Oil Dehydration and Emulsion Treatment

Introduction

The fluid produced at the wellhead consists usually of gas, oil, free water, and emulsified water (water–oil emulsion). Before oil treatment begins, we must first remove the gas and free water from the well stream. This is essential in order to reduce the size of the oil–treating equipment.

As presented in previous lectures, the gas and most of the free water in the well stream are removed using separators. Gas, which leaves the separator, is known as ''primary gas.'' Additional gas will be liberated during the oil treatment processes because of the reduction in pressure and the application of heat. Again, this gas, which is known as ''secondary gas,'' has to be removed. The free water removed in separators is limited normally to water droplets of 500 μm and larger. Therefore, the oil stream leaving the separator would normally contain free water droplets that are 500 μm and smaller in addition to water emulsified in the oil. This oil has yet to go through various treatment processes (dehydration, desalting, and stabilization) before it can be sent to refineries or shipping facilities.

First specialist has deals with the dehydration stage of treatment. The objective of this treatment is first to remove free water and then break the oil emulsions to reduce the remaining emulsified water in the oil. Depending on the original water content of the oil as well as its salinity and the process of dehydration used, oil-field treatment can produce oil with a remnant water content of between 0.2 and 0.5 or 1%. The remnant water is normally called the basic sediments and water (B.S. &W.). The treatment process and facilities should be carefully selected and designed to meet the contract requirement for B.S.&W.

The basic principles for the treating process are as follows:

1) breaking the emulsion, which could be achieved by either any, or a combination of the addition of heat, the addition of chemicals, and the application of electrostatic field;

2) coalescence of smaller water droplets into larger droplets;

3) settling, by gravity, and removal of free water.

Oil Emulsions

Rarely does oil production takes place without water accompanying the oil. Salt water is thus produced with oil in different forms as illustrated in Figure 4.1. Apart from free water, emulsified water (water-in-oil emulsion) is the one form that poses all of the concerns in the dehydration of crude oil.

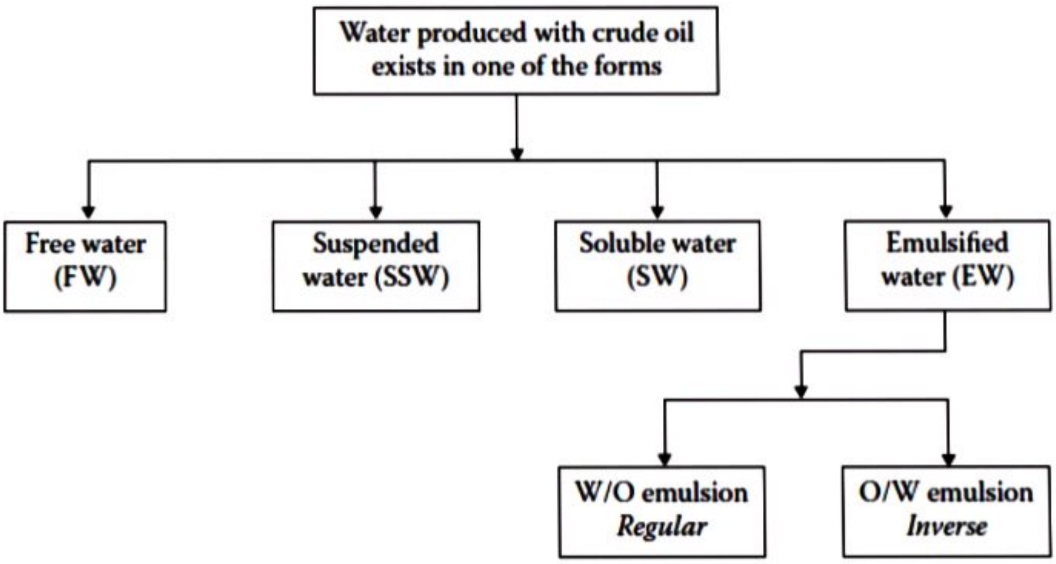

Figure 4.1 – Forms of saline water produced with crude oil.

Oil emulsions are mixtures of oil and water. In general, an emulsion can be defined as a mixture of two immiscible liquids, one of which is dispersed as droplets in the other (the continuous phase) and is stabilized by an emulsifying agent. In the oil field, crude oil and water are encountered as the two immiscible phases together. They normally form water-in-oil emulsion (W/O emulsion), in which water is dispersed as fine droplets in the bulk of oil. This is identified as part (c) in Figure 4.2. However, as the water cut increases, the possibility of forming reverse emulsions (oil-in-water, or O/W emulsion) increases, as shown by part (b) in Figure 4.2.

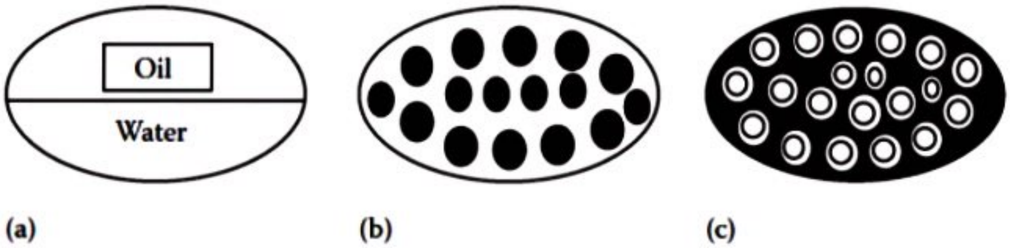

Figure 4.2 – Schematic representation of (a) a non-dispersed system, (b) an O/W emulsion, and (c) a W/O emulsion.

For two liquids to form a stable emulsion, three conditions are to be fulfilled:

1. The two liquids must be immiscible.
2. There must be sufficient energy of agitation to disperse one phase into the other.
3. An emulsifying agent must be present.

Conditions 2 and 3 are discussed in the following subsections.

Energy of Agitation

Emulsions normally do not exist in the producing formation but are formed because of the agitation that occurs throughout the oil production system, the fluids are subjected to agitation due to the turbulent flow. This energy of agitation, which forces the water drops into the bulk of oil.

A crucial question that can be asked now is the following: Can the plant designer prevent emulsion formation? Well, the best he can do is to reduce its extent of formation based on the fact that the liquids initially are not emulsified. From the design point of view, primarily reducing the flowing velocity of the fluid and minimizing the restrictions and sudden changes in flow direction could minimize formation of emulsion.

Emulsifying Agents

If an oil emulsion is viewed through a microscope, many tiny spheres or droplets of water will be seen dispersed through the bulk of oil. A tough film surrounds these droplets; this is called a stabilizing film. Emulsifying agents, which are commonly found in crude oil or water in the natural state or introduced in the system as contaminants during drilling and maintenance operations, create this type of film.

Some of the common emulsifiers are as follows:

- Asphaltic materials
- Resinous substances
- Oil-soluble organic acids
- Finely dispersed solid materials such as sand, carbon, calcium, silica, iron, zinc, aluminum sulfate, and iron sulfide

These emulsifying agents support the film formation encasing the water droplets, hence the stability of an emulsion.

Dehydration/Treating Processes

The method of treating wet crude oil for the separation of water associated with it varies according to the form(s) in which water is found with the crude. Free-water removal comes first in the treating process, followed by the separation of combined or emulsified water along with any foreign matter such as sand and other sediments. The basic approaches of handling wet crude oils are illustrated in Figure 4.3.

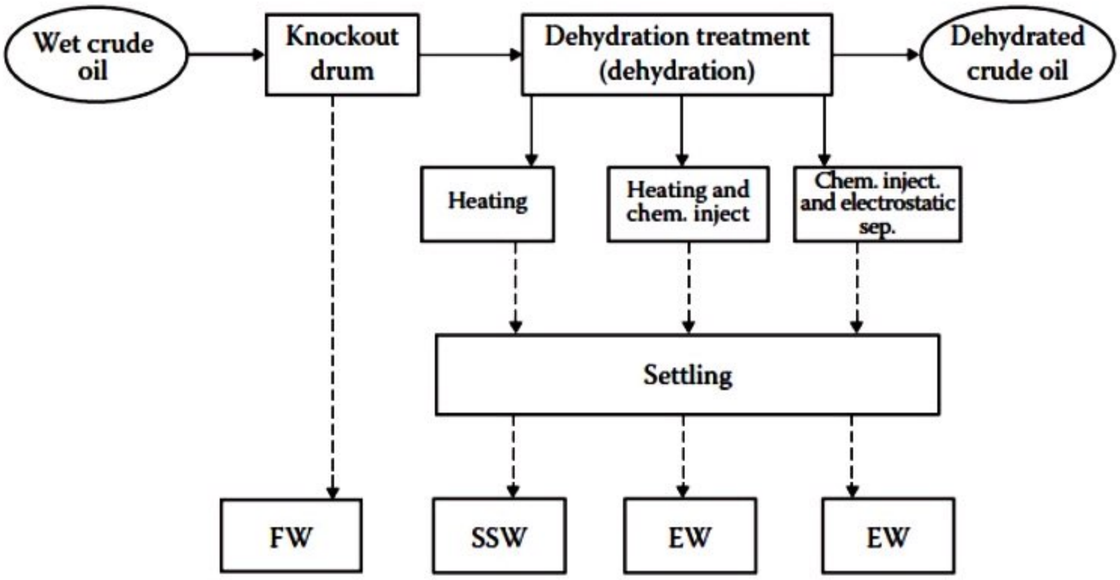

Figure 4.3 - Basic approach of handling wet crude oil. (EW, emulsified water; FW, free water; SSW, suspended water.)

From an economic point of view, removal of free water at the beginning will reduce the size of the treating system, hence its cost. The same applies for the separation of associated natural gas from oil in the gas–oil separator plant (GOSP).

A dehydration system in general comprises various types of equipment. Most common are the following:

- Free-water knockout vessel
- Wash tank
- Flow treater (heater-treater)
- Chemical injector
- Electrostatic dehydrator

It is very common to use more than one dehydrating aid, particularly for emulsion breaking. Examples are the heater-treater and chem-electric dehydrator.

The role played by adding chemicals to break emulsions should not be overlooked. These chemicals act as de-emulsifiers—once absorbed on the water–oil interface, they will rupture the stabilizing film causing emulsions.

Removal of Free Water

Free water is simply defined as that water produced with crude oil and will settle out of the oil phase if given little time. There are several good reasons for separating the free water first:

1. Reduction of the size of flow pipes and treating equipment
2. Reduction of heat input (water takes about twice as much heat as oil)
3. Minimization of corrosion because free water comes into direct contact with the metal surface, whereas emulsified water does not.

Free water, on the other hand, has its distinctive benefits. Free water found in the reservoir fluid will carry twice as much heat as oil and take it up the tubing to the surface. Eventually, it will help in breaking oil emulsions. It is to be observed that:

- a well producing salt water (free water) will be much warmer than a well producing oil only.

Further, free water contributes to what is called "water wash", which is the action of the salt water to break the oil emulsions.

Free water removal takes place using a knockout vessel, which could be an individual piece of equipment or incorporated in a flow treater.

Resolution of Emulsified Oil

This is the heart of the dehydration process, which consists of three consecutive steps:

1. Breaking the emulsion: This requires weakening and rupturing the stabilizing film surrounding the dispersed water droplets. This is a destabilization process and is affected by using what is called an "aid", such chemicals and heat.

2. Coalescence: This involves the combination of water particles that became free after breaking the emulsion, forming larger drops by applying an electrostatic field, and water washing.
3. Settling, by gravity, and removal of free water.

Because these steps are in series, Figure 4.4, the slowest one is the most controlling. Out of these, coalescence is the slowest step. In other words, using either heat or chemicals followed by gravitational settling can break some emulsions, but the process is dependent on the time spent in coalescence. This time is the element that determines the equipment size, hence its capital cost.

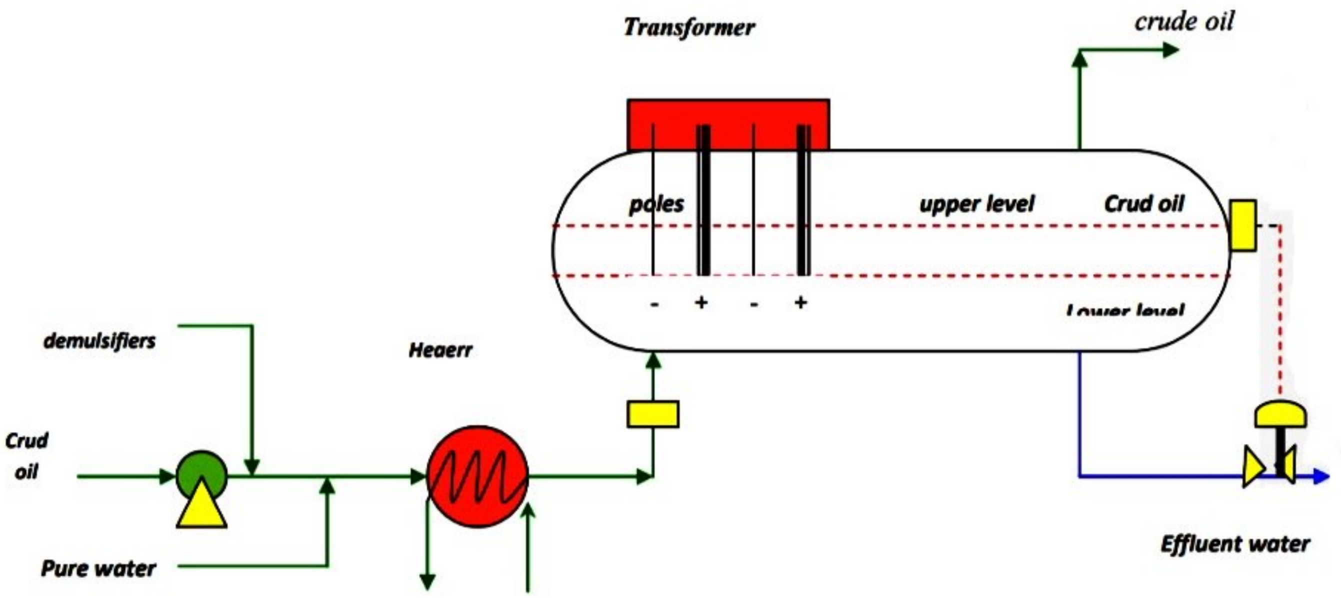

Figure 4.4- Dehydration system

Desalting of Crude Oil

When the crude oil enters the unit, it carries with it some brine in the form of very fine water droplets emulsified in the crude oil. The salt content of the crude measured in pounds per thousand barrels (PTB) can be as high as 2000. Desalting of crude oil is an essential part of the refinery operation. The salt content should be lowered to between 5.7 and 14.3 kg/1000m^3 (2 and 5 PTB). Poor desalting has the following effects:

- Salts deposit inside the tubes of furnaces and on the tube bundles of heat exchangers
- creating fouling, thus reducing the heat transfer efficiency;
- Corrosion of overhead equipment; and,
- The salts carried with the products act as catalyst poisons in catalytic cracking units.

The two most typical methods of crude-oil desalting, chemical and electrostatic separation, use hot water as the extraction agent. **In chemical desalting**, water and chemical surfactant (demulsifiers) are added to the crude, heated so that salts and other impurities dissolve into the water or attach to the water, and then held in a tank where they settle out. **Electrical desalting** is the application of high-voltage electrostatic charges to concentrate suspended water globules in the bottom of the settling tank. Surfactants are added only when the crude has a large amount of suspended solids. Both methods of desalting are continuous. A third and less-common process involves filtering heated crude using diatomaceous earth.

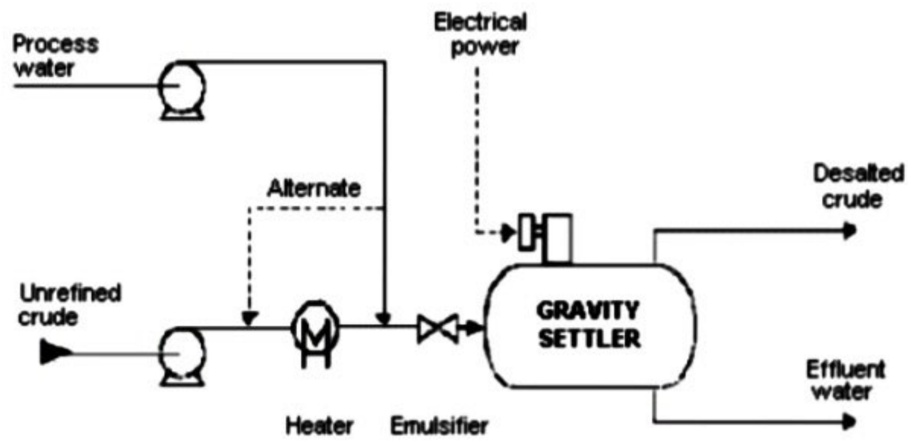

Figure 4.4- Electrical desalting

In both methods, the feedstock crude oil is heated to between 150° and 350°F to reduce viscosity and surface tension for easier mixing and separation of the water. The temperature is limited by the vapor pressure of the crude-oil feedstock. In both methods other chemicals may be added. Ammonia is often used to reduce corrosion. Caustic or acid may be added to adjust the pH of the water wash. Wastewater and contaminants are discharged from the bottom of the settling tank to the wastewater treatment facility. The desalted crude is continuously drawn from the top of the settling tanks and sent to the crude distillation (fractionating) tower.

Stabilization and Sweetening

Once degased, dehydrated, and desalted, crude oil should be pumped to gathering facilities for storage. However, stabilization and sweetening are a must in the presence of hydrogen sulfide (H_2S). H_2S gas is frequently contained in the crude oil as it comes from the wells. It not only has a vile odor, it is also poisonous. It can kill a person if inhaled. It is also corrosive in humid atmosphere forming sulfuric acid. Pipeline specifications require removal of acid gases (carbon dioxide, CO_2) along with H_2S.

The stabilization process—basically a form of partial distillation—does two jobs at the same time: it sweetens "sour" crude oil (removes the hydrogen sulfide (H_2S) and carbon dioxide (CO_2)) and reduces vapor pressure, thereby making the crude safe for shipment in tankers. Vapor pressure is exerted by light hydrocarbons, such as methane, ethane, propane, and butane, changing from liquid to gas as the pressure on the crude is lowered. If a sufficient amount of these light hydrocarbons is removed, the vapor pressure becomes satisfactory for shipment at approximately atmospheric pressure.