Basic Production Technology in Oilfield

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DSc Dževad Hadžihafizović (DEng)

Sarajevo 2024

Basic Production Technology

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Chapter 1

Wellhead, Flow Line and Inlet Manifold

1.1 WELLHEAD AND FLOW CONTROL EQUIPMENT

1.1.1 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.

1.1.2 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.

1.1.2.1 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.

1.1.2.2 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.

1.1.2.3 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.

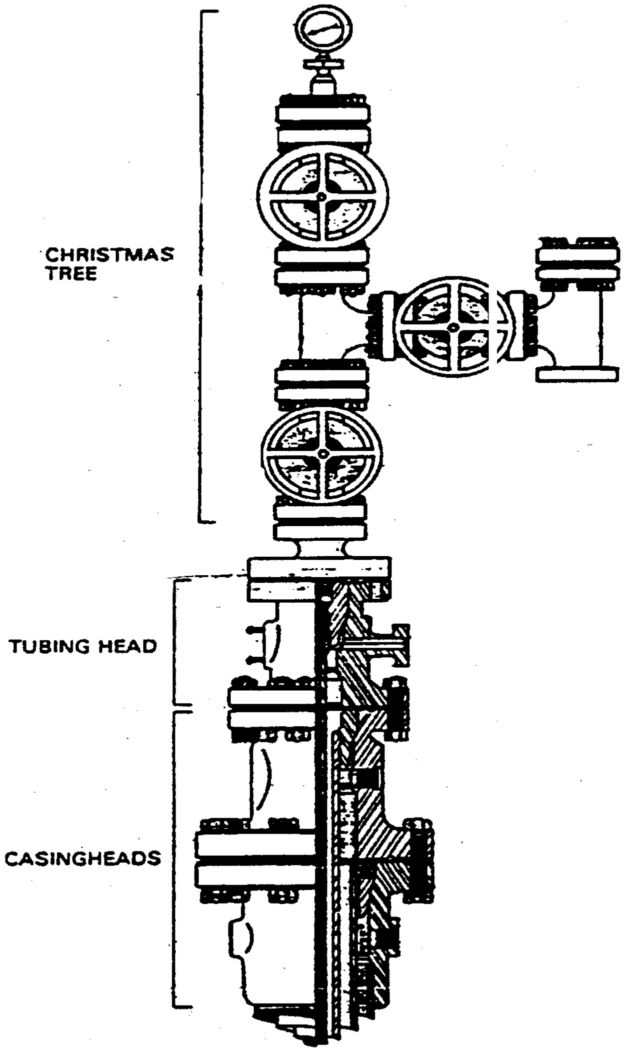


Figure 5.1 A Typical Wellhead

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.

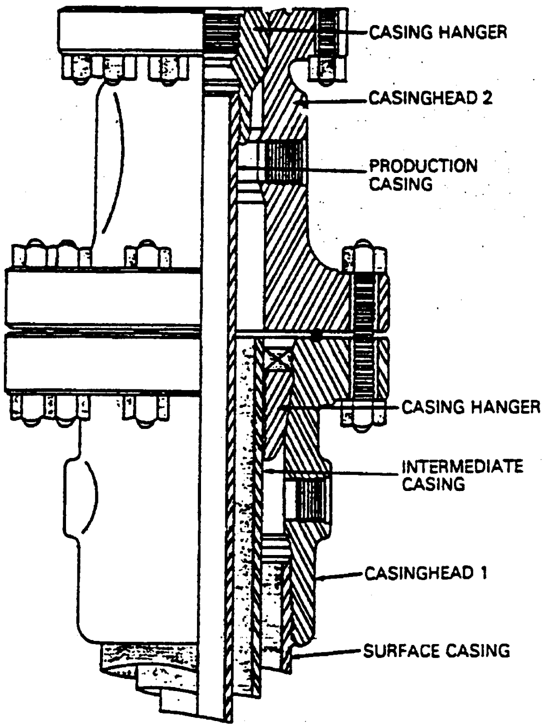


Figure 5.2 Casing Head

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.

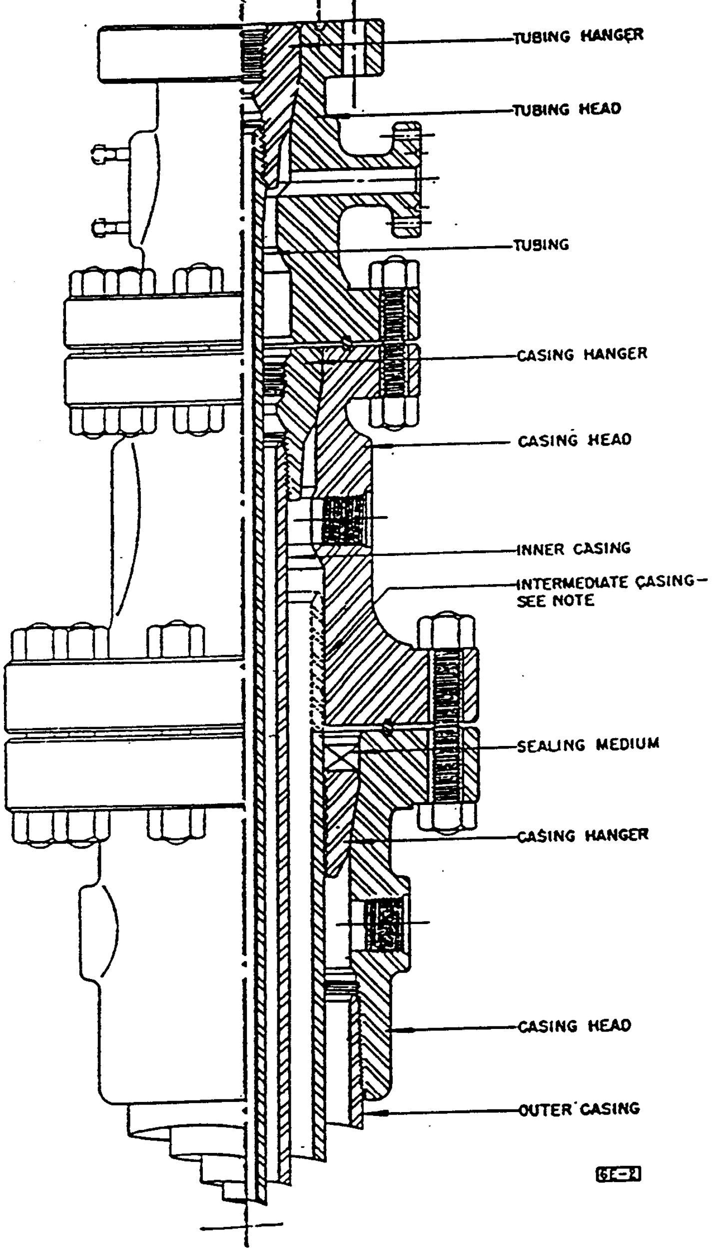


Figure 5.3 Tubing Head

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.

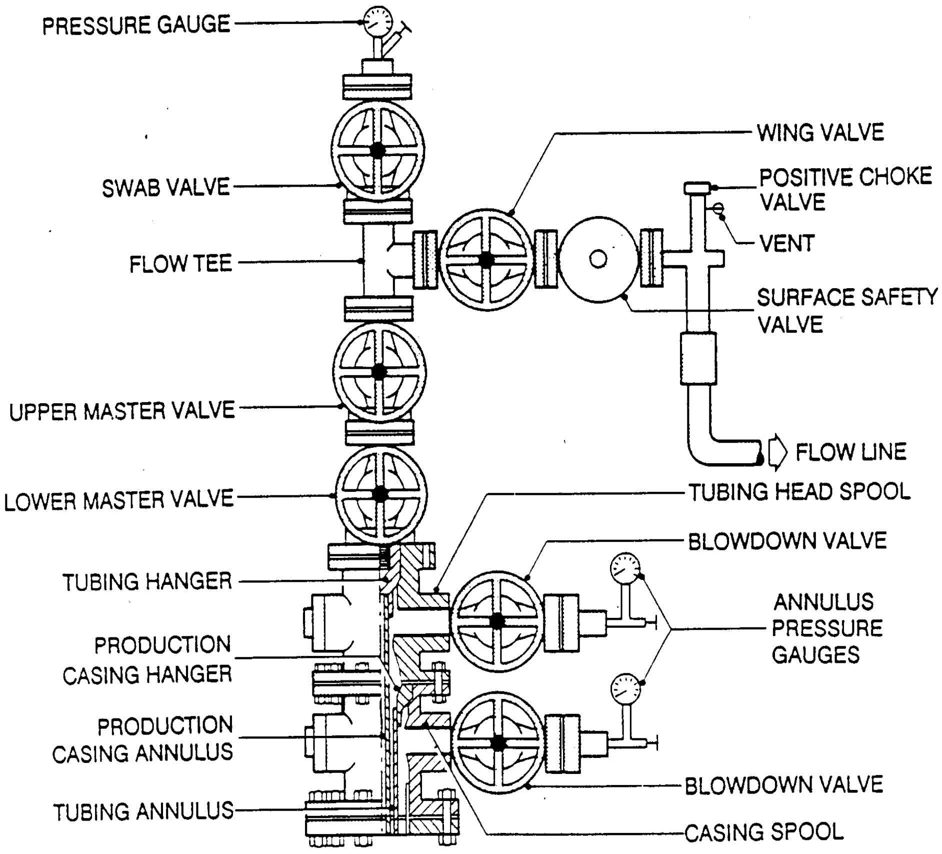


Figure 5.4 Typical Single Christmas Tree

1.1.3 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.

1.1.3.1 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.

1.1.3.2 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.

1.1.3.3 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.

1.1.3.4 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.

1.1.3.5 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.

1.1.3.6 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.

1.1.3.7 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.

1.1.3.8 Tubing Pressure Gauge

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

1.1.3.9 Casing Pressure Gauge

Measures pressure in the tubing annulus.

1.1.4 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.

1.1.4.1 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.

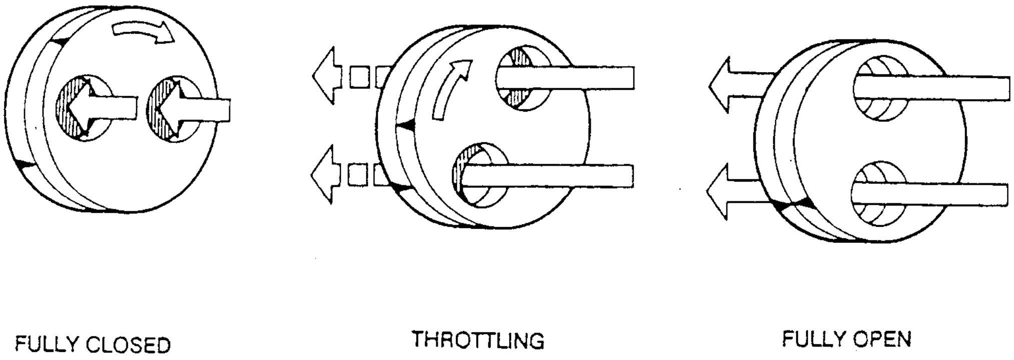


Figure 5.5 Willis Choke

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.

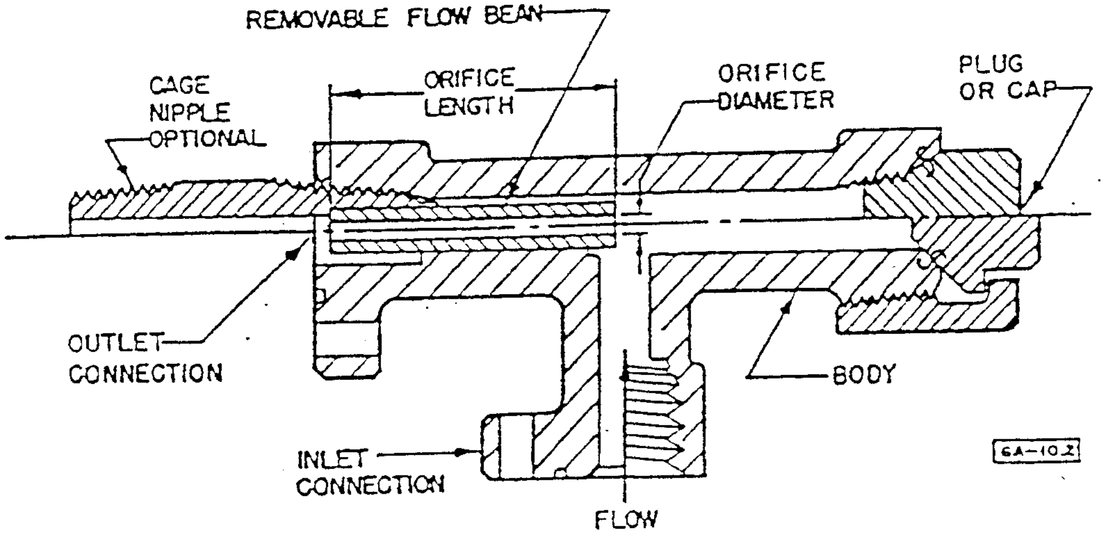


Figure 5.6 Positive Choke

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.

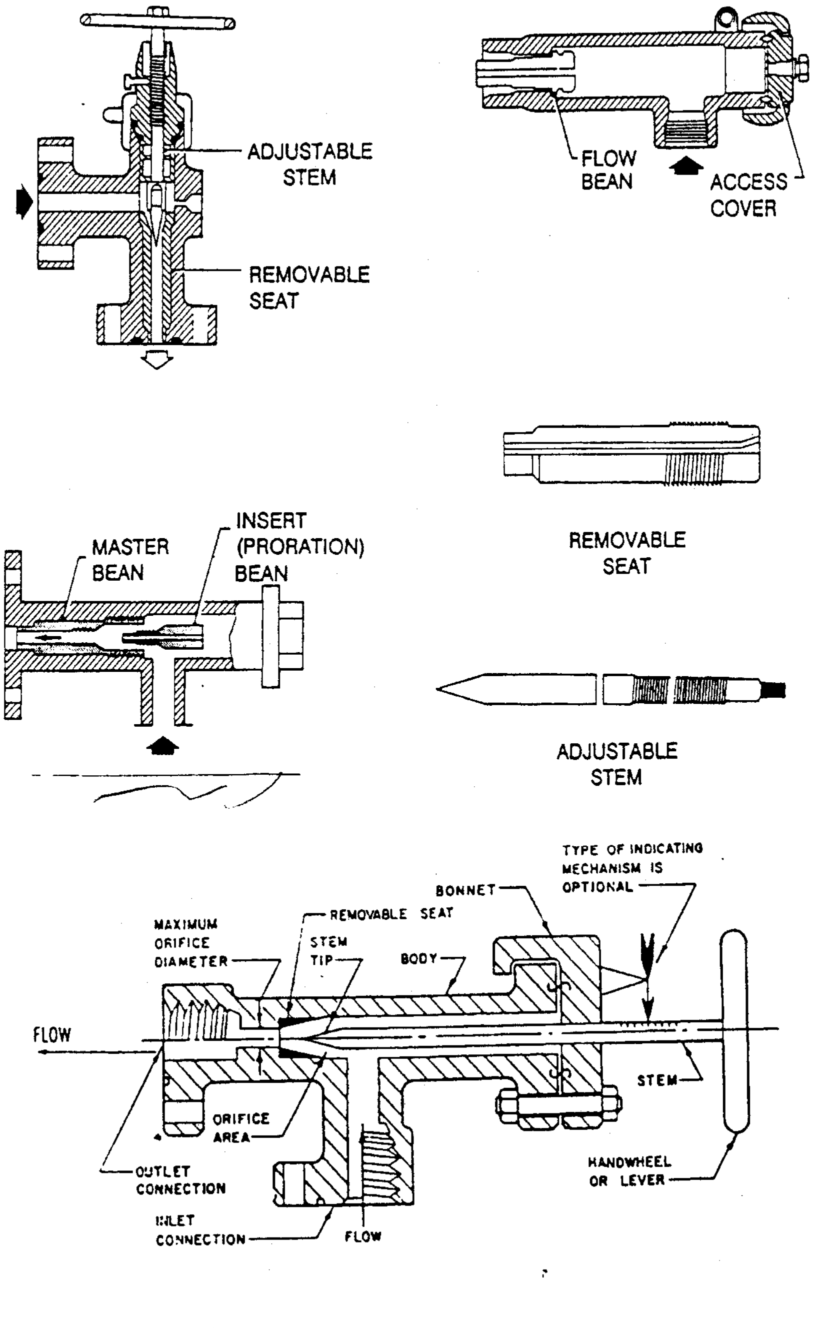


Figure 5.7 Adjustable Choke

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.

1.1.4.2 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.

1.1.4.3 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 (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/ annum = 48400.456 metric tons/annum

= 48.4 MT/annum (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.

1.1.5 Well Control (Protection)

1.1.5.1 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.

1.1.5.2 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.

1.1.5.3 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.

1.1.5.3.1 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.

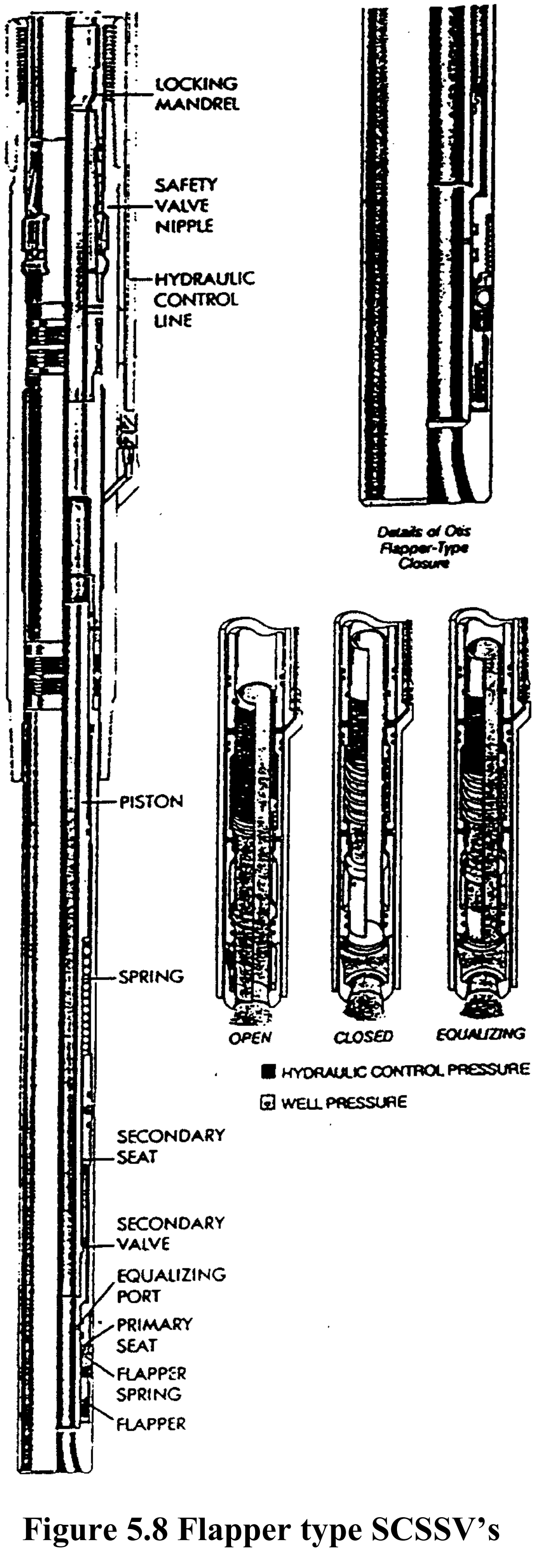


Figure 5.8 Flapper type SCSSV's

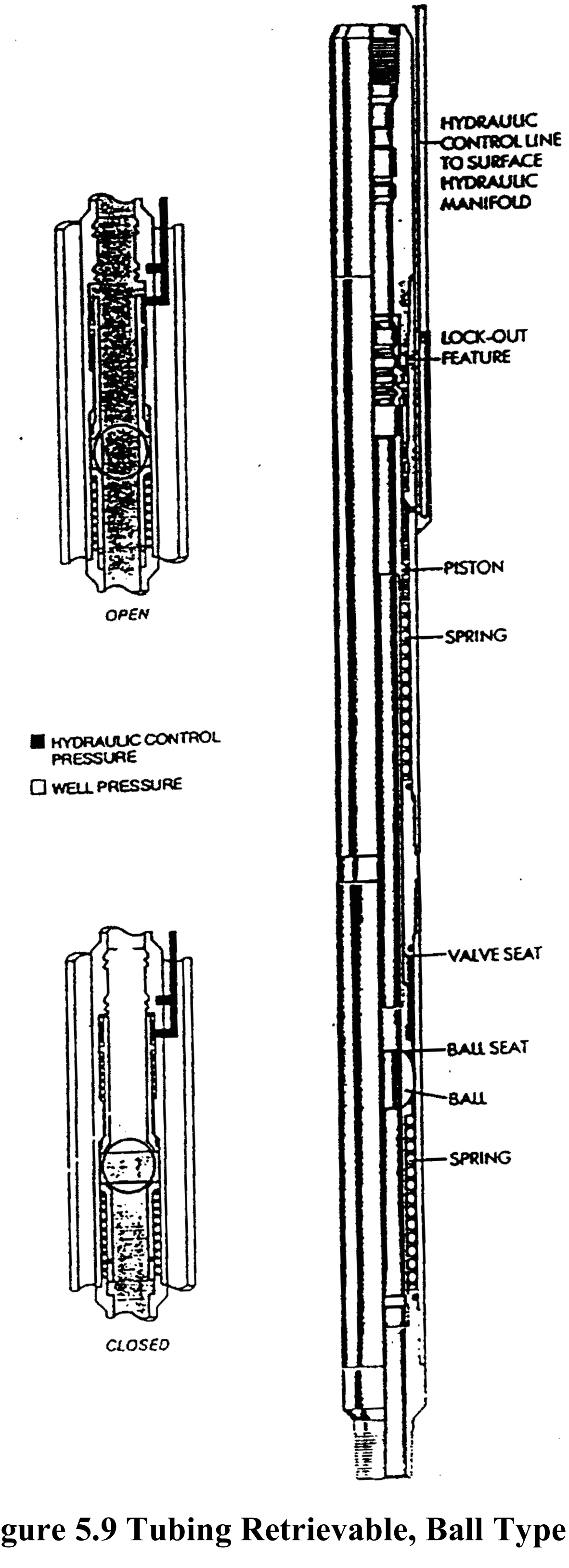


Figure 5.9 Tubing Retrievable, Ball Type SC-SSSV

1.1.5.3.2 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.

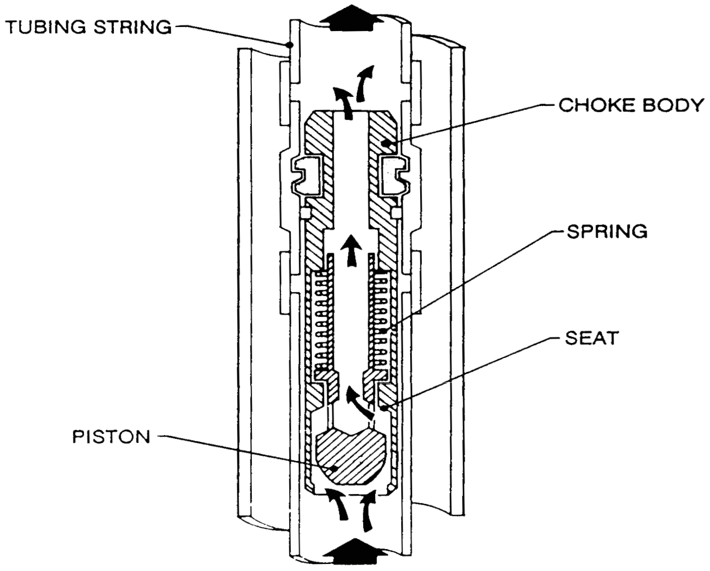


Figure 5.10 Storm Choke

1.2 FLOW LINES

1.2.1 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.

1.2.2 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.

1.3 INLET MANIFOLDS

1.3.1 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.

1.3.2 Manifold Headers and Their Functions (Figure 5.11)

1.3.2.1 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.

1.3.2.2 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.

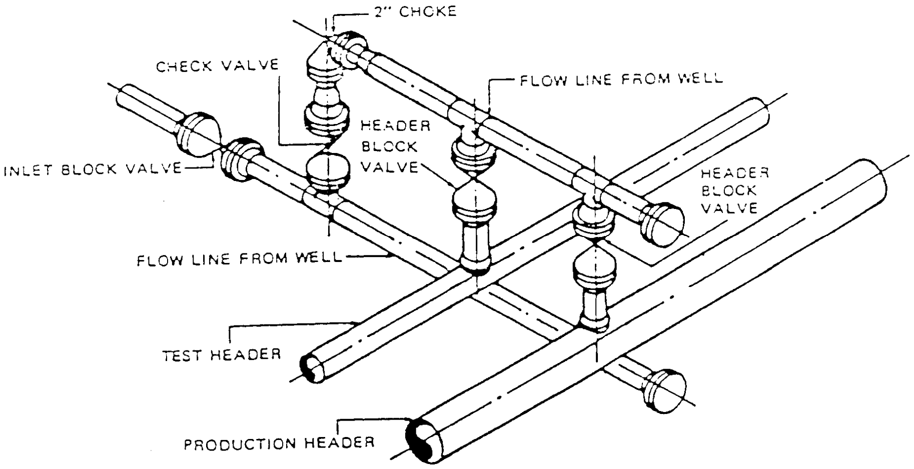


Figure 5.11 Basic Elements of a Manifold

1.3.2.3 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.

1.3.2.4 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.

1.3.2.5 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.

1.3.3 Inlet Manifold Components (Figure 5.11)

1.3.3.1 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.

1.3.3.2 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.

1.3.3.3 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.

1.3.3.4 Instruments

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

1.3.3.5 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 2

Gas Liquid Separation

Chapter 2 Contents

Chapter 2

Gas Liquid Separation

2.1 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.

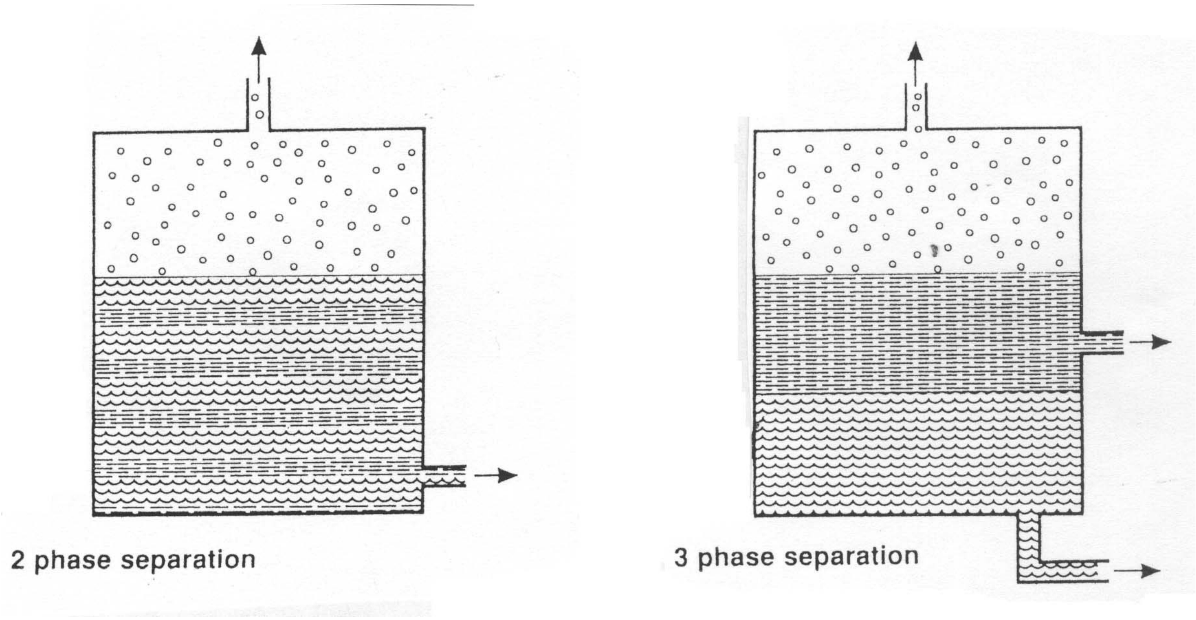
2.2 SEPARATION PROCESS

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.



2 phase separation

3 phase separation

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

2.3 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.

2.6.1 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.

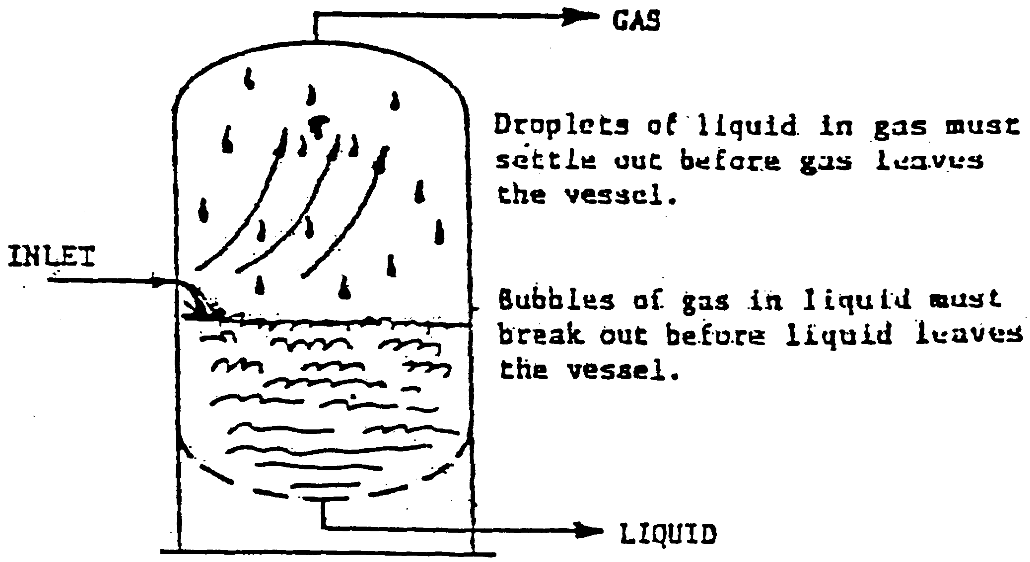


Figure 6.2 Separation Process

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.**

2.6.2 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.

2.6.3 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.

2.4 PHASES OF SEPARATION

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

2.4.1 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.

2.4.2 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.

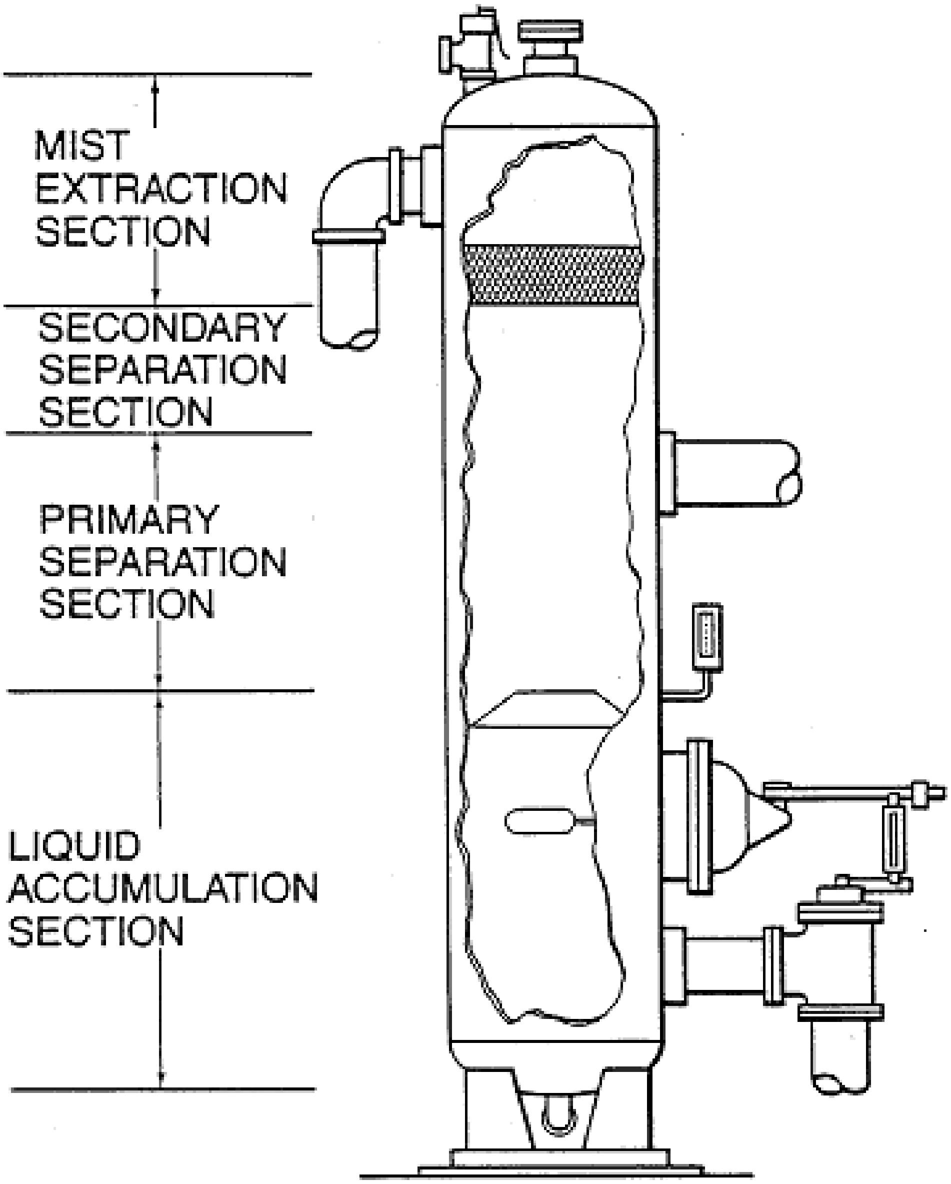


Figure 6.3 Separator Sections

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.

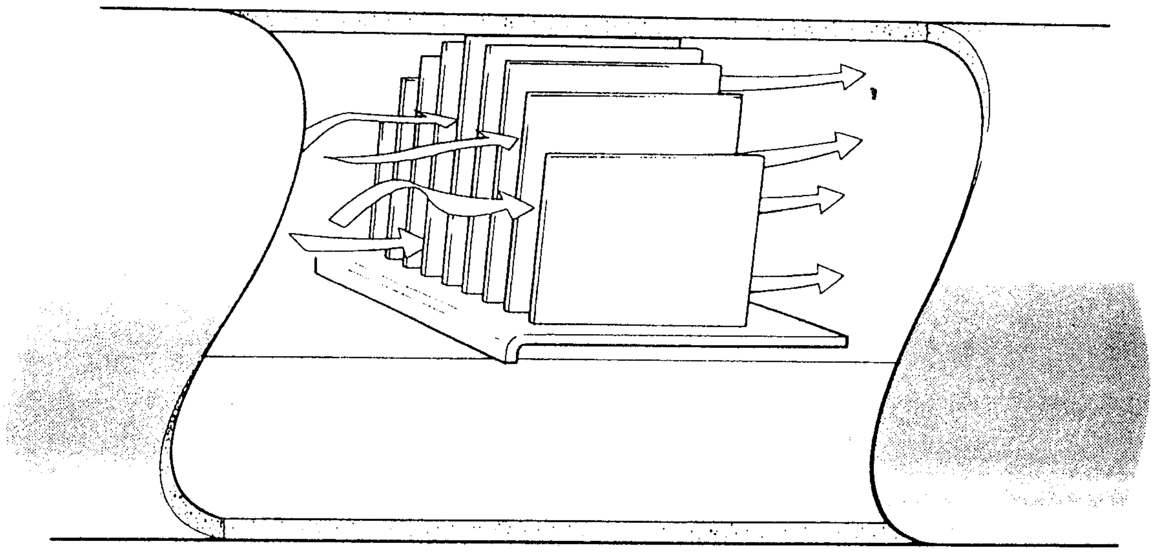


Figure 6.4 A Typical Set of Straightening Vanes inside a Vessel

2.4.3 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.

2.4.4 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.

2.4.5 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.

2.5 TERMINOLOGY AND APPLICATIONS:

2.5.1 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).

2.5.2 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.

2.6 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.

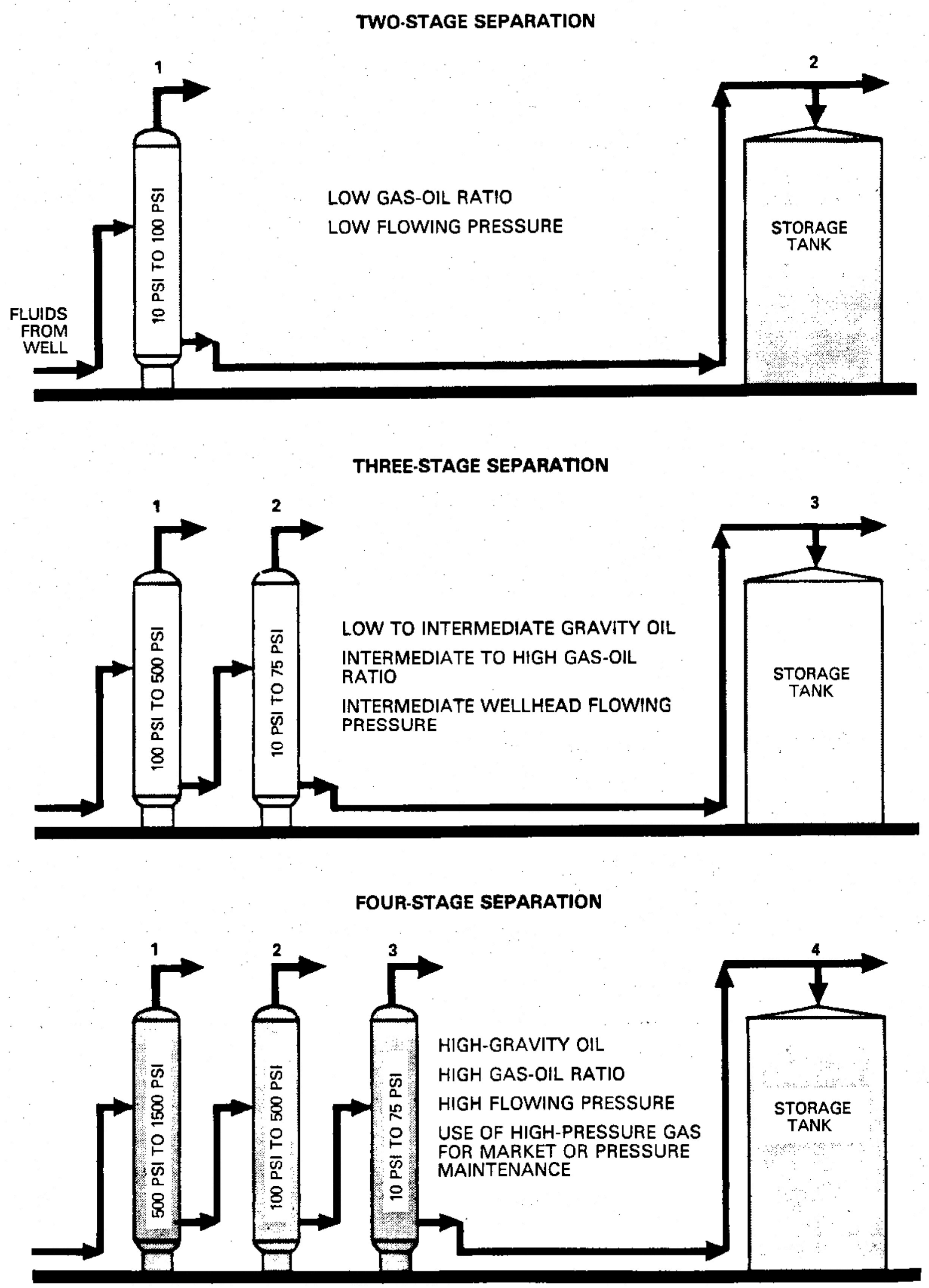
When ideal separation has been accomplished, the, gas and liquids have reached a **state of equilibrium** at the temperature and pressure within the vessel. In other words, at these conditions of temperature and pressure, no further separation would take place.

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.



TWO-STAGE SEPARATION

THREE-STAGE SEPARATION

FOUR-STAGE SEPARATION

Figure 6.5 Stage Separation Flow Diagrams

2.7 CLASSIFICATION OF SEPARATORS

Separators are classified into two ways:

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

2.7.1 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.

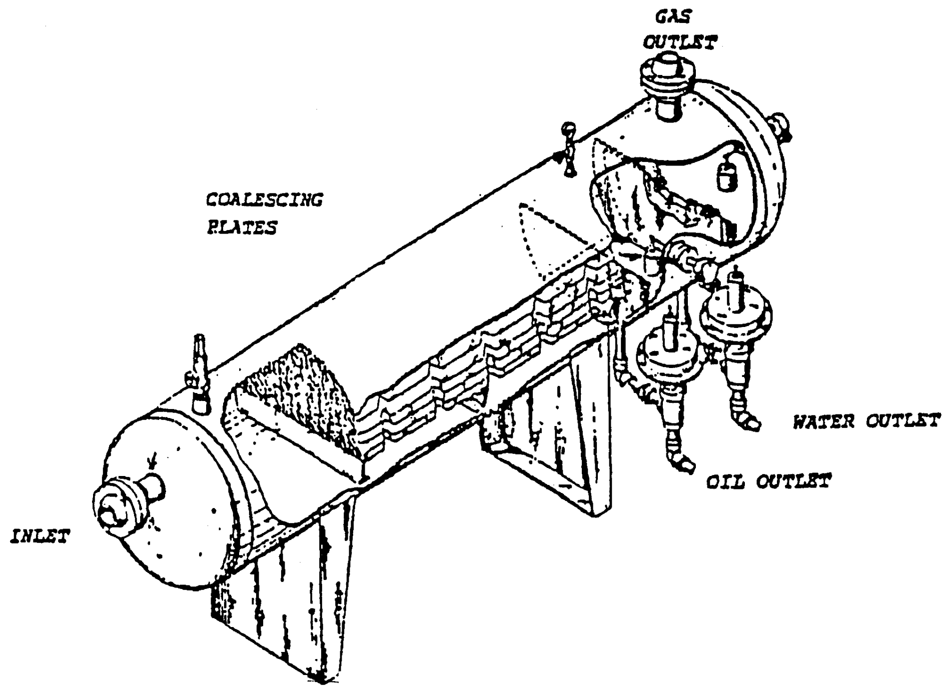
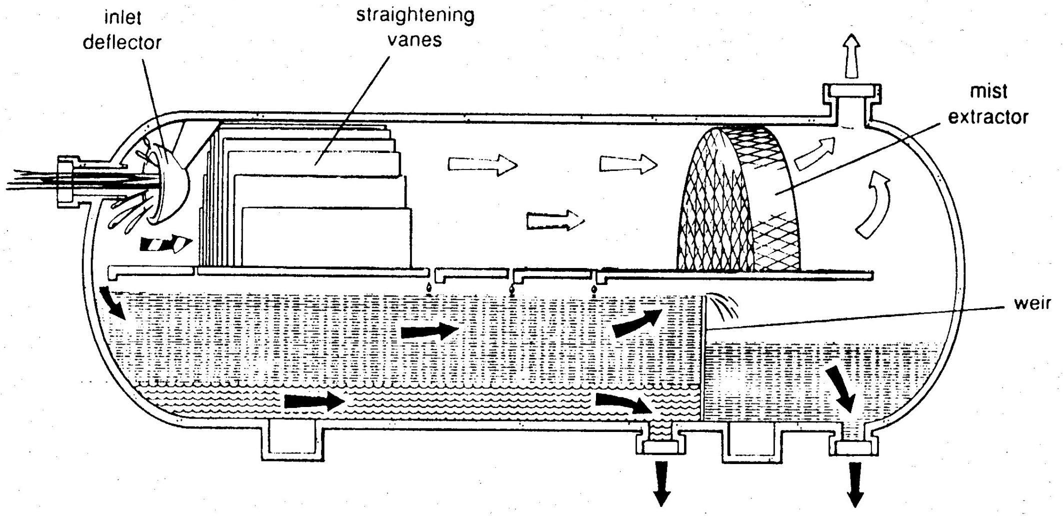


Figure 6.6 Three-Phase Horizontal Separator



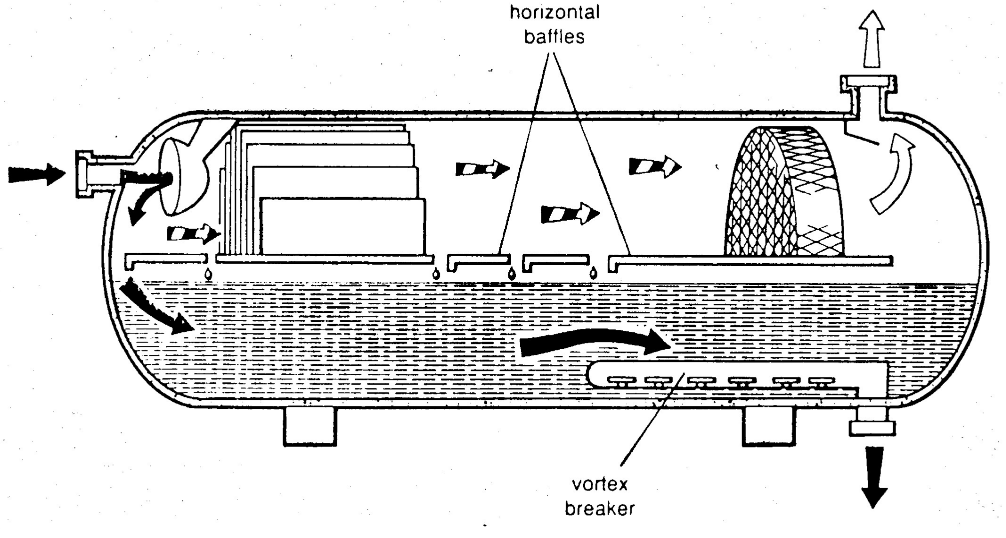
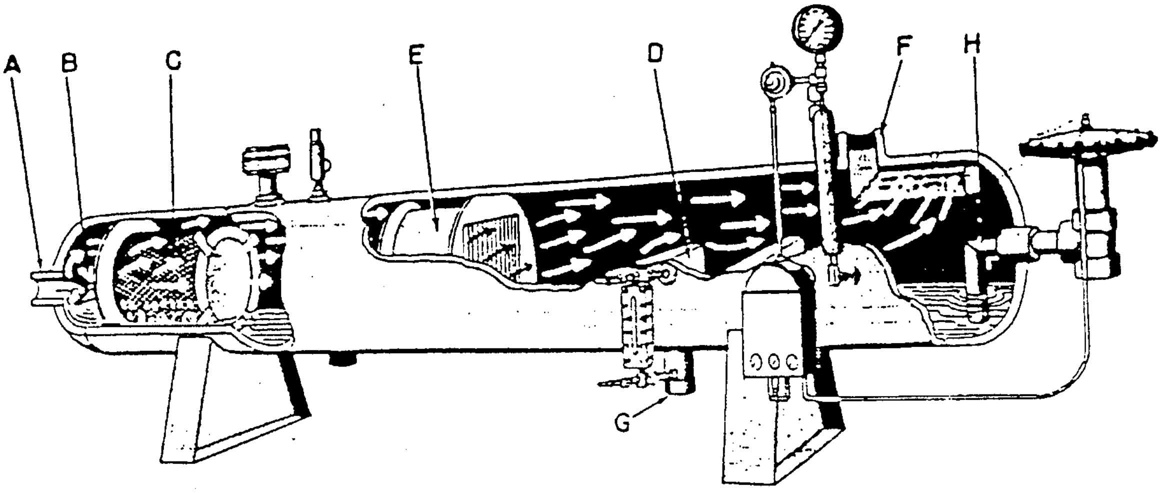


Figure 6.7 Two (bottom) and Three-Phase (top) Horizontal Separators

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

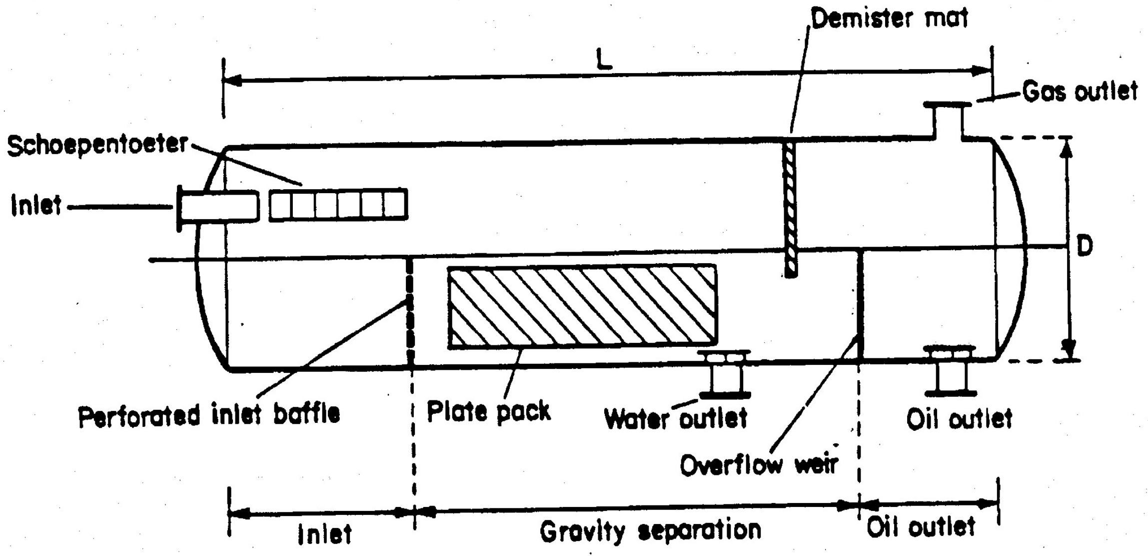


Figure 6.9 Typical Horizontal Three-Phase Separator with parallel plates

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.

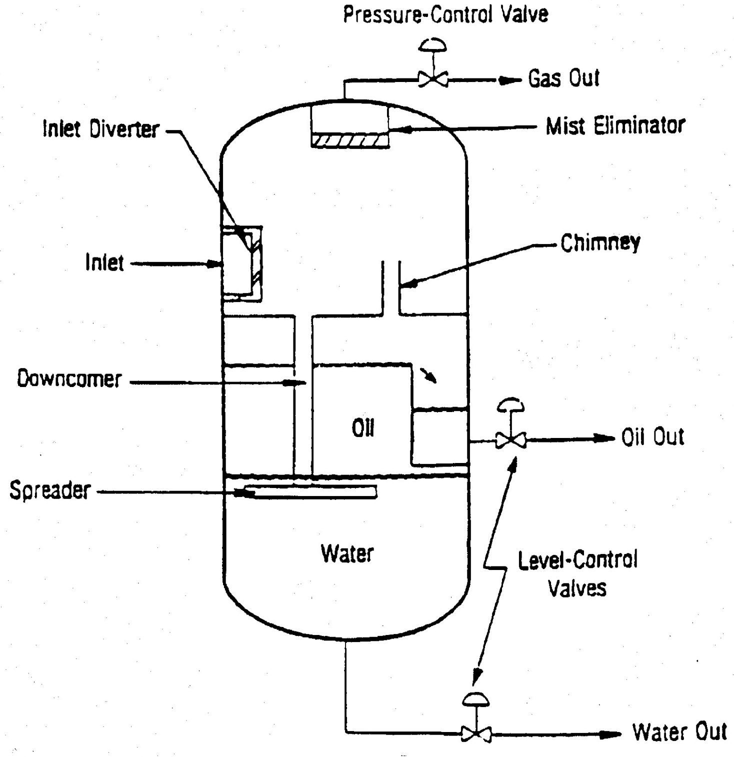


Figure 6.10 Typical Vertical Three-Phase Separator with parallel plates

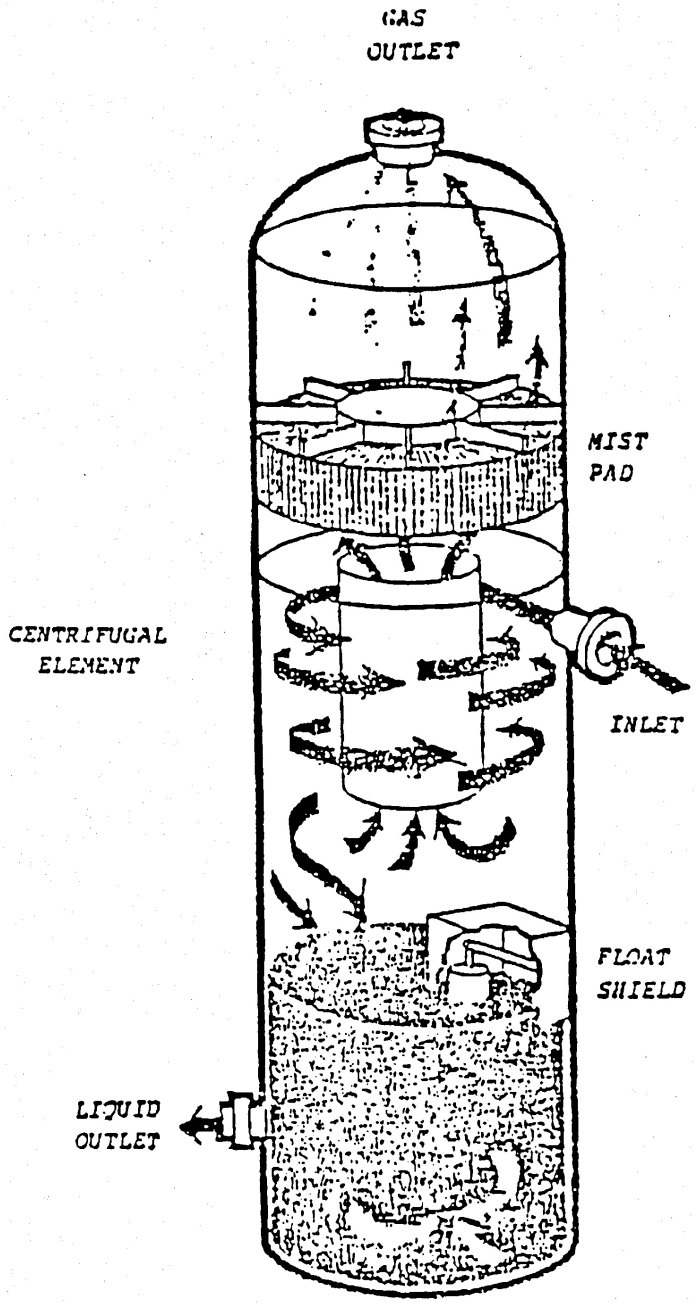


Figure 6.11 Two-Phase Vertical Separator

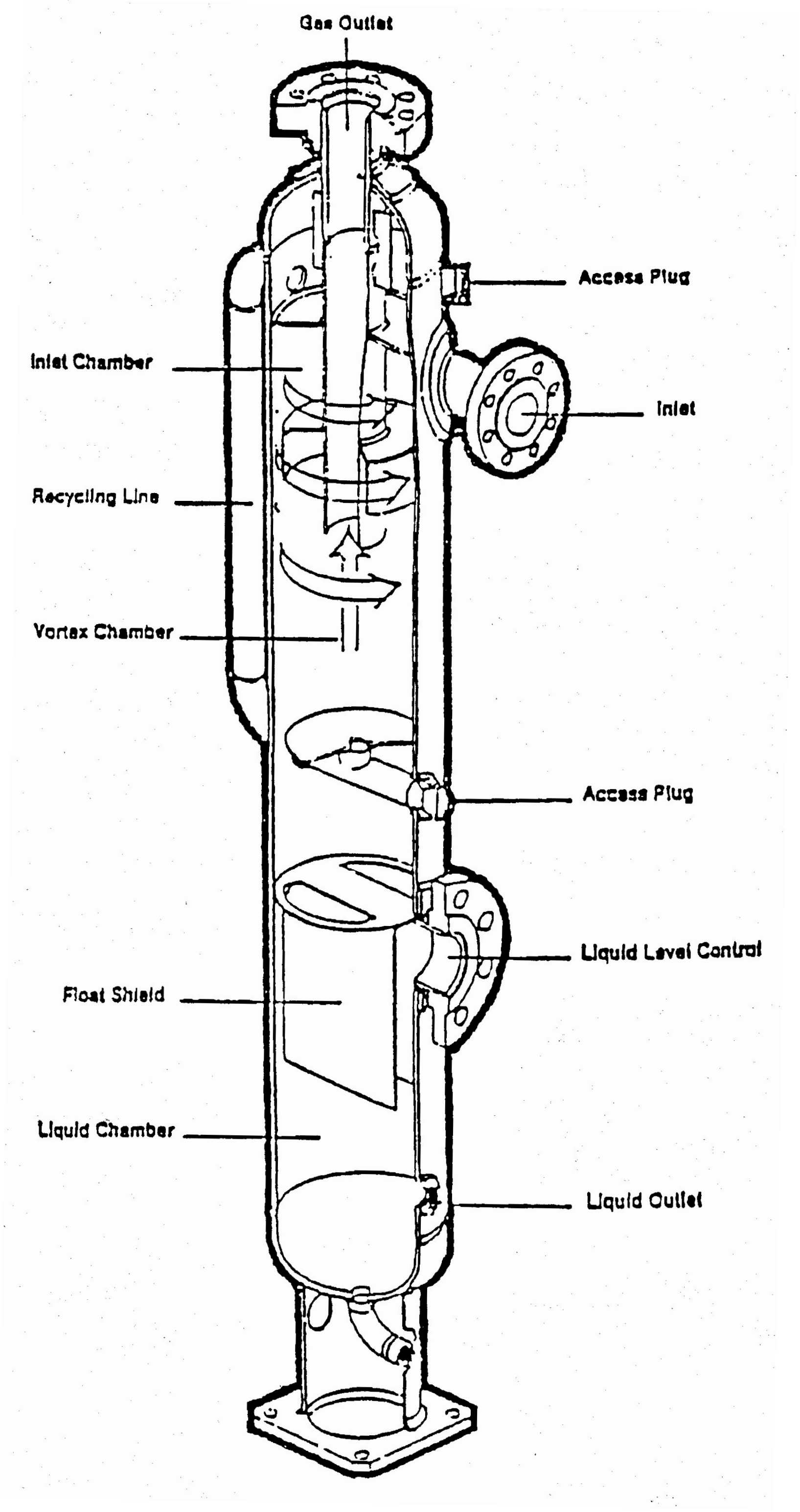


Figure 6.12 Two-Phase Vertical Separator

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.

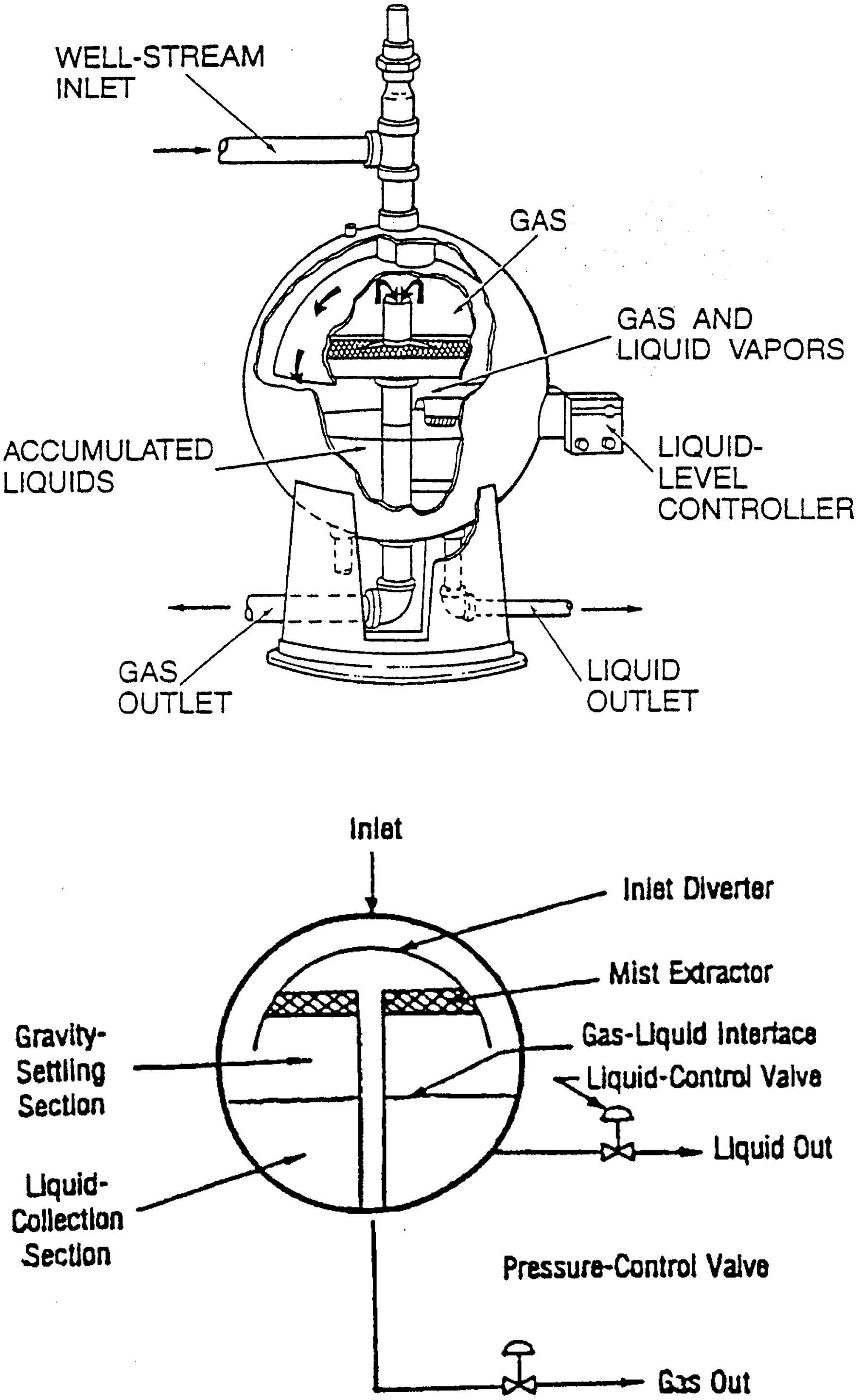


Figure 6.13 Spherical Separator

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.

2.7.2 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

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- Fuel gas scrubbers.

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2.8 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**
-

2.8.1 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:

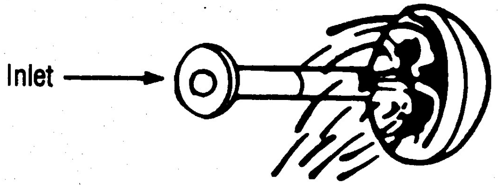
1. To aid in the separation of entrained gas from the liquid.
2. To divert the fluid flow downstream.

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.

Deflector Baffle



Cyclone Inlet

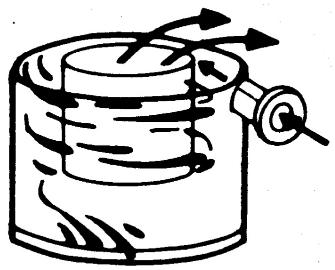
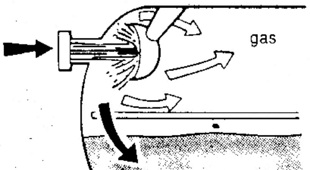


Figure 6.14 Two Basic Types of Inlet Diverters

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.



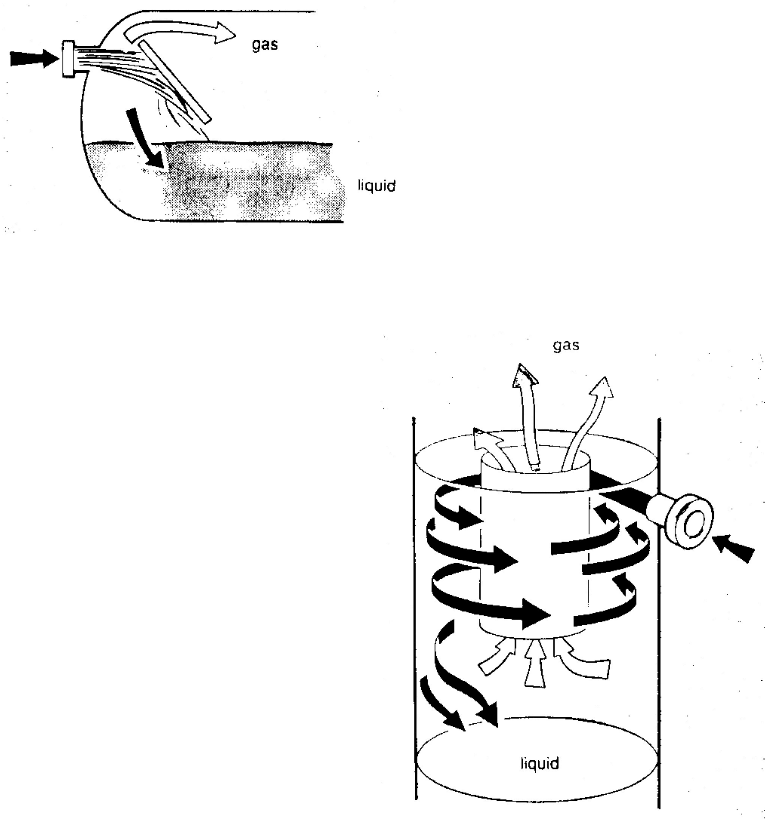


Figure 6.15 Inlet Diverter Types

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.

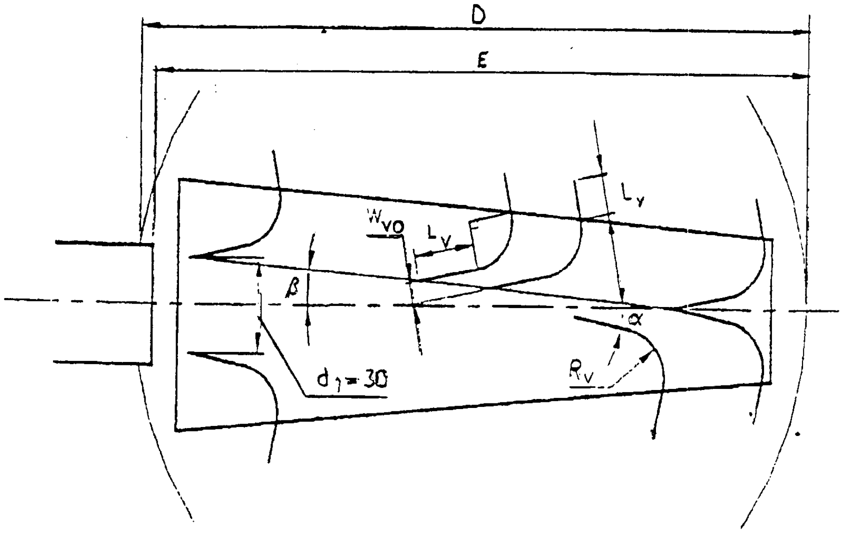


Figure 6.16 Schematic Outline of the Schoepentoeter

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_l = 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.

2.8.2 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.

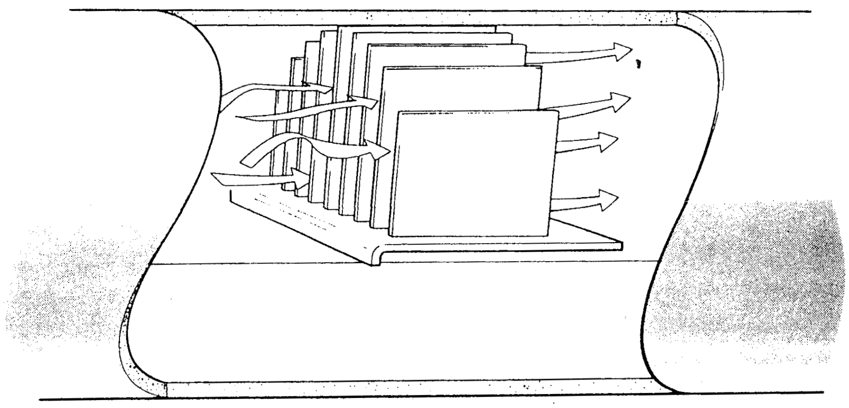


Figure 6.17 Straightening vanes

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.

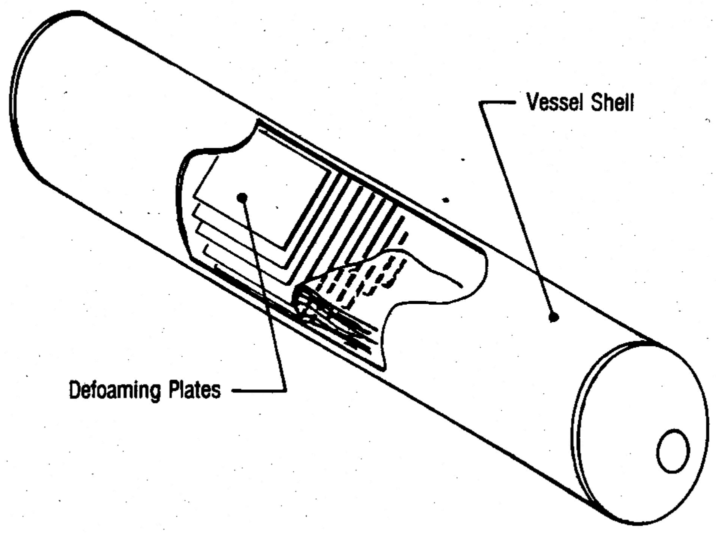


Figure 6.18 A Schematic of Defoaming Plates

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.

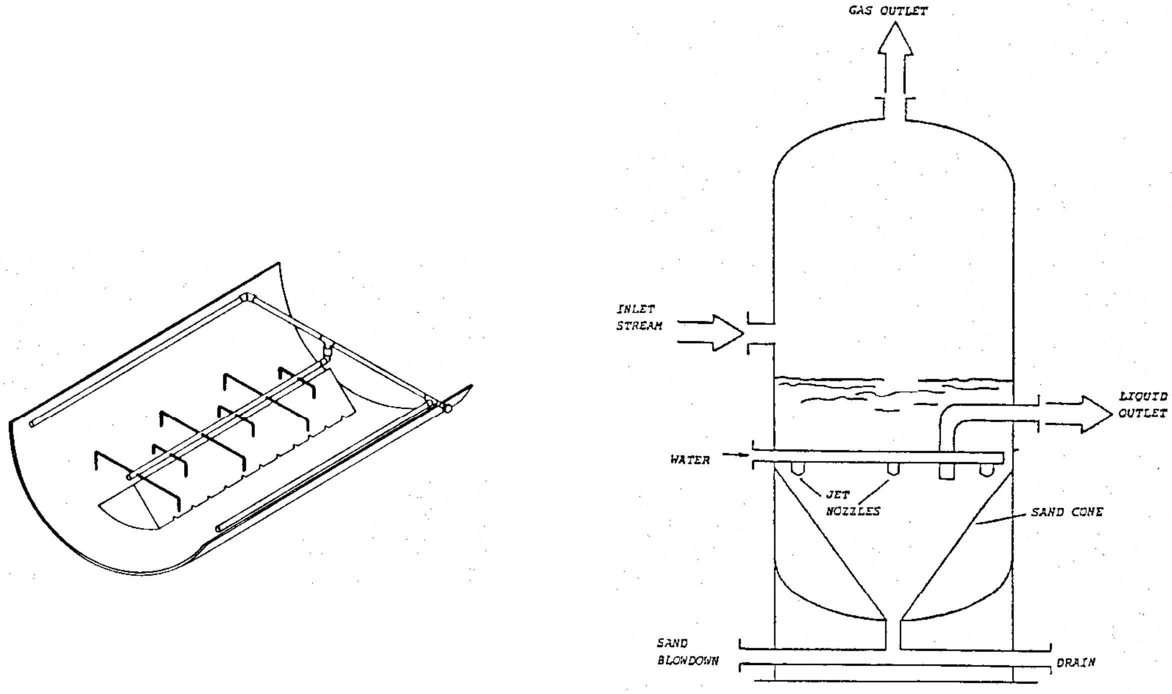


Figure 6.19 Sand Jets and Piping Inside Horizontal and Vertical Separator. Triangular Cover Prevents Plugging of Drains.

2.8.3 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**)

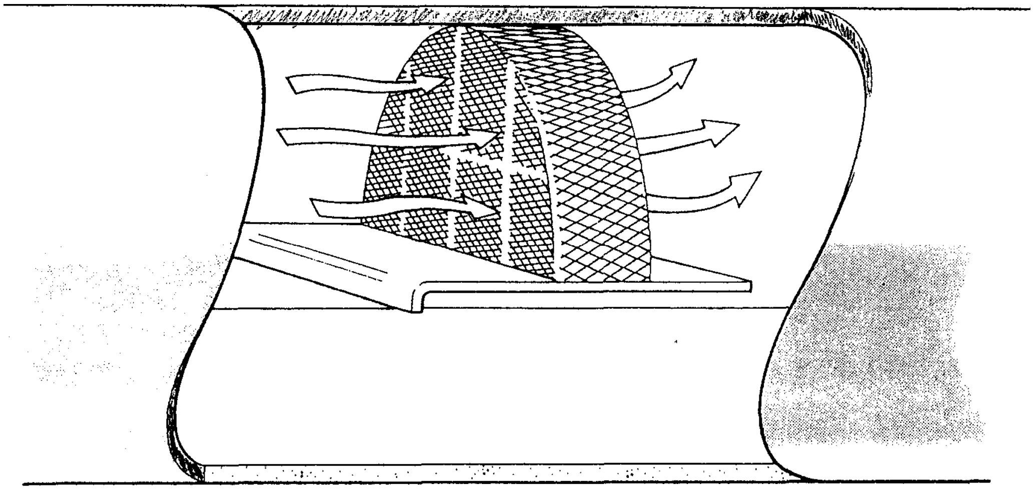


Figure 6.20 A knitted Wire Mesh Pad

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.

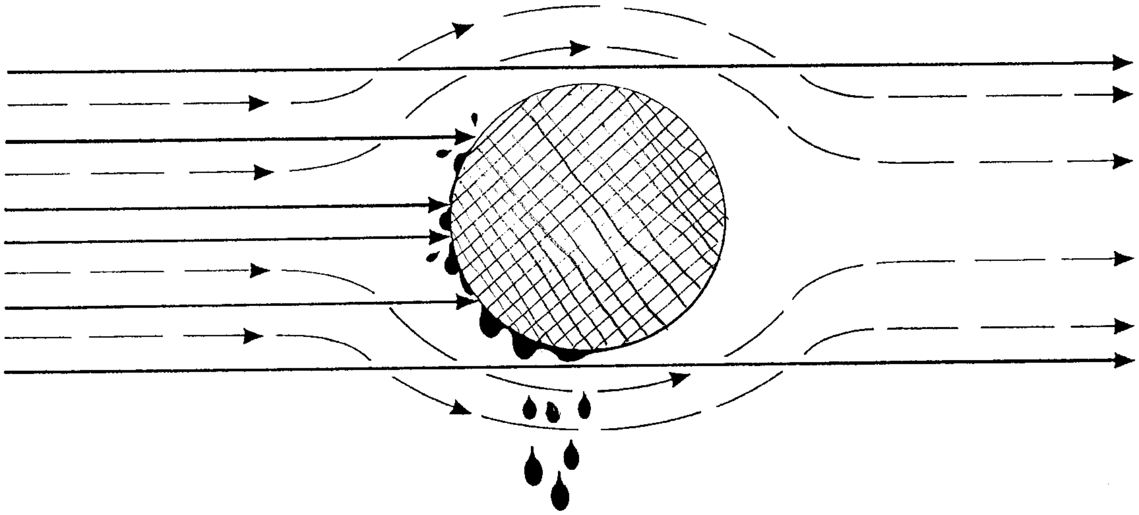


Figure 6.21 The Action of a Knitted Wire Mesh Pad

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.

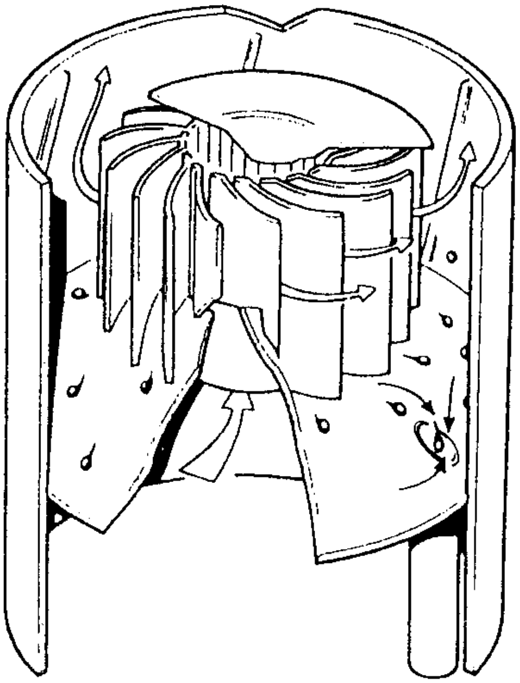


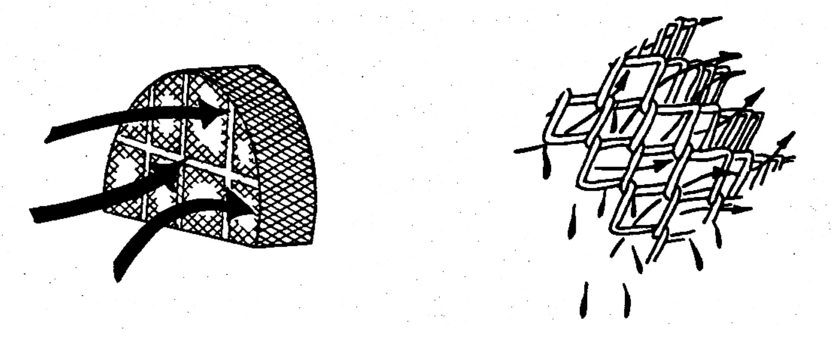
Figure 2.22 A Centrifugal Force Type Mist Extractor

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.

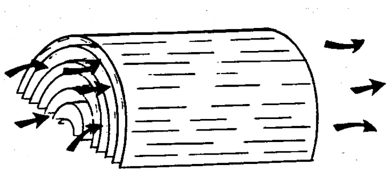
The stainless steel woven wire mesh mist-eliminator of thickness 10 – 20 cm (4-8 inch) is considered to be the most efficient type. It is held in place by a sturdy grid which prevents it from being swept out or torn by a sudden surge of gas, and has been proven by removing up to 99.5% or ore of the entrained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

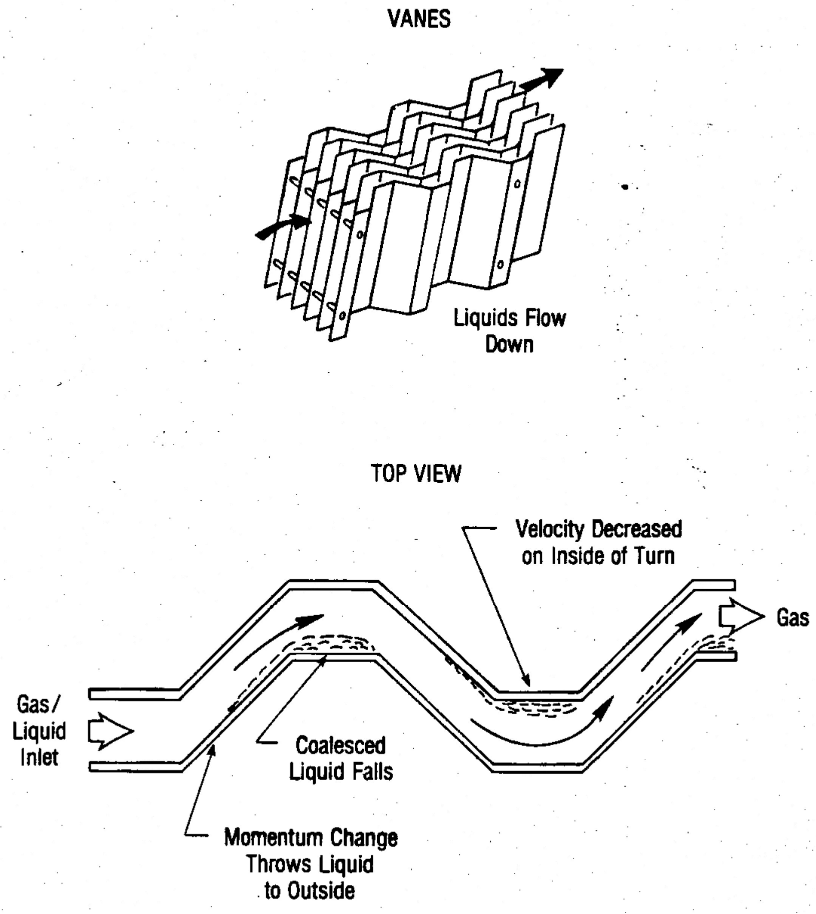


Figure 6.24 A Common Mist Extraction Device using Vanes

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.

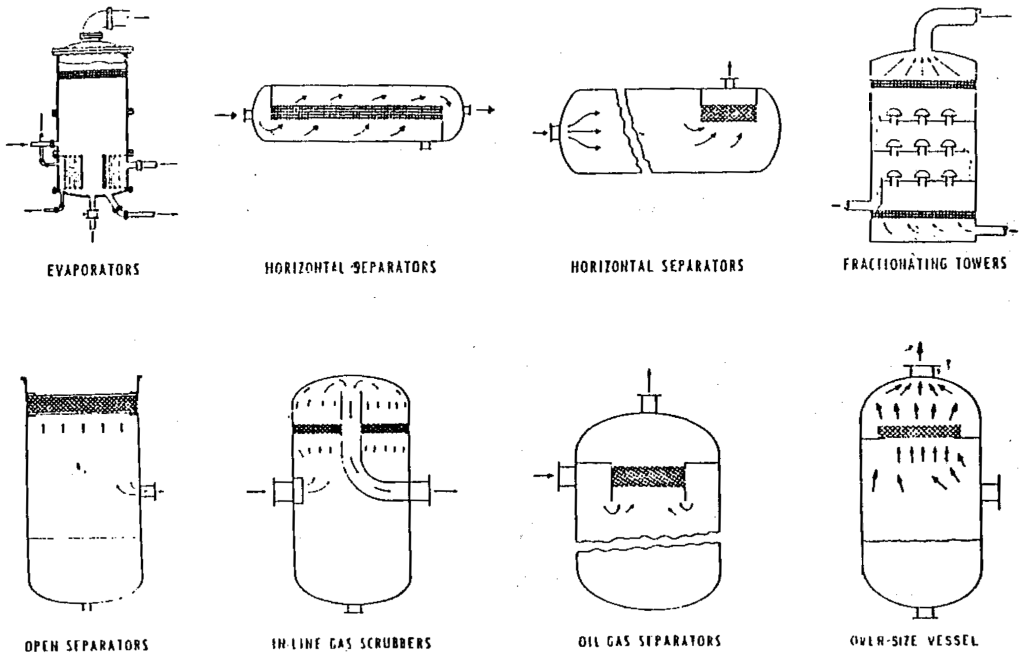
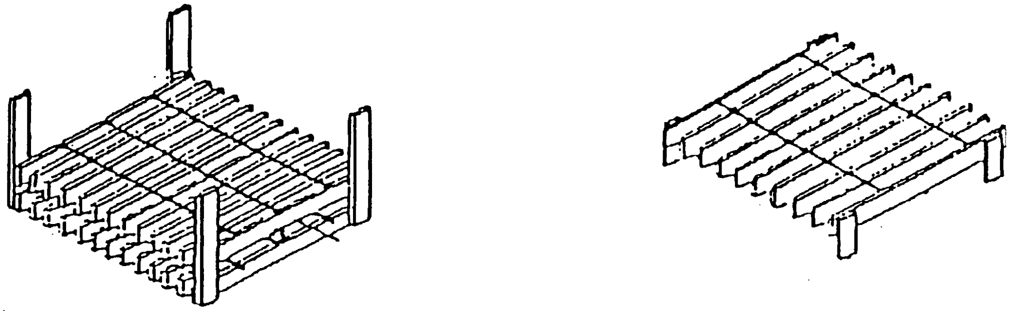


Figure 6.25 Mist Extractors in Various Types Vessels

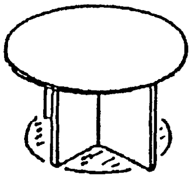
Vortex Breakers

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

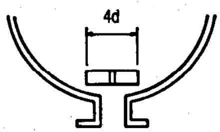


Liquid Vortex Breaker

Figure 6.26 Outlet Vortex Breaker

Longitudinal Section

Plan



Cross Section

Figure 6.27 Three Views of Typical Vortex Breaker

2.9 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.

2.9.1 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.

2.9.2 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.

2.9.3 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.

2.9.4 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.

2.9.5 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 3

Crude Oil Dehydration

Chapter 3 Contents

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Crude Oil Dehydration

3.1 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.

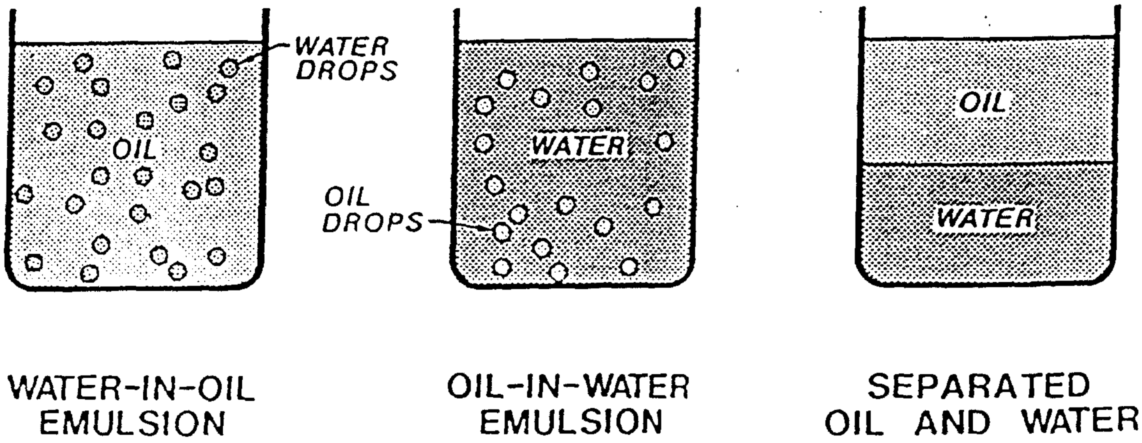


Figure 7.1 Oil - Water Emulsion

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.

3.2 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.

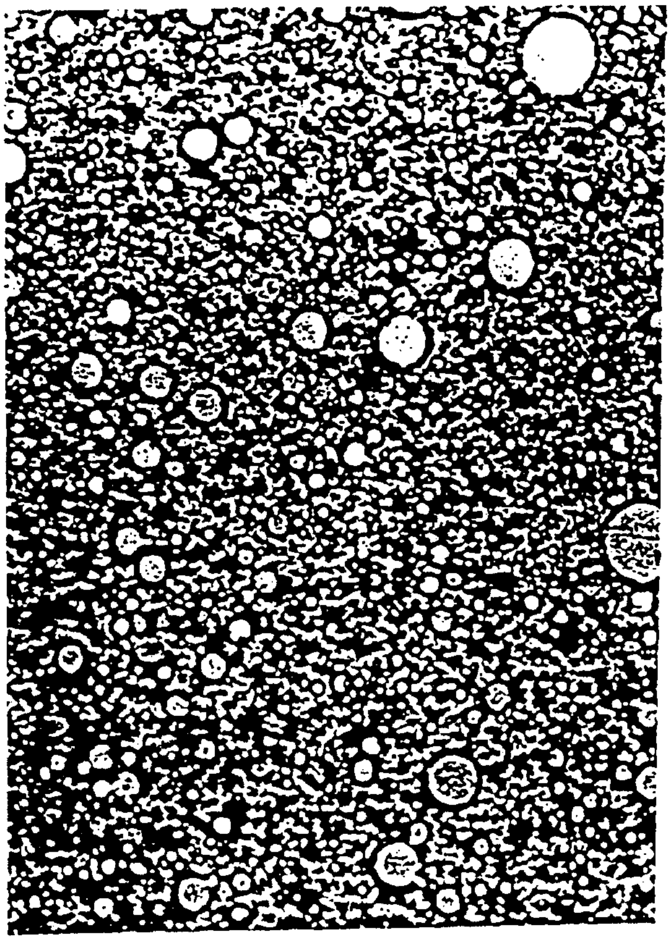


Figure 7.2 Photomicrograph of an Oil - in -Water Emulsion

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

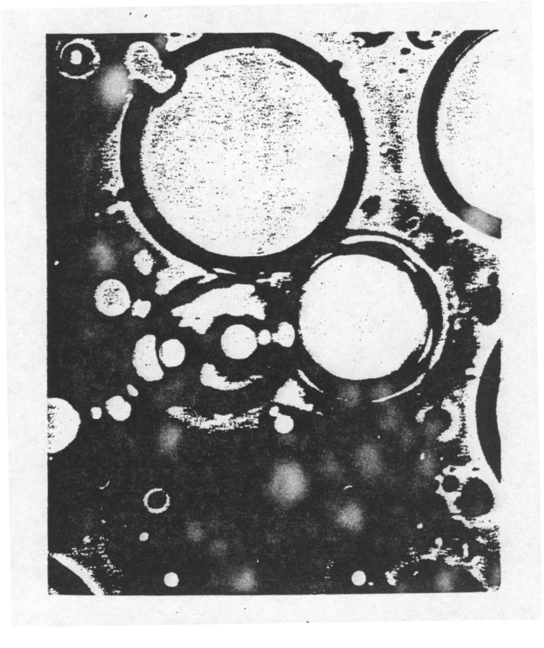


Figure 7.4 Photomicrograph Showing two Droplets Touching but Unable to Coalesce because of the Emulsifying Agent Skin Surrounding the Droplets

3.2.1 Emulsion Terminology

3.2.1.1 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.

3.2.1.2 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".

3.2.1.3 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.

3.2.1.4 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.

3.3 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.

3.4 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.

3.5 CRUDE OIL TREATING (Emulsion Treating)

3.5.1 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.

3.5.2 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.

3.5.2.1 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.

3.5.2.2 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.

3.5.2.3 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.

3.5.3 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:

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

Where:

$\mathbf{V_T}$ = Terminal settling velocity of droplet, in m/s

$\mathbf{g}$ = Acceleration due to gravity, in m/s^2

$\mathbf{d}$ = Diameter of droplet, in m

η = Dynamic viscosity of the continuous phase, in Pa .s

$\rho\ \mathbf{w}$ = Density of water, in kg/m^3

$\rho\ \mathbf{o}$ = 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.

($\rho_w - \rho_o$), η: 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**).

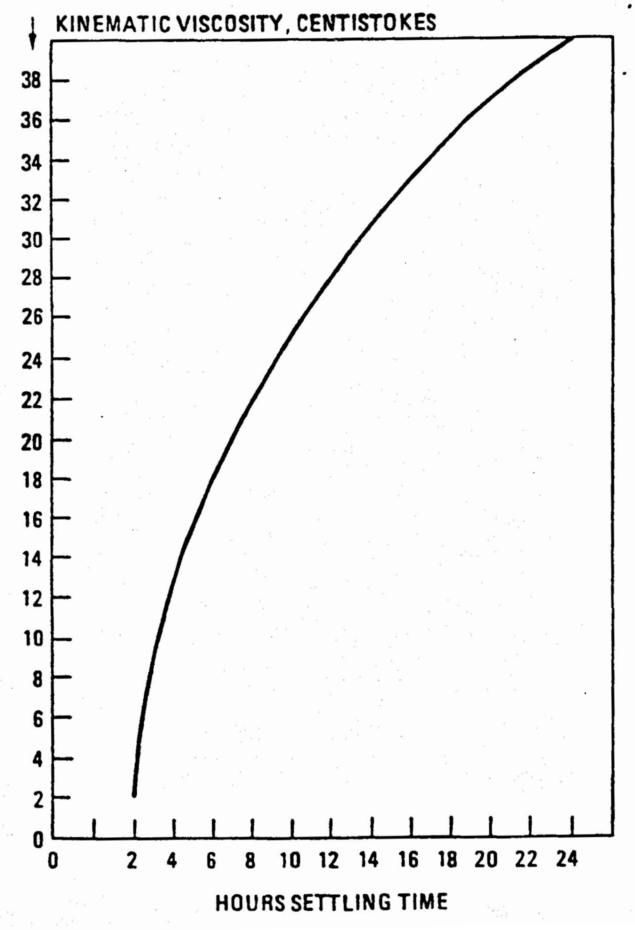


Figure 7.5 Approximate Time / Viscosity Curve

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.

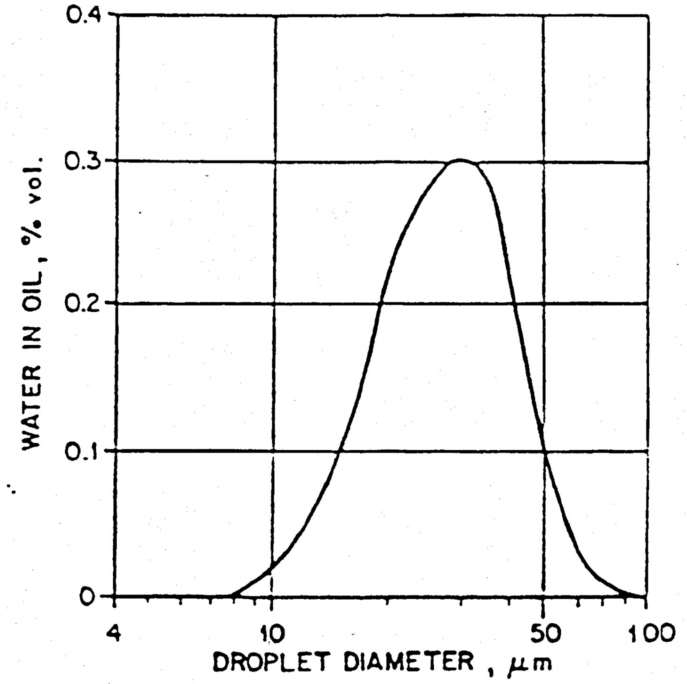


Figure 7.6 Droplets Size Distribution Curve

3.6 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

ΔSG = Difference in the specific gravity relative to water of the droplet and the continuous phase

μ = 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.

3.6.2 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.

3.6.3 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:

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

$$\mu = \text{ע}\ (SG) \qquad (4)$$

Where: T = Temperature, ºC
ע = kinematics viscosity, c s
μ = Absolute viscosity, c p

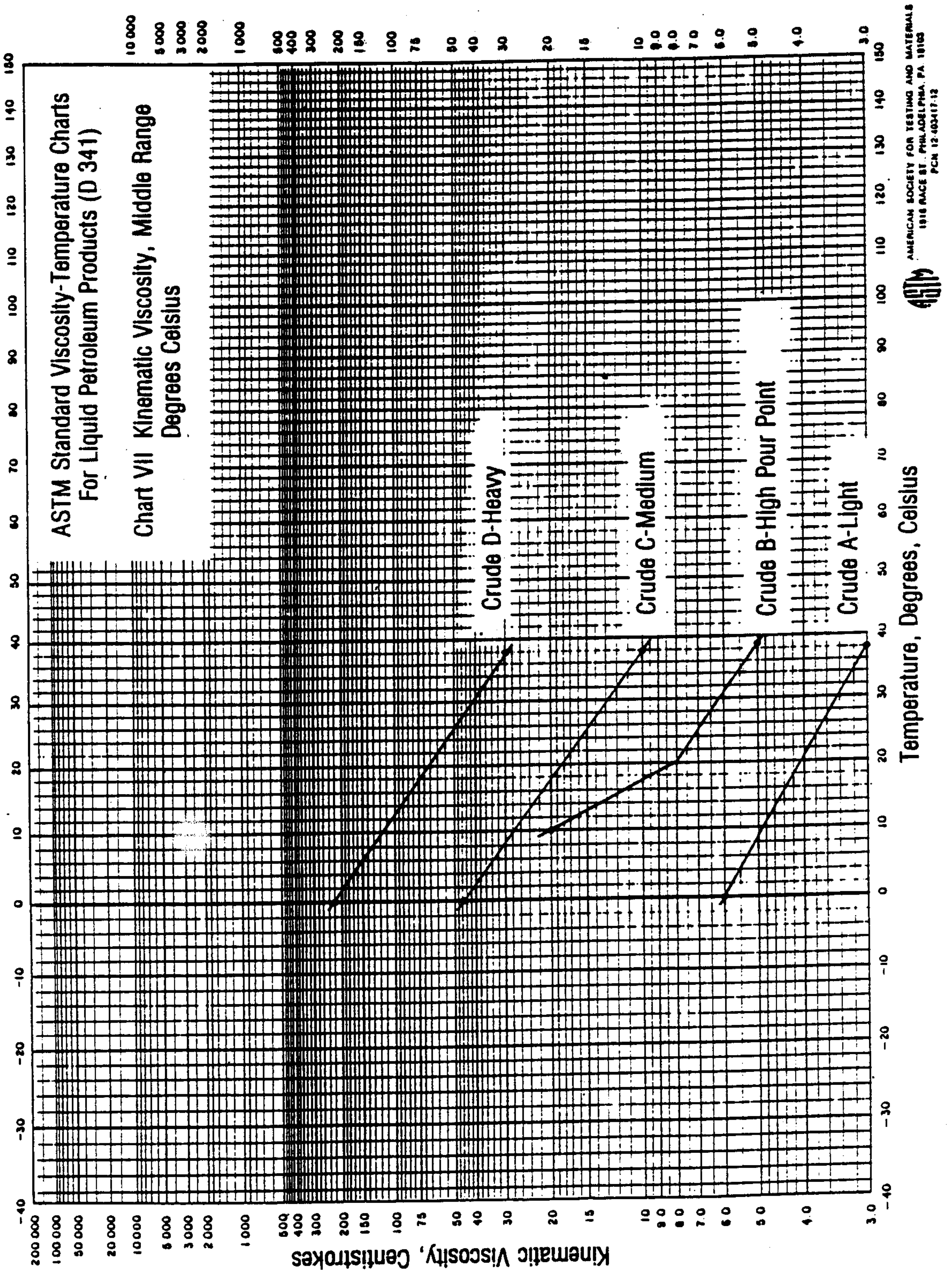


Figure 7.7A Viscosity-Temperature Chart

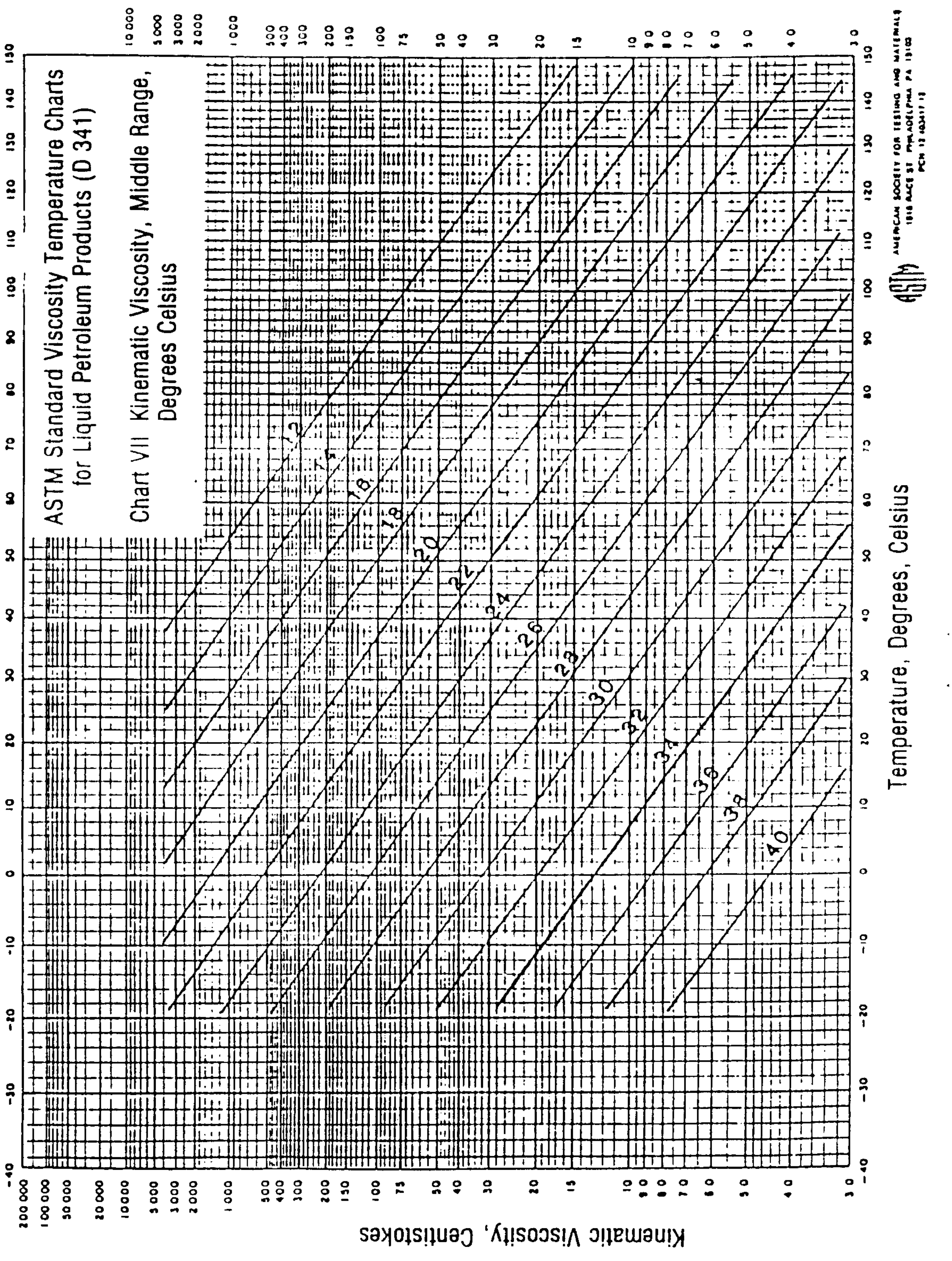


Figure 7.7B Viscosity-Temperature Chart

3.6.4 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

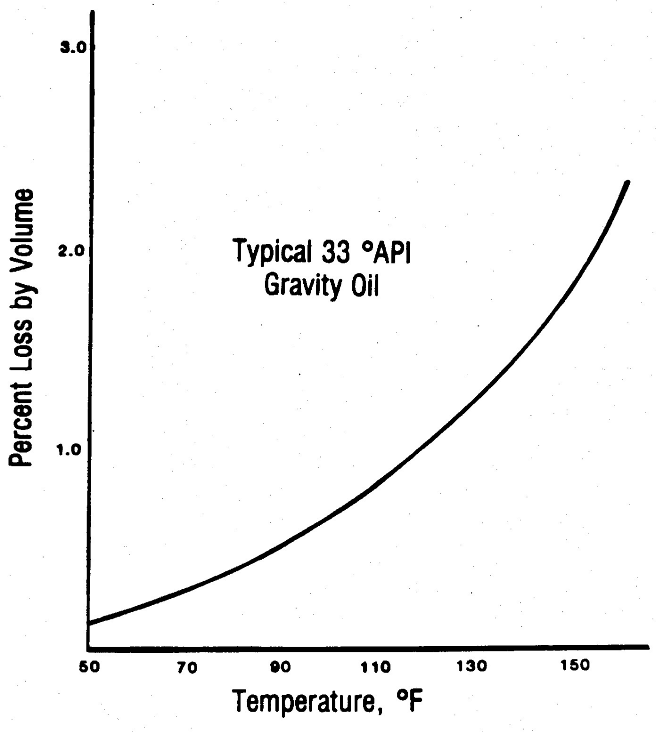


Figure 7.8 Percent loss by Volume as a Function of Temperature

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.

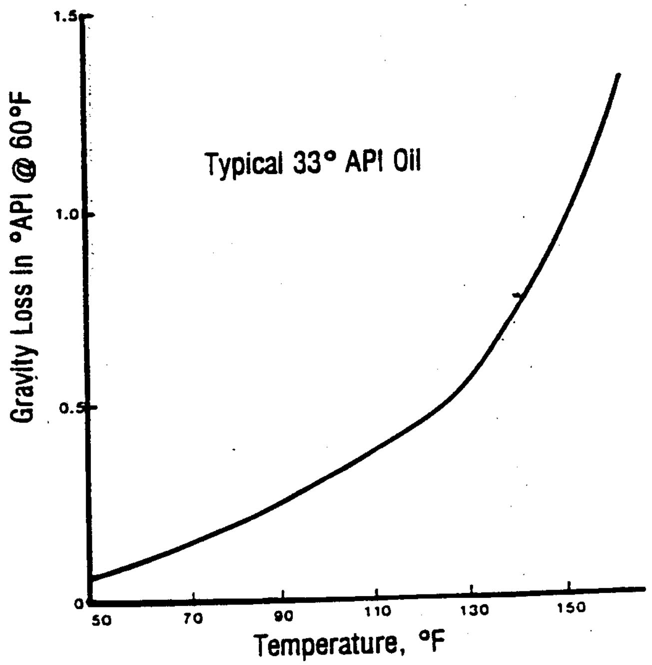


Figure 7.9 API Gravity Loss as a Function of Temperature

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.

3.6.5 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:

$\mathbf{q}$ = heat input, Btu / hr
$\mathbf{Q_O}$ = oil flow-rate, BOPD
ΔT = temperature difference
$\mathbf{(SG)_O}$ = oil specific gravity relative to water
$\mathbf{(SG)_W}$ = water specific gravity
$\mathbf{W_C}$ = inlet percent water cut, percent

3.6.6 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.

3.6.7 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.

3.7 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

3.7.1 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.

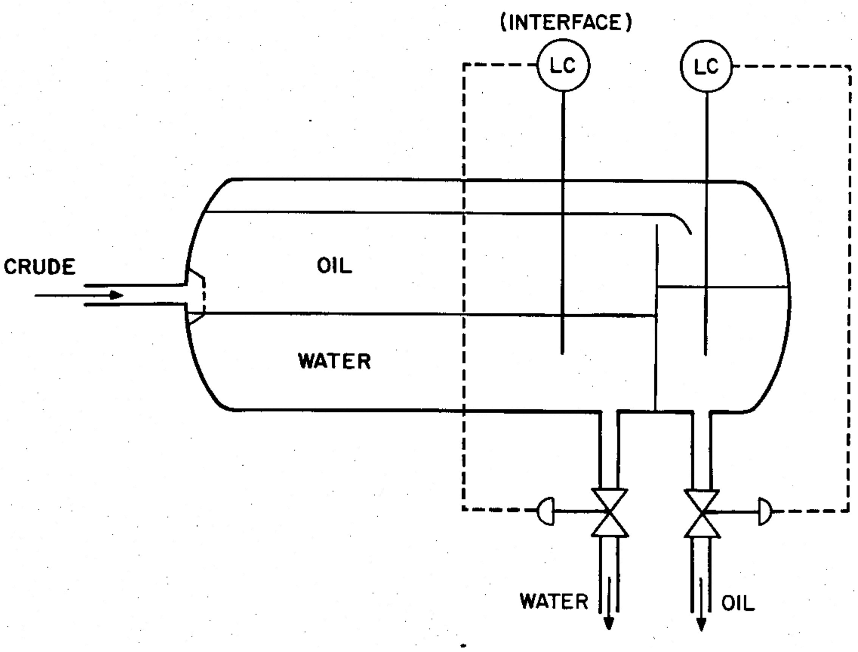


Figure 7.10 Horizontal Free Water Knockouts

3.7.2 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.

3.7.2.1 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).

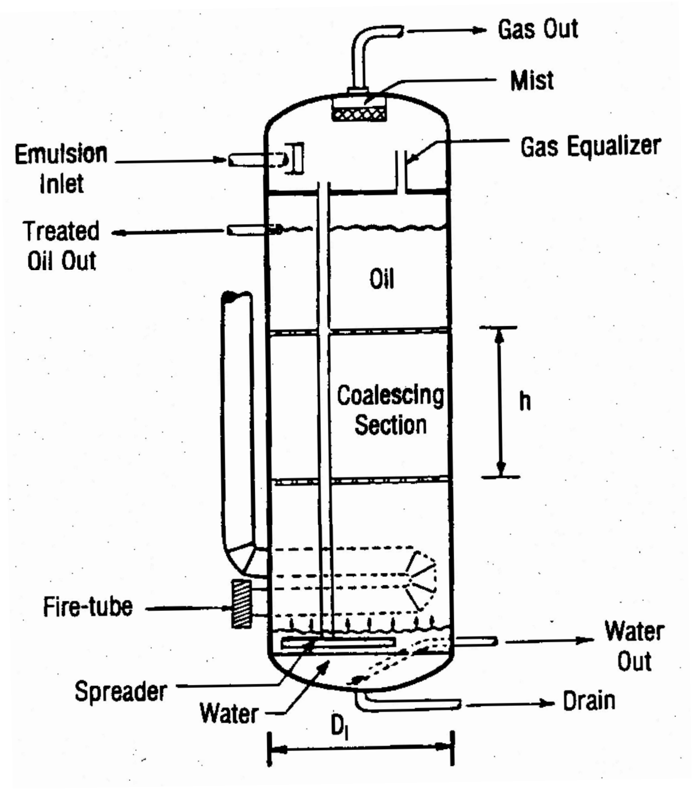


Figure 7.11 Simplified Schematic of a Vertical Heater Treater

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.

3.7.2.2 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.

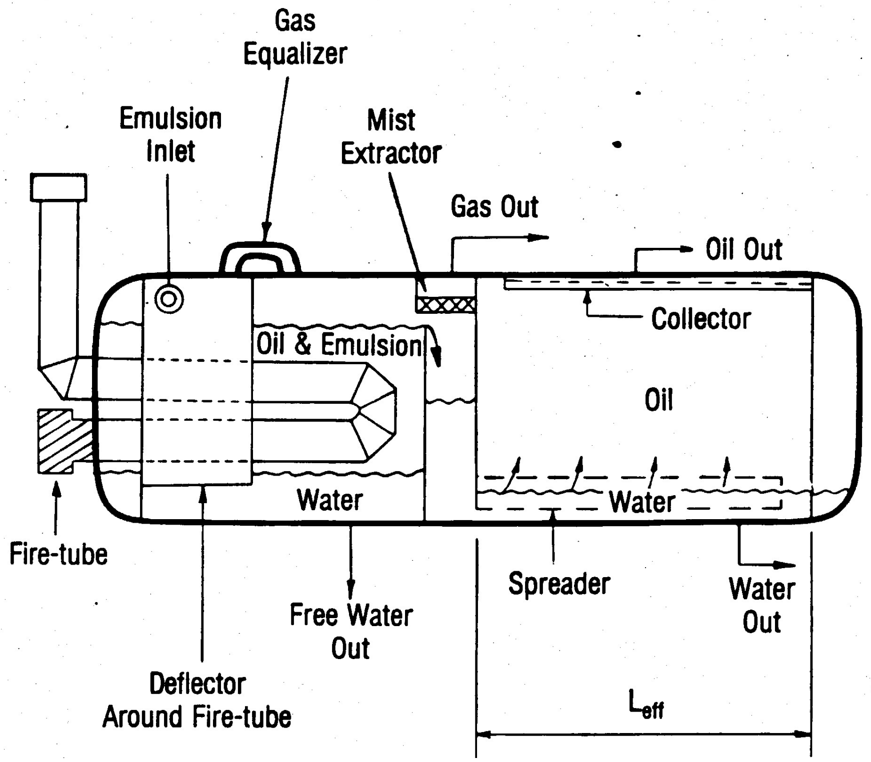


Figure 7.12 Simplified Schematic of a Horizontal Treater

3.7.3 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.

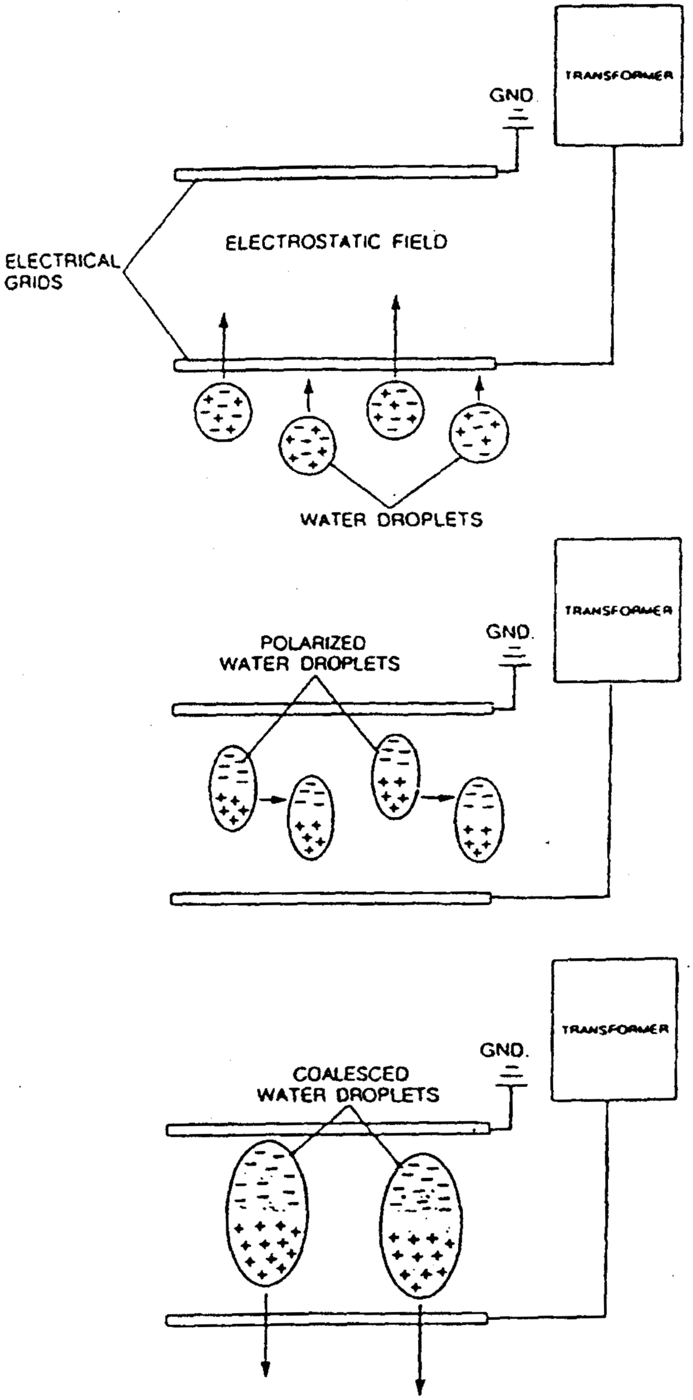


Figure 7.13 Electrostatic Treating

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.

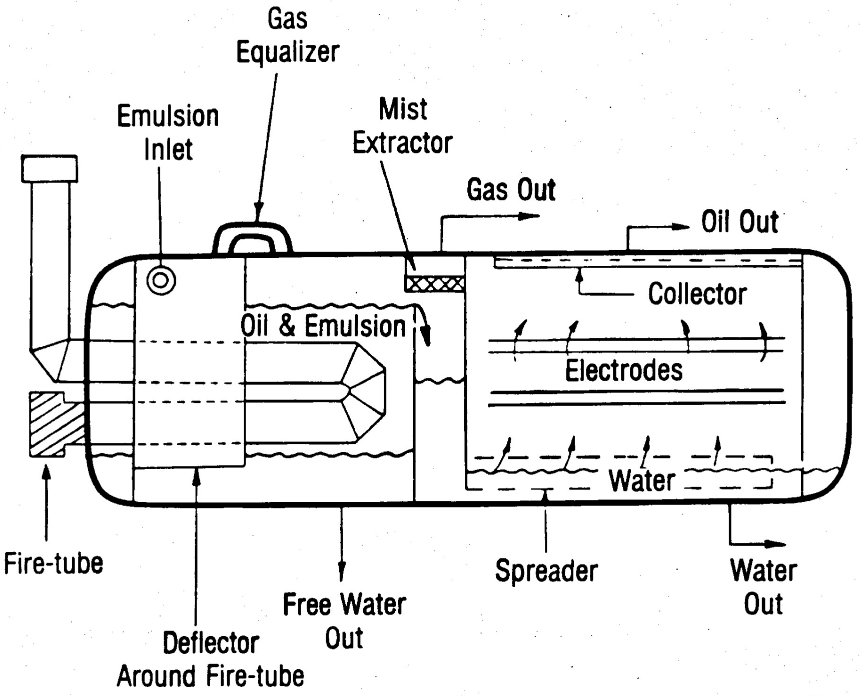


Figure 7.14 Simplified Schematic of an Electrostatic Treater

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 4

Storage Tanks

Chapter 4 Contents

Chapter 4

Storage Tanks

Introduction

Crude oil tanks are usually used in the oil fields as intermediate storage tanks for the produced treated clean oil. These tanks are installed upstream of the main booster pump station. They serve as feeder tanks prior to transferring the clean oil by the main oil trunk lines to the farm tanks for sales. Also they are used for crude oil storage at the shipment terminal farm tanks.

Generally, storage tanks have walls with suitable thickness. They are high to eliminate oil spill / fire spreading out as a safety precaution measure in case of a tank burst, oil leakage or fire in the tank. In addition, storage tanks are connected to the plant fire fighting system, so that suitable action can be made in the event of fire in a tank.

4.1 Types of Storage Tanks

There are two common designs:

1- The fixed roof tanks.
2- Floating roof tanks.

4.1.1 The Fixed Roof Tanks

1- They store crude oil near atmospheric pressure (Figure 12.1).

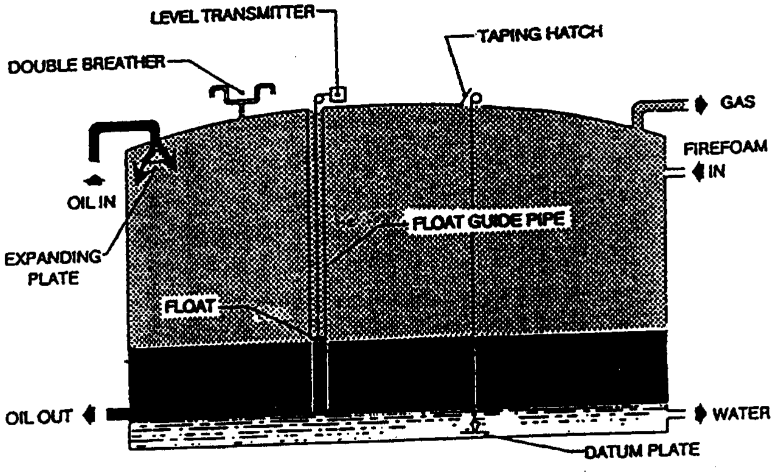
2- The entering oil strikes an expanding plate to assist separation of any remaining gas, which then goes to the low-pressure flare.

3- Oil level is detected by a float inside a guide tube and transmitted to the control room. The level is also checked periodically by dipping.

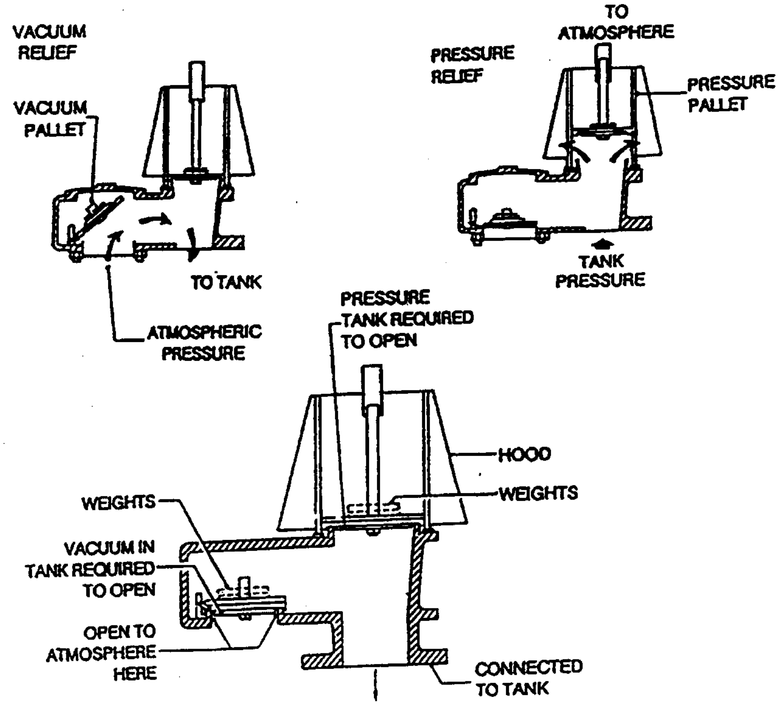
4- The fire foam inlet is sealed by a thin sheet of glass, which prevents gas escaping, and will shatter if foam arrives behind it.

A major problem experienced with fixed roof tanks is the variation of internal pressure due to temperature changes causing expansion or contraction of the tank contents.

The tank may be subjected to either pressure or vacuum. This is prevented by using a combined pressure / vacuum relief valve installed in the roof as shown in Figure 12.1.



FIXED ROOF TANK



PRESSURE VACUUM SAFETY VALVE (Double Breather)

Figure 12.1 Fixed Roof Tank and Accessories

If the tank contents can evaporate under atmospheric conditions, a nitrogen blanket is maintained over the liquid surface. If the liquid does evaporate, the tank will vent nitrogen (gas). Therefore, cooling of crude oil occurs and contraction of the oil takes place. Air will be drawn into the tank but the nitrogen blanket will form a barrier between air and the hydrocarbon thus reducing the fire hazard.

Tanks are equipped with inlet and outlet valves, a level gage, a double breather and a drainage outlet.

Pressure / Vacuum Safety Valve (Double Breather)

The double breather valve shown in Figure 6.1 is specially calibrated to bleed off into the atmosphere when the internal pressure exceeds 20 mm of water. It sucks in air from the atmosphere when a vacuum of 10 mm of water is created inside.

4.1.2 The Floating Roof Tanks

These tanks are so called because the roof floats on the liquid and eliminates the vapour space above the liquid. This allows for storage of higher vapour pressure products such as gasoline, naphtha, etc.

There are two types, the pontoon roof and the hard top pan roof tanks. This type of tanks is extensively used because it reduces costly evaporation losses from tanks.

4.1.2.1 The Pontoon Roof Tanks

The floating roof has an annular ring of pontoon (Figure 12.2) surrounding a single deck centre. The rim of the roof is sealed using shoes held against the sides by weights or springs as shown in Figure 12.3.

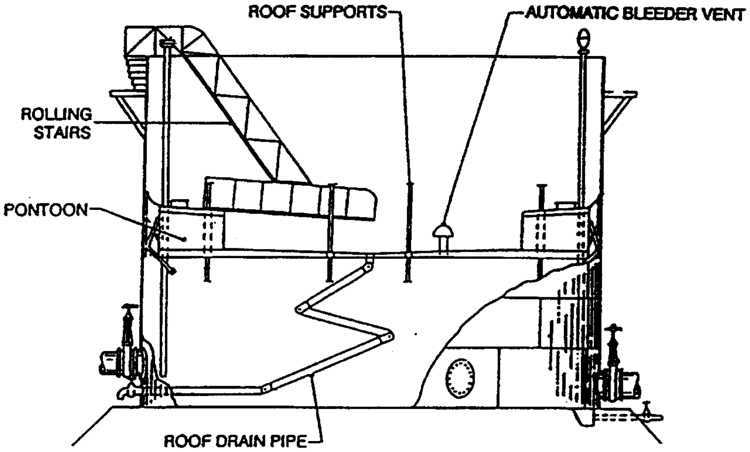
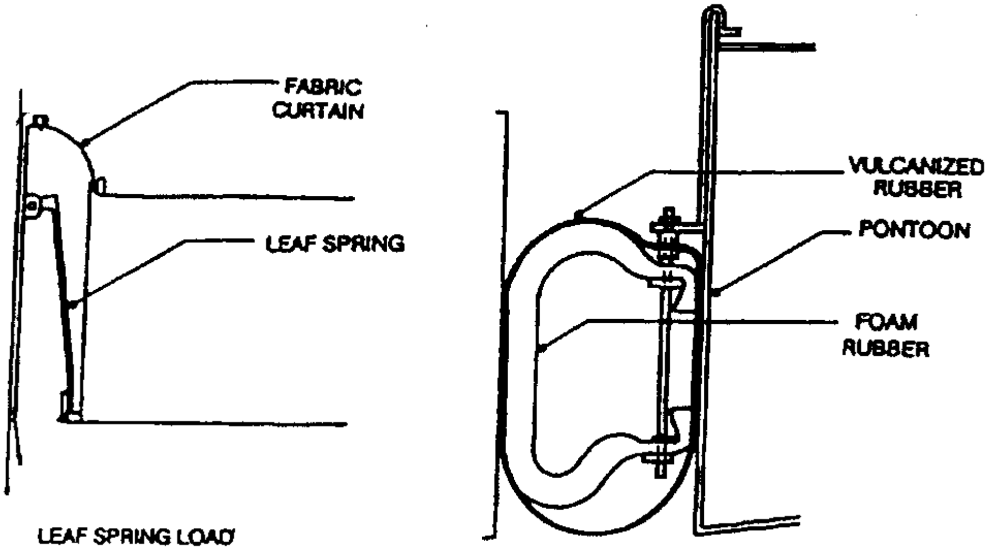
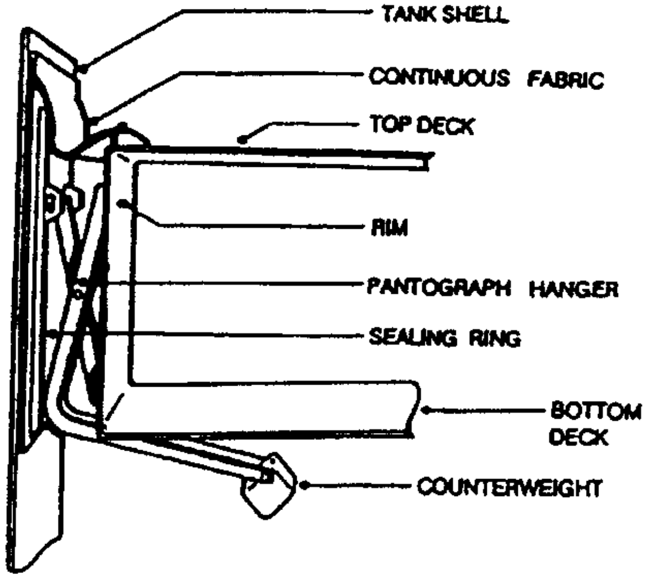


Figure 12.2 Pontoon roof tank



LEAF SPRING LOAD

FOAM RUBBER LOAD



COUNTERWEIGHT LOAD

Figure 12.3 Floating Roof Tank Sealing Method

4.1.2.2 The Hard Top Pan Roof Tanks

This type of floating roof shown in Figure 12.4 has all the advantages of the pontoon roof for vapour conservation and better safety against fire. In addition, it has a fixed cone roof, which protects the floating roof elements. The floating roof has no need for roof water drainage. The cost of this type of tanks is generally less where the tank size does not exceed 100 feet in diameter.

The floating roof rests on the liquid and has the form of an inverted shallow pan of single thickness steel. The roof contacts the liquid over its entire surface. Hard top pan roof has automatic vents. Figure 12.4 shows an illustration of a typical hard top pan floating roof sealing method.

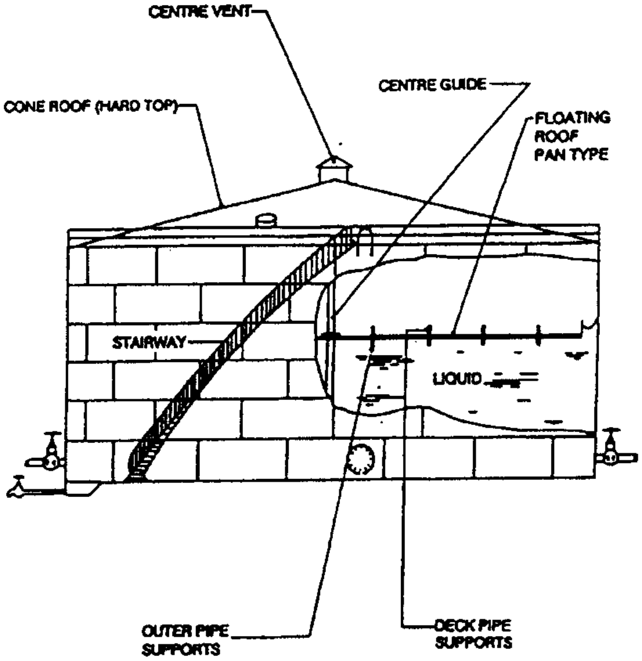


Figure 12.4 Hard Top Pan Floating Tank

4.2 Maintenance of Storage Tanks

4.2.1 Cleaning

Steel tanks should be kept clean and free from spilled oil or other materials. They should be painted to minimize corrosion. All water and accumulated dirt should be removed from the bottom edge of the tanks.

4.2.2 Maintenance

If leaks occur, they have to be repaired temporarily. The leaks should be repaired permanently as soon as possible. Maintenance and inspection of tanks must cover the following on a regular basis:

1- Tank basin and access ways.
2- Tank foundations.
3- Earthing system.
4- Bottom.
5- Shell.
6- Roof.
7- Ladders and gangways.
8- Fire fighting system.
9- Instruments.

The maintenance includes inspection before and after cleaning, suggested repairs, effected repairs and inspection after effected repairs of any or all of the above items.

On the following pages, more details about the tank maintenance and the required safety precaution in different cases.

4.3 Tank Maintenance

Tanks require maintenance, both internally and externally. This includes preventive measures to fight tank corrosion and pipeline connections, accessories, and access ladders and walkways. It also includes repair.

4.3.1 External Maintenance of Tanks

External maintenance consists of the regular inspection and renewal of the protective coating of the tank shells and the proper functioning of the cathodic protection system. The purpose of cathodic protection of tanks is to supplement bottom exterior coatings by the metal at possible coating voids.

Protective coating is usually formed by one or more layers of paint.
Depending on the type of paint used, however, painting will only extend the service life of the tank when it has a perfect bond to the metal. Therefore to be sure of proper application it is important to follow the instructions of the paint supplier.

In addition to corrosion protection the painting of a tank has a further advantage: white or other light paints reflect heat and stabilize the internal temperature of the tank.

It is difficult to specify how often a tank should be repainted, because the climate is the principal factor in this decision. Humid, salt-bearing air near the coast can make it necessary to repaint as often as every three years, while under favorable conditions, paint coats may last for ten or even fifteen years.

As a rule, a tank should be painted as often as necessary to provide reasonable protection for the tank and its contents.

4.3.1.1 Application of Paint

1- Before any paint is applied, the surface of the plates should be cleaned of scale, rust, dirt, oil, grease and weathered paint to ensure a good bond to the metal. This is done by grit-blasting(sand – blasting), because this method is fast and comparatively safe. There are some points that require attention while grit-blasting;

   a. The grit should be clean and dry and the grit should be of equal size

   b. The compressed air must be as dry as possible. Moist air will result in rapid rusting of the freshly prepared surface. For the same reason grit-blasting (sand – blasting) should not be done during rainy or foggy weather, or when dew is present on the surface.

The presence of scale on the surface increases the time required to obtain bare metal, because of its hardness. Thus it may be advisable to allow the scale to drop off the metal surface by exposure to air for some time.

2- After grit-blasting, dust must be removed from all surfaces, and the plates must be primed as soon as possible to prevent moisture and dirt in the air Settling on the surface. Instead of immediate priming of the surface, a coat of a Positing solution may be applied. This solution provides a good foundation for all types of primers, and the application of primers may be delayed for as long as 24 hours.

3- Other methods of preparing for painting are:

   a. Wire brushing, either by hand or using pneumatic bushes.

   b. Scraping with special knives or scrapers.

   c. Chipping with hand hammers or pneumatic tools.

   d. Grinding with specially developed surface grinders.

4- Spark resistant tools must be used in explosive areas. Previously painted Surfaces also require some treatment before application of another layer. The Old Paint must be free from oil, grease, dirt, dust, foreign substances and flaking paint. This can be achieved by the use of suitable cleaning fluids, Steam cleaning, high pressure water jets or wire brushing.

5- Optimum conditions require the application of a full coat of priming paint on the prepared surface, followed by a full coat of finish paint. Paint can be applied by brush, roller, airspray or airless spray, in accordance with the manufacturers' recommendations.

Unless explosion proof, power driven spraying **equipment** must NOT be used in explosive areas

4.3.2 Internal Maintenance of Tank

1- Internal maintenance of tanks is mainly concerned with corrosion combat.

2- Internal corrosion occurs on tank bottoms and in the vapour space above the liquid. In this respect sour crudes present a much more serious problem than sweet crudes or refined products.

3- Steel which is wetted frequently by oil is unlikely to corrode quickly. Therefore, vapour zone problems in floating-roof tanks are confined to the small area under the fabric seal.

4- Iron sulphide scale and brine in the basic sediment and water layers can cause serious internal corrosion on tank bottoms. When combined with corrosion products dropping from the tank roof, basic sediment and water can quickly eat away tank bottoms unless protection is provided.

5- Although different coatings are used, preparation of the surface in the vapour zone and on tank bottoms is of utmost importance.

6- In both cases, long life of the coating is directly dependent on the surface preparation. The area to be coated should be free of scale and other foreign materials and completely dry. Sand-blasting is the most common method of cleaning the surfaces. For the most part, these coatings are coal tar paints or enamels with melting temperatures above 60° C (140° F). Proper primers must be used before the application of any type of coating and the primers should be applied within a limited time after the sand-blasting is completed. If rust forms or dirt collects on the steel before the primer is applied, the surface should be re-sand blasted or cleaned.

7- Bottom coatings are usually relatively thick in order to provide maximum protection. Glass reinforcing may be applied between coats. Most bottom coal tar coatings are applied by pouring, rather than by any other method.

Bottom coatings may extend from 30 cm (1 ft) to 1 m (3 ft) up the interior shell surface and up any roof supports. It is preferable to have the bottom coating applied under roof supports as well as around them. Vapour zone coatings also require a clean, dry surface for proper adherence. Appropriate primers must be used and are specified by the individual paint company.
Plastics as well as coal tar are used for vapour zone coating.

8- Vapour from oil contains hydrogen (more in sour crude, less in sweet crude) which combines with the iron of the tank roof to form iron sulphide and to free hydrogen. As iron sulphide scale accumulates, galvanic action begins between the scale and the deck material. Flexing of the roof causes pieces of the iron sulphide to break loose. On the tank bottom galvanic action again takes place between the scale and the bottom, often resulting in deep pitting and leaks.

4.3.2.1 Emptying and Blanking off the Tanks

1- Before any work is done which might release vapours, all sources of ignition should be eliminated from the area where flammable vapour may be present or may travel.

2- Roads should be closed and signs posted to keep vehicles and other potential sources of ignition away form the area. Particular attention should be paid to the wind direction in defining the extent of the hazard.

3- Normally, the operations department can be expected to have carried out any initial cleaning steps, such as hot gas oil circulation or treatment with chemicals. Furthermore, the operations department should also empty the tank to as low a level as possible using the normal system, prior to handing over the tank for cleaning.

4- Further product removal can then be achieved by either connecting a hose to the drain valve and pumping the bottoms to a slops tank, or by raising the oil level by pumping water into the tank and removing the oils through the normal suction line work. The use of water is particularly valuable if the tank is tilting or has an uneven bottom.

5- If water is used with certain products, such as motor gasoline containing an anti-icing additive, aviation fuels or other products with a critical water specification, such products should always be pumped to slops and not to the finished product tanks.

6- The presence of sediment or sludge may greatly hinder liquid removal. This is normally recognized in the initial stages and hot gas -oil or certain chemicals may be used to counter this, but nothing further should be done until the tank is opened after the gas-freeing step.

7- Next, all lines to and from the tank should be cleared and flushed with water or drained.

8- In the water flushing/pumping operations described above, care should be taken to restrict the flow of slops as well as water, to a velocity of I metre per second, in order to avoid static electricity hazards.

9- Swing arms, mixing spiders, and any other internal pipework should be washed through, after which the last remnants of product can be pumped away. At this stage some liquid may be held up in the legs of floating roof tanks because of plugged drain holes. This should be borne in mind later on in the tank cleaning operation, and legs should be checked and emptied if necessary when personnel first enter the tank. Permanent foam connections should also be checked for hydrocarbon content which may result from a burst seal.

10- After the completion of flushing, tank-side valves should then be closed, caution tabs attached to them, and the lines isolated either by disconnecting or blanking. Foam and drain lines are exceptions, and may remain in service until gas-freeing has been carried out.

11- After isolation has been completed, the tank will contain water with a thin film of product on its surface. This remaining liquid should then be drained off until traces of product appear; the remnants either being removed by vacuum truck, pumped by hand into barrels, or allowed to pass into the petroleum interceptor for skimming off.

12- Provisions should also be made for the disposal of sediment and for its removal from the tank compound. Burying of the sediment within the tank compound is not recommended because of possible contamination of groundwater and in the general interests of good housekeeping. If however, the amount of sediment is small, and is not pyrophoric, consideration can be given to disposal within the compound. When the expected amount of sediment is great, consideration may be given to building ramps over bund/fire walls, or using large containers that can be handled by a crane.

4.3.2.2 Gas Freeing

1- Before allowing people without suitable respiratory protection to enter a tank, the tank should be freed from flammable / toxic vapours, and the oxygen level raised to more than 20% v. Gas-freeing is usually done by either natural ventilation, mechanical ventilation, or, in certain cases, by steam. Figure 6.5 shows air ventilation arrangements. To a much lesser degree, inert gas and water displacement methods are used. Raising the oxygen level can of course only be achieved by either natural or forced ventilation.

2- Pure oxygen should never be used for ventilation because it enhances the explosion hazard.

3- If pyrophoric iron sulphide is present, special precautions are necessary during gas-freeing as the introduction of air may cause the deposits to ignite.

4.3.2.3 Tank Cleaning

1- Tank cleaning is usually done with the aid of portable machines. Some tanks that require frequent cleaning may be fitted with fixed cleaning guns. These guns clean the tanks with a rotating high pressure water jet. The water jet rotates in such a way that all pans of the tank are reached. The impact of the water jet loosens all adherent oil and dirt.

2- Oil or chemicals may be used for jetting instead of water. The accumulated oil and water mixture is removed from the tank bottom together with a large part of the basic sediment and water by pumping. The remaining basic sediment and water has to be removed by hand and for this purpose some tanks have a special removable plate in the lower course of the shell plates.

3- After the tank or vessel has been emptied (as far as possible), certified as gas-free and the work permit has been issued, cleaners are allowed to enter that tank and commence work.

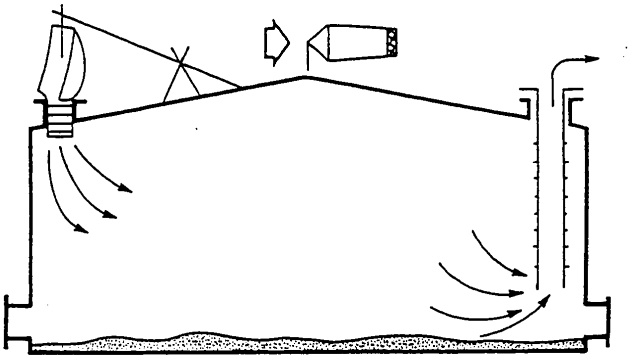
4- There are various cleaning methods possible, and a selection or combination of methods may be made depending on each particular case. In most instances, the use of water is widely applicable, and this is used in conjunction with pumps and nozzles, some with hand-held hoses, and others through fixed jets. If the tank cannot be maintained gas-free, (e.g. it still contains a large quantity of sludge), cleaning jets are used.

4.3.2.4 Cleaning of Fixed-Roof Tanks

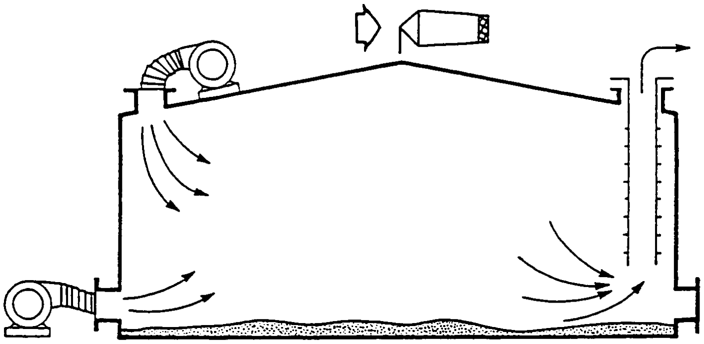
Cleaning with hand-held fire-hoses and high capacity fixed tank cleaning equipment is unsafe if the tank contains crude, gas oil, or lighter fractions.

This is because high electrostatic space charges may be created by water getting into the product remnants which could lead to incendiary discharges.

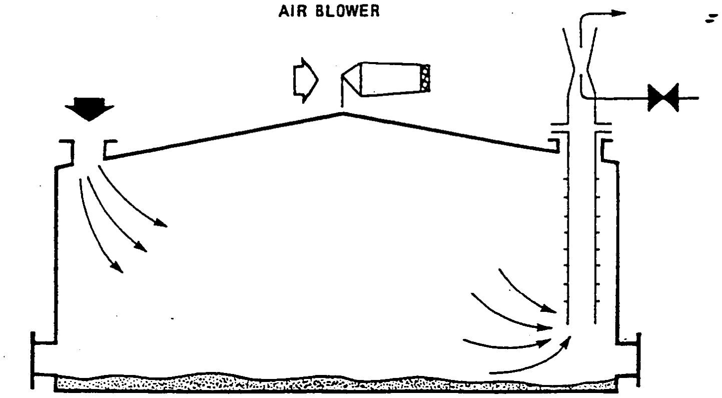
Electrostatic charges are high only if oil is present in the mist created by the jet. Hoses therefore may only be used if there are definitely no pools of oil present in the tank. This may be difficult to ensure if large quantities of sludge are present. However by filling the bottom of the tank with water, it may effectively float off any oil present.



WINDSAIL



AIR BLOWER



AIR EXTRACTOR

Figure 12.5 Air Ventilation of Tanks

4.3.2.5 Cleaning of Floating-Roof Tanks

1- Cleaning with hand-held fire-hoses and high capacity fixed tank cleaning equipment is safe, provided the roof is settled on its legs, and the leg settings do not exceed 2 metres. The flat pancake shape of the vapour space does not allow space charges to build up to dangerous voltage levels.

2- If the bottom sediment can no longer be pumped, gas oil or any other suitable light oil may be used to make the bottoms less viscous. This can be done by installing a pump (not combustion engine drive) in the tank pit, connecting the suction to a source of light oil, (e.g. a road tanker), and discharging via a rubber hose through a tank manhole**. (Note:** if the tank is not gas-free, any circulation of the oil should follow the rules given previously).

3- When the washing oil becomes fairly viscous, the oil is pumped out via the drain, or via the suction hose of a second pump, (not combustion engine driven) and the process is repeated until further cleaning in this way is no longer effective.

   At this stage, all leg drain holes of floating roof tanks must be checked and cleared if necessary. In addition, if the tank contains heating coils, they should be checked for product in the heating coils and cleared if necessary.

4- If pyrophoric iron is present, the internal surface of the tank should be kept wet to prevent spontaneous ignition.

5- In some cases, large quantities of sludge often remain which defy removal by methods other than manual, and the above process may well be limited in its effect. In practice two possibilities remain, either manual removal, or the use of water hoses from tank manholes which will, break down the sludge further for removal by vacuum truck or sludge pump. Manual removal requires cleaners wearing air-supplied breathing apparatus and equipped with wooden tools, squeegees etc. However, water jetting in a fixed-roof tank can be unsafe because of the following two factors:

   a. The tank vapour space can re-enter the explosive range as a consequence of sludge disturbance;

   b. Pools of liquid hydrocarbons may still be present, and create charged mists capable of causing an incendiary spark.

6- The potential hazards should always be evaluated for each specific case by an experienced operator. The decision to proceed either manually or with water jets can therefore only be taken as a result of a local assessment.

7- If complete oil removal is difficult, do not start to use water hoses until the tank is pronounced gas-free. There should be continuous forced ventilation while jetting, preferably using an air-extractor on a roof manhole with a flexible trunk extending to the bottom part of the tank. The forced ventilation may prevent explosive levels being reached, but vapour concentrations must be continuously monitored at several different places. If vapour concentrations rise to 10% LEL, jetting must stop until the atmosphere is again gas-free.

8- If forced ventilation is difficult, ensure that no pools of oil are present. This may be achieved by flooding the bottom of the tank with water, and pumping away the surface oil to slops. Provided no pools of oil are present, the mist formed by jetting is unlikely to create an explosion hazard.

9- Close attention must be paid to the appearance of the tank floor, and jetting stopped if oil pools re-form. Continuous checking of the tank vapour space is still a necessary safety measure, and work must stop if vapour concentrations rise to 10% LEL.

10- Finally the cleaners should enter the tank, wearing air supplied breathing apparatus, and using wooden tools, push the remaining sludge to the drain, pump suction, or tank manhole. Ventilation should continue during this period and frequent gas tests taken. If the concentration exceeds 10% LEL, consideration should be given to stopping the work because higher concentrations may be present elsewhere in the tank. In any case personnel should leave the tank if the concentration approaches 50% LEL.

Because of the difficulties in measuring vapour concentrations in such a large space, the levels recommended above should be interpreted with caution. In practice, any sign of gas should be considered a hazard and the source investigated.

11- Heating coils, roof supports and other internals should then be cleaned by hosing with gas oil.

12- The next step is further cleaning of tank walls, bottom and internals with water jets. The washing is usually done with a 10 bar water stream. Because of static hazards, this procedure may be unsafe if there is a possibility of vapour release creating an explosive atmosphere as a result of disturbing any remaining sludge. Special care is therefore still required at this stage to ensure that the tank vapour concentration is checked and kept gas-free. The scale or sediment will contain a high proportion of rust, and will have to be collected and removed.

This is usually done manually after the water has been discharged into the drainage system. Care should be taken that any pyrophoric iron is keptavet during removal.

13- Where vacuum trucks are available for general cleaning duties such as cleaning small tanks, oil-catchers, oil-sewers, etc., such vehicles can also be used for sludge removal from a tank. The advantage of this method is that the sludge is transferred directly from the tank into a transport medium, so that double handling is avoided. The relatively small capacity of the vacuum tank however, (typically $6m^3$), makes it unsuitable for cleaning jobs where large amounts of sediment have to be removed.

4.4 Hazardous Conditions and Safety Procedures

There are several causes of accidents which occur during tank inspection and cleaning:

1- Prominent among them are explosions due to the inadvertent ignition of an explosive air-vapour mixture within the tank. Conditions for creating explosive air-vapour mixtures in the vapour space of tanks storing petroleum products are seldom present under operational conditions. This is due to the fact that the upper and lower explosive limits for mixtures of hydrocarbons lie close to each other, approximately between 1 % and 10% for normal petroleum products. Tables are available giving the explosive limits and other combustion data for a range of compounds. It should be noted that the upper explosive limits of the lighter hydrocarbons are somewhat higher than those of the heavier products.

2- A hazardous condition may also occur outside a tank, due to gases expelled during ventilation. When a tank, vessel, or confined space, which has contained a volatile hydrocarbon, is being ventilated, e.g. prior to cleaning or repair, the large volume of vapourlair mixture which is released may travel beyond the limits of the usual safe distances. Continuous checks should therefore be made on wind direction and speed, and volume of discharge.

4.4.1 Explosive Air-Vapour Mixtures

In general, the vapour spaces of both crude and light product tanks will contain air-vapour mixtures which lie above the upper explosive limit. Only during the filling of an entirely empty tank is it certain that an explosive mixture will be present during a short period.

Explosive mixtures may also sometimes occur in fixed-roof tanks when emptying, due to the ingress of air into the vapour space. This also applies to floating-roof tanks when the roof is allowed to settle on to its legs.

Other products, such as gasoline and kerosene, can give rise to hazardous atmospheres under normal storage conditions, and, in a few cases, even heavy products may be considered hazardous, particularly if they are stored at temperatures above their flash points. In general, oil products are hazardous when the vapour pressure lies between 0.1 and 1.3 psi at storage temperature.

From this it can be seen that there is little danger of gas oil, diesel oils and fuel oils forming explosive mixtures under normal conditions. Nevertheless the procedure of gas testing, isolation of lines, and the issuing of gas-free and entry permits must be carried out.

Although crude oil and light product tanks will not contain explosive air-vapour mixtures under normal working conditions, the situation is quite different when such tanks have to be cleaned. Gas-freeing by ventilation will bring the air-vapour mixture in the tank through the explosive range and eventually below the lower explosive limit.

However, as long as traces of liquids remain in the tank, it is quite possible that, as a result of gradual evaporation, or of vapours being freed by the cleaning measures, the explosive zone is re-entered. This is one of the greatest dangers of tank cleaning, and frequent use of the combustible gas detector (explosimeter), is therefore essential. In order to reduce the risk of vapour concentrations rising to dangerous levels, good ventilation should be maintained at all times while men are working inside the tank.

4.4.2 Ignition Sources

In addition to the presence of an explosive mixture, a second condition is necessary for an explosion or fire; that is, a source of ignition in the vapour space. Sources of ignition are:

1. Static electricity.
2. Pyrophoric (self ignition) iron sulphide.
3. Sparks by metal-on-metal impact.
4. Use of electrical equipment.
5. Unsafe procedures, such as smoking in tanks.

4.4.2.1 Static Electricity

Static electricity is generated when any material moves relative to a different material. Generation of static charges occur in such operations as the filtering or agitating of liquids, or in vapour mists in which droplets of different sizes lead to the generation of space charges. This latter aspect is of particular importance in tank cleaning, when jets are often used to spray water or other fluids in the tank. These jets can create highly charged mists when rebounding off an oily internal tank surface. Once a space charge has been established, it is then possible that a dislodged piece of scale or even a slug of liquid from the jet, can act as an insulated conductor and pick-up charge whilst falling / travelling through the mist. When the charged object approaches an internal tank surface an incendiary spark is possible. In a non-gas-free tank an explosion may result.

All liquids in motion are capable of generating electrostatic charges. Under certain conditions, non-conducting liquids, for example hydrocarbons, may accumulate high static charges. Therefore, all equipment used in gas-freeing, cleaning and repairing work must be efficiently bonded and earthed. This also applies to the lines and hoses used for removing tank residues and mechanical ventilation exhausters, steam nozzles, jetting equipment and CO_2 inserting lines.

Steam is sometimes used for gas-freeing and cleaning of tanks, particularly the smaller sizes. Steaming is considered safe providing the steam is dry at the point of entry into the tank or vessel. Wet steam can give rise to high electrostatic space charges. Also, wet steam lines may contain slugs causing an incendiary spark, as described above. If this happens in the initial steaming period, before the steam has inerted the tank vapour space, an explosion may occur. Because of the location of some tank farms it is often difficult to ensure that it remains dry unless some form of superheating is employed and checks of steam quality are made in the vicinity of the tank being cleaned.

If superheated steam is used, care must be taken to ensure that the steam temperature does not exceed the auto-ignition temperatures in the region of 200° C.

The actual size and shape of the tank plays an important part in the level of charge that can be reached in the vapour space due to the effect of cleaning jets. For floating roof tanks, with the roof standing on its legs, the flat pancake shape of the vapour space does not allow the generation of dangerously high space charges with normal cleaning equipment. The different geometry of fixed-roof tanks, however, may lead to space charges high enough to create incendiary sparks, which is hazardous. The tank and equipment must be efficiently bonded and earthed, even if the space charges are considered to be at a safe level.

The use of cathodic protection for tanks, vessels or pipelines may be a source of danger. To prevent sparks on the bridging of insulating flanges or contact with earthed equipment, the power supply to any tank or pipeline which is cathodically protected should always be disconnected by an authorized person before any work is permitted. In order to allow time for depolarization, this should be done at least 24 hours before any work is commenced. The tank, vessel or pipeline should then be bonded to earth before the work is commenced.

4.4.2.2 Pyrophoric Iron Sulphide

Pyrophoric iron sulphide is formed by a chemical reaction between a sulphur compound, such as H_2S, and iron oxide (for example on the steel of a tank's inner surface), in an atmosphere virtually free of oxygen. This product remains innocuous so long as it does not dry out.

A hazard associated with pyrophoric iron sulphide may arise when the tank has been used for a continuous period in storing sour crude or some gasolines. When scale from such a tank is permitted to dry out, oxygen in the air may cause the scale to ignite spontaneously. This source of ignition can be controlled by dissipating the heat to prevent a temperature rise until the atmosphere in the tank is below the flammable range. This may be accomplished by wetting all interior surfaces with water or steam. The wetting also tends to isolate these pyrophoric deposits from oxygen present during ventilation.

While steam may be used to wet pyrophoric deposits it must be either dry or superheated at the point of entry into the tank. For large tanks, steam supply is often inadequate, and water has to be used to wet pyrophoric deposits. In non-gas-free fixed-roof tanks, water jets are dangerous and should not be used for this purpose. However, wetting can be safely achieved by filling the tank with water and using fog nozzles.

4.4.2.3 Spark Formation By Striking of Metal Objects

Great care is required when handling equipment on tank roofs or when removing manholes from non-gas-free tanks. In order to prevent the occurrence of incendiary sparks should articles be accidentally dropped, damp sacks should be placed on the roof and immediately below shell manholes. These sacks should be kept continuously dampened during the work and removed immediately on completion.

Light metal (e.g. aluminium, magnesium) are particularly dangerous in this respect because they can produce high energy sparks on impact with other metals or concrete. In view of this, it is recommended that aluminium water jet nozzles, hose connections, etc. should not be used in flammable atmospheres. Furthermore, the casing and connecting flanges of airblowers and extractors should preferably not be made of aluminium.

4.4.2.4 Electrical Equipment

When work has to be carried out in a non-gas-free atmosphere inside tanks, only the use of approved battery powered lights and air operated lighting equipment should be allowed. No other electrical appliances such as tools, handlamps, etc. should be used.

Floodlights should be installed outside the tank away from areas where vapours may enter. Only when it is certain that no explosion or fire hazard exists in the tank or vessel may any other electrical appliances (portable and transportable) be used. Such appliances must be adapted for a supply not exceeding 42V AC or 110V DC. The isolating safety transformers or rectifiers, subject to the issue of a relevant permit, should be placed outside the tank or vessel.

The condition of electrical appliances should always be checked before issue and after use.. When in use for some time they should be periodically checked. The equipment should not be used when in any way defective.

4.4.2.5 Smoking In the Tank

This hazard is by no means imaginary, especially when the cleaning job is performed by casual workmen employed by contractors who are not trained in refinery or oilfield work. Continuous strict supervision in this respect is necessary. As a precautionary measure workmen should not be permitted to carry matches or lighters in the tank farm area.

4.4.3 Gases Discharged During Gas-Freeing

Hydrocarbon vapours are generally heavier than air and although they can sometimes be easily and safely dispersed by a light breeze, a flammable concentration may travel a considerable distance in a still atmosphere. Thus when a tank, vessel, or confined space, which has contained a volatile hydrocarbon, is being ventilated prior to cleaning or repair, the large volume of vapourlair mixture which is released may travel beyond the limits of the usual safe distances. Continuous checks should therefore be made on wind direction and speed, and volume of discharge.

Particular attention should be paid to gases discharged from an eductor during gas-freeing. Measures should be taken to eliminate all sources or ignition from the vicinity of the eductor exhaust.

4.4.3.1 Petroleum Gases

In order to avoid any hazard to health through inhalation of toxic vapours, special care should be taken to ensure that hazardous areas are not entered by anyone except in an emergency. This includes personnel carrying out the gas-freeing procedure and other person who may happen to pass through the area. In emergencies, personnel must be provided with breathing apparatus and protective clothing. This is also applicable if inert gas has been used for purging and it is in the process of being replaced by air or hydrocarbon. In this case, there is a danger of asphyxiation in the area outside the tank.

Continuous supervision is therefore essential during the gas-freeing operation to ensure safety of personnel and equipment. The supervisor should stop the operation during very still air conditions or during electrical storms.

When a portable air compressor is used to supply air to the eductor, care should be taken that the compressor be placed at a safe distance outside the bund wall upwind of the source of the vapour. Distinction should be made between the hazards from: petroleum, hydrogen sulphide, organic lead compounds, benzene (benzol), and lack of oxygen.

When the percentage of petroleum vapours in an air-vapour mixture lies below the lower explosive limit, there may nevertheless still be a hazard through inhalation of petroleum vapours.

As a general rule, it is considered that exposure to petroleum vapour concentrations of less than 0.1% volume over a long period is unlikely to be damaging to the health of personnel. There are, however, many cases known where even lower concentrations have had an adverse effect on persons who are particularly susceptible.

4.4.3.2 Hydrogen Sulphide Gas

Besides the danger caused by the presence of petroleum gases in certain concentrations, hydrogen sulphide gas (H_2S) may also constitute a serious hazard.

Concentrations, even as low as low ppm of H_2S may cause unconsciousness and even death. Before a crew is allowed to enter a tank it is necessary to ascertain the extent of any hazard present. In certain circumstances suitable air supplied breathing apparatus and life-lines must be worn. The men should be under constant supervision by two others stationed outside the tank holding the life-lines, one of whom should also have air supplied breathing equipment at the ready.

It should be stressed that the odor of hydrogen sulphide is not a reliable guide to its presence as with exposure to the gas, the sense of smell is very rapidly lost.

Lack of oxygen may result from chemicals absorbing or replacing oxygen in the tank air, or from inert gas often used to exclude or to reduce the possibility of explosions.

Air in clean tanks which are closed for an extended period may become deficient in oxygen because of rusting (oxidation) of the metal of the tank.
Improper or inadequate ventilation during tank work may also result in a lack of oxygen. No tank should be entered without breathing apparatus unless the oxygen content is 20% or above.

4.5 Safety Procedures

4.5.1 General Safety Instructions

The above mentioned hazards can be minimized by following safety procedures that are summarized below. They should be adhered to for all operations that involve the entering of personnel into tanks.

1. All lines to and from the tank must be disconnected or blanked off.

2. A gas-free and oxygen certificate must be obtained or air-supplied breathing apparatus specified as appropriate.

3. Before entering the tank, a permit, signed by the supervisor, must be issued. The permit should list all safety measures and the necessary protective clothing and equipment, and should also be endorsed only for a specific time period. .

4. During a thunder-storm nobody should be allowed on the roof or inside the tank. If an explosive mixture could still be present, operations should be stopped, and, if there is time before the storm, the tank should be closed.

5. If work has to be done in non-gas-free tanks, there should always be two people present outside the tank for control of the air source (usually an air compressor), the air supply to the respirators, and for any emergency assistance to personnel in the tank.
   There should also be two independent air supply respirators, preferably self-contained, ready for immediate use in an emergency. One of the persons outside the tank should have one set at the ready, and be stationed at a tank manhole, keeping personnel in the tank under observation. If the personnel inside cannot remain within view of the outside observer, they must be joined inside by another person.

6. A fresh activated carbon type filter should always be connected in between compressor and respirators to absorb any obnoxious vapours. If there is a chance of temperatures near freezing point, air driers will also be needed. These should be connected between the compressor and the filter.

7. The air compressor should be located upwind of the tank being cleaned. A wind sock should be kept flying to indicate changes in wind direction.

8. Sludge of pyrophoric nature, (as could be the case in gasgline and crude tanks, and in tanks which have contained sour stocks), should be kept wet and, as soon as possible, taken out of the tank pit to a place for final safe disposal.

9. The maximum working temperature inside a tank should not be above 40°C unless special precautions are prescribed in the permit. The temperature can be decreased by ventilation. It should also be noted that the readings of combustible gas detectors tend to be low at high temperatures (40°C) and cautions required in the interpretation of results in hot weather.

10. Until a tank is declared gas-free, only approved battery powered lights and air operated lighting equipment should be permitted.

11. Portable lights used outside the tanks should preferably be placed away from possible vapour travel. If this cannot be done, these lights should be of an explosion-proof type, connected to extension cords equipped with connectors or switches approved
for hazardous locations. Such equipment should be thoroughly inspected prior to its use.

12. Only tools that are specifically covered by the work permit should be used in tanks that are not gas-free.

13. Cleaners etc. should always wear protective clothing whilst working with products of a corrosive nature, both inside and outside the tank. This should consist of plastic gloves, boots, and face-mask with helmet, and preferably, also PVC-coated clothing.
Specific requirements should be stated on the work permit.

14. Fire fighting equipment should always be on site during cleaning in accordance with the permit. Personnel should be trained in handling the type of equipment prescribed.

15. Pumping equipment should be preferably air-.or steam-driven, If this is not possible, care should be taken that:

- The equipment is installed at the windward side;
- The flammable vapours will not be released at ground level;
- The area around the equipment is properly tested for flammability before any equipment is connected;
- Spark arrestors and overspeed prevention devices are fitted if applicable.

16. Smoking inside a tank should never be allowed even when the tank has been declared gas-free and clean.

17. The power supply to any tank that is cathodically protected should be disconnected at least 24 hours before any work is permitted, in order to allow time for depolarization.

18. If work has to be done inside a tank, vessel or other confined space, which is gas-free and well ventilated and where entry is permitted without breathing apparatus, there should always be two persons present.

19. If a tank being cleaned remains unattended, e.g. during lunchtime, at night, or during the weekend, warning signs must be posted.

20. If either steam or water jets are used during the gas-freeing or early cleaning stages when the tank is not gas-free, certain precautions are essential to avoid static electricity hazards.

21. If tanks are cleaned at night, exits should be clearly marked by suitable means in case of power failure.

22. Before the last manhole of a tank is closed, the supervisor should ascertain that no people, tools or materials have been left behind and that all work has been satisfactorily completed.

4.5.2 Protective Clothing

1- Boots of good quality (with safety toe-caps), in good condition, and made of material resistant to water and oil should be worn by tank cleaners. Boots should be discarded if the safety toes become exposed, because of the possibility of causing an incendiary spark. It is also good practice to wear gloves made of materials resistant to water and oil, because excessive exposure may irritate and burn the skin. Acid-proof rubber, neoprene, vinyl, etc., are acceptable as resistant materials. Protective hats must always be worn.

2- If there is a danger that clothing can get badly splashed or soiled, special protective clothing (e.g. PVC overalls) should be worn with suitable face/eye protection. When cleaning leaded gasoline tanks, the Octel recommendations on clothing should always be followed.

3- If at any time normal clothing. (e.g. cotton overalls), becomes contaminated with oil or sludge, such clothing should be removed immediately. The clothing should be kept away from any source of ignition, because vapour given off by such clothing may be flammable. A bath with soap and water should be taken promptly, and clean clothing should be put on. Oil contaminated clothing should not be kept in locker rooms or stored in lockers. It should be dry cleaned and not laundered to ensure removal of all contamination.

4- Tank cleaners should take a bath with soap and water at the end of each day's work, and when the tank cleaning job has been completed. In the event of hands, etc. becoming contaminated, cleaners should wash with soap and water, preferably hot, as soon as possible.

4.5.3 Respiratory Protection

- Protective respiratory equipment for tank cleaners should provide a positive air pressure in a full-face piece mask or hood throughout the breathing cycle.
  Canister type masks are not permitted for working in confined spaces or tank cleaning because they do not provide proper protection against vapour concentrations above 2%, nor do they protect against oxygen deficiency.

- Positive air pressure may be supplied to the full-face piece mask in one of the following ways:

1. From a positive-pressure blower either hand-operated or (preferably) motor driven, the discharge of which is connected to the mask by means of a low-pressure hose-line.

2. From an air compressor with activated-carbon filter and, if necessary, air driers. The discharge of this equipment is connected by an intermediate-pressure air line to a reducing valve worn by the cleaner. A low-pressure air line connects the low-pressure side to the mask.

3. Use of air from plant air lines or from compressors supplying power tools should not normally be permitted because the air from such sources is not free from toxic contaminants, nor is the supply under control of the tank crew. If, however, absolutely no other source of air supply is available and air from plant lines etc. is used, it should be purified, e.g. by carbon filter.

4. From one or more high-pressure breathing air cylinders fitted with reducing valves.

5. From a high-pressure breathing air cylinder carried by the tank cleaner. Because of the limited air supply this self-contained equipment is recommended only for tank entries of short duration, such as for inspection, gas testing or to provide emergency assistance.

If an air supply, other than an air cylinder carried by the cleaner, is used, measures must be taken to ensure that, in case the air is interrupted, the people inside the confined space will have enough time to get out safely.

Such measures could consist of placing a pressure vessel between source and mask, or keeping a second air compressor running. If a 'Bloman' apparatus is used, men can breathe with the blower stopped, but must leave the tank in such a case.

Where air is supplied from a blower or compressor, such equipment should always be located to the upwind side of the tank, and should not be near an engine exhaust or other source of contamination.

After the full-face piece mask has been adjusted to the face and tightened, it should be tested for leaks/gas-tightness. This is accomplished by closing the end of the tube with the palm of the hand, or pinching the tube to cut off the air, and inhaling. If the mask collapses against the face, the fit is satisfactory.
If it does not, leaks should be located and eliminated. Under no circumstances should anyone remove his mask while inside the tank.

Face pieces of the mask sets should be cleaned with soap and water at least at the end of each day, and after completion of the job. They should then be dried and tested by a competent person to ensure that the valves are not sticking.

Other parts of the mask sets including hoses and life-lines should be cleaned after completion of each job and protected against excessive heat.

4.5.4 Eye-Protection Equipment

Eye protection equipment, of a full-coverage type, should be worn during the scraping of scale, cutting of rivets and the spreading of sawdust or other absorbent. Such equipment should be cleaned frequently and should be washed and sterilized upon completion of each job.

4.5.5 Use of Life-Lines

Under very special circumstances, e.g. for inspection purposes, tanks and confined spaces which have not been gas-freed or which are deficient in oxygen, may be entered. The use of an air-supplied breathing apparatus, body harness and life-line attached to the person(s) entering, (if safe to do so) is required.

The free end of the life-line should be secured to a fixed object outside the tank and should be attended by two persons, one of whom will keep the personnel in the tank constantly within his vision. The observer may pass tools, but he must have no other job which will take his attention away from the personnel in the tank, or which will interfere with his attempt to withdraw a victim by use of the life-line, or will require his leaving the vicinity of the tank for any time whatever.

In case of emergency, the outside observer must never enter the tank until he is relieved at his post. It is his job to summon aid immediately (various alarms, such as a whistle, may be used), to attempt to remove the victim by use of the life-line and to perform all necessary rescue functions from the outside. Upon arrival of help, he may enter the tank for rescue work only when he is assured that outside assistance is adequate. Such observers should be well trained in basic First Aid principles, such as rescue breathing techniques. Rescuers entering the tank must be protected with the safety facilities required by the situation I.e. life-line and harness and proper personal protective equipment.

Life-lines can often be a hindrance and may well prejudice effective emergency action under certain conditions. In small spaces containing fittings (e.g. steam coils, stirrers, swing arms, etc.), or in large floating-roof tanks with many legs, entanglement of a life-line may make it extremely difficult or even impossible to extricate an unconscious person. While as a general principle the use of life-lines should always be considered in confined spaces, a local management decision may be made not to use them, if, by doing so, a less safe situation is created. However, a life-line, fitted for quick attachment to a harness, should always be available at the tank entry point.

Tank cleaning operations, especially in the preliminary stages of preparation and gas-freeing, should always be under direct supervision. A competent person, aware of the hazards of the operation and fully conversant with the cleaning procedure and with the use and fitting of protective equipment should be in attendance throughout the entire operation. This particularly applies when such work is performed by contractors.

Chapter 5

Introduction to Gas Processing

Chapter 5 Content

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Introduction to Gas Processing

5.1 The Natural Gas Processing Industry

The natural gas processing industry has grown extensively over the years.

The complexity and cost of the new plants changes continuously to reflect the changing requirements and economics.

5.1.1 Definitions

It is desirable to define several of the terms that will be used in the book. The main ones are as follows:

* **Raw Gas (Natural Gas)**	Untreated gas from / or in the reservoir
* **Pipeline gas or Residue**	Gas that has the quality to be used as a domestic or industrial fuel. It meets the specifications set by a pipeline transmission company, and / or a distributing company.
* **Sour Gas**	Gas that contains more than 1 grain of H_2S per 100 scf.
* **Sweet Gas**	Gas in which the hydrogen sulphide content is less than 1 grain per 100 scf.
* **Wet Gas**	Gas that contains more than 0.1 gallons (US) of condensate per 1000 of gas.
* **Dry Gas**	Gas that contains less than 0.1 gallons of condensate per 1000 of gas.
* **g.p.m. for a gas**	Gallons of liquid per 1000 of gas.
* **Rich Gas**	Gas containing a lot of compounds heavier than ethane, about 0.7 US gallons of C_3+ per 1000 scf of feed to a processing plant.
* **Lean Gas**	Gas containing very little propane and heavier – or the effluent gas from a processing plant.

*** Pentanes (C_5+)**	The pentane and heavier fraction of hydrocarbon stream.
*** Condensate**	The hydrocarbon liquid fraction obtained from a gas stream containing essentially pentanes$^+$.
*** Natural Gasoline**	A specification product of a certain vapour pressure.
*** Lean Oil**	Absorption oil sent to an absorber.
*** Rich Oil**	Absorption oil containing absorber material. The effluent from an absorber.
*** Lean Solution**	A stripped sweetening solution.
*** Rich Solution**	A sweetening solution containing absorbed acid gases.

5.1.2 General Gas Plant Process Schemes

To simplify these process and understand the flows of the various stream, an imaginary gas plant has been selected (Figure 5.1). We will follow the gas and liquid stream in this gas plant block diagram one by one explaining the equipment, the operations malfunctions and other pertinent details.

5.1.2.1 Development of Gas Plants

A significant factor in the development and building of gas plants initially was the need to extract the hydrogen sulphide content as a means of sweetening raw natural gas for sale as domestic and commercial fuel. To avoid the dangers and hazardous combustion conditions involved in burning natural gas in its raw state, processing plants had to be designed and built to purify the gas before sending it to the energy market.

More recently however, the discovery of large natural gas reserves with high hydrogen sulphide content has made the production of Sulphur from hydrogen sulphide an important section of the gas processing industry.

This necessitated the development and installation of more sophisticated facilities for hydrogen sulphide removal to take advantage of this important factor in the overall exploitation of natural gas.

Sulphur marketed each year is valued at many millions of dollars making the extraction of H_2S and recovery of Sulphur a significant factor and sometimes a dominant factor in the design of new plants.

Another important aspect of natural gas plants is to remove liquefiable hydrocarbons (propane and heavier in most cases, but also ethane in some cases) for meeting the hydrocarbon dew point requirement of sales gas or deeper “cuts” for satisfying the market for these components.

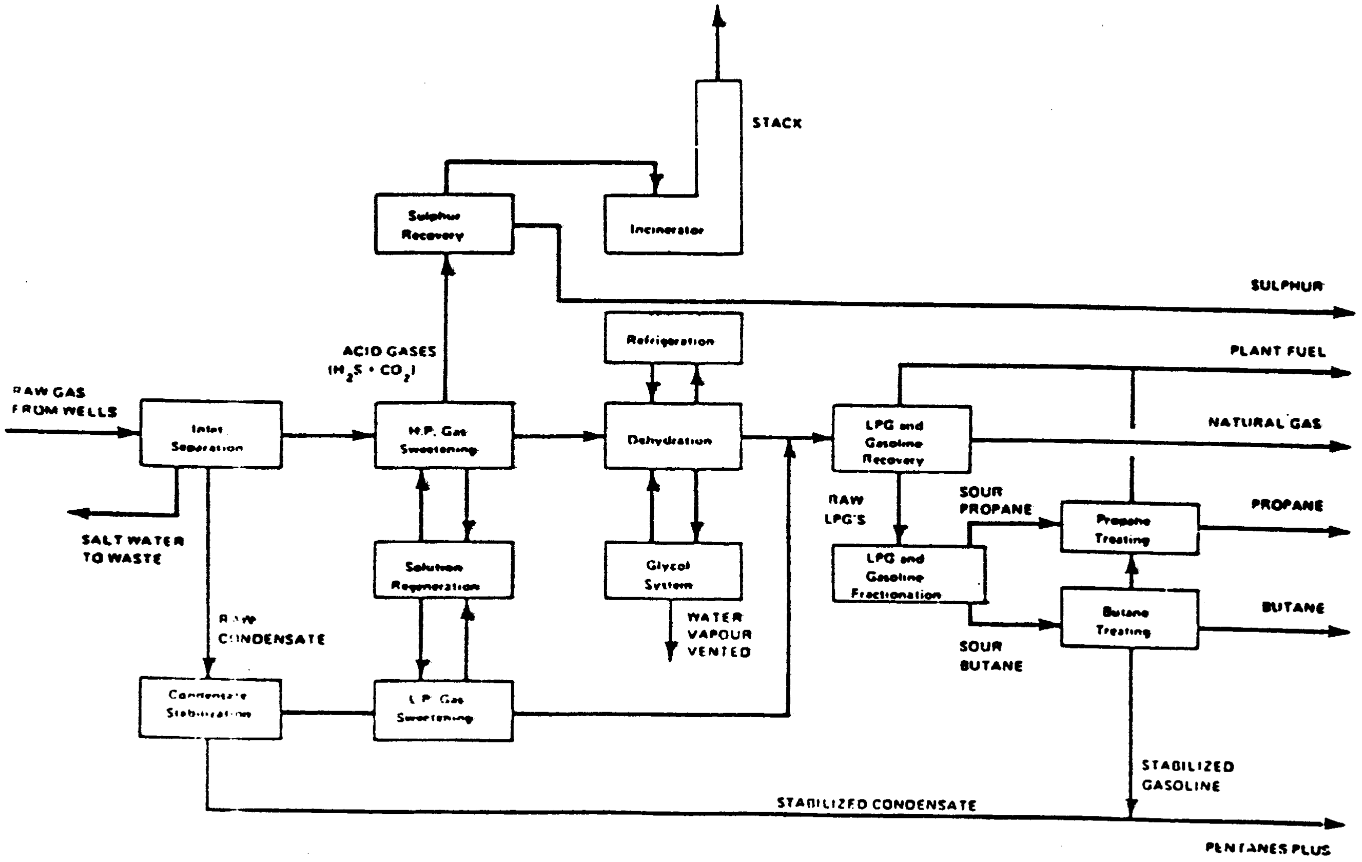


Figure 5-1 Block Diagram of Gas Processing Plant

5.1.2.2 Purposes of Natural Gas Plants

Natural gas plants are expected to meet the requirements of rigid regulations of the applicable authorities and to meet quality specifications imposed by sales contracts.

Specifications laid down as to the purity, pressure, temperature etc., of the sales gas and other products must be strictly adhered to.

The main functions of gas plants may be summarized as follows:

1. To receive the raw natural gas withdrawn from underground geological reservoirs and remove all the impurities which are objectionable to the pipeline transmission companies.

2. To deliver the gas at a specified pressure. Since gas plant process may result in gas pressure reduction, the plants must be capable of repressuring the gas for transmission purposes. Increased gas pressures may be also required for gas cycling, pressure maintenance of reservoir or gas lift work. Pipeline gas pressure is usually around 1,100 psi.

3. Depending on the nature and constituents of the raw gas, to separate and remove certain by-products such as ethane, propane, butane, condensate, Sulphur, helium and / or others.

4. To conserve hydrocarbons. This may be regarded as one of the gas plant main concerns as gas wastage must be restricted to a minimum.

5.1.2.3 Gas Plant Requirements

Gas processing plants, in order to fulfill the above functions must be able to:

1. Remove acid gases from the feed stock.
2. Handle the required volumes of gas or liquids.
3. Withstand high operational pressures.
4. Have equipment of rugged design for minimum corrosion.
5. Have equipment accessible for adjustments cleaning and repairs.

5.1.3 Types of Gas Plants

Generally speaking, all raw gas must be processed to make it marketable. The processing required and the type of facilities employed will depend on the nature of the field and the composition of the raw gas. They may very in complexity from the most simple removal of water vapour to the most extensive removal of sulphurous compounds, noncombustible gases and many of the heavier hydrocarbons.

Gas plants built for one or more of the above purposes may be classified as follows:

5.1.3.1 Gas Dehydration plant

This is a plant designed to separate and remove the water content from the gas stream and make it suitable for transmission in the pipeline. Gas dehydration may be accomplished in the field, or may be a process of its own as is case of most gas plants in this province.

Control of the dew-point in the sales gas is attained in several ways. The most popular dehydration processes today are: Solid desiccants, Glycol scrubbing and refrigeration.

During a dehydration process the recovery of some liquid hydrocarbons may also be possible.

5.1.3.2 Gas Cycling (or Re-cycling) Plant

This plant is designed to recover liquid hydrocarbons by producing the gas from the reservoir, separating the liquids and injecting the dry gas back into the formation.

The design of early gas cycling plants was brought about by the lack of an immediate market for the residue dry gas and the relatively high percentage of liquefiable hydrocarbons contained in the raw gas. Very simple facilities and equipment were employed for this purpose and while the recovered LPG and condensate products were delivered to markets the residue gas was recompressed and injected back into the reservoir.

With the opening, however, of new markets for residue gas and the construction of pipelines to the populated areas, the cycling plants changed their profile and at the end of the cycling process an abundant supply of dry gas was available for the market.

Plants that recover natural gasoline and other liquefiable components from the raw gas and return the dry gas back to the producing formation normally.

5.1.3.3 Conventional Gas Processing Plant

This a plant designed to include a number of processes necessary to sweeten the highly toxic sour gas and produce marketable sales gas and / or processes capable to extract from the gas stream liquefiable constituents, if their presence is sufficiently high, and produce propane, butane and pentane. Furthermore, it may be equipped with Sulphur recovery facilities to convert the hydrogen sulphide to elementary Sulphur.

Some Gas Processing plants are not equipped with LPG and gasoline recovery and fractionation facilities or for economic reasons do not recover Propane and butane contained in the inlet gas stream.

In this case, the heating value of the marketed gas is higher and the producers are compensated accordingly.

Most gas plants are using a full range of processes, a typical sequence of which is illustrated in (Figure 5.2)

5.1.4 Gas Plant Operations and Processes

The gas processing companies in their modern gas plants are using some of the most novel processes to produce marketable gas. These Processes may include the removal of the water vapour from the raw gas, extraction of the acid and other non-combustible gases, separation and recovery of the liquid hydrocarbons, removal of sulphurous compounds and other operations.

Modern gas plant operations are based on the most up-to-date chemical engineering techniques and are the results of the industry's years of research work and development in this field. They are inter related and are designed to perform certain functions before the gas or liquid is directed from one stage to the other. Gas plant processes may be summarized as follows, using Figure 1.2 as a pictorial guide.

5.1.4.1 Inlet Separation

The first step in processing the feed gas after entering the plant is the separation of its liquid components. Certain other impurities, such as salt water, silt, sand etc., are also removed in this section.

The equipment items, employed in this stage are separations. They may be of vertical or horizontal design and sized sufficiently to allow the free condensate and salt water to separate from the gas phase.

5.1.4.2 Gas Sweetening

Next, the gas is directed to the sweetening section which removes the sour and other undesirable gases from the feed gas stream. These gases may include, hydrogen sulphide (H_2S), carbon dioxide (CO_2), and mercaptans (RSH). The extracted "acid gases", as they are commonly called, are used as feed stock in the Sulphur plant, where most are converted to elemental Sulphur.

The H_2S content of most gas fields in Alberta is high enough to warrant the installation of Sulphur facilities. However, if it is low enough and economics so not favor its conversion to Sulphur, it may be burned in specially designed incinerators or flare stacks to Sulphur dioxide and disposed to the atmosphere together with the carbon dioxide.

Various types of sweetening processes are employed to-day by the industry most of which involve the absorption of the acid gases from the sour gas using a circulating, scrubbing solution. A large number of solutions are available on the market, each one being adaptable to a specific type of sour gas.

The most widely used solvents are the Ethanolamines, (monoethanolamine and Diethanolamine) and sulphinol.

After scrubbing the gas in the absorption towers the rich solution is directed to the regeneration section where the acid gases are released with the assistance of heat at low pressure. The regenerated scrubbing solution is then re-circulated to the scrubbing contactor for removal of more acid gases from the sour feed gas.

5.1.4.3 Dehydration

Dehydration of the gas follows the sweetening process to reduce the water content to the level permitted by the transmission line contract. Most of the water vapours, absorbed into the gas during its direct contact with the sweetening agents, must be removed here to eliminate a potential source of trouble in high pressure pipelines.

In some plants, and depending on the type of process used, the sales gas water content is specifically controlled in this stage. Other plants using more processing facilities downstream can reduce the water vapour content in the gas as specified.

The predominant types of dehydration processes are:

A. Glycol Process

This is used in plants where the water vapour content is high. The wet gas is contacted with a glycol solution of specified strength in the absorption towers to absorb the water content on a continuous basic. The rich glycol solution then flows to the glycol regenerator where its water content is released by heating.

B. Solid Desiccants

Another method of gas dehydration consists of directing the wet gas through a bed of solid desiccants. The desiccants may be one or more of several varieties and have the property of absorbing the water present in the wet gas. Silica gel particles or some variation of this substance are well known for their drying ability.

Small gas plants with no other LPG and gasoline facilities may employ dry desiccants designed to extract the water from the gas stream and remove all the gasoline constituents as well.

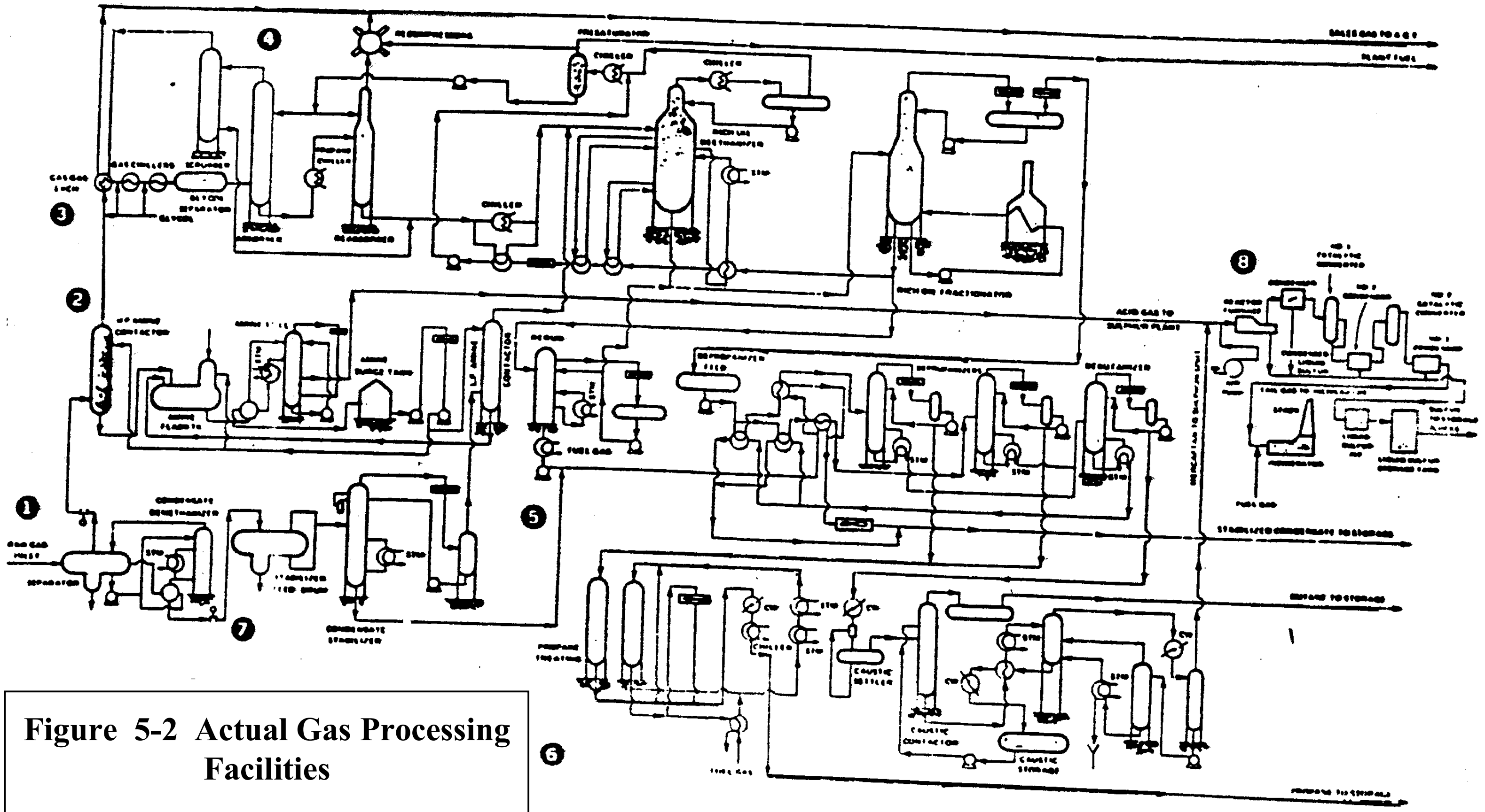


Figure 5-2 Actual Gas Processing Facilities

1- Inlet Separation
2- Gas Sweetening
3- Dehydration

4- LPG & Gasoline Recovery
5- LPG & Gasoline Fractionation
6- Propane & Butane Treating

7- Condensate Stabilization
8- Sulfur Plant

5.1.4.4 Refrigeration

In this method the gas stream is chilled by means of refrigeration to condense the water vapour and the heavier hydrocarbon vapours, such as propane, butane and pentane. To prevent the water vapour from freezing upon condensation the gas is sprayed with glycol at points ahead of the chillers. Separation equipment then removes the gasoline from the water – glycol mixture.

The rich glycol is sent to the glycol regeneration facilities to drive the absorbed water out by heating. The regenerated glycol is then available for removal of more water present in the gas. The gasoline constituents, removed from the refrigeration systems, are further processed downstream.

Refrigeration, generally, is favored in modern gas plants as being the best single step for preparing the gas stream for LPG recovery and removal of a large portion of gasoline constituents.

5.1.4.5 Recovery of LPG and Gasoline

This is a section installed in major gas plants to scrub the chilled gas stream with low molecular weight absorption oil and remove liquefiable hydrocarbons and gasoline constituents. The basic processing scheme is to direct the pre-chilled gas to the bottom of an absorbing tower and to bring it in direct contact with pre-chilled lean absorption oil. Raw LPG products and gasoline are recovered using a re-absorber, rich oil de-etherizer and a rich oil fractionator.

The absorbed hydrocarbons are stripped from the rich oil by heating in a dry stripper called a rich oil fractionator. The warm lean oil is pumped back to the absorption towers for further scrubbing duties while the raw liquid hydrocarbons are sent to the fractionation process to become finished products.

One pre-requisite in LPG recovery is that both the gas stream and the circulating lean oil must be chilled before the absorption process.

Gas temperature as low as 0ºF are required for 70% recovery of the propane and 96% of the butane contained in the inlet gas to the plant. Gas temperature of - 20ºF can result in yields as high as 90% of propane and 98% of Butane from the same inlet gas. Propane recovery is increased as inlet gas and lean oil temperature are lowered.

More recent developments for high recovery of Ethane and heavier hydrocarbons are primarily cryogenic in nature, (i.e.) gas cooling to - 100ºF or lower. As high as 90% of Ethane and 98% or better of propane and heavier components can be recovered by these processes. Cascade refrigeration cycles and / or turbo expander processes are most common.

5.1.4.6 Condensate Stabilization

The condensate Stabilization process is a step designed to eliminate all possible vapour hydrocarbons and toxic gases contained in the raw condensate that was separated in the inlet separation facilities of the plant. The stabilizer operates at lower pressure than it source of feed to flush off its light vapours, (Methane and Ethane), hydrogen sulphide and other non-combustible gases and recycle them into the same gas stream for further processing. The stabilized condensate is withdrawn and pumped to the storage tanks or to sales.

Nearly all gas plants, small or large, are equipped with condensate stabilization facilities to stabilize the condensate which is always present in the wet gas.

5.1.4.7 Sulphur Recovery

Where an appreciable percentage of hydrogen sulphide is contained in the sour gas stream, the installation of Sulphur recovery facilities to convert this to elemental Sulphur is economically warranted.

There are several thermal methods of converting the H_2S content to elemental Sulphur. Most plants use the modified CLAUS method in which one-third of the hydrogen sulphide in the acid gas feed is burned completely to from Sulphur dioxide. The remaining hydrogen sulphide is then brought together with the produced Sulphur dioxide to from a 2/3, 1/3 mixture of H_2S and SO_2. The mixture then is fed into a catalytic reactor, and passed through a bauxite catalyst bed after preheating. Here, the Claus gas reaction takes place to form elemental Sulphur in the vapour state.

Liquid Sulphur is produced when the vapours are cooled and condensed in a condenser. The heat recovered is used, in most cases, to generate low pressure steam for process requirements. The liquid sulphur is then withdrawn from the condenser and pumped to storage or sales.

The 2/3, 1/3 mixture of hydrogen sulphide and sulphur and Sulphur dioxide is passed through a second, or a third and sometimes a fourth stage of combustion, catalytic conversion and condensing for maximum Sulphur recovery efficiency.

Waste gases from the end of the last stage are directed to the incinerator to convert the remaining hydrogen sulphide to sulphur dioxide and increase the tail gas temperature before dispersion to the atmosphere. Carbon dioxide, which went through the process with no reaction is also vented together with any remaining sulphur dioxide.

Sulphur plant extraction efficiencies of up to 97% have been reported with the Claus method together with generation of 250 psi steam in the sulphur boiler and 60 psi in the sulphur condensers.

5.1.4.8 LPG and Gasoline Fractionation

L.PG and gasoline fractionation facilities are installed, in conjunction with the LPG and gasoline recovery equipment, to fractionate the hydrocarbon mixture into the respective products of Propane, Butane and Gasoline.

The fractionation process involves a De-propanizing section, which separates and removes the propane from the mixture, and a De-butanizing stage, which removes butane from the gasoline. The gasoline is withdrawn from the bottom of the De-butanizer tower and sent to storage or sales after blending it with the stabilized condensate. The separated Propane and Butane products are subjected to further treating for removal of certain undesirable components, such as hydrogen sulphide, mercaptans and water. The distillation processes in the De-propanizer towers are accomplished through temperature and pressure gradients established and maintained across the towers. Close control of the temperature and pressure conditions is required to produce finished products of definite vapour pressures.

5.1.4.9 LPG Product Treating

Propane and Butane are subjected to further purification treatments to eliminate the residual hydrogen sulphide and other sulphurous contaminants that have escaped from the earlier gas sweetening process and were carried through the rest of the plant. Fur-thermo pipeline specifications may impose certain penalties on the producer delivering off-specification LPG products.

Propane treating is usually accomplished by passing the product through a mole sieve bed. Mole sieve is a substance that has a great affinity for hydrogen sulphide, mercaptans, water and other polar compounds. These impurities are adhered to and sustained on the mole sieve surfaces until regeneration with hot fuel gas is carried out. Clean Propane is next withdrawn from the bottom of the mole sieve and pumped to storage or sales.

Mole sieve beds apply similarly to treating Butane products but Caustic wash systems may be more efficient and effective.

5.1.5 Gas Plant Utilities

The above has been an outline of plant processes employed to purify the raw gas and achieve pipeline specification required by contract. Many utility systems are also required for these complex plants. Some of these are:

5.1.5.1 Steam Generation Facilities

The sour gas processing and treatment would be difficult without steam. Therefore, adequate quantities of steam of proper pressures must be generated in the plant to furnish the heat required for the various processes. Steam generating units, packaged or field erected types fired with plant fuel gas, may provide the required process steam and sometimes steam to run turbo-electric generators. Plants equipped with sulphur units also supply steam of lower pressure as operations by product. The process heat requirements of some plaints are provided by circulating hot oil systems.

5.1.5.2 Electrical Generation Facilities

Many gas plants generate their own electrical power' from generators driven either by gas or diesel units or steam turbines and, the exhaust steam from the turbines may be used either in the process or for heating. On site generation of electrical power has proved to be both satisfactory and profitable in many large capacity wet sour gas processing plants.

5.1.5.3 Water Supply

Water supply is usually drawn from wells drilled in location surrounding the plant. Water wells are completed in such a manner that shallow wells produce hard water and the deeper wells produce soft water, thus allowing considerable flexibility in make-up requirements, as for example in cooling towers. Effective inhibitors are often necessary to use against corrosion, control of pH or to reduce the scaling tendencies in various types of water. Other chemicals may also be needed in the water to eliminate stream pollution as required by government agencies.

5.2 Process Flow

It would be advisable at, this time to examine the inlet gas flows and trace the various streams of the plant briefly, in order to understand the sequence of the various operations employed in the hypothetical plant selected. Each gas plant may operate on a specific type of process of its own, the principles involved however, apply generally to all plants.

The gas plant processes and operations are essentially a continuation of the field operations out-line in previous lectures.

Referring to Figure 5.2 it is shown that the warm gas and liquids from the gas fields (the raw gas) enters into the first stage of processing which is inlet separation. Here, this raw feed stock is separated into its three phases, gas, liquid hydrocarbons (condensate) and water.

The gas leaves the top of the separator and after being metered is sent to the gas sweetening facilities.

The liquid hydrocarbons are pumped to the condensate demethanizer to flash off the methane content by heating before being metered. Then the liquid flows to a lower pressure in preparation for stabilization. The stripped methane is returned to the inlet separator.

The water is separated from the liquid hydrocarbons in the inlet separator and drops out into a boot, at the bottom of the vessel, and is then dumped to the waste disposal facilities.

In the H.P. Contactor of the gas sweetening stage, the sour gas is contacted with a sweetening agent (Ethanolamines, sulphinol or others), by circulating counter-currently in the towers. This removes the hydrogen sulphide, carbon dioxide and other objectionable gases. Sweet gas off the contactor flows through the gas to gas heat exchanger and then to the chilling facilities.

The rich scrubbing solution, containing the absorbed contaminants from the gas stream, is withdrawn from the bottom of the contactors and pumped to the regeneration still where these contaminants are flashed off. These acid gases are then fed to the suphur plant for their conversion to elemental4 Sulphur. The lean solution from the bottom of the still is then pumped back to the contactors to sweeten more feed gas.

In the chillers the heavier hydrocarbons are condensed at - 20ºF, a temperature well below that required to achieve the contractually specified hydrocarbon dew-points. Glycol is injected ahead of the heat exchangers and chillers to prevent hydrate formation and to dry the gas.

Low gas temperature obtained here are of particular benefit to the LPG and gasoline recovery process which follow later. In the glycol separator, the mixture of water and glycol is withdrawn from the bottom of the vessel and pumped to the glycol regeneration stage for regeneration. The water vapour from the glycol regenerator is vented to the atmosphere while lean glycol is returned again to the chillers.

The gas liquid hydrocarbon streams flow to the bottom of the Absorber next, where the gas is contacted with circulated lean absorption oil at fairly low temperature (-20ºF). The gas leaves the absorber overhead at 10ºF flows through the scrubbers and gas to gas heat exchangers and finally enters the sales gas line.

The liquid hydrocarbons condensed by refrigeration are mixed with the rich absorption oil in the absorber base and flashed to the re-absorber and rich oil flash tank. The re-absorber flash gas is contacted with small lean oil stream before being recompressed into the sales lines.

The absorption oil, rich with LPG flows to the de-ethanizer next which rejects methane and ethane overhead and limits the quantity of ethane in the propane product. De-ethanizer residue gas is used to pre-saturate the absorption oil and the excess gas is used for plant fuel or after recompression, is sent to the sales. Pre-saturation of the lean oil is essential to minimize the temperature rise in the absorber-re absorber section. Rich oil de-ethanizer bottoms then flow to the fractionator which is a stripper designed to recover the raw hydrocarbon product (LPG and gasoline) from the absorption oil.

Now lean oil from the fractionator bottoms supplies heat to the de-ethanizer side re boilers before being cooled and pre-saturated with de-ethanizer residue gas. The chilled, pre-saturated, lean oil is pumped from the pre-saturator separator to the absorber and re-absorber to complete the cycle.

A re-run system may be designed and installed, in conjunction with the LPG recovery stage, to withdraw a side stream of lean oil, process it in a column and pump it back into the still to prevent an accumulation of heavy ends in the lean oil.

The raw LPG product from the fractionation feed drum is pumped first into the depropanizer to remove all possible propane and then into the debutanizer to separate the butane from the gasoline.

Fractionation is accomplished by a series of distillations designed to separate the product of a definite boiling point from a mixture of hydrocarbons having several vapour pressures.

The resultant propane and butane products are individually treated next to remove mercaptans and water before storing. The propane is treated in mole sieve bed treaters while the butane is washed with caustic solution.

The rich caustic solution is regenerated later in a still for further treating duties while the flashed off acid gases join the acid gas feed to the Sulphur plant.

Referring back to the inlet separation units, it was mentioned that the liquids are partially demethanizer before being pumped to the stabilization system. In the stabilizer the light ends are removed from the top and the bottom stabilized condensate product flows to storage as specification natural gasoline.

The stabilized overhead gas is further treated in the low pressure gas sweetening section and combined with the feed to the rich oil deethanizer. The process flow just described, is mostly employed in major gas plants. Small plants, however that the not equipped with elaborate processes, such as LPG recovery and fractionation facilities, may be of a less complicated nature.

Appendix 1

Important Conversion Factors (*SI Units)

Length

1 cm = 10 mm = 0·01 m*
= 0·0328 ft
= 0·3937 in

1 ft = 12 in = 0·333 yd
= 30·48 cm
= 304·8 mm
= 0·3048 m

Area

1 cm^2 = 100 mm^2 = 10^{-4} m^2*
= 1·076 × 10^{-3} ft^2
= 0·155 in^2

1 ft^2 = 144 in^2 = 0·1111 yd^2
= 0·92903 × 10^3 cm^2
= 0·92903 × 10^5 mm^2

Volume

1 cm^3 = 10^3 mm^3 = 10^{-6} m^3*
= 35·315 × 10^{-6} ft^3
= 6·1024 × 10^{-2} in^3

1 ft^3 = 1728 in^3 = 0·03704 yd^3
= 28·3167 × 10^3 cm^3
= 28·3167 × 10^6 mm^3 = 0·02832 m^3

also 1 Imp. gal = 1·201 U.S. gal = 0·16055 ft^3
= 4·54596 l.

1 U.S. gal = 0·83267 Imp. gal = 0·1337 ft^3
= 3·7853 l.

1 ft^3 = 7·481 U.S. gal = 6·24 I.G.

Density

1 g/cm^3 = 1·000028 kg/l = 10^3 kg/m^3*
= 62·43 lb/ft^3

1 lb/ft^3 = 0·13366 lb/U.S. gal = 0·16053 lb/Imp. gal
= 0·01602 g/cm^3
= 16·0185 kg/m^3*

Pressure

1 lb/in^2 abs. = 27·68 in w.c. = 2·307 ft w.c.
= 2·0367 in Hg = 51·715 mmHg (torr)
= 0·070306 kg/cm^2
= 0·068047 atm
= 0·068948 bar
= 0·68948 N/cm^2*

1 bar = 1·01972 kg/cm^2 = 750·06 torr
= 0·98692 atm = 10 N/cm^2*
= 14·50 lb/in^2 abs.
= 401·47 in w.c. = 29·53 in Hg

Energy 1 Btu = 2·93 × 10^{-4} kWh = 1 × 10^{-5} therm
= 3·93 × 10^{-4} HPh
= 0·251996 kcal
= 1·05506 kJ*

1 kcal = 1·1628 × 10^{-3} kWh
= 3·9683 Btu
= 39·68 × 10^{-6} therm
= 4·1868 kJ*

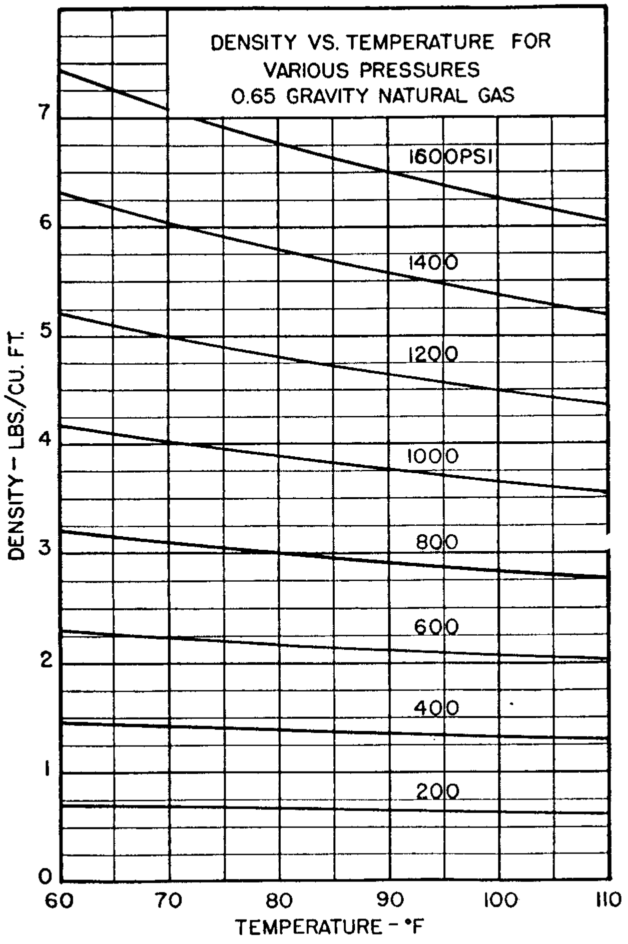
Gas volume 1 SCF (Standard cubic foot) (60°F, 30 in, sat.) = 0·02641 N m^3 (15°C, 760 mmHg, dry)

1 Nm^3 = 37·875 SCF

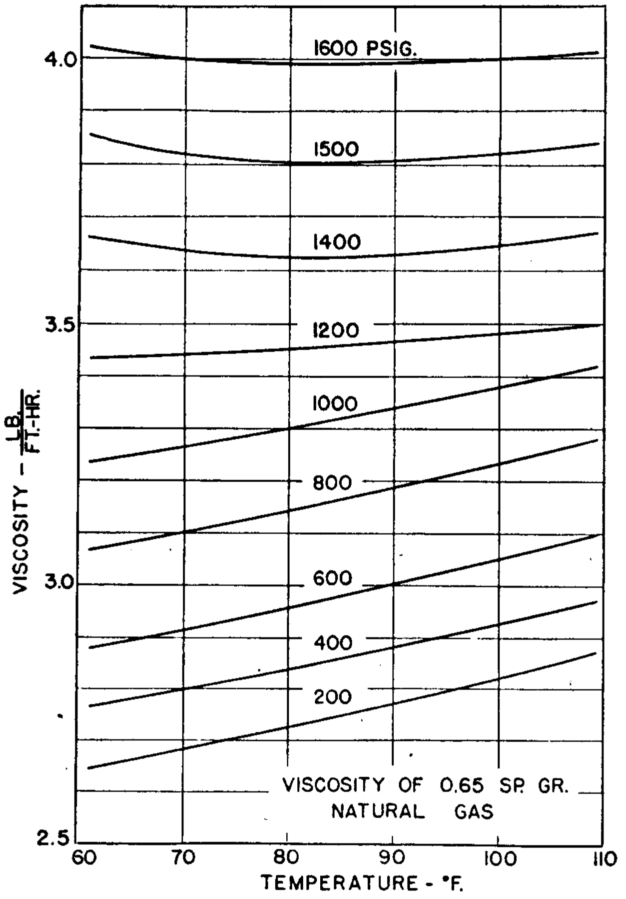
Gas density 1 lb/SCF = 17·187 kg/N m^3*
1 kg/N m^3 = 0·05818 lb/SCF

Gas calorific Value 1 Btu/SCF = 1·018 Btu/ft^3 (60°F, 14·7 lb/in^2 abs., dry)
= 9·548 kcal/N m^3
= 39·978 kJ/N m^3*

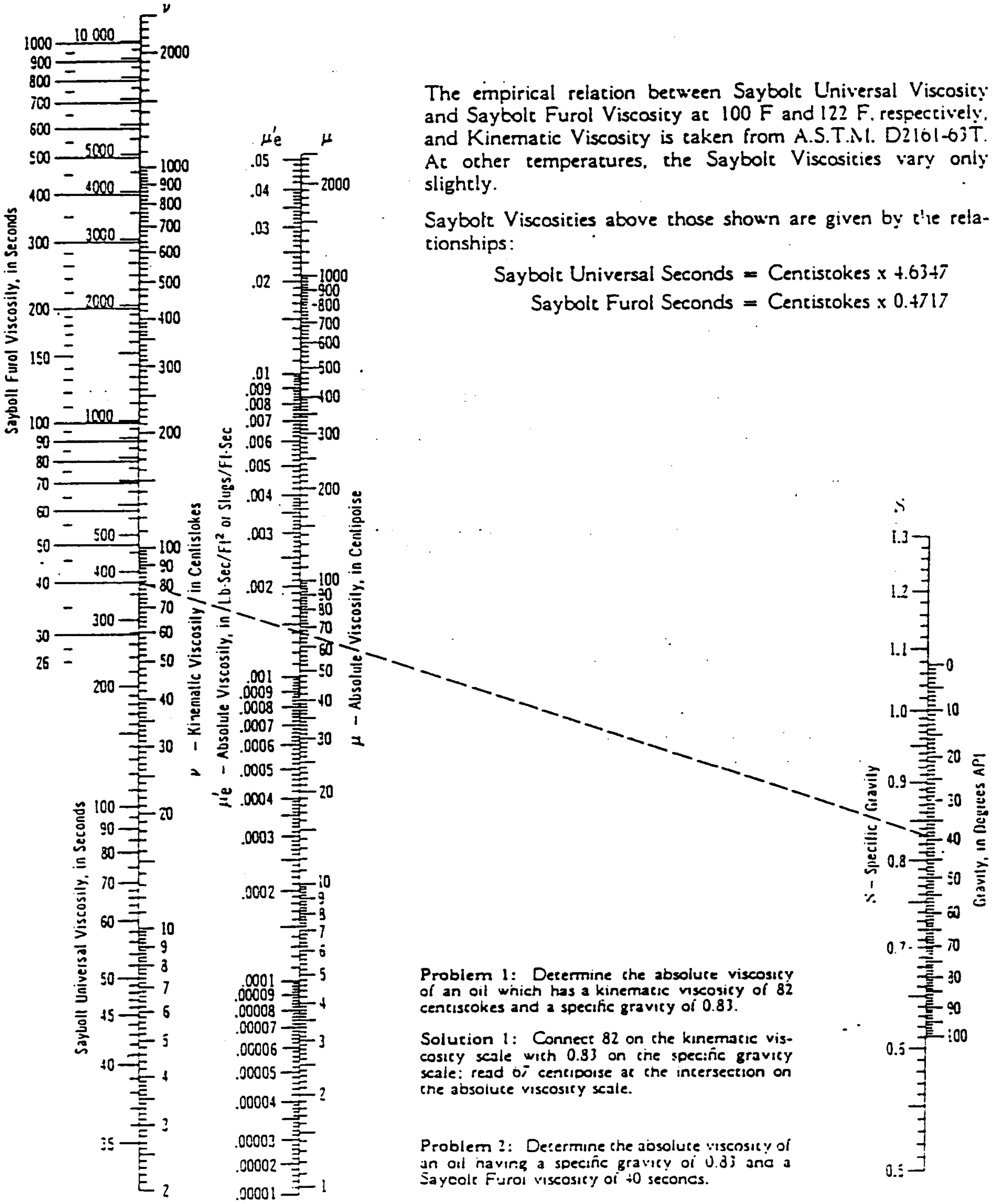
1 kcal/N m^3 = 0·948 kcal/m^3 (15°C, 760 mmHg, dry)
= 0·10473 Btu/SCF
= 0·10661 Btu/ft^3 (60°F, 14·7 lb/in^2 abs., dry)
= 4·187 kJ/N m^3*



Density of natural gas as a function of temperature and pressure.



Viscosity of natural gas as a function of temperature and pressure.



The empirical relation between Saybolt Universal Viscosity and Saybolt Furol Viscosity at 100 F and 122 F, respectively, and Kinematic Viscosity is taken from A.S.T.M. D2161-63T. At other temperatures, the Saybolt Viscosities vary only slightly.

Saybolt Viscosities above those shown are given by the relationships:

Saybolt Universal Seconds = Centistokes x 4.6347
Saybolt Furol Seconds = Centistokes x 0.4717

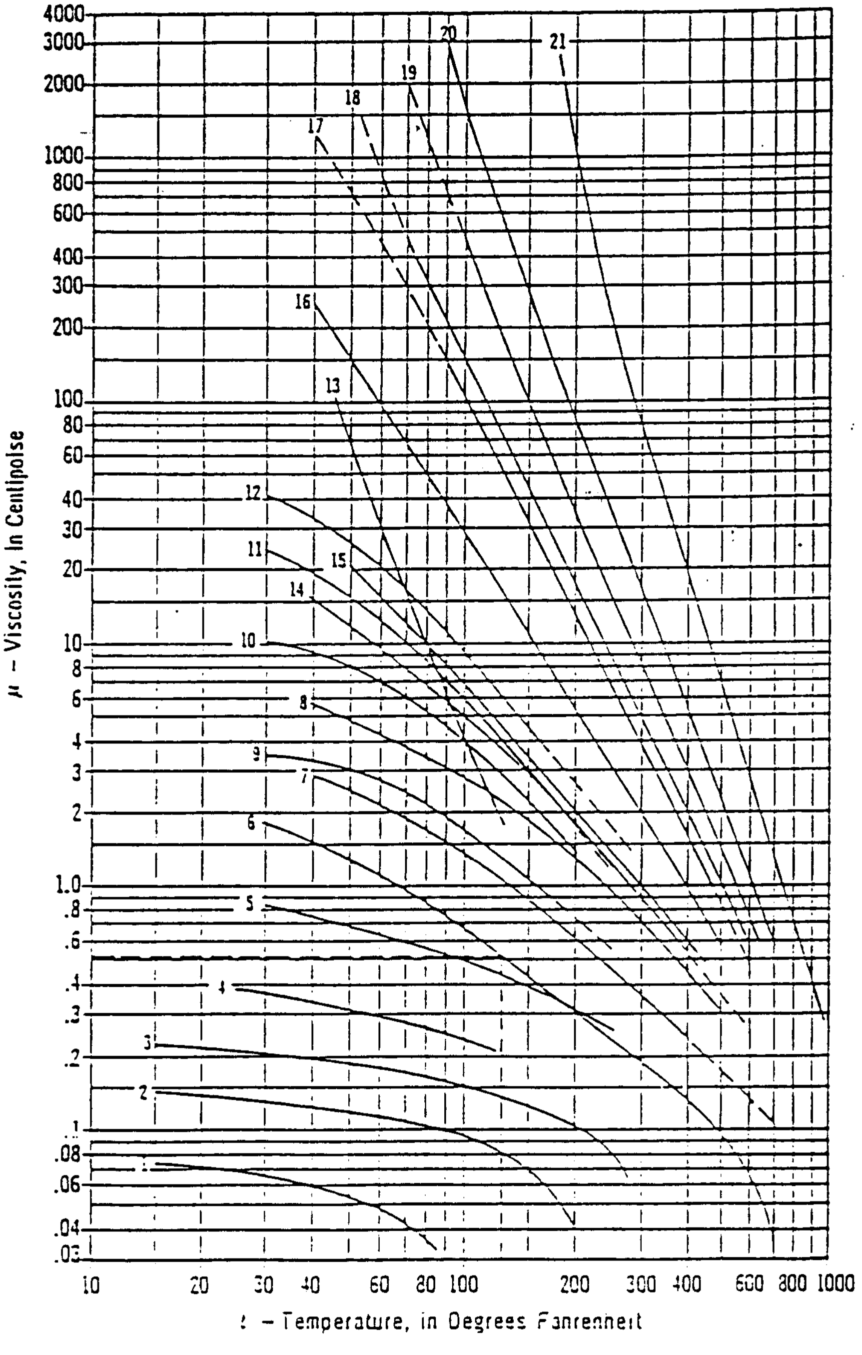
Problem 1: Determine the absolute viscosity of an oil which has a kinematic viscosity of 82 centistokes and a specific gravity of 0.83.

Solution 1: Connect 82 on the kinematic viscosity scale with 0.83 on the specific gravity scale; read 67 centipoise at the intersection on the absolute viscosity scale.

Problem 2: Determine the absolute viscosity of an oil having a specific gravity of 0.83 and a Saybolt Furol viscosity of 40 seconds.

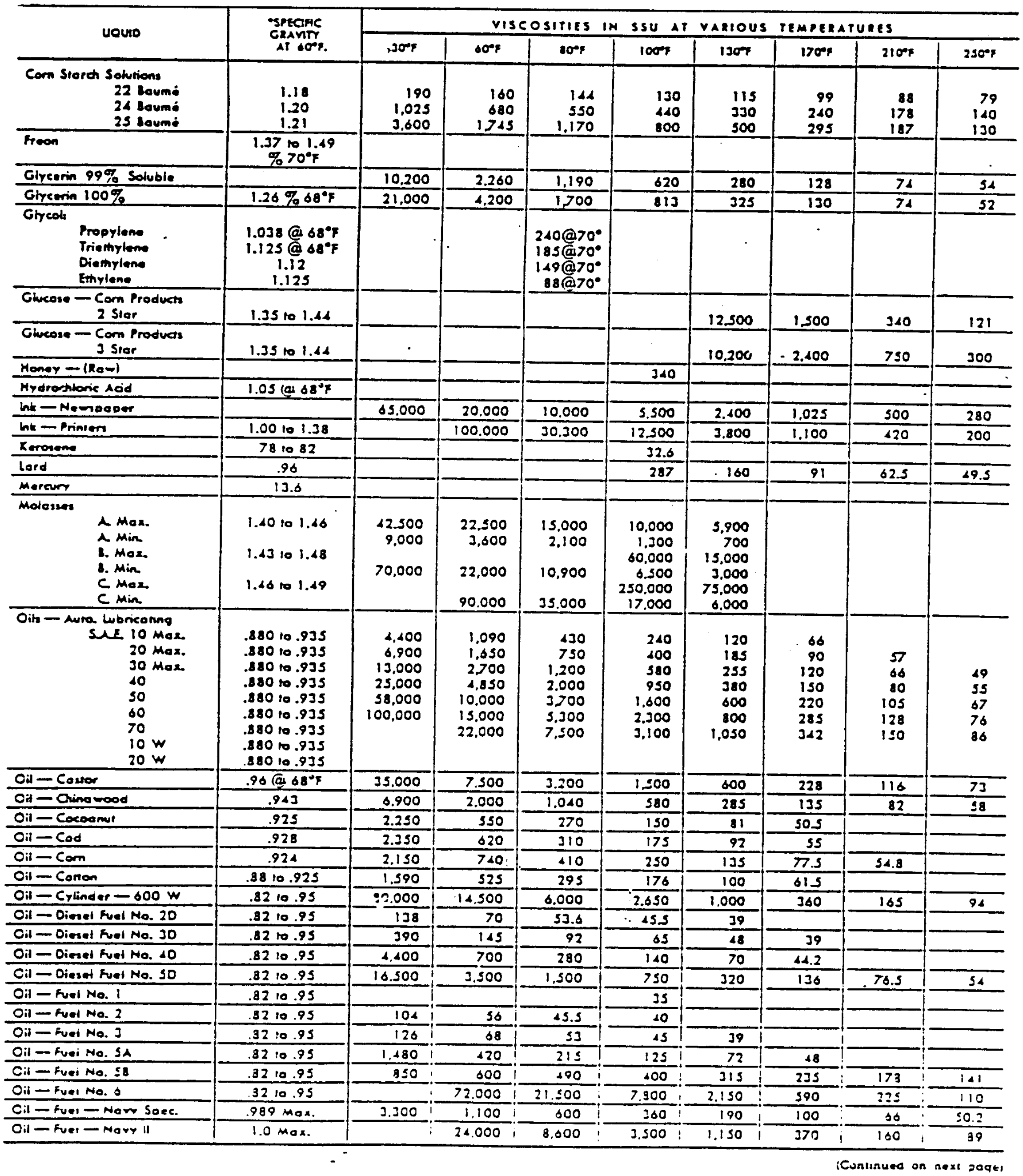
Solution 2: Connect 0.83 on the specific gravity scale with 40 seconds on the Saybolt Furol scale; read 67 centipoise at the intersection on the absolute viscosity scale.

Equivalents of Kinematie, Say bolt Universal, Say bolt Fural, and Absolute Viscosity



Viscosity of Water and Liquid Petroleum Products

Example: The viscosity of water at 125 F is 0.52 centipoise (Curve No. 6).



LIQUID	*SPECIFIC GRAVITY AT 60°F.	VISCOSITIES IN SSU AT VARIOUS TEMPERATURES							
		30°F	60°F	80°F	100°F	130°F	170°F	210°F	250°F
Corn Starch Solutions									
22 Baumé	1.18	190	160	144	130	115	99	88	79
24 Baumé	1.20	1,025	680	550	440	330	240	178	140
25 Baumé	1.21	3,600	1,745	1,170	800	500	295	187	130
Freon	1.37 to 1.49 % 70°F								
Glycerin 99% Soluble		10,200	2,260	1,190	620	280	128	74	54
Glycerin 100%	1.26 % 68°F	21,000	4,200	1,700	813	325	130	74	52
Glycol:									
Propylene	1.038 @ 68°F			240@70°					
Triethylene	1.125 @ 68°F			185@70°					
Diethylene	1.12			149@70°					
Ethylene	1.125			88@70°					
Glucose — Corn Products 2 Star	1.35 to 1.44					12,500	1,500	340	121
Glucose — Corn Products 3 Star	1.35 to 1.44					10,200	2,400	750	300
Honey — (Raw)					340				
Hydrochloric Acid	1.05 @ 68°F								
Ink — Newspaper		65,000	20,000	10,000	5,500	2,400	1,025	500	280
Ink — Printers	1.00 to 1.38		100,000	30,300	12,500	3,800	1,100	420	200
Kerosene	78 to 82				32.6				
Lard	.96				287	160	91	62.5	49.5
Mercury	13.6								
Molasses									
A. Max.	1.40 to 1.46	42,500	22,500	15,000	10,000	5,900			
A. Min.		9,000	3,600	2,100	1,300	700			
B. Max.	1.43 to 1.48				60,000	15,000			
B. Min.		70,000	22,000	10,900	6,500	3,000			
C. Max.	1.46 to 1.49				250,000	75,000			
C. Min.			90,000	35,000	17,000	6,000			
Oils — Auto. Lubricating									
S.A.E. 10 Max.	.880 to .935	4,400	1,090	430	240	120	66		
20 Max.	.880 to .935	6,900	1,650	750	400	185	90	57	
30 Max.	.880 to .935	13,000	2,700	1,200	580	255	120	66	49
40	.880 to .935	25,000	4,850	2,000	950	380	150	80	55
50	.880 to .935	58,000	10,000	3,700	1,600	600	220	105	67
60	.880 to .935	100,000	15,000	5,300	2,300	800	285	128	76
70	.880 to .935		22,000	7,500	3,100	1,050	342	150	86
10 W	.880 to .935								
20 W	.880 to .935								
Oil — Castor	.96 @ 68°F	35,000	7,500	3,200	1,500	600	228	116	73
Oil — Chinawood	.943	6,900	2,000	1,040	580	285	135	82	58
Oil — Cocoanut	.925	2,250	550	270	150	81	50.5		
Oil — Cod	.928	2,350	620	310	175	92	55		
Oil — Corn	.924	2,150	740	410	250	135	77.5	54.8	
Oil — Cotton	.88 to .925	1,590	525	295	176	100	61.5		
Oil — Cylinder — 600 W	.82 to .95	52,000	14,500	6,000	2,650	1,000	360	165	94
Oil — Diesel Fuel No. 2D	.82 to .95	138	70	53.6	45.5	39			
Oil — Diesel Fuel No. 3D	.82 to .95	390	145	92	65	48	39		
Oil — Diesel Fuel No. 4D	.82 to .95	4,400	700	280	140	70	44.2		
Oil — Diesel Fuel No. 5D	.82 to .95	16,500	3,500	1,500	750	320	136	76.5	54
Oil — Fuel No. 1	.82 to .95				35				
Oil — Fuel No. 2	.82 to .95	104	56	45.5	40				
Oil — Fuel No. 3	.82 to .95	126	68	53	45	39			
Oil — Fuel No. 5A	.82 to .95	1,480	420	215	125	72	48		
Oil — Fuel No. 5B	.82 to .95	850	600	490	400	315	235	173	141
Oil — Fuel No. 6	.82 to .95		72,000	21,500	7,800	2,150	590	225	110
Oil — Fuel — Navy Spec.	.989 Max.	3,300	1,100	600	360	190	100	66	50.2
Oil — Fuel — Navy II	1.0 Max.		24,000	8,600	3,500	1,150	370	160	89

(Continued on next page)

Viscosity and Specific Gravity of Common Liquids

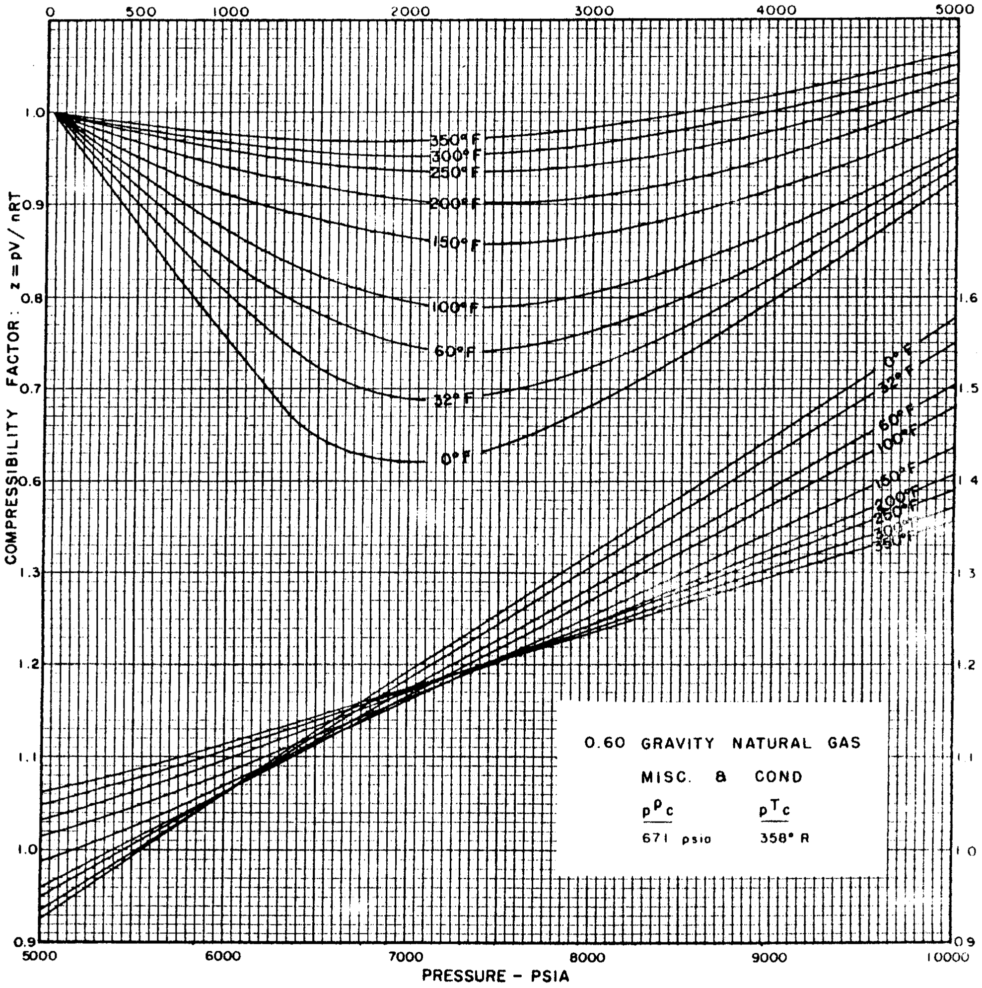
LIQUID	*SPECIFIC GRAVITY AT 60°F.	VISCOSITIES IN SSU AT VARIOUS TEMPERATURES							
		30°F	60°F	80°F	100°F	130°F	170°F	210°F	250°F
Oil — Gas	.887	205	89	62.5	50	41			
Oil — Insulating		439	152	92	65	47.5	38.6		
Oil — Lard	.912 to .925	1,400	560	340	220	128	76	55.2	
Oil — Menhadden	.933	750	330	210	140	90	60.5		
Oil — Neats Foot	.917		1,020	440	235	120	74		
Oil — Olive	.912 to .918	1,500	550	320	200	115	70	51.5	
Oil — Palm	.924	1,790	640	360	221	125	74	53	
Oil — Peanut	.920	1,325	515	300	195	112	69.5	51.5	
Oil — Quenching	None Given		850	350	240	148	87	61	
Oil — Rape Seed	.919	1,550	625	340	250	145	87	61.5	49.5
Oil — Rosin	.980	35,400	7,600	3,200	1,500	600	238	115	72.5
Oil — Rosin (Wood)	1.09 Avg.							9,000	750
Oil — Sesame	.923	1,150	470	282	184	110	69	52	44
Oil — Soya Bean	.927 to .98	1,320	470	265	165	96	60		
Oil — Sperm	.883	400	215	150	110	78	57		
Oil — Turbine Heavy	.91 Avg.	4,800	1,280	625	350	170	86	57	
Oil — Turbine Light	.91 Avg.	770	330	208	138	87	58.8		
Oil — Whale	.925	1,070	460	280	184	112	72	53.5	45
Petrolatum	.825	350	220	167	130	97	72	58	50
Phenol (Carbolic Acid)	.95 to 1.08	6	65 @ 65°						
Silicate of Soda Baumé 41° Ratio 1:3.3		3,500	350	125	66	42.5			
Silicate of Soda Baumé 41° Ratio 1:3.22		800	195	100	64	45			
Silicate of Soda Baumé 42° Ratio		1,650	380	180	104	60.5	45.5		
Syrup — Corn — Karo			60,000	15,500	5,000	1,300	350	136	
Syrup — Orange	None Given	50,000	9,400	3,700	1,690	650	242	117	72.6
Syrup — Corn 41° Baumé	1.395		70,000	25,000	11,000	3,600	1,100	450	225
Syrup — Corn 42° Baumé	1.409			54,000	20,000	6,000	1,650	600	280
Syrup — Corn 43° Baumé	1.423				42,500	10,000	2,200	700	300
Syrup — Corn 44° Baumé	1.437					22,500	3,900	1,050	380
Syrup — Corn 45° Baumé	1.450					55,000	7,000	1,460	480
Syrups — Sugar:									
60 Brix.	1.29	1,650	350	162	92	54.7	40.3		
62 Brix.	1.30	2,600	480	215	111	62	42.5		
64 Brix.	1.31	4,400	720	298	148	72	45.5		
66 Brix.	1.326	7,400	1,100	420	195	86	49.5		
68 Brix.	1.338	12,000	1,650	620	275	114	57.5	42.1	
70 Brix.	1.35	28,000	3,100	1,000	400	145	63.5	44	
72 Brix.	1.36	45,000	4,800	1,550	640	220	85	51.5	
73 Brix.	1.37	26,500	3,800	1,325	580	220	89	54	42.9
74 Brix.	1.376		11,000	3,050	1,100	340	112	60	44.5
76 Brix.	1.39		19,000	5,500	2,000	620	190	87.9	56
Sweetose	None Given	70,000	7,700	2,400	950	320	114	62	46
Sulphuric Acid	1.83								
Tallow	.918 Avg.								
Tar — Coke Oven	1.12+		19,000	4,500	1,400	380	114	58.5	43.5
*Tar — Gas House	1.16 to 1.30		33,000	7,000	2,000	480	128	61	44
Tar — Pine	1.06		55,000	10,000	2,500	550	135	61.8	43.7
Tar — Road — RT 2	1.07	14,000	2,800	1,180	580	250	107	63.6	49
Tar — Road — RT 4	1.08		13,900	4,300	1,650	540	180	85	55
Tar — Road — RT 6	1.09		80,000	19,500	5,900	1,400	350	130	71
Tar — Road — RT 8	1.13				30,000	5,000	850	240	100
Tar — Road — RT 10	1.14 —			FIGS.	TOO	HIGH	FOR	LOG	PAPER
Tar — Road — RT 12	1.15 —			FIGS.	TOO	HIGH	FOR	LOG	PAPER
Varnish — Spar	.9	3,800	1,600	1,000	650	370	200	125	37

* Depends on origin, or percent and type of solvent used.

Viscosity and Specific Gravity of Common Liquids (Cont'd)

Simplified Compressibility Factor Charts for Natural Gas Calculations

CHART 1

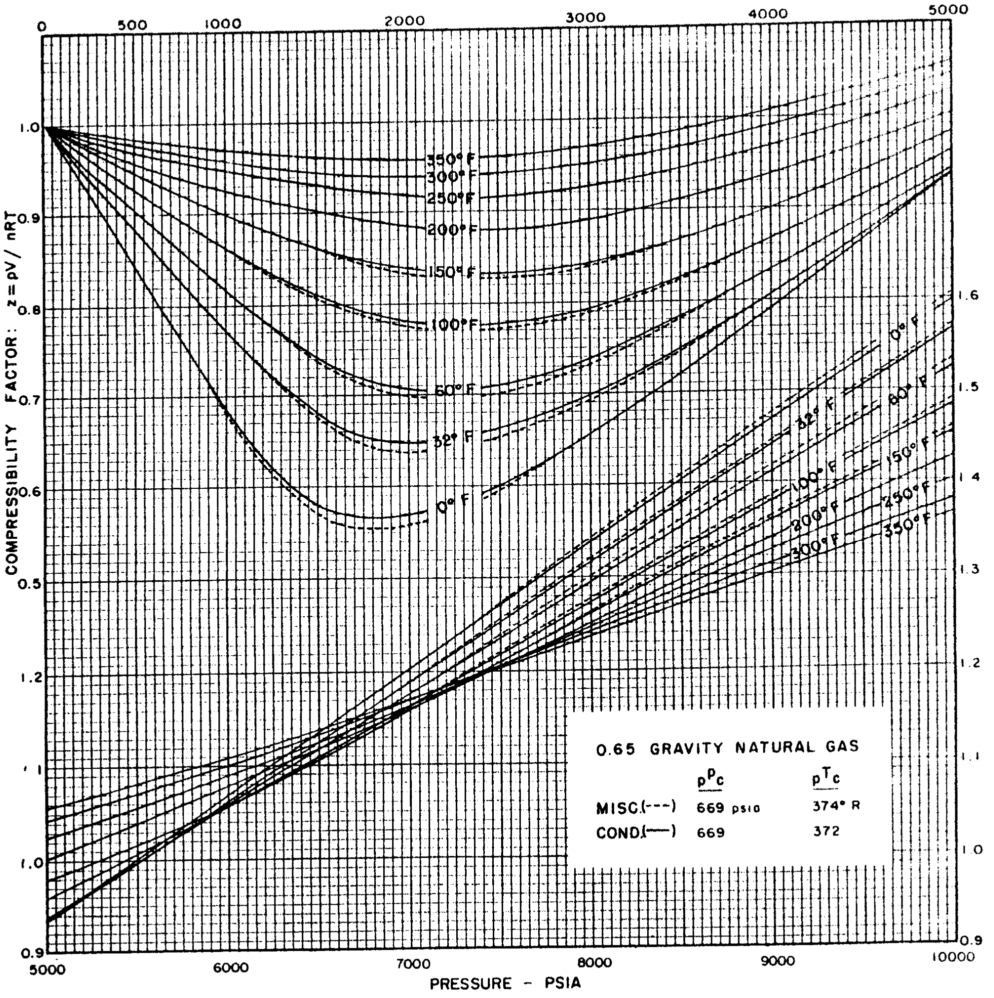


Carl Gallin, University of Tulsa

American Gas Journal, GAS HANDBOOK ISSUE, August 15, 1959

Simplified Compressibility Factor Charts for Natural Gas Calculations

CHART 2



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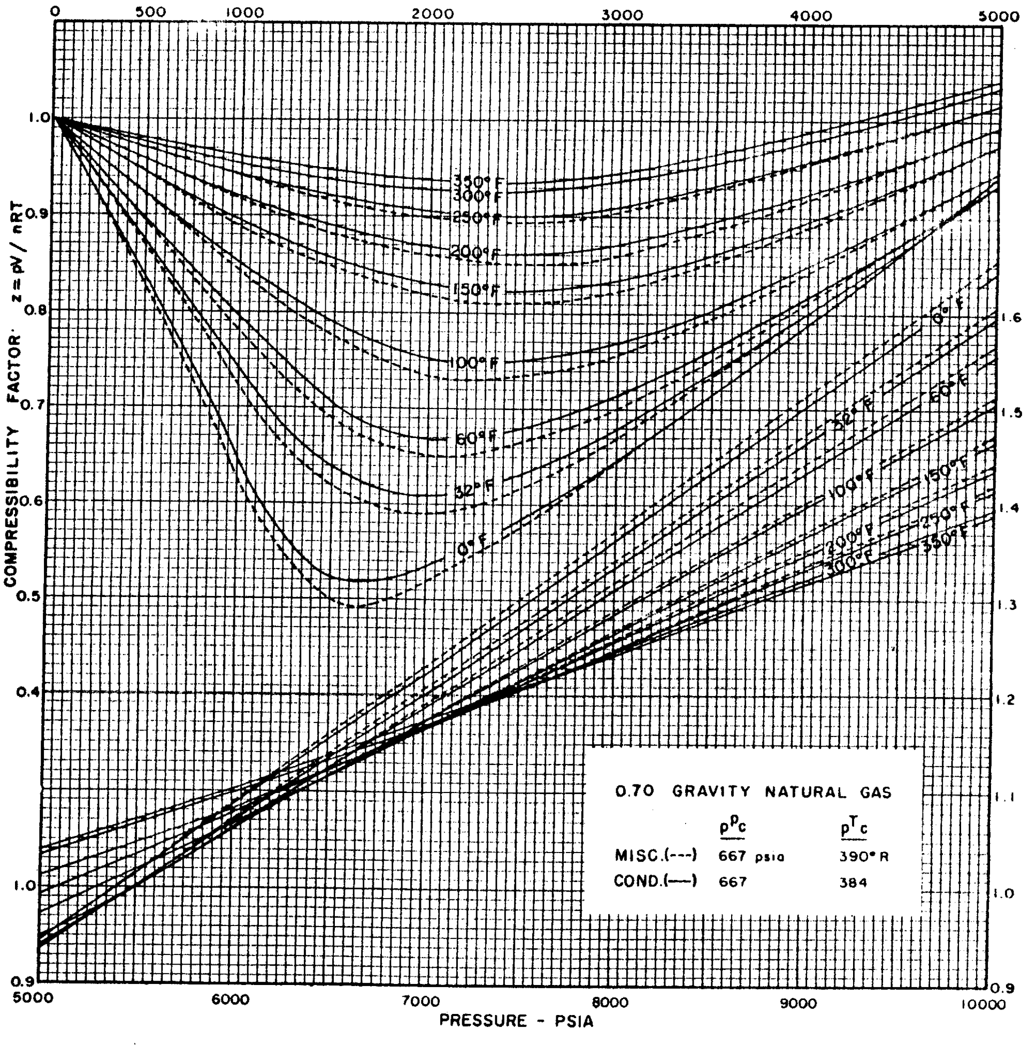
American Gas Journal, GAS HANDBOOK ISSUE, August 15, 1959

Simplified Compressibility Factor Charts for Natural Gas Calculations

CHART 3



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