Oil and gas processing

Oil and gas wells produce a mixture of hydrocarbon gas, condensate or oil; water with dissolved minerals, usually including a large amount of salt; other gases, including nitrogen, carbon dioxide (CO_2), and possibly hydrogen sulfide (H_2S); and solids, including sand from the reservoir, dirt, scale, and corrosion products from the tubing. The purpose of oil and gas processing is to separate, remove, or transform these various components to make the hydrocarbons ready for sale.

For the hydrocarbons(gas or liquid) to be sold, they must be:

- Separated from the water and solids
- Measured
- Transported by pipeline, truck, rail, or ocean tanker to the user

A production facility's job is to separate the well stream into three components, commonly referred to as "phases" (oil, gas, and water), and then process or dispose of these phases in an environmentally safe manner. In mechanical devices called "separators" gas is flashed from the liquids and "free water" is separated from the oil.

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Hydrocarbon Preparation

The goal is to produce oil that meets the purchaser's specifications that define the maximum allowable amounts of the following:

- Water
- Salt
- Other impurities

Similarly, the gas must be processed to meet purchaser's water vapor and hydrocarbon dewpoint specifications to limit condensation during transportation.

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

- Emulsion tightness (stability).
- Specific gravity of the produced oil and water
- The oil, gas, and produced water are corrosive.
- The scalability of the produced water.
- The amount of fluid to be treated and the percentage of water in the fluid.
- Availability of a gas sales line.
- Optimal operating pressure for the equipment
- The crude oil's proclivity to form paraffin.

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The produced water must meet the following requirements:

- Regulatory requirements for disposal in the ocean if the wells are offshore
- Reservoir requirements for injection into an underground reservoir to avoid plugging the reservoir
- Technical requirements for other uses, such as feed to steam boilers in thermal-flood operations, or in special cases, for irrigation

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Oil field emulsions are typically water-in-oil; however, some emulsions are oil-in-water and are referred to as reverse emulsions. Emulsions are complicated, and each should be considered separately. To break a crude oil emulsion and obtain clean oil, the emulsifier and its film must be displaced. This arrangement causes the coalescence of water droplets and necessitates a period of undisturbed settling of the coalesced water drops.

To treat an oil emulsion, several methods are used in conjunction with one another.

Oil Facility

Heater Treater

In most cases, a heater-treater is used to treat oil emulsions. To break emulsions, oil treatment equipment typically employs thermal, gravity, mechanical, and, on occasion, chemical or electrical methods. Heater-treaters can be designed to be vertical or horizontal. The size is determined by the amount of oil and water to be handled. Electrode-equipped treaters are typically horizontal in design. These devices are known as electrostatic coalescers or chem-electric treaters. These treaters are the most desirable in some applications because they treat at a lower temperature than a conventional heater-treater, saving fuel and conserving oil gravity.

Free Water Knockout

When a lease has enough free water production, a free water knockout (FWKO) is often installed to separate free gas and free water from free oil and emulsion. This vessel can be designed to be horizontal or vertical. The size is determined by the desired retention time and the volume of water to be handled per day. When FWKOs are used, time, gravity, mechanical, and occasionally chemical methods are used to facilitate separation. When heat is required to break an emulsion, the FWKO can save a significant amount of fuel gas. Heating unnecessary water is not only wasteful, but it also consumes more than twice as many British thermal units (BTUs) as heating an equivalent amount of oil. This can be very expensive. Hydrocyclones are increasingly being used in place of traditional FWKOs.

Desalters

Desalters work by diluting the brine with fresh or brackish water and increasing the volume of salt water in the oil so that it can be precipitated more easily. Electrostatic precipitation is commonly used in desalters.

Gunbarrel

An oil-water emulsion is not always very stable. Because water has a higher specific gravity than oil, if enough time is allowed, water will settle to the bottom of a tank and oil will rise to the top. Heat and chemicals can be used to reduce the amount of time required for setting up and improve the separation of the two liquids. A gun barrel or wash tank is the name given to the settling vessel. The gun barrel comes in a variety of designs, but it usually has enough height to allow clean oil to flow into the stock tanks by gravity. The water is drawn off via the water leg, which also controls the oil-water interface level.

Gas Facility

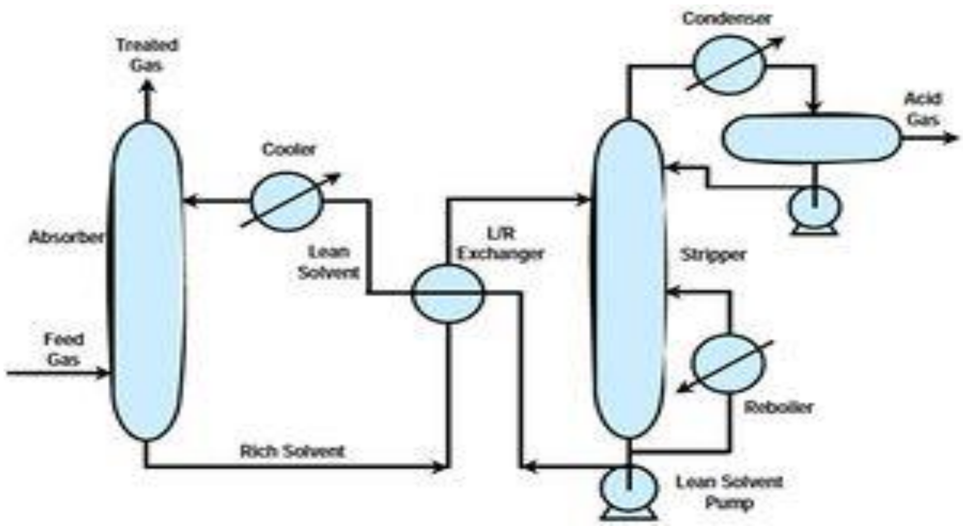
Condensate Stabilization

The liquids separated from the gas stream in the first separator must go straight to a tank or be stabilized in some way. Because of its lower viscosity and larger density difference with water, gas condensate may include a high percentage of intermediate components and may be easily separated from entrained water. As a result, each gas well production facility should consider some form of condensate stabilization.

Multi Stage Separation

Because the light molecules are removed from the first separator, they are no longer 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 be if the first separator did not exist. The second separator performs the same function as the third separator in terms of raising the partial pressure of the intermediate components, and so on. Installing a low-pressure separator downstream of an initial high-pressure separator is the most basic method of condensate stabilization. Ethane, propane, butane, and other natural gas liquids are recovered from the gas stream at a gas-processing facility. Some of these liquids are also recovered using a condensate stabilizer. The greater the recovery of these components as liquids, the colder the gas exiting the overhead condenser in a reflux stabilizer, or the colder the feed stream in a cold-feed stabilizer, and the higher the pressure in the tower. Any stabilizing technique that results in more molecules being recovered in the final liquid product is effectively eliminating those molecules from the gas stream. In this way, a stabilizer may be thought of as a basic gas-processing plant. It's impossible to say when a condensate stabilizer transforms into a gas plant. If the liquid product is sold as a condensate, the equipment is typically referred to as a condensate stabilizer. The same operation would be designated a gas plant whether the product is marketed as a mixed natural gas liquid stream (NGL) or separated into its constituent components. The least volatile NGL stream has an RVP of 10 to 14 and contains enough light hydrocarbons to evaporate 25% of the entire volume at 140°F.

Acid Gas Treatment



Acid Gas Removal Process

Compounds like carbon dioxide, hydrogen sulfide (H2S), and other sulfur compounds like mercaptans may require total or partial removal before a gas purchaser would take it. These substances are referred to as "acid gases." Hydrogen sulfide reacts with water to generate a weak form of sulfuric acid, whereas CO reacts with water to form carbonic acid, thus the phrase "acid gas." "Sour gas" refers to natural gas that contains H2S or other sulfur compounds, whereas "sweet gas" refers to a gas that contains solely carbon dioxide. Both hydrogen sulfide and carbon dioxide are undesirable because they promote corrosion and lower the heating value of the gas, lowering its saleability.

Sour Gas Sweetenening

Gas sweetening techniques have been created using a range of chemical and physical concepts. For example, Solid bed absorption:

- Iron Sponge
- SulfaTreat
- Zinc Oxide Molecular Sieves
- Chemical solvents like Monoethanolamine (MEA)
- Diethanolamine (DEA)
- Methyldiethanol amine (MDEA)
- Diglycol amine (DGA)
- Diisopropanol amine (DIPA)
- Proprietary carbonate systems
- Physical solvents like Rectisol, etc.

Gas Dehydration

The act of eliminating water vapor from a gas stream in order to reduce the temperature at which water will condense from the stream is known as gas dehydration. This temperature is referred to as the gas's "dew point." Most gas sales contracts stipulate a maximum amount of water vapor that can be present in the gas. In the southern United States, typical values are 7 lb/MMscf, 4 1b/MMscf in the northern United States, and 2 to 4 lb/MMscf in Canada. In a 1,000 psi gas line, these values equate to dew points of roughly 32°F for 7 lb/MMscf, 20°F for 4 lb/MMscf, and 0°F for 2 lb/MMscf[2]. Dehydration at dew points below the temperature to which the gas would be exposed prevents the formation of hydrates and corrosion caused by condensed water. This is especially critical in carbon dioxide or hydrogen sulfide gas streams because the acid gas components will react with the condensed water to generate an acid. The most prevalent techniques of dehydration are liquid glycol and solid bed dehydration systems. The most prevalent techniques of dehydration are liquid glycol and solid bed dehydration systems.

Glycolysis

Contacting natural gas with a hygroscopic liquid, such as one of the glycols, is by far the most frequent method for dehydrating it. The water vapor in the gas stream is dissolved in a reasonably pure glycol liquid solvent stream in this absorption process. Glycol dehydration is very affordable since the water in the glycol can be readily "boiled" out using heat. This procedure is known as "regeneration" or "reconcentration," and it allows the glycol to be recovered for reuse in absorbing more water with less glycol. Commonly used glycol for this process is the TEG that is Triethylene Glycol.

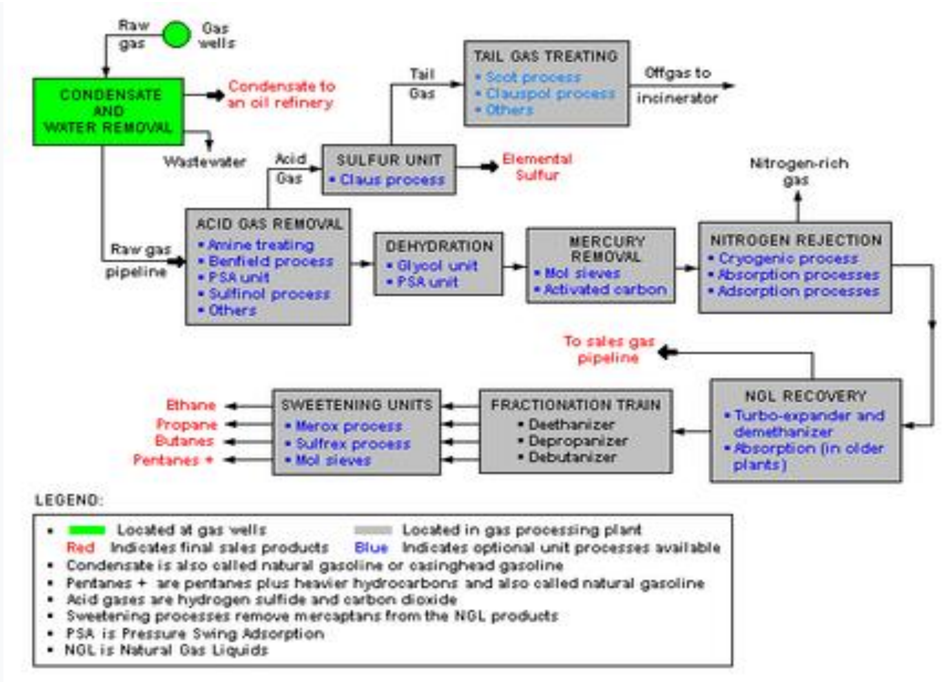
Soil Bed Dehydration

Adsorption is the basis of solid bed dehydration methods. Adsorption is a type of adhesion between the solid desiccant's surface and the water vapour in the gas. The water condenses into a very thin layer that is attracted to the desiccant surface, but there is no chemical reaction. Because of a plethora of tiny pores and capillary openings, the desiccant is a solid, granulated drying or dehydrating medium with an unusually large effective surface area per unit weight.

Gas Processing

Al-Mustaqbal University
Department of chemical engineering
Class (third) Subject (Chemicals from oil)
Lecturer (MSc Noor Aldeen saad ALKadhim)

$2^{st}/2^{nd}$ term – Lect. ١(Oil and gas processing)



Natural Gas Processing

The removal of ethane, propane, butane and other heavier components from a gas stream is referred to as "gas processing." They can either be fractionated and marketed as "pure" components or blended and sold as a natural gas liquids mix, or NGL.

In a gas processing plant, the first step is to separate the components to be recovered from the gas into an NGL stream. It may then be necessary to fractionate the NGL stream into ethane, propane, iso-butane, or normal-butane liquefied petroleum gas (LPG) components. NGL is mostly composed of pentanes and heavier hydrocarbons, with some butanes and extremely minor quantities of propane thrown in for good measure. It cannot contain heavy components that boil at more than 375°F. In most cases, gas processing plants are built because it is more cost-effective to extract and sell liquid products, despite the fact that this reduces the heating value of gas. The increased volume of liquids sales might be worth substantially more than the money lost from gas sales due to a fall in the heating value of the gas.

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Absorption/Lean oil

Absorption/lean oil plants, as illustrated in are the earliest form of the gas plant. They circulate a kerosene-like oil throughout the plant. The "lean oil" is used to absorb the gas's light hydrocarbon components. The rich oil is separated from the light components, and the lean oil is recycled.

Before entering the absorber, the input gas is usually cooled by a heat exchanger with the output gas and a cooler. The absorber is a contact tower, comparable to the glycol contact tower in terms of design. The gas rushes upward against the absorber oil, while the lean absorber oil drips down over trays or packing. The gas exits via the top of the absorber, while the absorber oil, which is now rich in light hydrocarbons, exits through the bottom. The larger the proportion of hydrocarbons eliminated by the oil, the colder the incoming gas stream. Rich oil is pumped to a de-ethanizer (or de-methanizer) that rejects methane and ethane (or just methane) as flash gas. The ROD unit in most lean oil facilities rejects both methane and ethane since the lean oil recovers relatively little ethane.

For the rich oil, the ROD is comparable to a cold feed stabilizing tower. By exchanging heat with the hot lean oil flowing from the still, heat is supplied at the bottom to drive out practically all of the methane (and most likely ethane) from the bottom's product. The absorber oil is then sent through a still, where it is heated to a temperature high enough to drive the propanes, butanes, pentanes, and other natural gas liquid components to the overhead. The still resembles a refluxed crude oil stabilizer. The purer the lean oil that is recirculated to the absorber, the closer the bottom temperature approaches the boiling temperature of the lean oil. The condenser's temperature regulation prevents lean oil from being lost in the overhead.

Refrigeration

The incoming gas is chilled to a low enough temperature in a refrigeration facility to condense the necessary proportion of LPG and NGL. The refrigerant can either be freon or propane. To avoid hydrate formation, the free water must be removed and the dew point of the gas decreased before chilling the feed. With TEG, it is feasible to dehydrate the gas.

The glycol and water separate in the cold separator and are directed to a regenerator, where the water is boiled off and the glycol is pumped back to the input Stream. A kettle-type exchanger is commonly used as a chiller. Freon can chill gas to around -15 degrees Fahrenheit. If lower gas temperatures and higher recovery efficiencies are sought, propane, which can be chilled below -40°F, is occasionally employed.

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The cold separator, which is a three-phase separator, separates the gas and liquid. Water and glycol are discharged from the bottom, hydrocarbon liquids are sent to the distillation tower, and gas is discharged from the top. A de-methanizer is still used when it is desirable to recover ethane. A de-ethanizer is used when only propane and heavier components are to be recovered. The gas is referred to as "plant residue" and is the plant's exhaust gas.

Fractionation

Any gas plant's bottom liquid can be marketed as a mixed product. This is prevalent in small, isolated operations if local demand is minimal. The blended product is transferred to a central site for further processing by truck, rail, barge, or pipeline. Separating the liquid into its various components and selling it as reflux condensing temperature and tower operating pressure is often more cost-effective. If the pentanes-plus levels are greater than expected, further reflux cooling or a higher operating pressure will be required to condense the pentanes-plus from the butane overheads.

Secondary Process

In addition to processing the oil and gas for sale, the produced water and solids must be treated for disposal. For produced water, treating usually includes removal of dispersed and dissolved hydrocarbons and, in addition to separation or oil skimming, may include:

- Filtration
- Deionization
- Pumping

If treating of solids is required, it may include water washing and agitating the solids to remove the oil and then separating the water from them.

Oil is often sold through a LACT unit in big facilities, which is designed to meet API requirements as well as whatever other measuring and sampling criteria the crude customer requires. The price paid for crude is usually determined by its gravity, BS+W concentration, and volume. As a result, the LACT unit must not only precisely measure the volume, but also continually monitor the BS +W content and obtain a sufficiently representative sample in order to determine the gravity and BS+W.

Auxiliary Systems

In addition to the process systems, auxiliary process heating and cooling may be required. Process heat is usually needed for oil treating and superheating fuel gas for use in gas turbine generators or compressors. Process cooling is usually required for gas compression.

While, if necessary, facilities can be run without electric power, power generation and electrical systems will usually be included for a facility that is large or complex or for living quarters that are provided for personnel.

All facilities require safety systems, including:

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- Safety instrumentation and shutdown system
- Fire and gas detection
- Fire-fighting equipment
- A means of evacuation, such as life rafts and escape capsules for offshore
- Other equipment, depending on the location and complexity of the facility and whether it is manned

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