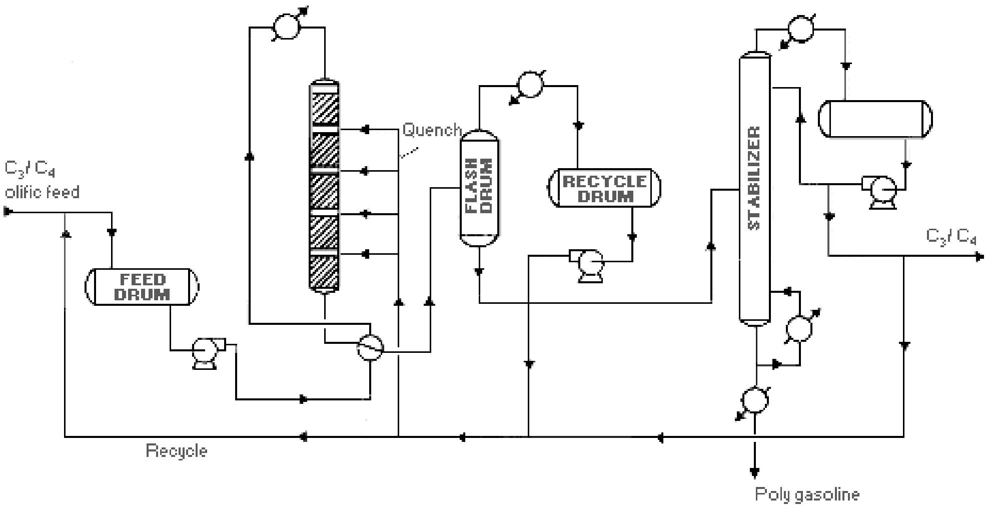


Figure 9.15 Schematic of polymerization Process

## 9.8.2 Safety & Corrosion Considerations

The potential for an uncontrolled exothermic reaction exists should loss of cooling water occur. Severe corrosion leading to equipment failure will occur should water make contact with the phosphoric acid, such as during water washing at shutdowns. Corrosion may also occur in piping manifolds, reboilers, exchangers, and other locations where acid may settle out. There is a potential for exposure to caustic wash (sodium hydroxide), to phosphoric acid used in the process or washed out during turnarounds, and to catalyst dust.