

## Treating Processes

The essential purpose of the **primary processes** is to produce the required amounts of various products from the available crude. The products obtained are, as a general rule, unsuitable as such for immediate use, for the following reasons:

- 1) Inadequate performance
- 2) Instability in storage
- 3) Objectionable odor and appearance and contamination with water or particulate matter.

**Secondary refining processes** (finishing or treating processes) are required to give the products acceptable concerning the above criteria.

### Main Finishing Processes

- a) The removal of the objectionable gases (Acid gas removal).
- b) The removal of objectionable odors.
- c) The improvement in storage stability.
- d) Improvement in performance characteristics.
- e) The removal of water and particulate matter.

### The removal of the objectionable gases

Hydrogen sulphide ( $H_2S$ ): has to be removed from products because:

1. Toxic
2. Foul-smelling
3. Corrosive
4. Traces of it may seriously contaminate regenerative treating solvents such as a solarize used for the final sweetening of the products.

### Sweetening gas

Natural gas has a wide range of acid gas concentrations, from parts per million to 50 volume per cent and higher, depending on the nature of the rock formation from which it comes. Because of the corrosiveness of  $H_2S$  and  $CO_2$  in the presence of water and because of the toxicity of  $H_2S$  and the lack of heating value of  $CO_2$ , sales gas is required to be sweetened to contain no more than a quarter grain  $H_2S$  per 100 standard cubic feet (scf) (4 parts per million) and to have a heating value of no less than 920 to 980 Btu/scf, depending on the contract. The most widely used processes to sweeten natural gas are those using alkanol amines, and of the alkanol amines the two most common are monoethanolamide (MEA) and di-ethanolamine (DEA).

**Removal Methods of (H<sub>2</sub>S):**

1. Scrubbing with caustic soda
2. Girbotol process

**Scrubbing with caustic soda:** It is still the most widely used process for the removal of H<sub>2</sub>S, mainly because it simultaneously removes other constituents such as CO<sub>2</sub>, carbonyl sulphide, lower aliphatic mercaptans, phenols fatty acids and naphthenic acids.

The **disadvantage** of this process is that there is no known cheap method of regenerating the spent soda, and if H<sub>2</sub>S is present in gross amounts, as is frequently in crude gases, especially the C<sub>2</sub> -C<sub>3</sub> fractions, a regenerative method of extraction such as the girbotol method is more generally used.

This method is more **economical** than caustic washing but caustic washing may still be required as a final cleaning-up operation for the removal of the last traces of H<sub>2</sub>S.

The **combination of the two processes** not only provides a very low H<sub>2</sub>S content economically but also safe guards against high sulfur contents in the treated products should there be a temporary failure of the regenerative treating plant.

In the **caustic washing** of gases rather weak solutions of 2-10%wt NaOH have to be used to prevent the deposition of sodium sulphide crystals. The reaction proceeds almost to the complete conversion of NaOH to NaHS.

Traces of H<sub>2</sub>S often appear in fractions much heavier than C<sub>2</sub> -C<sub>3</sub> fraction because of a slight breakdown of sulfur compounds owing to pyrolysis during re-distillation or a similar operation. Caustic soda may be employed for its removal.

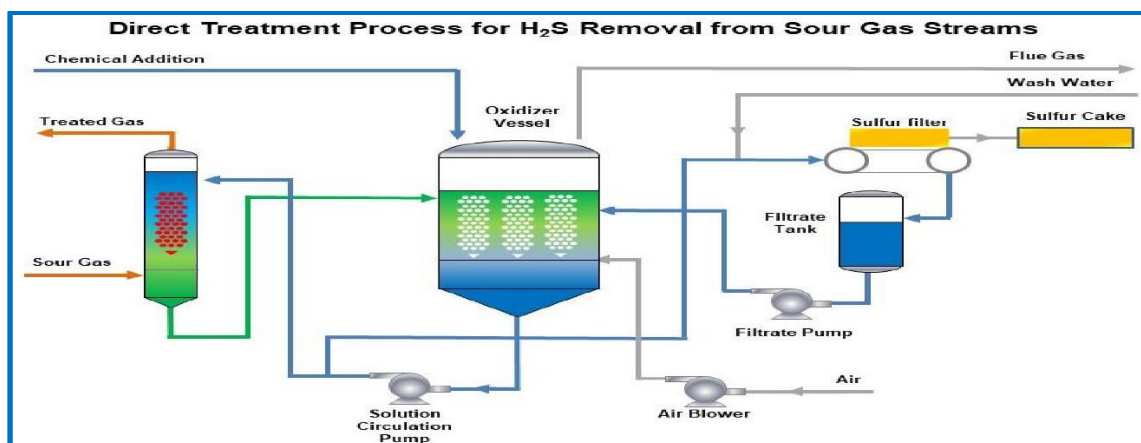


Fig (1) H<sub>2</sub>S removal from gases by caustic washing

**Girbotol process :**

Hydrogen sulphide ( $H_2S$ ) and carbon dioxide ( $CO_2$ ) readily combine with aqueous solutions of certain **alkanol amines** at temperatures usually close to ambient and may be driven off from the fat solutions by heating to about  $100^\circ C$ .

The reaction with hydrogen sulphide is essential:

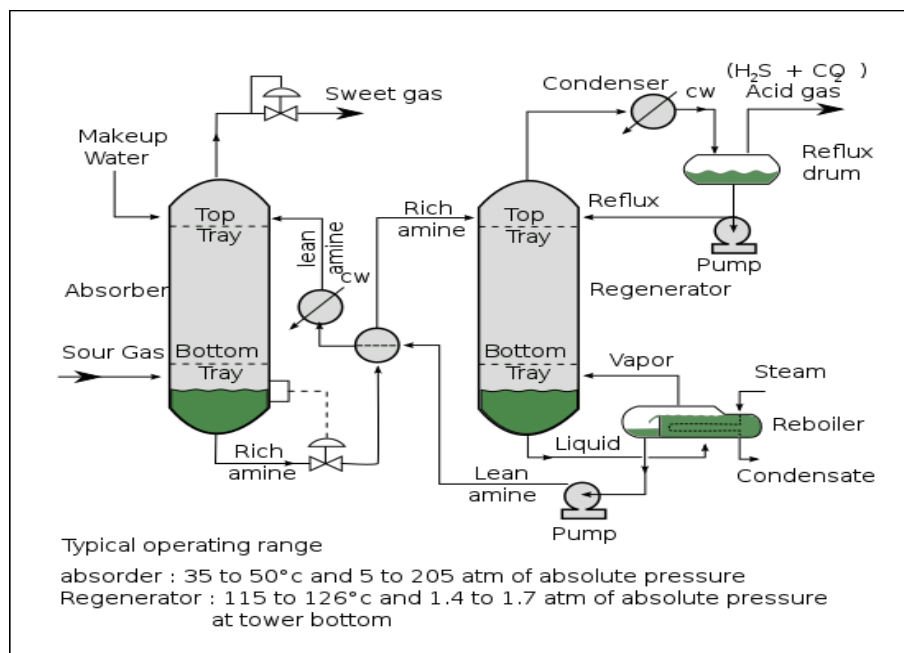


Amine (mono- di and tri ethanol amines and methyl di ethanol amine)

The conventional equipment comprises a bubble-cup tower together with a bubble-cup tower for regeneration. The treating temperature is  $5$  to  $10^\circ C$  above the dew point of the gas to ensure that no hydrocarbons liquid condenses out of the plant.

The **Girbotol process** is the most widely used method for the regenerative removal of  $H_2S$  from both gases and liquids. Its use is not only in refineries but also for **oilfield treatment of natural gases and LPG.**

The choice of the proper amine and solution depends on the composition of the gas to be treated and the final purity desired.



**Fig (2) Girbotol process**

**Carbon dioxide :**

Carbon dioxide is frequently found in natural gas and is also present in the products of catalytic crackers since regenerated catalyst always carries with them a small quantity of carbon dioxide. Its removal is rarely a direct aim but the major part of it will be removed by a caustic wash applied for the removal of H<sub>2</sub>S. When CO<sub>2</sub> removal is a direct aim one of the regeneration processes such as the Girbotol process would normally be used.

**Common amines:**

There are several liquid solvents in commercial use for the removal of H<sub>2</sub>S and CO<sub>2</sub> from refinery gases. Among the more common are the amines. These include:

MEA	Monoethanolamine
DEA	Diethanolamine
DGA	Diglycolamine
MDEA	Methyldiethanolamine

**1. Monoethanolamide (MEA):**

This is one of the most common acid gas absorption processes. Normally 15–20 wt. % MEA in water is circulated down through a trayed absorber to provide intimate contact with the sour gas. The rich solution is routed to a steam stripping column where it is heated to about 250 °F at 10 psig to strip out the acid gases. The lean MEA solution is then returned to the absorber. MEA is the most basic (and thus reactive) of ethanolamine's. MEA will completely sweeten sour gases, removing nearly all acid gases if desired. The process is well-proven in refinery operations.

**2. Methyl Di-ethanolamine (MDEA)**

The amine that is growing in popularity for H<sub>2</sub>S removal from gases is methyl di-ethanolamine. MDEA has taken over many of the applications formerly allocated to MEA and DEA. MDEA is a tertiary amine that selectively removes H<sub>2</sub>S, with less affinity for CO<sub>2</sub>. This means that the sour gas from MDEA regeneration contains less CO<sub>2</sub> and places a lower volume load on the sulfur recovery units. MDEA is relatively noncorrosive and is commonly used at 50 % concentration without corrosion inhibitors. It is not degraded significantly by impurities in the gas and has a relatively low heat of vaporization and specific heat.

### 3. Diethanolamine (DEA):

DEA is a weaker base (less reactive) than MEA. This has allowed DEA to be circulated at about twice the solution strength of MEA without corrosion problems.

DEA systems are commonly operated at strengths up to 30 wt. % in water, and it is not unusual to see them as high as 35 wt. %. This results in the DEA solution circulation rate usually being a little less than MEA for the same system design parameters.

### Crude Oil Pre-treatment

In a producing oil field, the fluid produced at the wellhead consists usually gas, oil, free water, emulsified water (water–oil emulsion) salt and solid particles .

The fluid obtained at the wellhead is submitted to :

1. Degassing Operation
2. Desalting operation (if required)
3. Dehydration operation

#### Degassing

At the high pressure existing at the bottom of the producing well, crude oil contains great quantities of dissolved gases. When crude oil is brought to the surface, it is at a much lower pressure. Consequently, the gases that were dissolved in it at the higher pressure tend to come out from the liquid.

#### *Two-Phase (Gas–Oil Separation)*

High-pressure crude oils containing large amounts of free and dissolved gas flow from the wellhead into the flow line, which routes the mixture to a gas–oil separator plant (GOSP). In the GOSP, the pressure of the gas–oil mixture is successively reduced to atmospheric pressure in a few stages. In the separator, crude oil separates, settles, and collects in the lower part of the vessel.

Gas goes out the top of the separators to a gas collection system, a vapor recovery unit (VRU), or a gas flow line. Crude oil, on the other hand, goes out the bottom and is routed to other stages of separation, if necessary, and then to the stock tank (*Fig. 3*).

Volatile components are either sent to consumer centers as natural gas or used to re-pressurize the oil field.