Natural Gas

Processing Technology

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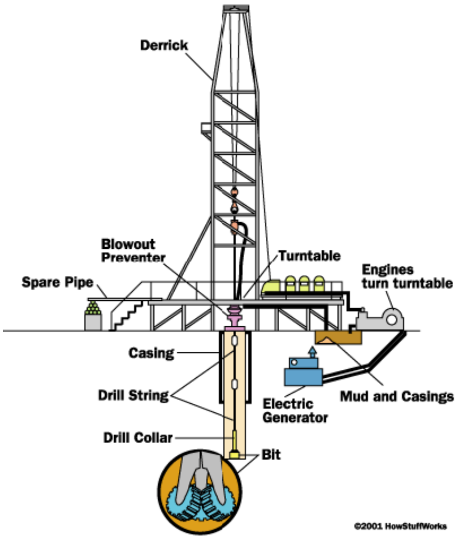
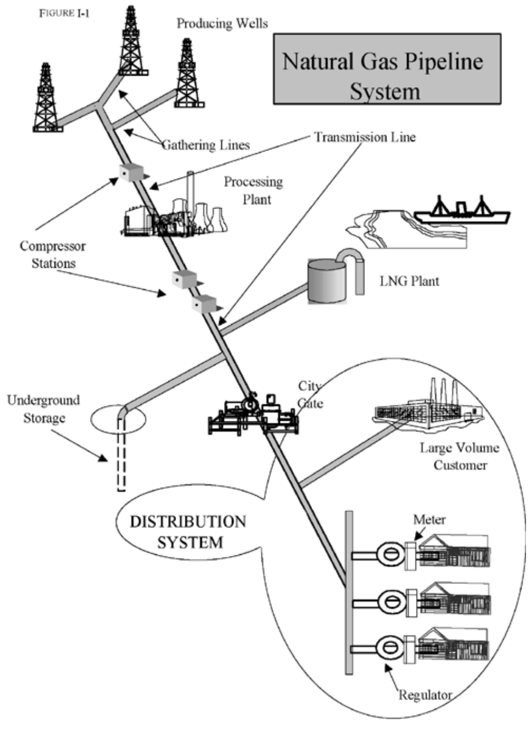
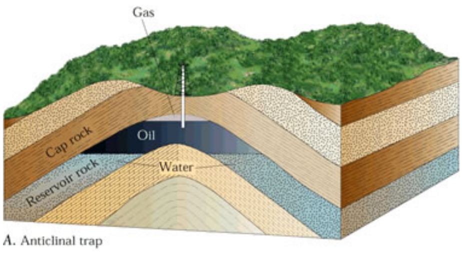
Content

Natural gas

Origin, Accumulation and production







A. Anticlinal trap

Natural gas

Origin, Accumulation and production

Contents:

1. Introduction

- We know that both Oil and Natural Gas are called Hydrocarbons because they are made up of the two elements Hydrogen (H) and Carbon (C).
- Crude oil and natural gas are referred to collectively as petroleum.
- Crude oil is the heavier constituents of hydrocarbons that naturally occur in liquid form.
- Natural gas refers to the lighter constituents of petroleum that naturally occur in gaseous form.
- Thus, in the main, the geologic features that apply to the origin, migration, and accumulation of petroleum will apply equally well to crude oil and natural gas.
- This entails consideration of the natural features of the earth where commercial quantities of petroleum have been discovered all over the world.

2. Origin and Accumulation of Oil and Gas

- To understand how oil and gas originated, it is necessary to learn something about the basic characteristics of rocks. Most oil is found in rocks.
- Natural gas is also found in rocks and is often associated with oil.
- Both oil and natural gas are called hydrocarbons because they are made of up the two elements. Hydrogen (H) and Carbon (C).
- Certain rocks contain many tiny openings called pores or spaces. If a rock has pores, then it is porous and has porosity. Some rocks have high porosity, others have low porosity or even no porosity.
- Oil and gas are found in these pores. Another desirable, feature of oil and gas bearing rocks is permeability.
- Rock is permeable, or has permeability. This is where the pores of the rock are connected. Permeability provides a way for any oil and gas in the rock to move or flow from pore to pore. Rocks have high permeability and other have low permeability.

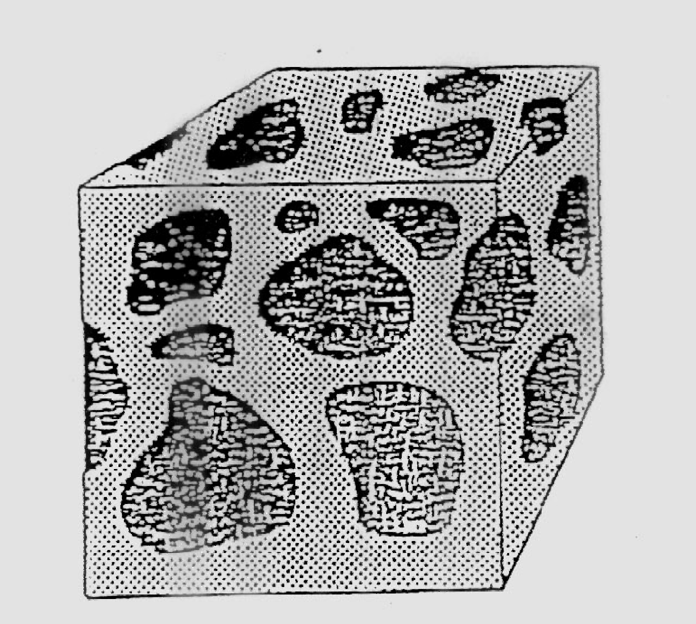


Figure 1: Porous rock containing oil

3. Petroleum Accumulations

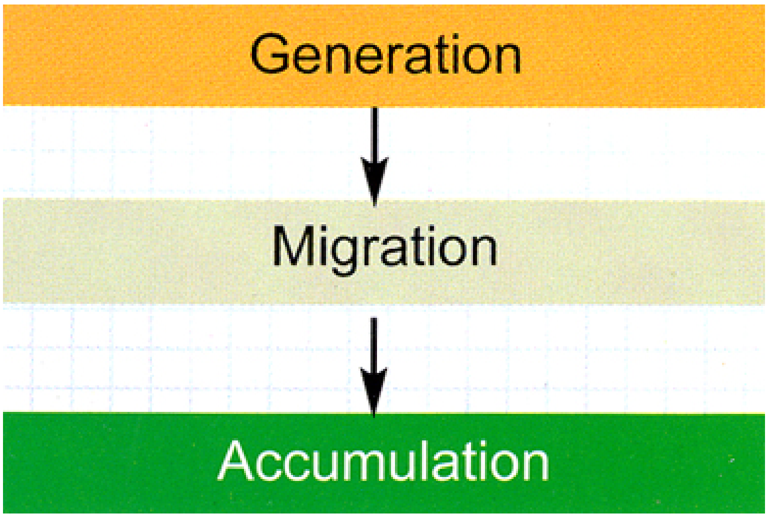
- For petroleum to accumulate there must be:
    - A source of oil and gas.
    - A porous bed must exist which is permeable enough top permit the oil and gas to flow through it- the reservoir rock.
    - A trap, which is a barrier to fluid flow so that accumulation can occur against it.
- Much knowledge has been obtained from experience and observations, but certain generalizations can be made.
    - Petroleum originates from organic matter.
    - To become commercial, the hydrocarbons must be concentrated.
    - Petroleum reservoirs are mostly in sedimentary rocks.

How Oil and Gas formed :

- There are 3 stages to the formation of Oil and Gas:
    - Generation
    - Migration
    - Accumulation
- In **Generation** the debris (sand, and dead vegetation and animals) falls to the bottom of the sea and builds up a level over millions of years.

- In **Migration** the layers of sand and dead vegetation and animals change to a substance called **kerogen**, which is the start of Oil and Gas. More layers mean more heat and temperature, which changes the kerogen to Oil and Gas.

- In **Accumulation** the Oil and Gas is trapped inside non-permeable rock which keeps the fluids underground, as the non-permeable rock does not let the oil and gas to escape.



4. Migration of Petroleum

- Put very simply, in Hydrocarbon Migration, Oil and Gas moves from the very fine grained to rough and uneven rocks like limestone and sandstone where it settles. This is called Primary Migration.

- In Secondary Migration the Hydrocarbons move through the rock holding the oil and gas called carrier beds and build up levels in the reservoirs or lakes.

- Several natural forces and condition that assist this migration include:
    - Compaction of source beds by the weight of the overlying rocks, thus providing a driving force tending to expel fluids through pore channels or fractures to regions of lower pressure and normally a shallower depth;
    - Gravitational separation of gas, oil, and water in porous rocks that are usually water saturated;
    - Pressure differential from any cause between two interconnected points in a permeable medium;
    - Faulting of the earth's strata.

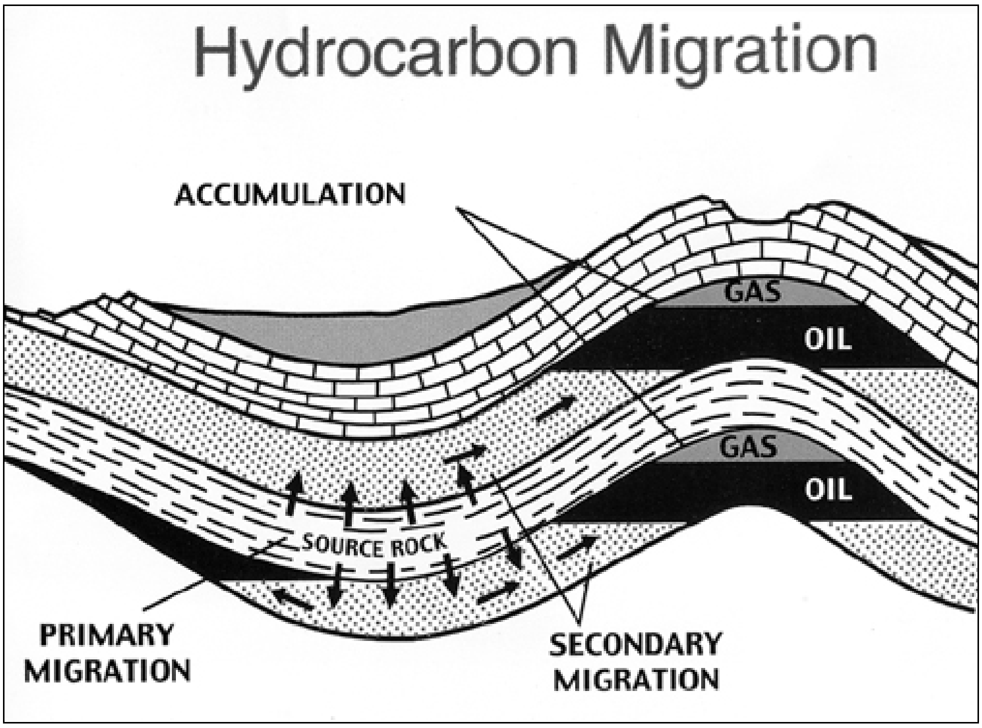
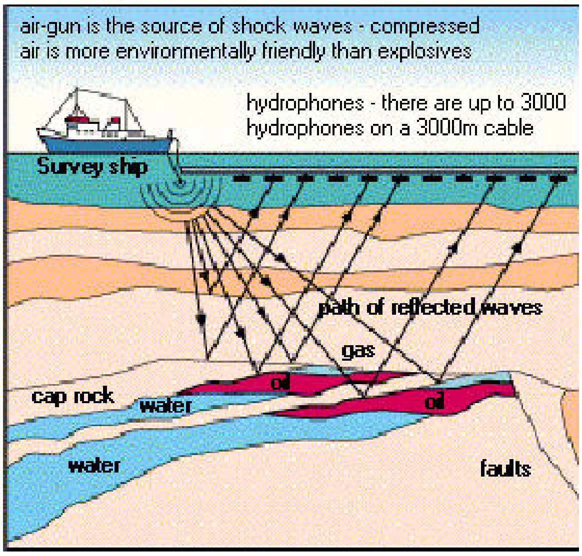


Figure 3: Hydrocarbon Migration

How oil and Gas Obtained (Exploration)?

Geologists and geophysicists are employed to try to find the right conditions for a gas or oil deposit. Geologists employ sophisticated technology to try to find pockets of oil and gas below the earth's surface. They need to have a clear picture of what is below the Earth's surface.

They use seismology, which is creating shock waves like tiny earthquakes that pass through hidden rock layers, and they then interpret the waves that are reflected back to the surface. The seismic information is changed into digital recordings that are written on computer tapes. The information is then transformed into a representation of what is below the Earth's surface.



High-speed computers are also used to help develop three-dimensional underground maps that help try to locate gas deposits. They also interpret satellite images to examine surface rocks and terrain.

Magnetometers are used to get measurements of magnetic characteristics of the crust. This device is able to measure small changes in the Earth's magnetic field at the surface, which indicates what kind of rock formations might be present underground.

The only way to actually find the gas deposits is to drill. Gas wells are drilled thousands of feet into the Earth's crust to extract natural gas from pockets in underground rock formations or from deep, salt-water aquifers and then big pumps bring it to the surface.

Petroleum Reservoirs

The accumulation of oil and gas into a commercial deposit required a reservoir to contain the oil and gas along with some water and a trap, which represented a set of geologic conditions that retained the oil and gas in the reservoir until discovery.

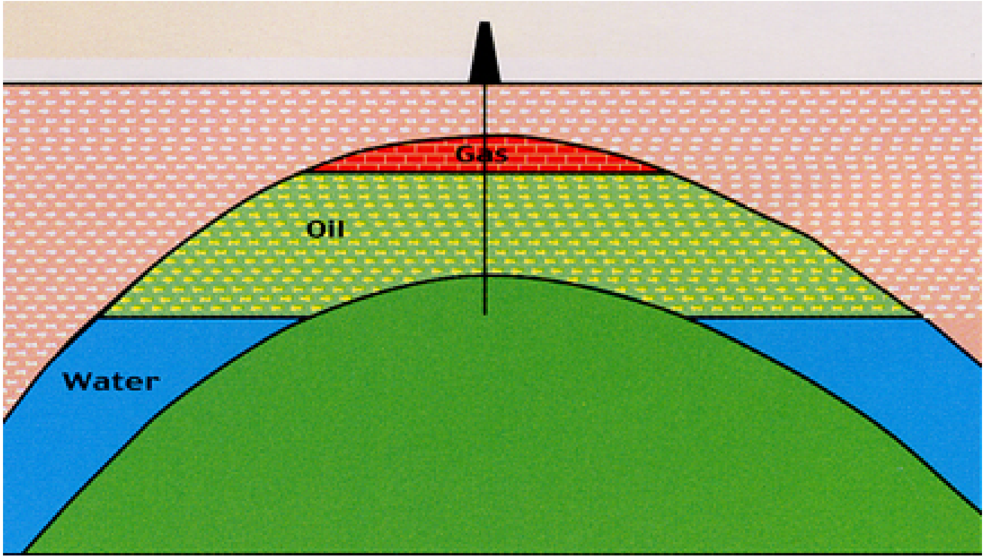


Figure 4: The diagram shows a structural trap formed by the folding of the rock layers (strata) into a large fold in the rocks called an **anticline**.

A petroleum reservoir is a rock capable of containing oil, gas, or water. To be commercially productive, it must have sufficient thickness, a real extent, and pore space to contain an appreciable volume of fluids hydrocarbons and it must yield the contained fluids at a satisfactory rate when penetrated by a well.

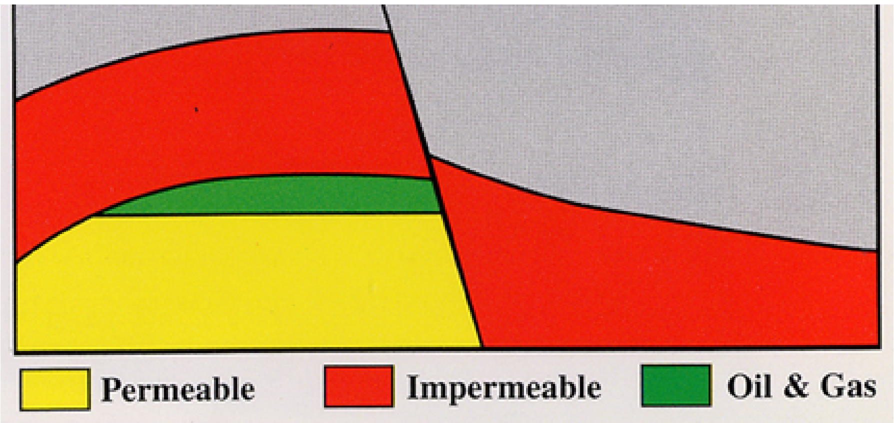


Figure 5: In the diagram above, the Oil and gas are trapped in the section of rock that has broken. This is called a **fault trap**.

Porosity

- Sandstone and carbonates are the most common reservoir rocks. In order to contain fluids. The rocks must have porosity. Porosity is having many holes and able to hold fluid in the holes.

- The porosity may be classified as

    - Primary, which represents the voids resulting from original deposition such as intergranular porosity of sandstone.

    - Secondary, which resulted from later physical or chemical change such as dolomitization, solution channels, or fracturing.

- Porosity is expressed as the ratio of void space to the bulk volume of the rock, usually expressed in percentage. Dependent upon the method of determination, porosity may represent either total or effective porosity.

- In many porous rocks, there are a certain number of blind or unconnected pores. Effective porosity refers to only those pores that are connected so as permit fluid passage.

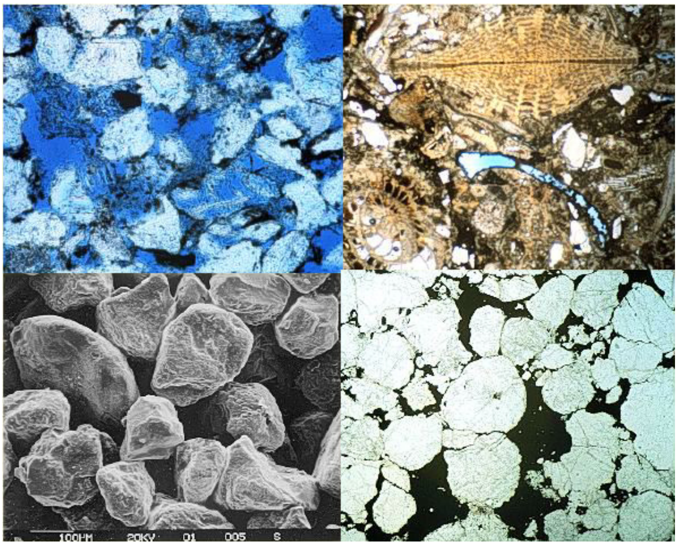


Figure 6: Major types of reservoir porosity

- Porosity in reservoir rocks is normally between 10% and 20%, but some excellent reservoirs may have porosity of 30% or more. Accumulations in reservoirs with less than about 5% porosity are usually not commercial.

- Porosity can be divided into several types, summarised in Figure 7. Sandstone usually has primary porosity, which decreases with depth of burial as the grains are compacted and inter-granular cementation develops.

- However, leaching of carbonate cements and unstable minerals in sandstone can cause good secondary porosity even at depth where they would normally be tight.

Permeability

- Permeability is a quantitative measure of the ease with which a porous rock will permit passage of fluids through it under the pressure gradient. Permeable means having holes and being able to leak.
- Link porosity, it is dependent upon rock grain shape, angularity, and size distribution. In addition, it is very strongly dependent on the size of the grains.
- The smaller the grains, the larger will be the surface area exposed the following fluid.
- The additional drag or frictional resistance of the larger surface area lowers the flow rate at a given pressure differential, and thus the smaller grain size will result in a lower permeability.

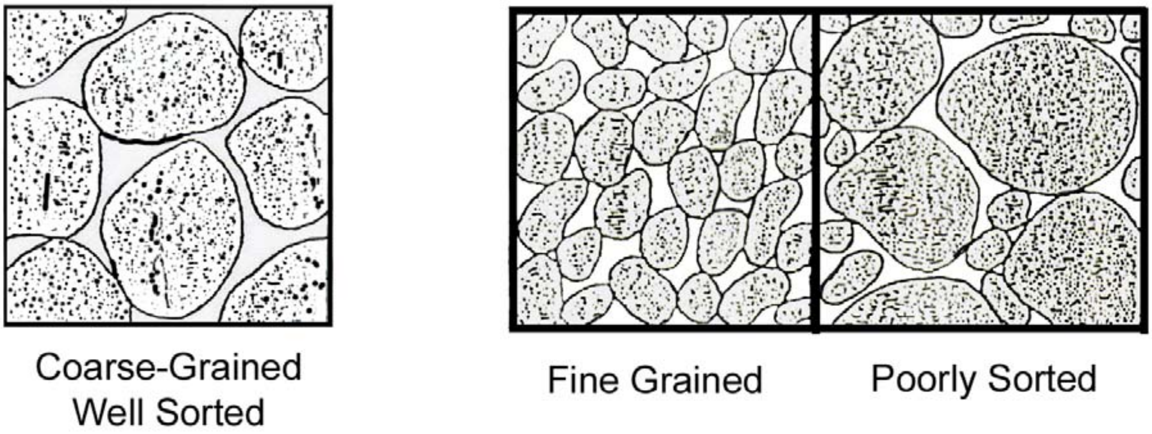


Figure 7: Porosity Types.

- The coarse-grained, well-sorted rock has good permeability as it holds a lot of oil. The fine grained and poorly sorted rock has poor permeability, as it does not hold a lot of oil.

Petroleum Traps

- A trap is a set of geologic rocks that has stopped the migration of oil and gas and caused oil and gas to be retained in a porous reservoir. The traps are like a box or underground prison, which keeps the oil and gas and water inside the porous rocks.
- These can be a dome or large bubble of salt, which was once liquid but boiled up and cooled in the porous rocks. This is called a Salt Dome.

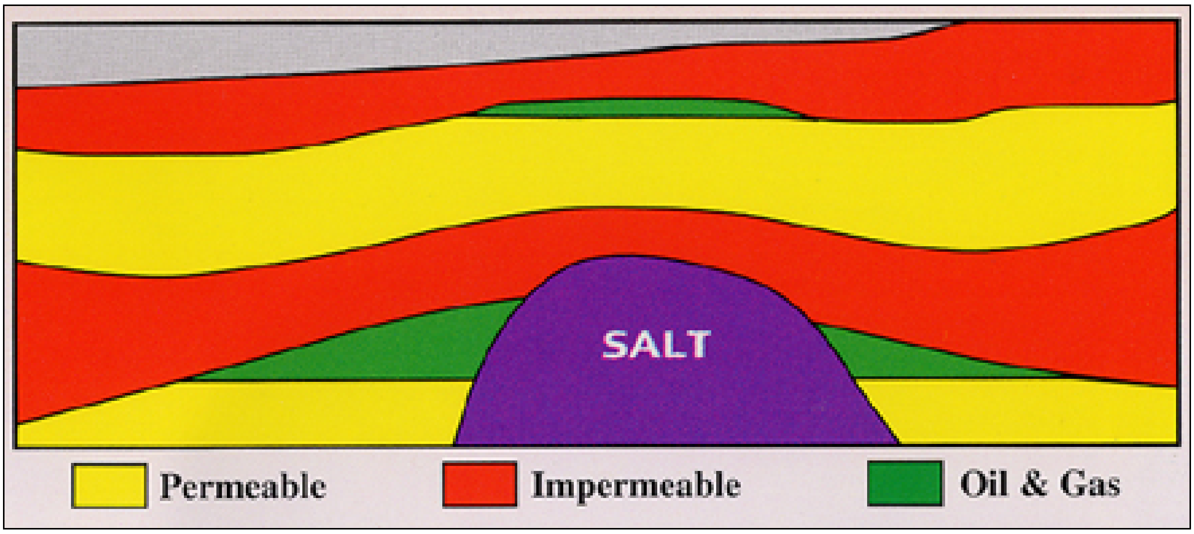


Figure 8: Salt Dome

- The other form of trap is called a **Stratigraphic Trap** in which a layer of rock changes type from Non-Porous to Porous and back to Non-Porous inside one rock layer.

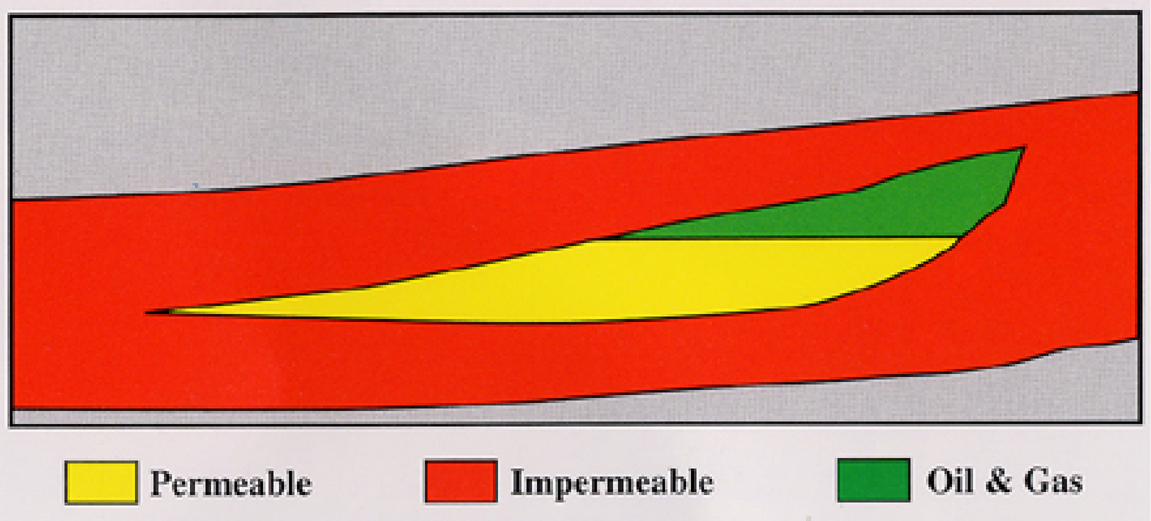


Figure 9: A Stratigraphic Trap

- A simple form of trap is illustrated in Figure (4) which shows a vertical cross section of a porous and permeable reservoir rock (such as a sandstone) that is overlain by a dense and impermeable bed (such as shale).
- It can be pictured that the oil and gas originated at a point located down-dip to the right or left of the fold. As gas and oil moved upward through pore passage of the water-filled reservoir rock, they encountered the sealing bed of shale or similar rock overlying the reservoir rock and continued to move upward and laterally below the sealing surface until stopped by the attic of the fold.

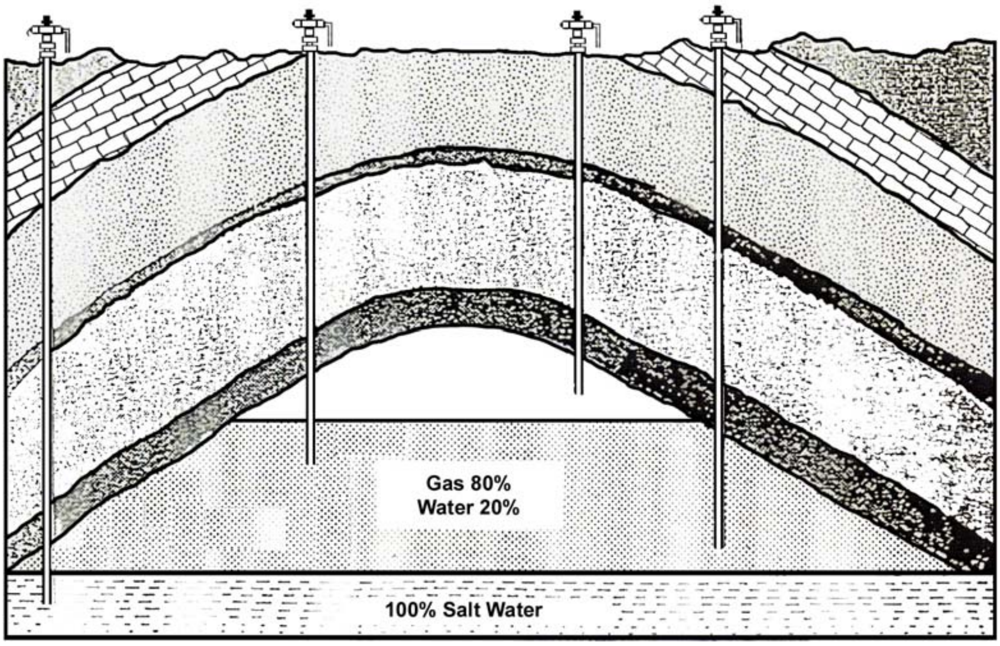


Figure 10: Oil Reservoir Layers

- The gas, being lightest of the three fluids, would accumulate at the crest; and the oil, being next in density, would form a layer below the gas and above the water.
- Actually, the accumulated oil and gas would not displace all of the water originally contained in the pores of the reservoir rock, and this would constitute the interstitial or connate water content of the reservoir.
- This nonreplaced water is of particular significance in making volumetric estimates of oil and gas reserves.
- Normally, for an intergranular type of reservoir, the interstitial water content will be in the range of 20 to 50 percent of pore space and, in some cases, either above or below this range.
- The connate water content is greatly influenced by the surface character of the sand grains, by the level of 100 percent water. In general, oil-wet sand has a much lower connate-water saturation than water-wet sands. Also, sands of low permeability show higher connate-water saturation. Furthermore, in a reservoir with very small pores, there is a transition zone at the bottom where over a vertical interval the connate water gradually increases to 100 percent.
- This happening explains why that on the edge of many reservoirs significant percentages of oil saturation may be observed from cuttings and cores, yet he production will be all water.
- Transition zones are more extensive and of more significance in oil reservoirs than in non-associated gas reservoirs.

Associated and Non-associated Gas

- Natural gas produced from a reservoir that contains oil is called associated gas. The term applies to both free gas from a gas cap and to solution gas. In general, the term casing-head gas is synonymous with associated gas since it commonly refers to gas production from oil wells.
- Gas produced from a reservoir that does not contain oil is referred to as non-associated gas on the basis that it is not directly associated with oil underground.
- In certain fields, these terms assume particular importance because regulatory and control measured applied to associated gas are directed toward a consideration of the effect of gas production upon oil production rates and ultimate recovery, whereas the production of non-associated gas does not involve such consideration.

Preparing for Drill :

Once the site has been selected, it must be surveyed to determine its boundaries, and environmental impact studies may be done. Lease agreements, titles and right-of way accesses for the land must be obtained and evaluated legally. For off-shore sites, legal jurisdiction must be determined.

Once the legal issues have been settled, the crew goes about preparing the land:

The land is cleared and leveled, and access roads may be built.

Because water is used in drilling, there must be a source of water nearby. If there is no natural source, they drill water well.

They dig a reserve pit, which is used to dispose of rock cuttings and drilling mud during the drilling process, and line it with plastic to protect the environment. If the site is an ecologically sensitive area, such as a marsh or wilderness, then the cuttings and mud must be disposed offsite -- trucked away instead of placed in a pit.

Once the land has been prepared, several holes must be dug to make way for the rig and the main hole. A rectangular pit, called a cellar, is dug around the location of the actual drilling hole. The cellar provides a work space around the hole, for the workers and drilling accessories. The crew then begins drilling the main hole, often with a small drill truck rather than the main rig. The first part of the hole is larger and shallower than the main portion, and is lined with a large-diameter conductor pipe. Additional holes are dug off to the side to temporarily store equipment -- when these holes are finished, the rig equipment can be brought in and set up.

Depending upon the remoteness of the drill site and its access, equipment may be transported to the site by truck, helicopter or barge. Some rigs are built on ships or barges for work on inland water where there is no foundation to support a rig.

Oil and gas Rig Systems:

Once the equipment is at the site, the rig is set up. Here are the major systems of a land oil rig:

Power system

Large diesel engines - burn diesel-fuel oil to provide the main source of power

Electrical generators

Powered by the diesel engines to provide electrical power

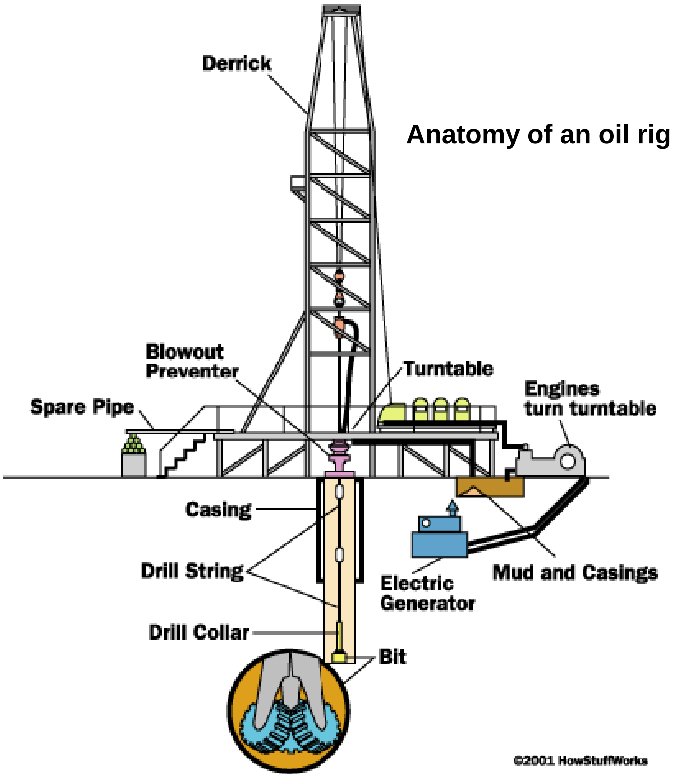
Mechanical system –

Driven by electric motors

Hoisting system

Used for lifting heavy loads; consists of a mechanical winch (drawworks) with a large steel cable spool, a block-and-tackle pulley and a receiving storage reel for the cable

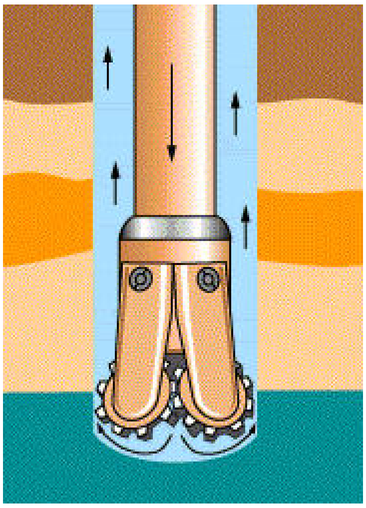
Turntable - part of the drilling apparatus



Rotating equipment

Used for rotary drilling

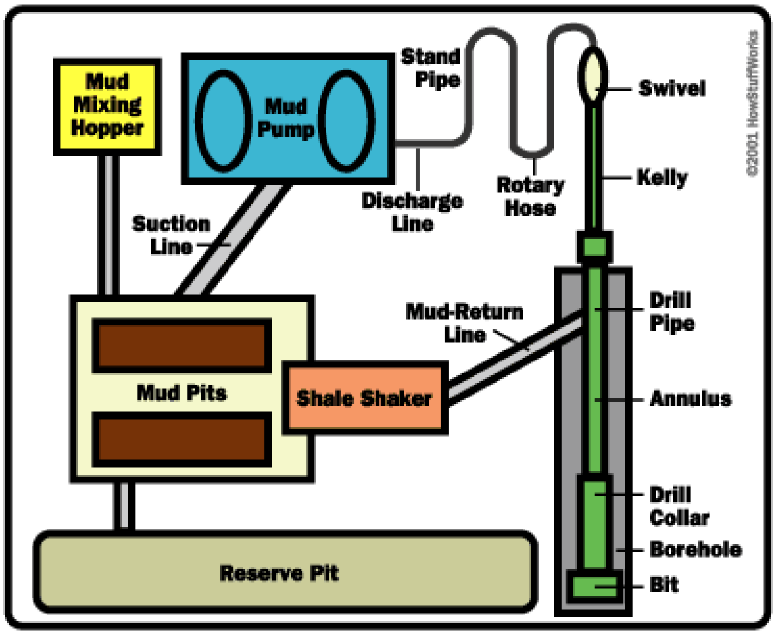
- **swivel** - large handle that holds the weight of the drill string; allows the string to rotate and makes a pressure-tight seal on the hole
- **Kelly** - four- or six-sided pipe that transfers rotary motion to the turntable and drill string
- **turntable** or **rotary table** - drives the rotating motion using power from electric motors
- **drill string** - consists of **drill pipe** (connected sections of about 30 ft / 10 m) and **drill collars** (larger diameter, heavier pipe that fits around the drill pipe and places weight on the drill bit)
- **drill bit(s)** - end of the drill that actually cuts up the rock; comes in many shapes and materials (tungsten carbide steel, diamond) that are specialized for various drilling tasks and rock formations
- **Casing** - large-diameter concrete pipe that lines the drill hole, prevents the hole from collapsing, and allows drilling mud to circulate



Mud circulation in the hole

- **Circulation system** - pumps **drilling mud** (mixture of water, clay, weighting material and chemicals, used to lift rock cuttings from the drill bit to the surface) under pressure through the kelly, rotary table, drill pipes and drill collars
- **pump** - sucks mud from the mud pits and pumps it to the drilling apparatus

- **pipes and hoses** - connects pump to drilling apparatus
- **mud-return line** - returns mud from hole
- **shale shaker** - shaker/sieve that separates rock cuttings from the mud
- **reserve pit** - collects rock cuttings separated from the mud
- **mud pits** - where drilling mud is mixed and recycled
- **Derrick** - support structure that holds the drilling apparatus; tall enough to allow new sections of drill pipe to be added to the drilling apparatus as drilling progresses

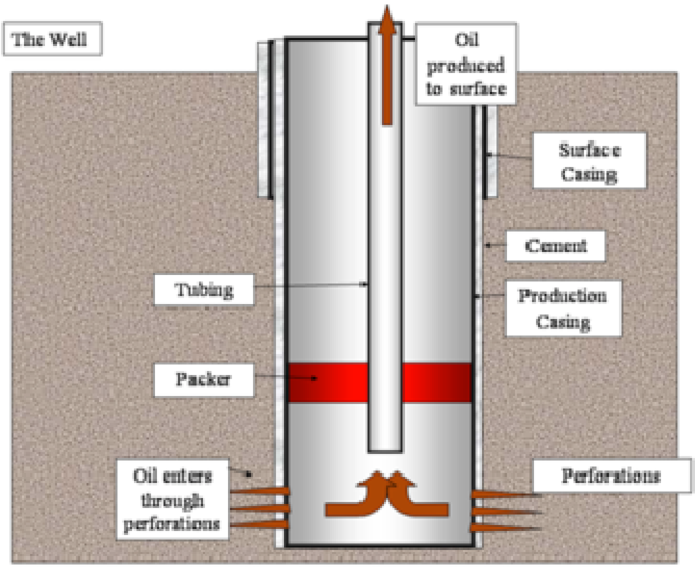


Drill-mud circulation system

Well Completion

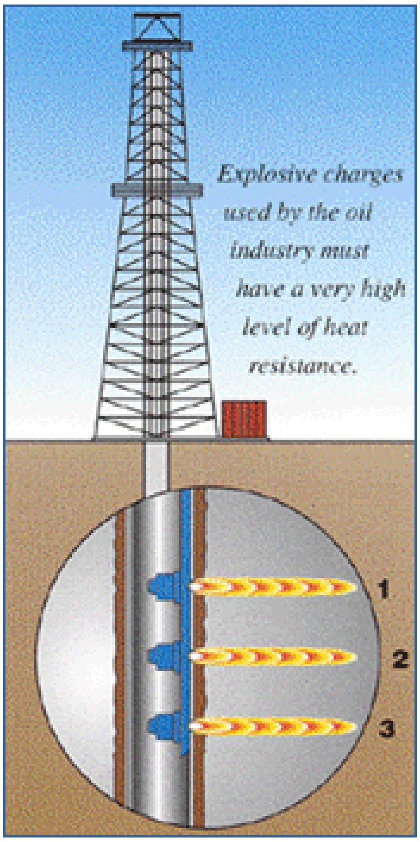
After drilling and casing the well, it must be 'completed'. Completion is the process in which the well is enabled to produce oil or gas.

In a cased-hole completion, small holes called perforations are made in the portion of the casing which passed through the production zone, to provide a path for the oil to flow from the surrounding rock into the production tubing. In open hole completion, often 'sand screens' or a 'gravel pack' is installed in the last drilled, uncased reservoir section. These maintain structural integrity of the well bore in the absence of casing, while still allowing flow from the reservoir into the wellbore. Screens also control the migration of formation sands into production tubulars and surface equipment, which can cause washouts and other problems, particularly from unconsolidated sand formations in offshore fields.



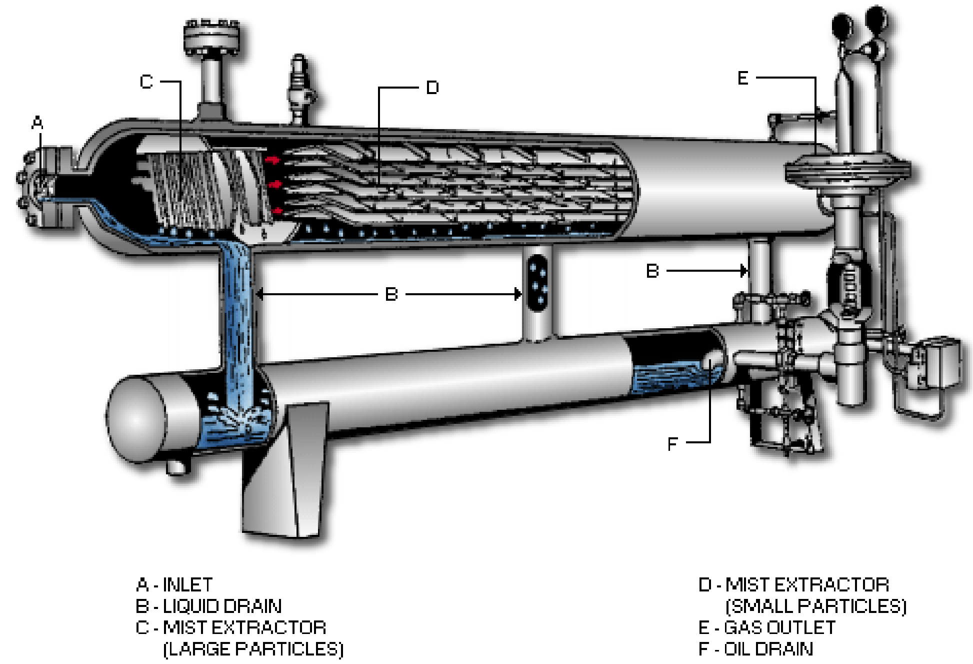
After a flow path is made, acids and fracturing fluids are pumped into the well to fracture, clean, or otherwise prepare and stimulate the reservoir rock to optimally produce hydrocarbons into the wellbore.

In many wells, the natural pressure of the subsurface reservoir is high enough for the oil or gas to flow to the surface. However, this is not always the case, especially in depleted fields where the pressures have been lowered by other producing wells, or in low permeability oil reservoirs. Installing a smaller diameter tubing may be enough to help the production, but artificial lift methods may also be needed.



Oil and Gas

Separation



Oil and Gas Separation:

Contents:

INTRODUCTION

Phase separation of the production stream is usually performed as soon as is conveniently possible because:

1. It is technically easier and less costly to process the gas, crude oil, and produced water phases separately.
2. The produced water is often corrosive. Therefore, removing the water often allows less costly materials of construction to be used downstream and reduces corrosion damage.
3. Less energy is required to move the separated single phases; so phase separation permits the back pressure to be lowered and this, in turn, increases well production.

The current emphasis is on two-phase (gas/liquid) and three-phase (gas/crude/free-water) separation.

First, the plentiful and somewhat confusing terminology used to describe separators is reviewed. Then vertical and horizontal separators and, far more briefly, double-barreled horizontal, spherical, filter coalescer, and sub-sea separators are described with special attention given to the features common to all separators. Next, the advantages, disadvantages, and applications of vertical and horizontal separators are compared. Then phase separation theories including retention time, droplet settling, and hydraulics (residence time distributions) are summarized. Design methods for both horizontal and vertical separators are reviewed next. Emphasis is on overall considerations, data required, sizing equations, separator geometry, mist extractors, and concerns such as foaming. Recent use of computational fluid dynamics is also summarized. Detailed design examples for vertical and horizontal separators are also presented. Maintenance, operating problems, and troubleshooting conclude the course. Centrifugal separators are used primarily for liquid/liquid or liquid/solid separations; therefore, they are outside the present scope.

OILFIELD TERMINOLOGY

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

1. Separator.
2. Stage separator.
3. Knockout vessel, knockout drum, knockout trap, water knockout, or liquid knockout.
4. Flash drum, flash vessel, or flash trap.
5. Expansion separator or expansion vessel.
6. Scrubber (gas scrubber).
7. Filter (gas filter), filter separator.
8. Skimmer, liquid hydrocarbon skimmer.
9. Slug catcher.

Separator and stage separator :

The terms separator and stage separator refer to a conventional oil and gas separator. These separating vessels are normally used on a producing lease or platform near the wellhead, manifold, or tank battery to separate fluids produced from oil and gas wells into oil and gas or liquid and gas (Figure-1). They must be capable of handling "slugs" or "heads" of well fluids. Therefore, they are usually sized to handle the highest instantaneous rates of flow.

knockout vessel, drum, or trap

may be used to remove only water from the well fluid or to remove all liquid, oil plus water, from the gas. In the case of a water knockout for use near the wellhead, the gas and liquid petroleum are usually discharged together, and the free 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 drum or vessel

Normally refers to a conventional oil and gas separator operated at low pressure, with the liquid from a higher-pressure separator being "flashed" into it. This flash drum is quite often the second or third stage of separation, with the liquid being discharged from the flash drum to storage.

Expansion vessel

It is the first-stage separator vessel on a low-temperature or cold-separation unit (LTS). This vessel may be equipped with a heating coil to melt hydrates, or a hydrate-preventive liquid (such as glycol) may be injected into the well fluid just before expansion into this vessel.

Gas scrubber

It may be similar to an oil and gas separator. Usually it handles fluid that contains less liquid than that produced from oil and gas wells. Gas scrubbers are normally used in gas gathering, sales, and distribution lines where they are not required to handle slugs or heads of liquid, as is often the case with oil and gas separators. A "scrubber" can refer to a vessel used upstream from any gas-processing vessel or unit (scrubbers are often used ahead of compressors, glycol and amine units), and they are often applied downstream of field separators to remove entrained and/or condensed liquids to protect the downstream vessel or unit.

Filter (gas filter or filter/separator), dust Scrubber, or Coalescer.

These separators are designed to remove small quantities of mists, oil fogs, rust, scales, and dust from gases. Typical applications are upstream of compressors, dehydration units, amine units, custody transfer and town-border stations. Solids are trapped by the filter fibers while liquid droplets are coalesced into large drops that are then separated by gravity. These filter separators are used for final "polishing" and are often preceded or protected, by a conventional scrubber or separator.

Skimmer, liquid hydrocarbon skimmer

Normally refers to a conventional oil and gas separator operated at low pressure to separate a liquid from another liquid.

Slug catcher,

A particular separator design able to absorb large volumes at irregular intervals. Usually found on gas gathering system or two-phase pipeline systems. A slug catcher may be a single large vessel or a manifolded system of pipes.

All of the previous separators use gravity as the separating force. External force fields (electrostatic and centrifugal) can and have been used. However, electrostatic fields are used primarily to break water-in-crude emulsions. Centrifugal force (i.e., a hydrocyclone) is most useful for separating primary oil-in-water dispersions. Skid-mounted rotating thermal separators have also been used to recover natural gas liquids from associated gas.

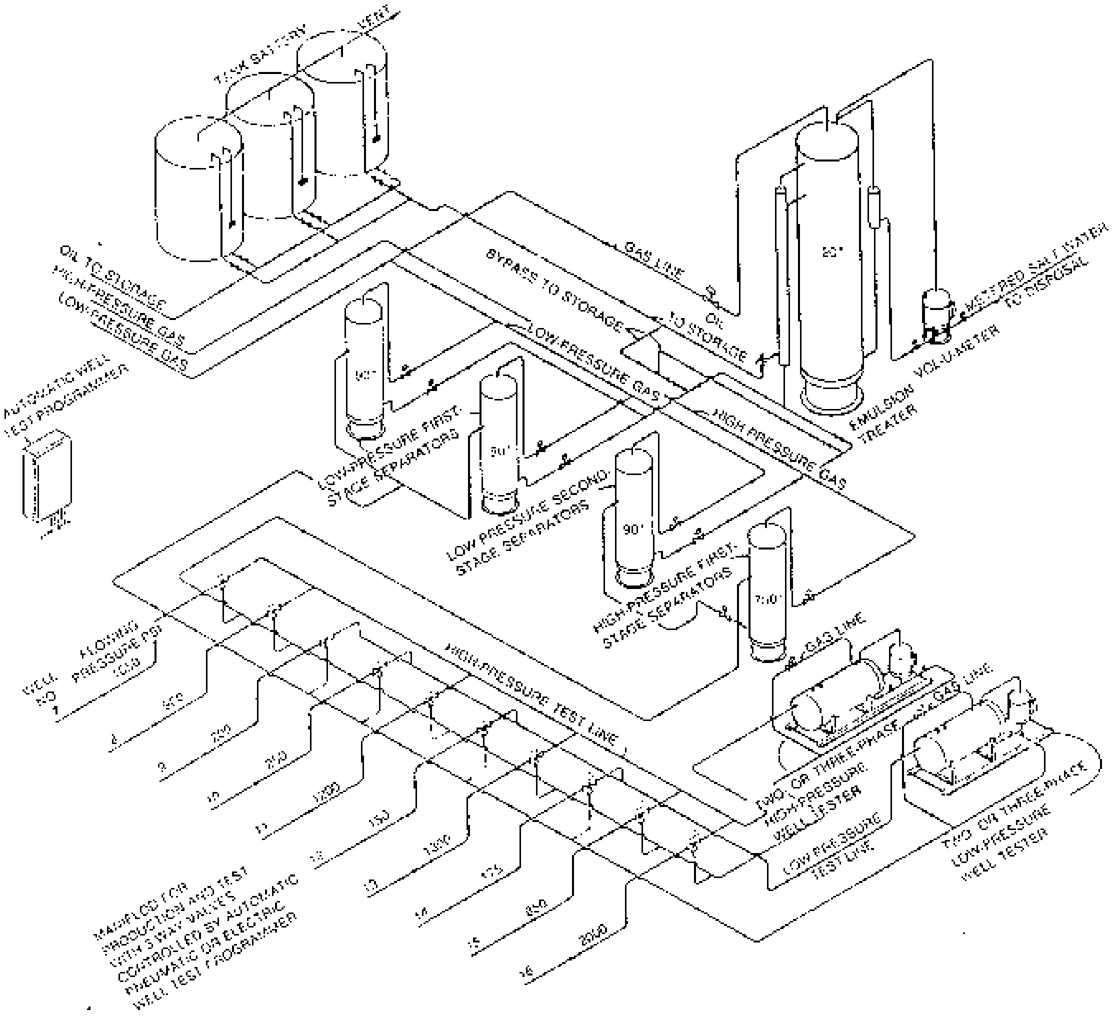


Figure- 1 Typical surface equipment for handling oil and gas separators and other related equipment

WELL FLUIDS AND THEIR CHARACTERISTICS

Some of the physical characteristics of well fluids handled by oil and gas separators are briefly outlined in this section.

Crude Oil.

Crude oil is a complex mixture of hydrocarbons produced in liquid form. The API gravity of crude oil can range from 6 to 50oAPI and viscosity from 5.0 to 90,000 cP at average operating conditions. Color varies through shades of green, yellow, brown, and black.

Condensate.

This is a hydrocarbon that may exist in the producing formation either as a liquid or as a condensable vapor. Liquefaction of gaseous components of the condensate usually occurs with reduction of well-fluid temperature to surface operating conditions. Gravities of the condensed liquids may range from 50 to 120oAPI and viscosities from 2.0 to 6.0 cP at standard conditions. Color may be water-white, light yellow, or light blue.

Natural Gas.

A gas may be defined as a substance that has no shape or volume of its own. It will completely fill any container in which it is placed and will take the shape of the container. Hydrocarbon gas associated with crude oil is referred to as natural gas and may be found as "free" gas or as "solution" gas. Specific gravity of natural gas may vary from 0.55 to 0.90 and viscosity from 0.011 to 0.024 cP at standard conditions.

Free Gas.

Free gas is a hydrocarbon that exists in the gaseous phase at operating pressure and temperature. Free gas may refer to any gas at any pressure that is not in solution or mechanically held in the liquid hydrocarbon.

Solution Gas.

Solution gas is homogeneously contained in oil at a given pressure and temperature. A reduction in pressure and/or an increase in temperature may cause the gas to be emitted from the oil, whereupon it assumes the characteristics of free gas.

Condensable Vapors.

These hydrocarbons exist as vapor at certain pressures and temperatures and as liquid at other pressures and temperatures. In the vapor phase, they assume the general characteristics of a gas. In the vapor phase, condensable vapors vary in specific gravity from 0.55 to 4.91 (air = 1.0), and in viscosity from 0.006 to 0.011 cP at standard conditions.

Water.

Water produced with crude oil and natural gas may be in the form of vapor or liquid. The liquid water may be free or emulsified. Free water reaches the surface separated from the liquid hydrocarbon. Emulsified water is dispersed as droplets in the liquid hydrocarbon.

Impurities and Extraneous Materials.

Produced well fluids may contain such gaseous impurities as nitrogen, carbon dioxide, hydrogen sulfide, and other gases that are not hydrocarbon in nature or origin. Well fluids may contain liquid or semi-liquid impurities, such as water and paraffin. They may also contain solid impurities, such as drilling mud, sand, silt, and salt.

PRIMARY FUNCTIONS OF OIL AND GAS SEPARATORS

Separation of oil from gas may begin as the fluid flows through the producing formation into the well bore and may progressively increase through the tubing, flow lines, and surface handling equipment. Under certain conditions, the fluid may be completely separated into liquid and gas before it reaches the oil and gas separator. In such cases, the separator vessel affords only an "enlargement" to permit gas to ascend to one outlet and liquid to descend to another.

Removal of Oil from Gas

Difference in density of the liquid and gaseous hydrocarbons may accomplish acceptable separation in an oil and gas separator. However, in some instances, it is necessary to use mechanical devices commonly referred to as "mist extractors" to remove liquid mist from the gas before it is discharged from the separator. Also, it may be desirable or necessary to use some means to remove non-solution gas from the oil before the oil is discharged from the separator.

Removal of Gas from Oil

The physical and chemical characteristics of the oil and its conditions of pressure and temperature determine the amount of gas it will contain in solution. The rate at which the gas is liberated from a given oil is a function of change in pressure and temperature. The volume of gas that an oil and gas separator will remove from crude oil is dependent on:

(1) physical and chemical characteristics of the crude,
(2) operating pressure,
(3) operating temperature,
(4) rate of throughput,
(5) size and configuration of the separator, and
(6) other factors.

Rate of throughput and liquid depth in the separator determine the "retention" or "settling" time of the oil. Retention time of 1 to 3 minutes is generally adequate to obtain satisfactory separation of crude oil and gas unless foaming oil is being handled. When foaming oil is separated, retention time should be increased to 5 to 20 minutes, dependent on the stability of the foam and on the design of the separator. Advancements in field processing systems and production procedures - such as automatic custody transfer - emphasize the need for complete removal of non-solution gas from the oil. Agitation, heat, special baffling, coalescing packs, and filtering materials can assist in the removal of non-solution gas that otherwise may be retained in the oil because of the viscosity and surface tension of the oil.

Separation of Water from Oil

In some instances it is preferable to separate and to remove water from the well fluid before it flows through pressure reductions, such as those caused by chokes and valves. Such water removal may prevent difficulties that could be caused downstream by the water - such as corrosion, hydrate formation, and the formation of tight emulsion that may be difficult to resolve into oil and water.

The water can be separated from the oil in a three-phase separator by use of chemicals and gravity separation. If the three-phase separator is not large enough to separate the water adequately, it can be separated in a free-water knockout vessel installed upstream or downstream of the separators. If the water is emulsified, it may be necessary to use an emulsion treater to remove it. Figures-2, 3 and 4 are illustrations for three-phase separators.

SECONDARY FUNCTIONS OF OIL AND GAS SEPARATORS

Maintain Optimum Pressure on Separator

For an oil and gas separator to accomplish its primary functions, pressure must be maintained in the separator so that the liquid and gas can be discharged into their respective processing or gathering systems. Pressure is maintained on the separator by use of a gas backpressure valve on each separator or with one master backpressure valve that controls the pressure on a battery of two or more separators (Figures-5 and 6).

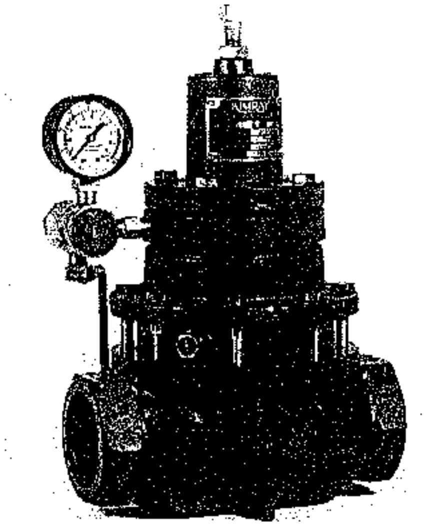


Fig-5 : Low pressure – gas backpressure valve.

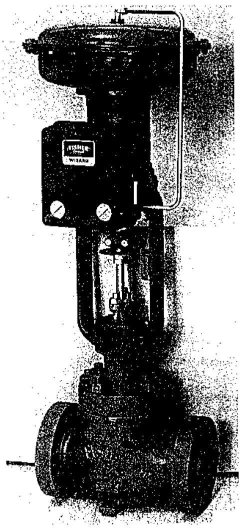


Fig-6 : High- pressure – gas backpressure

The optimum pressure to maintain on a separator is the pressure that will result in the highest economic yield from the sale of the liquid and gaseous hydrocarbons. This optimum pressure can be calculated theoretically or determined by field tests.

Maintain Liquid Seal in Separator

To maintain pressure on a separator, a liquid seal must be effected in the lower portion of the vessel. This liquid seal prevents loss of gas with the oil and requires the use of a liquid-level controller and a valve. The oil discharge control valve can be actuated by a float-operated pilot, by a floatless liquid-level controller, or by a torque tube-type (displacement) liquid-level controller (Figures-7, 8, 9 and 10).

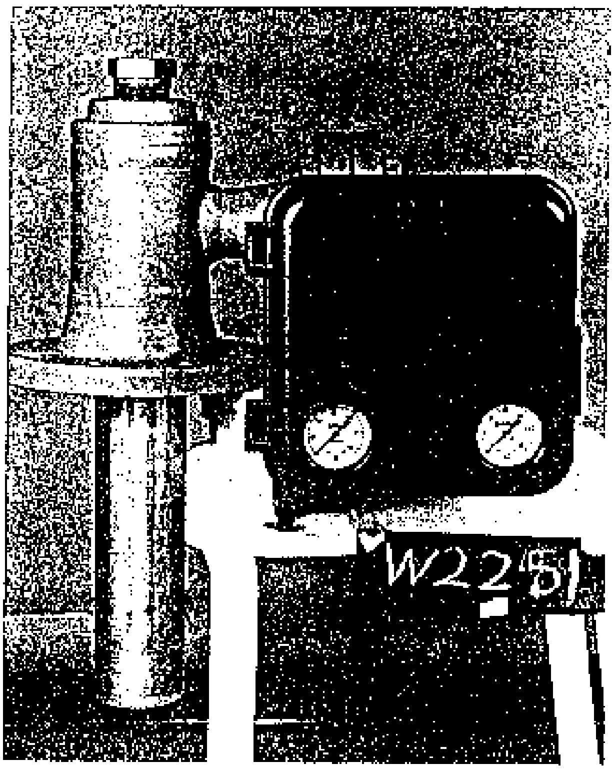


Fig-7 : torque-tube (displacement)-type liquid-level controller .

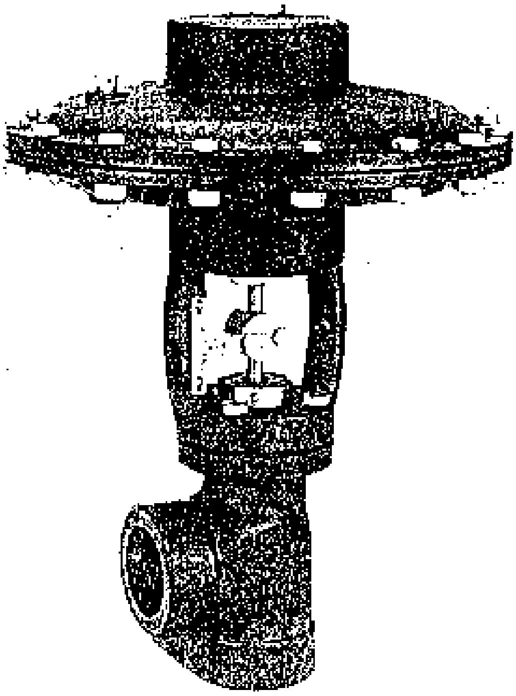


Fig-8 : Diaphragm-motor-type oil-discharge control valve

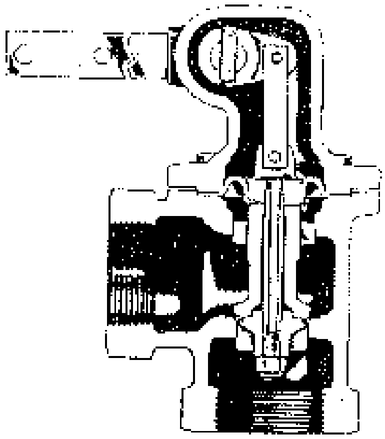


Fig-9 : Floatless liquid-level controller and diaphragm-motor pil-control valve on high-pressure oil and gas separator .

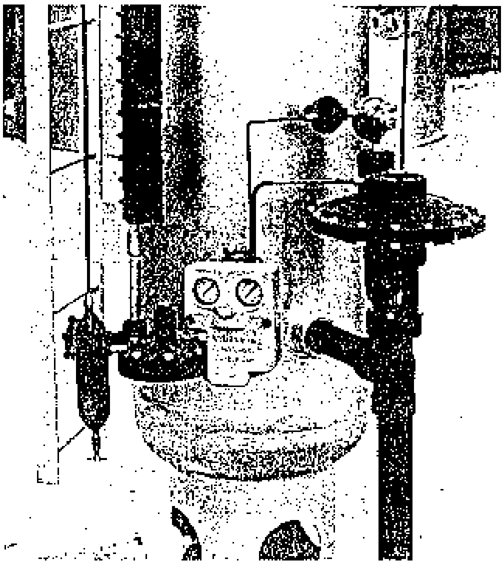


Fig-10 : level type valve for controlling oil discharge from oil and gas separators . Valve is float operated .

METHODS USED TO REMOVE Liquid FROM GAS IN SEPARATORS

Liquid mist can be effectively removed from the gas stream in an oil and gas separator by a well-designed mist extractor. Condensable vapors in the gas cannot be removed by mist extractors. Condensation of these vapors, caused by reduction of temperature, may occur after the gas has been discharged from the separator. Thus, existence of liquid in the effluent gas from an oil and gas separator in many instances may not necessarily reflect the efficiency of the separator. Because condensable vapors may have the characteristics of natural gas at separator temperature and pressure, condensation of these vapors may occur immediately after being discharged from the separator.

Density difference of liquid and gas may accomplish separation of liquid droplets from a gas stream where the velocity of the stream is slow enough and sufficient time is allowed to accomplish separation. Limiting the gas velocity in a separator may obtain satisfactory separation without a mist extractor. However, mist extractors are generally installed in conventional oil and gas separators to assist in separation and to minimize the amount of liquid (mist) carried out with the gas.

The methods used to remove oil from gas in oil and gas separators are density difference (gravity separation), impingement, change of flow direction, change of flow velocity, centrifugal force, coalescence, and filtering.

Density Difference (Gravity Separation)

Natural gas is lighter than liquid hydrocarbon. Minute particles of liquid hydrocarbon that are temporarily suspended in a stream of natural gas will, by density difference or force of gravity, settle out of the stream of gas if the velocity of the gas is sufficiently slow. The larger droplets of hydrocarbon will quick]y settle out of the gas, but the smaller ones will take longer.

At standard conditions of pressure and temperature, the droplets of liquid hydrocarbon may have a density 400 to 1,600 times that of natural gas. However, as the operating pressure and temperature increase, the difference in density decreases. At an operating pressure of 800 psig, the liquid hydrocarbon may be only 6 to 10 times as dense as the gas. Thus, operating pressure materially affects the size of the separator and the size and type of mist extractor required to separate adequately the liquid and gas.

The fact that the liquid droplets may have a density 6 to 10 times that of the gas may indicate that droplets of liquid would quickly settle out of and separate from the gas. However, this may not occur because the particles of liquid may be so small that they tend to “float" in the gas and may not settle out of the gas stream in the short period of time the gas is in the oil and gas separator.

Particles of liquid hydrocarbon with diameters of 100 µm and larger will generally settle out of the gas in most average-sized separators. However, mist extractors usually are needed to remove smaller particles from the gas.

As the operating pressure on a separator increases, the density difference between the liquid and gas decreases. For this reason, it is desirable to operate oil and gas separators at

as low a pressure as is consistent with other process variables, conditions, and requirements.

Impingement

If a flowing stream of gas containing liquid mist is impinged against a surface, the liquid mist may adhere to and coalesce on the surface. After the mist coalesces into larger droplets, the droplets will gravitate to the liquid section of the vessel. If the liquid content of the gas is high, or if the mist particles are extremely fine, several successive impingement surfaces may be required to effect satisfactory removal of the mist.

Change of Flow Direction

When the direction of flow of a gas stream containing liquid mist is changed abruptly, inertia causes the liquid to continue in the original direction of flow. Separation of liquid mist from the gas thus can be effected because the gas will more readily assume the change of flow direction and will flow away from the liquid mist particles. The liquid thus removed may coalesce on a surface or fall to the liquid section below.

Change of Flow Velocity

Separation of liquid and gas can be effected with either a sudden increase or decrease in gas velocity. Both conditions use the difference in inertia of gas and liquid. With a decrease in velocity, the higher inertia of the liquid mist carries it forward and away from the gas. The liquid may then coalesce on some surface and gravitate to the liquid section of the separator. With an increase in gas velocity, the higher inertia of the liquid causes the gas to move away from the liquid, and the liquid may fall to the liquid section of the vessel.

Centrifugal Force

If a gas stream carrying liquid mist flows in a circular motion at sufficiently high velocity, centrifugal force throws the liquid mist outward against the walls of the container. Here the liquid coalesces into progressively larger droplets and finally gravitates to the liquid section below. Centrifugal force is one of the most effective methods of separating liquid mist from gas. Efficiency of this type of mist extractor increases as the velocity of the gas stream increases. Thus for a given rate of throughput, a smaller centrifugal separator will suffice.

Separators and scrubbers using centrifugal force for the removal of liquid mist from the gas can handle large volumes of gas.

Small-diameter oil and gas separators (below 3 or 4 ft in diameter) using centrifugal force are generally not used as the primary separator on producing leases. This is because of the possibility that the small vessels may be inundated with a "slug" or "head" of liquid that may allow excessive liquid to exit with the gas and excessive gas to exit with the liquid. Therefore, primary separators on oil and gas streams are usually "conventional" units (other than centrifugal) to prevent the possibility of "overloading" the separators with liquid.

Coalescence

Coalescing packs afford an effective means of separating and removing liquid mist from a stream of natural gas. One of their most appropriate uses is the removal of liquid mist from gas in transmission and distribution systems where the amount of liquid in the gas is low. Coalescing packs can be made of Berl saddles, Raschig rings, knitted wire mesh, and other such tower-packing materials. The packs use a combination of impingement, change of direction, change of velocity, and coalescence to separate and to remove liquid mist from gas. These packs provide a large surface area for collection and coalescence of the liquid mist .

A word of caution is appropriate concerning the use of coalescing packs in oil and gas separators for general field use. Coalescing packs may be made of frangible material that can be damaged during transit or installation if they are installed in the separator in the manufacturing shop before shipment to point of use. Knitted wire mesh may foul or plug from paraffin deposition and other foreign material and thus make a separator inoperative after a short period of service. Also, excessive pressure drop across the pack may force the pack out of place and allow channeling around or through the pack.

Even though coalescing packs are very effective in the removal of liquid mist from gas, it is usually preferred to use vane-type mist extractors for most oil and gas separators because they may be used under widely varying field conditions. Because of the "fouling" tendency of coalescing-type mist extractors, their use may appropriately be restricted to gas scrubbers used in gas gathering, transmission, and distribution systems.

Filtering

Porous filters are effective in the removal of liquid mist from gas in certain applications. In effect, the porous material strains or filters the liquid mist from the gas. The porous material may use the principles of impingement, change of flow direction, and change of velocity to assist in separation of liquid mist from gas.

Pressure drop through mist extractors used in separators should be as low as practical while maximum separating efficiency is still maintained. Generally, filter-type mist extractors will have the highest pressure drop per unit volume of capacity and the coalescing type will have the lowest. Pressure drop through the other types of mist extractors will usually range between these two extremes.

See all the following Figures-11, 12, 13, 14, 15, 16, 17, 18, 19 and 20

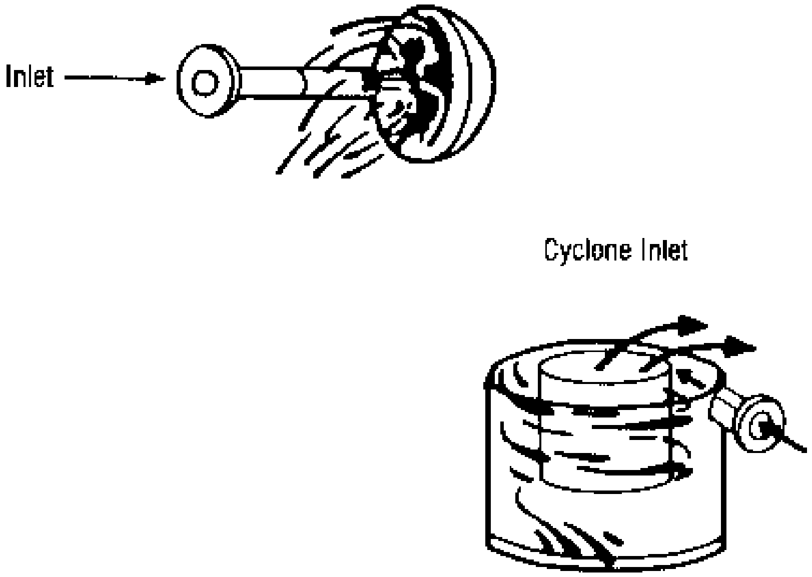
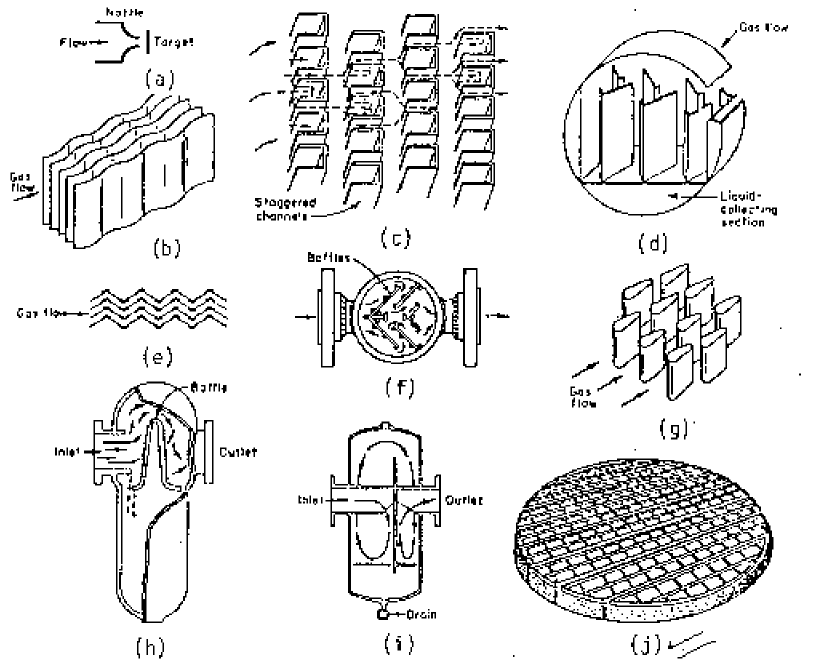
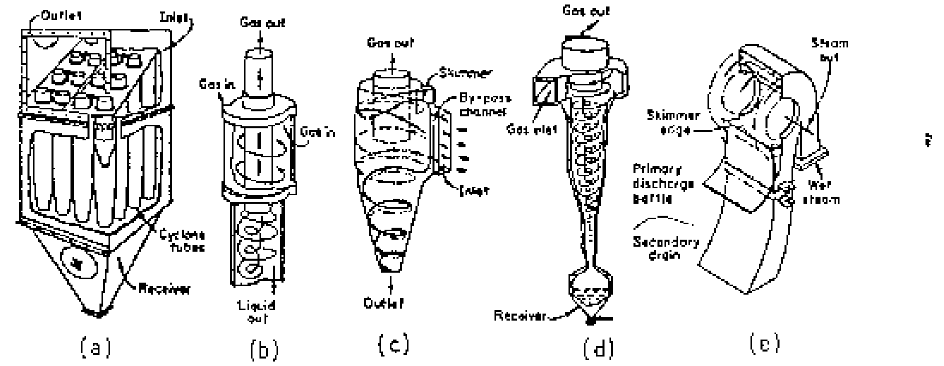


Fig-9 : Two basic types of inlet diverters .

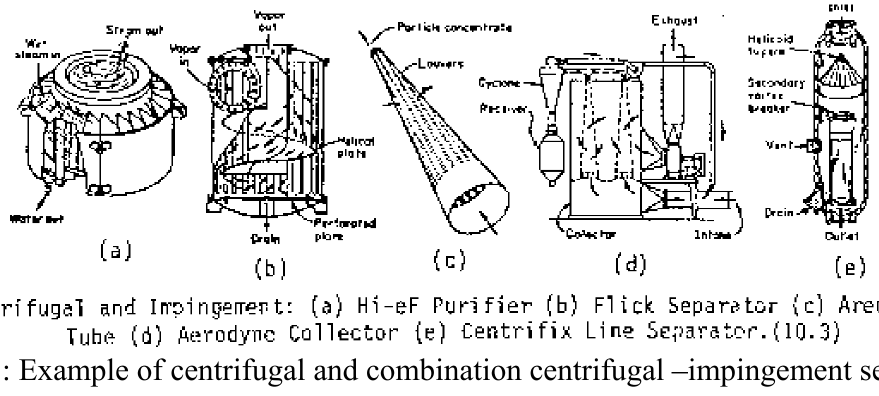


(a) Jet Impactor (b) Ware Plate (c) Staggered Channels (d) Vane Type (e) Peerless Line Separator (f) Strong Separator (g) Karbate Line Separator (h) Type E Horizontal Separator (i) PL Separator (j) Wire Mesh Demister.

Fig 12 : example of typical impingement separator



Centrifugal: (a) MultiCyclone (b) Thermix Tube (c) Van Tongeren Cyclone (d) Sirocco Collector (e) Horizontal Steam Separator.



Centrifugal and Impingement: (a) Hi-eF Purifier (b) Flick Separator (c) Areodyne Tube (d) Aerodyne Collector (e) Centrifix Line Separator.(10.3)

Fig-13: Example of centrifugal and combination centrifugal –impingement separators

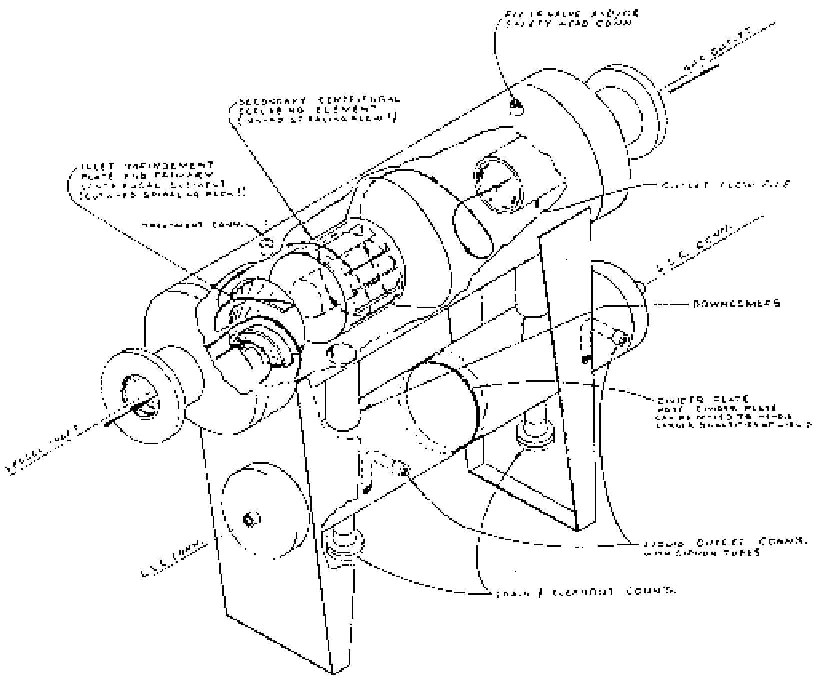


Fig-14 : dual-tube horizontal two-phase oil and gas separator with centrifugal primary and secondary separating element

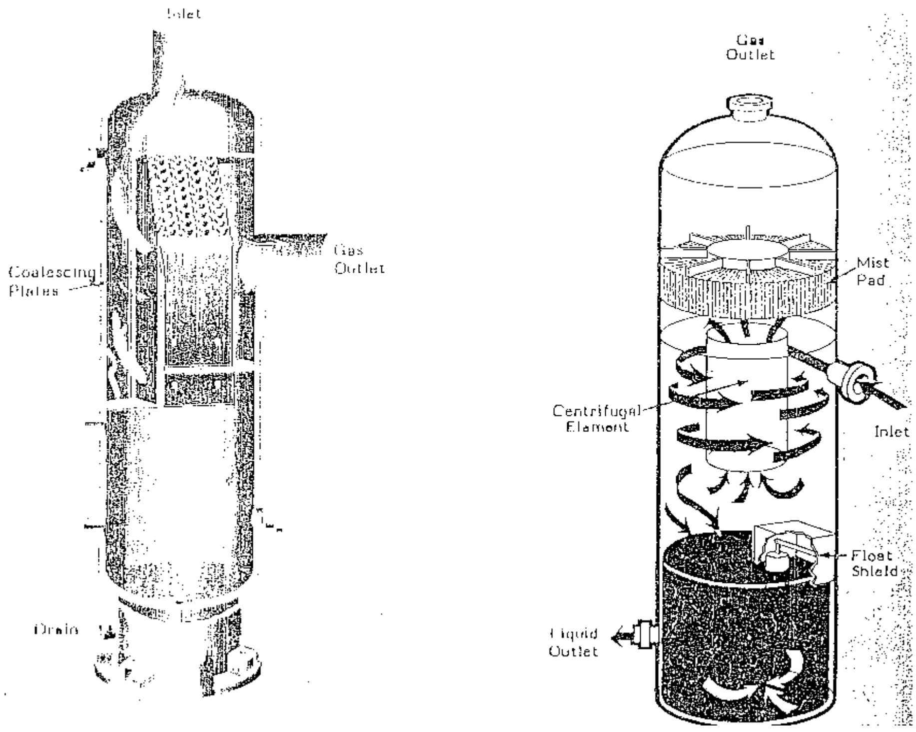


Fig-16 : 2 phase vertical separator

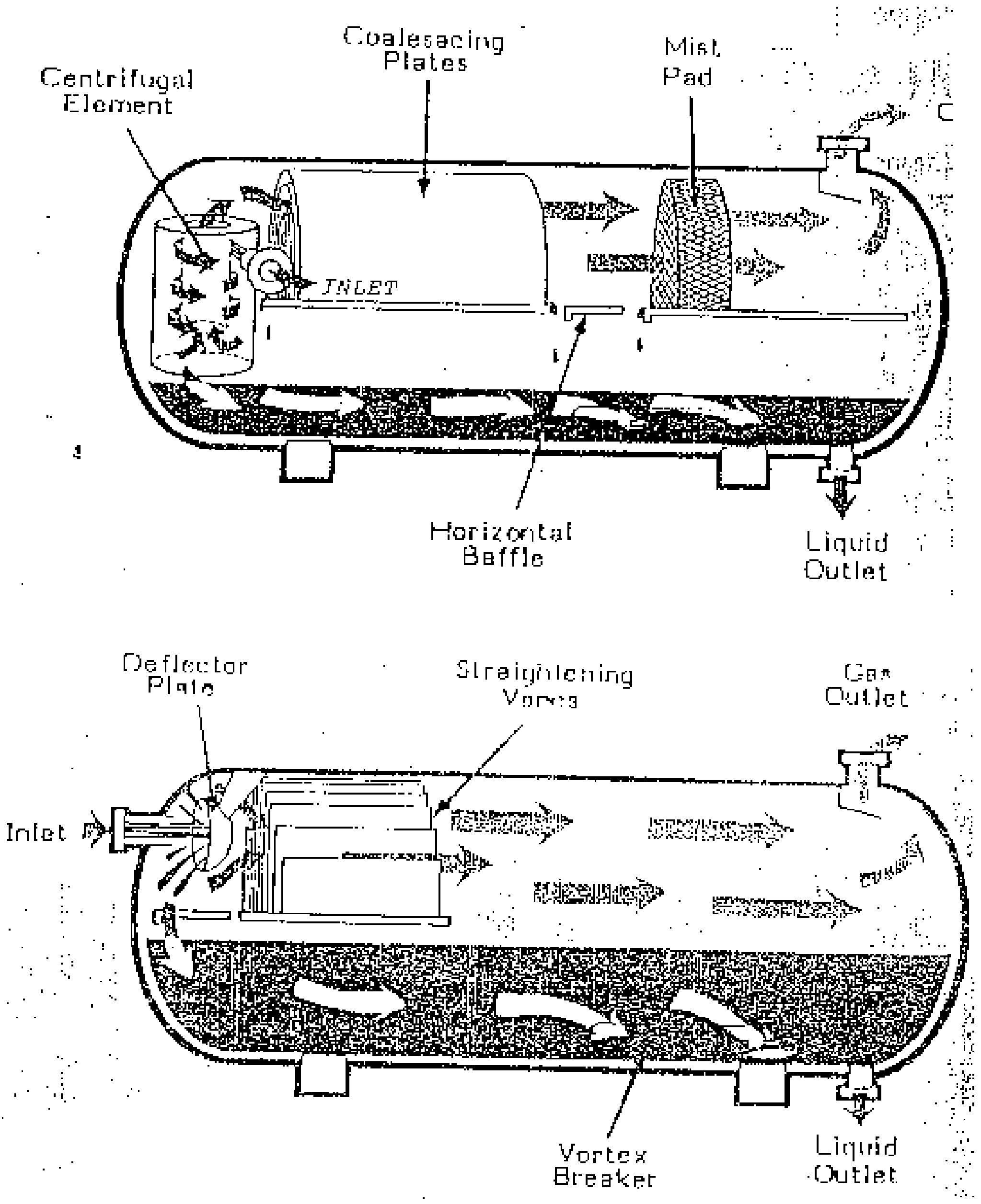
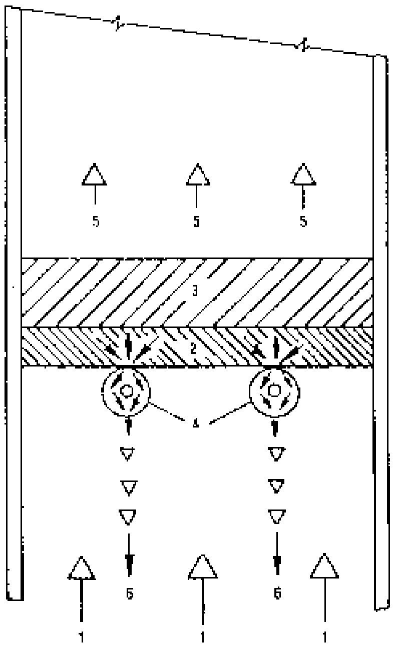


Fig-16 : 2 phase vertical separator



1 Mist-laden Gas
2 Mist Eliminator, Extra Fine Mesh, 3" Thick
3 Mist Eliminator, Fine Mesh, 6" Thick
4 Liquid Drain Cylinders, 3" Diameter
5 Dry Gas
6 Liquid Drain to Vessel Sump

Fig. 18 —Coalescing-type mist-eliminator pad with drain cylinders.

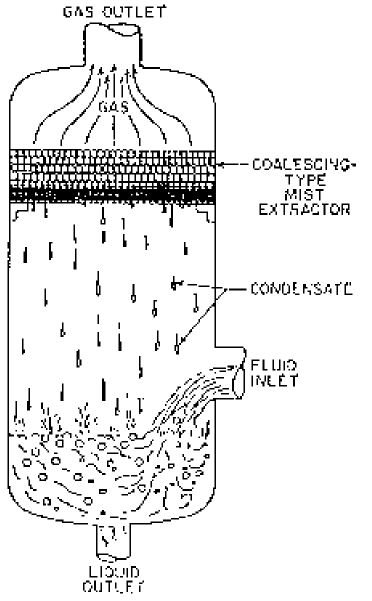


Fig. 19 —Coalescing-type mist extractor with knitted wire mesh. Used in gas scrubbers and oil and gas separators.

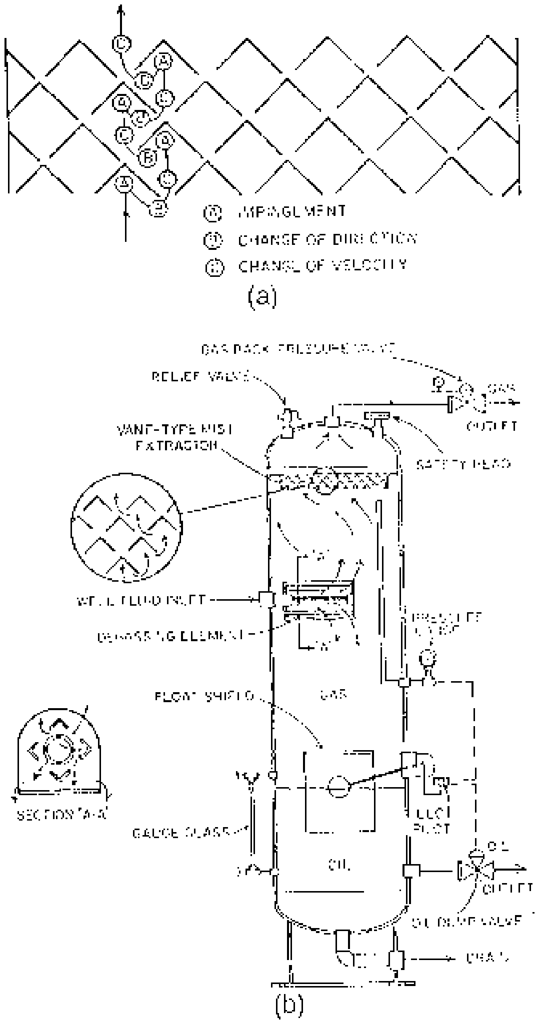


Fig. 17—Vertical two-phase oil and gas separator. (a) Illustration of impingement, change of flow direction, and change of flow velocity methods of mist extraction. (b) Separating and degassing element on inlet of vessel shown in detail in Section A-A.

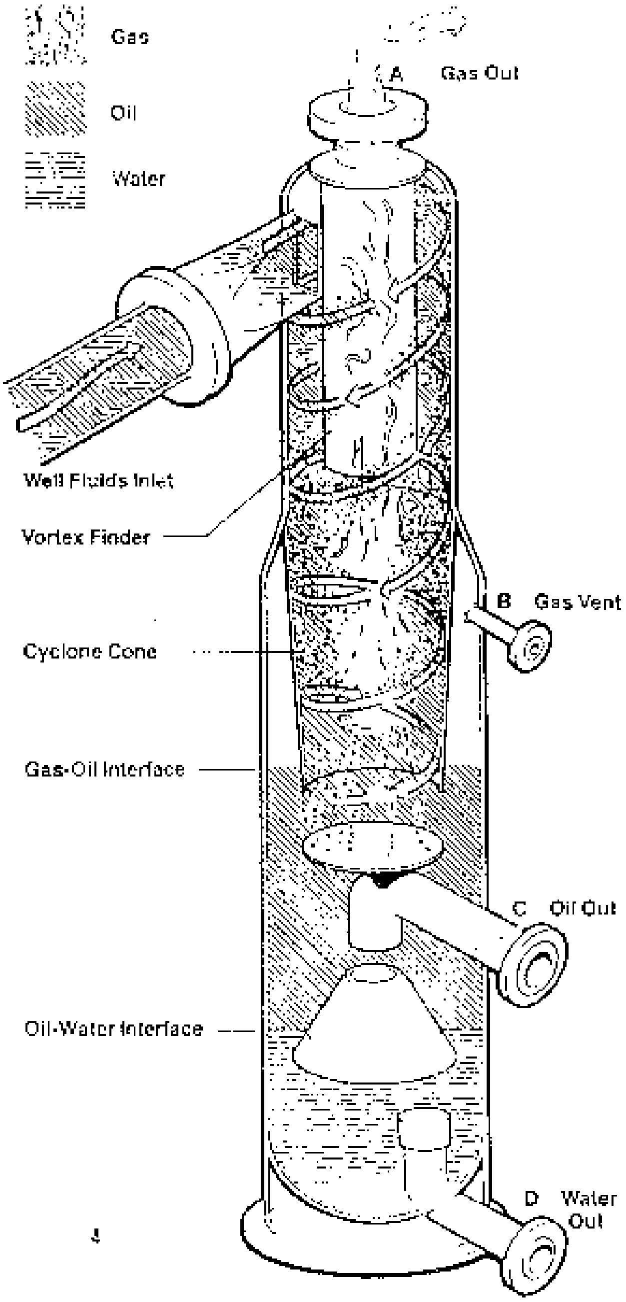


Fig. 20 —Vertical three-phase separator with centrifugal force to obtain primary separation.

METHODS USED TO REMOVE GAS FROM OIL IN SEPARATORS

Because of higher prices for natural gas, the widespread reliance on metering of liquid hydrocarbons, and other reasons, it is important to remove all non-solution gas from crude oil during field processing.

Methods used to remove gas from crude oil in oil and gas separators are settling, agitation, baffling, heat, chemicals, and centrifugal force.

Settling

Gas contained in crude oil that is not in solution in the oil will usually separate from the oil if allowed to settle a sufficient length of time. An increase in retention time for a given liquid throughput requires an increase in the size of the vessel and/or an increase in the liquid depth in the separator. Increasing the depth of oil in the separator may not result in increased emission of non-solution gas from the oil because "stacking up" of the oil may prevent the gas from emerging. Optimum removal of gas from the oil is usually obtained when the body of oil in the separator is thin - i.e., when the ratio of surface area to retained oil volume is high.

Agitation

Moderate, controlled agitation is helpful in removing non-solution gas that may be mechanically locked in the oil by surface tension and oil viscosity. Agitation usually will cause the gas bubbles to coalesce and to separate from the oil in less time than would be required if agitation were not used. Agitation can be obtained by properly designed and placed baffling.

Baffling

An inlet degassing element can be installed on the inlet of the separator to assist in introducing the well fluid into the separator with minimum turbulence and in removing gas from the oil (Figure-21). This element disperses the oil in such a manner that gas can more readily escape from the oil. This type of element eliminates high-velocity impingement of fluid against the opposite wall of the separator. The baffles placed in the separator between the inlet and the oil level spread the oil into thin layers as it flows downward from the inlet to the oil section. The oil is rolled over and over as it cascades down the baffles, and the combination of spreading and rolling is effective in releasing entrained gas bubbles. This type of baffling is effective in handling foaming oil.

Special perforated baffles or tower packing can be used to remove non-solution gas from crude oil. Such baffling or packing provides slight agitation, which allows the gas bubbles to break out of the oil as it flows through the baffles or packing.

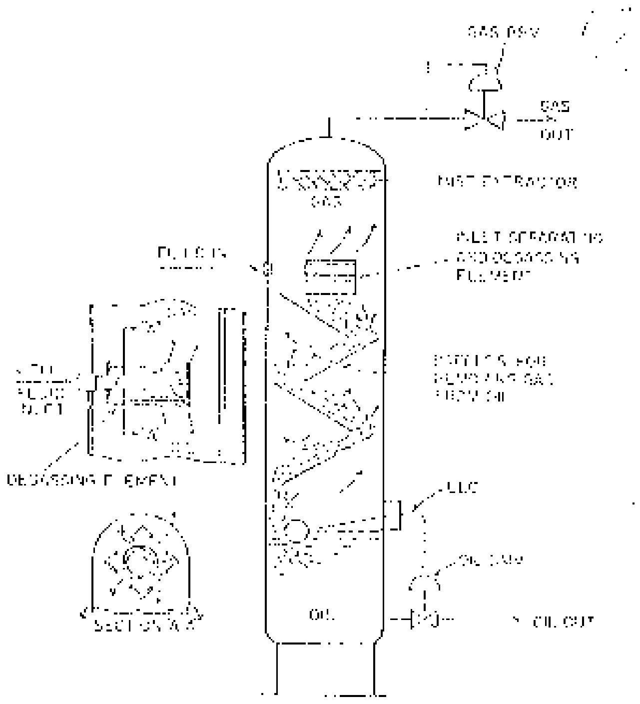


Fig. 21 —Vertical oil and gas separator with special baffling to remove gas from oil, especially beneficial in handling foaming oil. Upper left view and Section A-A show inlet separating element that assists in removing gas from oil.

Heat

Heat reduces surface tension and viscosity of the oil and thus assists in releasing gas that is hydraulically retained in the oil. The most effective method of heating crude oil is to pass it through a heated-water bath. A spreader plate that disperses the oil into small streams or rivulets increases the effectiveness of the heated-water bath. Upward flow of the oil through the water bath affords slight agitation, which is helpful in coalescing and separating entrained gas from the oil. A heated-water bath is probably the most effective method of removing foam bubbles from foaming crude oil. A heated-water bath is not practical in most oil and gas separators, but heat can be added to the oil by direct or indirect fired heaters and/or heat exchangers, or heated free-water knockouts or emulsion treaters can be used to obtain a heated-water bath.

Chemicals

Chemicals that reduce the surface tension of crude oil will assist in freeing non-solution gas from the oil. Such chemicals will appreciably reduce the foaming tendency of the oil and thereby increase the capacity of a separator when foaming oil is handled. In one particular case, the capacity of an oil and gas separator was increased from 3,800 to 9,600 B/D when silicone was injected into and mixed with the oil upstream of the separator with no other change made in the system. Silicone is effective in reducing the foaming tendency of crude oil when it is mixed with the oil in such small quantities as parts per million or parts per billion.

Centrifugal Force

Centrifugal force is effective in separating gas from oil. The heavier oil is thrown outward against the wall of the vortex retainer while the gas occupies the inner portion of the vortex. A properly shaped and sized vortex will allow the gas to ascend while the liquid flows downward to the bottom of the unit (Figure-20, 22 and 23).

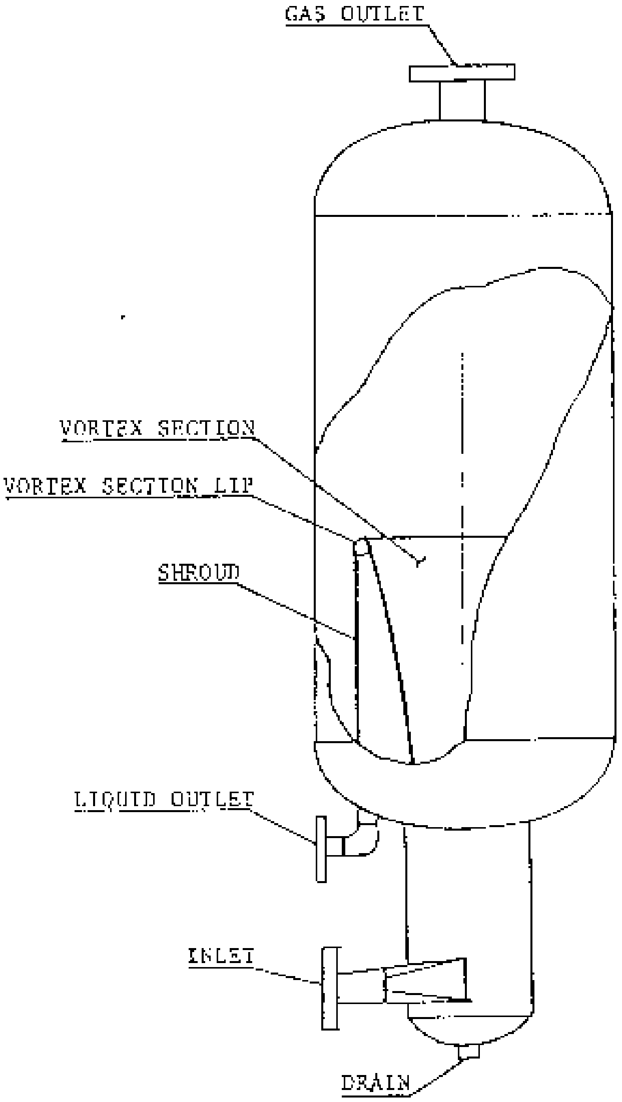


Fig. 22—Diverging vortex separator.

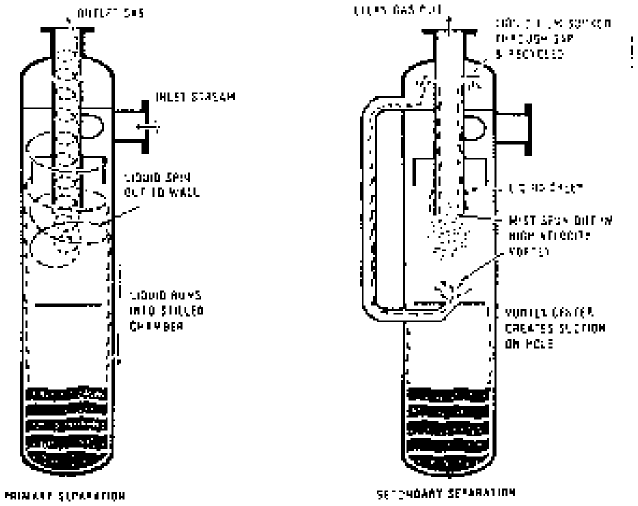


Fig. 23 —Schematic of vertical recycling separator with centrifugal force to obtain primary and secondary separation of oil and gas.

Estimated Quality of Separated Fluids

Crude Oil

The free (non-solution) gas content of separated crude oil will vary widely depending on many factors, such as size and configuration of the separator, design and arrangement of the separator internals, operating pressure and temperature, rate of flow, GOR, depth of liquid in the separator, viscosity, and surface tension of the oil.

The factors listed previously, in addition to the agitation resulting from pressure reduction and flow, well-fluid water content, impurities, and degree of emulsification of the oil and water will determine the water content of the separated crude oil.

When special chemicals, equipment, procedures, and techniques have been used or applied they improve the quality of the separated crude oil.

Separated Water

It is probable that the effluent water from a three-phase separator will contain oil. The quality of the separated water discharged from a three-phase separator depends on the same factors as previously listed for controlling the water content of the effluent oil. When special chemicals and separating techniques have been used or applied they improve the quality of the effluent water.

If the difference in the specific gravities of the oil and water at separator operating conditions is less than 0.20, special attention is required because the small difference in the densities of the oil and water will result in limited and incomplete separation. Lower qualities of effluent oil and water may result in such cases.

Gas

The oil (liquid hydrocarbon) content of the gas discharged from an oil and gas separator probably will be in the range of 0.10 gal/MMscf to 1.00 gal/MMscf (0.01 to 0.13 ppmv). Currently, it is difficult to measure the amount of oil in the separated gas under field operating conditions. With experience and patience, it can be done with a laser liquid particle spectrometer. The previously mentioned range of oil content in the separated gas has been accepted in recent years as an approximation of the performance of standard commercially available oil and gas separators under normal or average conditions equipped with suitably designed mist extractors.

Gas Quality From Scrubbers

The liquid content of gas discharged from gas scrubbers is usually less than the liquid content of gas discharged from oil and gas separators. Gas scrubbers are normally installed downstream of oil and gas separators or other separating equipment. If there is a separator upstream of the scrubber, the liquid hydrocarbon content of the scrubbed gas should be less than 0.10 gal/MMscf (less than 0.01335 ppmv).

PHYSICAL DESCRIPTION

Wellhead separators are often classified by their geometrical configuration (vertical, horizontal, horizontal double-barrel, or spherical) and by their function (two-phase), (vapor-liquid), or three-phase (gas-oil-water) separation. These four shapes are illustrated in Figure-24, 25, 26 and 27, respectively.

The features common to all separators are reviewed first and then vertical, horizontal, double-barrel horizontal, spherical, filter and subsea separators are described briefly. Finally, two important internals (mist extractors and level controls) are discussed.

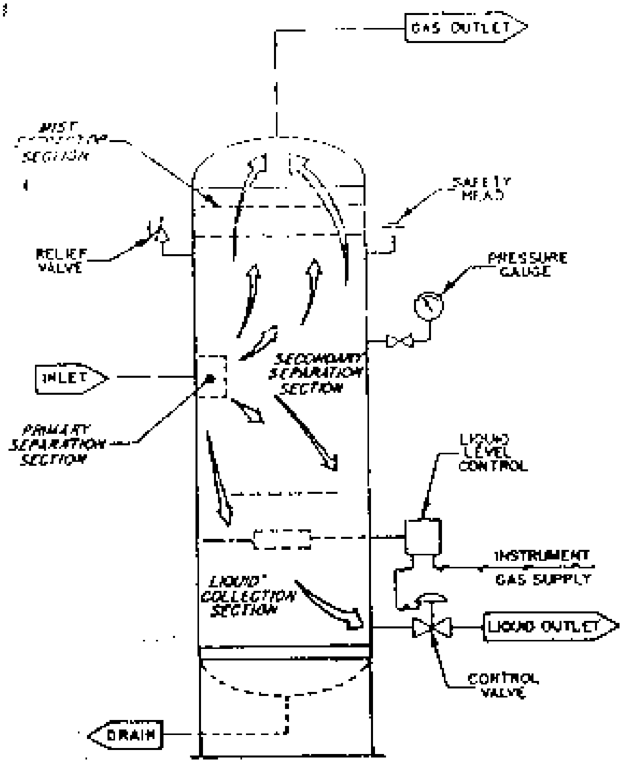


Figure 24 Vertical, Two-Phase Separation Configuration (API Spec 12J, 1989, p.10). Reprinted courtesy of the American Petroleum Institute.

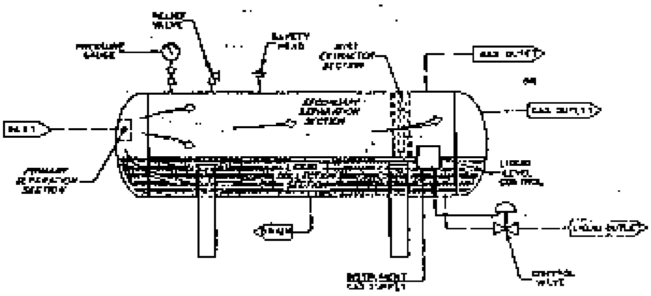


Figure 25 Horizontal, Two-Phase Separator Configuration (API Spec 12J, 1989, p.10). Reprinted courtesy of the American Petroleum Institute.

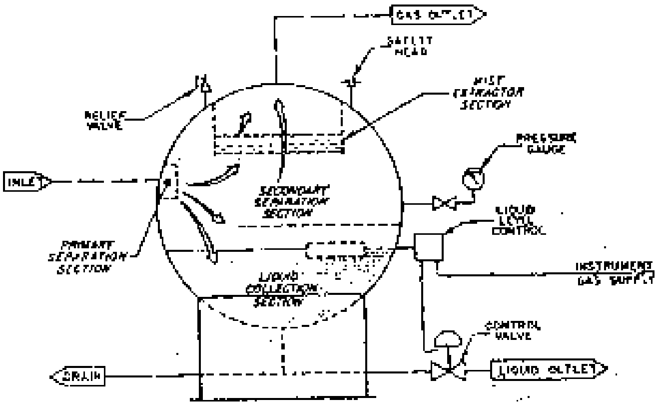


Figure 27 Spherical, Two-Phase Separator Configuration (API Spec 12J, 1989, p.11). Reprinted courtesy of the American Petroleum Institute.

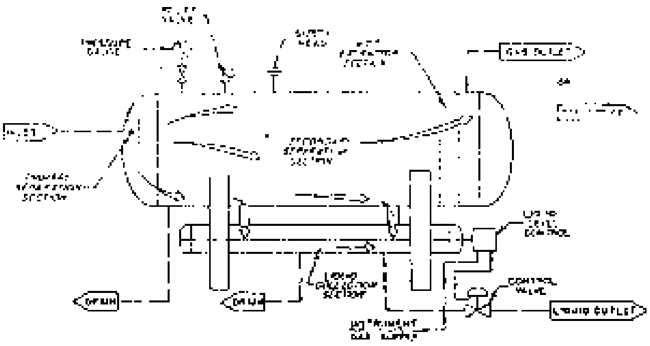


Figure 26 Horizontal, Two-Phase Double-Barrel Configuration (API Spec 12J, 1989, p.11). Reprinted courtesy of the American Petroleum Institute.

Common Components

All separators normally have the following components or features:

Primary Separation Section. For collecting and removing the bulk of the liquid in the inlet stream. Some form of inlet baffling is usually used to exploit the momentum of the inlet stream either by creating centrifugal force (as in vertical separators) or an abrupt change of direction (as in horizontal separators) thus separating most of the incoming liquid. In horizontal units, the inlet baffle reduces the incoming fluid velocities so that quiescent settling, or gravity, can complete the phase separation. Many different and proprietary shapes have been tried for the inlet baffling device, but structural channel iron is usually a very good choice.

Secondary or Gravity Settling Section. Here the gas velocity and turbulence is reduced so that entrained liquid drops can settle out by gravity. Internal baffling is often used to dissipate foams, further reduce turbulence, and accelerate drop removal.

Mist Extraction or Coalescence Section. The mist extractor, which can consist of a series of vanes, a woven wire mesh pad, or a centrifugal device, removes small droplets (normally down to 10 micron diameter) of liquid from the gas stream before the gas leaves the vessel. Liquid carry-over often meets a 0.1 gallon per MMscf spec.

Well-designed and operated mist extractors can be very efficient at removing liquid mists from gas streams. In the final analysis, liquid removal is accomplished by gravity; that is, by the large density difference between the "heavy" (40-60 lb/ft^3) liquid and the "light" (< 4 lb/ft^3) gas.

Vane-Type extractors are shown in Figure-28(E), 29(D), 30, 31, and 32. Figure-29(D) and 30 show Dixon plates that were an industry standard. Dixon plates are essentially flat plates oriented parallel to the gas flow and inclined at 45 degrees to the horizontal. They markedly reduce the level of turbulence in the gas flow because the gas must now flow between the plates that are spaced about 1 in. apart. Dixon plates; also reduce the vertical distance a liquid drop must fall due to gravity to be collected.

Blade-type mist extractors, today's standard, accelerate the separation using impingement, change in gas flow direction and velocity, and coalescence. Figures-31 and 32 show two types of very efficient blade mist extractors; namely, chevron blade and serpentine vane. Figure-31 also shows how drop impingement, change in direction of gas flow and change in gas velocity are used to enhance drop removal. In serpentine vane (Figure-32), liquid drainage occurs outside and at right angles to the gas flow, thus minimizing liquid re-entrainment.
The plates or vanes, which are usually spaced 0.5-3 in. apart, can be made of carbon or stainless steel. PVC, or polypropylene. Excellent removal (> 90%) of drops larger than 10 mm is often claimed for vane extractors and entrainment losses of 0.1 gal/MMscf are often guaranteed. Vane extractors enjoy two big advantages. They are inexpensive, and they do not plug or foul as readily with paraffin, wax, solids, etc. Nevertheless, cleaning provisions should be made (e.g., suitably located manholes for steam lances). Typically, pressure drops vary from 2 or 3 to 6 or 8 in. water.

Wire-Mesh or *Fibrous mist extractors* (Figure-33) are used only for clean inlet streams where plugging by solids is unlikely. Wire-mesh mist extractors are made by knitting wire typically 0.002-0.020 in. diameter. Wire-mesh mist eliminators are available in carbon or stainless steel, monel, nickel, aluminum, or plastic. A common type is made from 0.011 in. wire and has a void fraction of 97.7%, a bulk density of 12 lb/ft^3, and a surface area of 110 ft^2/ft^3. In the past wire-mesh designs consisted of a random distribution of wire; however, a structured order of wire-mesh arrangement is now available. A 4- to 6-inch pad is often used at pressure drops of 0.1-1.0 in. water. Droplets as small as 5 µm and liquid entrainments lower than 0.1 gal/MMscf can be achieved. Wire-mesh pads capture liquid drops by three mechanisms; inertial impaction, direct interception, and Brownian capture (Figure-34).

Dirty liquids such as crude oil plug wire-mesh pads very readily. Therefore, wire-mesh mist extractors are not generally used for oilfield separators except when the vessel is too small for vane packs.

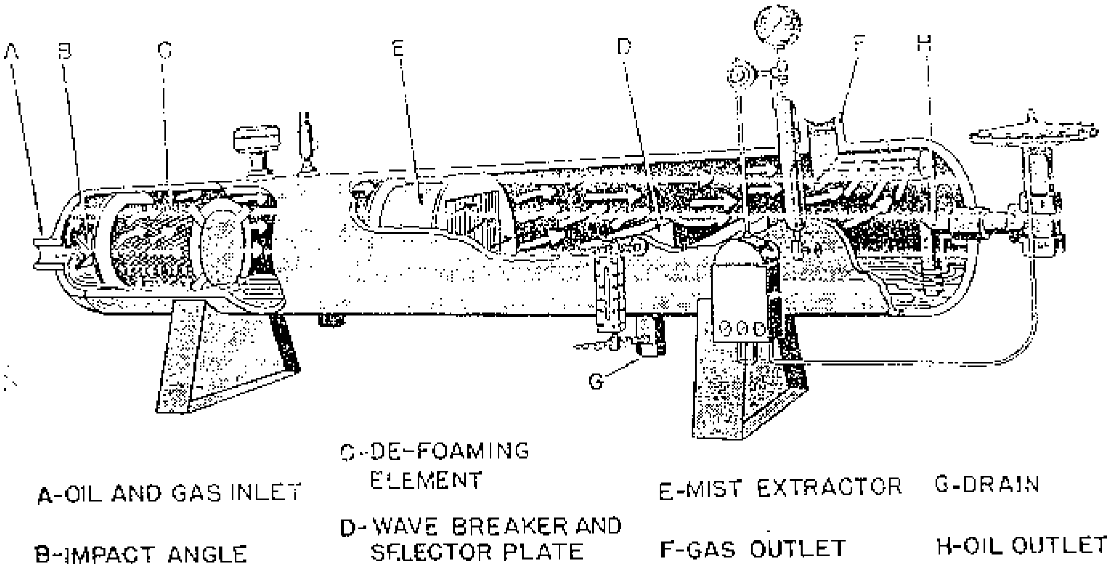


Fig. 28 Single-Shell Horizontal Separator (API, 1976, p. 34)

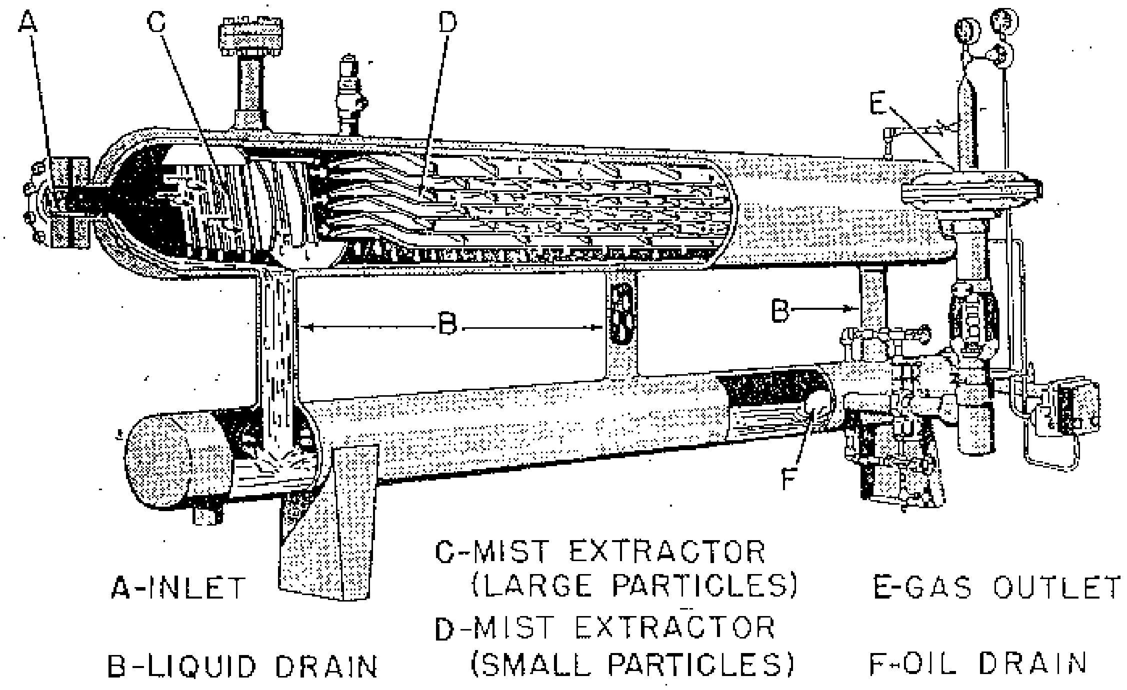


Fig. 29 Double-Barrel, Horizontal Separator (API, 1976, p. 34)

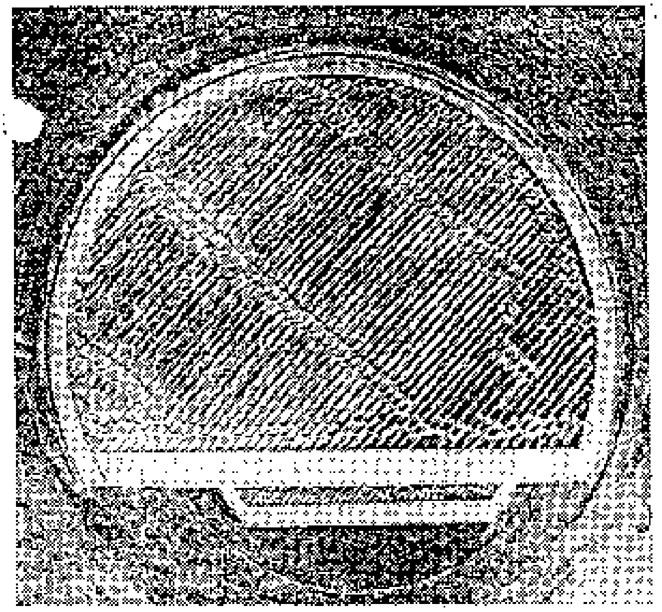


Fig. 30 Horizontal Separator with Dixon Plates

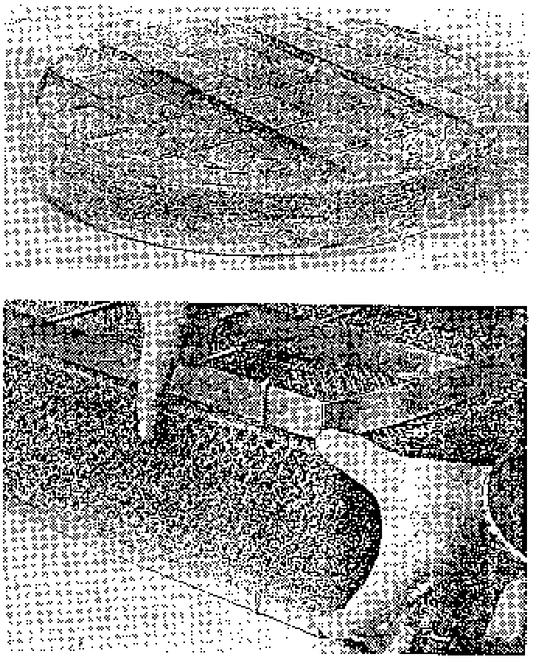


Fig.33 Demister® Wire Mesh Mist Eliminator

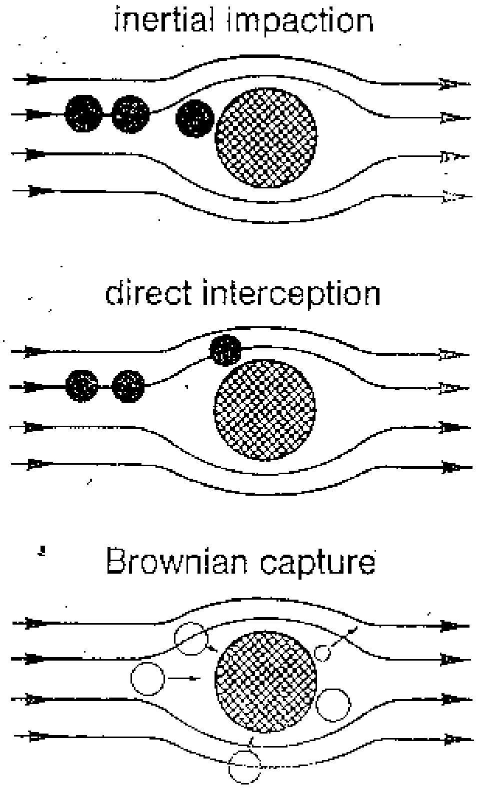


Fig.34. Three Basic Mechanisms for Mist

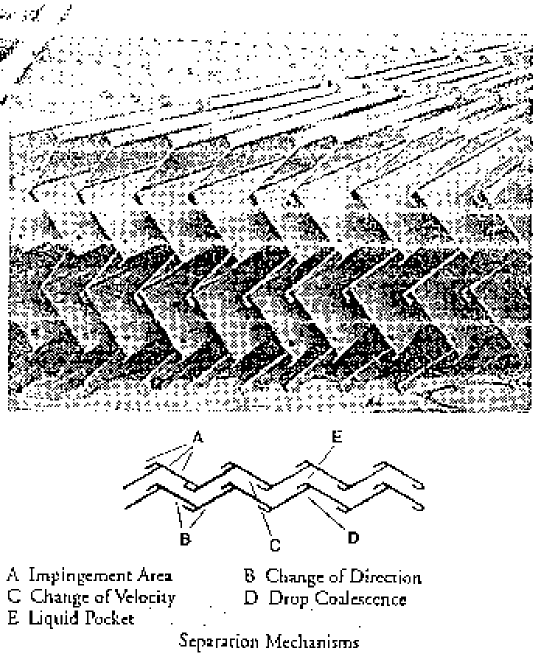
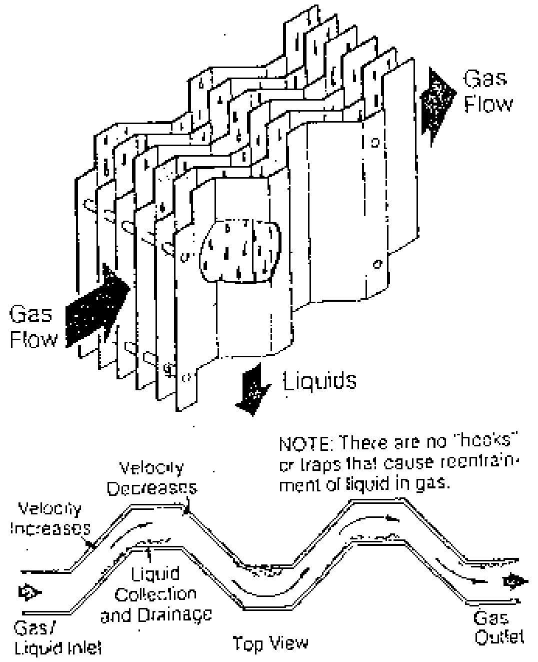


Fig.31 Chevron Vane Mist Extractors ([illegible])



NOTE: There are no "hooks" or traps that cause reentrainment of liquid in gas.

Fig.32 Serpentine Mist Extractor (NATCO, 1993)

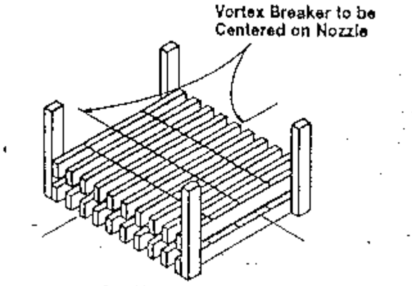
Liquid Accumulation Section.

This section collects the liquid(s) removed from the gas and provides sufficient capacity to handle surges in liquid flow. Adequate retention time is necessary to allow for removal of any gas breaking out of solution and, in three-phase separators, for separation of free water and oil. A vortex breaker may be located over the liquid outlet nozzle(s) to prevent gas or vapor entrainment with the bottom liquid.

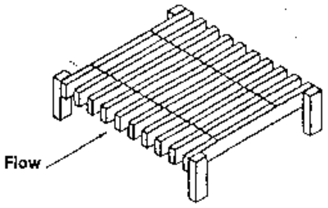
Poor outlet design can result in the formation of vortexes at the outlets. This, in turn, causes large amounts of liquid carry-over and gas slippage. *Vortex formation* is often not detected, even though it causes excessive pressure drop and, of course, poor separation. Vortex formation can be prevented by installing vortex breakers and by maintaining adequate liquid levels upstream of the outlet. Figures-35 and 36 show types of gas and liquid vortex breakers.

Recommended minimum liquid levels are:

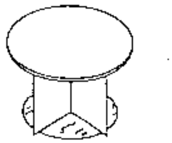
1. A liquid level of at least two outlet nozzle diameters for gas/liquid interfaces.
2. A liquid level of at least three times the outlet nozzle diameter for liquid/liquid interfaces.



Gas Vortex Breaker



Liquid Vortex Breaker



Liquid Vortex Breaker

Fig. 36 Outlet Vortex Breaker Designs (NATCO,

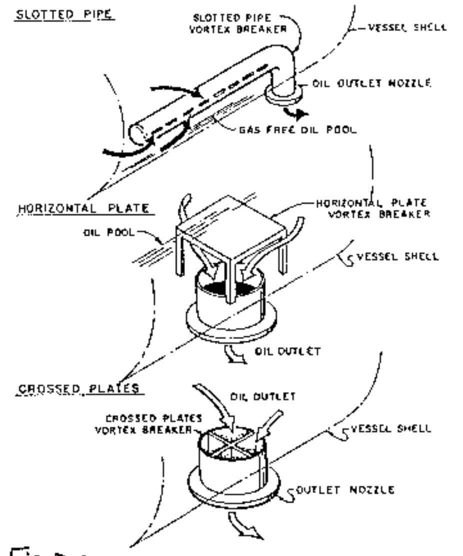
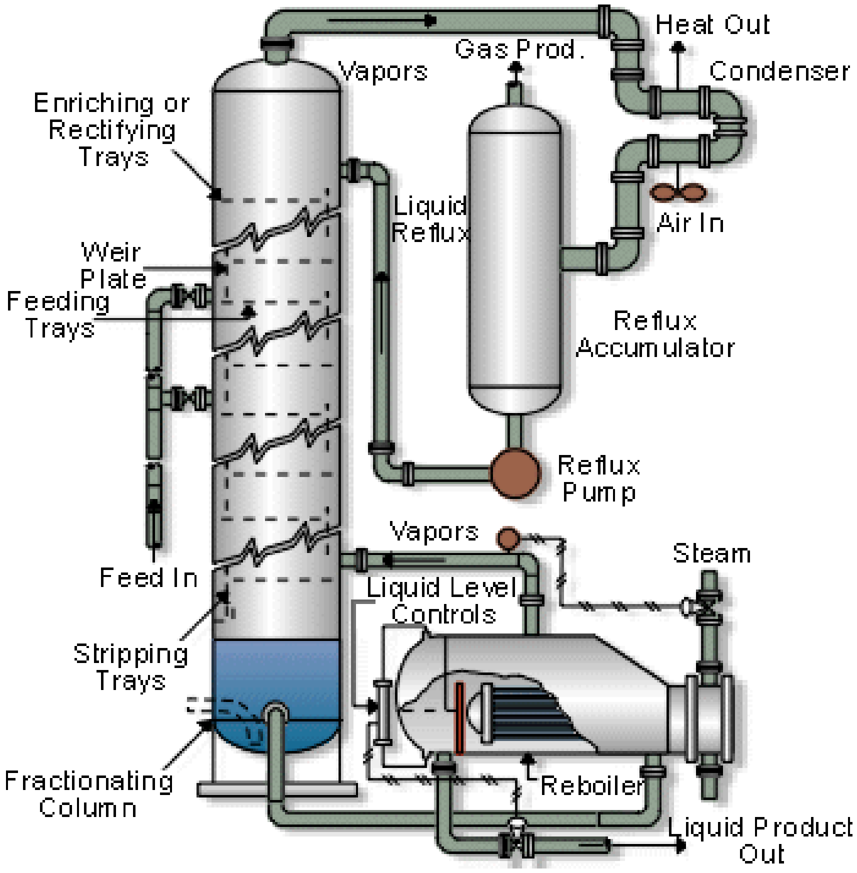


Fig.35 Several Types of Anti-Vortex Devices.

Summary for the Function of Separator Internals

Internal Device	Purpose of Device or Situation where Device should not be used
1- Mist Pad	a- remove liquid mist from gas. b- break oil-water emulsion. c- not used where hydrate, wax, or dirt may be present.
2- Deflector Plate	a- separate liquid from gas. b- used in all services.
3- Coalescing Plate	a- remove liquid mist from gas. b- separate oil from water. c- not used where hydrate, corrosion, wax or dirt present.
4- Straightening Vanes	a- remove liquid mist from gas. b- separate oil from water. c- not used where hydrate, corrosion, wax or dirt present.
5- Filter Elements	a- remove solid particles from gas or liquid. b- separate oil from water. c- remove mist from gas. d- not used where wax or hydrate may be present.
6- Coalescing Materials	a- separate oil from water. b- not used where wax may be present.
7- Centrifugal Devices	a- separate gas from liquid. b- not used where wax or dirt may be present. c- not used with intermittent gas flow.
8- Horizontal Baffles	a- usually used in large gas-liquid vessels where waves occur.
9- Vortex Breakers	a- should be used on all liquid outlet nozzles in gas-liquid separators. b- are not needed if vessel is full of liquid.
10- Float Shield	a- should be used when internal level control float is used.
11- Water Jets and Sand Cones	a- used only when solids may be present.

Condensate Stabilization



Condensate Stabilization

Contents:

Introduction :

The liquids that are separated from the gas stream in the first separator may be flowed directly to a tank or may be "stabilized" in some fashion.

These liquids contain a large percentage of methane and ethane, which will flash to gas in the tank.

This lowers the partial pressure of all other components in the tank and increases their tendency to flash to vapors. The process of increasing the amount of intermediate (C3 to C5) and heavy (C6 +) components in the liquid phase is called "stabilization." In a gas field this process is called condensate stabilization and in an oil field it is called crude stabilization.

In almost all cases the molecules have a higher value as liquid than as gas. Crude oil streams typically contain a low percentage of intermediate components. Thus, it is not normally economically attractive to consider other alternatives to multistage separation to stabilize the crude. In addition, the requirement to treat the oil at high temperature is more important than stabilizing the liquid and may require the flashing of both intermediate and heavy components to the gas stream.

Gas condensate, on the other hand, may contain a relatively high percentage of intermediate components and can be easily separated from entrained water due to its lower viscosity and greater density difference with water. Thus, some sort of condensate stabilization should be considered for each gas well production facility.

PARTIAL PRESSURES

The fraction of any one component that flashes to gas at any stage in a process is a function of the temperature, pressure, and composition of the fluid at that stage. For a given temperature this tendency to flash can be visualized by the partial pressure of the component in the gas phase that is in equilibrium with the liquid. Partial pressure is defined as:

$$\text{Partial Pressure}_n = \frac{\text{Moles}_n}{\text{Sum of Moles}} \times \text{Gas Pressure}$$

The partial pressure at a given pressure and temperature is lower when there are more moles of other components in the gas phase. The lower the partial pressure the greater the tendency of the component to flash to gas. Thus, the higher the fraction of light components in the inlet fluid to any separator, the lower the partial pressure of intermediate components in the gas phase of the separator, and the greater the number of intermediate component molecules that flash to gas.

MULTISTAGE SEPARATION

Figure 6-1 shows a multistage separation process. By removing molecules of the light components in the first separator they are not available to flash to gas from the liquid in the second separator, and the partial pressure of intermediate components in the second separator is higher than it would have been if the first separator did not exist. The second separator serves the same function of increasing the partial pressure of the intermediate components in the third separator and so forth.

The simplest form of condensate stabilization is to install a low-pressure separator downstream of an initial high-pressure separator. Unless the gas well produces at low pressure (less than 500 psi) and the gas contains very little condensate (less than 100 bpd), the additional expenditure for this stage of separation is almost always economical when balanced against increased liquid production. If vapor recovery from the tank is required by environmental regulations, the flash separator will significantly reduce the horsepower required. If vapor recovery is not required, the gas from the flash separator may be economically feasible to be recovered and recompressed for sales even if it is not feasible to recover stock tank vapors.

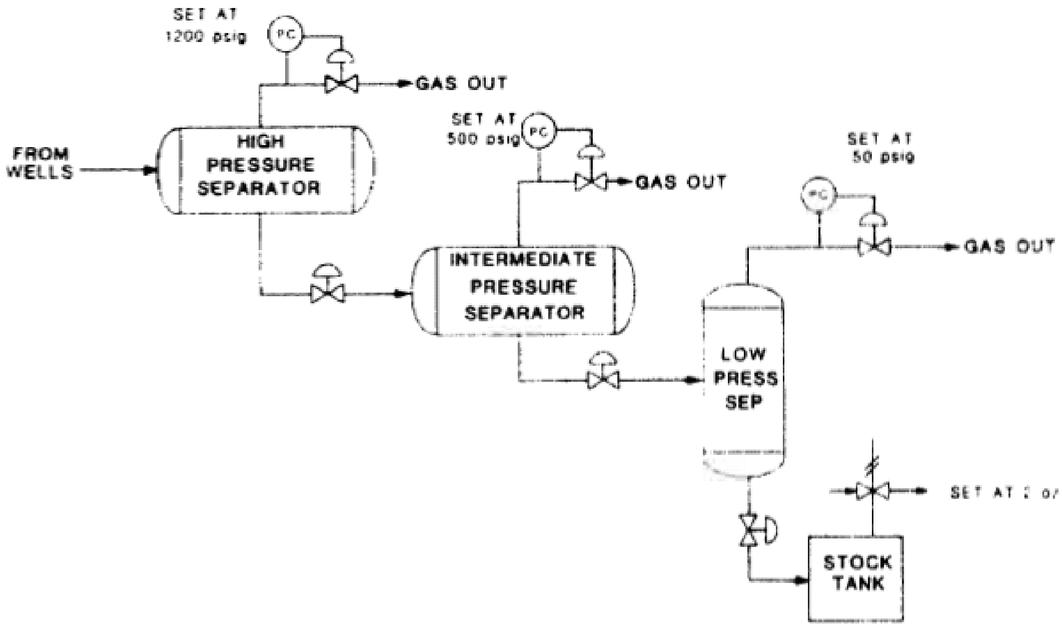


Figure 6-1. Multistage separation process.

MULTIPLE FLASHES AT CONSTANT PRESSURE AND INCREASING TEMPERATURE

It is possible to stabilize a liquid at a constant pressure by successively flashing it at increasing temperatures as shown in Figure 6-2. At each successive stage the partial pressure of the intermediate components is higher than it could have been at that temperature if some of the lighter components had not been removed by the previous stage. It would be very costly to arrange a process as shown in Figure 6-2, and this is ever done. Instead, the same effect is obtained in a tall, vertical pressure vessel with a cold temperature at the top and a hot temperature at the bottom. This is called a "condensate stabilizer."

Figure 6-3 shows a condensate stabilizer system. The well stream flows to a high pressure, three-phase separator. Liquids containing a high fraction of light ends are cooled and enter the stabilizer tower at approximately 200 psi. In the tower the liquid falls downward in a process that results in many flashes at ever-increasing temperatures. At the bottom of the tower, some of the liquids are cycled to a reboiler where they receive heat to provide the necessary bottoms temperature (200°F to 400°F). The reboiler could be either a direct-fired bath, an indirect-fired bath, or a heat medium exchanger.

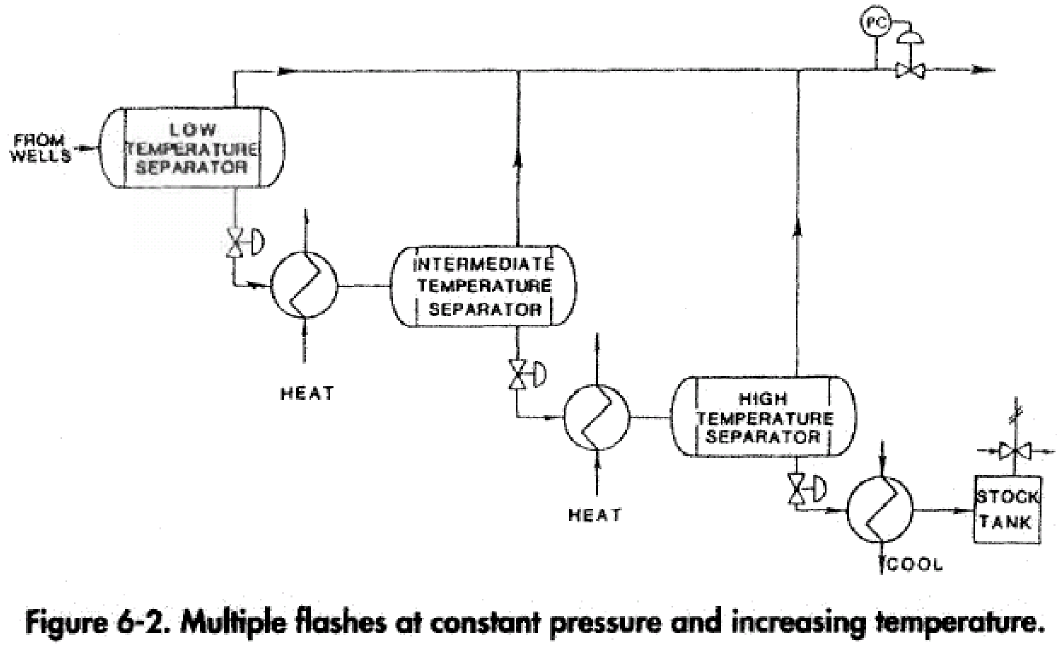
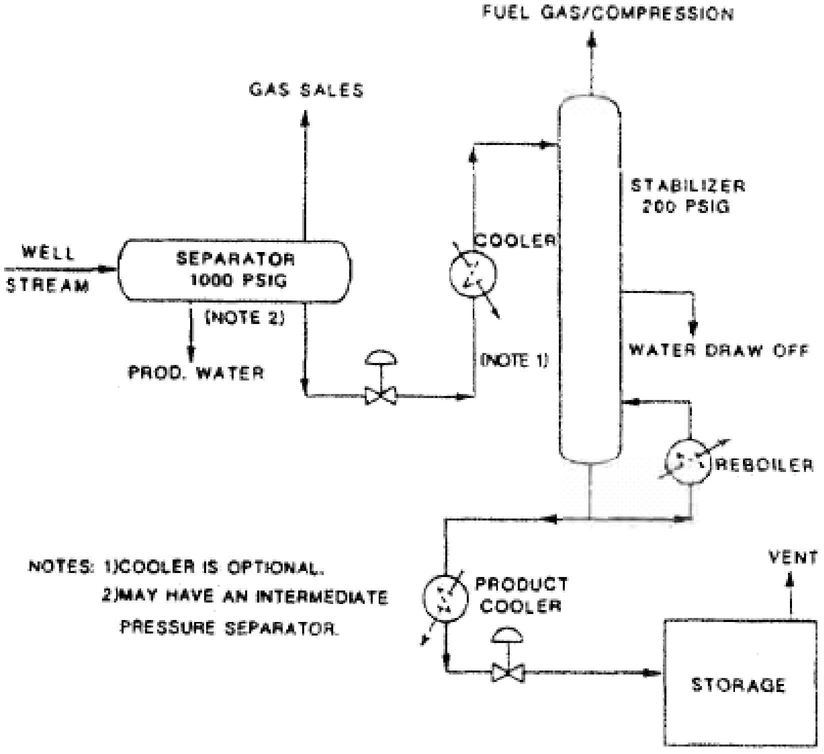


Figure 6-2. Multiple flashes at constant pressure and increasing temperature.



NOTES: 1)COOLER IS OPTIONAL.
2)MAY HAVE AN INTERMEDIATE
PRESSURE SEPARATOR.

Figure 6-3. Condensate stabilization system.

The liquids leaving the bottom of the tower have undergone a series of stage flashes at ever-increasing temperatures, driving off the light components, which exit the top of the tower. These liquids must be cooled to a sufficiently low temperature to keep vapors from flashing to atmosphere in the storage tank.

COLD FEED DISTILLATION TOWER

Figure 6-4 shows the cold feed distillation tower of Figure 6-3. The inlet stream enters the top of the tower. It is heated by the hot gases bubbling up through it as it falls from tray to tray through the downcomers. A flash occurs on each tray so that the liquid is in near-equilibrium with the gas above it at the tower pressure and the temperature of that particular tray.

As the liquid falls, it becomes leaner and leaner in light ends, and richer and richer in heavy ends. At the bottom of the tower some of the liquid is circulated through a reboiler to add heat to the tower. As the gas goes up from tray to tray, more and more of the heavy ends get stripped out of the gas at each tray and the gas becomes richer and richer in the light ends and leaner and leaner in the heavy ends (just the opposite of the liquid). The gas exits the top of the tower,

The lower the temperature of the inlet liquid, the lower the fraction of intermediate components that flash to vapor on the top trays and the greater the recovery of these components in the liquid bottoms. However, the colder the feed, the more heat is required from the reboiler to remove light components from the liquid bottoms. If too many light components remain in the liquid, the vapor pressure limitations for the liquid may be exceeded. Light components may also encourage flashing of intermediate components (by lowering their partial pressure) in the storage tank.

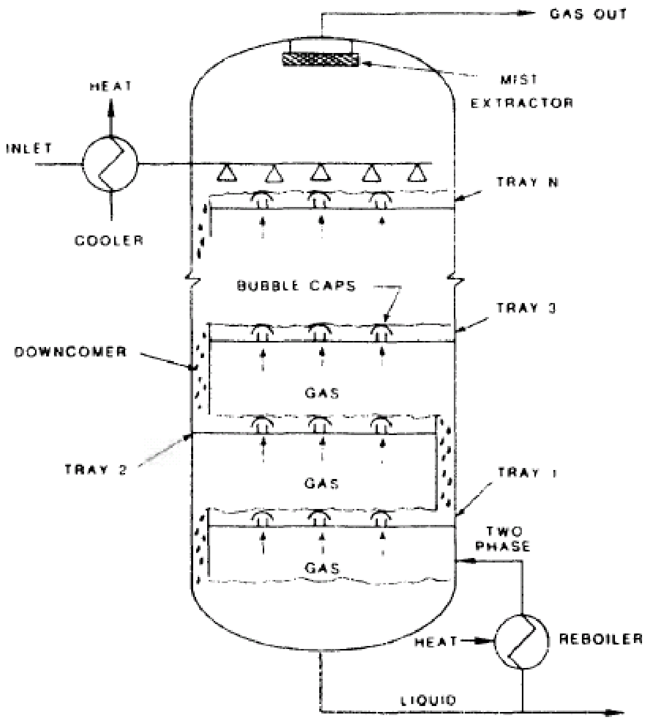


Figure 6-4. Cold-feed distillation tower of condensate stabilization system.

There is a balance between the amount of inlet cooling and the amount of reboiling required.

Typically, the liquid out the bottom of the tower must meet a specified vapor pressure. The tower must be designed to maximize the molecules of intermediate components in the liquid without exceeding the vapor pressure specification. This is accomplished by driving the maximum number of molecules of methane and ethane out of the liquid and keeping as much of the heavier ends as possible from going out with the gas.

DISTILLATION TOWER WITH REFLUX

Figure 6-5 shows a stabilizer with reflux. The well fluid is heated with the bottoms product and injected into the tower, below the top, where the temperature in the tower is equal to the temperature of the feed. This minimizes the amount of flashing. In the tower, the action is the same as in a cold-feed stabilizer or any other distillation tower. As the liquid falls through the tower, it goes from tray to tray, and gets increasingly richer in the heavy components and increasingly leaner in the light components.

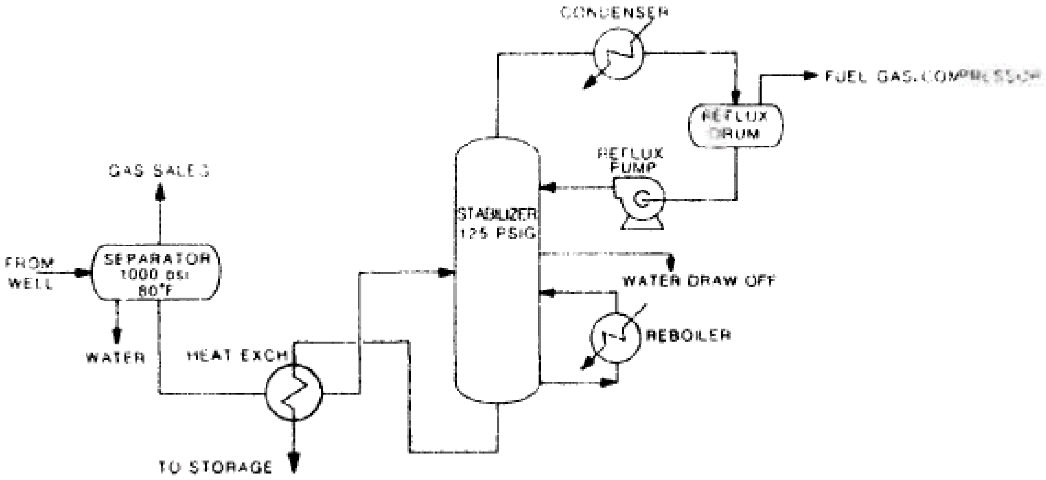


Figure 6-5. Stabilizer with reflux and feed/bottoms heat exchanger.

The stabilized liquid is cooled in the heat exchanger by the feed stream before flowing to the stock tank.

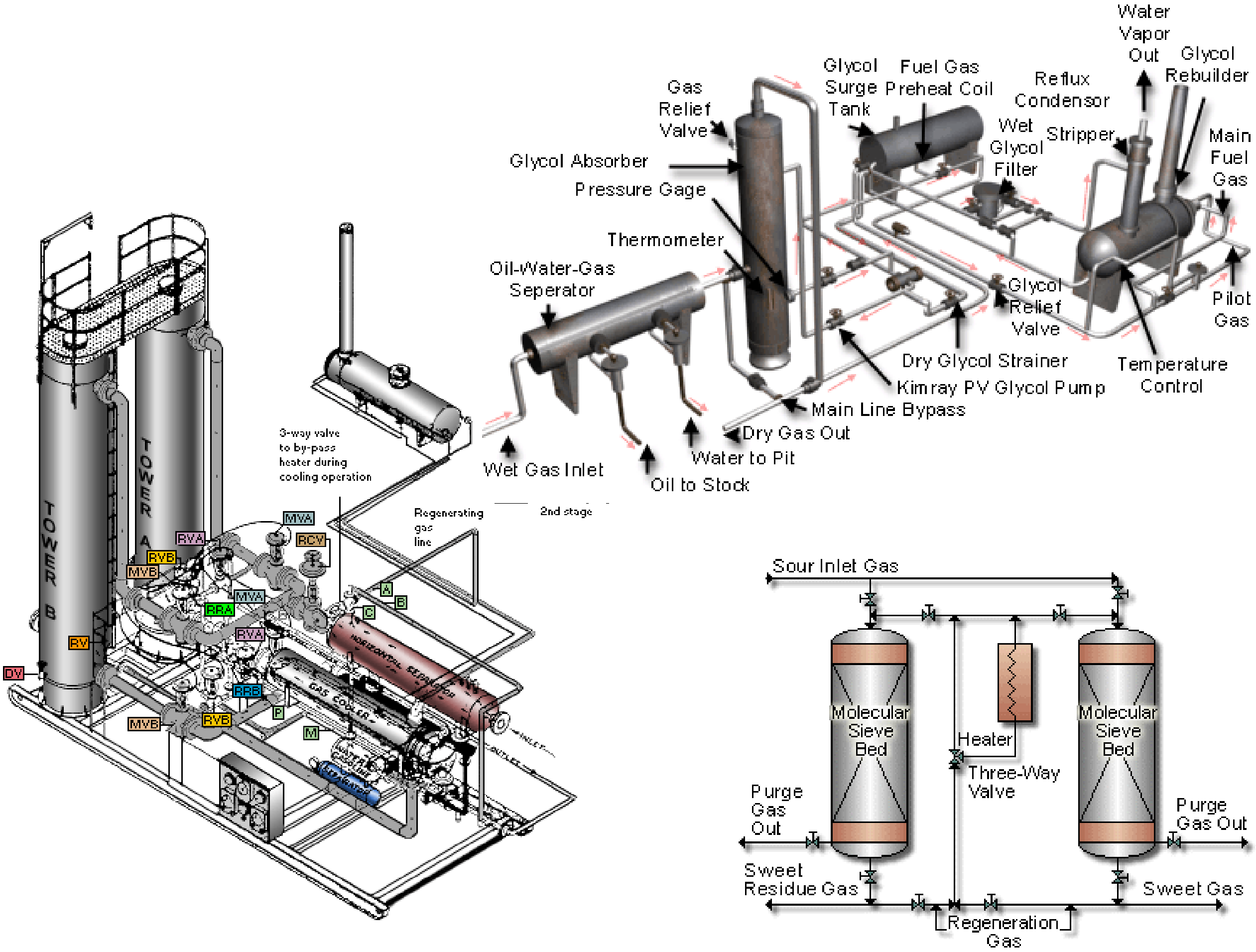
At the top of the tower any intermediate components going out with the gas are condensed, separated, pumped back to the tower, and sprayed down on the top tray. This liquid is called "reflux," and the two-phase separator that separates it from the gas is called a "reflux tank" or "reflux dram," The reflux performs the same function as the cold feed in a coldfeed stabilizer. Cold liquids strip out the intermediate components from the gas as the gas rises.

The heat required at the reboiler depends upon the amount of cooling done in the condenser.

The colder the condenser, the purer the product and the larger the percentage of the intermediate components that will be recovered in the separator and kept from going out with the gas. The hotter the bottoms, the greater the percentage of light components will be boiled out of the bottoms liquid and the lower the vapor pressure of the bottoms liquid,

A condensate stabilizer with reflux will recover more intermediate components from the gas than a cold-feed stabilizer. However, it requires more equipment to purchase, install, and operate. This additional cost must be justified by the net benefit of the incremental liquid recovery; less the cost of natural gas shrinkage and loss of heating value, over that obtained from a cold-feed stabilizer.

Gas Dehydration



Gas Dehydration

Contents:

PRINCIPLES OF GAS DEHYDRATION

Background

Liquid water and/or water vapor are removed from natural gas to:

- Prevent formation of hydrates in transmission lines.
- Meet a water dew point requirement of a sales gas contract.
- Prevent corrosion.

Techniques for dehydrating natural gas include:

- Absorption using liquid desiccants.
- Adsorption using solid desiccants.

Through absorption, the water in a gas stream is dissolved in a relatively pure liquid solvent stream. The reverse process, in which the water in the solvent is transferred into the gas phase, is known as stripping. The term regeneration is also used to describe stripping (or purification) because the solvent is usually recovered for reuse in the absorption step.

Absorption and stripping are frequently used in gas processing and most gas sweetening operations, as well as in glycol dehydration.

The second major process by which water vapor is removed from a gas stream is called adsorption. Adsorption is a physical phenomenon that occurs when molecules of a gas are brought into contact with a solid surface and some of them condense on the surface.

Dehydration of a gas with a dry desiccant is an adsorption process in which water molecules are preferentially held by the desiccant and removed from the stream.

Water Content of Hydrocarbon

Based on experimental data, Fig-2 shows the solubility of water in sweet hydrocarbon liquids. In sour hydrocarbon liquids, water solubility can be substantially higher.

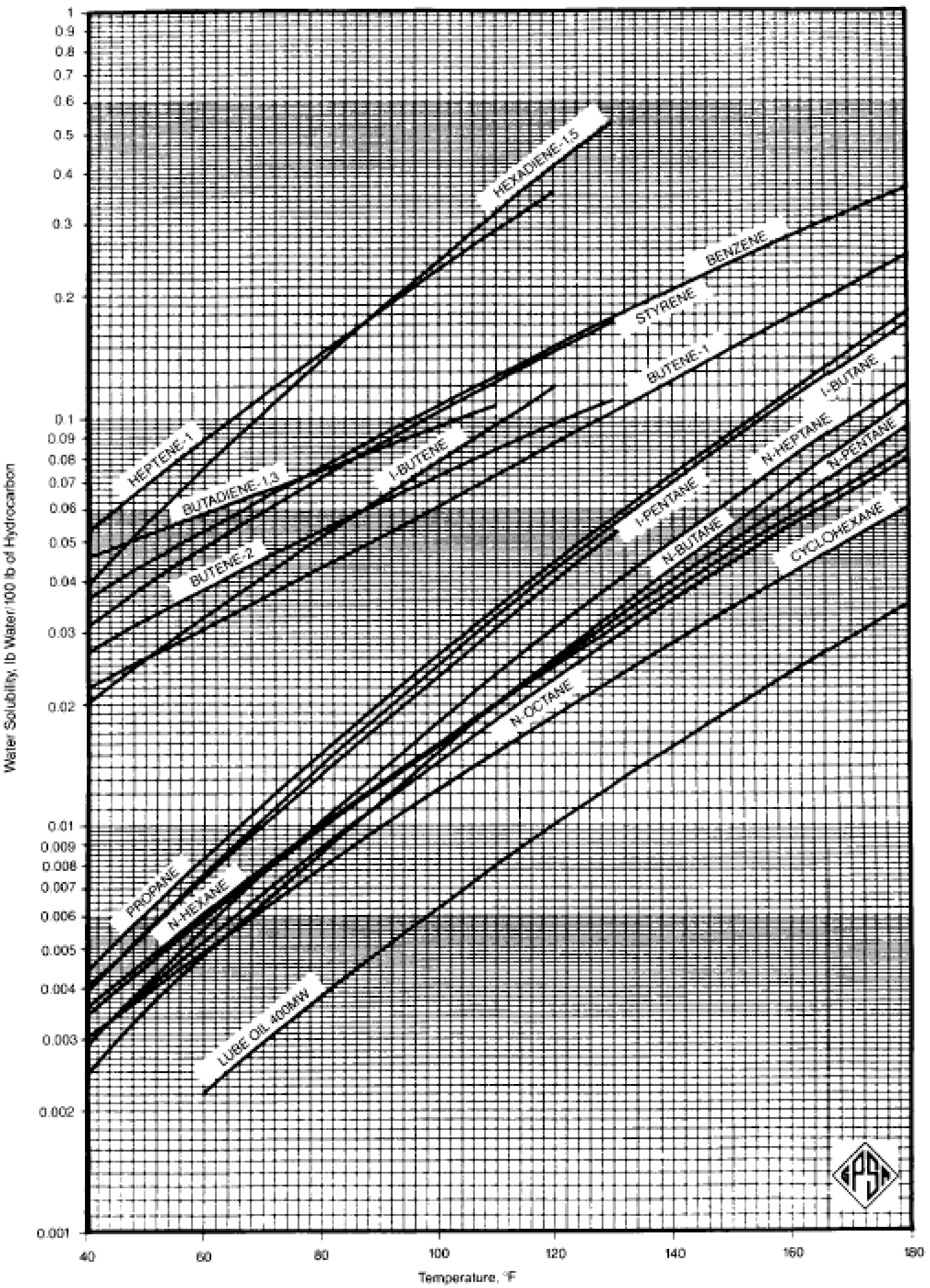


Fig 2 - Solubility of Water in Liquid Hydrocarbons

WATER CONTENT OF GASES

The saturated water content of a gas depends on pressure, temperature, and composition. The effect of composition increases with pressure and is particularly important if the gas contains CO_2 and/or H_2S. For lean, sweet natural gases containing over 70% methane and small amounts of heavy hydrocarbons, generalized pressure-temperature correlations are suitable for many applications. Fig.-3 is an example of one such correlation which has been widely used for many years in the design of "sweet" natural gas dehydrators. The gas gravity correlation should never be used to account for the presence of H_2S and CO_2 and may not always be adequate for certain hydrocarbon effects, especially for the prediction of water content at pressures above 1500 psia. The hydrate formation line is approximate and should not be used to predict hydrate formation conditions.

The following examples are provided to illustrate the use of Fig.-3:

Example 20-1 — Determine the saturated water content for a sweet lean hydrocarbon gas at 150°F and 1,000 psia.

From Fig. -3,

$W = 220$ lb/MMscf

For a 26 molecular weight gas,

$C_g = 0.98$ (Fig. -3)

$W = (0.98)(220) = 216$ lb/MMscf

For a gas in equilibrium with a 3% brine,

$C_s = 0.93$ (Fig. -3)

$W = (0.93)(220) = 205$ lb/MMscf

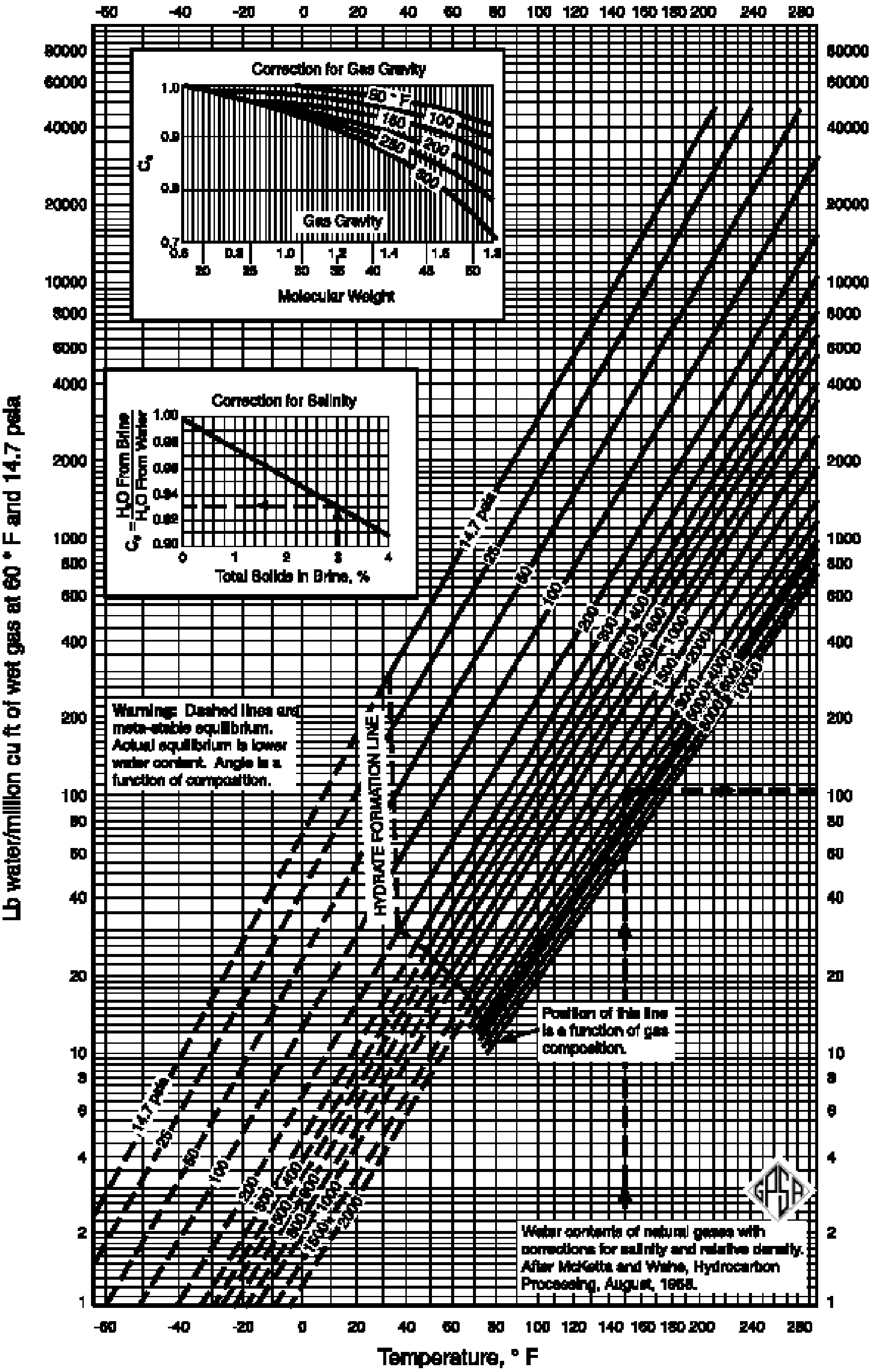


Fig- 3 : Water Content of Hydrocarbon Gas

Water Content of High CO_2/H_2S Gases

Both H_2S and CO_2 contain more water at saturation than methane or sweet natural gas mixtures. The relative amounts vary considerably with temperature and pressure. Fig. -4 and-5 display saturated water content of pure CO_2 and H_2S, respectively, at various temperatures and pressures. Fig. -6 shows the saturated water contents of pure CH_4, CO_2 and selected mixtures vs. pressure at 100°F. Fig. -7 exhibits the saturated water content of pure CH_4, CO_2 and a 95% CO_2 – 5% CH_4 mixture vs. pressure at 100°F. Several significant observations can be made from these figures and other available data.

1. Saturated water content of pure CO_2 and H_2S can be significantly higher than that of sweet natural gas, particularly at pressures above about 700 psia at ambient temperatures.
2. Corrections for H_2S and CO_2 should be applied when the gas mixture contains more than 5% H_2S and/or CO_2 at pressures above 700 psia. These corrections become increasingly significant at higher concentrations and higher pressures.
3. The addition of small amounts of CH_4 or N_2 to CO_2 or H_2S can dramatically reduce the saturated water content compared to the pure acid gas.

FIG-4
Water content of CO2

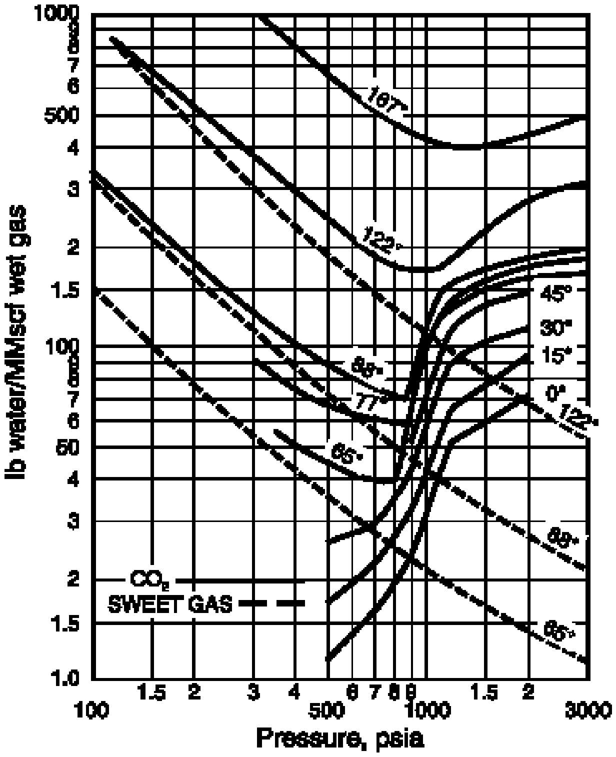


FIG-5

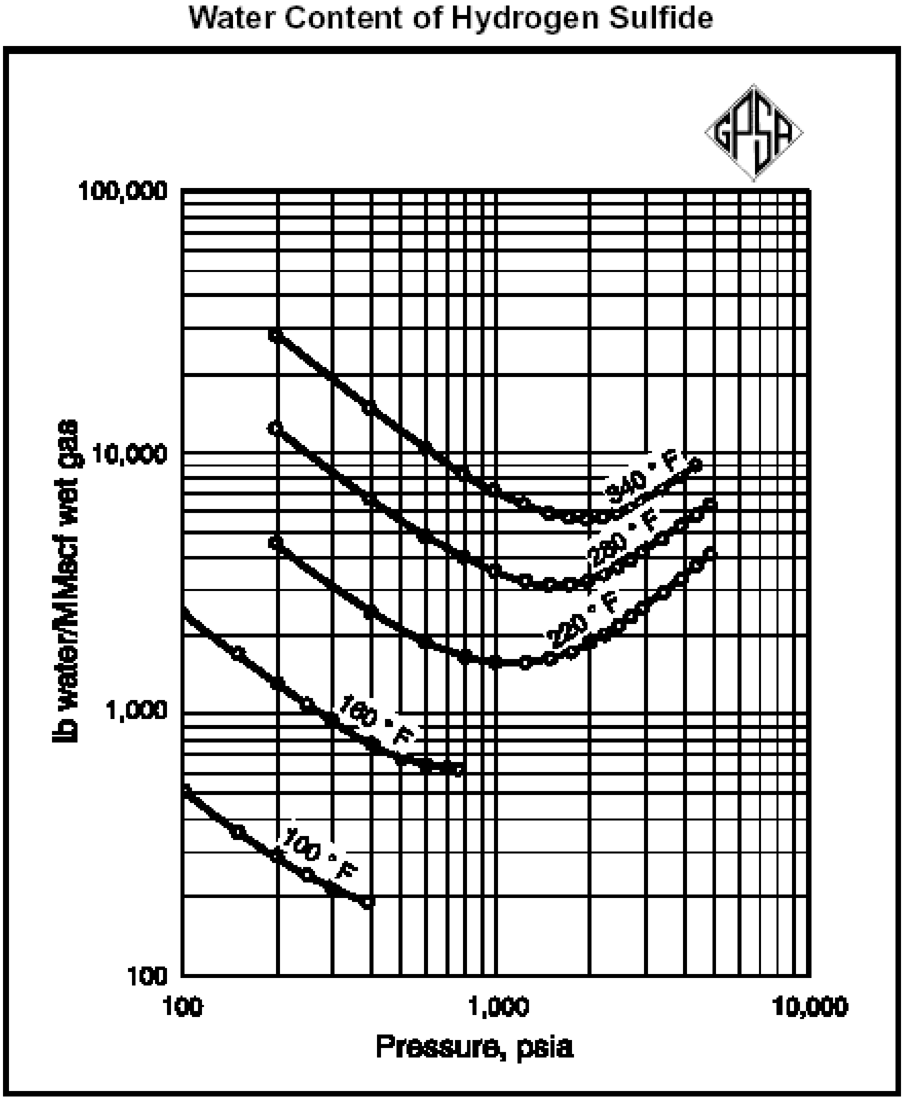

Water Content of Hydrogen Sulfide
GPSA
100,000
10,000
1,000
100
100
1,000
10,000
Pressure, psia
lb water/MMscf wet gas
340 °F
280 °F
220 °F
160 °F
100 °F

FIG-6

Experimental Values for Water Content of Acid Gases

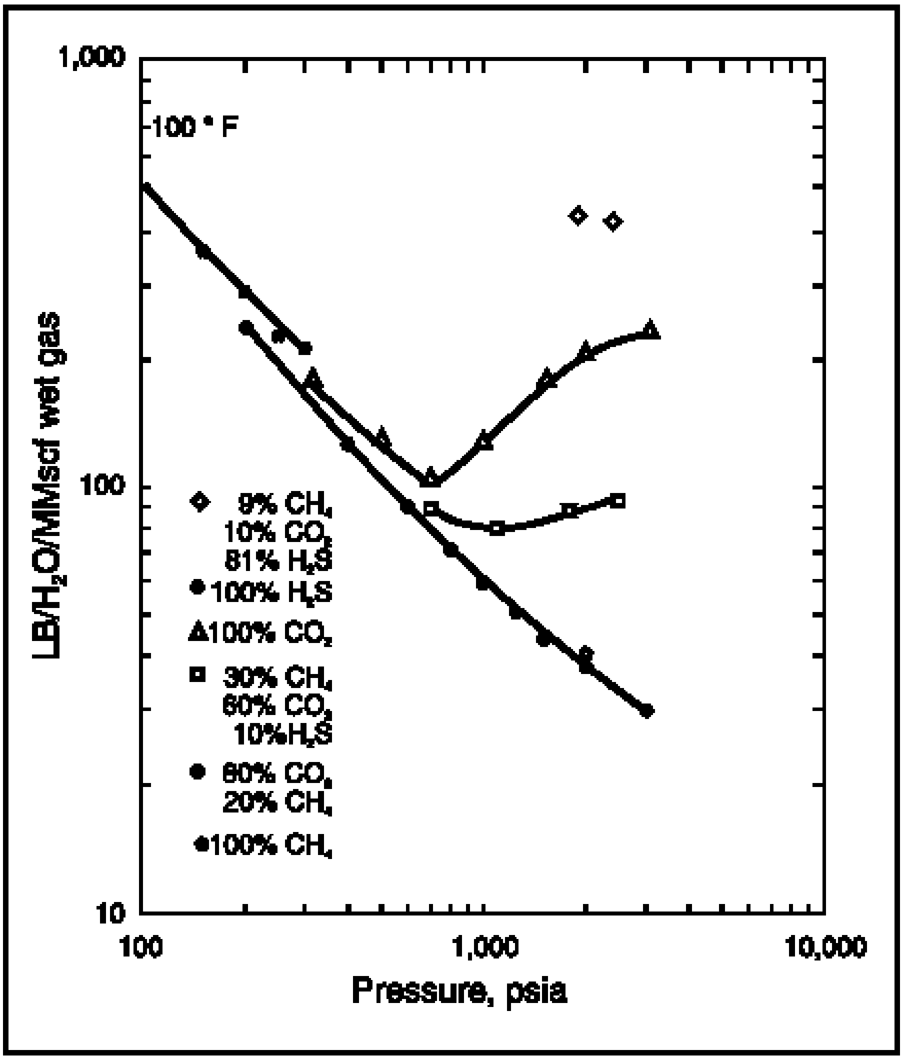
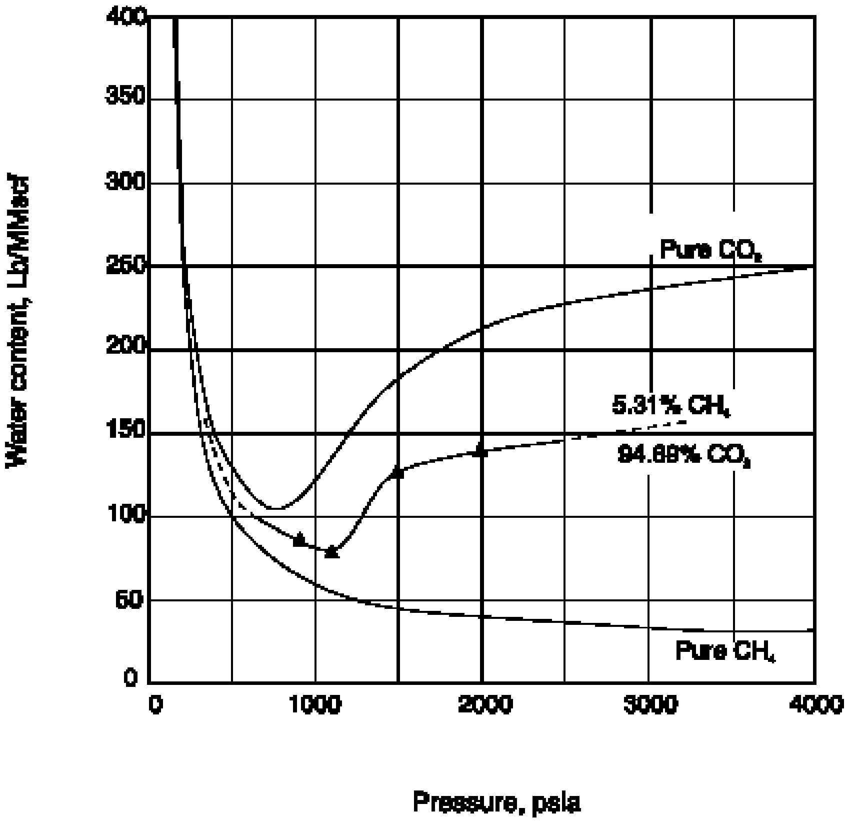


FIG-7

Saturated Water Content of CO_2 - Rich Mixtures at 100°F



Acid gas water content is a very complex subject. The data and methods presented here should not be used for final design. Fig. -4, -5, -6 and -7 are all based on experimental data. A cursory study of these figures reveals the complexities involved. An accurate determination of water content requires a careful study of the existing literature and available experimental data. In most cases additional experimental data is the best way to verify predicted values.

Below 40% acid gas components, one method of estimating the water content uses Eq -1 and Fig. -3, -8, and -9.

$$W = y_{HC} W_{HC} + y_{CO2} W_{CO2} + y_{H2S} W_{H2S} \qquad \textbf{Eq -1}$$

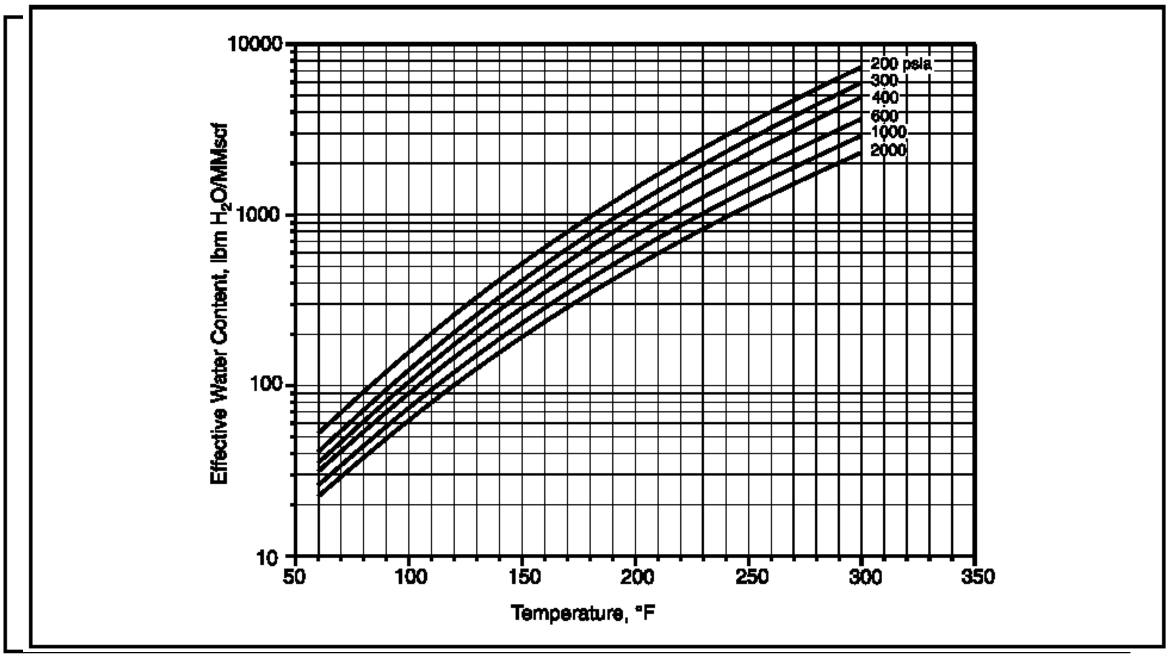
where:

W = Saturated water content of gas stream, lb H_2O/MMSCF
Wxx = Effective saturated water content of each component, lb H_2O /MMSCF
yxx = Mole fraction of component in gas stream

Note that Fig. -8 and -9 provide values for what is termed the "effective" water content of CO_2 and H_2S in natural gas mixtures for use only in Eq -1. These are not pure CO_2 and H_2S water contents.

FIG-9

Effective Water Content of CO_2 in Natural Gas Mixtures vs. Temperature at Various Pressures



Another method for estimation of the saturated water content of acid gas mixtures up to 6000 psia uses Fig. -10 and -11. With gases containing CO_2, the CO_2 must be converted to an "equivalent" H_2S concentration. For purposes of this method, it is assumed the CO_2 will contribute 75% as much water to the gas mixture, on a molar basis, as H_2S.

FIG-10

Calculated Water Content of Acid Gas Mixtures to 2000 psia

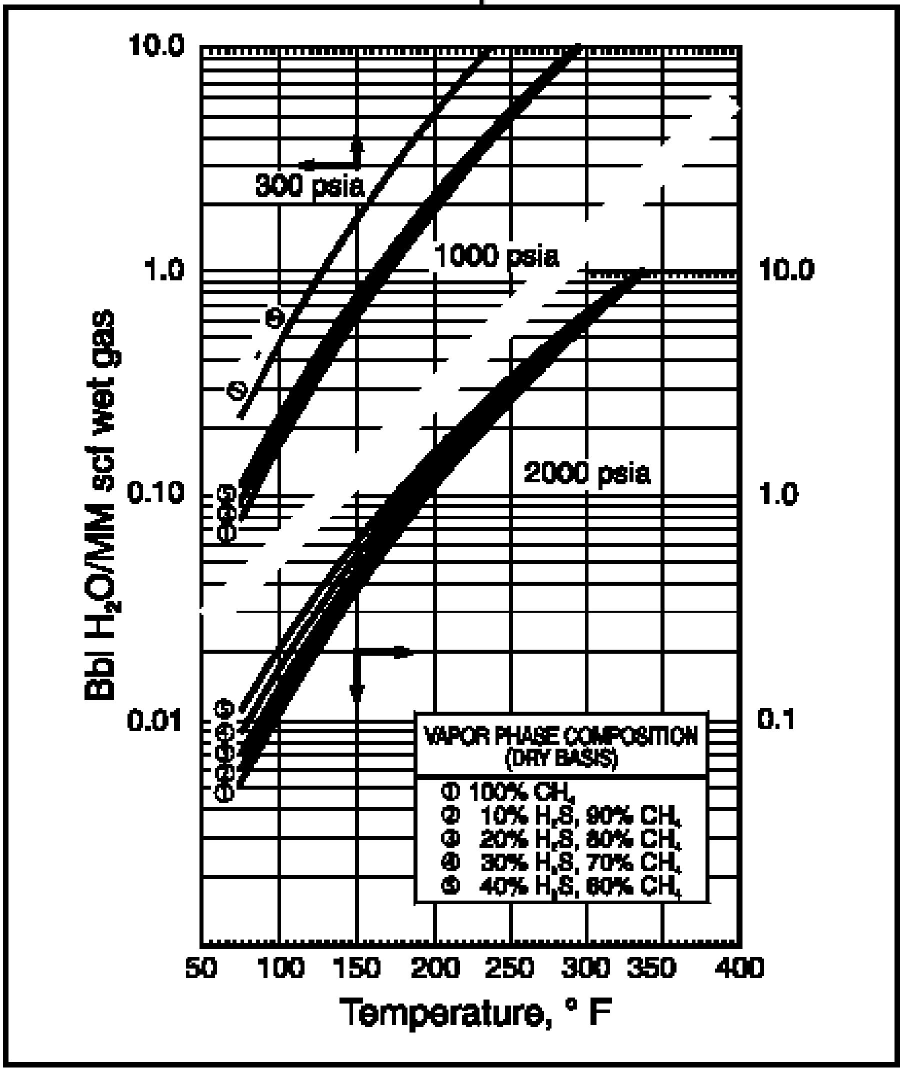
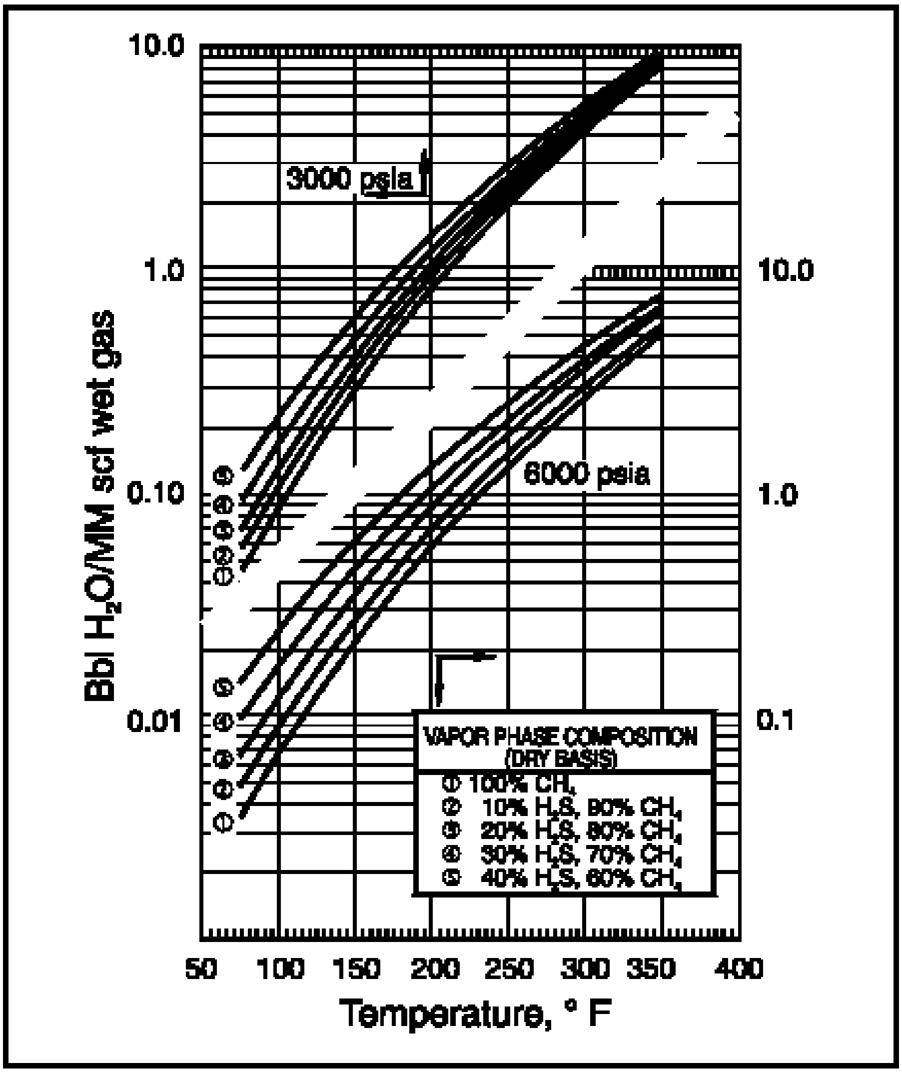


FIG-11

Calculated Water Content of Acid Gas Mixtures
to 6000 psia



Example 20-2 — Determine the saturated water content of an 80% C_1, 20% CO_2 mixture at 160 °F and 2000 psia. The experimentally determined water content was 172 lb/MMscf.

Method One

W_{HC} = 167 lb/MMscf (Fig. -3)
W_{CO_2} = 240 lb/MMscf (Fig. -9)
W = (0.80)(167) + (0.20)(240)
= 182 lb/MMscf

Method Two

First the composition must be converted for use with Fig. -10.

y_{H_2S} (pseudo) = (0.75)(y_{CO_2}) = (0.75)(0.20) = 0.15
W = 0.49 bbl/MMscf (Fig. -10)
Density of water = 350 lb/bbl
= (0.49)(350) = 172 lb/MMscf

Fig. -12 compares the two methods presented for saturated water content determination of high CO_2/H_2S gas mixtures with some of the available experimental data. The last four data points shown in Fig. -12 indicate the dangers involved with extrapolation to higher CO_2 or H_2S contents. In one case, the estimated water content agrees within 11% of the experimental value. In another case, the experimental value is over 6 times the estimated water content.

Fig -12 Comparison of Experimental vs. Calculated Water Contents for Acid Gases

Mixture	T, °F	P, psig	Water Content lb/MMscf		
			Experimental	Eq -1	Fig.-10 &-11
11% CO2/89% C1	100	2000	40.6	42	39.2
11% CO2/89% C1	160	1000	286	277	287
20% CO2/80% C1	100	2000	40.6	43	44.1
20% CO2/80% C1	160	1000	282	278	287
8% H2S/92% C1	130	1500	111	105	112
27.5% H2S/72.5% C1	160	1367	247	258	273
17% H2S/83% C1	160	1000	292	278	290
C1/CO2/H2S 30%/60%/10%	100	1100	81	72	NA
C1/CO2/H2S 9%/10%/81%	100	1900	442	72	NA
5.31% C1/94.69% CO2	77	1500	109.2	38	NA
5.31% C1/94.69% CO2	122	2000	164.6	105	NA

Hydrate Formation

A hydrate is a physical combination of water and other small molecules to produce a solid that has an "ice-like" appearance, but possesses a different structure than ice.

The conditions that promote hydrate formation are:

Primary Considerations

- Gas must be at or below its water dew point with "free" water present.
- Low temperature.
- High pressure.

Secondary Considerations

- High velocities.
- Pressure pulsations.
- Introduction of a small crystal of the hydrate.
- Physical site for crystal formation such as a pipe elbow, an orifice, thermowell, or line scale.

All of these primary and secondary considerations should be minimized when forced to operate near a possible hydrate region.

Determining the Hydrate-Formation Temperatures of Sweet and Sour Gas Streams

Chemical Makeup of Hydrates

Hydrates form when free water combines with the following gases:

- Butane (C4)
- Carbon dioxide (CO2)
- Ethane (C2)
- Hydrogen sulfide (H2S)
- Methane (C1)
- Nitrogen (N2)
- Propane (C3)

Liquid water has a mobile lattice structure. This lattice structure has two vacant lattice positions. When gas molecules fill these vacancies, the lattice is immobilized, and the gas and water form a solid structure.

Composition

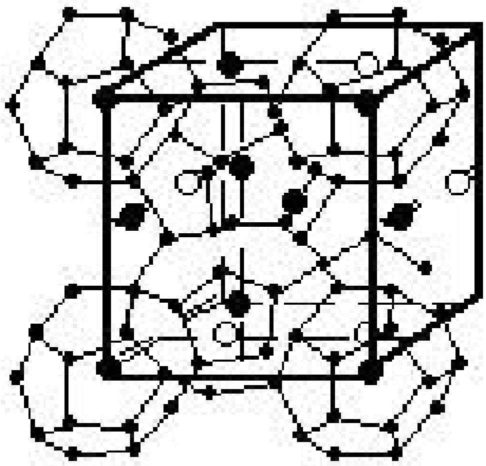
Hydrocarbons with five or more carbon atoms (C5+) do not fit into these lattice vacancies, so they do not form hydrates. Pure n-butane does not form hydrates by itself, but n-butane does exist in hydrates when other smaller hydrate-forming molecules are present. Hydrates are 90 wt% water with specific gravities that range from 0.96 to 0.98. Therefore, hydrates float on water, but sink in hydrocarbon liquids.

Structure

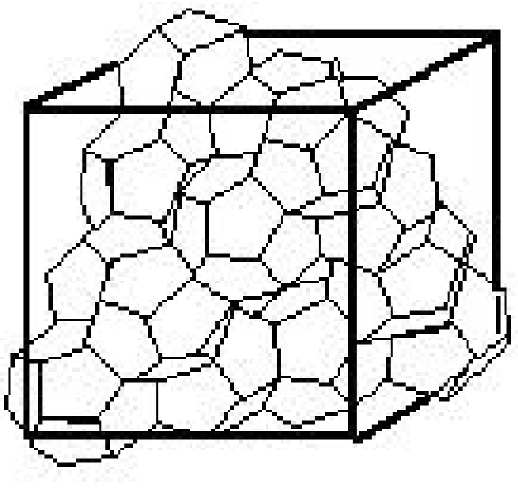
Hydrates form one of two different crystalline structures: Structure I or Structure II. Figure-13 summarizes the characteristics of hydrate crystalline structures. Figure-14 shows Structure I and Structure II lattices.

STRUCTURE I	STRUCTURE II
2 small and 8 large voids	16 small and 6 large voids
Generally formed by CH_4, C_2H_6, H_2S, CO_2	Generally formed by C_3H_8, i-C_4H_{10}, CH_2Cl_2, $CHCl_3$
5 3/4 water molecules per gas molecule MAX	17 water molecules per gas molecule MAX

FIGURE 13: CHARACTERISTICS OF HYDRATE CRYSTAL STRUCTURES



Structure I



Structure II

Factors Promoting Hydrate Formation

Primary

The following are the primary conditions that promote hydrate formation:

- Free water (Gas is at or below its dew point.)
- High pressure
- Low temperature

Secondary

Secondary conditions that promote hydrate formation include the following:

- High velocities.
- Physical sites where crystals might form such as pipe elbows, orifices, or line scale.
- Pressure pulsations.
- Small crystals of hydrates that may act as seed crystals.
- Turbulence in gas streams (promotes crystal growth by agitating supercooled solutions).

Other Considerations

Gas composition greatly affects hydrate-formation temperatures. High H2S concentrations promote hydrate formation. The presence of ethane and propane also promotes the formation of hydrates. Gases with higher specific gravities form hydrates at lower pressures.

Hydrates take several hours to form. In one test, hydrate crystals took more than 10 hours to form in gases super-cooled to 14°F.

Effects of Composition on Hydrate Formation Conditions

C1 Through C3

The smaller natural gas molecules, methane (C1) and ethane (C2), form stable structure I hydrates. However, even small concentrations of propane (C3) or ethane strongly promote the formation of hydrates in gas streams. In a test performed by Deaton and Frost, a 1% solution of propane in methane at 50°F lowered the hydrate formation pressure of methane nearly 400 psi. Deaton and Frost found ethane produced similar results as propane.

H2S and CO2

H2S and CO2 form stable Structure-I hydrates. H2S in a gas stream strongly promotes the formation of hydrates. Above 85°F H2S does not form hydrates. This critical temperature above which hydrates do not form is higher for H2S than for other components typically found in natural gas streams. Therefore, in gas streams of equal densities, the gas stream with H2S forms hydrates more readily.

Using Graphical Techniques to Predict Hydrate-Formation Conditions
Generally, hydrate formation temperatures should be evaluated anytime a gas stream containing water and hydrate-forming components is cooled below 80°F. It is not necessary to evaluate hydrate formation temperatures below 32°F since pure water freezes anyway.

Figure 15 plots hydrate-formation temperatures of pure light gases. Hydrate formation will occur in the region above and to the left of the curve for a given compound. The discontinuities in the lines correspond to changes in phase of the nonhydrate phases.

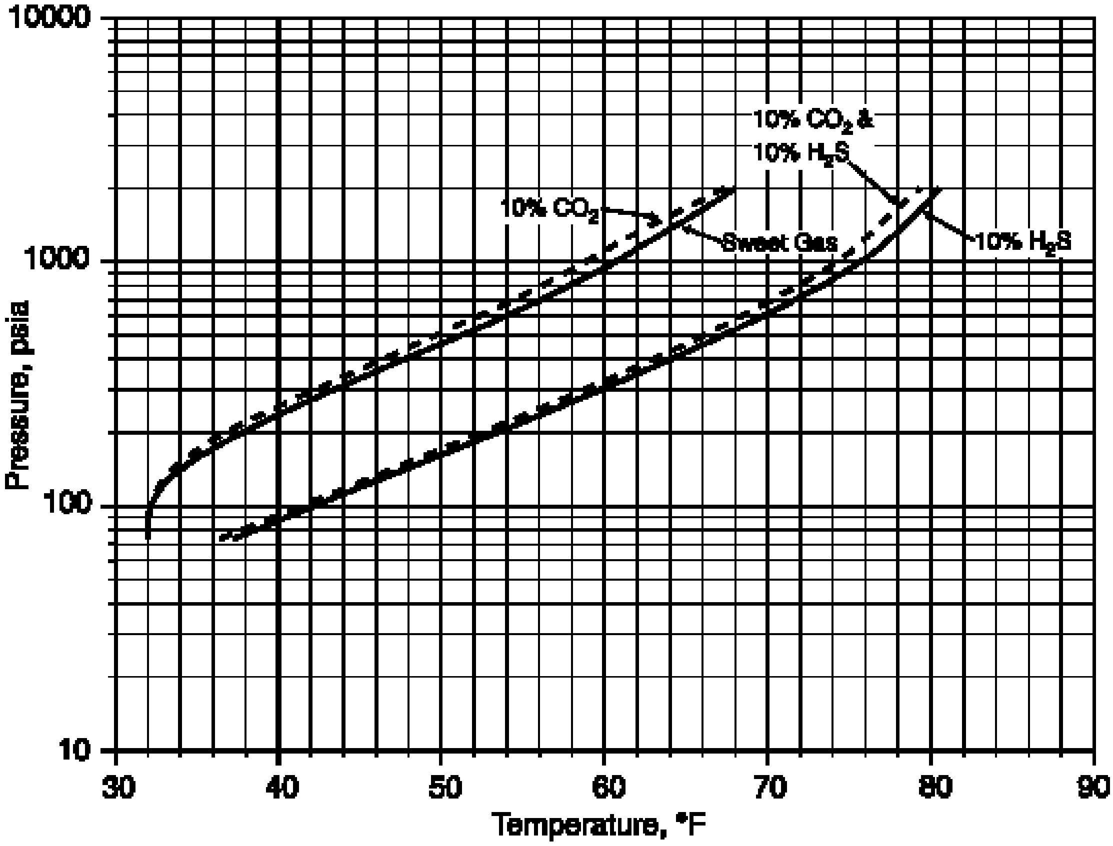


FIGURE 15: HYDRATE FORMATION CONDITIONS OF PURE LIGHT GASES

Empirical hydrate formation graphs may be used to determine the hydrate formation conditions of a gas stream. The gravity graphic method and the K-value method are the two graphical methods used to predict hydrate formation conditions.

Computer programs are more commonly used, but the gravity graphic method is still useful for roughly approximating hydrate formation conditions.

Gravity Graphic Method

Figure 16 plots the hydrate-formation conditions of gases based on their specific gravity relative to air (MW = 29).

Because hydrocarbon mixtures belong to the same chemical family, the method's use of specific gravity makes some adjustment for the composition of the gas stream.

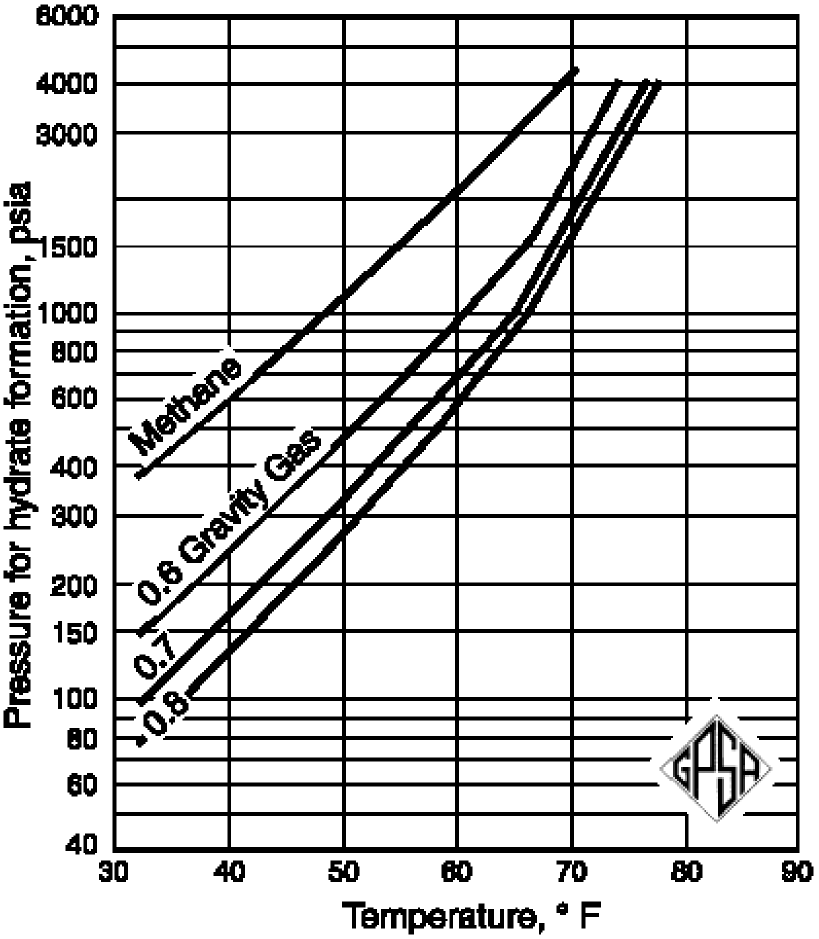


FIGURE 16: Pressure-Temperature Curves for Predicting Hydrate Formation

The gravity graphic method roughly approximates hydrate formation conditions. This method should not be used on gas streams with substantial concentrations of non-hydrocarbons (N2, CO2, and especially H2S).

Procedures and Resources for Determining the Hydrate-Formation Temperatures of Sweet and Sour Gas Streams (Gravity Graphic Method)

1. Calculate the weight of component per mole of gas mixture by multiplying the mole fraction of each component by the molecular weight of each component. Record the partial molecular weight of each component in the right column of the table provided with the exercise.
2. Calculate the total molecular weight of the gas mixture. To make this calculation, total the partial molecular weights in the right column of the table provided with the exercise.
   Record the total weight at the bottom of the right column of the table provided with the exercise.
3. Use Eqn. 6 to calculate the specific gravity (relative to air) of the gas mixture.

$$\text{sp. gr.(gas)} = \left[\frac{\text{MWgas}}{\text{MWair}}\right] \qquad \text{(Eqn. 2)}$$

where: sp. gr.(gas) = Specific gravity of the gas stream
MWgas = Molecular weight of gas stream, lb/mole
MWair = Molecular weight of air
= 29 lb/mole

4. Use Figure 16 to determine the hydrate-formation temperature of the gas stream.

The following sample problem demonstrates the gravity graphic method

Sample Problem: Determine the Hydrate-Formation Temperatures of Sweet and Sour Gas Streams (Gravity Graphic Method)

Calculate the approximate temperature at which the gas stream entering a chill down train at a Gas Plant forms hydrates. Use the gravity graphic method. The left column of Figure 17 lists the composition of the gas stream and the right column is provided to help organize the calculations.

Given:

Pressure = 424 psig
Temperature from dehydrator = 80°F

COMPONENT	MOLE FRACTION	MOLECULAR WEIGHT	lb/Mole OF MIXTURE
N2	0.0066	28.0	0.185
CO2	0.0003	44.0	0.0132
H2S	0.0	34.3	0.00
C1	0.6317	16.0	10.1
C2	0.2111	30.1	6.35
C3	0.1088	44.1	4.80
i-C4	0.0078	58.1	0.453
n-C4	0.0242	58.1	1.41
i-C5	0.0031	72.2	0.224
n-C5	0.0048	72.2	0.346
n-C6	0.0014	86.2	0.121
C7+	0.0002	100.2	0.020
TOTAL GAS STREAM	1.00	--	24.0

FIGURE 17: TABLE FOR CALCULATING THE MOLECULAR WEIGHT OF THE GAS STREAM

Solution:

1. The right column of Figure 17 shows the calculation of the weight of each gas component per mole of gas stream.
2. The weight of each gas component per mole of gas stream is totaled at the bottom of the right column of the table provided in Figure 17.
3. The use of Eqn. 2 to calculate the specific gravity (relative to air) of the gas mixture results in the following:

$$\text{sp. gr.} = \left[\frac{\text{MWgas}}{\text{MWair}}\right] = \left[\frac{24.0 \text{ lb / mole}}{29.0 \text{ lb / mole}}\right] = 0.828 \qquad \text{(Eqn.2)}$$

4. From Figure 16, the hydrate-formation temperature of the gas stream at 424 psig (439 psia) is determined to be 57°F.

Answer:

Hydrates can form in this gas stream at approximately 57°F.

Allowable Gas Expansions

Graphical methods also predict permissible gas expansions. These graphs use the gravity graphic method to determine the allowable expansion (decrease in pressure) at various initial temperatures. As with the gravity graphic method, these graphs are useful for initial estimates, but should not be used for design.

Temperature Control Methods and Equipment Used To Inhibit Hydrate Formation in a Natural Gas Stream

Heating a natural gas or depressurizing it (thus cooling it) while it is under hot conditions can inhibit hydrate formation. In above ground operations, the temperature drop caused by depressurizing (expanding) a gas can result in the temperature of the gas stream dropping below its hydrate-formation temperature. Because of the high temperatures underground, a gas stream can be expanded underground without the resulting temperature dropping below its hydrate-formation temperature. Therefore, expanding a gas stream in a well bore helps prevent hydrate-formation in downstream processing.

The two main pieces of equipment used to control gas stream temperature and inhibit hydrate formation are downhole regulators and indirect heaters. Downhole regulators inhibit hydrate formation by expanding gas streams while they are in the wellbore. Indirect heaters inhibit hydrate formation both at wellheads (wellhead heaters) and along flowlines (flowline heaters).

Indirect heaters are often used to inhibit hydrate formation caused by expansion or to replace heat lost by a flowline to the surrounding air and ground.

Downhole Regulators

The use of downhole regulators to inhibit hydrate formation by controlling gas stream temperatures is generally feasible when the gas well has the following conditions:

- A high reservoir pressure that is not expected to decline rapidly
- Excess pressure
- High capacity

The temperature and pressure of a gas stream as well as its composition determine whether hydrates will form when gas is expanded into the flowlines. Cooling occurs as gas is expanded across the choke. Downhole regulators lower the pressure of the gas stream from well pressure to near-salesline pressure in the wellbore. Operating conditions resulting from the expansion of the gas are outside the hydrate-formation range of the gas stream because of the high temperatures in the well.

Downhole Regulator Design

Downhole regulators contain a spring-loaded valve and stem that outside vendors set from the surface by using a wireline (wire used to lower tools into the wellbore) run through the wellbore tubing. The pressure drop across the regulator remains constant and does not depend, within a broad range, on the flow rate of the well.

The design of downhole regulators requires using complex calculations that must account for the following:

- Downhole pressures and temperatures
- Well depth
- Wellbore configuration

Indirect Heaters

Two types of indirect heaters are used to inhibit hydrate formation: wellhead and flowline.

The expansion of gas streams at or near wellheads often results in the formation of hydrates.

Wellhead heaters keep the temperatures of these gas streams above their hydrate-formation temperatures.

Flowlines some parts of the world often lose enough heat to the surrounding air and ground to lower the temperature of the gas stream below its hydrate-formation temperature. Flowline heaters inhibit hydrate formation by replacing this lost heat and keeping the temperature of the gas stream above its hydrate-formation temperature. Flowline heaters also inhibit hydrate formation by heating gas streams expanded or choked downstream from the wellhead.

Indirect Heater Design

Different heater designs accomplish the same purpose: to heat the gas. Flowline heaters do not require the chokes and high-pressure safety valves that wellhead heaters need.

Indirect heaters are vessels that contain a fire tube and a coil immersed in a heat transfer fluid (usually water or a glycol and water mixture) within a heater shell. The fire tube is usually fired by gas. The coil contains the fluid (the gas stream) to be heated and operates at full gas pressure. The heater shell operates at atmospheric pressure. Figure 18 shows a typical indirect heater.

Flowline Heaters - Flowline heaters heat gas streams above their hydrate-forming temperatures. In many cases, properly designed and placed wellhead heaters provide sufficient heat to eliminate the need for flowline heaters.

Indirect Heater Sizing

The determination of the size of a heater depends on the following conditions:

- Amounts of gas, water, oil, or condensate expected in the heater
- Inlet temperature and pressure
- Outlet temperature and pressure (to avoid hydrate-forming conditions)

The size of heater coils to use depends on the volume of fluid flowing through the coil and the required heat-transfer load.

When heater coils are sized, it is important to consider operating conditions in addition to normal, steady-state operating conditions. Transient startup of a shut-in well may require extra heating capacity. The temperature and pressure conditions of a shut-in well and the extra liquids accumulated while the well was shut in may increase the heating load. Often, heaters are necessary only while wells are being started up. Installing preheat coils ahead of chokes is generally practical for wells operated only intermittently.

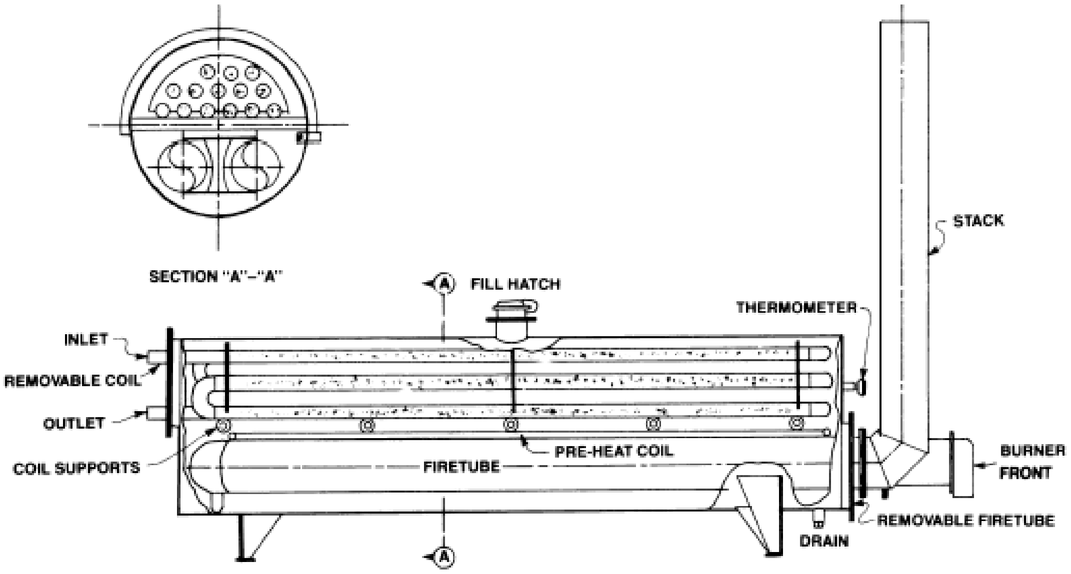


FIGURE 18: TYPICAL INDIRECT HEATER

Advantages and Disadvantages of Temperature Control Methods

Downhole Regulators

Downhole regulators have the following advantages:

- Low initial investment
- Do not require routine service

Downhole regulators have the following limitations or disadvantages:

- They may not inhibit hydrate formation during startup. It may be necessary to inhibit hydrate formation by injecting either methanol or glycol until the gas flow and temperature stabilize.

- When well output falls below normal production levels, processors must remove and replace downhole regulators with another hydrate inhibition method.
- When work is performed inside a wellbore, the well may be permanently damaged.

Indirect Heaters

The advantages of using indirect heaters to inhibit the formation of hydrates include the following:

- Minimal maintenance or attention required
- Very low chemical requirements

The disadvantages of using indirect heaters to inhibit hydrates include the following:

- Difficulty of supplying clean and reliable fuel to remote locations
- Large operating (fuel) costs if cheap fuel is not available
- Potentially large capital costs
- Significant plot space required
- Special safety equipment needed because of fire hazard

Comparison of Temperature Control Methods

Figure 19 compares the use of downhole regulators and wellhead heaters to inhibit hydrate formation. The high capital costs of heaters generally limit their use to large hydrate inhibition installations. Downhole regulators work best in large reservoirs with high gas pressures that are not expected to decline rapidly.

DESIGN FACTORS	DOWNHOLE REGULATORS	WELLHEAD HEATERS
Investment	Very low	Very high
Fuel	None	Very high
Operating Maintenance	Low	Low
Chemicals	None	Very low
Plot Area	None	Very high
Hazards	High	High

FIGURE 19: COMPARISON OF TEMPERATURE CONTROL METHODS

Methanol Injection Rate Required To Inhibit Hydrate Formation in a Natural Gas Stream

Chemical Injection

Currently, methanol (MeOH) and monoethylene glycol (MEG) are the two chemicals most commonly injected into gas streams to inhibit hydrate formation. Consider the use of chemical injection to inhibit hydrate formation for the following:

- Gas pipelines in which hydrates form at localized points
- Gas streams operating a few degrees above their hydrate formation temperature
- Gas-gathering systems in pressure-declining fields
- Situations where hydrate problems are of short duration

Hydrate inhibitors act similarly to antifreeze. Adding a known quantity of an inhibitor to a known quantity of pure liquid reduces the hydrate-formation temperature by a calculable amount.

Methanol

Methanol works well as a hydrate inhibitor because of the following reasons:

- It can attack or dissolve hydrates already formed.
- It does not react chemically with any natural gas constituents.
- It is not corrosive.
- It is reasonable in cost.
- It is soluble in water at all concentrations.

Methanol significantly depresses hydrate-formation temperatures.

Methanol Applications

Because methanol's material cost is so low and its vapor losses so high, methanol is often not recovered. Not requiring a recovery system significantly reduces capital costs. Therefore, methanol injection is generally economical for temporary installations, situations with low gas volumes, or situations with mild, infrequent, or seasonal hydrate problems.

Methanol Injection System

Figure 20 shows a simplified schematic of a typical methanol injection system. This system inhibits hydrate formation at a choke or pressure-reducing valve. A gas-driven pump injects the methanol into the gas stream upstream of the choke or pressure-reducing valve. The temperature controller measures the temperature in the gas stream and adjusts the power-gas control valve. The power-gas control valve controls the flow of power gas, which controls the methanol injection rate.

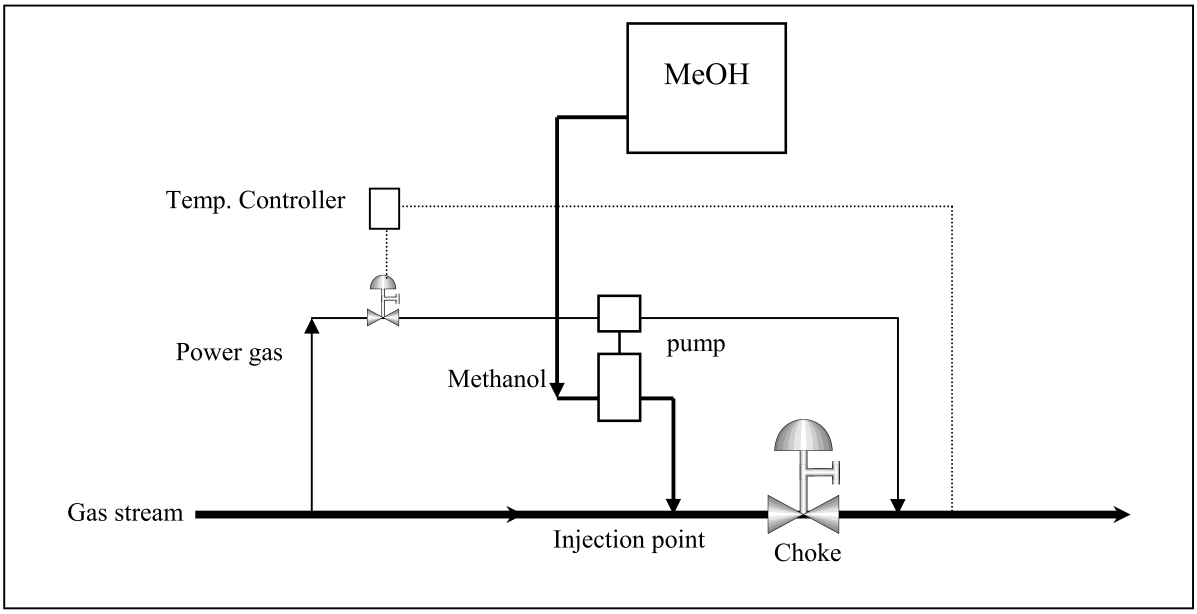


FIGURE 20: METHANOL INJECTION SYSTEM

Method of Injecting Methanol - The injection of methanol considerably upstream of a hydrate-forming location allows the methanol to distribute and vaporize completely. Because of methanol's high volatility, nozzle placement and design are not as critical as they are for glycol injection. Methanol injection nozzles should be located as follows:

- Upstream of front-end exchangers
- At the inlets of turboexpanders
- At any refrigerated condensers in downstream fractionation

Glycol Injection Rate Required To Inhibit Hydrate Formation in a Natural Gas Stream

Like methanol, glycol inhibits hydrate formation when injected into gas streams. Figure 21 compares the advantages and disadvantages of glycol and methanol injection.

INHIBITOR	ADVANTAGES	DISADVANTAGES/ LIMITATIONS
Glycol	Usually lower operating cost than methanol when both systems recover injected chemical Low vapor losses (low volatility)	High initial cost Possibility of glycol contamination Limited use (only non-cryogenic applications) Cannot dissolve hydrates already formed
Methanol	Relatively low initial cost Simple system Does not generally need to be recovered Low viscosity When injected, distributes well into gas streams Can dissolve hydrates already formed	High operating cost Generally, use glycol injection if methanol injection rate is over 30 gph Large vapor losses (high volatility)

FIGURE 21: COMPARISON OF CHEMICAL INJECTION INHIBITORS

Glycol does not evaporate as easily as methanol. In some applications, glycol does not dissolve into liquid hydrocarbons as easily as methanol. Glycol solubility in hydrocarbon liquid increases with:

- Glycol molecular weight
- Temperature increase
- Increase in glycol concentration in water-glycol mixture

Glycol Concentration and Dilution:

In addition to inhibiting hydrate formation, you also need to choose glycol concentrations that do not freeze. Figure 22 shows the freezing points of various aqueous glycol solutions.

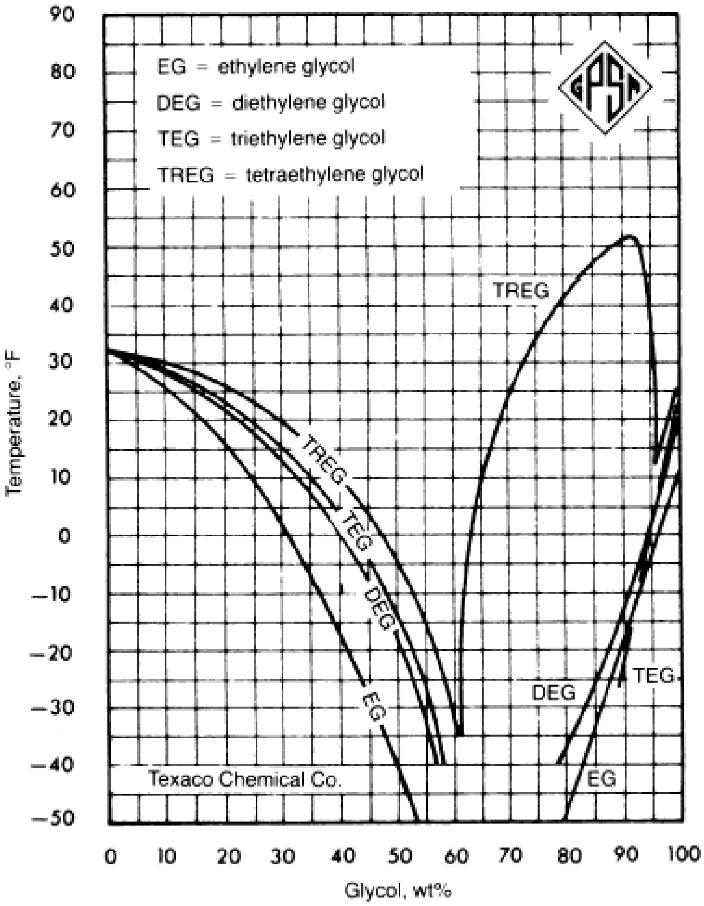


FIGURE 22: FREEZING POINTS OF AQUEOUS GLYCOL SOLUTIONS

Note that solutions with glycol concentrations between about 60 wt % and 80 wt % do not freeze. Because of this, glycol solutions are generally kept between these concentrations, even if lower concentrations are required to depress the hydrate-formation temperature.

When glycol injection is performed below 20°F, the glycol freezing point must be considered. Glycols crystallize, but do not freeze solid, which inhibits flow and proper separation. For this reason, it is common practice to keep glycol concentrations between 60-80 wt %.

To avoid the formation of emulsions, the water content of the injected inhibitor (lean glycol) solution should be greater than 20 wt %. Therefore, the injection rate of pure glycol required by the system to inhibit hydrate formation is first calculated and then the injection rate of the lean glycol solution is calculated.

To keep the concentration of the glycol between 60 wt % and 80 wt %, the extent to which the free water dilutes the injected glycol must be determined. Figure 23 lists and summarizes dilution restrictions

SITUATION	ALLOWABLE OR RECOMMENDED DILUTION OF GLYCOL
Unknowns about the system exist	Not over 5% to 10%
Spot injection (in a heat exchanger, for example)	If distribution of glycol is a problem, limit to about 5%
Pipelines operating above 20°F	Up to about 20%

FIGURE 23: ALLOWABLE GLYCOL DILUTIONS

Selecting Glycol Type

The glycols normally used for hydrate inhibition are the following:

- MEG
- DEG
- TEG

Selection of the appropriate type of glycol depends on the composition of the gas stream and on information provided by the glycol vendor.

For instance, Dow Chemical recommends that its glycols be used at concentrations of 70 wt % to 75 wt % to avoid freezing problems. Dow Chemical also makes the recommendations for selecting glycols listed in Figure 24.

SITUATION/CONDITION	RECOMMENDATION
Natural gas transmission in which recovery is not important	Use MEG because it depresses hydrate formation temperatures the most.
Injected glycol contacts hydrocarbon liquids	Use MEG because it has the lowest solubility of the glycols in high molecular weight hydrocarbons.
Severe vapor losses	Use DEG or TEG because both glycols have lower vapor pressures than the other glycols.
Severe vapor losses and injected glycol contacts hydrocarbon liquids	When both of these conditions are present, DEG may be the best choice

FIGURE 24: GLYCOL RECOMMENDATIONS

Glycol Injection and Recovery System Using a Three-Phase Separator

Figure 25 shows a typical glycol injection and recovery system that uses a three-phase separator. The power-gas-driven pump, the temperature controller, and the injection point shown in Figure 15 are similar to the methanol injection system shown in Figure 5. A gas driven pump injects the glycol into the gas stream upstream from the choke or pressure reducing valve. The temperature controller measures the temperature in the gas stream and adjusts the power-gas control valve. The power-gas control valve controls the flow of power gas, which controls the injection rate.

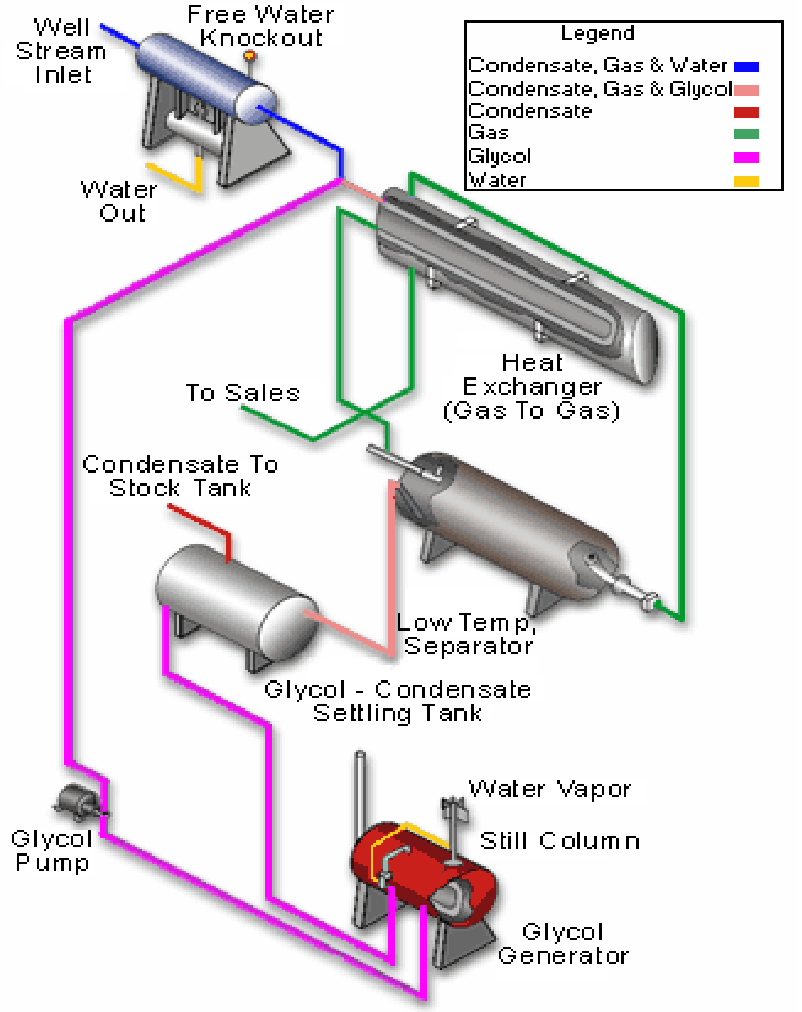


FIGURE 25: GLYCOL INJECTION AND RECOVERY SYSTEM

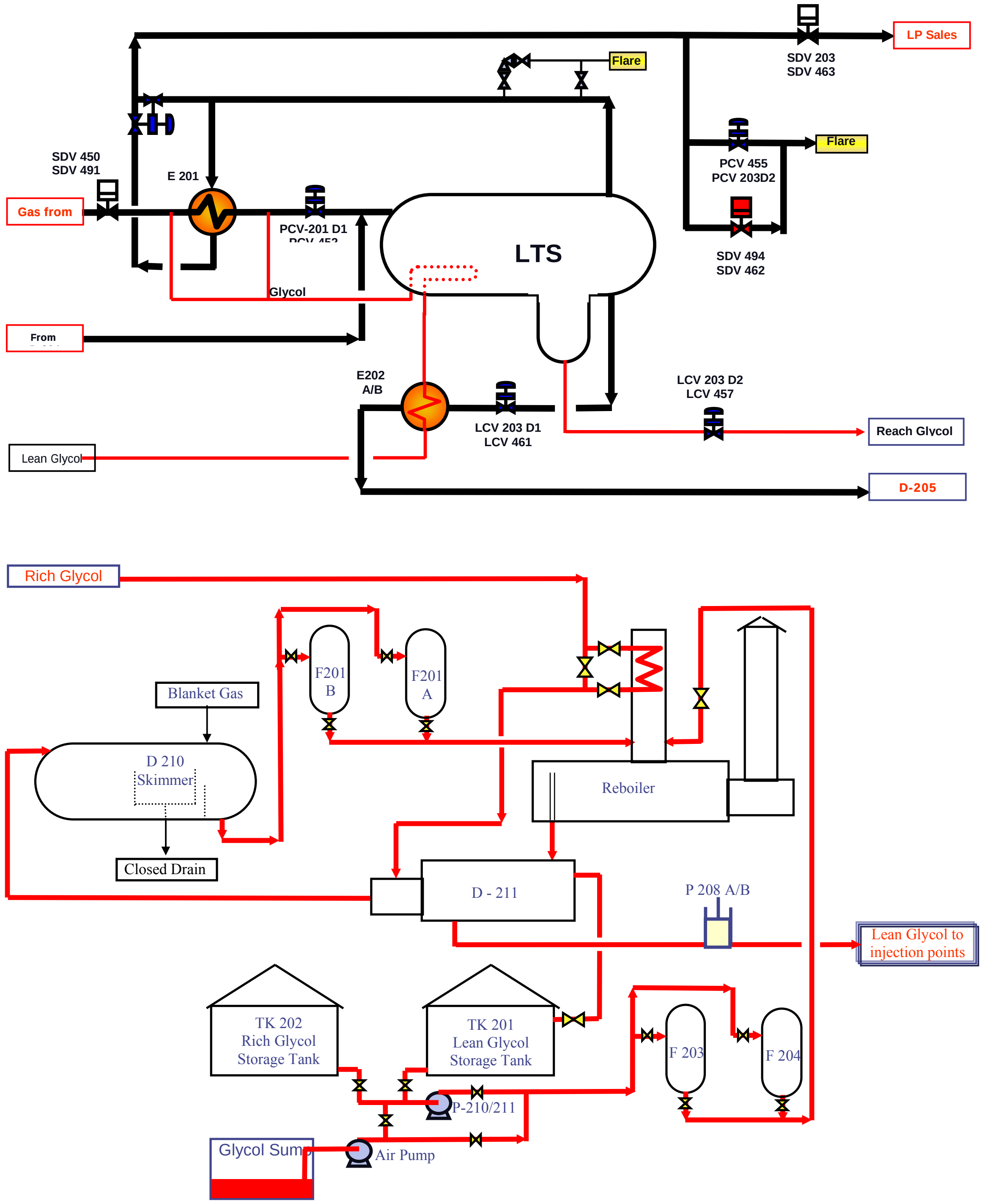


FIGURE 26: GLYCOL INJECTION AND RECOVERY SYSTEM

The recovery side of the system shown in Figure 25 includes a reboiler and a three-phase separator. The glycol injection and recovery cycle is as follows:

- The injection nozzle injects the lean glycol into the gas stream.
- The lean glycol absorbs the water and inhibits hydrate formation in the choke or pressure-reducing valve.
- The three-phase separator separates the water and rich glycol from the hydrocarbon gas and liquid.
- The separated components are piped to their respective destinations.
- The reboiler boils off excess water from the rich glycol, and thereby prepares it to be injected again.

Glycol Injection and Recovery System Components

Separators

The low-temperature separator shown in Figure 25 separates the hydrocarbon gas from the hydrocarbon condensate-rich glycol mixture. The glycol-oil separator in Figure 25 flashes the remaining hydrocarbon condensate-rich glycol mixture to a low pressure and then separates out the rich glycol.

Separating the rich glycol from the hydrocarbon liquid is more difficult than separating hydrocarbon liquid from vapor. Performing both separations in one vessel sacrifices some effectiveness and efficiency. Generally, three-phase separators require longer residence times (20 to 40 minutes) and suffer higher glycol losses.

Reboiler

The temperature in the reboiler depends on the type and concentration of the glycol used. Reboilers in hydrate inhibition systems do not regenerate glycols to the same high levels of purity used in dehydration systems.

Glycol skimmer

A two -phase separator with a 5 to 10 minute liquid retention time prevents excess hydrocarbon vapor from entering the stripping column. If hydrocarbons enter the stripping column, they can flash, increase glycol losses, and possibly break the ceramic packing.

If the specific gravity of the gas stream is high, then a three-phase separator (containing vapor, aqueous, and liquid hydrocarbon phases) with a 20 to 30 minute residence time is preferred.

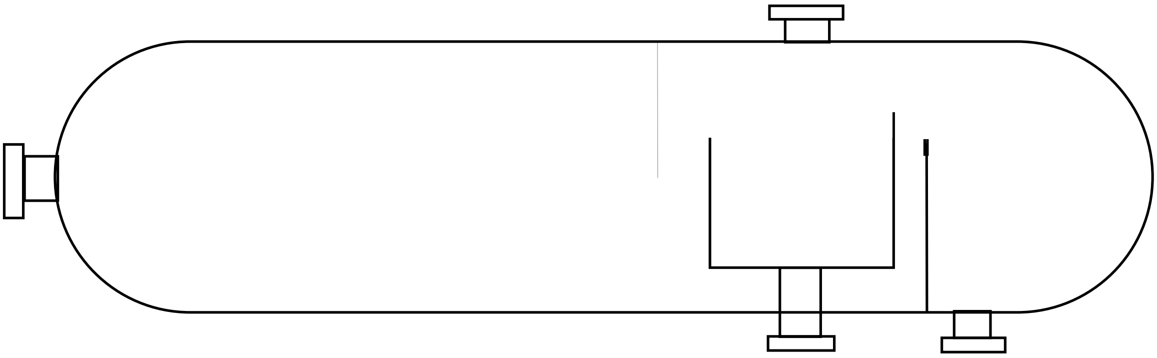


FIGURE 27: GLYCOL SKIMMER

Inhibitor Pump

A drum on top of a typical power-gas-driven pump contains the inhibitor: methanol or glycol. The drum connects directly to the pump (generally, a positive displacement pump). Methods for monitoring the inhibitor injection rate include inserting a calibrated dipstick through the top of the drum or pumping the inhibitor into a measured vessel. Drums are replaced when empty.

Glycol Losses

Glycol injection systems that involve both hydrocarbon liquids and gases generally lose glycol to the following:

- Solubility (normally about 0.3 to 3 gallons of glycol per 1000 barrels of hydrocarbon liquid produced)
- Leakage
- Carryover with hydrocarbon liquid and in the reboiler
- Vaporization in the reboiler and during injection

Nozzle Selection and Placement

Nozzle selection and placement indirectly affect glycol injection calculations. Although calculated to inhibit hydrate formation, injection rates may need to be adjusted to maintain a flow rate or pressure recommended for a particular nozzle design or placement.

Because of glycol’s low vapor pressure, nozzle design is more critical for glycol than it is for methanol. To mix adequately with the natural gas, glycol requires a fine, well-distributed mist. Also, to inhibit hydrates fully, the nozzle must be placed to ensure full coverage.

Installing backup nozzles in parallel with the primary nozzle allows nozzle removal, replacement, or inspection without interrupting inhibitor service.

Nozzle Selection - Nozzle design is especially important in the design of glycol injection systems for cold separation facilities. The criteria for selecting a nozzle include the following:

- Capacity
- Spray angle
- Sufficient pressure drop between the nozzle and the gas stream over the expected range of operating conditions

Normally, a pressure differential of 100 psi to 150 psi sufficiently atomizes glycol. Also, gas stream velocities above 12 ft/s help ensure atomization.

Nozzle Placement - Normally, nozzles are located just upstream of the heat exchanger or chiller where hydrates form. The spray from a properly located nozzle covers the entire tube sheet of a heat exchanger.

Inadequate atomization causes the formation of glycol droplets that settle and flood the bottom of the heat exchanger. As a result, the glycol inhibits hydrate formation in the bottom, but not the top, of the heat exchanger. Flooding of the bottom of the heat exchanger also significantly decreases its effectiveness.

Inadequate coverage can leave some tubes with a concentration of glycol that is too low, which will result in the formation of hydrates. As shown in Figure 18, hydrates plug the tubes, and thereby increase the differential pressure across the heat exchanger.

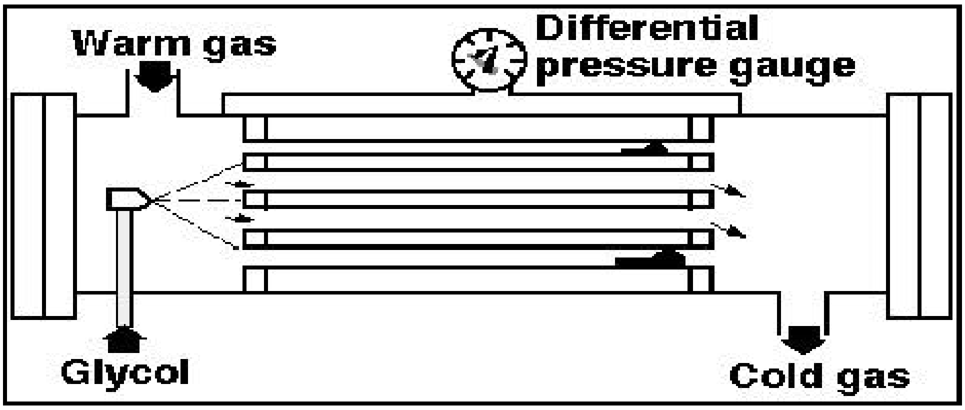
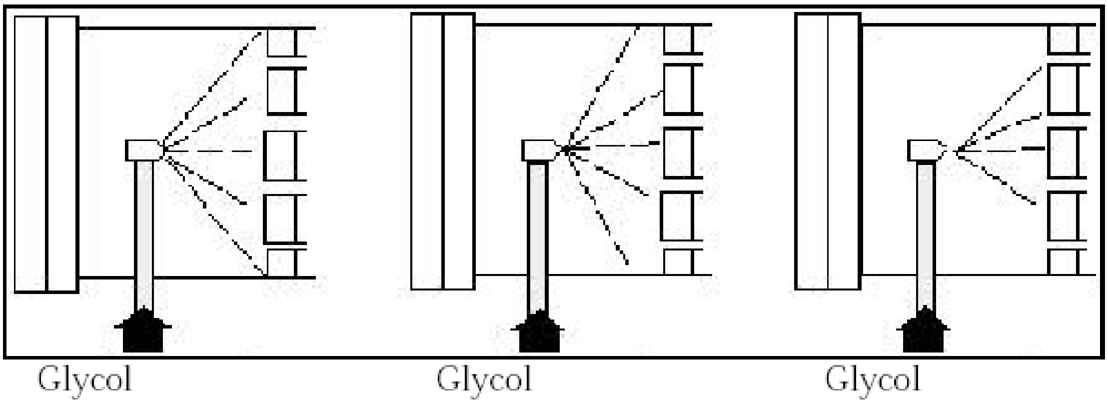


FIGURE 28: INCREASE IN PRESSURE DROP BECAUSE OF HYDRATE FORMATION

Figure 29 shows one nozzle location but three flow rates. Too low a nozzle flow rate produces the same result as a nozzle located too close to the tube sheet. Too high a nozzle flow rate produces the same result as a nozzle located too far from the tube sheet.



Spray pattern at
proper glycol
flow rate

Spray pattern at
high glycol
flow rate

Spray pattern at
low glycol
flow rate

FIGURE 29: NOZZLE PLACED AT ONE LOCATION: THREE FLOW RATES

WATER REMOVAL PROCESSES

Liquid/Solid Desiccants

In those situations where inhibition is not feasible or practical, dehydration must be used. Both liquid and solid desiccants may be used, but economics favor liquid desiccant dehydration when it will meet the required dehydration specification.

Liquid desiccant dehydration equipment is simple to operate and maintain. It can easily be automated for unattended operation; for example, glycol dehydration at a remote production well. Liquid desiccants can be used for sour gases, but additional precautions in the design are needed due to the solubility of the acid gases in the desiccant solution.

Solid desiccants are normally used for extremely low dew point specifications as required to recover liquid hydrocarbons.

Glycol Dehydration

Background

The more common liquids in use for dehydrating natural gas are diethylene glycol (DEG), triethylene glycol (TEG), and tetraethylene glycol (TREG). In general, glycols are used for applications where dew point depressions of the order of 60°F to 120°F are required.

DEG was the first glycol to be used commercially in natural gas dehydration and can provide reasonable dew point control. With the exception of TEG, DEG is the best liquid available.

However, with normal field equipment, DEG can be concentrated to only 95% purity, whereas TEG concentrations can reach 98 to 98.5% without special equipment. Although both glycols perform sufficient dehydration in many situations, TEG is used more commonly because it requires lower circulation rates for a comparable dew point depression than DEG does and can reach lower dew points. It is not advisable to use triethylene glycol for dehydration at low temperatures (approximately 50°F), due to its high viscosity. TREG is primarily used when dehydration conditions fall between those encountered in normal TEG operations, and those in which gas stripping or vacuum distillation becomes necessary.

A process flow diagram of a glycol dehydration unit is shown in Figure 30. Good practice dictates installing an inlet gas scrubber, even if the dehydrator is near a production separator.

The inlet gas scrubber will prevent accidental dumping of large quantities of water, hydrocarbons, and/or salt water into the glycol contractor. Even small quantities of these materials can result in excessive glycol losses due to foaming, reduced efficiency, and increased maintenance.

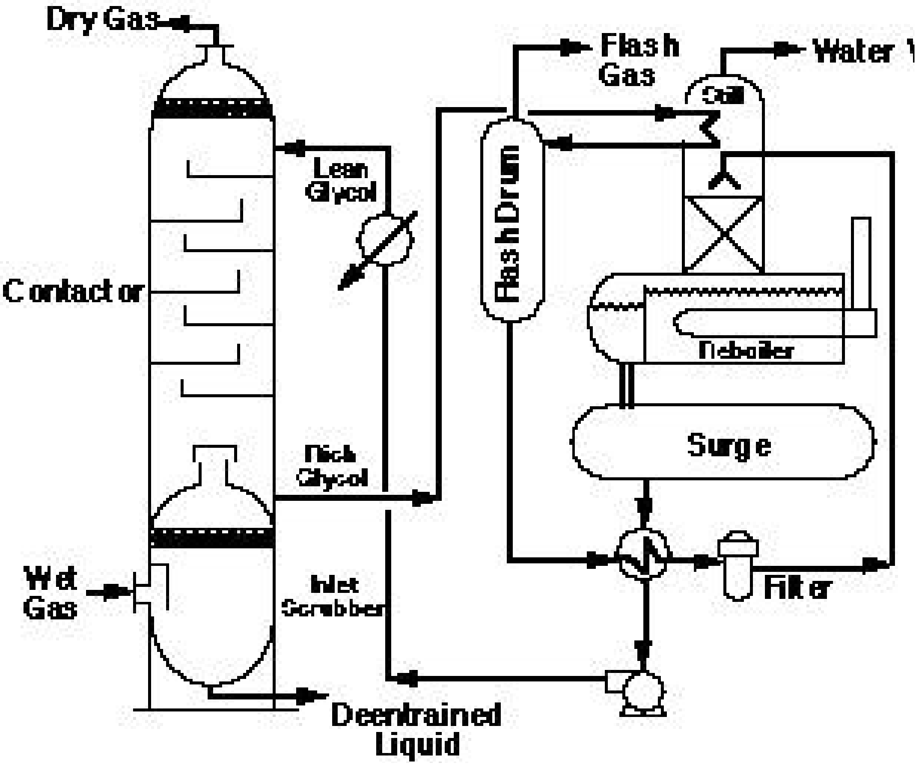


FIGURE 30: PROCESS FLOW DIAGRAM FOR GLYCOL DEHYDRATION UNIT

In the glycol dehydration process, regenerated glycol is pumped to the top tray of the contactor (absorber). The glycol flows down through the contactor countercurrent to the gas flow. Water rich glycol is removed from the bottom of the contactor, passes through the condenser coil, flashes off gas in a flash drum, and flows through the glycol-glycol heat exchanger to the regenerator. In the regenerator, absorbed water is removed from the glycol at atmospheric pressure by heating. The regenerated glycol is cooled in the glycol heat exchangers and is recirculated to the contactor by the glycol pump.

TEG will absorb about 1 SCF of natural gas per gal at 1000 psig absorber pressure. There will be more absorption if aromatic hydrocarbons are present. A three to five minute residence time in the flash drum is required for degassing. Excessive hydrocarbons in the glycol may cause high glycol losses and foaming. The overhead vent from the glycol regenerator may contain hydrocarbons and should be piped to a safe location.

The separation of TEG and water in the regenerator is accomplished easily with only internal reflux. The separation of DEG and water is more difficult due to DEG's higher vapor pressure.

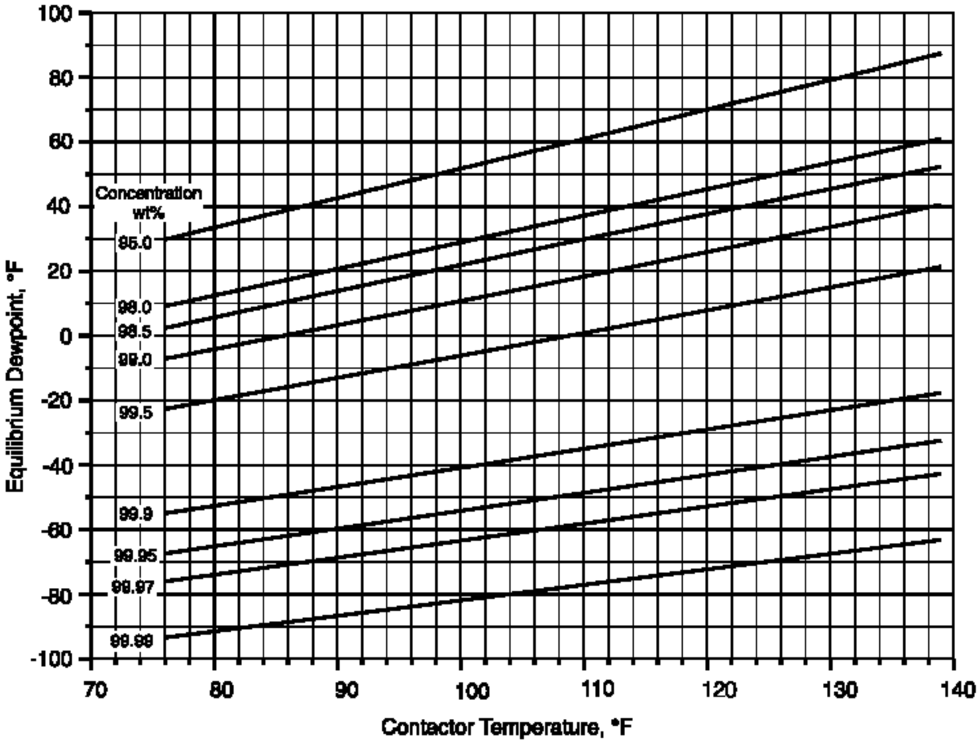


Fig-31 EQUILIBRIUM WATER DEW POINTS FOR GASES IN CONTACT WITH VARIOUS CONCENTRATIONS OF TEG

To obtain the high glycol concentrations required for high dew point depressions, stripping gas or vacuum distillation must be used in the reboiler portion of the regeneration unit. The amount of stripping gas required to re-concentrate the glycol to a high purity ranges from 2 to 10 ft3 per gallon of glycol circulated. If stripping gas is used, a recovery system may be justified.

The dew point depression obtainable with triethylene glycol can be estimated from Figure 31 based on the contact temperature and the concentration of the reconcentrated glycol that is used. Figure 31 shows the equilibrium water dew point at different temperatures for gases in contact with various concentrations of glycol. To use this plot, locate the contact temperature, read up to the glycol concentration, and then read across to find the equilibrium water dew point. In practice it is seldom economical for actual gas dew points to approach equilibrium dew points closer than 20°F.

DESCRIBING THE GLYCOL DEHYDRATION PROCESS

In general, the process of dehydrating natural gas streams with glycol is similar to using glycol injection to inhibit hydrate formation. However, because the glycol must not only absorb, but also remove the water from the gas stream, dehydration systems absorb the water in contactors (also called absorbers) instead of by injection. Glycol dehydration systems also require higher and more precisely regulated temperatures in their reboilers.

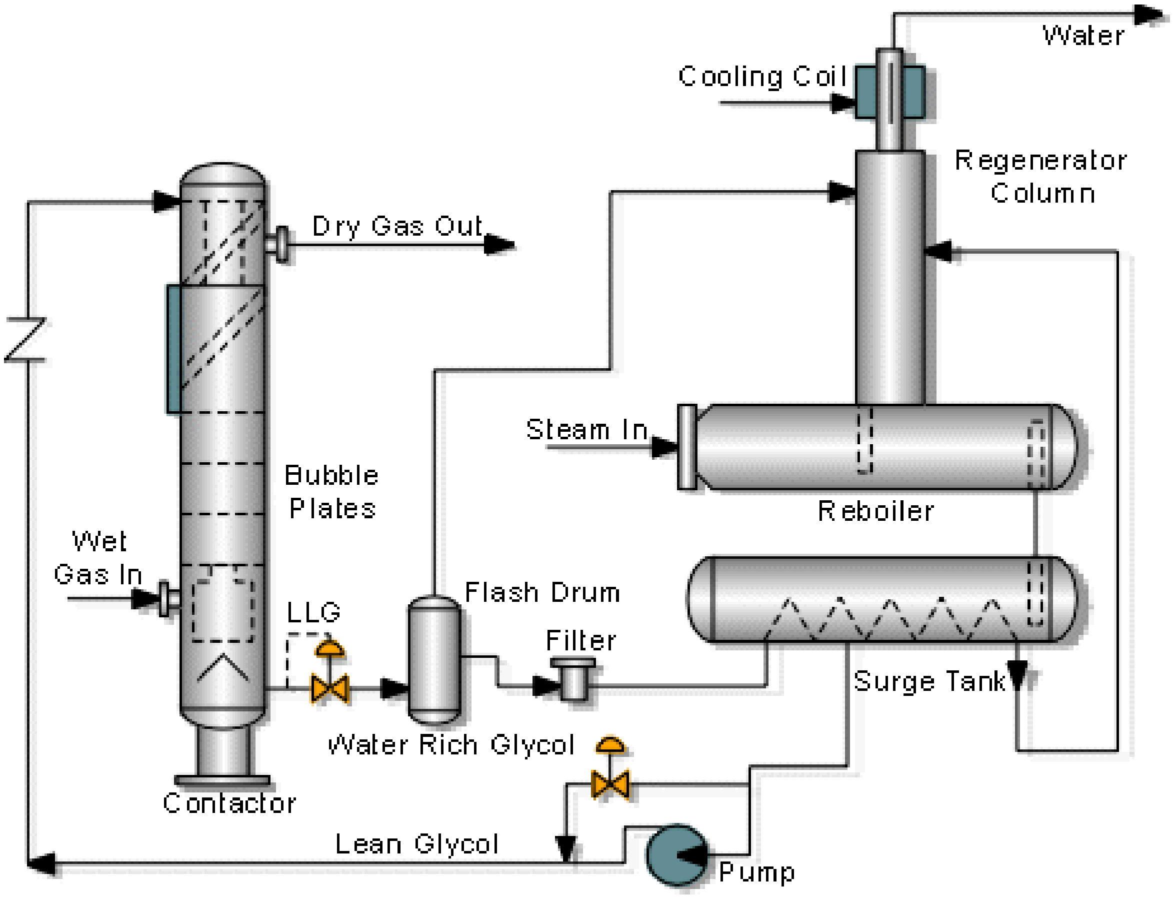


FIGURE 32: GLYCOL DEHYDRATION SYSTEM

Glycol Dehydration Process

Figure 33 shows the simplified glycol dehydration system. Wet inlet gas enters the bottom of the contactor while lean glycol enters the top. As the wet gas stream flows upward, it contacts the downward flowing lean glycol. During this contact, the glycol absorbs water from the gas stream. Dry outlet gas leaves the top of the contactor and rich glycol exits the bottom.

The rich glycol enters the top of the stripping column and countercurrently contacts steam rising from the reboiler. The rich glycol then enters the reboiler, which boils the water out of the glycol. The lean glycol leaves the bottom of the reboiler and enters the surge tank for storage. The pump raises the glycol to system pressure, preparing it for another dehydration cycle.

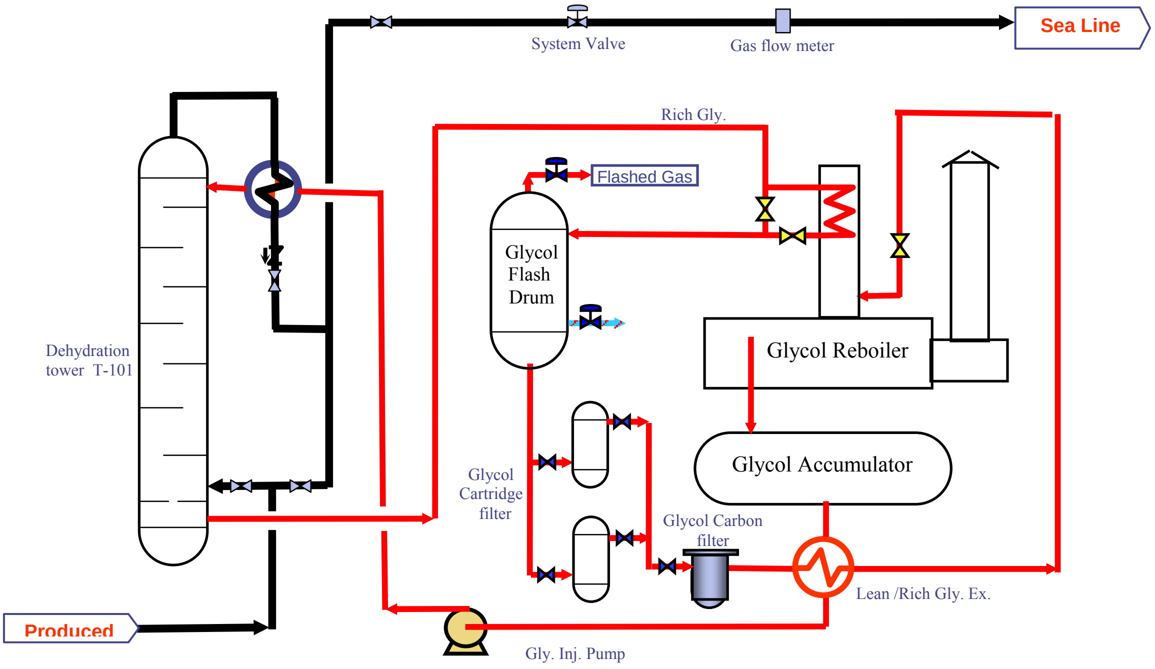


FIGURE 33: GLYCOL DEHYDRATION SYSTEM

Most glycol dehydration systems are much more complex than the one shown in Figure 33. In addition to the contactor, reboiler, still column, surge tank, and glycol pump in Figure 33, most glycol dehydration systems use:

- A flash tank separator
- A heat exchanger: lean gas/glycol and glycol/glycol
- An inlet scrubber
- Filters
- Stripping column

This additional equipment improves the efficiency and effectiveness of the simplified system . Figure 34 shows another glycol dehydration system.

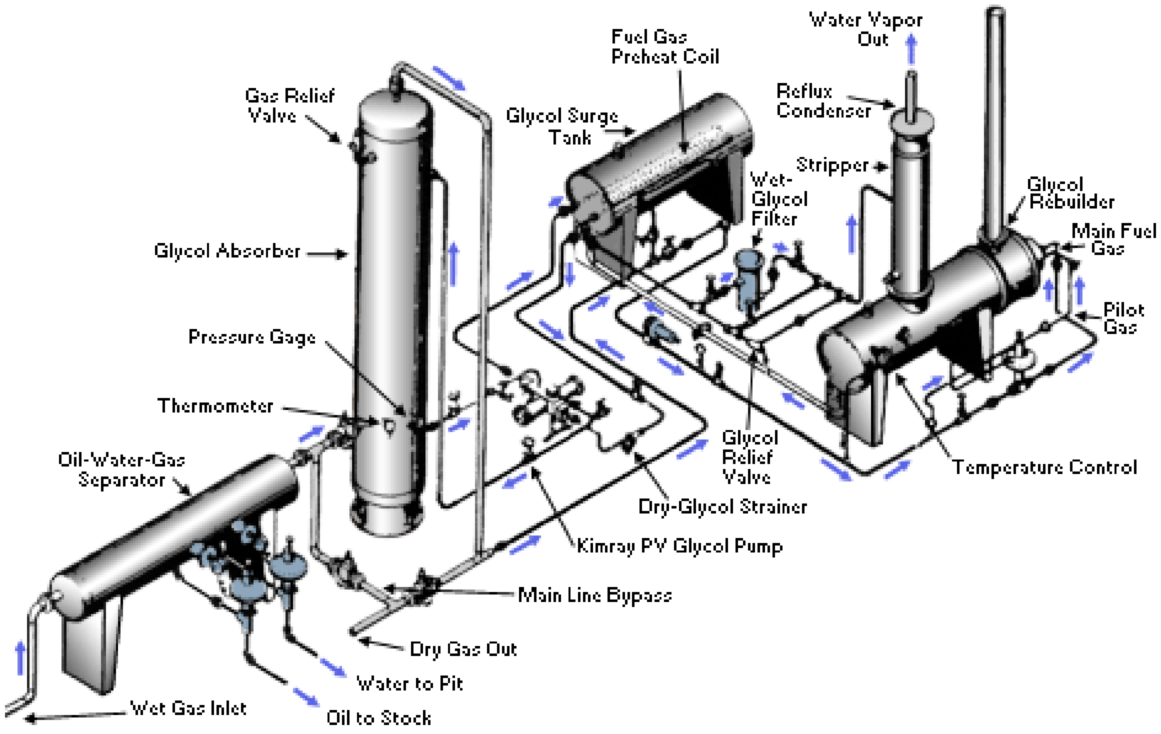


FIGURE 34: PROCESS FLOW OF A GLYCOL DEHYDRATION SYSTEM

Glycol Dehydration System Components

This section describes the major components in a glycol dehydration system and how they function. The following components are covered in this section:

- Inlet scrubber
- Contactor
- Flash tank separator
- Filters
- Glycol pump
- Heat exchangers
- Still column
- Reboiler

Inlet Scrubber

Inadequate scrubbing causes about half of all glycol dehydration system problems. Inlet scrubbers remove free water and many contaminants from the inlet gas stream. In addition to free water, these contaminants include:

- Oils or hydrocarbons
- Entrained brine
- Downhole additives
- Solids, such as sand and corrosion products

Figure 35 summarizes the problems caused by these contaminants if not removed by the inlet scrubber.

CONTAMINANT	PROBLEMS
Free Water	Increases glycol recirculation, reboiler heat duty, and fuel costs If the dehydration system becomes overloaded with water, glycol can carry over from the contactor and/or still . Sales gas specification may not be achieved
Oils or Hydrocarbons	Reduce the drying capacity of the glycol With water present, can cause foaming Undissolved oils can: • Plug absorber trays • Foul heat transfer surfaces in the reboiler • Increase the viscosity of the glycol • Light hydrocarbons can flash in the stripping column and cause loss of glycol and/or damage to the packing
Entrained Brine	Dissolves into glycol Corrodes steel, especially stainless steel Deposits on reboiler fire tubes, causing hot spots and firetube burnout
Downhole Additives	Cause foaming, corrosion, and, if they deposit on fire tubes, hot spots
Solids	Promote foaming Erode valves and pumps Eventually plug trays and packing

FIGURE 35 : PROBLEMS CAUSED BY CONTAMINANTS

Contactor

Contactor towers contact the lean glycol with the wet gas stream. As Figure 5 shows, contactor towers consist of three sections:

- Scrubbing section in the bottom
- Drying (mass transfer) section in the middle
- Glycol cooler and mist extractor in the top

Note: The scrubber section in the glycol contactor's base and the glycol cooling coil are optional items (restricted to small field units) .

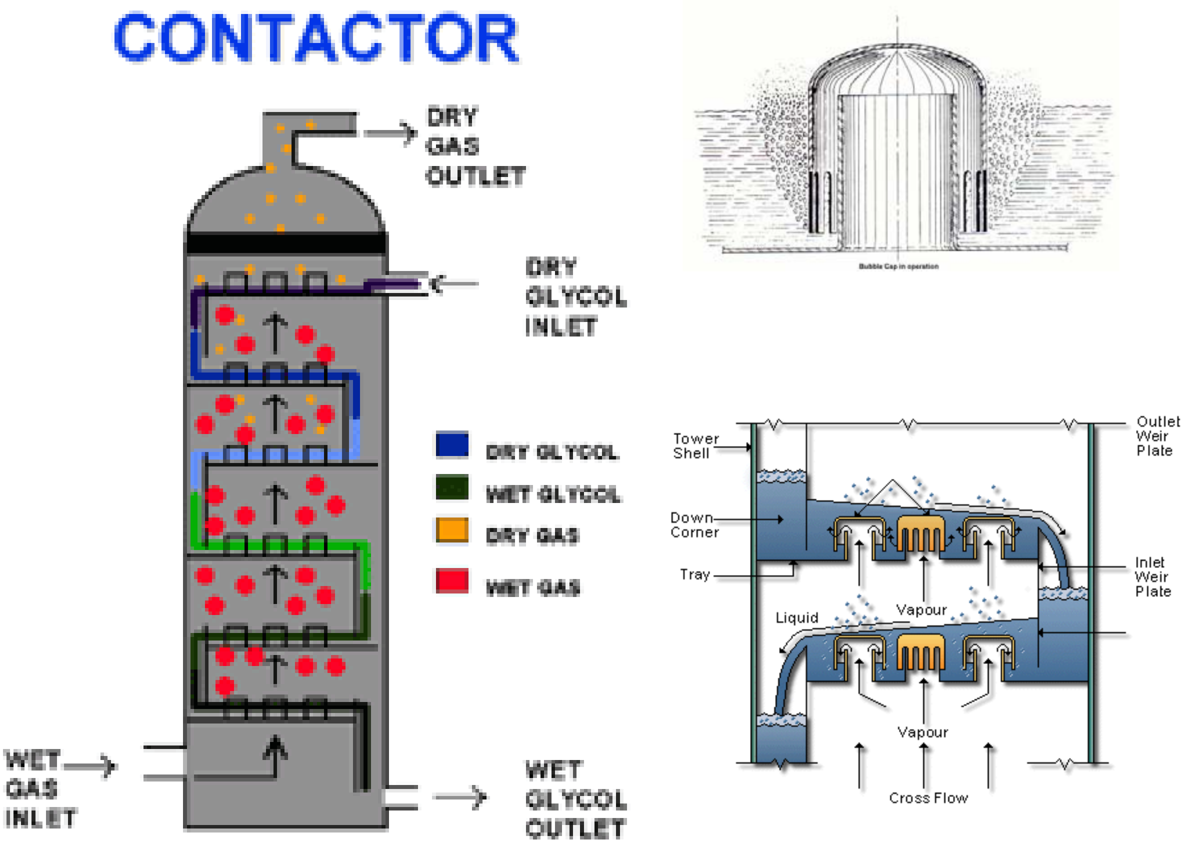


FIGURE 36 : CONTACTOR TOWER

Scrubbing Section - The gas stream enters the bottom section of the contactor and then enters a second scrubber integrated into the contactor and a wire mesh mist extractor. These remove any contaminants and entrained liquids not removed by the inlet scrubber. This second stage of scrubbing further minimizes the contamination of the glycol and helps prevent the free water from overloading the system.

Drying Section - In the middle section of the contactor, the gas stream flows upward and thoroughly contacts the downward flowing lean glycol through valve trays, bubble caps, or packing.

Mist Extractor - A mesh or woven mist extractor reduces carryover to less than 1 lb liquid glycol/MMSCF. For the mist extractor, 4 to 8 inches of stainless steel mesh and 4 inches of Dacron are generally recommended.

Flash Drum Separator

The flash tank separates hydrocarbon liquid and vapor from the glycol. TEG absorbs 1 SCF/gal glycol at 1,000 psig and 100°F, but glycol absorbs heavier hydrocarbons much more readily. Flash tanks separate gas condensate and glycol best between 100°F to 150°F and between 50 psig and 75 psig.

A two-phase separator with a 5 to 10 minute liquid retention time prevents excess hydrocarbon vapor from entering the stripping column. If hydrocarbons enter the stripping column, they can flash, increase glycol losses, and possibly break the ceramic packing. If the specific gravity of the gas stream is high, then a three-phase separator (containing vapor, aqueous, and liquid hydrocarbon phases) with a 20 to 30 minute residence time is preferred.

Filters

Keeping the solids content in glycol below 0.01 wt % helps prevent the wearing of pumps, plugging of heat exchangers, foaming, fouling of contactor trays and still packing, cell corrosion, and hot spots on reboiler fire tubes. Placing a filter after the glycol-glycol heat exchanger takes advantage of the reduced viscosity of the heated glycol.

Two types of filters are typically used for the glycol solution. Cartridge filters remove solids, that is, corrosion products. Activated carbon filters remove hydrocarbon impurities, for example, well treating chemicals and compressor oils. The placement of a rich glycol filter after the lean/rich glycol exchange has the advantage of a lower glycol viscosity, but the lower viscosity is at the expense of a potential increase to the fouling rate of the rich side of the lean/rich glycol exchanger.

Glycol Pump

Glycol circulation pumps contain the only moving parts in a glycol dehydration system. The three types of pumps used in dehydration systems are:

- Electric-motor driven
- High-pressure gas-operated
- High-pressure liquid-operated

Larger dehydration systems generally use electric-motor driven pumps. Smaller dehydration systems and those remotely located generally use high-pressure gas-operated or high-pressure liquid-operated pumps.

Installing a second (spare) pump capable of providing full glycol circulation ensures continuous dehydration if the primary glycol circulation pump fails.

Heat Exchangers

Glycol dehydration systems often use three heat exchangers:

- Lean gas/glycol
- Glycol/glycol
- Reflux coil located in still column

Lean Gas/Glycol Heat Exchangers use lean gas to further cool the glycol to 5°F to 15°F above the exit temperature of the gas stream before the glycol enters the top of the contactor.

Generally, glycol dehydration systems use double-pipe or shell-and-tube heat exchangers for lean gas/glycol heat exchangers.

Glycol/Glycol Heat Exchangers preheat the rich glycol leaving the bottom of the contactor before it enters the reboiler and cools the lean glycol leaving the reboiler before it goes to the lean gas/glycol heat exchanger and the top of the contactor.

The reflux coil (using cool, rich glycol) or the cooling fins on the still column (whichever is applicable) maintains the temperature at the top of the still column. The glycol/glycol heat exchangers essentially increase the energy efficiency of the system. The large difference between the exit temperatures of the lean and rich glycol from these heat exchangers requires counter current flow to prevent temperature cross. Therefore, larger glycol dehydration systems generally use two double-pipe or plate-and-frame heat exchangers in series.

Still Column

Reflux Coil - The top of the still column contains a cooling coil that condenses some of the steam rising from the reboiler, providing reflux for the column. This cooling coil controls condensation and reduces glycol losses.

In addition to the reboiler, the still column also reconcentrates glycol. Still columns countercurrently contact rich glycol with steam rising from the reboiler. This steam strips water from the liquid glycol. Still columns usually contain 4 to 8 ft of ceramic packing although some large units use trays.

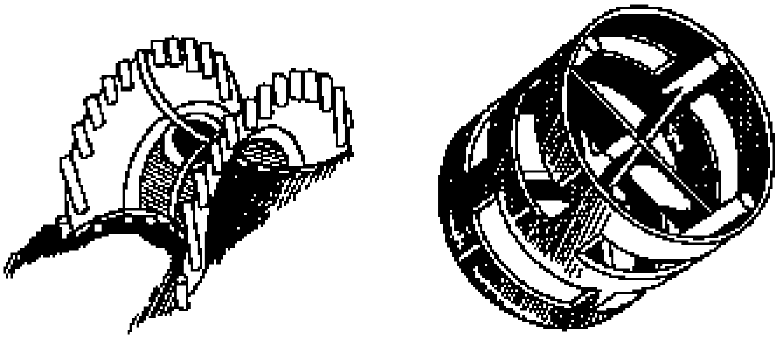


FIGURE 37 : STILL COLUMN PACKING

Reboiler

Reboilers provide enough heat to boil the water out of the glycol. Glycol dehydration systems often use direct-fired heaters, but not when the fire hazard they present poses too much of a threat. In such locations, for example, offshore platforms, fire codes and safety require the use of indirect-fired heaters.

The bulk temperature of TEG must be kept below 400°F and the maximum fire-tube skin temperature below 430°F to help prevent thermal decomposition of the TEG. The U-shaped fire tube in a TEG reboiler must be sized for an average heat flux of 6,000 to 8,000 Btu/hr-ft2 to keep the TEG and the reboiler below these temperatures.

Surge Tank (Accumulator)

The surge tank (accumulator) holds glycol to compensate for fluctuations in the load on the glycol dehydration systems. During normal operation, surge tanks are only about half full of glycol. During shutdown, however, they need to hold all of the glycol that drains down from the trays, vessels, and piping. Contact with air can result in degradation of the glycol. A gas blanket usually protects the glycol from air contamination.

Stripping Gas

Adding a stripping gas to the still column increases the glycol purity produced by the glycol reconcentrator from about 98.5% to 99.9%. Glycol dehydration systems using stripping gas generally inject dry, sales gas into the top of the reboiler. The stripping gas flows up counter currently to the glycol, further stripping water from the glycol. Using sales gas increases the cost of the system because of the loss of revenue.

Process/Design Variables

Several process and design variables have an important effect on the successful operation of a glycol dehydration system.

Gas Temperature

Plant performance is especially sensitive to the temperature of the incoming gas. At constant pressure, the water content of the inlet gas increases as this temperature is raised. Glycol vaporization losses are also increased at the the higher temperature. Furthermore, problems can result from too low a temperature (below 50°F) because glycol becomes very viscous.

Lean Glycol Temperature

The temperature of lean glycol entering the absorber has a significant effect on the gas dew point depression, and should be held to a minimum to achieve the best operation. However, it should be kept at least 10°F above the inlet gas temperature to minimize hydrocarbon condensation in the absorber and subsequent foaming.

Glycol Reboiler Temperature

The reboiler temperature controls the concentration of the water in the glycol. With a constant pressure, the glycol concentration increases with higher reboiler temperatures. The reboiler temperature should never be allowed to remain at or above the glycol degradation temperatures. When higher glycol concentrations are required, stripping gas can be added to the reboiler.

Regenerator Top Temperature

The temperature in the top of the regenerator is also important. A high temperature can increase glycol losses due to excessive vaporization. The recommended temperature in the top of the column is about 225°F. If the temperature in the top of the column drops too low, too much water can be condensed and washed back into the regenerator to flood the column and fill the reboiler with excessive liquids.

Reboiler Pressure

Reducing the pressure in the reboiler at a constant temperature results in higher glycol purity. This pressure reduction lowers the water partial pressure in the vapor, increasing the driving force under which water leaves the glycol solution.

Glycol Concentration

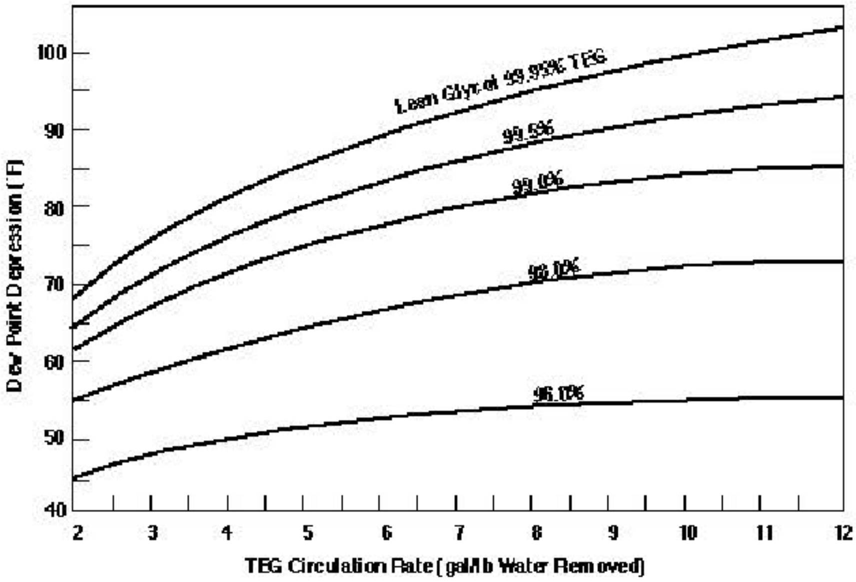
The water content of the dehydrated gas depends primarily on the lean glycol concentration. The dry gas leaves the contactor approaching equilibrium with the lean glycol. The leaner the glycol flowing to the absorber, the more efficient the dehydration. Figure 31 shows the effect of glycol concentration on gas dew point.

Glycol Circulation Rate

When the number of absorber trays and glycol concentration are fixed, the dew point depression of a saturated gas is a function of the glycol circulation rate. Whereas the glycol concentration mainly affects the dew point of dry gas, the glycol rate controls the total amount of water that can be removed. A typical glycol circulation rate is about three gallons of glycol per pound of water removed (seven maximum). The minimum circulation rate to assure good glycol-gas contacting is about two gallons of glycol for each pound of water removed.

A greater dew point depression is easier to achieve by increasing the glycol concentration rather than by increasing the glycol circulation rate (see Figure 4). To use this plot, locate the glycol circulation rate, read up to the glycol concentration, and then read across to find the dew point depression. An excessive circulation rate, especially above the design capacity, overloads the reboiler and prevents good glycol regeneration. It also prevents adequate glycol-gas contacting in the absorber, increases pump maintenance problems, and can increase glycol losses.

Figure 38: Effect of TEG circulation rate and concentration on dew point depression



Optimizing and Troubleshooting Dehydrator Operations

Glycol Maintenance

Operating and corrosion problems usually occur when the circulating glycol gets dirty. Therefore, to achieve a long, trouble-free life from the glycol, it is necessary to recognize these problems and know how to prevent them. Some of the major areas are discussed below:

Methanol

Methanol in the feed gas to a glycol dehydrator will be absorbed by the glycol. This results in the following problems:

- Methanol will add additional heat duty on the reboiler and additional vapor load on the regenerator. High methanol injection rates and slug carryover can cause flooding.
- Aqueous methanol causes rust in carbon steel, so corrosion can occur in the regenerator and reboiler vapor space.

Most of the methanol absorbed in the rich glycol solution can be removed by flashing in the regenerator. Activated carbon filters are used to adsorb methanol from the lean glycol solution to avoid these problems.

Thermal Decomposition

Excessive heat, a result of one of the following conditions, will decompose glycol and form corrosive products:

- High reboiler temperature above the glycol decomposition level.
- Localized overheating, caused by deposits of salt or tarry products on the reboiler fired tubes or by poor flame direction on the fired tubes.

pH Control

New glycol has a neutral pH of approximately seven. As it is used, however, the pH always decreases and the glycol becomes acidic and corrosive, unless pH neutralizers or buffers are used. The equipment corrosion rate increases rapidly with a decrease in the glycol pH. Acids created by glycol oxidation, thermal decomposition products, or acid gases picked up from the gas stream are the most troublesome of corrosive contaminants. A low pH accelerates the decomposition of glycol. Ideally, the glycol pH should be held at a level of 7.0 to 7.5. A value above 8.0 to 8.5 tends to make glycol foam and emulsify.

Borax, ethanolamines (usually triethanolamine), or other alkaline neutralizers can be used to control the pH. These neutralizers should be added with great care -- slowly and continuously -- for best results. An overdose of neutralizer will usually precipitate a suspension of black sludge in the glycol. The sludge could settle and restrict glycol circulation. Frequent filter element changes should be made while pH neutralizers are added.

Salt Contamination

Salt deposits accelerate equipment corrosion, reduce heat transfer in the reboiler tubes, and alter specific gravity readings when a hydrometer is used to measure glycol-water concentrations. This troublesome contaminant cannot be removed with normal regeneration.

Therefore, an efficient scrubber upstream of the glycol plant should be used to prevent salt carryover with the incoming gas. In areas where large quantities of brine are produced, some salt contamination will occur. The removal of salt from the glycol solution is then necessary.

Salt contaminated glycol may be reclaimed by several methods. Scraped-surface heat exchangers in conjunction with centrifuges are used in cases of extreme contamination. Other reclamation methods are vacuum distillation or ion exchange.

Hydrocarbons

Liquid hydrocarbons, a result of carryover with the incoming gas or condensation in the absorber, increase glycol foaming, degradation, and losses. They must be removed with a glycol-gas separator, hydrocarbon liquid skimmer, or activated carbon beds.

Sludge

An accumulation of solid particles and tarry hydrocarbons very often forms in the glycol. This sludge is suspended in the circulating glycol; over a period of time, the accumulation becomes large enough to settle out. This action results in the formation of black, sticky, abrasive gum that can cause trouble in pumps, valves, and other equipment, usually when the glycol pH is low. The gummy substance becomes hard and brittle when deposited on the absorber trays, stripper packing, and other places in the circulating system. Good solution filtration prevents a buildup of sludge.

Foaming

Foaming can increase glycol losses and reduce plant capacity. Entrained glycol will be carried over the top of the absorber with the sales gas when stable foam builds up on the trays. Foaming also causes poor contacting between the gas and glycol, decreasing the drying efficiency.

Some foam promoters are:

- Hydrocarbon liquids.
- Field corrosion inhibitors.
- Salt.
- Finely divided suspended solids.

Excessive turbulence and high liquid-to-vapor contacting velocities usually cause the glycol to foam. This condition can be caused by mechanical or chemical problems.

The best way to prevent foaming is proper care of the glycol. This involves effective gas cleaning ahead of the glycol system and good filtration of the circulating solution. The use of defoamers does not solve the basic problem, and serves only as a temporary control until the conditions generating foam can be identified and removed.

Analysis and Control of Glycol

Analysis of glycol is essential to good plant operation. Meaningful analytical information helps pinpoint high glycol losses, foaming, corrosion, and other operating problems.

Analyses enable the operator to evaluate plant performance and make operating changes to obtain maximum drying efficiency.
A glycol sample should first be visually inspected to identify some of the contaminants:

- A finely divided black precipitate may indicate the presence of iron corrosion products.
- A black, viscous solution may contain heavy hydrocarbons.
- The characteristic odor of decomposed glycol (a sweet aromatic odor) usually indicates thermal degradation.
- A two-phase liquid sample usually indicates the glycol is heavily contaminated with hydrocarbons.

The visual inspections should next be supported by chemical analysis. Samples of the lean and rich glycol should be taken and routine tests performed: salt analysis, solids content, pH, iron content, foam test, and titration procedure (to determine the amount of neutralizer necessary to raise the pH to a safe level). These analyses usually provide sufficient information to determine the condition of the glycol.

Glycol Loss Prevention

Glycol losses can be defined as liquid carryover from the contactor (normally 0.10 gal/ MSCF with a standard mist eliminator) plus vaporization from the contactor and regenerator, and spillage. Glycol losses, exclusive of spillage, range from 0.05 gal/MSCF for high pressure, low temperature gases to as much as 0.30 gal/MSCF for low pressure, high temperature gases.

There are several ways to reduce glycol losses.

- A certain amount of glycol always vaporizes in the sales gas stream. Adequate cooling of the lean glycol before it enters the absorber minimizes these losses.
- Normally, most of the glycol entrainment is removed by a mist eliminator in the top of the absorber. Excessive gas velocities and glycol foaming in the absorber sharply increase the glycol carryover. A downstream gas scrubber can pay for itself quickly and save much money by trapping the carryover and recovering the excess glycol. This gas scrubber also helps prevent problems downstream of the glycol plant.
- Vaporization losses in the stripper can be held to a minimum with good glycol condensation and control of the tower top temperature. Glycol entrainment, or mechanical carryover, can be reduced with proper maintenance of the stripper and reboiler.
- Mechanical leaks can be reduced by keeping the pump, valves, and other fittings in good order. The glycol from these leaks should be collected and reprocessed.
- Excessive entrainment losses may be the result of foaming in the absorber and/or regenerator. Defoamers are sometimes used.

Glycol Filtration

Filters extend the life of the glycol pumps, and prevent an accumulation of solids in the absorber and regeneration equipment. Solids that settle on metal surfaces frequently set up cell corrosion. Filters also remove the solids that contribute to fouling, foaming, and plugging. Sock-type filters are preferred, although fine screens and cartridge filters are also suitable. The filters should be designed to remove all solid particles over 5 microns in size.

They should be able to operate up to pressure drops of 20 to 25 psi. For best results, filters should be placed in the rich glycol line, but the lean glycol can also be filtered to help keep the glycol clean. Frequent filter changes may be needed during plant start-up, or when neutralizers are added to control the glycol pH.

Solid Desiccant Dehydration

Background

Since solid desiccant units cost more than glycol units, their use is usually limited to applications such as very sour gases, very low water dew point requirements, simultaneous control of water and hydrocarbon dew points, and special cases such as oxygen containing gases, etc. In cryogenic plants, solid desiccant dehydration usually is preferred over methanol injection to prevent hydrate and ice formation. Solid desiccants are also often used for the drying and sweetening of NGL liquids.

Desiccants in common commercial use fall into one of three categories:

- Alumina - Regenerable aluminum oxide base desiccant.
- Silica Gel - Regenerable silicon oxide adsorbent.
- Molecular Sieves - Regenerable solid desiccants composed of crystalline metal aluminosilicates (zeolites).

Each desiccant category offers advantages in different services. The best choice is not routine.

Activated alumina has a strong affinity for water and high internal adsorption area due to the presence of pores or very fine capillaries. Alumina condenses and holds the water in the pores by surface adsorption and capillary attraction. Activated alumina desiccant can be used for drying liquids which do not contain unsaturates such as olefins or diolefins. It is less costly than molecular sieve desiccant but its capacity for absorbing water also tends to be lower, particularly when attempting to reach very low water levels, e.g. 5 wppm in the product.

Silica gel has a higher equilibrium adsorption capacity (see Figure 6) than alumina because its available surface is greater. Due to silica gel's higher price per pound, alumina is generally the economic choice. Silica gel is not used where free water can be present, because free water destroys silica gel. Free water over long-term operation, either as droplets or slugs, will also damage molecular sieve and activated alumina by mechanical attrition and should be avoided.

Molecular sieves have the feature of uniform pore size, which allows them to exclude molecules based on size. Because different pore size molecular sieves are produced, selection of proper type of sieve can alleviate the problem of undesirable coadsorption.

Molecular sieves have a higher design adsorption capacity than the other regenerable desiccants, but this is often offset by their considerably higher price per pound.

Molecular sieve dehydrators are commonly used ahead of NGL recovery plants where extremely dry gas is required. Cryogenic NGL plants designed to recover ethane produce very cold temperatures and require very dry feed gas to prevent formation of hydrates.
Dehydration to approximately 1 ppmw is possible with molecular sieves.

Two types of molecular sieves, Type 3A and Type 4A, are commonly used for drying hydrocarbon liquids. Type 4A sieves are less costly than Type 3A sieves and are used for distillates which do not contain unsaturates. When unsaturates are present in the feed, Type 3A are used to assure good regeneration.

Solid desiccants are used in gas dehydrators containing two or more towers. Figure 7 is a simple two-tower system. One tower is onstream adsorbing water from the gas, while the other tower is being regenerated and cooled. Figure 8 shows a typical molecular sieve dehydrator vessel. Hot gas removes the adsorbed water, after which the tower is cooled. The towers are switched before the onstream tower becomes water saturated. Generally a bed is designed to be on line for 8 to 24 hours. When the bed is taken off-line, the water is removed by heating the bed to 450-600°F. The regeneration gas used to heat the bed is usually a slipstream of dry process gas. The regeneration gas is returned to the process after it has been cooled and the free water removed. Since heat is a major operating cost, this is a major design consideration.

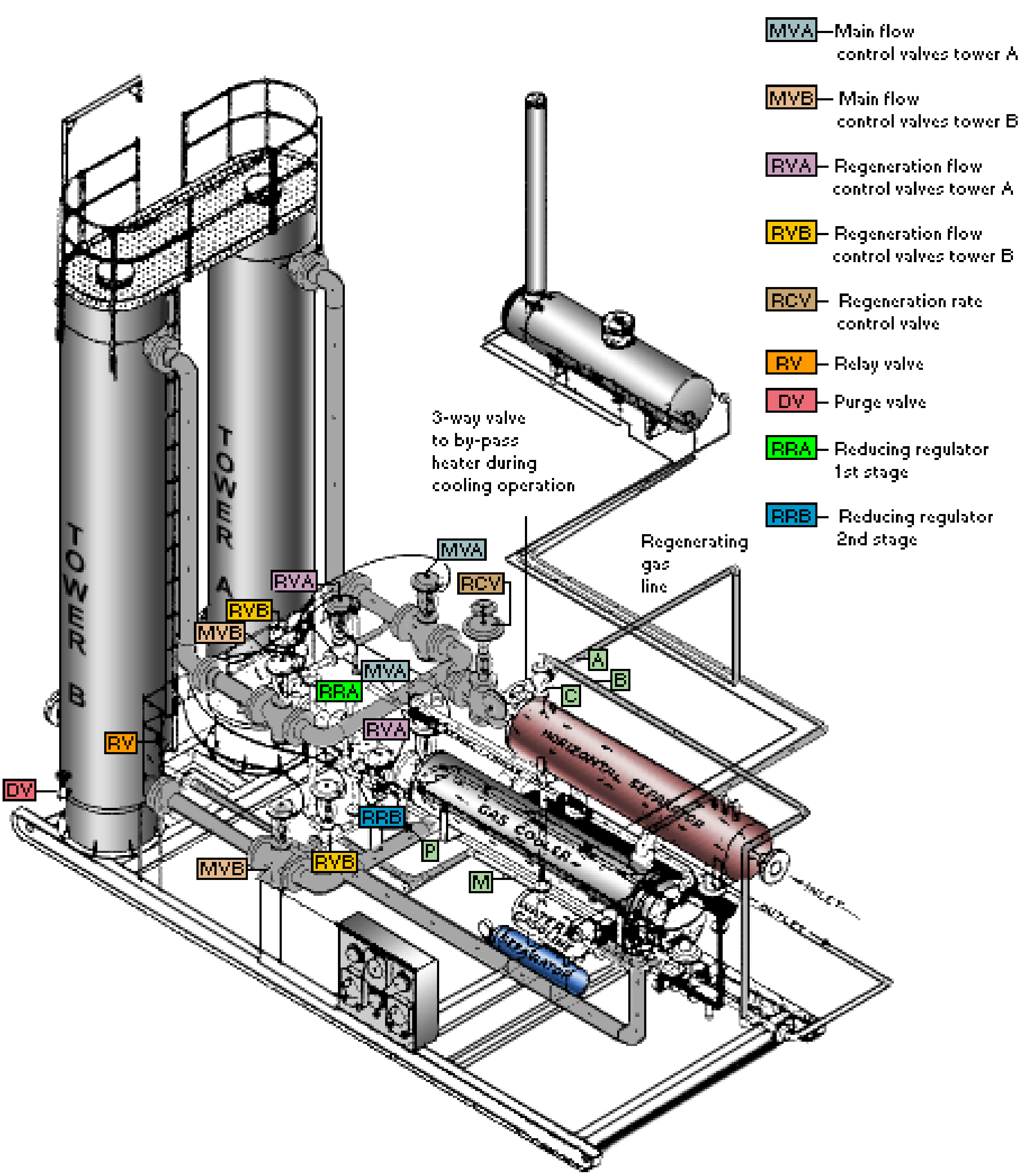


FIGURE 39 : SOLID DESICCANT DEHYDRATOR TWO TOWER SYSTEM

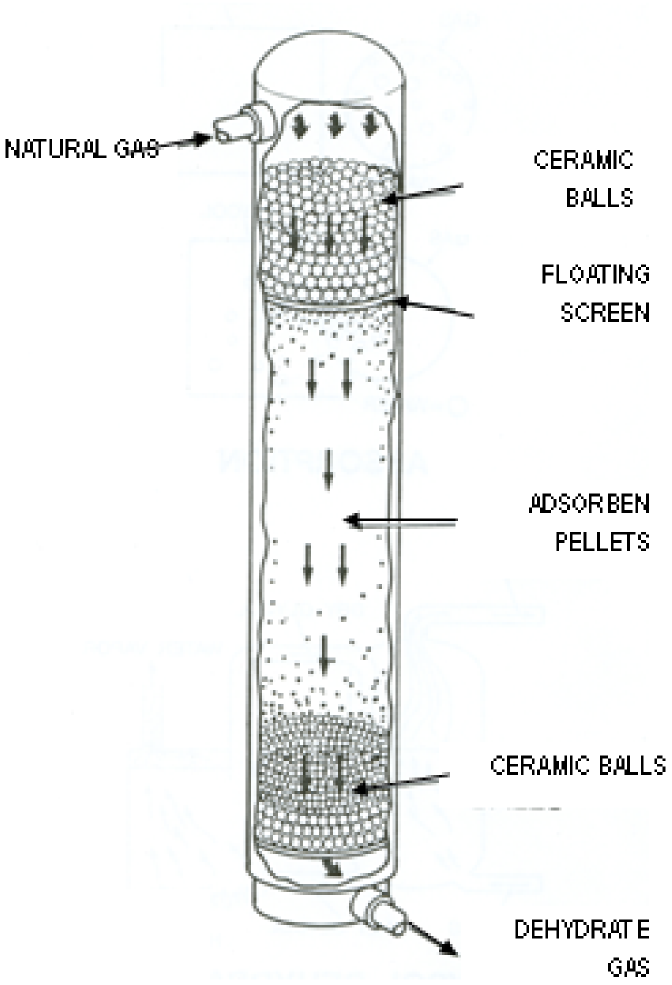


FIGURE 40: TYPICAL MOLECULAR SIEVE GAS DEHYDRATION VESSEL

Adsorption Calculations

Adsorption calculations for a molecular sieve dehydrator are discussed below. The allowable superficial vapor velocity through the bed is the first parameter that must be estimated using Figure 41. To use this plot, locate the operating pressure, read up to the type sieve, then read across to find the allowable superficial velocity. Once the allowable superficial velocity is estimated, the bed diameter can be calculated for a design vapor rate. The design pressure drop through the bed is calculated using Equation 3 and should be about five psi. A design pressure drop higher than eight psi is not recommended.

- Molecular sieve pressure drop.

$$\frac{DP}{L} = B\mu V + C\rho V^2 \qquad \text{(Eqn. 3)}$$

where:

DP = Pressure drop, psi.
L = Length of packed bed, ft.
V = Vapor velocity, ft/min.
μ = Vapor viscosity, cP.
ρ = Vapor density, lb/ft3.

Constants:

Desiccant Type	B	C
1/8 in. bead	0.0560	0.0000889
1/8 in. extrudate	0.0722	0.000124
1/16 in. bead	0.152	0.000136
1/16 in. extrudate	0.238	0.000210

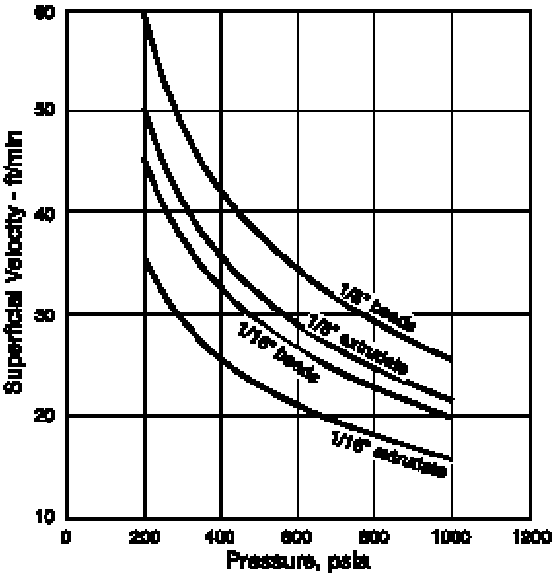


FIGURE 41 ALLOWABLE VELOCITY FOR MOLE SIEVE DEHYDRATOR

The next step is to choose a cycle time and calculate the pounds of sieve required. Eight to twelve hour cycles are common. Cycles greater than 12 hours may be justified, especially if the gas is not water saturated. Long cycles mean fewer regenerations and longer sieve life, but larger beds and additional capital investment are required.

During the adsorption cycle, the bed operates with three zones The top zone is called the saturation zone. The molecular sieve in this zone is in equilibrium with the wet inlet gas. The middle or mass transfer zone (MTZ) is where the water content of the gas is reduced from saturation to < 1 ppm. Normally a system is designed so that there is a moisture analyzer to indicate when the mass transfer zone is likely to break through the end of the bed. A guard bed zone (typically one to two feet deep) is provided after this point to prevent actual breakthrough before the system has a chance to change to the regenerated bed.

Unfortunately, both the water capacity and the rate at which the molecular sieves adsorb water change as the molecular sieves age. The object of the design is to install enough sieve so that three to five years into the life of the sieve, the mass transfer zone will be at the bottom of the bed at the end of the adsorption cycle.

In the saturation zone, the molecular sieve is expected to hold approximately 13 pounds of water per 100 pounds of sieve. This capacity needs to be adjusted when the gas is not water saturated or when the temperature is above 75°F. See Figures 42 and 43 for the correction factors. To determine the pounds of molecular sieve required in the saturation zone, calculate the amount of water to be removed during the cycle and divide by the sieve capacity (use Equations 4 and 5).

Molecular sieve requirement in adsorber saturation zone

$$S_S = \frac{W_r}{(0.13)(C_{SS})(C_T)}$$

Equ. 4

where: S_S = Amount of molecular sieve required in saturation zone, lb
C_{SS} = Saturation correction factor for sieve See fig 42
C_T = Temperature correction factor See fig 43

Length of molecular sieve packed bed saturation zone.

$$L_S = \frac{(S_S)(\rho_{bd})(4)}{(3.14)(D^2)}$$

Equ. 5

where: ρ_{bd} = Bulk density
L_S = Length of packed bed saturation zone, ft.
D = Bed diameter, ft.

Even though the MTZ will contain some water, the saturation zone is calculated assuming it will contain all the water to be removed. The length of the mass transfer zone can be calculated using Equation 7 from Work Aid 4. The total bed height is the summation of the saturation zone, mass transfer zone, and guard bed zone heights. Approximately six feet free space above and below the bed is needed.

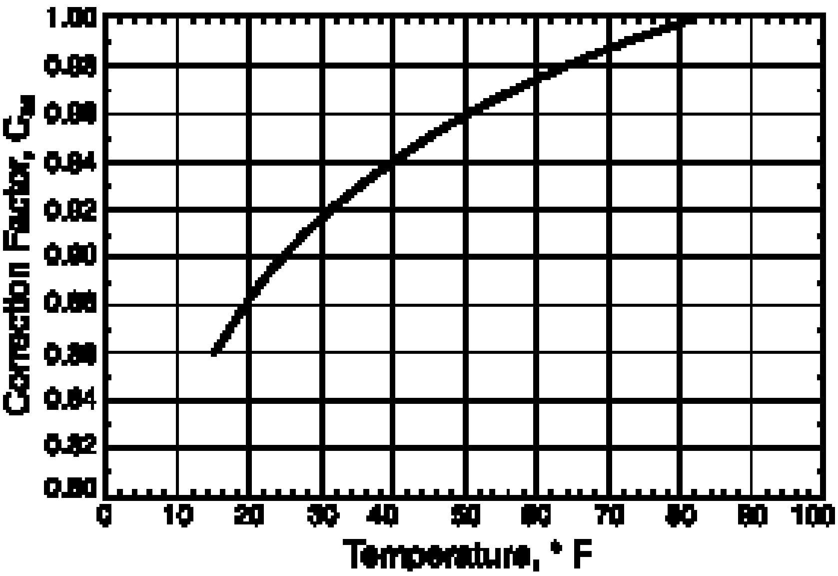


FIGURE 42 MOLE SIEVE CAPACITY CORRECTION FOR UNSATURATED INLET GAS

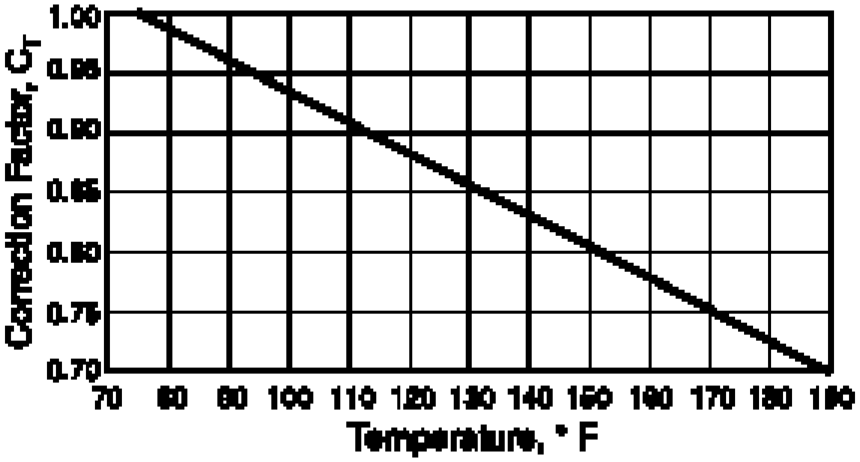


FIGURE 43 MOLE SIEVE CAPACITY CORRECTION FOR TEMPERATURE

Process Flow and the function of the major components of Solid Desiccant Dehydrators

Unlike glycol dehydration system's continuous processing, the adsorption process is a batch procedure with multiple desiccant beds used in cyclic operation to dry the gas on a continuous basis. Adsorber towers must be taken out of drying service to be regenerated. Because of this, solid desiccant dehydrators typically use two, three, or four adsorber towers. Some applications use as many as twelve towers. There are economic and process advantages for three or more adsorber tower designs in some situations.

The following three separate functions must alternate in each adsorber tower:

- An adsorbing or gas-drying cycle
- A heating or regenerating cycle
- A cooling cycle to prepare the regenerated bed for another adsorbing cycle

At any given time, one of the towers is on stream in the adsorbing or drying cycle while the other is in the process of being heated or cooled. Several automatically operated switching valves and a controller route the inlet gas and regeneration gas to the right tower at the proper time. Typically, a tower is on the drying or adsorbing cycle for 4 to 12 hours, with 8 hr the usual time. The tower being regenerated is heated for about 5 to 6 hours and cooled during the remaining 2 to 3 hours.

Process of Regeneration

As the wet inlet gas flows downward through the tower on the adsorption cycle, each of the adsorbable components is adsorbed at a different rate. The water vapor is immediately adsorbed in the top layers of the desiccant bed. Each of the light hydrocarbon gases and heavier hydrocarbons moving down through the bed are also adsorbed to a greater or lesser extent. With molecular sieves, minimal adsorption of hydrocarbons occurs due to the exclusion from the smaller pores. Heavier hydrocarbons displace the lighter ones in the desiccant bed as the adsorbing cycle proceeds. As the upper layers of desiccant become saturated with water, water in the wet gas stream begins displacing the previously adsorbed hydrocarbons in the lower layers.

For each component in the inlet gas stream, there will be a section of bed depth, from top to bottom, where the desiccant is saturated with that component and where the desiccant below is just starting to adsorb it. The depth of bed from saturation to initial adsorption is the mass transfer zone (MTZ) described earlier.

As the flow of gas continues, the MTZ's move downward through the bed and water displaces all of the previously adsorbed gas until, finally, the entire bed is saturated with water vapor. When the bed is completely saturated with water vapor, the outlet gas is just as wet as the inlet gas. Before the desiccant bed has become completely saturated, the towers must be switched from the adsorption cycle to the regeneration cycle (See Figure 44).

One regeneration-gas-supply scheme consists of taking a pressure drop across a pressurereducing valve that forces a portion (5% to 15%) of the entering wet-gas stream through the regeneration system. In most plants, a flow controller regulates the volume of regeneration gas used. This gas is heated until it reaches 400° to 600°F, then it is piped to the tower being regenerated. The adsorbed water begins to desorb at the start of the regeneration cycle if dry regeneration gas is used. The bulk of the water is removed from the molecular sieve at a temperature of 240°F to 250°F, but the desorption continues, although at a continually diminishing rate, until the end of the heating cycle.

After all the water has been removed, heating is maintained to drive off any heavier hydrocarbons and contaminants that do not vaporize at lower temperatures. The desiccant bed is properly regenerated when the outlet gas (peak-out) temperature has reached 350° to 550°F.

After the heating cycle, the desiccant bed is cooled by flowing unheated regeneration gas until the desiccant is sufficiently cooled.

All of the regeneration gas used in the heating and cooling cycles is passed through a heat exchanger where it is cooled to condense the water removed from the regenerated desiccant bed. This water is separated in the regeneration gas separator, and the gas is mixed with the incoming wet-gas stream. This entire process is continuous and automatic.

The following sections cover the process flow of dehydrators using two, three, and four adsorber towers.

Process Flow of Solid Desiccant Dehydrators

Two-Tower Dehydrators

Solid desiccant dehydrators using two adsorber towers offer only one flow arrangement. While one tower dehydrates the process fluid stream, the other tower regenerates. The two towers alternate between drying and regeneration. Figure 11 shows the process flow of the process fluid (gas or liquid) and the regeneration gas in a two-tower solid desiccant dehydrator.

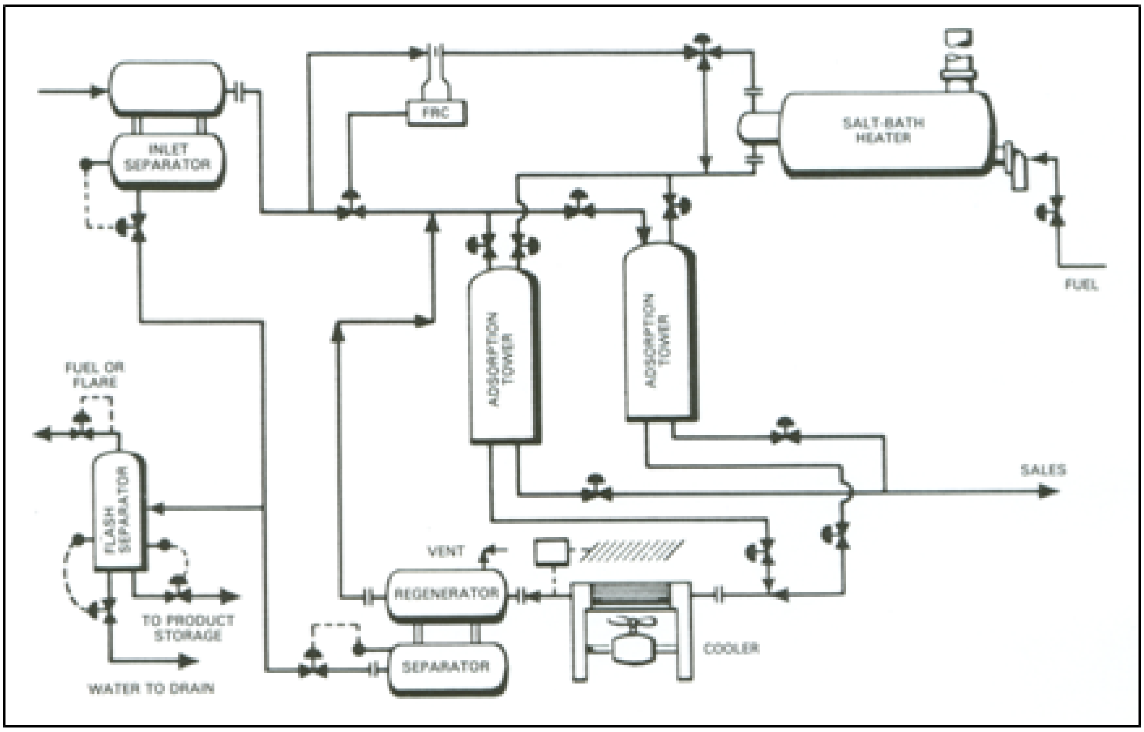


FIGURE 44: PROCESS FLOW OF TWO-TOWER SOLID DESICCANT DEHYDRATOR

In the dehydrator shown in Figure 44, the process fluid passes through the inlet separator. As in glycol dehydrators, the inlet separator removes free water and other contaminants from the process fluid. From the inlet separator, the process fluid flows to and down through whichever adsorber tower is in the adsorbing phase (In Figure 44, this is Tower 2.). In the tower, the solid desiccant adsorbs water from the process fluid. From the tower, the dried process fluid flows to the outlet filter and out of the dehydrator.

While Tower 2 dries the process fluid, the regeneration gas removes the water from the solid desiccant in Tower 1. The regeneration gas flows through the regeneration gas heater, up through Tower 1, to the regeneration gas cooler, and to the regeneration gas separator. Once the heated regeneration gas has dried the solid desiccant, the regeneration gas bypasses the regeneration gas heater and cools the desiccant.

Gases used for regeneration include:

- Dry product gas
- Gas diverted from the process gas stream (5% to 10% of the main flow)
- Gases from outside the dehydrator, such as demethanizer overhead

In this example, after the adsorbent in Tower 2 is saturated, valves redirect the process fluid and the regeneration gas so that Tower 1 adsorbs and Tower 2 regenerates.

Three-Tower Dehydrators

Solid desiccant dehydrators with three adsorbing towers offer several process flow variations.

The process cycle of three towers may be arranged so that two towers dehydrate in parallel while one tower regenerates. Or, the process cycle may be arranged so that one tower is adsorbing, one tower is regenerating, and one tower is cooling.

Parallel (Split-Flow Design) - Figure 45 shows a three-tower dehydrator with two towers adsorbing in parallel. The process flow of the dehydrator shown in Figure 45 is similar to the flow shown in Figure 44, except that the flow of the process fluid is split between two towers.

A three-bed system (two beds in parallel) may be economical for a large installation since there are three smaller beds rather than two large beds. If three beds (vessels) are less expensive, the vessel savings is then weighed against the additional piping and valves required for a three-bed system. If economic considerations are inconclusive, process advantages or past experiences may dictate this three-tower system. For example, this configuration can be operated continuously with only two towers at reduced throughput, facilitating desiccant replacement on the run.

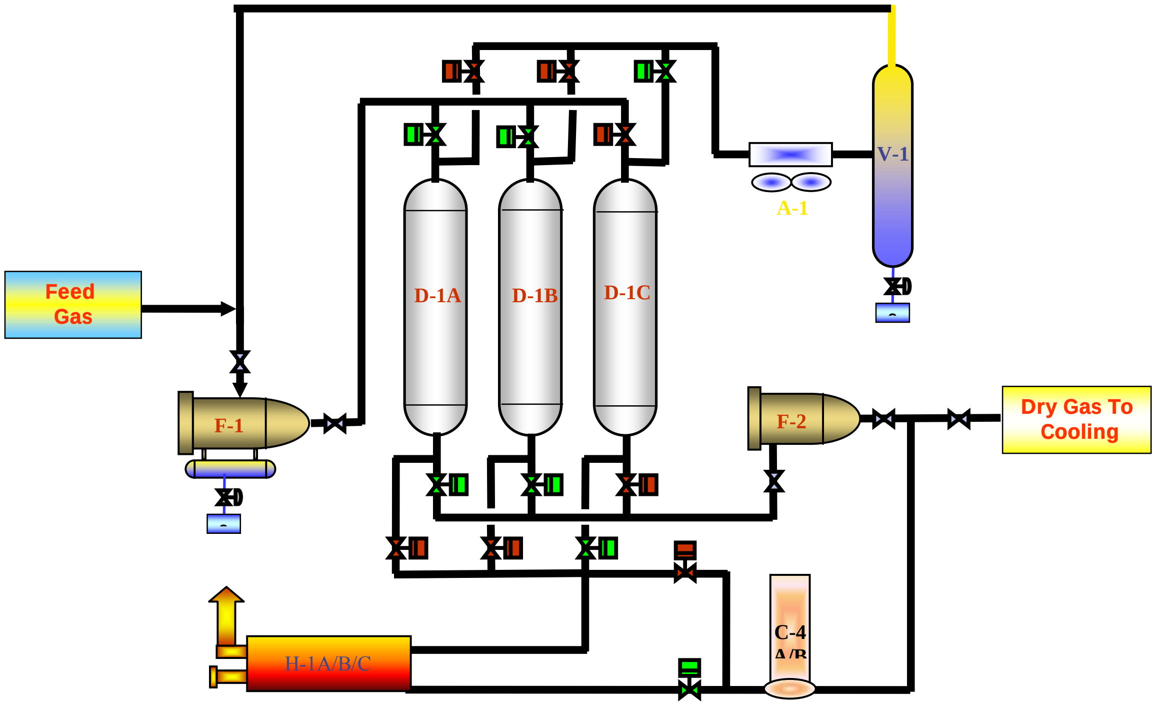


FIGURE 45: PROCESS FLOW OF THREE-TOWER SOLID DESICCANT DEHYDRATOR

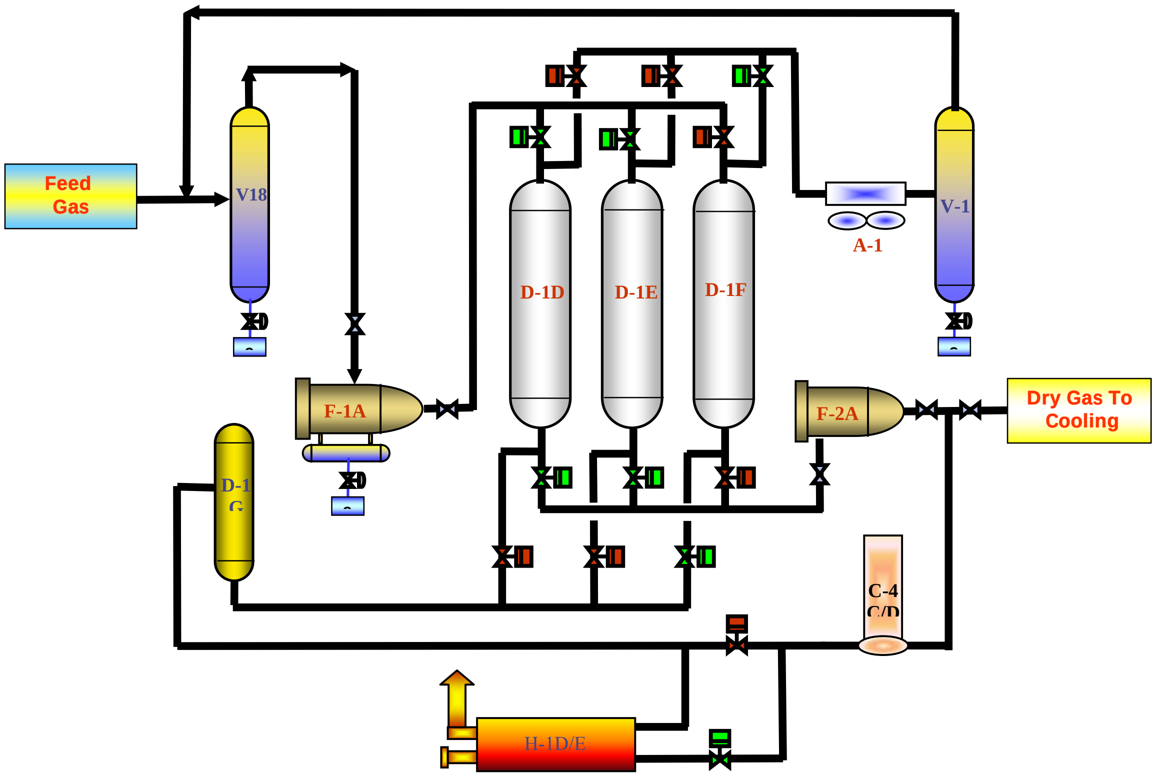


FIGURE 46 PROCESS FLOW OF THREE-TOWER SOLID DESICCANT DEHYDRATOR

Function of Major Components of Solid Desiccant Dehydrators

This section describes the function, design, and operation of the major components of a solid desiccant dehydrator.

The following are the essential components of any solid desiccant dehydration system:

- An inlet gas stream separator/liquid coalescer.
- Two or more adsorption towers (contactors) filled with solid desiccant.
- A high-temperature heater that provides hot regeneration gas to reactivate the desiccant in the towers.
- A regeneration gas cooler that condenses water from the hot regeneration gas.
- A regeneration gas separator (knockout) that removes the condensed water from the regeneration gas.
- Piping manifolds, switching valves, and controls that direct and control the flow of gases according to the process requirements.

Inlet Separator/Coalescer

As with glycol dehydrators, inlet separators protect the dehydrator from impurities such as free water, salt, compressor oils, hydrocarbon liquids, paraffins, corrosion inhibitors, glycol, amines, rust, iron sulfide, iron oxide, fractionation sands, drilling mud, pipeline scale, and sulfur. These impurities impact the desiccant bed and cause breaking and powdering of the desiccant. Methanol (used for hydrate inhibition) can also damage some adsorbents.

Nonvolatile liquids coat the desiccant and block its pores. Solid impurities plug the bed increasing the pressure drop and crushing the desiccant. All of these effects shorten the operating life of the desiccant. If the dehydration unit is downstream of an amine unit, glycol unit, or compressors, a filter-separator or liquid coalescer (for liquid service) may be needed.

Adsorber Tower

The adsorber tower holds the solid desiccant and contacts it with the process fluid. Figure 47 shows a typical adsorber tower.

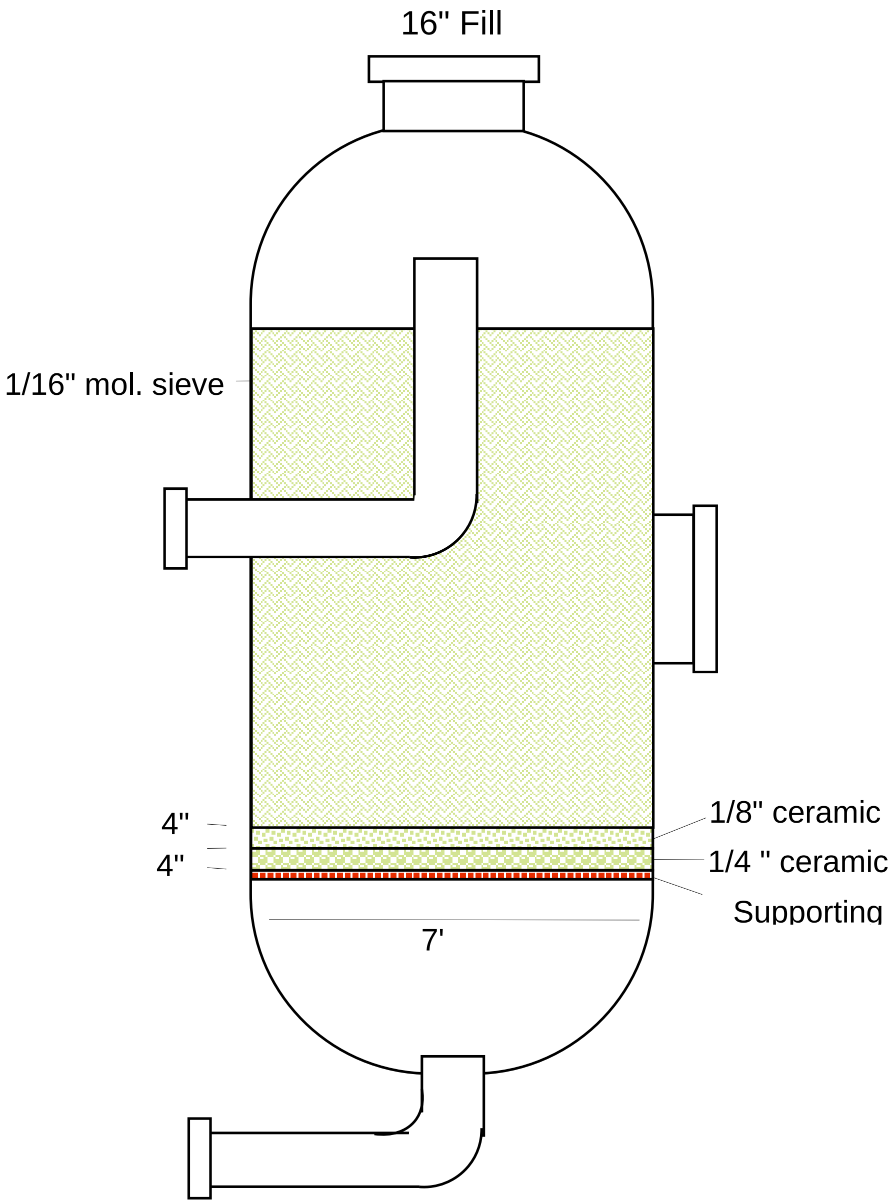


FIGURE 47: ADSORBER TOWER

Three problems that frequently cause poor operation are insufficient distribution, inadequate insulation, and improper bed supports.

Distribution - Poor gas distribution at the inlet and outlet of the desiccant beds can cause gas channeling and desiccant damage. The inlet gas distributor should be provided with adequate baffling before the gas enters the desiccant bed. Neither the gas to be dehydrated nor the regeneration gas should impinge directly on the bed nor should there be any sudden changes of direction near the surface of a desiccant bed. When the bottom head of the vessel is filled with support balls, a gas distributor may be needed between the balls and the lower portion of the desiccant bed when upflowing heating or cooling is used. This distributor should be used particularly on very large diameter vessels to prevent gas channeling and poor reactivation of the desiccant. Channeling, high localized velocities, and swirling can cause desiccant dusting (breakage) and high pressure drop through the desiccant bed. The lodging of the desiccant dust between the standard-size particles increases the pressure drop.

Inert balls are also required on top of the adsorbent bed to prevent bed movement resulting from high fluid velocities. The use of a 6" layer of these inert balls is recommended. A floating screen should be placed between the inert balls and the adsorbent to prevent the migration of inert balls to the interior of the bed. This migration is caused by the cyclic nature of the adsorption process.

Insulation - Internal or external insulation for the adsorber may be used. The main purpose of internal insulation is to reduce the total regeneration-gas requirements and costs. Internal insulation reduces heat transfer to the adsorber vessels. Normally, a castable refractory lining is used for internal insulation.

The refractory must be applied and properly cured to prevent liner cracks. Provision must also be made for expansion and contraction of the internal insulation so that there will be no cracking or weld failures. Liner cracks permit some of the wet gas to bypass the desiccant bed. Only a small amount of wet, bypassed gas can cause freezeups in cryogenic plants.
Ledges installed every few feet along the vessels wall can help eliminate bypassing. For heating cycles longer than two hours, provision should be made for heat transferred to the vessel shell and heads.

Bed Supports - The bed support can be in the form of a mechanical grid, such as subway type grating on I-beams , The grid must be of sufficient strength to support the adsorbent bed, inert balls, and the bed pressure drop. A set of wire screens, sized to retain the adsorbent particles, should be fastened on top of the grid. The screens (usually stainless steel) are fastened in place by tying them to the support gridwithstainlesssteel wire. To prevent the loss of desiccant and support balls through the gap between the vessel and the wire screen, this gap is sealed using some suitable rope-like material (typically asbestos) that can withstand the regeneration temperatures and the process/regeneration gas fluid.

Several layers of inert support balls are required between the adsorbent and the wire screens to prevent grinding between them. These layers also prevent desiccant dust or whole particles from plugging the screen openings. Normally, for 1/8-in. desiccant, a 2-3 inch layer of 1/2-in. balls is gently placed on the screen followed by a smooth 2-3 inch layer of 1/4-in. balls. For 1/16-in. desiccant (commonly used for liquid dehydration), an additional layer of 1/8-in. balls are placed on top of the 1/4-in. balls. This complies with the 2:1 ratio between the layers as recommended by the desiccant vendors.

Regeneration Gas Heater

The regeneration gas heater heats the regeneration gas to about 500°F. Solid desiccant dehydrators use many types of heaters including salt bath, direct fired, hot oil, and steam.

Small units (8 MMBtu/hr) generally use indirect-fired, salt bath heaters for safety reasons.

Larger units tend to use direct-fired heaters. In addition, other sources of heat are used including compressor-exhaust gases and waste heat from turbines and other heat sources.

Regeneration Gas Cooler

Regeneration gas coolers reduce the temperature of the regeneration gas to condense the adsorbed water and, sometimes, hydrocarbons. Cooling the regeneration gas also prepares it for further processing.

Coolers are heat exchangers that use air, water, or natural gas to cool the regeneration gas.

Typically, they use ambient air to cool the regeneration gas to within 15°F to 20°F of the air temperature.

Regeneration Gas Separator

Regeneration gas separators remove liquids condensed by the regeneration gas cooler from the regeneration gas. If the liquid is primarily water, then a two-phase separator, similar (except smaller), to the inlet separator is used. If the liquid contains substantial amounts of hydrocarbons, then the dehydrator requires a three-phase separator to remove the liquid from the gas stream and separate the liquid into water and hydrocarbons.

Switching Valves

Switching valves direct the process fluid and regeneration gas to the appropriate component of the dehydrator. Two-way valves leak less than three-way valves. Switching valves are in a harsh operating service as they must operate with all combinations of cold gas and hot gas on either side of the valve. This temperature cycling can cause valves to stick and/or leak.

Valve sequencing and opening times are also important to prevent a sudden upflow of gas which could fluidize the bed and damage the desiccant. Switching valves require frequent servicing to eliminate leakage.

Instrumentation

The monitoring of solid desiccant dehydrators requires a variety of instrumentation to measure or control the following process variables:

- Flow rate, temperature, and pressure of the process fluid
- Water content of the product fluid
- Flow rate and pressure of the regeneration gas
- Inlet and outlet temperatures of the regeneration gas
- Temperature of the regeneration gas leaving the regeneration gas cooler
- Adsorbent differential bed pressure
- Cycle time controllers

Measuring the flow rate, temperature, and pressure of the inlet gas monitors the load on the dehydrator. Monitoring the temperature and water content of the outlet gas measures the performance of the dehydrator. Measuring the conditions of the regeneration gas and the regeneration cooler monitors the efficiency of the regeneration cycle.

A moisture sample probe should be located in the adsorbers in cryogenic plants several feet from the outlet end of the bed and extend to the center. This probe, used in conjunction with the outlet-gas moisture probe, offers valuable flexibility in studying and solving dehydrator problems. If gas is channeling through the desiccant bed a high dew point is seen in the outlet gas. However, unless the gas is channeling through the bed at the exact point where the sample probe is located, the desiccant surrounding the probe will ensure that the probe will continue to “see” only dry gas. The probe also permits capacity tests for optimizing drying cycle times. These tests can be conducted with reasonable safety because movement of the water front can be detected prior to breakthrough.

Temperature recording devices plot the temperature of the regeneration gas entering and exiting the adsorber tower against the elapsed time of the cycles.

It is important to monitor bed differential pressure. An increase in differential pressure can indicate desiccant problems such as excessive plugging or the formation of fines.

Effects of Key Process Variables on the operation of a Solid Desiccant Dehydrator

This section covers the following key process variables that affect the performance and operation of solid desiccant dehydrators:

- Direction of process fluid and regeneration gas (downflow vs. upflow)
- Quality of inlet process fluid (level of contamination, including free water)
- Temperature of process fluid and regeneration gas
- Pressure of process gas and regeneration gas
- Adsorption, heating and cooling cycle times
- Velocity of process fluid and regeneration gas
- Regeneration gas source (wet or dry)
- Special liquid service considerations

Direction of Gas Flow

The following section discusses the effects of the direction of flow of the process fluid on dehydrator performance during the drying, regeneration, and cooling cycles. The flow direction influences effluent purity, regeneration gas requirements, and desiccant life.

Drying Cycle

Normally, gas flows down through adsorber towers during the drying cycle. Increasing the rate of upward flow of gas through a tower fluidizes the adsorbent bed. Any such unsettling or movement can erode and/or crack the desiccant which decreases the drying performance and life of the desiccant, and generates desiccant fines. Also, downward flow allows higher velocities, which allow smaller and less expensive towers.

Conversely, hydrocarbon liquids normally flow up through adsorber towers. Hydrocarbon liquid streams frequently contain some gaseous components. Upward liquid flow allows any gas bubbles to pass through the desiccant bed. Downward liquid flow allows these gaseous components to accumulate at the top of the tower. This accumulation reduces the amount of desiccant exposed to the hydrocarbon liquid decreasing the effective capacity of the tower.

Sometimes downward liquid flow is also used to avoid early breakthrough of water. This is particularly true when the water content of the liquid is high. Choice of upflow versus downflow is also dictated by the flow magnitude of the streams to be dried.

Regeneration (Heating) Cycle

Normally, regeneration gas flows in the direction opposite of the process fluid in the drying cycle. For drying hydrocarbon gas, this direction is up through the adsorber tower. If the regeneration gas flows in the same direction as the process fluid, then regeneration gas must displace the water and contaminants concentrated at the top of the bed down through the entire bed. Same direction flow risks the contamination of the rest of the adsorbent bed and can require longer regeneration times. Typical regeneration flow direction for liquid dehydrators is downward.

With regeneration gas flowing in the direction opposite of the process fluid in the drying cycle, the hot regeneration gas in the lower part (upper part for hydrocarbon liquids) of the bed strips contaminants from the desiccant. If the hot regeneration gas sufficiently increases the partial pressure of the contaminants, the contaminants will desorb off the desiccant. This flow direction also produces extremely dry adsorbent at the bottom of the adsorber tower.

During the dehydrating cycle, this dry adsorbent removes the last amounts of water from the process fluid and produces effluent with very low water contents. If the contaminants do not desorb off the desiccant, they will build up and potentially coke or polymerize.

Cooling Cycle

If a system uses wet gas for cooling, then the cooling gas flows in the same direction as the process fluid. This partially preloads the desiccant bed with water. The additional water load deposited during cooling must be included when the amount of desiccant required is calculated.

If a system uses dry product gas for cooling, then the cooling gas flows in the direction opposite of the process fluid. This direction of flow results in more complete desiccant regeneration.

Quality of Inlet Gas (Process Fluid)

The relative saturation of the inlet gas is the most important variable in determining the weight of desiccant to use. The use of wet gas to regenerate a desiccant bed does not remove all of the water from the bed. Therefore, the use of wet gas requires the determination of the residual capacity of the desiccant bed. The residual capacity of the desiccant bed is the difference between the dynamic capacity of the desiccant bed and the weight percent of water left in the desiccant bed after the wet gas has regenerated it. This variable is the driving force that affects the transfer of water to the adsorbent. If saturated gas (100% relative humidity) is being dried, a much greater useful capacity can be expected for most desiccants than when partiallly saturated gases are being dried. The exception is the molecular sieve. Its equilibrium curve is almost flat from 20% to 100% relative humidity.

Contaminants

The most important variable affecting the decline rate of desiccant capacity is the chemical composition of the gas or liquid to be dried. Compressor oils, corrosion inhibitors, glycols, amines, and other high-boiling contaminants may be present in the feed gas. Normal regeneration temperatures do not vaporize the heavy materials. The residual contaminants slowly build up on the desiccant's surface, reducing the area available for adsorption. Many corrosion inhibitors chemically attack certain desiccants and permanently destroy their usefulness. Silica gels shatter when free water or hydrocarbon liquids are carried into the beds.

Methanol in the inlet gas is a major contributor to the coking of molecular sieves where regeneration is carried out at temperatures above 550°F. Polymerization of methanol during regeneration produces intermediates which cause coking of the beds. An Exxon affiliate that had been using substantial amounts of methanol to inhibit hydrate production in a two-phase system experienced rapid declines in sieve life because of coking. Conversion to ethylene glycol injection for hydrate control has greatly increased sieve life and added at least 10% to sieve capacity.

Temperature

The higher the temperature of a process fluid, the greater its saturated water content. Solid desiccants have significantly higher adsorbing capacity at lower temperatures.

Regeneration gas may be combined with the incoming wet gas ahead of the dehydrator. If the temperature of these gases differs by more than 15 to 20°F then water and hydrocarbons may condense out of the warmer gas stream. High regeneration-gas temperatures assure good desorption of water and contaminants. Regeneration gas condenser temperatures should be as low as possible to condense and remove water and heavy hydrocarbons from the gas.

If a dehydrator uses wet gas to cool its desiccant, overcooling the desiccant causes the solid desiccant to adsorb water from the cooling gas and presaturate the adsorbent bed. The cooling cycle should be ended when the desiccant bed reaches about 125°F. If dry gas is used for cooling the desiccant may be cooled to within 10 to 20°F of the feed gas temperature.

Pressure

The adsorptive capacity of a desiccant bed unit decreases as the pressure is lowered when adsorbents are operating below saturation capacity. Also, the water content of a gas increases as the pressure is lowered. If the dehydrators are operated well below design pressure, the drying cycle time is shortened to counter the reduced driving force and to remove the increased mass of water in order to maintain the desired effluent dew point. The same mass flow rate of incoming gas at a reduced pressure increases gas velocity and increases the bed pressure drop. Excessive pressure drop causes dusting (adsorbent breakage) and damage to the desiccant. At pressures above 1,300 psia to 1,400 psia, the coadsorption effects of hydrocarbons sometimes become significant.

Cycle Time

The drying cycle time is the runlength of the drier before it requires regeneration. The design drying cycle sets the drier water loading and, hence, drier size. Since desiccant capacity decreases with age (number of regenerations) initial cycle times are considerably longer than design cycle times. Design cycle times are used to establish when desiccant replacement is necessary. The design cycle time is approximately equal to the regeneration time at the design flow rate. Therefore, when less time is required to saturate a desiccant than to regenerate it, either the dessiccant must be replaced, or the flow rate decreased.

Typically, the adsorption cycle is operated on a fixed time. Fixed time cycles are common as are dehydrator installations that switch beds on water breakthrough measurements. As the desiccant ages, the cycle time must be shortened to prevent water breakthrough. More regenerations reduce desiccant life, thus, a compromise between cycle time and cycle frequency must be achieved. The cycle length should provide an economic balance between cost of the drier and regeneration facilities, and regeneration frequency, which affects desiccant life and operability.

Listed below are the steps required in the regeneration cycle and the approximate time required to perform these steps. Some of these steps are unique to a particular service. This information will aid the designer in establishing a drying cycle, or if the drying cycle, is already set, it will indicate the available time for heating and cooling.

		Approximate Time*
1.	Depressure:	1 hour
2.	Drain (for liquid drying only):	1 hour
3.	Cold Purge (not always performed, discussed below):	1 hour
4.	Heat to Regeneration Temperature:	Variable
5.	Heat Soak (not always performed, discussed below):	1-2 hours
6.	Cool to Temperature Approaching Drying Temperature:	Variable
7.	Fill (for liquid drying only)/Pressure:	1 hour

* Where automated regeneration facilities are provided for small size equipment considerably shorter times may be practical.

Gas Velocities

Inlet (Process) Gas

Decreasing the gas velocity during the drying cycle usually achieves both lower effluent moisture contents and longer drying-cycle times. Figure 18 shows the general effect of gas rate on the extent of dehydration. Minimum flow rates utilize the desiccant fully. However, low linear velocities require towers with large cross-sectional areas. In selecting the linear flow rate, a compromise must be made between the tower diameter and the maximum utilization of the desiccant. A high linear flow rate causes agitation of the granules, dusting and loss of capacity to adsorb. In addition, fluidization can occur if the gas velocity (or liquid in the case of liquid drying) upwards through the bed exceeds the fluidization velocity.

Regeneration Gas

Producing very low effluent water contents (less than 0.1 ppm) requires sufficiently high regeneration gas velocities. Low gas velocities produce channeling which results in poor regeneration. Frequently, achieving very low effluent water contents requires regeneration gas velocities of at least 10 ft/min.

Regeneration Gas Source

The source of gas for heating and cooling desiccant beds depends on plant requirements and, possibly, on the availability of a suitable gas stream. Using dry regeneration gas produces effluent with low water contents. Using wet feed gas results in moderate effluent water contents. Graphs plotting isoteres (lines of constant water loading) can be used to predict the regeneration gas conditions required to achieve a given effluent water content.

The effectiveness of reactivation can also play a major role in retarding the decline of a desiccant adsorptive capacity and in prolonging its useful life. Not removing all of the water from the desiccant during each regeneration sharply decreases its usefulness. For example, if the dynamic adsorptive capacity of a thoroughly reactivated desiccant is 10%. A 3% residual water remaining on the desiccant because of insufficient regeneration, would cause its capacity to drop from 10% to 7%.

Although gases rich in heavier hydrocarbons may be dried satisfactorily with molecular sieves, the use of this same rich gas in a 500° to 600°F regeneration service aggravates coking problems. Lean dry gas is always preferable for regeneration.

Optimizing Adsorption-Type Dehydrators

Desiccant Performance

Operating data should be monitored to try to prevent permanent damage to the desiccant. Performance tests are frequently scheduled on a routine basis, ranging from monthly during early operations, to six months or longer. The size of the unit and the quantity of the desiccant also affect the frequency of performance tests.

Desiccants decline in adsorptive capacity at different rates under varying operating conditions. Markedly different capacity-decline rates may be experienced for the same desiccant under similar conditions of gas flow, temperature, pressure, water removal requirements, cycle times, and regeneration temperatures. Desiccant aging is a function of many factors, including the number of cycles experienced and exposure to any harmful contaminants present in the inlet stream. Many of these contaminants are not completely removed during normal reactivation. Contaminants may be the cause of 90% of unsatisfactory solid desiccant operations. Therefore, the single most important variable affecting the decline rate of desiccant capacity is the chemical composition of the gas or liquid to be dried. Feed stream composition should always include the contaminants.

The capacity of a new desiccant will decline slowly during the first few months in service because of cyclic heating, cooling, and wetting. Desiccant capacity usually stabilizes at about 55 to 70% of the initial capacity. To get maximum use out of the desiccant, a moisture analyzer can be used to optimize the drying cycle time. That time can be shortened as the desiccant ages. Both inlet and outlet moisture-analyzer probes should be used. Moisture analyzers for very low water contents require care to prevent damage to the probes. Sample probes and temperature probes must be installed to reach the center of the gas phase.

Proper conditioning of the inlet gas is important. Compressor oils, corrosion inhibitors, glycols, amines, and other high-boiling contaminants present in the feed gas cause a further decline in desiccant capacity, because normal reactivation temperatures will not vaporize the heavy materials. The residual contaminants slowly build up on the desiccant's surface, reducing the area available for adsorption. Many corrosion inhibitors chemically attack certain desiccants, permanently destroying their usefulness. A layer of less expensive desiccant can be installed on the top of the bed to catch these contaminants.

Although gases rich in heavier hydrocarbons may be dried satisfactorily with molecular sieves, the use of this same rich gas in a 550 to 600°F regeneration service aggravates coking problems. Lean dry gas is always preferable for regeneration, if it is available.

Methanol in the inlet gas is a major contributor to the coking of molecular sieves where regeneration is carried out at temperatures above 550°F. Polymerization of methanol during regeneration may produce dimethyl ether and other intermediates that will cause coking of the beds.

Monitoring bed differential pressure is important. An increase in differential pressure can indicate desiccant problems such as excessive coking or the formation of fines. The differential pressure along with the bed run length should also be recorded when doing a performance test on a desiccant bed.

The useful life of most desiccants ranges from one to four years in normal service. A longer life is possible if the feed gas is kept clean. The effectiveness of reactivation can also play a major role in slowing the decline of a desiccant's adsorptive capacity and in prolonging its useful life. Obviously, if all the water is not removed from the desiccant during each regeneration, its usefulness will sharply decrease.

Performance data are used for monitoring desiccant life and planning for desiccant change out. The steps involved are as follows:

- Plot plant capacity and cycle time versus number of cycles.
- Extrapolate to determine when shortest cycle possible with existing regeneration equipment will be reached.
- At that point, or during the nearest regular plant turnaround preceding that point, an adsorbent change must be planned.

Regeneration gas not only supplies heat but also acts as a carrier to remove water vapor from the desiccant bed. Insufficient reactivation can occur if the regeneration gas temperature or velocity is too low. The desiccant manufacturer will generally recommend the optimum regeneration temperature and velocity for the product. Velocity should be high enough to remove the water and other contaminants quickly. This measure will minimize the amount of residual water and protect the desiccant.

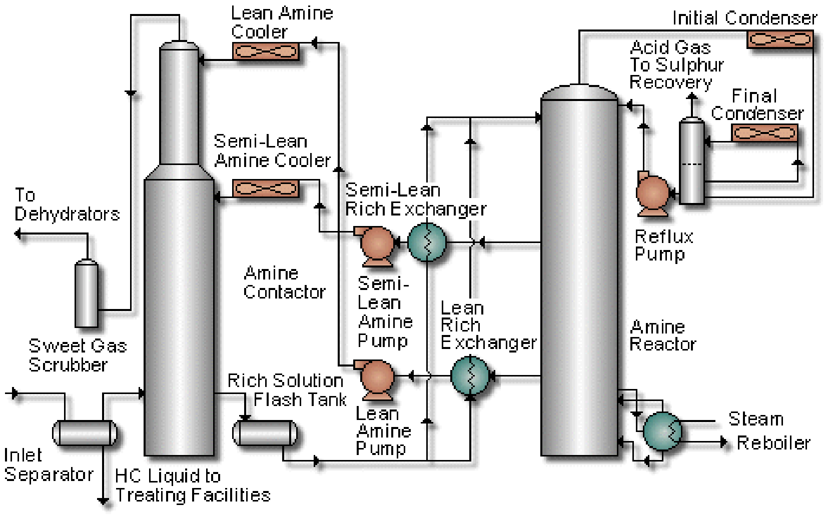
To maximize desiccant capacity and to ensure the minimum effluent moisture content, a higher reactivation temperature or a drier reactivation gas, or both, may be needed. Higher reactivation temperatures may also be used to remove volatile contaminants before they can form coke on the desiccant. The final effluent hot gas temperature should be held one or two hours to achieve effective desiccant reactivation.

Equipment Items

In addition to the above process variables, engineers can optimize solid desiccant dehydration equipment by considering the following:

- An accurate estimation of bed sizes in order to realistically evaluate competitive bids from desiccant vendors.
- Optimal design of adsorber internals (inlet gas distributor, internal insulation and bed supports), switching valves, and control systems.
- Proper design of regeneration gas systems.
- Since mole sieve can produce dust, filters are frequently installed downstream to protect subsequent equipment.

Sweetening processes
And sulfur recovery



Sweetening processes and sulfur recovery

Contents:

Gas Sweetening

Sour Gas contains either components H_2S or CO_2. H_2S is by far the most dangerous but CO_2 can cause problems with solids formation in compression and cooling. Both these components are acid gases and are removed by similar "sweetening" processes.

Introduction

Quality requirements for gas entering LNG plants include:

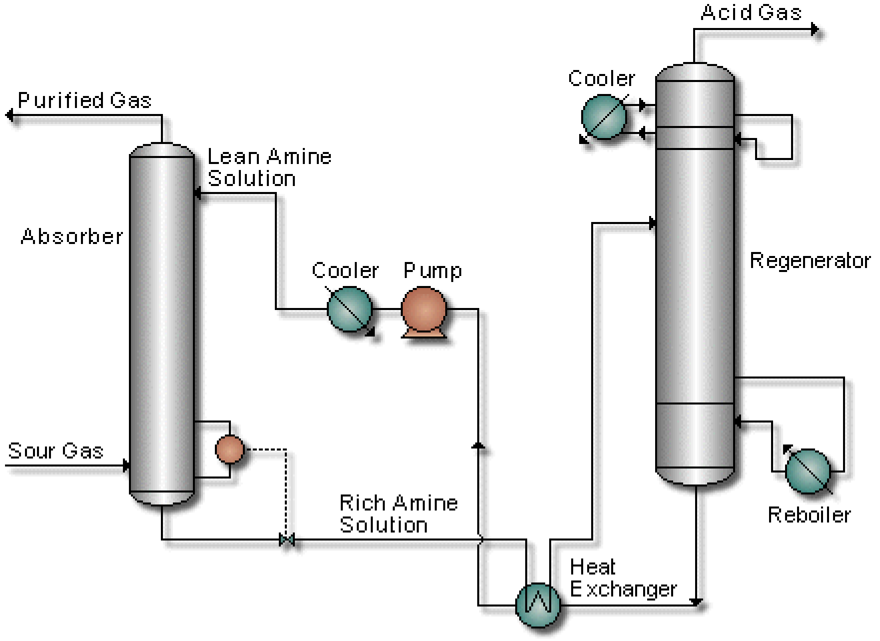
i) Shall not contain more than 23 mg of H_2S per m^3. (16 ppmv)

ii) Shall not contain more than 115 mg of total Sulphur per m^3

iii) Shall not contain more than 2% by volume of CO_2.

- sweetening processes remove sour and undesirable gases from the gas stream:

H_2S - Hydrogen Sulphide
CO_2 - Carbon Dioxide
COS - Carbonyl Sulphide
CS_2 - Carbon Disulphide



Basic Flow Diagram of Amine Treating Process for CO_2 and H_2S Removal

Reasons for Sweetening

- Safety and Environmental Protection
- Product Specification (see above)
- Corrosion Prevention
- Improved Heating Values

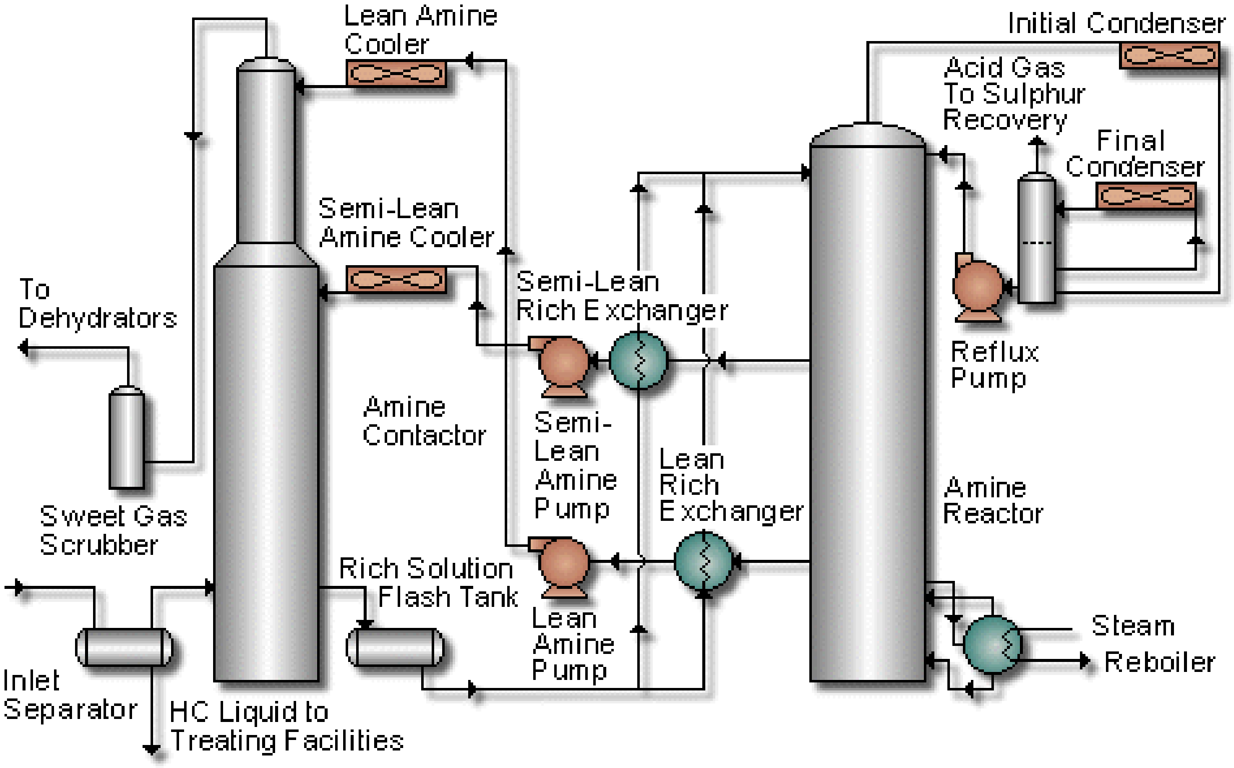
- CO_2 Solid formation (cryogenic operations)
- Economics (sometimes)

- sour gas is supplied to the sweetening system from the inlet separator and the condensate stabilizer.
- sour products recovered in this process are further processed in a sulphur recovery unit (SRU)
- if the volume is low enough (less than 1 tonne of sulphur per day in the inlet gas), the gases are incinerated and released to atmosphere as CO_2 and SO_2.
- various types of sweetening processes are employed in industry today. All processes utilize a solid or liquid desiccant to recover the sour component. After the desiccant has recovered the sour component it must be regenerated to release the sour components so it can be reused.
- The most common liquid desiccants in use are “amines”.

Process Flow

Amine systems tend to be located in a central plant to service the entire sour gas production for a field.

A typical amine sweetening process is shown in the following diagram.



Inlet Separator

- Removal of liquids and/or solids
- Separator should be sized to handle surge capacity. Poor separator design can cause problems in the treating facilities.

Contactor

- Sour gas enters the bottom of the tower and moves upward through the trays
- H_2S and CO_2 in the gas react with the liquid amine solution and are removed from the gas stream.
- The reaction is often assisted by placing fresh lean amine on various trays down the tower. This ensures that the gas will contact lean amine a few times as it moves up the tower.(This is not shown on the diagram).
- As the sweet gas leaves the tower, it is often contacted with water to remove any amine that has vapourized and is travelling with the gas. The top 2 or 3 trays may be used for this function. This is considered a "water wash" section of the tower.
- The water wash is often used if the contactor temperature is especially high or if MEA is used as the amine.

Outlet Separator

- The sweetened gas is passed through a separator to remove any amine solution (or liquid water) that may be travelling with the gas flow
- The gas is now saturated with water and must proceed through dehydration facilities to lower the water dew point before sale.

Flash Drum

- From the contactor, the amine may enter a flash drum to allow any hydrocarbon an opportunity to leave the amine solution.

Heat Exchanger (HTEX)

- The rich amine passes through a heat exchanger where it picks up heat from the hotter lean amine on its way to the contactor.
- Since this service is clean, plate and frame exchangers can be used, but often a more common shell and tube exchanger is put in service.

Stripper

- The rich amine enters the stripper, where hot acid gas and steam heat the rich amine, removing the H_2S and CO_2 that is bound into the product.

Reboiler

- The amine at the bottom of the stripper tower is heated to 105^oC – 140^oC (depending on the type of amine being used).
- This causes the acid gas/amine reaction to reverse and the acid gas vapourizes with steam from the amine solution.

- The acid gas/steam vapour re-enters the stripper and contacts new rich amine on its way out the top. Amine carried with the acid gas/steam vapour tends to reunite with the rich liquid amine thereby removing it from the vapour flow.

Condenser

- After leaving the top of the stripper tower, the acid gas/steam vapour is cooled to remove heat and condense out the water from the flow.
- The water is separated in a reflux drum and returned to the stripper tower as a liquid.
- The acid gas vapour is sent downstream to a Sulphur Recovery Unit (SRU).
- If the plant has a gas sulphur inlet rate of less than 1 tonne/day (this is a very small amount), the acid gas may be incinerated. Burning the H_2S creates SO_2 which is a monitored pollutant.

Reclaimer

- a reclaimer may be used in MEA or DGA service.
- A reclaimer heats a slipstream of the amine from the reboiler to higher temperatures. In MEA service, a caustic solution is added to increase the pH of the mixture.
- This higher temperature (and higher pH) cleans out some products of “side reactions” and an amine sludge is created. This must be disposed of properly.

Rich Amine

The amine picks up H2S and CO2 in the contactor tower.

Lean Amine

- A lean amine stream from the bottom of the reboiler (or bottom of the tower) is pumped back to the contactor.
- The lean amine is often passed through a charcoal filtration system to remove entrained solids
- If anti-foam additives are added to the system, the charcoal filters will remove them, so they should be taken off-line during addition.
- The lean amine must be cooled to approximately 6^{o}C warmer than the inlet gas temperature before it enters the contactor.

Sulphur Recovery unit

Acid Gas Options

The acid gas stream from the sweetening unit contains mainly H2S and CO2. The proportion of each will depend on the inlet gas composition and the type of amine that you are using.

The H_2S in the acid gas is very toxic (and smelly) so it could not possibly be released to the atmosphere without some further processing.

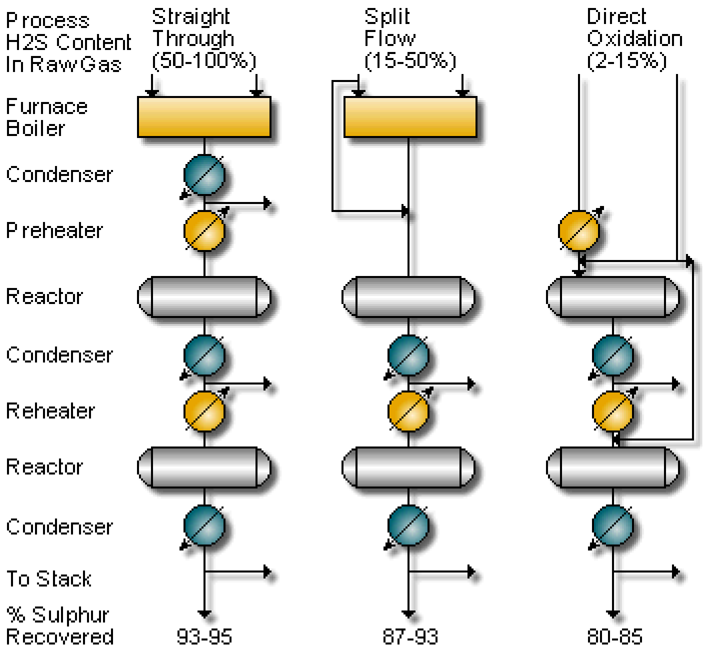
The options facing an operator are:

1. Re-inject the acid gas into a formation.
2. Burn the acid gas, converting the H_2S into SO_2. Release the SO_2 to the atmosphere.
3. Convert the H_2S into elemental sulphur (S). Sell the sulphur into the world market. The most common method of converting H_2S into S is the Claus process.

Modified Claus Process

- If H_2S is reacted with oxygen (burned), it will form SO_2 and water. This is a very exothermic reaction – it creates a lot of heat. Even though SO_2 is not as deadly as H_2S, it is still a pollutant that can have adverse health effects in high concentrations. Therefore creating SO_2 is undesirable.
- The "Modified Clause Process" was developed in 1937 and involves a Combustion Reaction & Catalytic Reaction (in stages)
- The combustion reaction occurs in a reaction furnace where acid gas from the sweetening system is reacted with oxygen to form H_2O and SO_2,
  But….
- Only 1/3 of the H_2S is converted. This means that only enough oxygen (air) is fed into the reaction to convert 1/3 of the H_2S stream to SO_2.
- This gas is then cooled and any pure sulphur that has formed is condensed out.
- The gas mixture is then reheated and fed into a vessel with a catalyst bed of activated alumina. The remaining H_2S and SO_2 react with each other to form elemental sulphur (S) and H_2O.

$$2H_2S + SO_2 \rightarrow 2H_2O + 3S$$



Processes for Sulphur Recovery

- This creates more heat as the reaction occurs. Therefore, as the gas mixture leaves the first catalytic reactor, it is cooled and sulphur condenses out and drains to a holding tank (usually heated with steam coils and located underground).
- The remaining gas is again reheated and enters a second reactor where the same reaction takes place.
- Depending on the amount of conversion required, 3 or 4 reactor vessels may be employed. (Four reactors is uncommon)

- Acid gas is made up of $H_2S + CO_2$ and often contains small amounts of hydrocarbons also. The efficiency of the Modified Claus Process depends on the concentration of the H_2S in the acid gas (because of partial pressures).
- If the concentration of acid gas is high – say > 80% by weight, then you could expect the following conversion efficiencies as the acid gas works its way through the process:

Initial reaction furnace → 62% of the H_2S converted to S
1st catalytic bed → 86% of the H_2S converted to S
2nd catalytic bed → 93% of the H_2S converted to S
3rd catalytic bed → 97% of the H_2S converted to S
4th catalytic bed → 98% of the H_2S converted to S

- Lower conversion percentages can be expected with lower concentrations of H_2S because of lower partial pressures – reactions are slower.
- You can see that sulphur is created in the reaction furnace. This is because the H_2S and SO_2 start to react on their own without help from any catalyst.

The H_2S product is then processed in a Claus Plant.

reaction (1) $2 H_2S + 3 O_2 \rightarrow 2SO_2 + 2 H_2O$

reaction (2) $SO_2 + 2 H_2S \xrightarrow[\text{catalyst}]{\text{Alumina}} 3S \text{ (stockpile)} + 2 H_2O$

• Tail gas is gas that exits the Claus plant with residual SO_2. It may be cleaned up according to environmental restrictions.

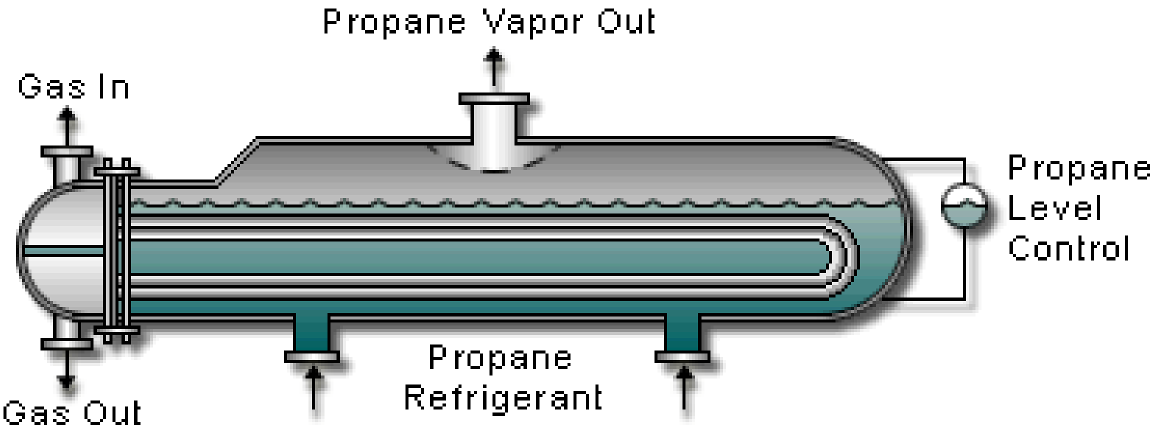
Mercury removal

The amalgamation of mercury and aluminum causes weak spots which will fail and cause leak . in is difficult to continue the process of making LNG when this occurs . To prevent this , mercury guard system have been established which remove mercury according to the reaction

$$Hg + S \xrightarrow{\text{Active S}} HgS$$

Mercury sulghied is then adsorbed on the activated carbon bed which must be replaced periodically after the bed is spent (usually each 6 years) .

Refrigeration



Refrigeration

Contents:

Refrigeration

5.1 INTRODUCTION

Refrigeration, by definition, is the process of moving heat from one temperature level to a higher temperature level. The heat at this higher temperature level is then rejected to a secondary medium.

Refrigeration, or cooling of the process stream, occurs because in changing its state from liquid to vapour, the refrigerant absorbs its latent heat from the process stream.

ECONOMICS OF LIQUID SEPARATION

The value of a natural gas stream is determined by the component make-up along with the demand and availability of users for the components. In some locations this means selling the dehydrated gas as a single product. For other markets it means liquefying and separating the heavier gases from the methane and selling the liquids as separate products.

Several different processes have been used to liquefy and separate the heavier gases. Three processes: lean oil absorption, refrigeration and cryogenics, are the most common in the gas processing industry. The appropriate process for a facility is determined by the make-up of the natural gas stream, available gas pressures and market for separate products.

Lean Oil Absorption

This process is one of the oldest separation processes, but it is still in use. High percentages of propane (90 – 95%) and heavier hydrocarbons (98 – 100 %) can be separated and recovered with this process. Lean oil absorption, however, can recover little or none of the ethane.

In this process heavier hydrocarbons are absorbed by the lean oil when it comes in contact with the natural gas stream. The oil with the trapped hydrocarbons must then be stripped to recover the heavy hydrocarbons and prepare the oil for recycling. The heavier hydrocarbons are recovered by raising the temperature of the oil mixture. This activity along with necessary pumping requires large amounts of energy. Because of this requirement, lean oil absorption is not very energy efficient and therefore relatively expensive to operate.

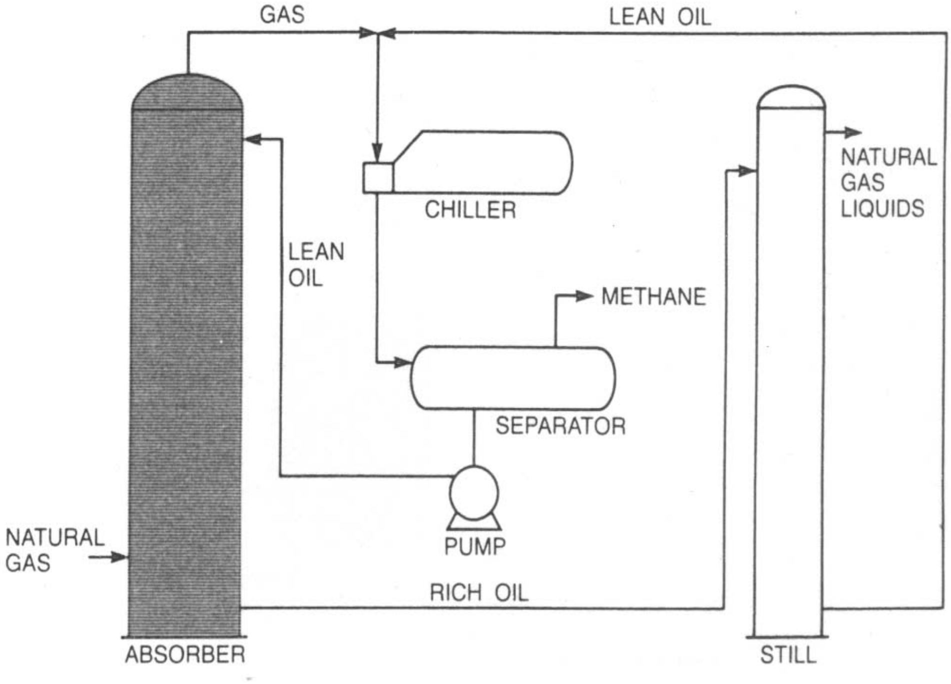


Figure 5.1 Lean Oil Absorption

Refrigeration

This process also has been in use for many years. Refrigeration separates about the same volume of propane and heavier hydrocarbons as lean oil absorption. In addition, it can recover small amounts of ethane.

Refrigeration cools the natural gas stream by passing the stream through a chiller. Chilling causes the heavier hydrocarbons to liquefy and these can then be separated from the gas.

The energy requirements are for compressing the refrigerant and driving the condenser. While the volume of heavier hydrocarbon recovery is somewhat less than lean oil absorption, the amount of equipment and energy used with refrigeration for recovery is much less.

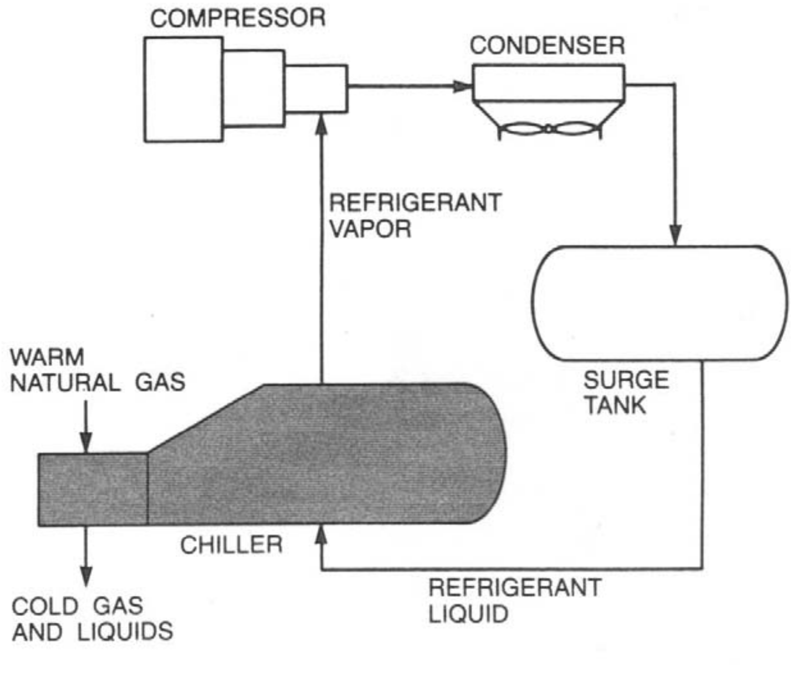


Figure 5.2 Refrigeration

Cryogenics

This is the newest of the three processes. Cryogenics can separate and recover similar quantities of propane and heavier hydrocarbons as lean oil absorption. However, cryogenics, unlike the other methods, can recover very high quantities of ethane (80 – 95 %).

Cryogenics cools a natural gas stream to extremely low temperatures to liquefy the ethane and heavier hydrocarbons. The liquids are then separated from the methane. While requiring additional compression to raise the pressure of the methane, cryogenics has moderate energy requirements when compared to lean oil absorption.

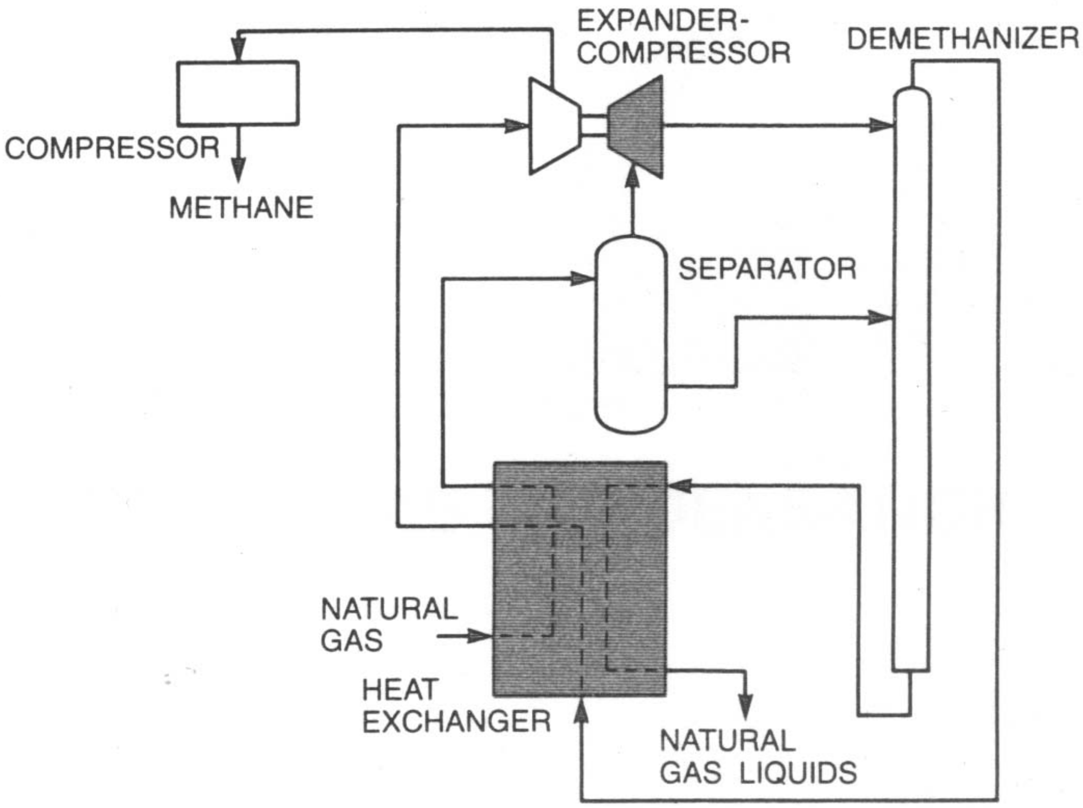


Figure 5.3 Cryogenics

GAS CHILLING

Whenever gas is cooled sufficiently, liquids begin to form. A good example of this separation process is the typical drinking glass. When the glass is filled with ice, condensation forms on the outside surface of the glass. This occurs because the warm moist room air is chilled when it contacts the cold glass and water vapor condenses. The temperature at which water condenses out of the air is called **dew point.** Other examples are clouds, fog or dew.

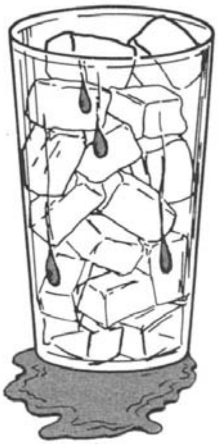


Figure 5.4 Condensation

When natural gas is chilled, some of the heavier hydrocarbon gases condense and separate from the gas. If natural gas is chilled to a very low temperature, e.g., –150 °F (–100 °C), much of the ethane, almost all of the propane and heavier gases will condense. The methane will remain as a gas.

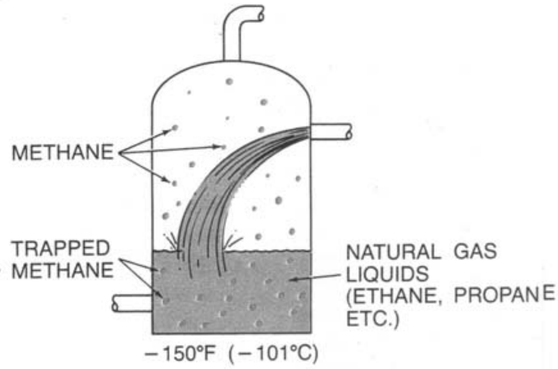


Figure 5.5 Gas Condensation

The chilling process will, however, trap some of the methane in the liquid. This is undesirable because Natural Gas Liquids (NGL's) with high methane content are not marketable. Trapped methane must be removed from the liquid hydrocarbons. Gas chilling operations maximize the amount of ethane or heavier hydrocarbons liquefied but minimize the quantity of trapped methane.

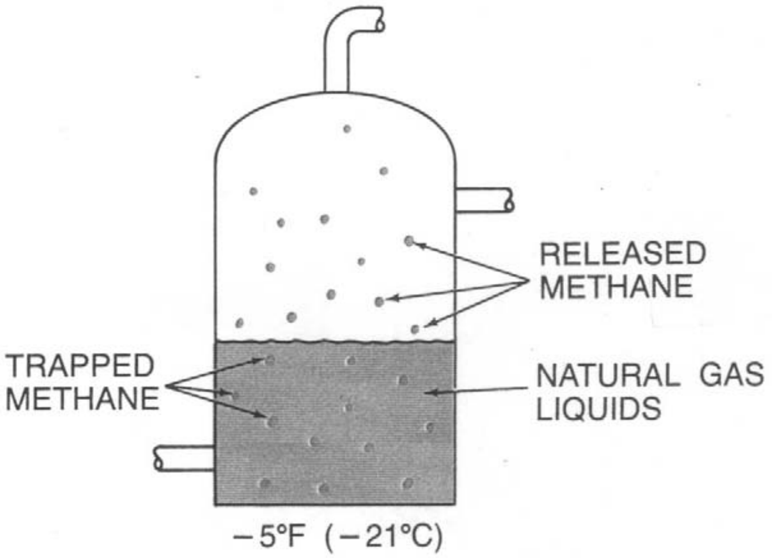


Figure 5.6 Released Methane

The quantity of methane which remains trapped during the chilling process depends on several factors:

- Pressure and temperature of the chilling system. Less methane will be trapped at low pressures.
- Rate at which chilling takes place. More methane will be trapped if the temperature is reduced very quickly.
- Mechanical efficiency of the vessel which separates methane from the liquids. If the separation process of methane from liquids is too warm, not only is the methane released, but so are some of the heavier gases.

Three methods are used for chilling natural gas:

Refrigeration, pressure reduction and expansion, each method is typified by temperature range and recovery efficiency.

Method	Temperature Range	Typical Percent Recovery
Refrigeration	0º to – 20ºF (–18º to – 29ºC)	Ethane 25 Propane 55 Butanes 93 Heavier 97
Pressure Reduction (J-T Process)	– 50º to – 70ºF (– 46º to – 57ºC)	Ethane 70 Propane 80 Butanes 97 Heavier 99
Expander Process	–125º to – 150ºF (– 87º to – 101ºC)	Ethane 80 Propane 96 Butanes 99 Heavier 100

A. **Refrigeration:** This method uses an external refrigeration system to chill the gas stream. Typical refrigeration systems use either propane or Freon as the refrigerant.

B. **Pressure Reduction:** With this method the pressure of the gas stream is reduced with a pressure reducing valve called a J-T valve. The reduction in pressure causes a reduction in temperature.

C. **Expansion:** Gas at a given temperature and pressure contains energy which is in the form of heat, pressure or velocity. This expansion method utilizes this energy. In this method the gas stream passes through an expander-compressor. As gas flows into the expander side of the expander-compressor, the pressure drops. The flowing gas also turns a wheel in the expander. Energy to turn the wheel is removed from the inlet gas and is transferred to the outlet gas being compressed in the compressor. The combination of gas expansion and removal of energy produces very low (cryogenic) gas temperatures.

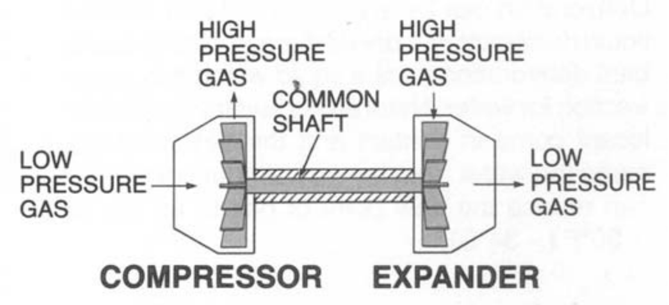


Figure 5.7 Expander Process

CRYOGENIC PROCESS

Cryogenic means very low temperatures, e.g., – 50 to –150 °F (– 46 to –101 °C). When a gas stream is chilled to these temperatures the process can be very efficient in condensing (liquefying) the heavier gas components. However, the successful recovery of the liquids requires a proper combination of temperature and pressure. Cryogenic processing of a natural gas stream involves three basic steps:

Dehydration, Chilling, and Fractionation

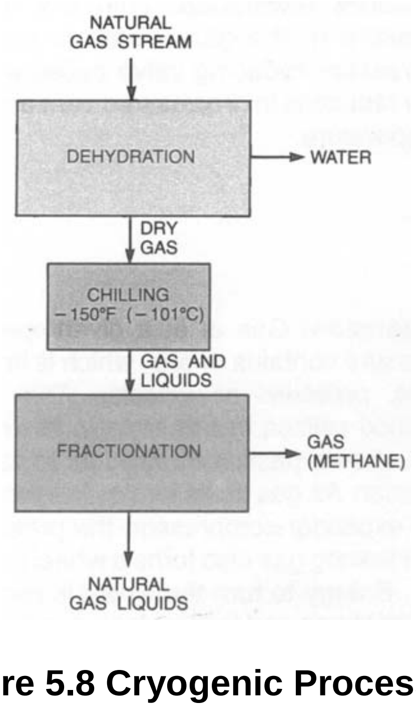


Figure 5.8 Cryogenic Processing

Dehydration

Dehydration is the removal of water or water vapor. Because of the very cold temperatures in cryogenic processing, almost all of the water vapor must be removed from the gas stream. Any water vapor remaining will form hydrates damaging equipment or stopping gas flow. This water is removed using different dehydration methods.

Dehydration can be accomplished with either a liquid desiccant or a dry desiccant. Liquid-desiccant dehydration uses a liquid which has an attraction for water. Natural gas and the liquid desiccant come in contact and the desiccant absorbs the water from the gas. A liquid desiccant can reduce the dew point of gas to as low as – 30 °F (– 34 °C).

If the gas must be drier, dry desiccant dehydration is used. A dry desiccant is a solid, granulated material which has an attraction for water. Gas flows through a bed of these granules and water attaches itself to the surface of the granules. This process is called adsorption. Dry desiccants can lower the dew point of gas to –150 °F (–101°C).

The method of dehydration at a specific facility depends on the water content of the inlet gas. Some cryogenic processes will have only dry-desiccant dehydration. However, if water content of the inlet gas is high, then first there will be liquid-desiccant dehydration followed by dry-desiccant dehydration.

Chilling

Chilling of the gas is the heart of the cryogenic process. Dry gas is chilled in stages to liquefy the heavier hydrocarbon gases.

The gas steam can be chilled by heat exchange with cold gas, by refrigeration, by pressure reduction and by pressure reduction with energy removal. The first three methods provide cold temperatures in the range of 0.0 °F to – 70 °F (–18°C to – 57 °C). To obtain the lowest temperatures, pressure reduction with energy removal is accomplished using the expander-compressor.

Fractionation

When the heavier gases condense out of natural gas during chilling, methane is trapped in the liquids. Fractionation is the process of separating the liquids from the gas or separating any one component from the chilled mixture.

The products of fractionation are gas and a liquid mixture. Methane is boiled from the chilled liquid mixture. Heat for this process comes from heat exchangers which are part of the cryogenic process. The remaining liquid, a mixture of heavier hydrocarbons, is the other product of fractionation.

REFRIGERATION SYSTEMS

Gas plant refrigeration processes can be divided into two broad classifications:

1) Turbo-expander processes

2) Externally refrigerated processes

The turbo-expander processes referred to also as Cryogenic (generation of cold) processes.

The externally refrigerated processes can in turn be broken down as follows:

1) Single component refrigeration (e.g. propane)
2) Cascade refrigeration (two or three stages)

All are low temperature processes commonly employing temperatures between – 34 °C and – 130 °C.

SINGLE COMPONENT REFRIGERATION (PROPANE)

The single component propane refrigeration process is most common gas plants employing familiar equipment which are fairly easy to maintain. At loads over 50% the performance of the system is rated as excellent achieving very low dew-points. Propane refrigeration is well suited to gas plant applications where chilling to between –12°C and –40°C is required. Boiling points of propane are – 42°C at 1 bar and 38°C at 131.0 bars.

Propane as Refrigerant

Propane as a refrigerant in externally refrigerated processes is effective when large rate of heat removal are required from the gas streams. It is readily available in large plants and has excellent thermodynamic qualities. It possesses much greater refrigerating effect than other refrigerants such as Freon, Ammonia and Carbon dioxide.

Propane boiling point at atmospheric pressure is fairly low and requires large amounts of heat to convert it from a liquid to a gas in the chillers. When in vapour form after compression, it requires a low pressure to condense it for use as a liquid in another cycle. It has no offensive odor and is not of poisonous or toxic nature. Further, propane has no corrosive action on metals and can be safely stored in properly designed vessels.

The biggest drawback of propane however, is that it is inflammable and explosive when mixed with air. Great care is required to handle it and all safety precautions should be adhered to when charging the system initially or periodically or during any maintenance work in the system.

Propane Refrigeration Equipment

Propane refrigeration systems require the following equipment to produce the required cold:

1) Chillers and Throttling Valve
2) Suction Scrubber
3) Centrifugal compressor
4) Condenser
5) Surge tank
6) Economizer
7) Propane Refrigerant Reclaimer

Chiller and Throttling Valve

The chillers accomplish the transfer of heat from the gas-stream to the boiling refrigerant thus lowering the temperature of the incoming gas.

Generally the entire refrigeration process depends upon two facts:

1) That propane refrigerant has a low boiling point and will boil as soon as it contacts the warm gas.

2) That the boiling point varies with the pressure of the refrigerant.

The chillers as in Figure 5.9, generally, are kettle type shell and tube heat exchangers cooling the raw gas to the designed temperature as it flows through the tubes. The liquid propane in the shell is maintained at such a level as to keep the tubes completely submerged. A standard throttling valve (JT valve) is used and normally operates on the chiller shell level control. The pressure of the whole system is controlled by a butterfly control valve located in the vapor line overhead. It acts as a back pressure controller.

The butterfly valve ensures that no excessive suction pressures overload the compressors and in addition, maintains the chiller gas temperature indirectly through the pressure variations. In operation, if the gas temperature rises above the specified temperature for a particular load, the butterfly valve opens allowing the chiller pressure to drop and propane to boil at a lower temperature. As a result, gas cooling is increased bringing the operating conditions back to normal. In other words, at maximum plant throughput, the butterfly valve will also be at the maximum opening while chiller pressure will be at the minimum.

In some plants this control valve is omitted to minimize flow restriction caused in the line. Chiller temperature control is accomplished through compressor speed variations.

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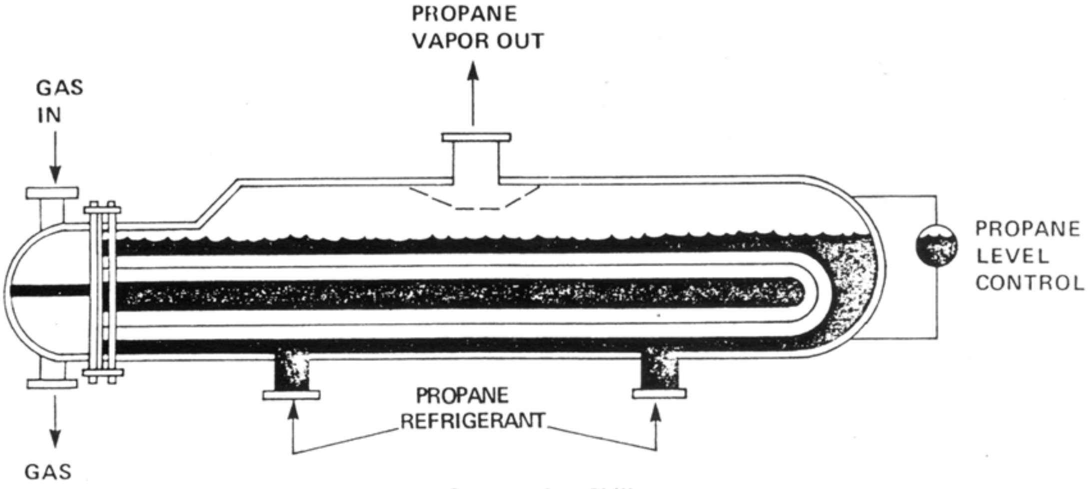

Propane Gas Chiller

Figure 5.9 Propane Gas Chillers

Compressor Suction Scrubber

The compressor suction drum which receives the cold propane vapor is a vertical vessel of 6 ft or more and is equipped with a heating coil near the bottom and a mist extractor near the top. The purpose of the coil is to provide the required heat to flash off any liquids returning from the chillers and protect the compressor from damage. This coil is kept warm at all times (around 46°C) and the outgoing propane temperature should be held at 10° cooler than the liquid propane in the storage drum.

Liquid problems can occur in the following conditions:

1) Liquid carryover from the evaporators or economizers caused from inadequate separation space, high liquid levels, plant upset conditions, improper construction of baffles, etc.

2) Migration and condensation in cold suction lines and compressor casing during system shutdown.

The liquid level in the suction drum is kept below the bottom of the gauge drum and an alarm usually installed at that point indicates the rising level of the liquid propane. A second controller and alarm, located slightly above the first one, shuts the compressor down in case the level in this drum becomes excessively high. Propane vapor from the suction scrubber overhead next, enters the first stage of the compressor.

The centrifugal compressor

Is driven by steam or gas turbine and is used to raise the pressure of the propane refrigerant.

The condenser

Is used to cool and condense the discharged propane vapor from the compressor back to its original liquid form.

Surge Drum

The surge drum is used for storage the liquid propane until it begins its next cycle. Makeup propane for losses occurred is handled at this point and is estimated at around 1 kg per MM cf of gas. The pressure in this drum must be maintained above 92.0 bars and in no case less than 35.0 bars above the compressor suction pressure. This enables the propane to force its way through the chiller level control valve and through the coils of the suction drum and re-claimed. A line may be provided from the fuel gas system to re-pressure the surge drum if required during the winter. All fresh propane purchased must be dry and free of any moisture. A drier installed down stream from the surge drum ensures of maximum propane dryness maintained in the system.

Economizers

The economizer is designed to lower the temperature of the liquid refrigerant by flashing or heat exchange and improves the refrigeration cycle efficiency.

The economizer, located in the liquid propane supply to the chillers, reduces the compressor requirements by as much as 20 % by cooling the liquid down before it commences its chilling duties. This is accomplished by stepping down the liquid propane pressure achieving some pre-cooling which assists in the overall refrigeration system. Economizer vapor from overhead is recompressed again in the second stage while the liquid from the bottom joins the liquid propane line to the chillers. The level of the liquid is held fairly constant in this drum to avoid any propane droplets entering into the second stage of the compressor and since the refrigeration loads are usually well balanced very little makeup should be required to maintain this level. However, as an added precaution, high level in the economizer will shut down the compressors and stop all flows in the system.

Economizers may be substituted by sub-coolers in some plants provided there is a cold stream available to exchange heat with the warm liquid propane.

Propane Refrigerant Reclaimer

A reclaimer is provided in conjunction with the gas chillers to purify the propane stream from the compressor lubricating oils causing reduced chilling capacities. A coil located near the bottom of this drum receives a portion of warm liquid propane and boils off batches of propane liquid withdrawn from the bottom of the chiller shell. The propane vapor then flows from overhead to the compressor suction, while any lube oil in the propane remains in the blowcase. This oil if left in the chillers turns viscous at the low temperatures encountered and forms a sludge which hampers the operations.

Reclaiming propane chiller bottoms is a lengthy operation and usually takes a whole shift to boil off one batch. Normally, several batches of propane with heavy ends can be boiled off before it is necessary to dump the lube oil residue from the re-claimer to the closed hydrocarbon drain system.

Principles of Operation

Referring to the general flow diagram in Figure 5.10 the cooling is accomplished in the chillers by passing the inlet gas through the tubes while maintaining a level of liquid propane at the proper pressure around the tubes in the shell of the chiller. The heat exchange surface, or outside area of the tubes in the chiller, is designed for an eight degree approach, which means that the gas leaving the chillers will be eight degrees warmer than the liquid propane in the chiller shell. Therefore, to cool the gas to – 37 ºC requires that the propane be maintained at – 42 ºC any pure liquid will have a specific boiling temperature corresponding to the pressure being exerted against it. For instance, water boils at 100°C when under atmospheric pressure at sea level. If the pressure is lowered, or a vacuum pulled on the water, the boiling temperature is also lowered until it will boil at a room temperature of 26 °C under a 29 inch vacuum. When the liquid boils, it absorbs heat from some source such as, in the case of a boiling pan of water, the flame below it. In the plant chillers the propane will boil at – 42 °C if the pressure on it is held at atmospheric level and the boiling liquid will absorb heat from the gas in the tubes. For each pound of propane vaporized a definite amount of heat will be absorbed from the gas. Thus, heat is removed until the temperature of the gas has decreased to the desired level of – 37 °C. To cool the design volume of gas to – 37 °C it will be necessary to vaporize 4041 kg per minute of propane.

To hold the pressure in the shell of the chillers down to 15 psia and to provide a continuous supply of propane to replace that 'which has vaporized, it is necessary to withdraw the vaporized propane from the chiller, compress it, cool it until it is again a liquid and reinject it into the chillers. Just as there is a definite boiling point for a pure liquid at any given pressure, so is there also a definite temperature at which the vapors will condense into a liquid for any pressure. Since the propane condenser was designed with the same 8° approach as the chillers, and the design cooling water temperature is 22 °C, the propane will leave the condenser shell at 50 °C. To condense of 50 ºC, the propane must be at 92.8 bars, however, to allow for pressure losses in the line and condenser, the compressor was designed for a discharge pressure of 96.6 bars. From the condenser, the liquid propane flows to a surge tank which is merely to allow for minor upsets and changes in operating conditions in the refrigeration system.

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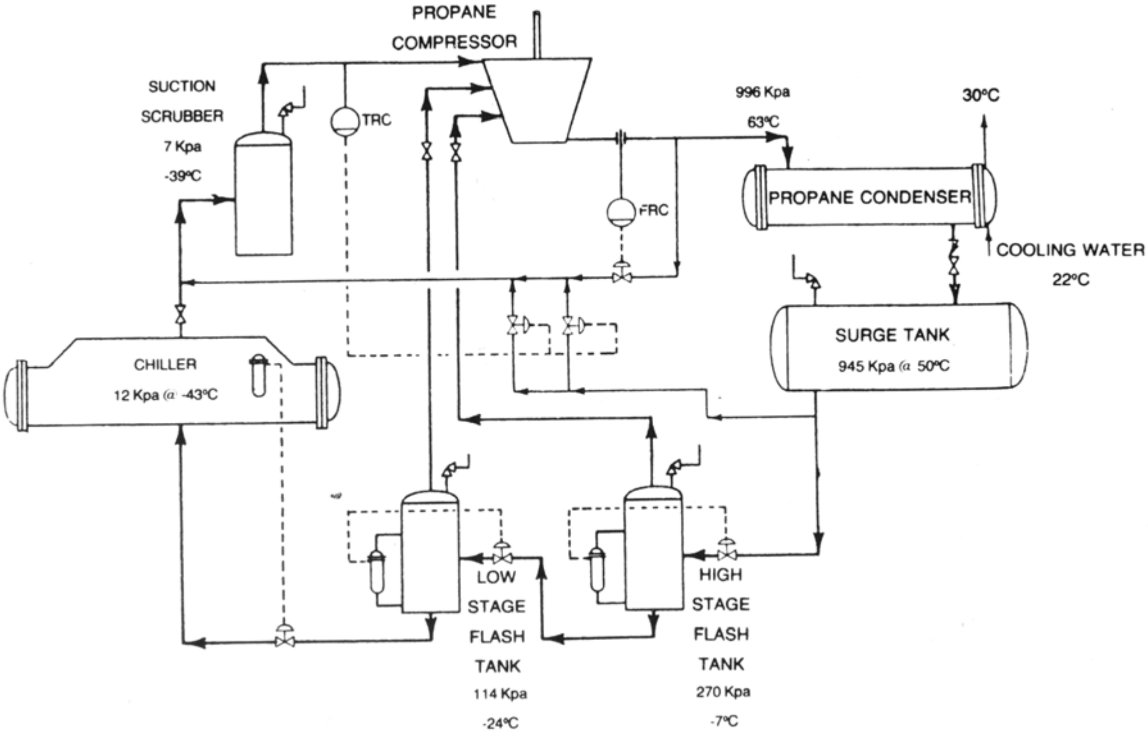

Figure 5.10 Propane Refrigeration Systems

In flowing from the surge tank where the temperature is 50 °C to the shell of the chillers where the temperature is – 42 °C, the propane loses much of its cooling capacity in cooling itself. The horsepower used in compressing the propane which has vaporized, only to cool the remaining liquid, is lost, inasmuch as it has not been used in cooling gas. To minimize this loss and increase the efficiency of the cycle, the pressure on the liquid is reduced in three steps. At the two intermediate steps, the liquid is allowed to boil or flash in vessels called flash tanks or open flash economizers, thus cooling itself to a temperature corresponding to the pressure level.

The resulting vapor must then only be compressed from that pressure level to 96.6 bars instead of from 7 to 96.6 bars. This results in considerable savings in horsepower

Propane Refrigeration Controls

Several controlling devices are involved in the automatic operation of refrigeration system including the protective equipment designed to shut down the units if and when abnormal operating conditions prevail. One of these is the operation of the butterfly valve, on the chiller vapor line, which may be over-ridden by another controller measuring the suction pressure to the compressor. This not only maintains correct chiller temperatures but ensures also that the compressor is not overloaded. This controller may also limit the compressor speed preventing the pull of a vacuum in the suction header. A high pressure alarm in the suction line alerts personnel when the butterfly valve is operated through the suction header controller while a low pressure alarm signals abnormal operating conditions.

Another controller, located in the discharge header of the compressor, serves to warn personnel when too much cooling is taking place in the condenser.

The above are just a few of the controllers involved in the operation of the refrigeration process. There are many more and may differ in principle from plant to plant.

PROPANE REFRIGERATION PROBLEMS

No system can be free of operational problems and this includes the refrigeration systems of gas plants.

Accumulation of liquid propane in the compressor suction line:

Beginning with the refrigerant compressors, especially on start up periods, the worst problem faced is the possible accumulation of liquid propane in the suction line. This problem will occur if the pressure and temperature conditions between the chillers and compressors are allowed to equalize and propane vapor to condense. To prevent this, all suction lines, liquid traps and drains should be always checked before the unit is started, particularly if the flow of propane to the chillers has not been blocked off.

Compressor high discharge head conditions:

Compressor high discharge head conditions, encountered particularly in reciprocating compressors due to an erratic operation of the condenser, could be alleviated by employing centrifugal types of compressors delivering a constant head at any particular speed or load.

Propane contamination with oil:

Propane contamination with oil picked up from the compressors is another problem in gas plants. This problem can be minimized by passing the compressed propane vapor through the oil separators, usually of cyclone type, separating the oil which is drained away later. The blow case (re-claimer) mentioned earlier is another means of removing the oil from the propane if this unit is properly operated.

Excess liquid level builds up in the suction scrubber:

Excess liquid level builds up in the suction scrubber and inter-stage bottles should be watched carefully and some liquid may have to be returned back to the surge drum or dumped to close the hydrocarbon drain system if levels become excessively high.

Compressor Surging:

The propane compressor is capable of a wide range in operating conditions, but there is a point for each impeller speed below which the compressor operation becomes unstable and starts to surge. When the differential pressure across an impeller exceeds that for which the impeller was designed, at that speed, it can no longer pump and gas will reverse flow.

As soon as enough gas has passed backward through the impeller to bring the differential pressure down within the limits of the impeller, it will immediately start to pump again until the differential limit of the impeller is again exceeded, at which time the entire cycle will be repeated. While gas is back flowing through the impeller and it is not pumping, there is no load on the driver and the speed increases rapidly.

Then as the impeller again starts to pump gas, the driver is loaded violently causing a decrease in speed. Besides being extremely noisy and stopping the flow of gas, surging can damage the compressor and driver and could even cause enough vibration to part the propane lines.

The causes of surging are:

(1) Throttling the suction and reducing the pressure by starving the compressor, or not supplying the minimum gas it must handle at the speed it is operating and,
(2) Throttling the discharge and increasing the pressure differential across the impeller.

During normal plant operations, the first would be the most likely cause or surging and could best be remedied by furnishing more gas to the compressor. A flow controller has been provided on the discharge of the compressor so that when the discharge volume approaches the surge point the controller will cause a motor valve to open in the recycle line and divert discharge gas back into the suction. This gas, however, will be at the discharge temperature of 63 °C and must be cooled to normal suction temperature or it will cause the discharge temperature to increase until the compressor becomes overheated and it will not put up the differential pressure. To accomplish this cooling, a temperature controller located in the compressor suction will cause liquid propane from the surge tank to be injected into the bypass line whenever the suction temperature rises above –39 °C. The liquid propane will vaporize on contact with the warm discharge gas, extracting heat from it and cooling it to the desired temperature.

Aerial coolers Problems:

Other equipment frequently requiring attention is the aerial coolers and their controlling equipment particularly in the summer time. It is well known to the operators that without some water spraying on these coolers during hot days the propane vapors would be difficult to condense unless the compressor discharge pressure is lowered and the load is cut back. Compressor pressures well designed will allow the vapor to condense at around 48°C. For colder weather methanol injection points are usually provided in the propane vapor lines in order to avoid freezing of water vapor that might be contained in the propane. Amount of methanol pumped should be controlled to avoid interference with propane condensation. Methanol injection may also be required into the propane liquid line just before the chiller level control valve, especially when wet propane has been added to the system.

Another frequent problem with aerial coolers is dirt accumulated on the tubes, such as baked on dust, seeds from poplar trees or others which decrease the heat transfer. Cleaning the condenser surfaces with jets of water or performing other repairs will largely improve plant production. Further, other foreign material collected inside the tube surfaces, such as oil carried with the propane from the compressors should be cleaned regularly to ensure proper heat transfer being maintained.

The chiller tubes:

The chillers require some attention at times to ensure the tubes are cleaned and free from oil coating which turns viscous and waxy like solid grease. This not only interferes with the proper heat transfer but accumulates around the level float preventing its free movements and resulting in erratic control of the liquid level. This level should be held as set at all times in order to avoid lower gas temperatures at low levels or liquid propane carried into the vapor line at high levels and eventually into the compressor suction drum. The chiller problems are minimized to some extent, by the use of the blow case and good operation of the oil separators located in the discharge header of the compressors.