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CRUDE OIL PROCESSING

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The main purpose of the training manual is to teach the students the basic methods of Crude Oil Processing.

Training manual provides well-organized theoretical and technical background knowledge on oil and gas field operations. Emphasis is given to the separation of the produced reservoir fluids, oil, gas, and water, as well as their subsequent treatments at various facilities at the oil field in order to produce marketable quantities of the products.

The manual is intended for the students trained on a specialty 6.050304 "Oil and gas extraction" in English

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THE LIST OF ABBREVIATIONS

GOSP – gas–oil separation plant;
BS&W – basic sediments and water;
PTB – pounds of salt per thousand barrels of oil;
API – American Petroleum Institute;
CCR – Conradson carbon residue;
RVP – Reid Vapor Pressure;
ppm – parts per million;
PTB – per 1000 barrels of oil;
ASTM – American Society for Testing and Materials
TBP – true boiling point;
EFV – equilibrium flash vaporization;
RR – reflux ratio;
GOR – gas–oil ratio;
VRU – vapor recovery unit;
LTS – Low-temperature separator;
PTB – pounds per thousand barrels (of oil);
MOM – multiple-orifice plate mixers;
PPI – parallel plate interceptors;
CPI – corrugated plate interceptors;
PFD – process flow diagram.

LECTURE 1
CRUDE OIL COMPOSITION

Crude oil processing

Crude oil–gas–water mixtures produced from wells are generally directed through flowlines and manifold system to a central processing and treatment facility normally called the gas–oil separation plant (GOSP). The first step in processing of the produced stream is the separation of the phases (oil, gas, and water) into separate streams. This takes place in mechanical devices known as two-phase gas–oil separators when the produced stream contains no water or three-phase separators when the produced stream contains water. Gas–oil separation carried out in these separators is recognized as the backbone process in a train of field processing units of oil and gas operations. The separators are used to relieve the excess pressure due to the gas associated with the produced crude and, consequently, separating it from the oil. When water exists in the produced stream, separators are also used to separate the free water from the oil. Once separation is done, each stream undergoes the proper processing for further field treatment, as shown in Fig. 1.1.

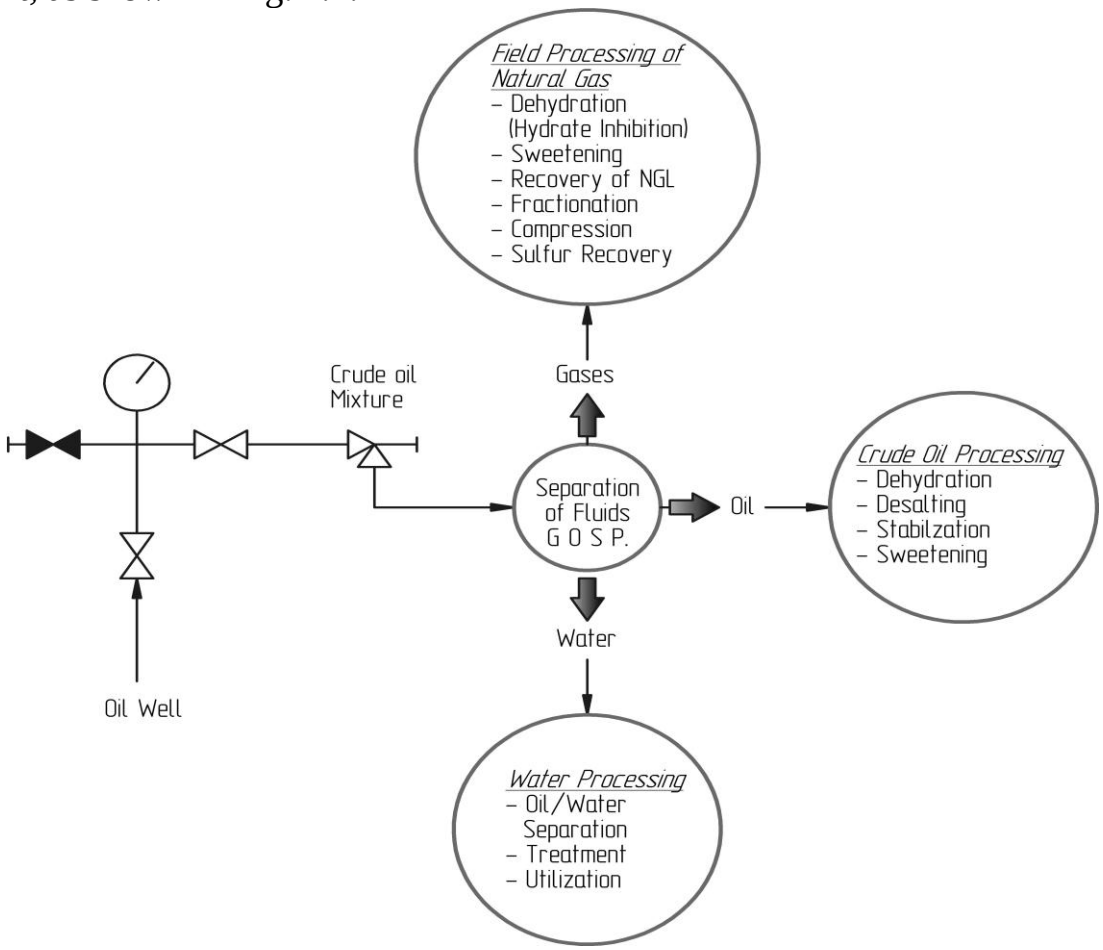

Figure 1.1 – An outline of the processing surface field operations

Oil leaving the separator does not generally meet the purchaser's specifications. Oil may still contain between 10% and 15% water that exists mostly as emulsified water. The presence of this salt water presents serious corrosion and scaling problems in transportation and refinery operations. Water remaining in the oil is known as the basic sediments and water (BS&W). A maximum of 1% BS&W and in some cases less than 0.5% BS&W is acceptable. The limit on the salt content of the remnant water in oils is usually in the range of 10 to 15 PTB (pounds of salt per thousand barrels of oil) [of 3.7 to 5.6 kg]. If these specifications are not met, then further treatment of the oil leaving the separator will be needed. Such treatment involves emulsion treatment/dehydration and desalting processes.

After oil treating, there may be a need to stabilize the crude oil to optimize the oil recovery and reduce its volatility. Some produced crude oils contain hydrogen sulfide and other sulfur products. When it contains more than 400 ppm of H_2S gas, the oil is classified as sour crude. Sour crude oils present serious safety and corrosion problems. In such cases, another treatment known as the sweetening process is needed to remove hydrogen sulfide or reduce its content to acceptable limits (Table 1.1).

Table 1.1 – Comparison of crude and treated crude oil

Crude oil	Characteristics:	Treated crude oil	Characteristics:
Water in 2 forms:		Water content	0.3 % maximum
emulsion	10%		
free water	30%		
Salt	50,000 – 250,000 mg/L formation water	Salt content	10 lbs (such as NaCl) per 1000 barrels of oil 3.73 kg of salt per 159,000 liters of oil
Gas:		Gas (only H_2S)	70 ppm
dissolved	600 scf/bbl crude oil 17 scm/bbl crude oil	Vapor pressure	10 psig (4-5 psi RVP) 0.7 bar (0.28-0.35 bar RVP)
H_2S	1000 ppm		

Crude oil composition

Crude oils are complex mixtures of a vast number of hydrocarbon compounds. Properties of crude petroleum vary appreciably and depend mainly on the origin. In this chapter, the chemical composition of the crude oils is viewed, including the hydrocarbon series as well as the nonhydrocarbon compounds. Physical methods generally used for identifying types of crude oils are described next.

Identification of the hydrocarbon constituents of crude oils and associated natural gas along with their corresponding commercial products are summarized in Table 1.2 [1].

Table 1.2 – Constituents of Crude Oil and Associated Gases*)

Hydrocarbons Identification of constituents			In the field streams										As commercial product
			Liquid phase (at normal conditions)				Two phases			Gaseous phases (and liquefied gases)			
Name	Formula	Normal B, P (°C)											
Methane	CH_4	-161,7					Field separator gas	Gas condensate well effluent	Crude oil well effluent	LNG	Dry gas		Natural gas
Ethane	C_2H_6	-88,9										NGL	Natural gas
Propane	C_3H_8	-42,2											Natural gas, propane
Isobutane	i-C_4H_{10}	-11,7	Stock tank crude oil	Stock tank condensate		Natural gasoline							Natural gasoline, butane
n-butane	n-C_4H_{10}	-0,6			Debutanized condensate							LPG	Natural gasoline, motor fuel, butane
Pentanes	C_5H_{12}	32,2											Natural gasoline, motor fuel
Hexane	C_6H_{14}	62,8											Natural gasoline, motor fuel
Heptane	C_7H_{16}	90,6											Natural gasoline, motor fuel
Octane	C_8H_{18}	118,3											Natural gasoline, motor fuel
Decanes	$C_{10}H_{22}$	173,9											Motor fuel
Tetradocane	$C_{14}H_{30}$	254,4											Kerosene, light furnace oil
Hexadecane	$C_{16}H_{34}$	287,2											Mineral seal oil, furnace oil
Triacontane	$C_{30}H_{62}$	457,2											Light lubricating oil, heavy fuel oil
Tetracontane	$C_{40}H_{62}$	544,4											Lubricating oil, heavy fuel oil
Asphalthene	$C_{80}H_{162}$	648,9											Asphalt, road oil, bunker fuel oil

- LPG – liquefied petroleum gases, NGL – natural gas liquid (normally $C_3^{+)}$, LNG – Liquefied natural gas

In general, composition of crude oil may be studied by two methods:

- Chemical approach;
- Physical methods.

Chemical composition describes and identifies the individual chemical compounds isolated from crude oils over the years. Physical representation, on the other hand, involves considering the crude oil and its products as mixtures of hydrocarbons and describing physical laboratory tests or methods for characterizing their quality.

Chemical Approach

Nearly all petroleum deposits are made up of a mixture of chemical compounds that consist of hydrogen and carbon, known as hydrocarbons, with varying amounts of nonhydrocarbons containing S, N_2, O_2, and other some metals. The composition of crude oil by elements is approximated as shown in Table 1.3 [1].

Table 1.3 – Composition of Petroleum Crude

Element	Percent by Weight
Carbon	83 - 87
Hydrogen	11 - 14
Sulfur	0.05 – 2.5
Nitrogen	0.1 - 2
Oxygen	0 - 2
Note: sulfur, nitrogen and oxygen are regarded as impurities	

It could be further stated that these hydrocarbon compounds making up oils are grouped chemically into different series of compounds described by the following characteristics:

- each series consists of compounds similar in their molecular structure and properties (e.g., the alkanes or paraffin series);
- within a given series, there exists a wide spectrum of compounds that range from extremely light or simple hydrocarbon to a heavy or complex one. For example: CH_4 for the former and $C_{40}H_{82}$ for the latter in the paraffinic series.

Hydrocarbon Series

The major constituents of most crude oils and its products are hydrocarbon compounds, which are made up of hydrogen and carbon only. These compounds belong to one of the following subclasses:

1. Alkanes or Paraffins: Alkanes are saturated compounds having the general formula C_nH_{2n+2}. Alkanes are relatively nonreactive compounds in comparison to other series. They may either be straight-chain or branched, the latter are more valuable than the former, because they are useful for the production of high-octane gasoline.

2. Cycloalkanes or Cycloparaffins (Naphtenes): Cycloalkanes and bicycloalkanes are normally present in crude oils and its fractions in variable

proportions. The presence of large amounts of these cyclic compounds in the naphtha range has its significance in the production of aromatic compounds. Naphtha cuts with a high percentage of naphthenes would make an excellent feedstock for aromatization.

3. Alkenes or Olefins: Alkenes are unsaturated hydrocarbon compounds having the general formula C_nH_n. They are practically not present in crude oils, but they are produced during processing of crude oils at high temperatures. Alkenes are very reactive compounds. Light olefinic hydrocarbons are considered the base stock for many petrochemicals. Ethylene, the simplest alkene, is an important monomer in this regard. For example, polyethylene is a well known thermoplastic polymer and polybutadiene is the most widely used synthetic rubber.

4. Aromatics: Aromatic compounds are normally present in crude oils. Only monomolecular compounds in the range of C6–C8 (known as B-T-X) have gained commercial importance. Aromatics in this range are not only important petrochemical feedstocks but are also valuable for motor fuels. Dinuclear and polynuclear aromatic compounds are present in heavier petroleum fractions and residues. Asphaltenes, which are concentrated in heavy residues and in some asphaltic crude oils, are, in fact, polynuclear aromatics of complex structures. It has been confirmed by mass spectroscopic techniques that condensed-ring aromatic hydrocarbons and heterocyclic compounds are the major compounds of asphaltenes.

Nonhydrocarbon Compounds

So far, a brief review of the major classes of the hydrocarbon compounds that exist in crude oils and their products was presented. For completeness, we should mention that other types of nonhydrocarbon compound occur in crude oils and refinery streams. Most important are the following:

- sulfur compounds;
- nitrogen compounds;
- oxygen compounds;
- metallic compounds.

Sulfur Compounds. In addition to the gaseous sulfur compounds in crude oil, many sulfur compounds have been found in the liquid phase in the form of organosulfur. These compounds are generally not acidic.

Sour crude oils are those containing a high percentage of hydrogen sulfide. However, many of the organic sulfur compounds are not thermally stable, thus producing hydrogen sulfide during crude processing. High-sulfur crude oils are in less demand by refineries because of the extra cost incurred for treating refinery products. Naphtha feed to catalytic reformers is hydrotreated to reduce sulfur compounds to very low levels (1 ppm) to avoid catalyst poisoning.

The following sulfur compounds are typical:

1. Mercaptans (H–S–R): Hydrogen sulfide, H–S–H, may be considered as the simple form of mercaptan; however, the higher forms of the series are even more objectionable in smell. For example, butyl mercaptan ($H–S–C_4H_9$) is responsible for the unusual odor of the shank.

2. Sulfides (R–S–R): When an alkyl group replaces the hydrogen in the sulfur-containing molecule, the odor is generally less obnoxious. Sulfides could be removed by the hydrotreating technique, which involves the hydrogenation of the petroleum streams as follows:

- R-S-R + 2H-H → 2R-H + H-S-H;
- R-S-R + H+H → R-R + H-S-H.

The hydrogen sulfide may be removed by heating and may be separated by using amine solutions.

3. Polysulfides (R–S–S–R): These are more complicated sulfur compounds and they may decompose, in some cases depositing elemental sulfur. They may be removed from petroleum fractions, similar to the sulfides, by hydrotreating.

Nitrogen Compounds

Nitrogen compounds in crude oils are usually low in content (about 0.1–0.9%) and are usually more stable than sulfur compounds. Nitrogen in petroleum is in the form of heterocyclic compounds and may be classified as basic and nonbasic.

Basic nitrogen compounds are mainly composed of pyridine homologs and have the tendency to exist in the high-boiling fractions and residues.

The nonbasic nitrogen compounds, which are usually of the pyrrole and indole, also occur in high-boiling fractions and residues. Only a trace amount of nitrogen is found in light streams.

During hydrotreatment (hydrodesulfurization) of petroleum streams, hydrodenitrogeneation takes place as well, removing nitrogen as ammonia gas, thus reducing the nitrogen content to the acceptable limits for feedstocks to catalytic processes. It has to be stated that the presence of nitrogen in petroleum is of much greater significance in refinery operations than might be expected from the very small amounts present. It is established that nitrogen compounds are responsible for the following:

- catalyst poisoning in catalytic processes;
- gum formation in some products such as domestic fuel oils.

Oxygen Compounds

Oxygen compounds in crude oils are more complex than sulfur compounds. However, oxygen compounds are not poisonous to processing catalysts. Most oxygen compounds are weakly acidic, such as phenol, cresylic acid and naphthenic acids. The oxygen content of petroleum is usually less than 2%, although larger amounts have been reported.

Metallic Compounds

Many metals are found in crude oils; some of the more abundant are sodium, calcium, magnesium, iron, copper, vanadium, and nickel. These normally occur in the form of inorganic salts soluble in water—as in the case of sodium chloride—or in the form of organometallic compounds—as in the case of iron, vanadium, and nickel.

The occurrence of metallic constituents in crude oils is of considerably greater interest to the petroleum industry than might be expected from the very small amounts present. The organometallic compounds are usually concentrated in the heavier fractions and in crude oil residues. The presence of high concentration of vanadium compounds in naphtha streams for catalytic reforming feeds will cause permanent poisons. These feeds should be hydrotreated not only to reduce the metallic poisons but also to desulfurize and denitrogenate the sulfur and nitrogen compounds.

Hydrotreatment may also be used to reduce the metal content in heavy feeds to catalytic cracking.

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LECTURE 2
PHYSICAL PROPERTIES OF CRUDE OIL

Crude oils from different locations may vary in appearance and viscosity and also vary in their usefulness as producers for final products. It is possible by the use of certain basic tests to identify the quality of crude oil stocks. The tests included in the following list are primarily physical (except sulfur determination):

1) distillation;
2) density, specific gravity, and API (American Petroleum Institute) gravity;
3) viscosity;
4) vapor pressure;
5) flash and fire points;
6) cloud and pour points;
7) color;
8) sulfur content;
9) basic sediments and water (B.S.&W.);
10) aniline point;
11) carbon residue.

The details of some of these tests are described next.

API Gravity

Earlier, density was the principal specification for petroleum products. However, the derived relationships between the density and its fractional composition were only valid if they were applied to a certain type of petroleum. Density is defined as the mass of a unit volume of material at a specified temperature. It has the dimensions of grams per cubic centimeter.

Another general property, which is more widely, is the specific gravity. It is the ratio of the density of oil to the density of water and is dependent on two temperatures, those at which the densities of the oil sample and the water are measured. When the water temperature is 4°C (39°F), the specific gravity is equal to the density in the CGS system (centimeters-gram-second system), because the volume of 1 g of water at that temperature is, by definition, 1 mL. Thus, the density of water, for example, varies with temperature, whereas its specific gravity is always unity at equal temperatures. The standard temperatures for specific gravity in the petroleum industry in North America are 60/60°F and 15.6/15.6°C all over the world.

Although density and specific gravity are used extensively in the oil industry, the API gravity is considered the preferred property. It is expressed by the following relationship:

$$API = \frac{141.5}{\gamma} - 131.5$$

where γ - is the oil specific gravity at 60°F (15.6°C). Thus, in this system, a liquid with a specific gravity of 1.00 will have an *API* of 10 deg. A higher *API* gravity indicates a lighter crude or oil product, whereas a low *API* gravity implies a heavy crude or product.

Carbon Residue

Carbon residue is the percentage of carbon by weight for coke, asphalt, and heavy fuels found by evaporating oil to dryness under standard laboratory conditions. Carbon residue is generally referred to as CCR (Conradson carbon residue). It is a rough indication of the asphaltic compounds and the materials that do not evaporate under conditions of the test, such as metals and silicon oxides.

Viscosity

The viscosity is the measure of the resistance of a liquid to flow, hence indicating the «pumpability» of oil.

Pour Point

This is defined as the lowest temperature ($5^{o}F/-15^{o}C$) at which the oil will flow. The lower the pour point, the lower the paraffin content of the oil.

Ash Content

This is an indication of the contents of metal and salts present in a sample. The ash is usually in the form of metal oxides, stable salts, and silicon oxides. The crude sample is usually burned in an atmosphere of air and the ash is the material left unburned.

Reid Vapor Pressure

The Reid Vapor Pressure (RVP) is a measure of the vapor pressure exerted by oil or by light products at $100^{o}F/37,8^{o}C$.

Metals

In particular, arsenic, nickel, lead, and vanadium are potential poisons for process catalysts. Metal contents are reported in parts per million (ppm).

Nitrogen

It is the weight of total nitrogen determined in a liquid hydrocarbon sample (in ppm). Nitrogen compounds contribute negatively to process catalysts.

Salt Content

Salt content is typically expressed as pounds of salt (sodium chloride, NaCl) per 1000 barrels of oil (PTB). Salts in crude oil and in heavier products may create serious corrosion problems, especially in the toptower zone and the overhead condensers in distillation columns.

Sulfur

This is the percentage by weight (or ppm) of total sulfur content determined experimentally in a sample of oil or its product. The sulfur content of crude oils is taken into consideration in addition to the API gravity in determining their commercial values. It has been reported that heavier crude oils may have high sulfur content [2].

Hydrogen Sulfide

Hydrogen sulfide dissolved in a crude oil or its products is determined and measured in parts per million. It is a toxic gas that can evolve during storage or in the processing of hydrocarbons.

The above tests represent many properties for the crude oils that are routinely measured because they affect the transportation and storage facilities. In addition, these properties define what products can be obtained from a crude oil and contribute effectively to safety and environmental aspects. The price of a crude oil is influenced by most of these properties.

To conclude, it can be stated that light and low-sulfur crude oils are worth more than heavy and high-sulfur ones. One can summarize the two approaches of examining crude oils as follows:

1. Chemical composition
2. Physical properties:

(a) API, S, salt, metals, nitrogen and so forth;

(b) Distillation: ASTM, TBP, EFV;

(c) Correlations: Kw, Ind,

where ASTM is Americal Society for Testing and Materials distilation TBP is true boiling point, EFV is equilibrium flash vaporization, Kw is Watson characterization factor, Ind is U.S. Bureau of Mines correlation index.

Crude oil comparisons and crude oil assay

In order to establish a basis for the comparison between different types of crude oil, it is necessary to produce experimental data in the form of what is known as an "assay". Crude assays are the systematic compilation of data for the physical properties of the crude and its fractions, as well as the yield. In other words, a crude assay involves the determination of the following:

- the properties of crude oil;
- the fractions obtained: (a) their percentage yield and (b) properties.

Analytical testing only without carrying out distillation may be considered an assay. However, the most common assay is a comprehensive one that involves all of the above-stated parameters.

The basis of the assay is the distillation of a crude oil under specified conditions in a batch laboratory distillation column, operated at high efficiency [column with 14 plates and reflux ratio (RR)]. Pressure in column is reduced in stages to avoid thermal degradation of high boiling components.

A comparison of the characteristics of different types of crude oil over the distillation range could be made via a graph that relates the following:

- the density of distillate fractions;
- their mid-boiling points.

Such a comparison is illustrated in Figure 2.1 [3]. The density level of a crude at given boiling point on the curve is a function of the relative

proportions of the main three hydrocarbon series: aromatics, cycloparaffins, paraffins; their densities decrease in that order.

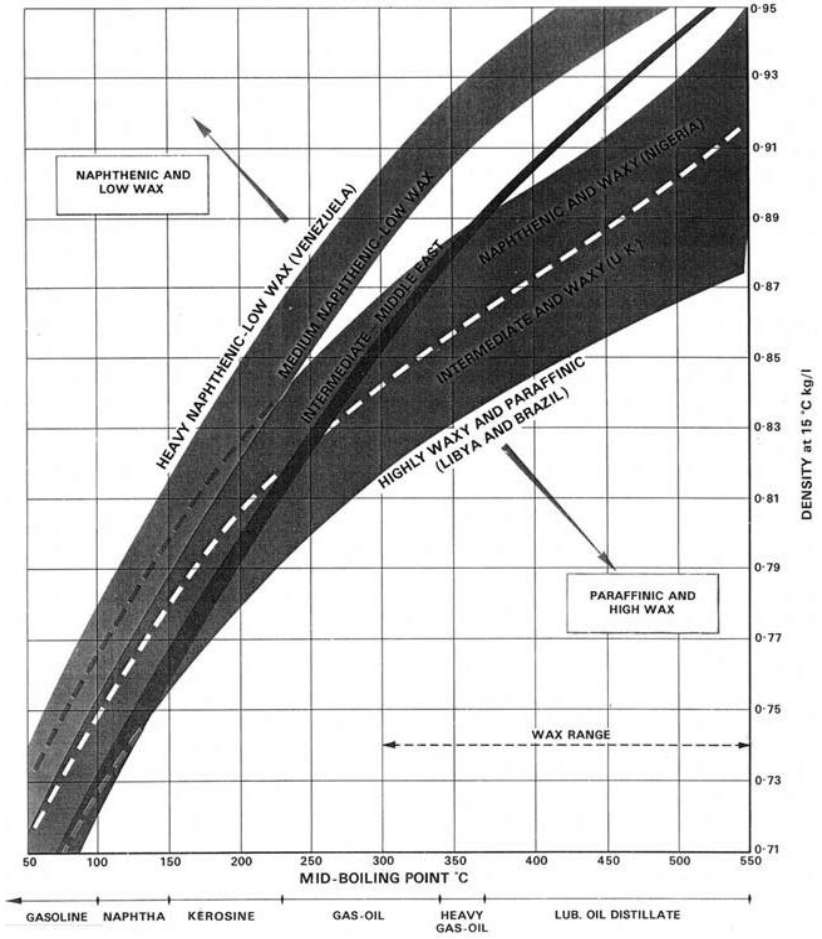

Figure 2.1 – Comparison of crude oils density/mid-boiling point basis [4]

In order to show how the properties of crude oils affect strongly processing requirements, product expectations, storage and transportation, and others, a comparison is presented as given in Table 2.1.

Table 2.1 – Properties of Some Reference Crude Oils

Property	Arabian light	Arun Indonesia	Beryl N.S Canada	Nigerian light	SJV Calif.
API (gravity)	33.9	54.1	36.5	37.6	15.2
Pour Point (^{o}F/^{o}C)	—45/-42.8	—55/-48.3	20/-6.7	5/-15	—5/-20.6
CCR (wt%)	3.6	0.01	1.3	1.1	7.0
Sulfur (wt%)	1.8	> 0.1	0.42	0.13	1.05
Nitrogen (ppm)	60	50	880	0.06	6200
Nickel (ppm)	3	0.65	0.8	3.6	63
Vanadium (ppm)	19	0.15	3.7	0.3	60
Salt Content (PTB)/ kg	10/3.73	3/1.1	7.4/2.8	5/1.9	14/5.2

Table 2.2, on the other hand, gives the percent yield and other characteristics of the fractions obtained by the distillation of a typical Arabian crude oil having an API gravity of about 34–37.

Table 2.2 – Fractions Obtained from Arabian Crude

Fractions	**Percent yield**	**No. of carbon atoms in molecule**	**Boiling range (^{o}C)**
Gases (dry/wet)	2	1–2	- 162 to - 90 dry
		3–4	- 48 to -1 wet
Naphtha	20–26	5–12	32–182
Kerosene	7–12	10–15	160–238
Diesel oil	10–14	12–20	204–316
Wax distillate	15–20	17–22	260–371
Residuum	35–40	20–90	316 and above

Crude oil classifications and characterization and classifications

Although there is no specific method for classifying crude oils, it would be useful to establish simple criteria to quantify the crude quality. Numerous attempts have been made to devise a system to classify crude oils into types based on the predominant hydrocarbon series present in the crude. Such attempts have only partially succeeded. In the OPEC, crude oils are classified into three types:

- paraffinic: paraffinic hydrocarbons with a relatively lower percentage of aromatics and naphthenes;
- naphthenic: cycloparaffins in a higher ratio and a higher amount of asphalt than in paraffinic crudes;
- asphaltic: fused aromatic compounds and asphalt in higher amounts.

Another method of classification is the following:

1) paraffinic base;
2) mixed base;
3) naphthenic base.

Based on this classification, a rating for the processing of crude oils is envisaged as follows for the production of certain products and their treatment (Table 2.3).

Table 2.3 - Rating for the processing of crude

Products / Type of oil:	Lub. oil	Asphalt	Gasoline	Treatment of products
Paraffinic	1	3	3	1
Mixed	2	2	2	2
Naphthenic	3	1	1	3
Rating: 1 - excellent; 2 - good; 3 – poor.				

Characterization Factors

Correlation indexes or characterization factors are used in the petroleum industry to indicate the crude type or class. There are several correlations between yield and type of crude in terms of aromaticity and paraffinicity. The two most widely accepted relationships are the following:

- Watson characterization factor:

$$K_W = \frac{T_b^{1/3}}{\gamma_o}$$

- U.S. Bureau of Mines Correlation Index:

$$Ind = T_b \cdot 87.552 + 473.7 \cdot \gamma_o - 456.8$$

where γ_o - is the specific gravity at 60 ^{o}F (15.6 ^{o}C) and T_b is the mean average boiling point (^{o}R).

The Watson factor ranges from 10.5, for highly naphthenic crude oils, to 12.9, for the paraffinic type [4].

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LECTURE 3
TWO-PHASE GAS–OIL SEPARATION

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. Some means must be provided to separate the gas from oil without losing too much oil.

In general, well effluents flowing from producing wells come out in two phases: vapor and liquid under a relatively high pressure. The fluid emerges as a mixture of crude oil and gas that is partly free and partly in solution. Fluid pressure should be lowered and its velocity should be reduced in order to separate the oil and obtain it in a stable form. This is usually done by admitting the well fluid into a gas–oil separator plant (GOSP) through which the pressure of the gas–oil mixture is successively reduced to atmospheric pressure in a few stages.

Upon decreasing the pressure in the GOSP, some of the lighter and more valuable hydrocarbon components that belong to oil will be unavoidably lost along with the gas into the vapor phase. This puts the gas–oil separation step as the initial one in the series of field treatment operations of crude oil. Here, the primary objective is to allow most of the gas to free itself from these valuable hydrocarbons, hence increasing the recovery of crude oil.

In some fields, no salt water will flow into the well from the reservoir along with the produced oil. This is the case we are considering in this lecture, where it is only necessary to separate the gas from the oil; (i.e., two-phase separation).

High-pressure crude oils containing large amount of free and dissolved gas flow from the wellhead into the flowline, which routes the mixture to the GOSP. In the separator, crude oil separates out, settles, and collects in the lower part of the vessel. The gas, lighter than oil, fills the upper part of the vessel. Crude oils with a high gas–oil ratio (GOR) must go through two or more stages of separation. Gas goes out the top of the separators to a gas collection system, a vapor recovery unit (VRU), or a gas flowline. 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. 3.1).

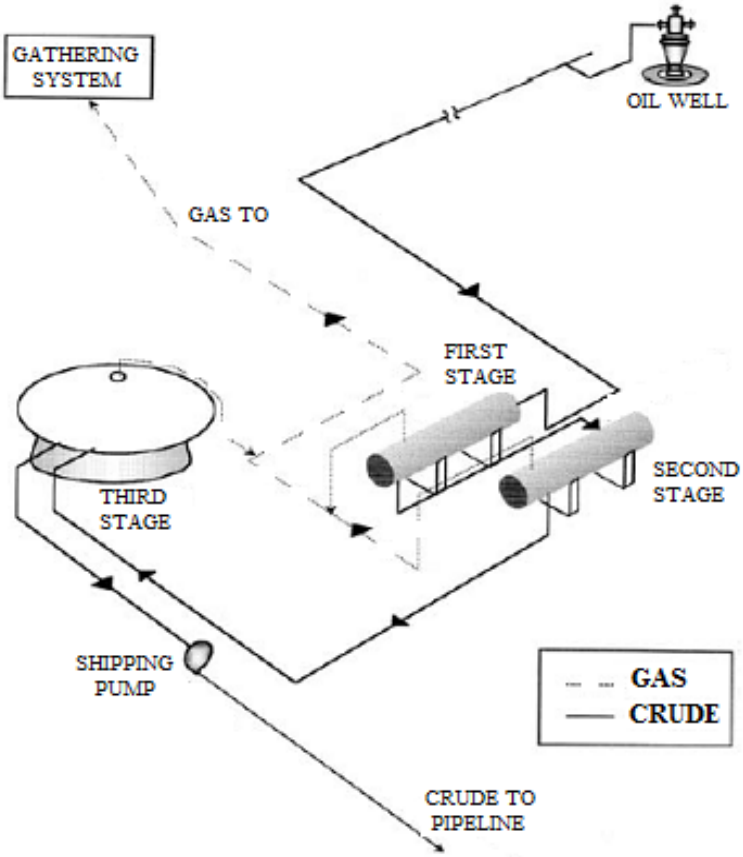

Figure 3.1 – Flow of crude oil from oil well through GOSP [3]

Movement of the crude oil within the GOSP takes place under the influence of its own pressure. Pumps, however, are used to transfer the oil in its final trip to the tank farm, or pipeline (Fig. 3.2).

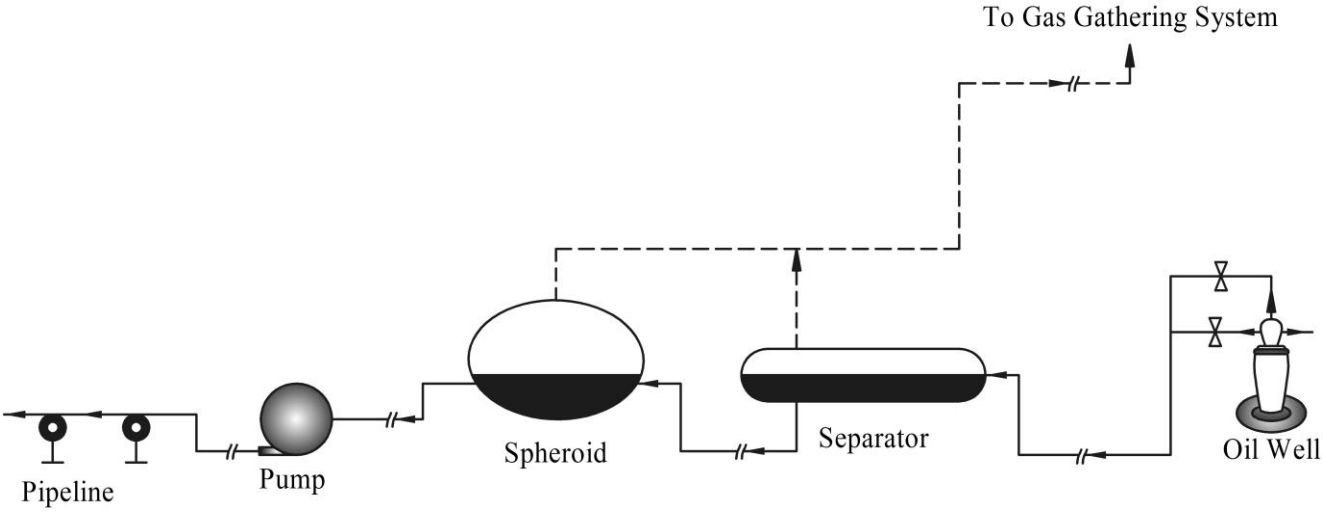

Figure 3.2 – Separation of gas from oil

Pressure reduction in moving the oil from stage to stage is illustrated in Fig. 3.3.

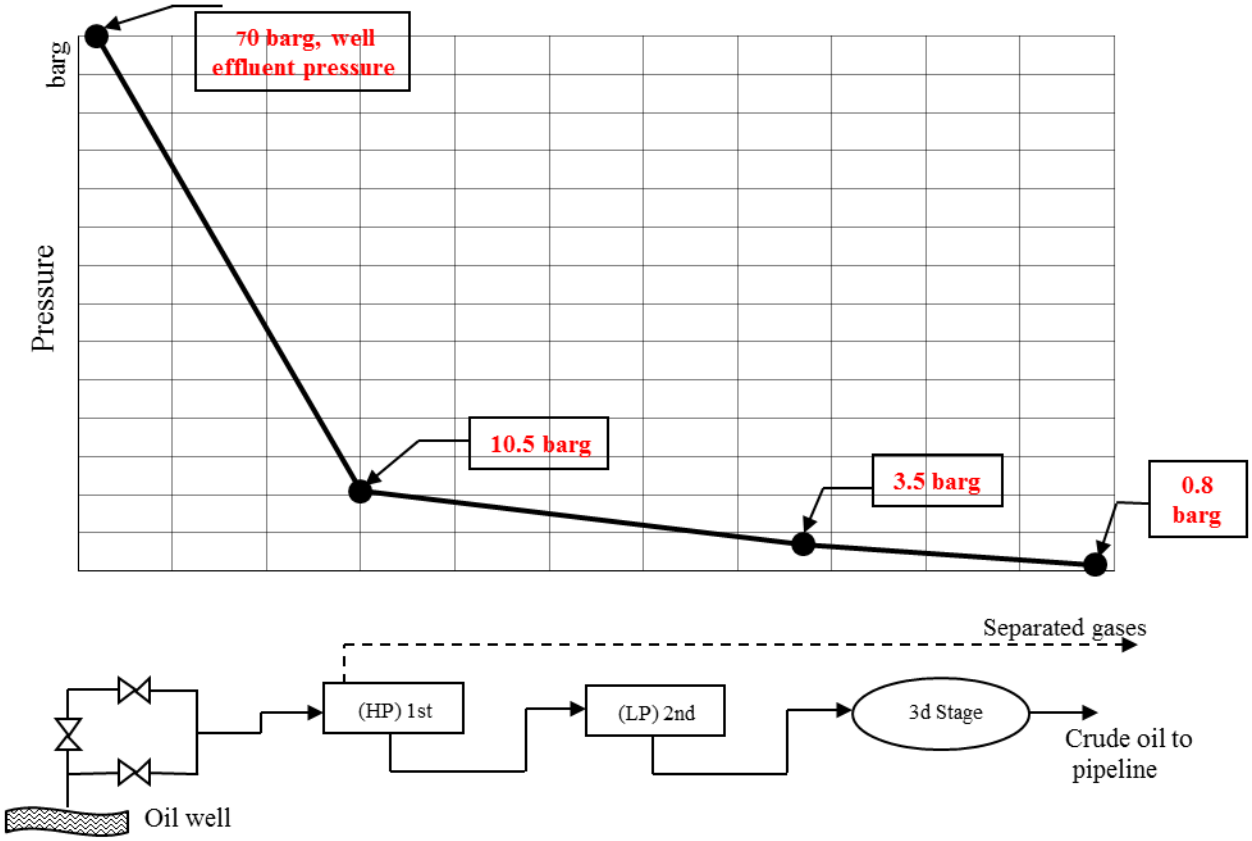

Figure 3.3 – Pressure-drop profile for a typical GOSP in the Middle East

Gas–Oil Separation Equipment

The conventional separator is the very first vessel through which the well effluent mixture flows. In some special cases, other equipment (heaters, water knockout drums) may be installed upstream of the separator. The essential characteristics of the conventional separator are the following:

1. It causes a decrease in the flow velocity, permitting separation of gas and liquid by gravity.

2. It always operates at a temperature above the hydrate point of the flowing gas.

The choice of a separator for the processing of gas–oil mixtures containing water or without water under a given operating conditions and for a specific application normally takes place guided by the general classification illustrated in Figure 3.4.

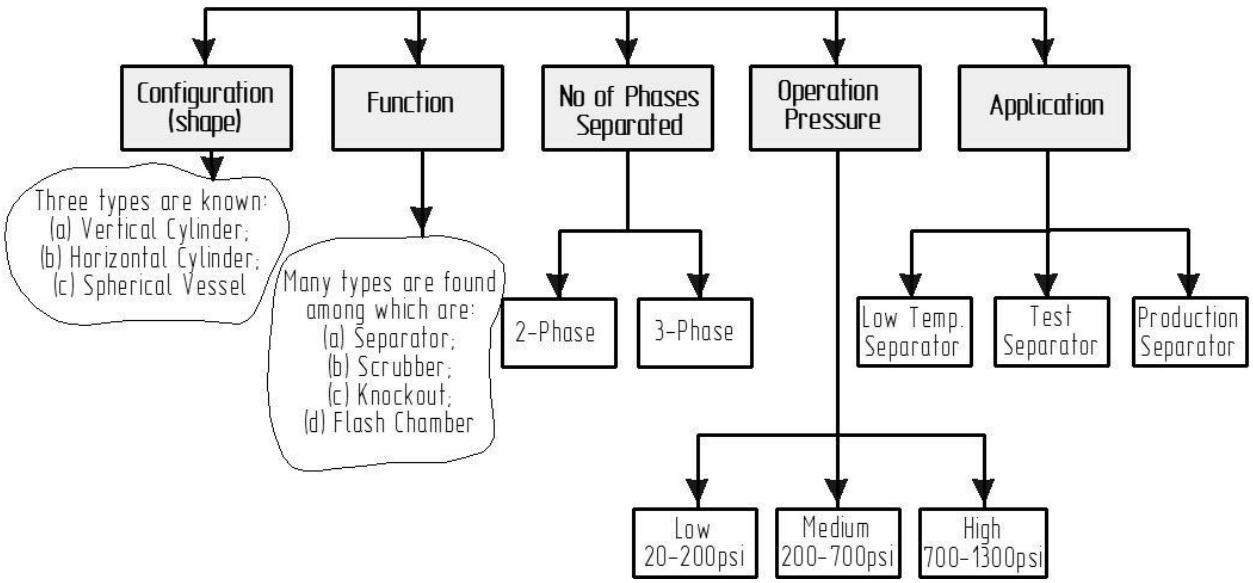

Figure 3.4 – Classification of separators

Functional Components of a Gas–Oil Separator

Regardless of their configuration, gas–oil separators usually consist of four functional sections, as shown in Figure 3.5:

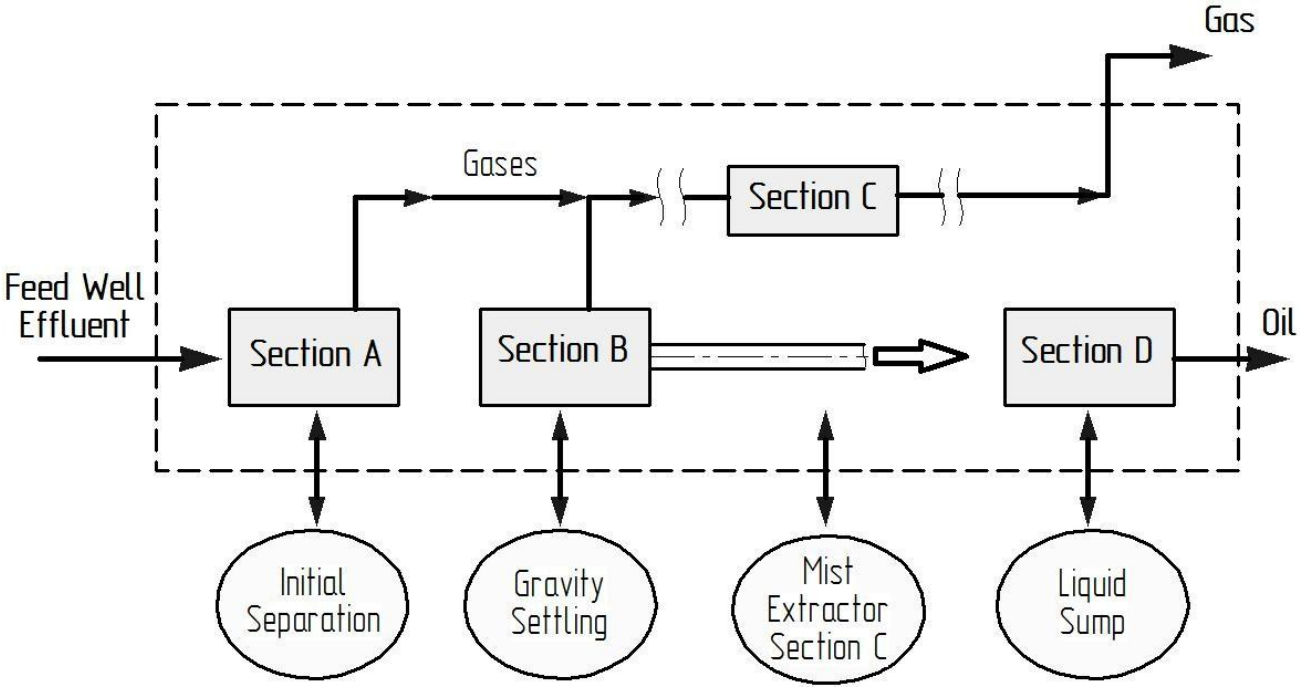

Figure 3.5 – Schematic outline of the main components in a gas–oil separator

1. Section A: Initial bulk separation of oil and gas takes place in this section. The entering fluid mixture hits the inlet diverter. This causes a sudden change in momentum and, due to the gravity difference, results in bulk separation of the gas from the oil. The gas then flows through the top part of the separator and the oil through the lower part.

2. Section B: Gravity settling and separation is accomplished in this section of the separator. Because of the substantial reduction in gas velocity and the density difference, oil droplets settle and separate from the gas.

3. Section C: Known as the mist extraction section, it is capable of removing the very fine oil droplets which did not settle in the gravity settling section from the gas stream.

4. Section D: This is known as the liquid sump or liquid collection section. Its main function is collecting the oil and retaining it for a sufficient time to reach equilibrium with the gas before it is discharged from the separator.

The separation process at all of listed above section is shown at figure 3.6.

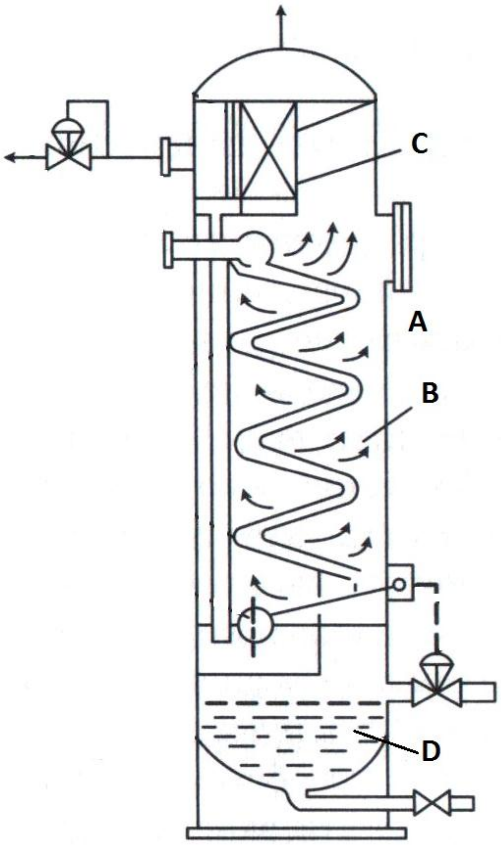

Figure 3.6 – Separation process

In separating the gas from oil, a mechanical mechanism could be suggested [3], as shown in Figure 3.7, which implies the following two steps:

(step 1) To separate oil from gas: Here, we are concerned primarily with recovering as much oil as we can from the gas stream. Density difference or gravity differential is responsible for this separation. At the separator's operating condition of high pressure, this difference in density between oil and gas becomes small (gas law). Oil is about eight times as dense as the gas. This could be a sufficient driving force for the liquid particles to separate and settle down. This is especially true for large-sized particles, having diameter of 100 mm or more. For smaller ones, mist extractors are needed.

(step 2) To remove gas from oil: The objective here is to recover and collect any nonsoluted gas that may be entrained or ‘‘locked’’ in the oil. Recommended methods to achieve this are settling, agitation, and applying heat and chemicals.

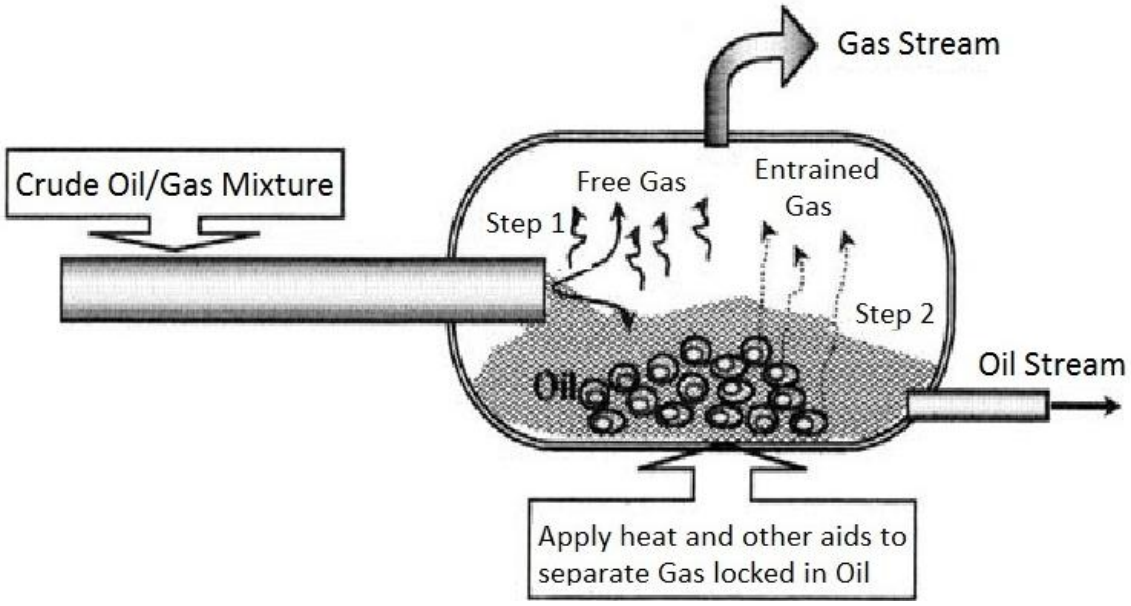

Figure 3.7 – Two-step mechanism of separating gas from oil [2]

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LECTURE 4
UPSTREAM PROCESS: COMMERCIAL TYPES OF GAS–OIL SEPARATOR

Based on the configuration, the most common types of separator are horizontal, vertical, and spherical, as illustrated in Figures 4.1, 4.2, and 4.3, respectively. A concise comparison among these three types is presented in Table 4.1. Large horizontal gas–oil separators are used almost exclusively in processing well fluids in the Middle East, where the gas–oil ratio of the producing fields is high. Multistage GOSPs normally consists of three or more separators.

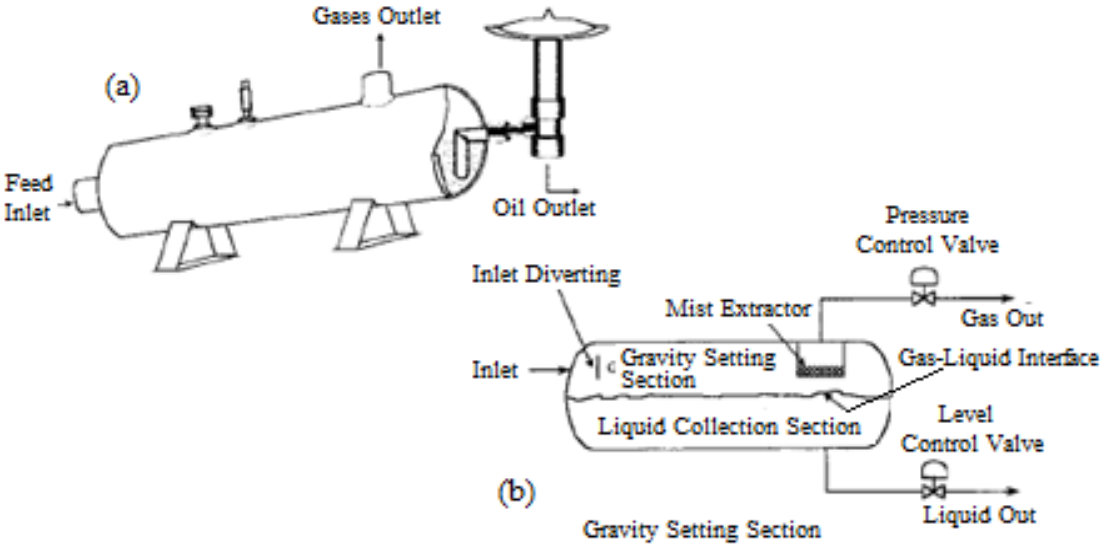


Figure 4.1 – (a) Single-barrel horizontal separator; (b) horizontal separator schematic [1]

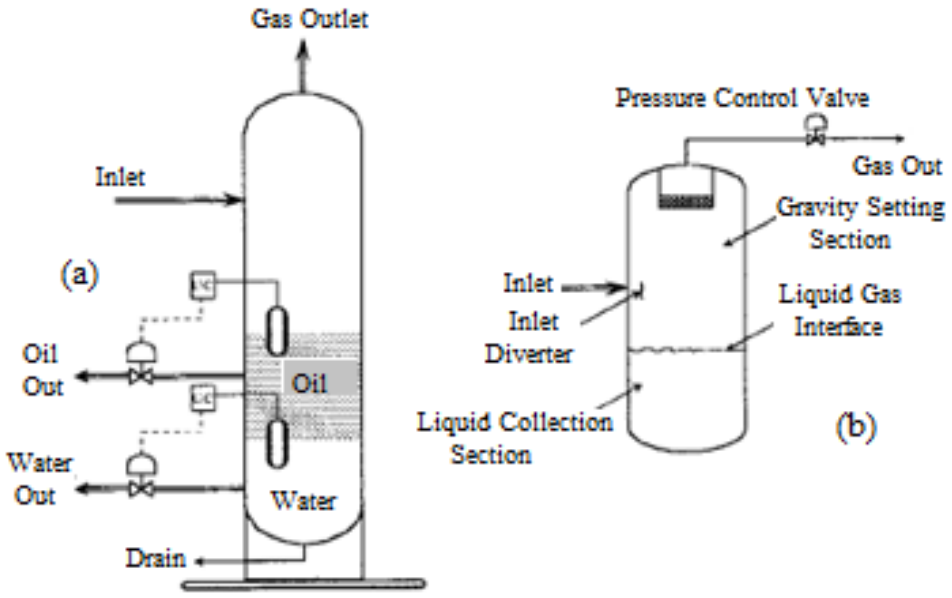


Figure 4.2 – (a) Vertical separator, three-phase operation; (b) vertical separator schematic [2]

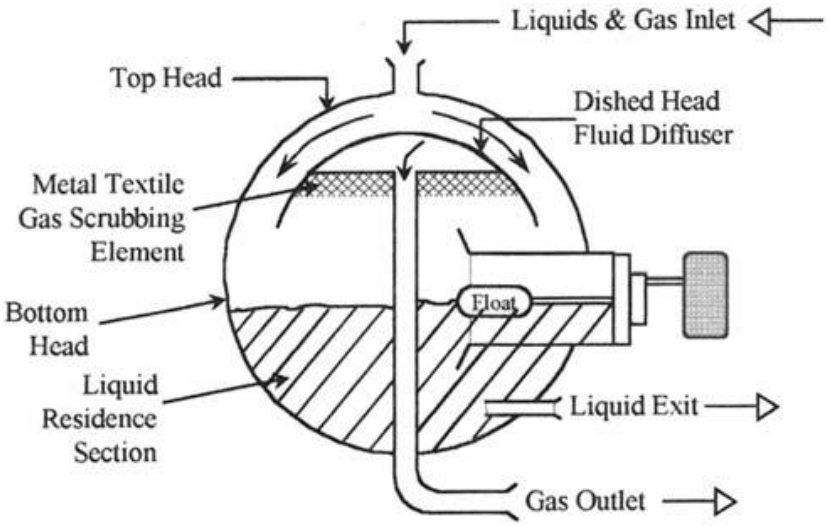
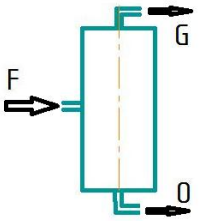
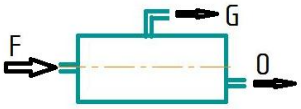
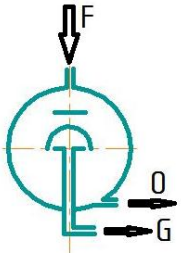


Figure 4.3 – Spherical separator [3]

Table 4.1 – Comparison among different configurations of gas–oil separators

Function	Vertical	Horizontal	Spherical
Usage	For low gas-oil ratio	For high gas-oil ratio	For small leases operating at moderate pressure
Location of inlet and outlet streams			
Capacity or efficiency	Large fluid capacity	Large gas capacity (handles high GOR)	Capacity rated less (low efficiency)
Handing foreign material	Rated No. 1	Rated No. 3	Rated No. 2
Separation efficiency	Rated No. 2	Rated No. 1	Rated No. 3
Rating in use in Middle East	Rated No. 2	Rated No. 1	Rated No. 3
Handing foaming oil	Rated No. 2	Rated No. 1	Rated No. 3
Maintenance and inspection	Very difficult	Accessible	Average
Cost per unit capacity	Average	Least expensive	Most expensive
Installation	Most difficult	Average	Easy

Controllers and Internal Components of Gas–Oil Separators

Gas–oil separators are generally equipped with the following control devices and internal components (figure 4.4) [4].

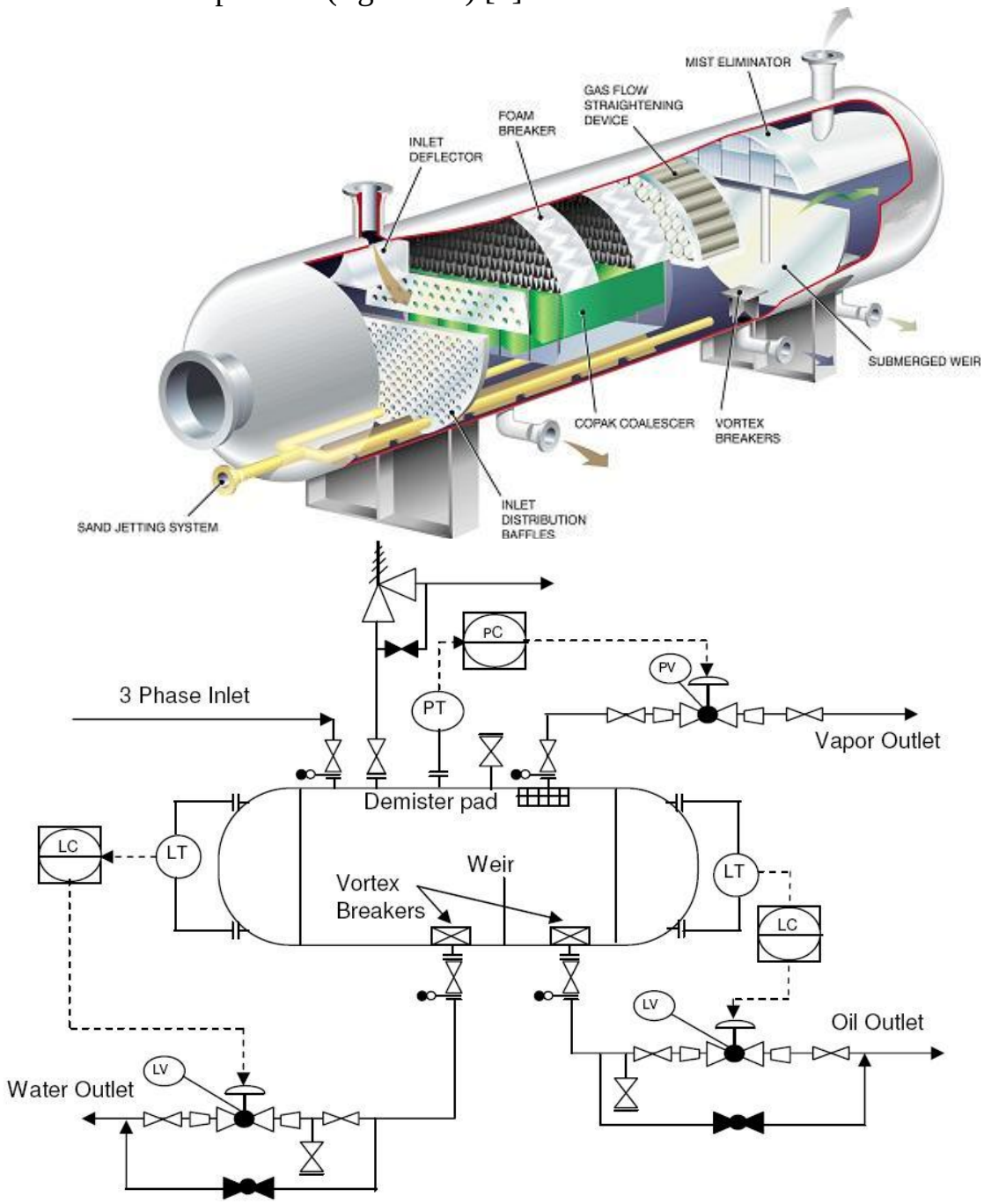


Figure 4.4 – Separator components (3-D and 2-D diagrams)

Liquid Level Controller

The liquid level controller (LLC) is used to maintain the liquid level inside the separator at a fixed height. In simple terms, it consists of a float that exists at the liquid–gas interface and sends a signal to an automatic diaphragm motor valve on the oil outlet. The signal causes the valve to open or close, thus allowing more or less liquid out of the separator to maintain its level inside the separator.

Pressure Control Valve

The pressure control valve (PCV) is an automatic backpressure valve that exists on the gas stream outlet. The valve is set at a prescribed pressure.

It will automatically open or close, allowing more or less gas to flow out of the separator to maintain a fixed pressure inside the separator.

Pressure Relief Valve

The pressure relief valve (PRV) is a safety device that will automatically open to vent the separator if the pressure inside the separator exceeded the design safe limit.

Mist Extractor

The function of the mist extractor is to remove the very fine liquid droplets from the gas before it exits the separator. Several types of mist extractors are available:

1. Wire-Mesh Mist Extractor: These are made of finely woven stainless-steel wire wrapped into a tightly packed cylinder of about 15 mm thickness. The liquid droplets that did not separate in the gravity settling section of the separator coalesce on the surface of the matted wire, allowing liquid-free gas to exit the separator. As the droplets size grows, they fall down into the liquid phase. Provided that the gas velocity is reasonably low, wire-mesh extractors are capable of removing about 99% of the 10-μm and larger liquid droplets. It should be noted that this type of mist extractor is prone to plugging. Plugging could be due to the deposition of paraffin or the entrainment of large liquid droplets in the gas passing through the mist extractor (this will occur if the separator was not properly designed). In such cases, the vane-type mist extractor, described next, should be used.

2. Vane Mist Extractor: This type of extractor consists of a series of closely spaced parallel, corrugated plates. As the gas and entrained liquid droplets flowing between the plates change flow direction, due to corrugations, the liquid droplets impinge on the surface of the plates, where they coalesce and fall down into the liquid collection section.

3. Centrifugal Mist Extractor: This type of extractor uses centrifugal force to separate the liquid droplets from the gas. Although it is more efficient and less susceptible to plugging than other extractors, it is not commonly used because of its performance sensitivity to small changes in flow rate.

Inlet Diverters

Inlet diverters are used to cause the initial bulk separation of liquid and gas. The most common type is the baffle plate diverter, which could be in the shape of a flat plate, a spherical dish, or a cone. Another type, is the centrifugal diverter; it is more efficient but more expensive. The diverter provides a means to cause a sudden and rapid change of momentum (velocity and direction) of the entering fluid stream. This, along with the difference in densities of the liquid and gas, causes fluids separation.

Wave Breakers

In long horizontal separators, waves may develop at the gas–liquid interface. This creates unsteady fluctuations in the liquid level and would negatively affect

the performance of the liquid level controller. To avoid this, wave breakers, which consist of vertical baffles installed perpendicular to the flow direction, are used.

Defoaming Plates

Depending on the type of oil and presence of impurities, foam may form at the gas–liquid interface. This results in the following serious operational problems:

1. Foam will occupy a large space in the separator that otherwise would be available for the separation process; therefore, the separator efficiency will be reduced unless the separator is oversized to allow for the presence of foam.

2. The foam, having a density between that of the liquid and gas, will disrupt the operation of the level controller.

3. If the volume of the foam grows, it will be entrained in the gas and liquid streams exiting the separator; thus, the separation process will be ineffective. The entrainment of liquid with the exiting gas is known as liquid carryover. Liquid carryover could also occur as a result of a normally high liquid level, a plugged liquid outlet, or an undersized separator with regard to liquid capacity. The entrainment of gas in the exiting liquid is known as gas blowby. This could also occur as a result of a normally low liquid level, an undersized separator with regard to gas capacity, or formation of a vortex at the liquid outlet.

Foaming problems may be effectively alleviated by the installation of defoaming plates within the separator. Defoaming plates are basically a series of inclined closely spaced parallel plates. The flow of the foam through such plates results in the coalescence of bubbles and separation of the liquid from the gas.

In some situations, special chemicals known as foam depressants may be added to the fluid mixture to solve foaming problems. The cost of such chemicals could, however, become prohibitive when handling high production rates.

Vortex Breaker

A vortex breaker, similar in shape to those used in bathroom sink drains, is normally installed on the liquid outlet to prevent formation of a vortex when the liquid outlet valve is open. The formation of a vortex at the liquid outlet may result in withdrawal and entrainment of gas with the exiting liquid (gas blowby).

Sand Jets and Drains

Formation sand may be produced with the fluids. Some of this sand will settle and accumulate at the bottom of the separator. This takes up separator volume and disrupts the efficiency of separation. In such cases, vertical separators will be preferred over horizontal separators. However, when horizontal separators are needed, the separator should be equipped with sand jets and drains along the bottom of the separator. Normally, produced water is injected though the jets to fluidize the accumulated sand, which is then removed through the drains.

The following is a brief description of some separators for some specific applications. In addition, the features of what is known as ‘‘modern’’ GOSP are highlighted.

Test Separators

These units are used to separate and measure at the same time the well fluids. Potential test is one of the recognized tests for measuring the quantity of

both oil and gas produced by the well in 24 hours period under steady state of operating conditions. The oil produced is measured by a flow meter (normally a turbine meter) at the separator's liquid outlet and the cumulative oil production is measured in the receiving tanks.

An orifice meter at the separator's gas outlet measures the produced gas. Physical properties of the oil and GOR are also determined. Equipment for test units is shown in Figure 4.5.

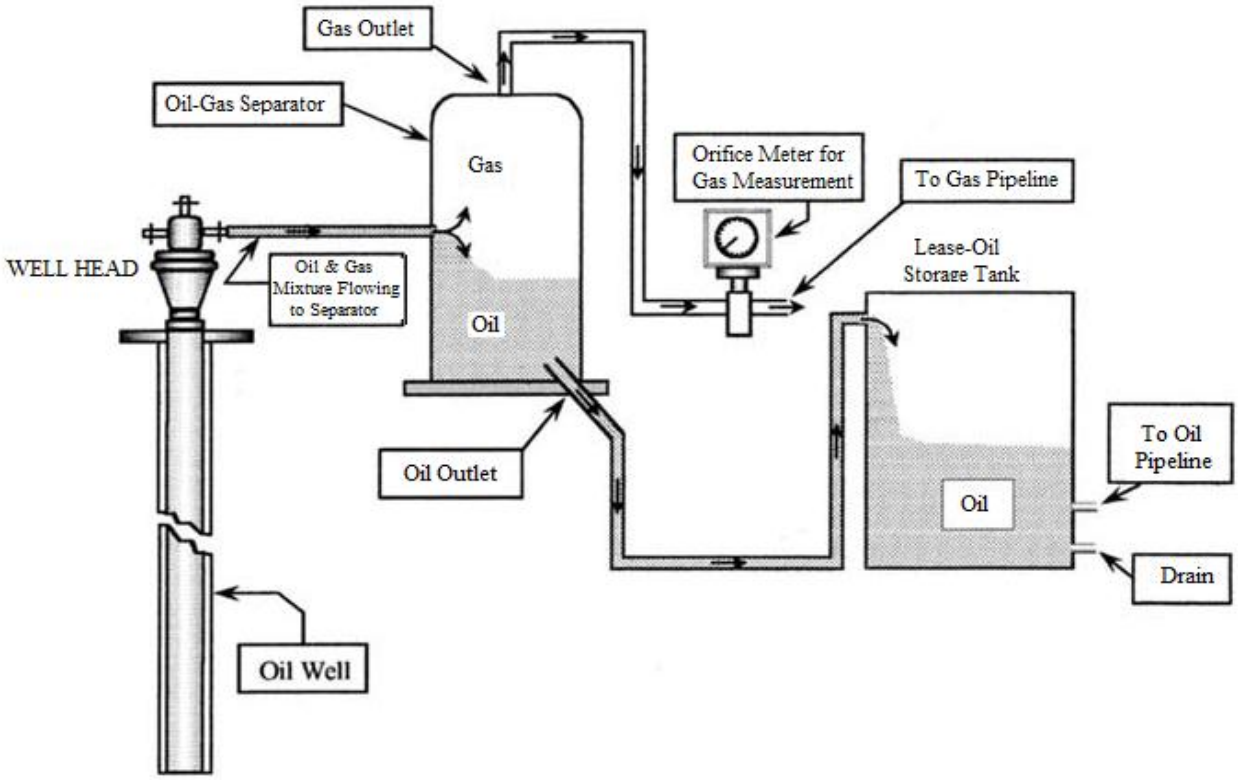


Figure 4.5 – Main equipment for test separator

Low-Temperature Separators

Low-temperature separators (LTSs) are used to effectively remove light condensable hydrocarbons from a high-pressure gas stream (gas condensate feed). Liquid (condensate) separation is made possible by cooling the gas stream before separation. Temperature reduction is obtained by what is known as the Joule–Thomson effect of expanding the well fluid as it flows through the pressure-reducing choke or valve into the separator. Condensation of the vapors takes place accordingly, where the temperature is in the range 0–10 °F (-12-18 ^{o}C). The process is shown at the figure 4.6.

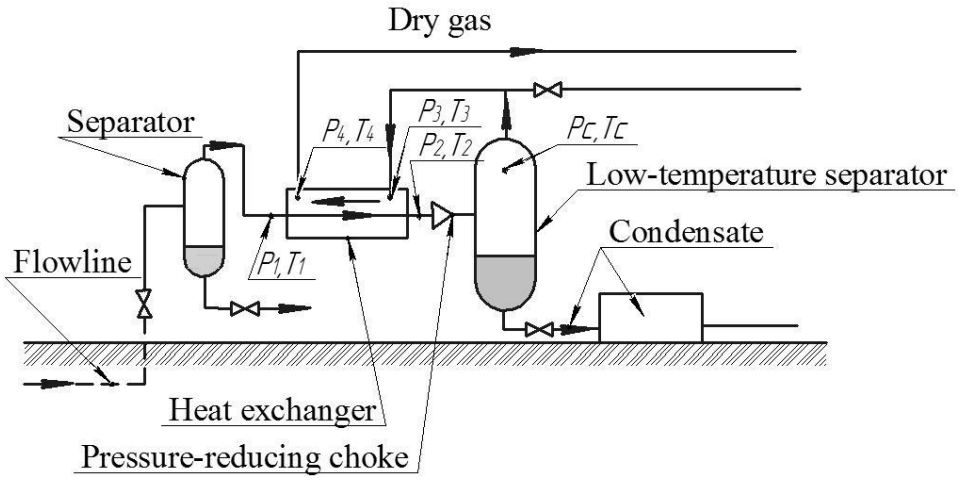


Figure 4.6 – Low temperature separation diagram

Modern GOSPs

Safe and environmentally acceptable handling of crude oils is assured by treating the produced crude in the GOSP and related crude-processing facilities. The number one function of the GOSP is to separate the associated gas from oil. As the water content of the produced crude increases, field facilities for control or elimination of water are to be added. This identifies the second function of a GOSP. If the effect of corrosion due to high salt content in the crude is recognized, then modern desalting equipment could be included as a third function in the GOSP design.

One has to differentiate between ‘‘dry’’ crude and ‘‘wet’’ crude. The former is produced with no water, whereas the latter comes along with water. The water produced with the crude is a brine solution containing salts (mainly sodium chloride) in varying concentrations.

The input of wet crude oil into a modern GOSP consists of the following:

1) crude oil;

2) hydrocarbon gases;

3) free water dispersed in oil as relatively large droplets, which will separate and settle out rapidly when wet crude is retained in the vessel;

4) emulsified water, dispersed in oil as very small droplets that do not settle out with time. Each of these droplets is surrounded by a thin film and held in suspension;

5) salts dissolved in both free water and in emulsified water.

The functions of a modern GOSP could be summarized as follows:

1) separate the hydrocarbon gases from crude oil;

2) remove water from crude oil;

3) reduce the salt content to the acceptable level [basic sediments and water].

It should be pointed out that some GOSPs do have gas compression and low-temperature or refrigeration facilities to treat the gas before sending it to gas processing plants. In general, a GOSP can function according to one of the following process operation:

1) three-phase, gas–oil–water separation;

2) two-phase, gas–oil separation;
3) two-phase, oil–water separation;
4) deemulsification;
5) washing;
6) electrostatic coalescence.

To conclude, the ultimate result in operating a modern three-phase separation plant is to change ‘‘wet’’ crude input into the desired outputs, as given in Figure 4.7. Outputs from a three-phase regular separation plant, on the other hand, are as shown in Figure 4.8.

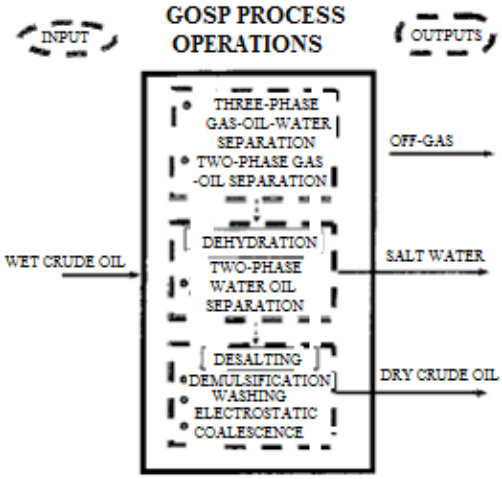


Figure 4.7 – Functions of modern GOSPs [2]

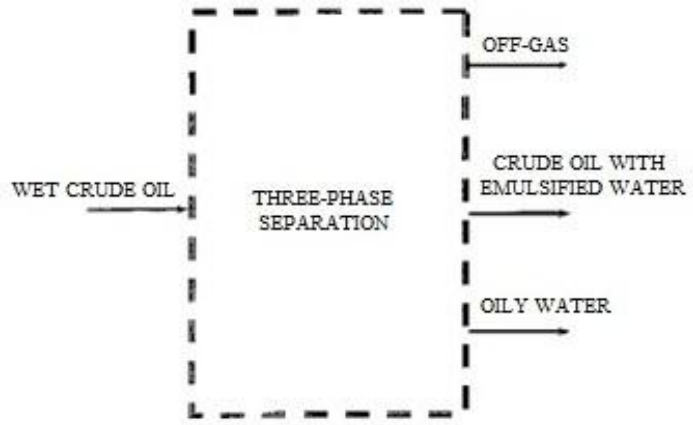


Figure 4.8 – Products obtained from a three-phase GOSP

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LECTURE 5
THREE-PHASE SEPARATION

In almost all production operations the produced fluid stream consists of three phases: oil, water, and gas.

Generally, water produced with the oil exists partly as free water and partly as water-in-oil emulsion. In some cases, however, when the water–oil ratio is very high, oil-in-water rather than water-in-oil emulsion will form. Free water produced with the oil is defined as the water that will settle and separate from the oil by gravity. To separate the emulsified water, however, heat treatment, chemical treatment, electrostatic treatment, or a combination of these treatments would be necessary in addition to gravity settling. This will be discussed later. Therefore, it is advantageous to first separate the free water from the oil to minimize the treatment costs of the emulsion.

Along with the water and oil, gas will always be present and, therefore, must be separated from the liquid. The volume of gas depends largely on the producing and separation conditions. When the volume of gas is relatively small compared to the volume of liquid, the method used to separate free water, oil and gas is called a free-water knockout. In such a case, the separation of the water from oil will govern the design of the vessel. When there is a large volume of gas to be separated from the liquid (oil and water), the vessel is called a three-phase separator and either the gas capacity requirements or the water–oil separation constraints may govern the vessel design. Free-water knockout and three-phase separators are basically similar in shape and components. Further, the same design concepts and procedures are used for both types of vessel. Therefore, the term three-phase separator will be used for both types of vessel throughout the lecture.

Three-phase separators may be either horizontal or vertical pressure vessels similar to the two-phase separators. However, three-phase separators will have additional control devices and may have additional internal components. In the following sections, the two types of separator (horizontal and vertical) are described and the basic design aspects are developed.

Horizontal three-phase separators

Three-phase separators differ from two-phase separators in that the liquid collection section of the three-phase separator handles two immiscible liquids (oil and water) rather than one. This section should, therefore, be designed to separate the two liquids, provide means for controlling the level of each liquid, and provide separate outlets for each liquid. Figures 5.1 and 5.2 show schematics two common types of horizontal three-phase separators. The difference between the two types is mainly in the method of controlling the levels of the oil and water phases. In the first type (Fig. 5.1), an interface controller and a weir provide the control. The design of the second type (Fig. 5.2), normally known as the bucket and weir design, eliminates the need for an interface controller.

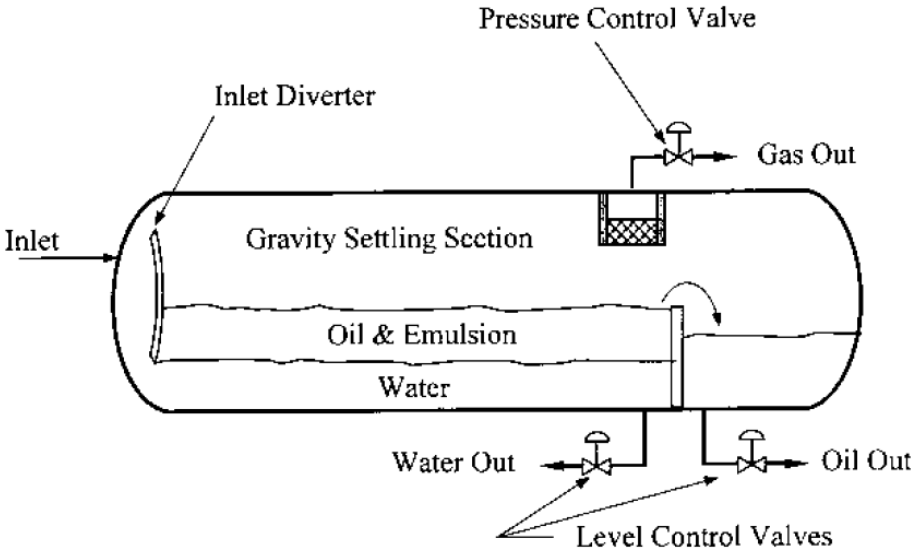

Figure 5.1 – Horizontal three-phase separator schematic of one type

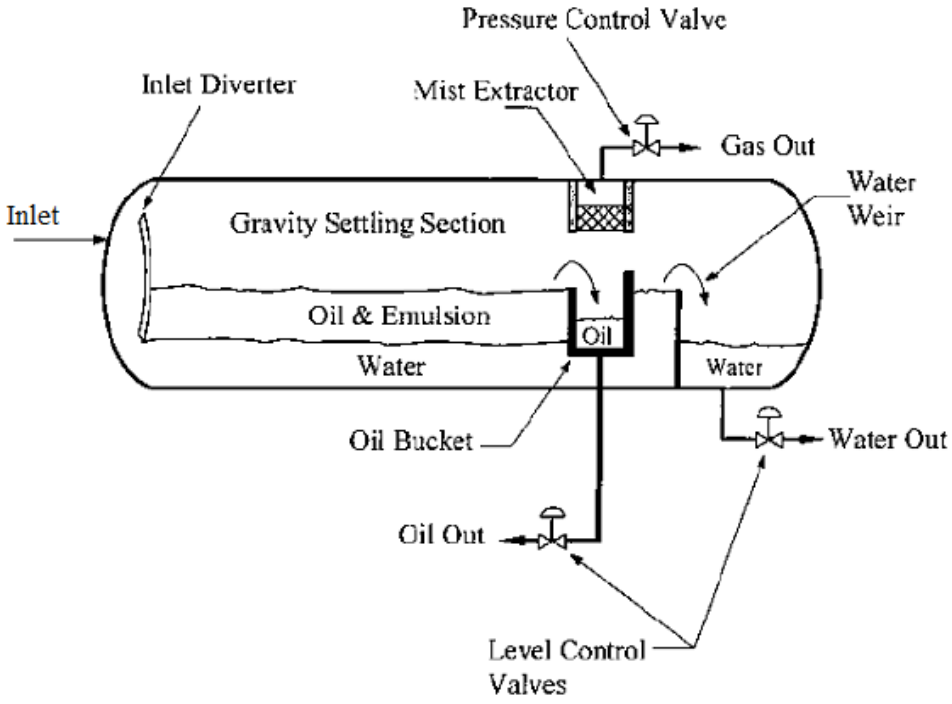

Figure 5.2 – Horizontal three-phase separator; bucket and weir design

The operation of the separator is, in general, similar to that of the two-phase separator. The produced fluid stream, coming either directly from the producing wells or from a free-water knockout vessel, enters the separator and hits the inlet diverter, where the initial bulk separation of the gas and liquid takes place due to the change in momentum and difference in fluid densities. The gas flows horizontally through the gravity settling section (the top part of the separator) where the entrained liquid droplets, down to a certain minimum size (normally 100 μm), are separated by gravity. The gas then flows through the mist extractor, where smaller entrained liquid droplets are separated, and out of the separator through the

pressure control valve, which controls the operating pressure of the separator and maintains it at a constant value. The bulk of liquid, separated at the inlet diverter, flows downward, normally through a downcomer that directs the flow below the oil–water interface. The flow of the liquid through the water layer, called water washing, helps in the coalescence and separation of the water droplets suspended in the continuous oil phase. The liquid collection section should have sufficient volume to allow enough time for the separation of the oil and emulsion from the water. The oil and emulsion layer forming on top of the water is called the oil pad. The weir controls the level of the oil pad and an interface controller controls the level of the water and operates the water outlet valve. The oil and emulsion flow over the weir and collect in a separate compartment, where its level is controlled by a level controller that operates the oil outlet valve.

The relative volumes occupied by the gas and liquid within the separator depend on the relative volumes of gas and liquid produced. It is a common practice, however, to assume that each of the two phases occupies 50% of the separator volume. In such cases, however, where the produced volume of one phase is much smaller or much larger than the other phase, the volume of the separator should be split accordingly between the phases. For example, if the gas–liquid ratio is relatively low, we may design the separator such that the liquid occupies 75% of the separator volume and the gas occupies the remaining 25% of the volume.

The operation of the other type of horizontal separator (Fig. 5.2) differs only in the method of controlling the levels of the fluids. The oil and emulsion flow over the oil weir into the oil bucket, where its level is controlled by a simple level controller that operates the oil outlet valve. The water flows through the space below the oil bucket, then over the water weir into the water collection section, where its level is controlled by a level controller that operates the water outlet valve. The level of the liquid in the separator, normally at the center, is controlled by the height of the oil weir. The thickness of the oil pad must be sufficient to provide adequate oil retention time. This is controlled by the height of the water weir relative to that of the oil weir. A simple pressure balance at the bottom of the separator between the water side and the water and oil side can be used to approximately determine the thickness of the oil pad as follows:

$$H_o = \frac{H_{ow} - H_{ww}}{1 - \dfrac{\rho_o}{\rho_w}} \tag{5.1}$$

where H_o is the thickness of the oil pad, H_{ow} is the height of the oil weir, H_{ww} is the height of the water weir, and ρ_o and ρ_w are the oil and water densities, respectively.

Equation (5.1) gives only an approximate value for the thickness of the oil pad. A more accurate value could be obtained if the density of the oil in Eq. (5.1) is replaced by the average value of the density of oil and density of emulsion, which depends on the thickness of the oil and emulsion layers within the oil pad. The height of the water weir should not be so small as to avoid the downward growth of

the oil pad and the possibility of the oil flowing below the oil bucket, over the water weir, and out with the water.

It is advisable to have the oil bucket as deep as possible and to have either the oil weir, or the water weir, or both to be adjustable to accommodate any unexpected changes in flow rates and/or liquids properties. Such problems are easily accommodated in the interface controller and weir design of Fig. 5.1, as the interface controller could be easily adjusted. In some cases, however, when the difference in density between the water and oil, or the water and emulsion are small (e.g., in heavy oil operations), the operation of the interface controller becomes unreliable and the bucket design (Fig. 5.2) will be preferred.

Vertical three-phase separators

The horizontal separators are normally preferred over vertical separators due to the flow geometry that promotes phase separation. However, in certain applications, the engineer may be forced to select a vertical separator instead of a horizontal separator despite the process-related advantages of the later. An example of such applications is found in offshore operations, where the space limitations on the production platform may necessitate the use of a vertical separator.

Figure 5.3 shows a schematic of a typical three-phase vertical separator.

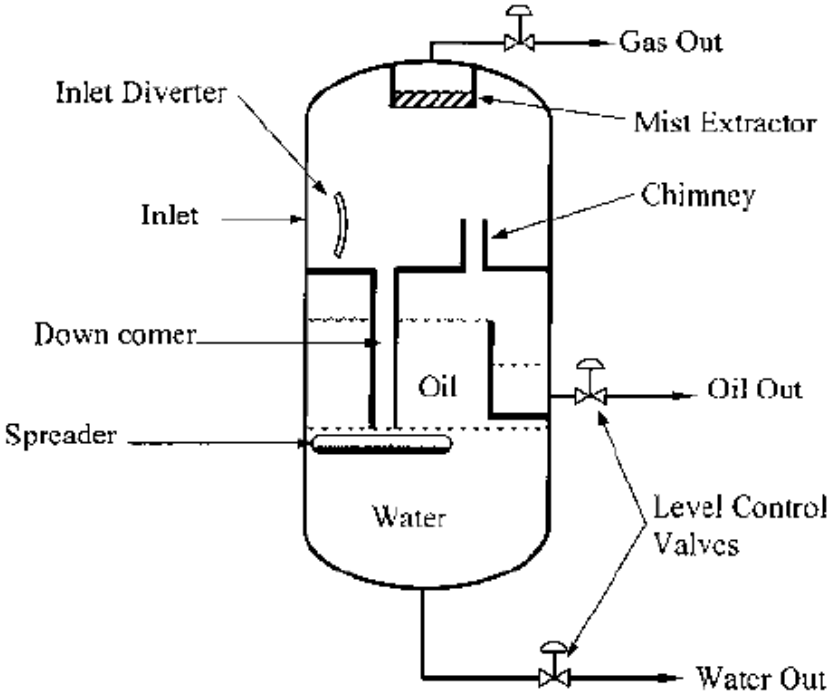

Figure 5.3 – Schematic of a three-phase vertical separator

The produced fluid stream enters the separator from the side and hits the inlet diverter, where the bulk separation of the gas from the liquid takes place. The gas flows upward through the gravity settling sections which are designed to allow separation of liquid droplets down to a certain minimum size (normally 100 μm) from the gas. The gas then flows through the mist extractor, where the smaller liquid droplets are removed. The gas leaves the separator at the top through a

pressure control valve that controls the separator pressure and maintains it at a constant value.

The liquid flows downward through a downcomer and a flow spreader that is located at the oil–water interface. As the liquid comes out of the spreader, the oil rises to the oil pad and the water droplets entrapped in the oil settle down and flow, countercurrent to the rising oil phase, to collect in the water collection section at the bottom of the separator. The oil flows over a weir into an oil chamber and out of the separator through the oil outlet valve. A level controller controls the oil level in the chamber and operates the oil outlet valve. Similarly, the water out of the spreader flows downward into the water collection section, whereas the oil droplets entrapped in the water rise, countercurrent to the water flow, into the oil pad. An interface controller that operates the water outlet valve controls the water level. In the design shown in Figure 5.3, a chimney must be provided, as shown in the figure, to allow the gas liberated from the oil to rise and join the rest of the separated gas and, thus, avoid overpressurizing the liquid section of the separator.

The use of the oil weir and chamber in this design provides good separation of water from oil, as the oil has to rise to the full height of the weir before leaving the separator. The oil chamber, however, presents some problems. First, it takes up space and reduces the separator volume needed for the retention times of oil and water. It also provides a place for sediments and solids to collect, which creates cleaning problems and may hinder the flow of oil out of the vessel. In addition, it adds to the cost of the separator.

Other methods of level control are also available. Figure 5.4 shows a schematic of a separator where an oil–water-interface controller and a gas–oil-interface controller control the water and oil levels, respectively.

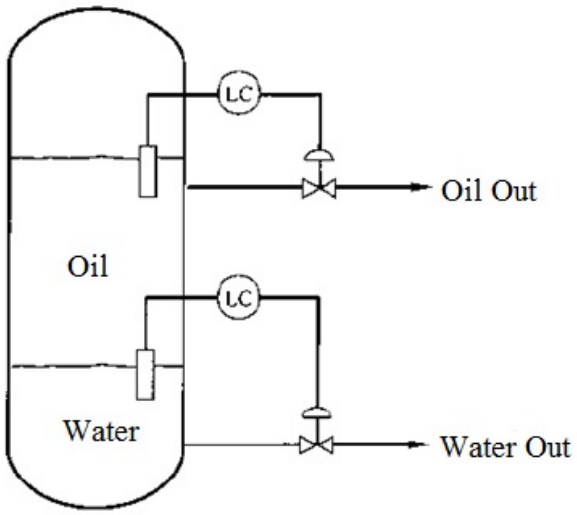

Figure 5.4 – Interface level control

Figure 5.5 shows yet another method of level control. In this design, an external water column equipped with adjustable weir is connected to the water section of the separator. The column is also piped to the gas section of the separator to establish pressure equilibrium between the water column and separator. A simple level controller controls the height of the water in the column,

which, in turn, controls the height of water in the separator. This eliminates the need for an oil–water interface controller and avoids the potential problems associated with such controllers. This design, however, takes additional space and adds additional significant cost.

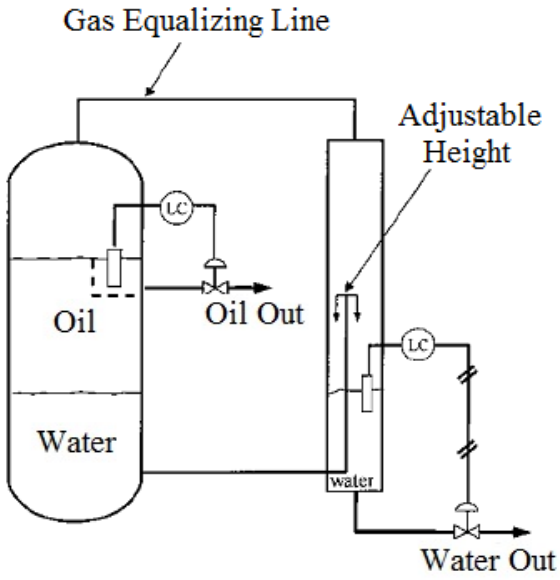

Figure 5.5 – Water leg with or without oil chamber

Liquid–liquid interface controllers will function effectively as long as there is an appreciable difference between the densities of the two liquids.

In most three-phase separator applications, water–oil emulsion forms and a water–emulsion interface will be present in the separator instead of a water–oil interface. The density of the emulsion is higher than that of the oil and may be too close to that of the water. Therefore, the smaller density difference at the water–emulsion interface will adversely affect the operation of the interface controller. The presence of emulsion in the separator takes up space that otherwise would be available for the oil and/or the water. This reduces the retention time of the oil and/or water and, thus results in a less efficient oil–water separation. In most operations where the presence of emulsion is problematic, chemicals known as deemulsifying agents are injected into the fluid stream to mix with the liquid phase. These chemicals help in breaking the emulsion. Another method that is also used for the same purpose is the addition of heat to the liquid within the separator. In both cases, however, the economics of the operations have to be weighed against the technical constraints.

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LECTURE 6
OIL EMULSION

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. Care should be taken not to exceed the target oil dryness. Removal of more remnant water than allowed by contract costs more money while generating less income because the volume of oil sold will be based on the contract value of the 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.

The economic impact of these treating processes is emphasized by Abdel-Aal et al. [8].

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 6.1.

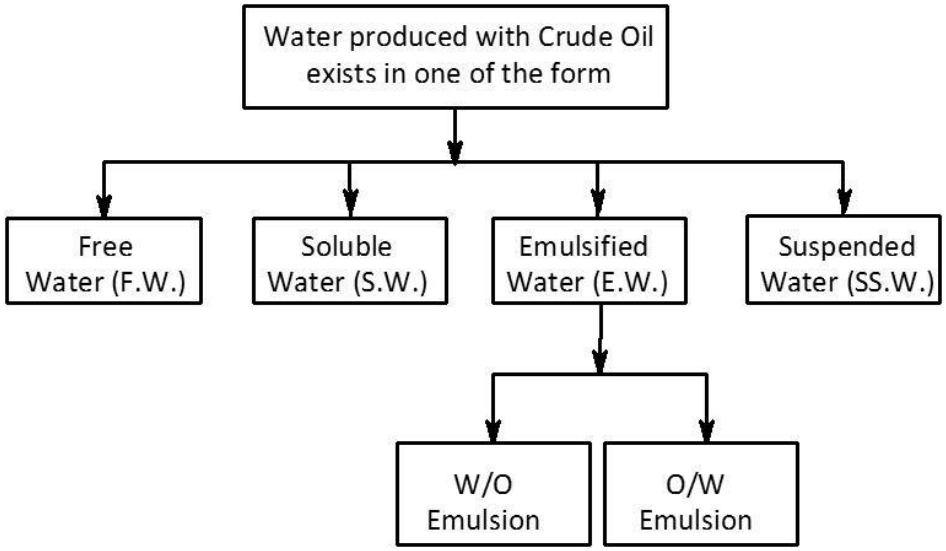

Figure 6.1 – Forms of saline water produced with crude oil

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. 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 type C in Figure 6.2.

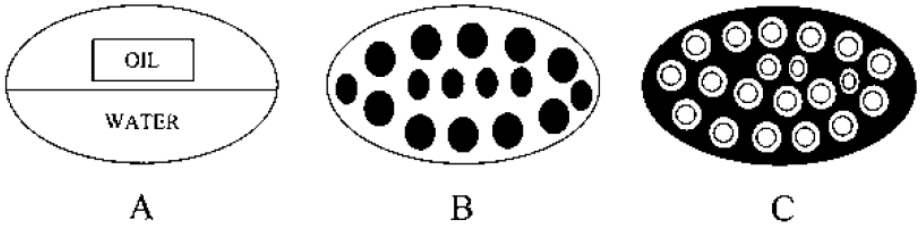

Figure 6.2 – Schematic representation of (A) a non-dispersed system, (B) an O/W emulsion, and (C) a W/O emulsion

However, as the water cut increases, the possibility of forming reverse emulsions (oil-in-water, or O/W emulsion) increases. This is type B in Figure 6.2.

For two liquids to form a stable emulsion, three conditions must exist:

1) the two liquids must be immiscible;

2) there must be sufficient energy of agitation to disperse one phase into the other;

3) there must be the presence of an emulsifying agent.

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. Starting within the producing formation, the oil and water migrate through the porous rock formation, making their way into the wellbore, up the well tubing, through the wellhead choke, and through the manifold into the surface separators. Throughout this journey, the fluids are subjected to agitation due to the turbulent flow. This energy of agitation, which forces the water drops in the bulk of oil, functions in the following pattern:

- first, energy is spent to overcome the viscous force between the liquid layers, leading to their separation into thin sheets or parts. This is what we call ‘‘shearing energy’’ and is mathematically approximated by the formula

$$SE = \tau \cdot A \cdot D_0 \tag{6.1}$$

where *SE* is the shearing energy, *A* is the shear surface area, D_o is the characteristic length, and τ is the shearing force per unit area, which is defined by Eq. (6.2) as follows:

$$\tau = \frac{C_d \cdot \rho \cdot v^2}{2 g_C} \tag{6.2}$$

where C_d is the drag coefficient, ρ is the density of the fluid, v is the velocity of flow, and g_c is a conversion factor.

- second, energy is used in the formation of “surface energy”, which occurs as a result of the separation of the molecules at the plane of cleavage. This surface energy is related to the surface tension, which involves the creation of an enormous area of interface with attendant free surface energy. Energy contained per unit area is referred to as “surface tension”, having the units of dynes/cm (N/m in SI).

The drops attain the spherical shape, which involves the least energy contained for a given volume. This is in accordance with the fact that all energetic systems tend to seek the lowest level of free energy [4]. Because the surface tension is defined as “the physical property due to molecular forces existing in the surface film of the liquid”, this will cause the volume of a liquid to be contracted or reduced to a shape or a form with the least surface area.

This is the same force that causes raindrops to assume a spherical shape. A schematic presentation of energy utilization in emulsion formation is given in Figure 6.3. 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.

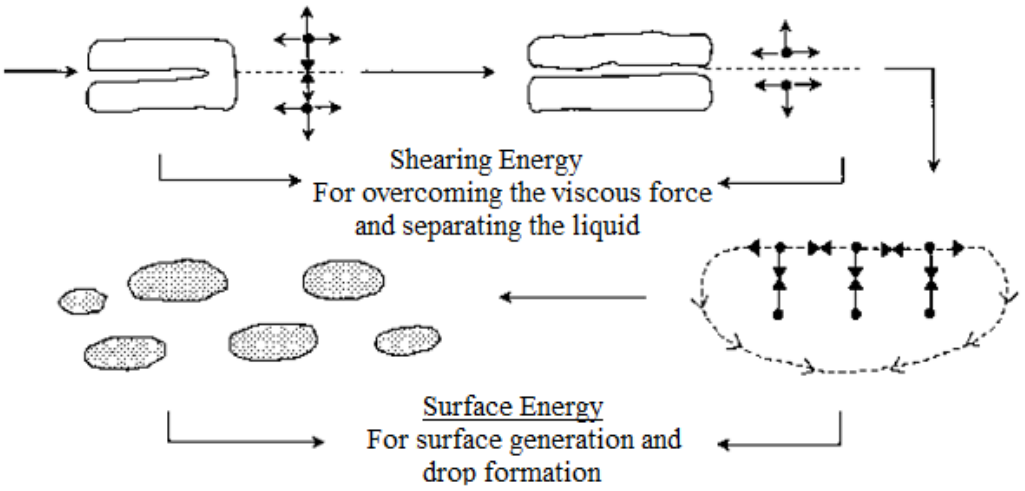

Figure 6.3 – Forms of energy participating in emulsification

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, as depicted in Figure 6.4. 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/or maintenance operations, create this film. Some of the common emulsifiers are as follows:

1) asphaltic materials;
2) resinous substances;
3) oil-soluble organic acids;
4) finely dispersed solid materials such as sand, carbon, calcium, silica, iron, zinc, aluminum sulfate, iron sulfide, and so on.

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

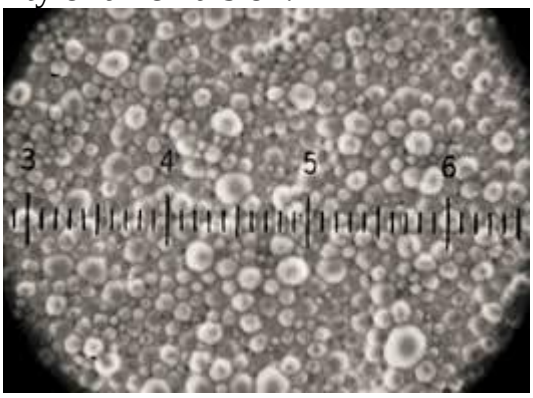

Figure 6.4 – Photomicrograph of loose emulsion containing about 30% emulsified water in the form of droplets ranging in diameter from about 60 μm downward

The stability of oil–water emulsions could be viewed through the following analysis. The relative difficulty of separating an emulsion into two phases is a

measure of its stability. A very stable emulsion is known as a ‘‘tight’’ emulsion and its degree of stability is influenced by many factors.

Accordingly, we can best understand the resolution problem and, hence, the treatment procedure if we consider the following factors:

1. Viscosity of oil: Separation is easier for a less viscous oil phase.

2. Density or gravity difference between oil and water phases: Better separation is obtained for a larger difference.

3. Interfacial tension between the two phases (which is related to the type of emulsifying agent): Separation is promoted if this force is lowered (i.e., decreasing the interfacial tension).

4. Size of dispersed water droplets: The larger the size of water drops, the faster is the separation. This could be readily concluded from Figure 6.5, which relates the velocity of settling of emulsified water drops to the diameter for different temperatures.

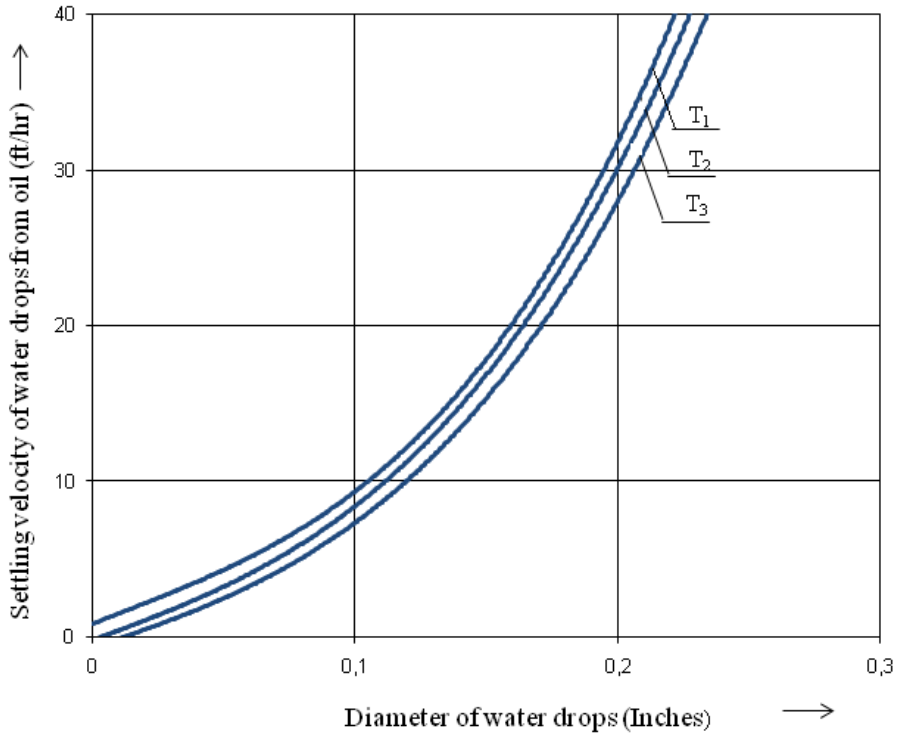

Figure 6.5 – The change of settling velocity with water drop size for different operating temperatures (40^{o}API oil)

The size of dispersed water droplets is an important factor in emulsion stability. A typical droplet size distribution for emulsion samples was determined by using a special computer scanning program. Results reported in Figure 6.6 [2] indicate that most of the droplets found in oil emulsions are below 50 μm.

5. Percentage of dispersed water: The presence of a small percentage of water in oil under turbulence conditions could lead to highly emulsified mixture. Water droplets are finely divided and scattered with very little chance of agglomerating to larger particles.

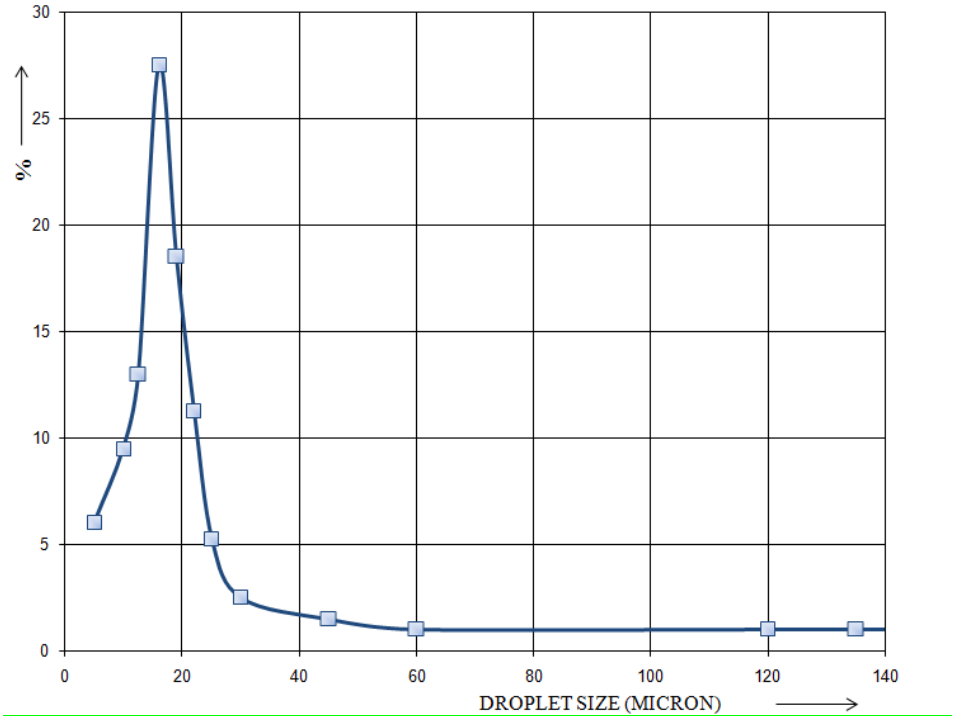

Figure 6.6 – Droplet size distribution for an emulsion sample

6. Salinity of emulsified water: Highly saline water will lead to a faster separation because of a higher density difference between the oil and the water phases.

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LECTURE 7
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 [1]. The basic approaches of handling ‘‘wet’’ crude oils are illustrated in Figure 7.1.

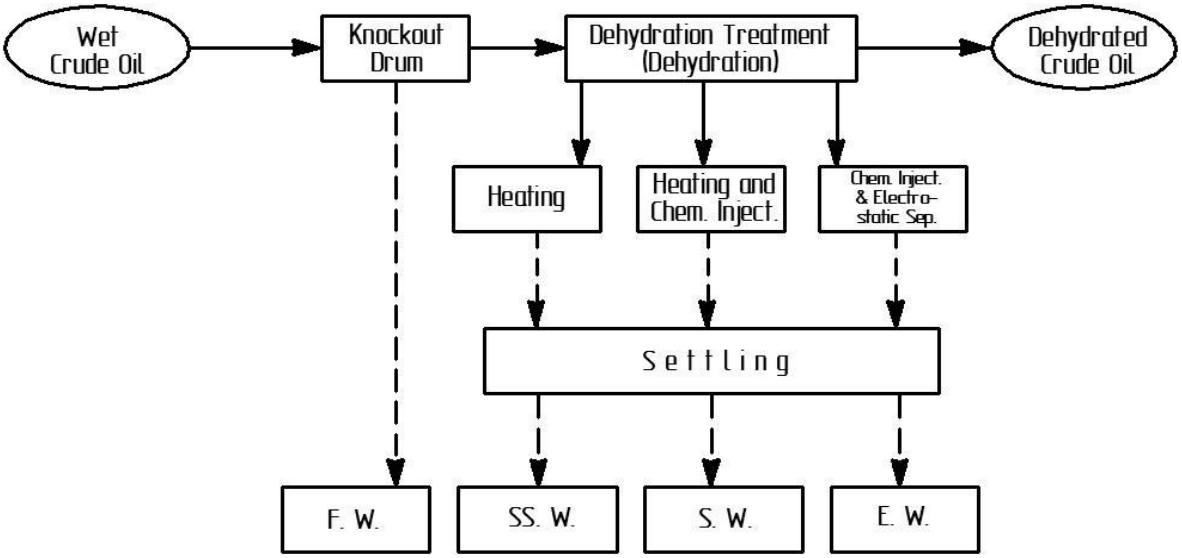

Figure – 7.1 - Basic approach of handling wet crude oil (F.W. = free water, SS.W. =suspended water, E.W. = emulsified water)

Again, 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 [1]:

- free-water knockout vessel;
- wash tank;
- gun barrel;
- flow treater (heater/treater);
- chemical/Injector;
- electrostatic dehydrator.

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 when heating the emulsion (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.

Figures 7.2 and 7.3 show some of the common types of two-phase and three-phase free-water knockout drums, respectively.

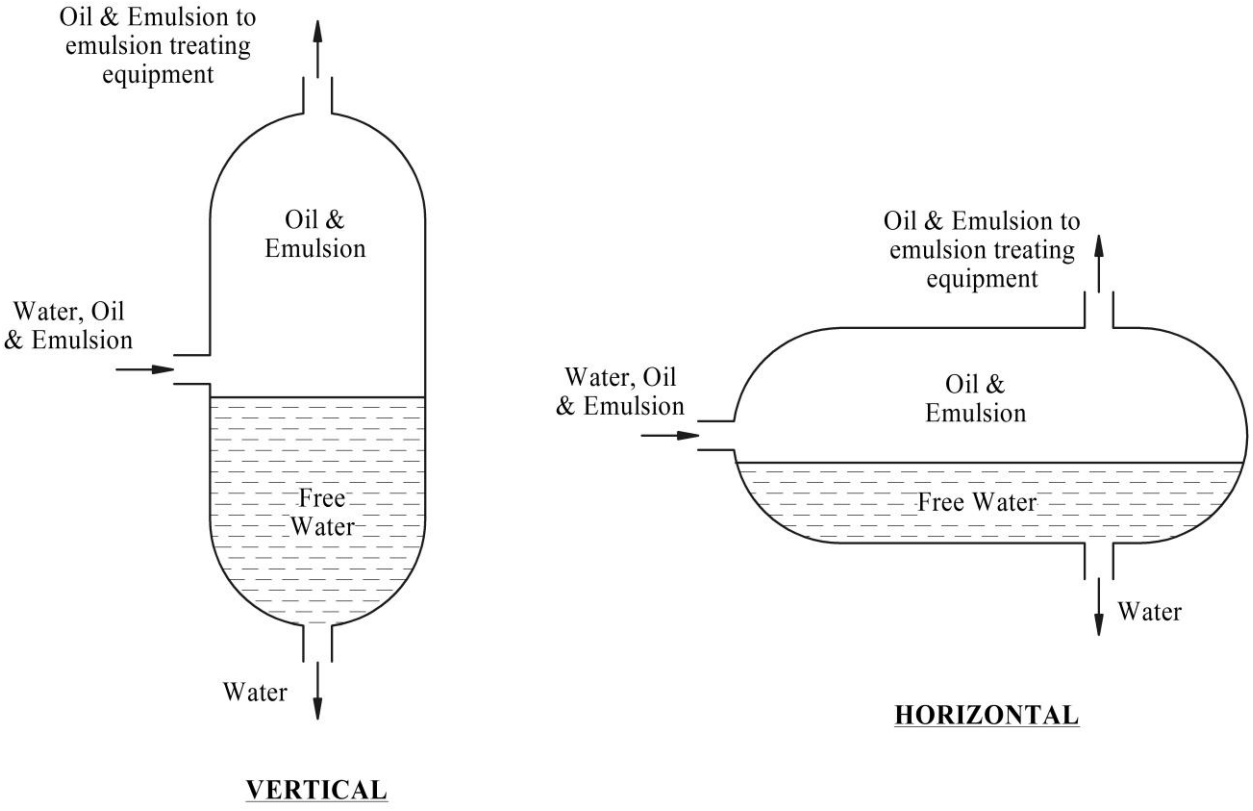

Figure 7.2 – Two-phase free-water knockouts

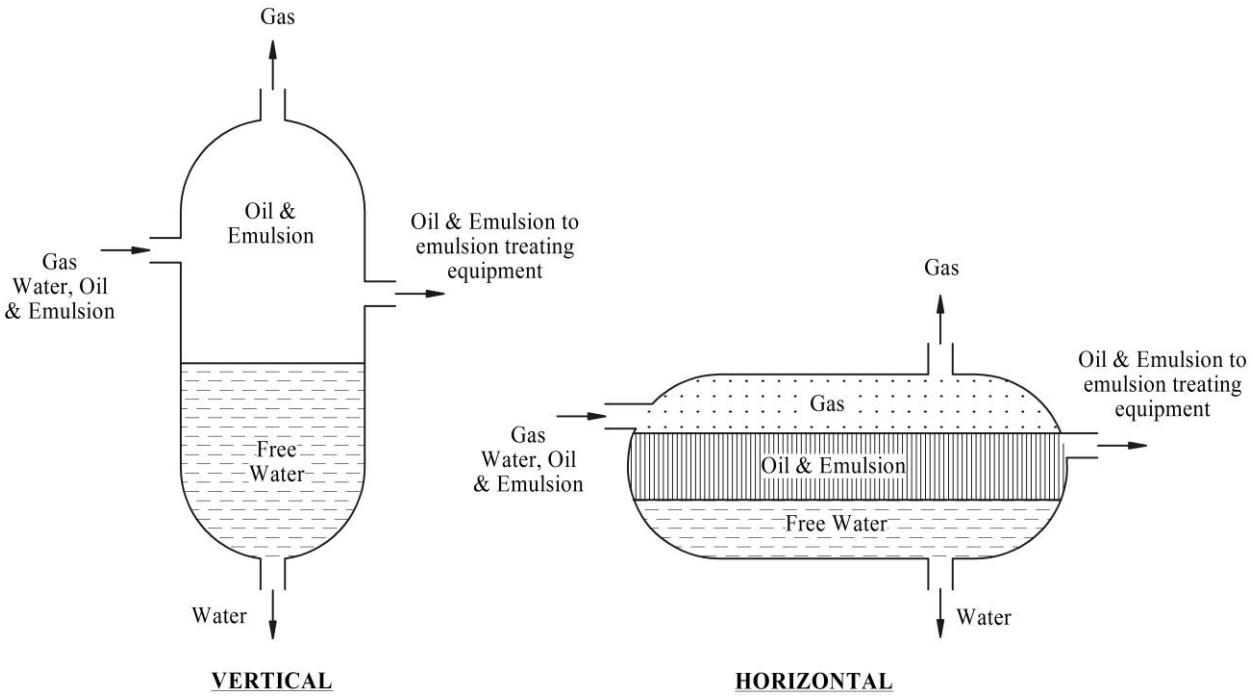

Figure 7.3 – Three-phase free-water knockouts

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. Coalescence is a strong function of time and is enhanced by applying an electrostatic field, impingement on a solid surface area, and water washing.

3. Gravitational settling and separation of water drops: The larger water droplets resulting from the coalescence step will settle out of the oil by gravity and be collected and removed.

Because these steps are in series, 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.

Treating the Emulsion

As explained earlier, using chemicals followed by settling can break some emulsions. Other emulsions require heating and allowing the water to settle out of the bulk of oil. More difficult (tight) emulsions require, however, both chemicals and heat, followed by coalescence and gravitational settling.

Basically, a dehydration process that utilizes any or a combination of two or more of the treatment aids mentioned earlier (heating, adding chemicals, and an

applying electrical field) is used to resolve water–oil emulsions [6, 7]. The role of each of these aids is discussed next in detail.

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LECTURE 8
HEATING

Heating is the most common way of treating water–oil emulsions. To understand how heating aids in the resolution of water–oil emulsions and separation of the water droplets from the bulk of oil, reference is made to the droplet settling velocity equation

$$u = 1.787 \cdot 10^{-6} \frac{(\Delta\gamma) d_m}{\mu_0} \; ft / \sec \tag{8.1}$$

where u is the water droplet settling velocity, $\Delta\gamma$ is the difference between water and oil specific gravities, d_m is the diameter of the water droplet (in μm) and μ_o is the oil viscosity.

Benefits and Drawbacks of Heating

Heating of water–oil emulsions aids in the resolution of the emulsion and the separation of the emulsified water in several ways. The most significant effect is the reduction of oil viscosity with temperature. The viscosity of all types of crude oil drops rapidly with increasing their temperature. From Eq. (8.1), such reduction in viscosity results in increasing the water droplet settling velocity and, thus, speeds and promotes the separation of water from the oil.

As the water and oil mixture is heated, the density (specific gravity) of both water and oil is reduced. However, the effect of temperature on oil density is more pronounced than on water density. The result is that the difference in density (or specific gravity) increases as the emulsion is heated. For example, if oil and water are heated from 15°C to 65°C, the following change in their specific gravity takes place.

Table 8.1 - Difference in specific gravity of oil and water at the different temperature

	at 15°F	at 65°F
Oil specific gravity	0.83	0.79
Water specific gravity	1.05	1.03
Difference in specific gravity	0.22	0.24

With reference to Eq. (8.1) an increase in $\Delta\gamma$ increases the settling velocity and, therefore, promotes the separation of water droplets from the bulk of oil. The change in the specific gravity difference is, however, small.

Therefore, this effect is not as significant as the effect of viscosity. In fact, we may completely ignore the effect of specific gravity on the process up to a temperature of 93°C. For some specific crude oils, increased temperature may cause a reverse effect on the difference in specific gravity. For some heavy oils, the specific gravity of the oil and water will be equal at certain temperature. This situation must be avoided, as it will stop the separation process completely.

Therefore, care should be exercised when determining the treating temperature for a specific crude oil.

Another beneficial effect of heating is that the increased temperature promotes movements of the small water droplets, which upon collision with one and the other, may form larger size droplets. The increased droplet size significantly speeds the settling process, as indicated by Eq. (8.1). Heat will also help to destabilize (weakening) the emulsifying film, hence breaking the emulsion. Further, heating will dissolve the small paraffin and asphaltenes crystals and, thus, neutralize their potential effect as emulsifiers.

Despite of all of the above-discussed benefits of heating, there are some drawbacks associated with this method of treatment. Heating of the oil can result in significant loss of the lighter hydrocarbon ends and thus results in loss of the oil volume. For example: heating 35^{o}API oil from 38°C to 65°C results in losing more than 1% of the oil volume. Of course, the evaporates (light ends) could be collected and sold with the gas. This, however, will not make up for the loss of revenue resulting from oil losses. In addition to oil losses, evaporation of the light ends leaves the treated oil with lower API gravity (i.e., lower quality), which will be sold at a lower price. Finally, heating requires additional investment for heating equipment and additional operating cost for the fuel gas and maintenance.

Because of the above drawbacks, it is generally recommended to avoid using heating as a treatment process if it is possible. Otherwise, some of the benefits of heating may be realized with the minimum amount of heating.

Methods of Heating Oil Emulsions

The fuel used to supply heat in oil-treating operations is practically natural gas. Under some special conditions, crude oil may be used.

Heaters are generally of two basic types:

1. Direct heaters, in which oil is passed through a coil exposed to the hot flue gases of the burned fuel (or to introduce the emulsion into a vessel heated using a fire tube heater).

2. Indirect heaters, in which heat is transferred from the hot flue gases to the emulsion via water as a transfer medium. The emulsion passes through tubes immersed in a hot water bath.

In general, the amount of free water in the oil emulsion will be a factor in determining which method is to be used. If free water is found to be 1–2%, then use an indirect heater. If the free-water content is more enough to hold a level around the fire tube, then use a direct heater. Both types are shown in Figure 8.1.

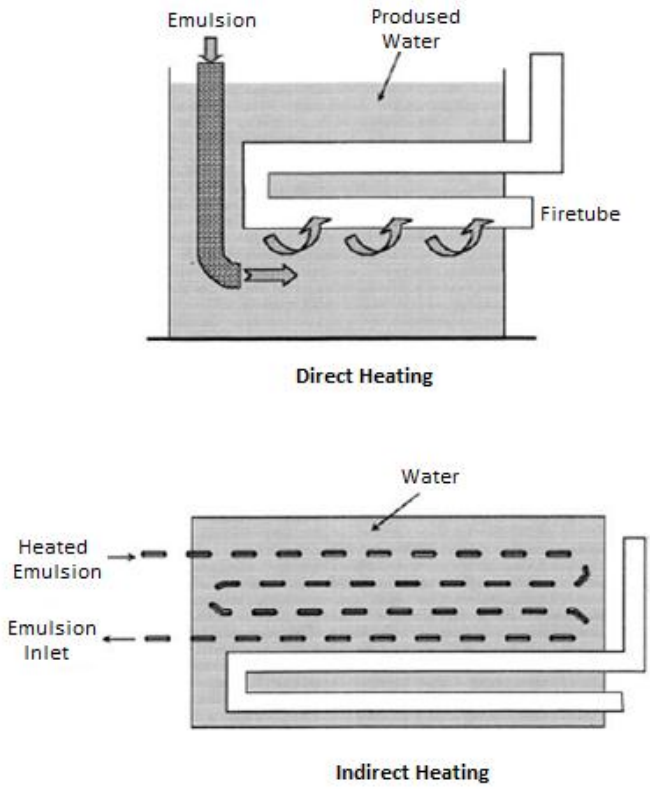

Figure 8.1 – Methods of heating the emulsion

Types of Heater Treater

The various types of field heater and heater treater and gunbarrel treaters are presented in Figures 8.2 and 8.3, respectively [1].

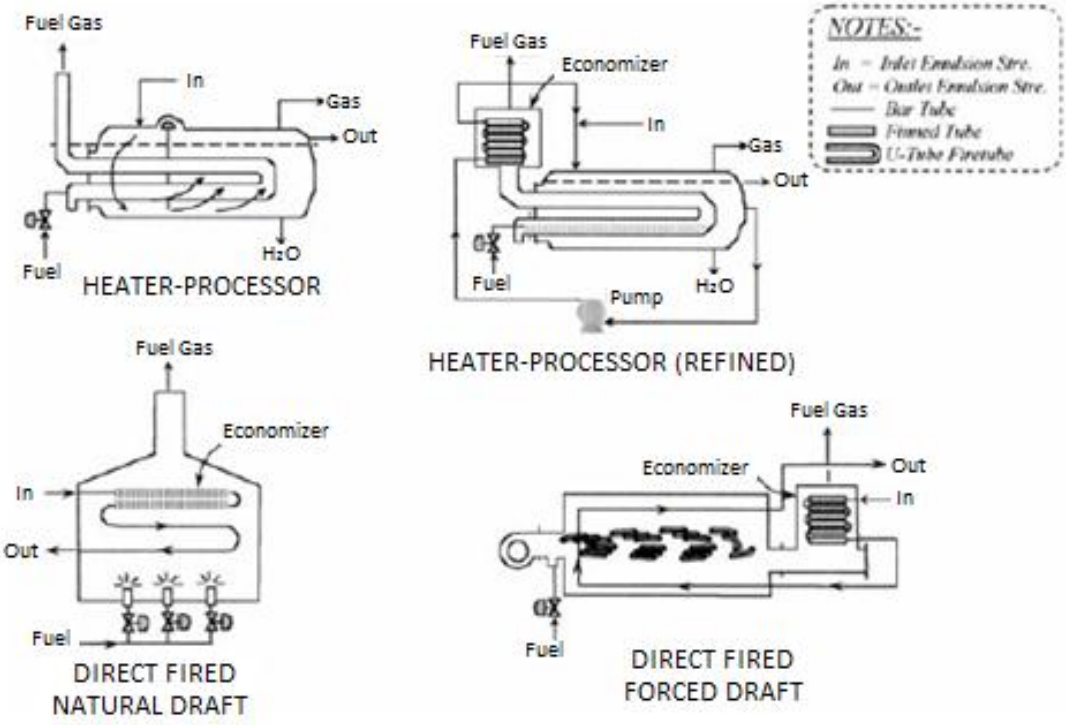

Figure 8.2 – Type of field heater

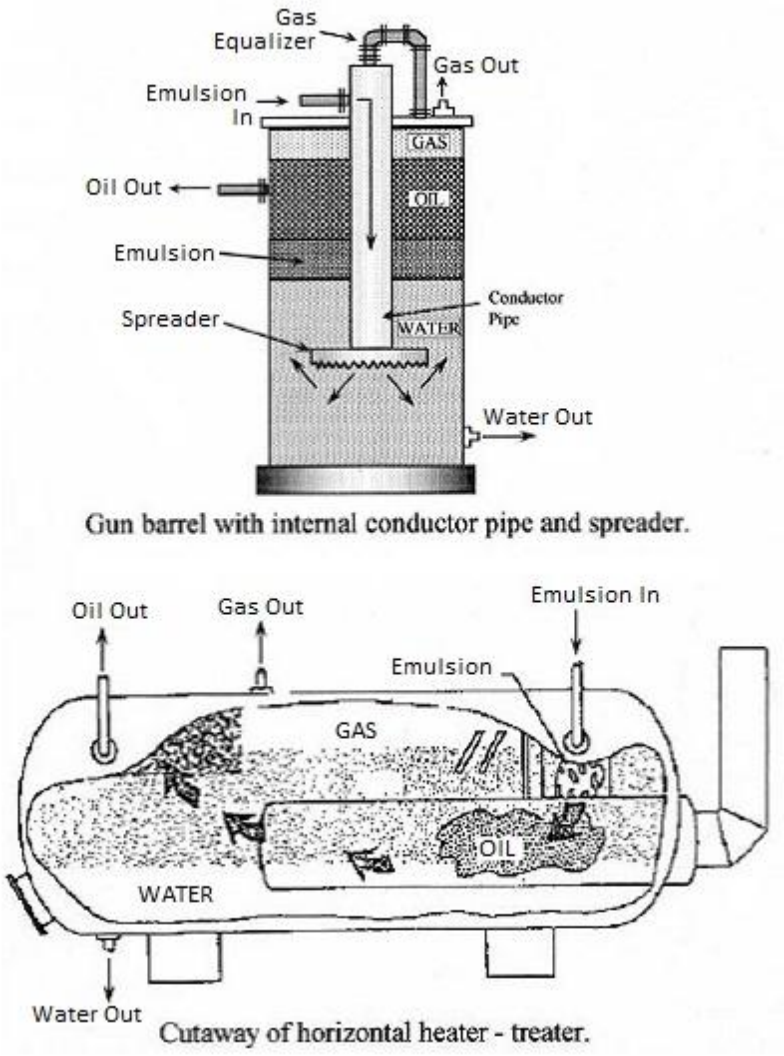

Figure 8.3 – Details of heater treater [2]

Vertical Treaters

Vertical treaters are commonly used as single-well treaters. The oil + emulsion stream enters the treater from the side at the top section of the vessel where gas, if any, separates and leaves the vessel at the top through a mist extractor. The liquid flows downward through a pipe called the downcomer and exits through a flow spreader located slightly below the water–oil interface to water wash the oil–emulsion stream. Water washing helps in coalescing the small water droplets suspended in the oil. The oil and emulsion flow upward, exchanging heat with the heater fire tubes, then through the coalescing section. The coalescing section, normally packed with porous material such as hay, is sized to provide sufficient time for the coalescence of the water droplets and their settling out of the oil. The treated oil is then collected from the treater.

Horizontal Treaters

This type of treater is normally used in centralized multiwell-treating facilities (GOSP). The oil and emulsion stream is introduced to heating section of the treater near the top where gas is flashed, separated, and exits the vessel at the top through a mist extractor. The liquid is made to flow tangent to the inside surface of the vessel and falls below the water–oil interface, where it is water washed. Water washing causes coalescence and separation of free water. The oil + emulsion rises up, exchanging heat with the fire tubes, and flows over a weir into an oil surge chamber. The hot oil + emulsion leaves the oil surge chamber near the bottom of the vessel and enters the coalescing section of the treater through a flow spreader, which ensures that the oil flows evenly throughout the length of the coalescing section. The oil flows upward, where it is withdrawn from the vessel through a collector. The spreader–collector system allows the oil flow to be vertical. This section of the treater is sized to allow sufficient retention time for the coalescence and settling of the water out of the oil. The separated water is removed from the treater at two locations:

- one at the bottom of the heating section;
- the other at the bottom of the coalescing section.

Interface level controllers control both outlet valves.

Gunbarrel Settling Tanks

Gunbarrel tanks are large-diameter vertical tanks operating mostly at atmospheric pressure. They are generally used for small fields where no or minimum heating is required for separation of the emulsion. When heating is needed, the most common way is to preheat the oil and emulsion stream before it enters the tank.

The oil + emulsion stream enters the tank at the top (where gas is flashed and separated) into a downcomer. It leaves the downcomer through a spreader located below the water–oil interface and rises vertically upward, flowing through the large cross-sectional area of the tank. As the oil + emulsion rises, it is first water washed to coalesce the water droplets. Then, it is retained for a sufficient time in the settling section to allow for the separation of the water droplets, which flow countercurrent to the oil flow and collects at the bottom section of the tank.

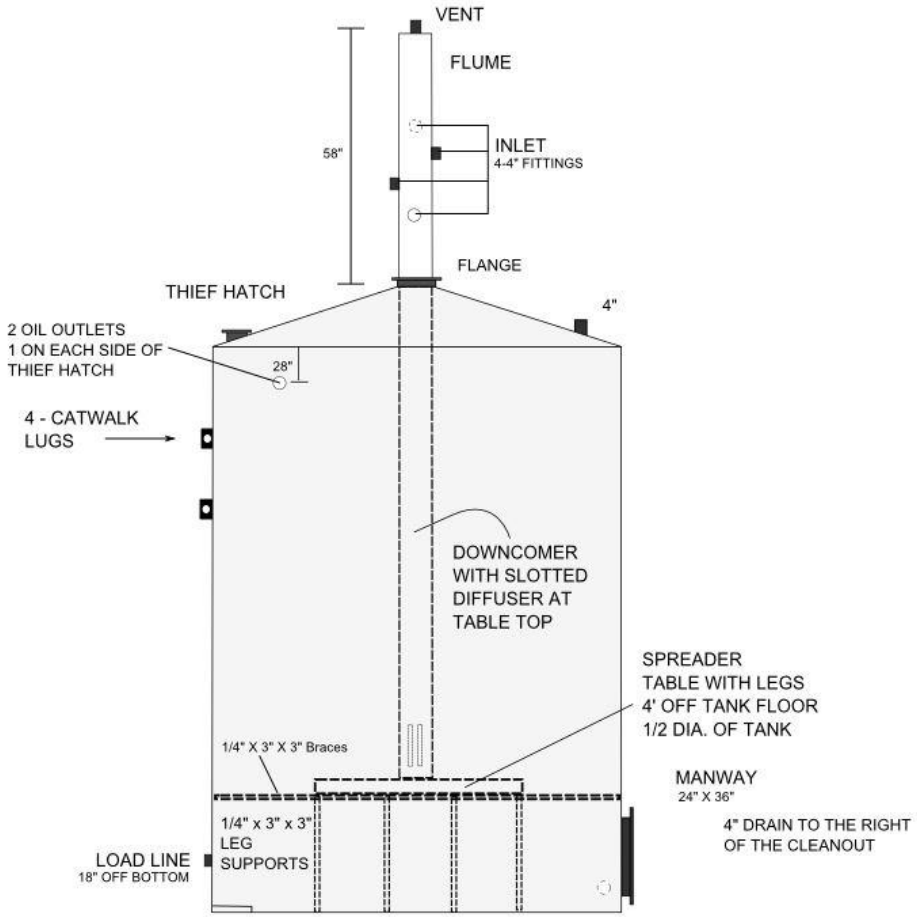

Figure 8.4 – Gunbarrel settling tanks [3]

REFERENCES:

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2 Abdel-Aal, H. K., Surface Petroleum Operations, Saudi Publishing & Distributing House, Jeddah, 1998.

3 tycoonequipment.com

LECTURE 9
CHEMICAL TREATMENT

As mentioned earlier, some oil emulsions will readily break upon heating with no chemicals added; others will respond to chemical treatment without heat. A combination of both «aids» will certainly expedite the emulsion-breaking process [1]. Chemical additives, recognized as the second ‘‘aid,’’ are special surface-active agents comprising relatively highmolecular-weight polymers. These chemicals (deemulsifiers), once adsorbed to the water–oil interface, can rupture the stabilizing film and/or displace the stabilizing agent due to the reduction in surface tension on the inside of the film (i.e., on the water side of the droplet). In other words, when the deemulsifiers are added to the oil, they tend to migrate to the oil–water interface and rupture the stabilizing film, as depicted in Figure 9.1. A deemulsifier, as it reaches to oil–water interface, functions in the following pattern: flocculation, then film rupture, followed by coalescence. The faster the deemulsifier reaches the oil–water interface, the better job it achieves. Figure 9.2 illustrates these steps.

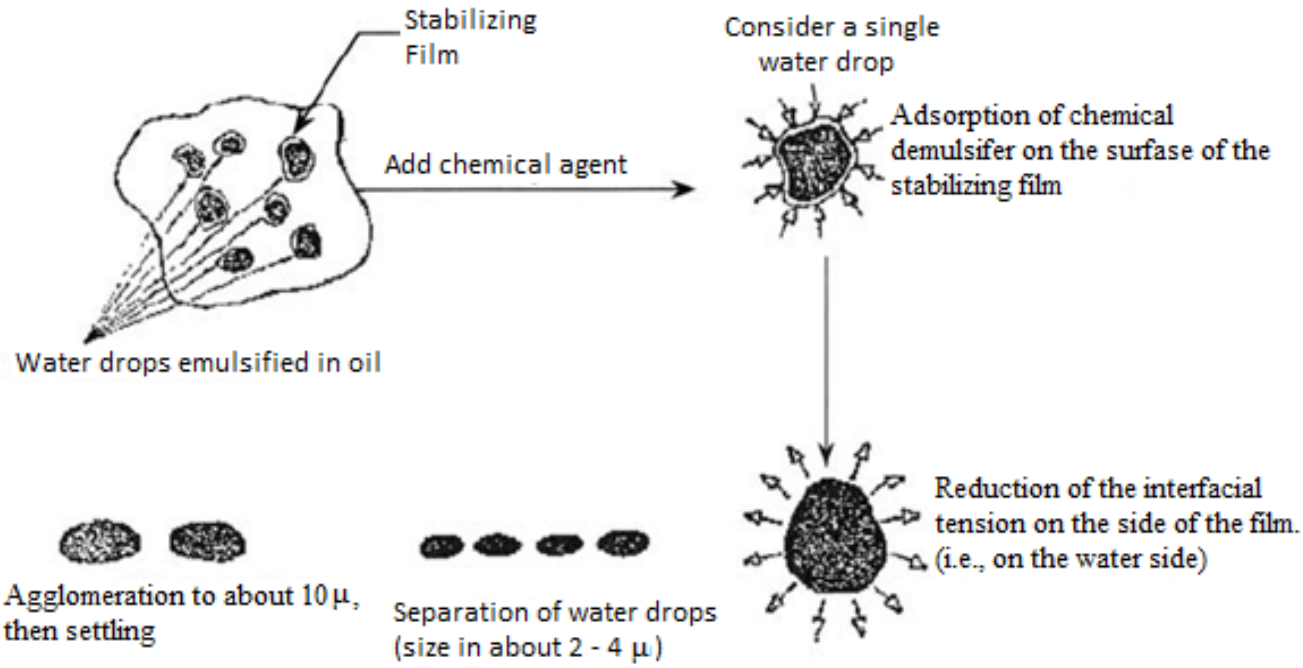

Figure 9.1 – Action of chemicals in deemulsification of water drops [2]

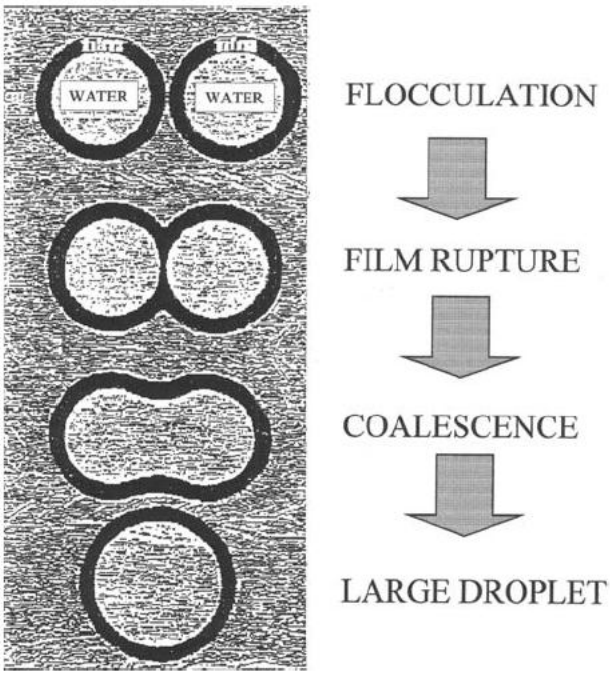

Figure 9.2 – Steps leading to large drop formation

Selection and Injection of Chemicals (Deemulsifiers)

The very first step for selecting the proper chemical for oil treating is testing an oil sample. The representative sample is measured into a number of bottles (12 or more). To each bottle, a few drops of different chemicals are added, followed by shaking to ensure good mixing between the emulsion and the chemical. Heat could be applied if needed. Final selection of the right chemical will be based on testing a sample of the oil to find out how complete the water removal was.

From the practical point of view, most oil deemulsifiers are oil soluble rather than water soluble. Because such small amounts are used in treating and to ensure thorough mixing, it is recommended to dilute the chemical with a solvent to have a larger volume of the solution to inject.

The point of deemulsifiers injection will depend largely on the type used. For the case of water-soluble deemulsifiers, injection is carried out after free water has been removed; otherwise, most of the chemical is lost down the drain. Three points of injection are recommended:

1. Upstream of the choke, where violent agitation takes place in the choke as the pressure is lowered from wellhead to that corresponding to the gas/oil separator. It is considered the ideal injection point. This is illustrated in Figure 9.3.

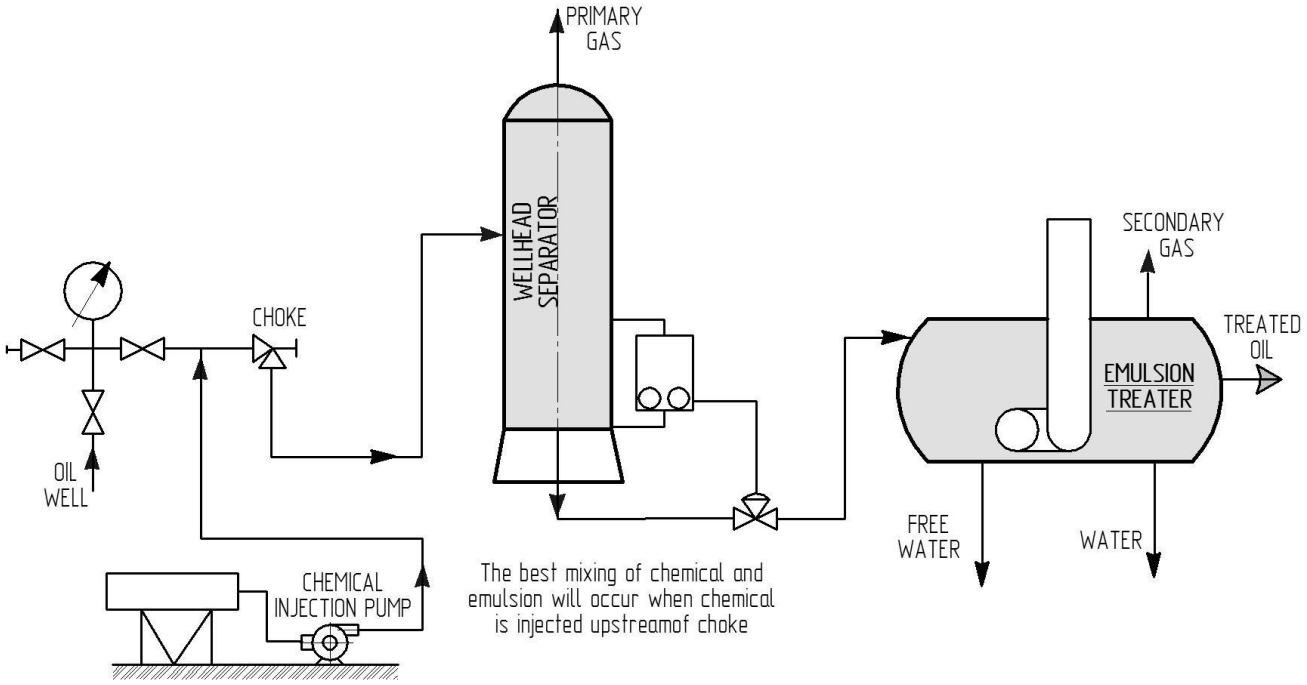

Figure 9.3 – Chemical injection: upstream of the choke

2. Upstream of the level control valve on the separator, where agitation occurs in the valve as the pressure is lowered. This is illustrated in Figure 9.4.

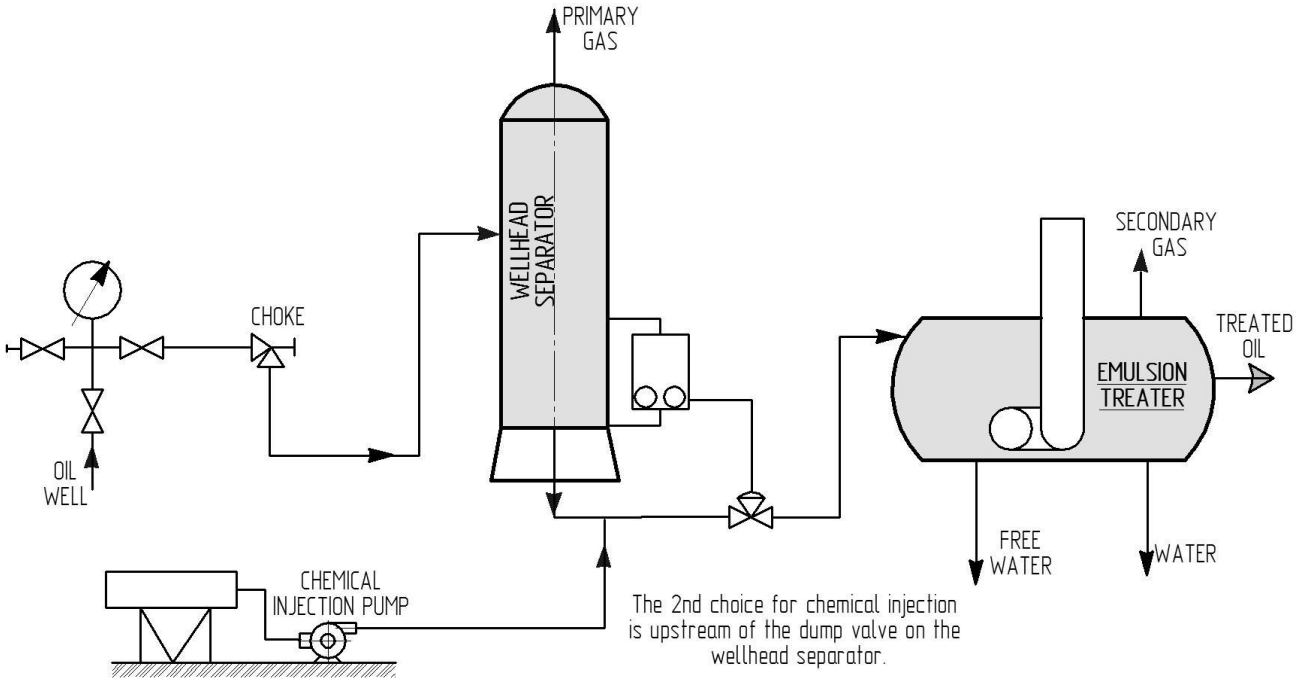

Figure 9.4 – Chemical injection: upstream of the level control valve of the gas–oil separator

3. For the case in which the treating system does not include a gas–oil separator, the injection point is placed 60–75 meters from the emulsion treater.

Chemicals are applied and injected using a small chemical pump. The pump is of the displacement plunger type. The chemical pump should be able to deliver

small quantities of the deemulsifier into the oil line. At normal treating conditions, 1 L of chemical is used for each 15–20 m^3 of oil (or about 1 qt per 100 bbl of oil). As was stated earlier, dilution of the chemical with proper solvents is necessary. Based on the type of oil, the required concentration of the chemical ranges between 10 and 60 ppm (parts per million) [3].

Chemical deemulsifiers (emulsion breakers) are complex organic compounds with surface-active characteristics. A combination of nonionic, cationic and anionic materials contributes the surface-active properties. Some of the deemulsifiers are sulfonates, polyglycol esters, polyamine compounds, and many others.

A final and important word is that excessive amounts of chemicals can do harm. Too much chemicals is usually called overtreating. In addition to the unnecessary additional operating cost, excessive treatment would lead to what is known as "burning of the emulsion" (i.e., unbreakable or tight emulsion).

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1. Manning, F. S. and Thomson, R., Oil-Field Processing of Petroleum, Penn-well Publishing, Tulsa, OK, 1991.

2 Abdel-Aal, H. K., Surface Petroleum Operations, Saudi Publishing & Distributing House, Jeddah, 1998.

3. Nalco Chemical Co., Theories of Emulsion Breaking, Technology Series CTS, Sugarland, TX, 1983, Vol. 3.

LECTURE 10
ELECTRICAL AID

This is the third aid of emulsion treating in crude oil dehydration. However, it should be realized that both heating and chemical treating work in order to "break the emulsion", whereas electrical emulsion treating is aimed at speeding up "coalescence", hence settling. In other words, electric dehydration does not break the emulsion electrically.

Looking at the three consecutive steps involved in the dehydration of emulsified crude oils (breaking the emulsion, coalescence of water droplets, and settling and separation) and assuming that the first and third steps are fast compared to the second step, it can be concluded that coalescence is the controlling step. In other words, coalescence, which is a function of time, influences settling. Consequently, in the design of dehydrators, some means should be implemented to reduce the coalescence time, hence the settling time. Some of these means are (1) installing a coalescing medium in the settling section to speed up the buildup and the formation of water drops, (2) applying centrifugal force to the emulsion that can promote separation, and (3) applying an electrical field in the settling section of the treater.

The principle of breaking oil–water emulsions using electrical current is known as electrostatic separation. Ionization of these emulsions with the aid of electric field was introduced in 1930 for crude oil desalting in oil refineries. High-voltage field (10,000 to 15,000 v) is used to help dehydration according to the following steps:

1. The water droplet is made up of polar molecules, because the oxygen atom has a negative end, and the hydrogen atoms have positive charges. These polar forces are magnetized and respond to an external electrical force field. Therefore, a dipole attraction between the water droplets in the emulsion is established, leading to coalescence, hence settling and separation (see Figure 10.1).
2. As a result of the high-voltage field, the water droplets vibrate rapidly, causing the stabilizing film to weaken and break.
3. The surface of the water droplets expands (droplets` shapes change into ellipsoids); thus attracted to each other, they collide and then coalesce, as depicted in Figure 10.2.
4. As the water droplets combine, they grow in size until they become heavy enough to separate by settling to the bottom of the treater.

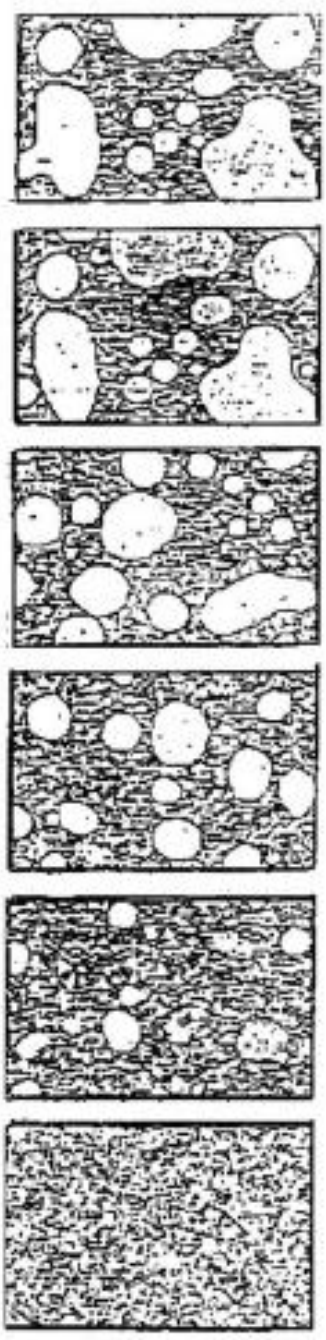

Figure 10.1 – Coalescence of water droplets in W/O emulsion [1]

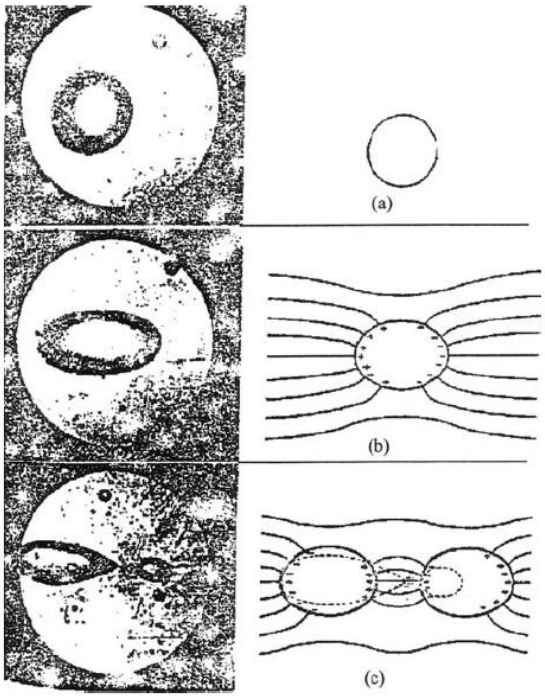

Figure 10.2 – Emulsion breaking with the aid of an electric current [2]

Chemielectric Dehydratros (Emulsion Treaters)

It is normal practice to call emulsion treaters ‘‘heater treaters.’’ However, when other or additional treating aids are used, the name of the treater would be made to reflect such aids of treatment. Consequently, a name such as chemielectric dehydrator is used to indicate that both chemical and electrical aids are used (in addition to heating) in the treatment.

Figure 10.3 is a sketch illustrating a typical chemielectrical treater.

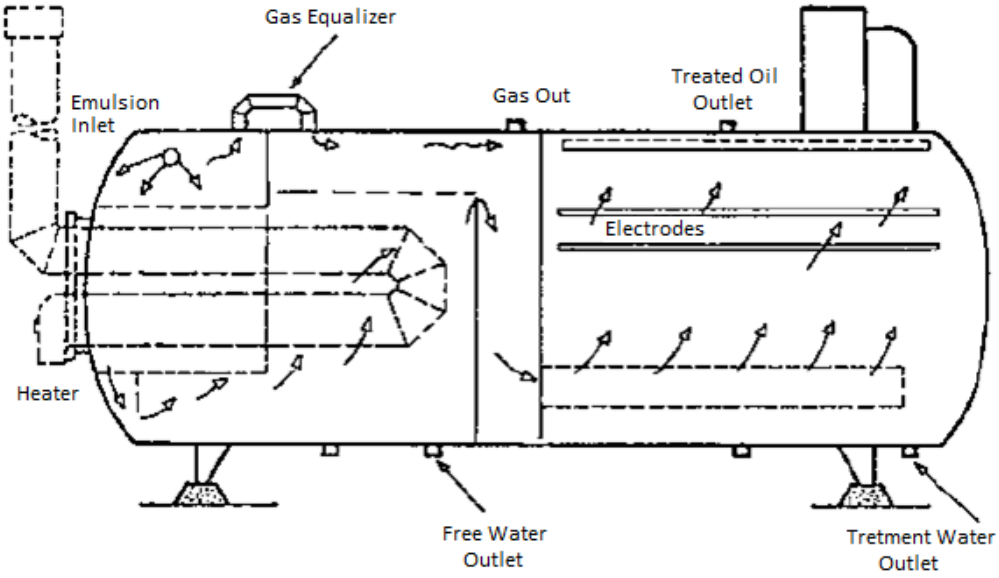

Figure 10.3 – Chemelectric dehydrator

The vessel is basically the same as the horizontal heater treater described earlier. Once the oil is heated, it flows to the settling section. Free water separated

from the emulsion (under the effect of both heat and chemicals) settles to the bottom. The oil on the other hand moves slowly upward, passing across the electric grid in the settling section, where remnant emulsified water is separated as explained earlier. Finally, clean oil flows to the top of the treater.

It should be made clear that most of the emulsified water is removed by the dual action of both heat and chemicals before the oil passes to the electric grid. The water content in the oil could be reduced to 1–0.5% before it gets to the grid.

The application of the electrical field has a significant impact on the treater's performance. This is exemplified by Figure 10.4, which clearly illustrates the improvement of a treater when an electric field is applied.

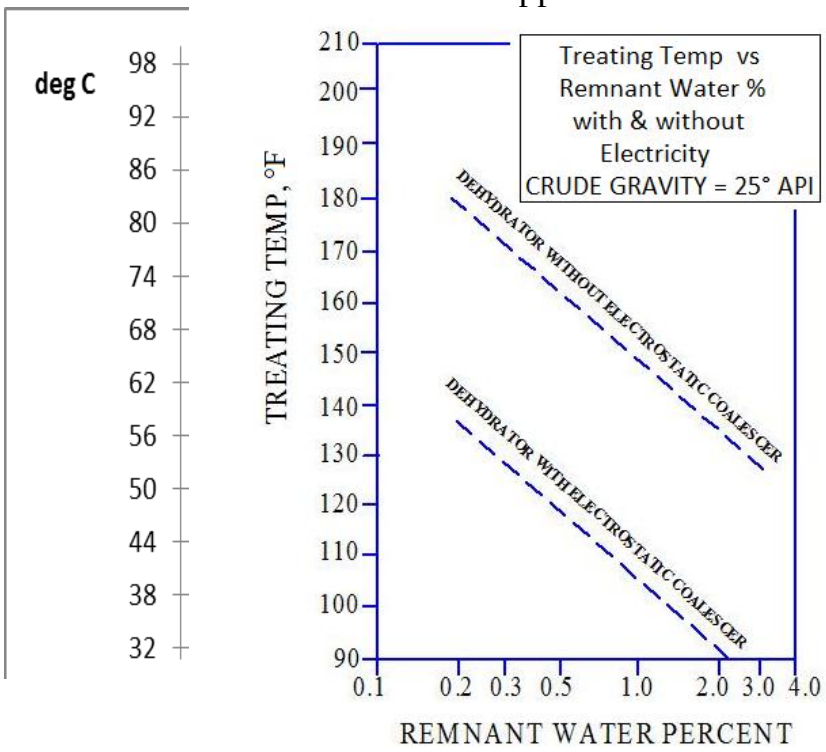

Figure 10.4 – Effect of an electrical field on coalescence

REFFERENCES:

1 Abdel-Aal, H. K., Surface Petroleum Operations, Saudi Publishing & Distributing House, Jeddah, 1998.

2 Arnold, K. and Stewart, M., Surface Production Operations: Design of Oil-Handling Systems and Facilities, 2nd ed., Gulf Publishing Co., Richardson, TX, 1998, Vol. I.

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LECTURE 11
DESALTING OF CRUDE OIL

The removal of salt from crude oil for refinery feed stocks has been and still is a mandatory step. This is particularly true if the salt content exceeds 20 PTB (pounds of salt, expressed as equivalent sodium chloride, per thousand barrels of oil).

The most economical place for the desalting process is usually in the refinery. However, when marketing or pipeline requirements are imposed, field plants are needed for processing the salty oil prior to shipping. The principals involved are the same whether desalting takes place at the refinery or in the field. Salt in crude oil is, in most cases, found dissolved in the remnant brine within the oil.

The remnant brine is that part of the salty water that cannot be further reduced by any of the dehydration methods described in the previous lectures. It is commonly reported as basic sediments and water (B.S.&W.). It is understood that this remnant water exists in the crude oil as a dispersion of very tiny droplets highly emulsified in the bulk of oil.

The mineral salts of this brine consist mainly of chlorides of sodium, calcium and magnesium. A summary of the properties of crude oil as received at the refinery is given in Table 11.1.

Table 11.1 – Properties of Crude Oils Shipped to Refineries

	Range	Average
Water in crude, % by volume of crude	0.1–2.0	0.3–0.5
Salt content in crude, PTB	10–250	60-130
Salt concentration in brine, wt%	0.4–25	—
Salt concentration in brine, ppm	4,000–250,000	—

Source: Ref. 1.

Nelson [1] compiled the data given in Table 11.2 on the amount of salts found in oils for various regions in the world.

Table 11.2 – Average Values for the PTB for Some Typical Crude Oils

Source of oil	**Avg. salt content (PTB)**
Middle East	8
Venezuela	11
United States	
Pennsylvania	1
Wyoming	5
East Texas	28
Gulf Coast	35
Oklahoma and Kansas	78
West Texas	261
Canada	200

The amount of salt in the crude oil is a function of the amount of the brine that remains in the oil W_R (% B.S.&W.) and of its salinity S_R in parts per million (ppm). In other words, this relationship could be written in the following functional form (after Manning and Thompson [2]):

$$PTB = 350\ \gamma_{Brine} \left(\frac{1000\ W_R}{100 - W_R} \right) \left(\frac{S_R}{10^6} \right) \tag{11.1}$$

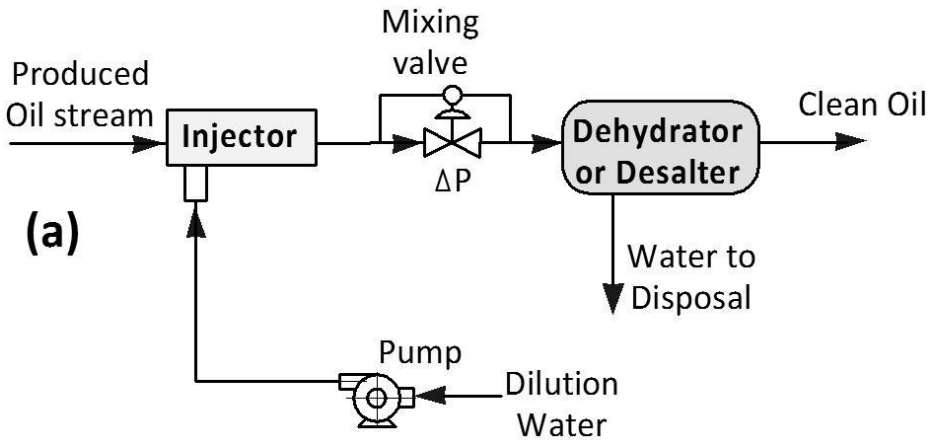
The method of reducing the PTB by lowering the quantity of remnant water W_R is usually referred to as the treating process of oil dehydration. The other alternative of reducing the PTB is to substantially decrease the dissolved salt content of the remnant water (i.e., its concentration, S_R). This practice is the one we are dealing with in this lecture and is known as desalting. Desalting of crude oil will eliminate or minimize problems resulting from the presence of mineral salts in crude oil. These salts often deposit chlorides on the heat transfer equipment of the distillation units and cause fouling effects. In addition, some chlorides will decompose under high temperature, forming corrosive hydrochloric acid [3]:

$$MgCl_2(aq.) \xrightarrow[H_20]{\text{High temp.}} Mg(OH)_2 + HCl \tag{11.2}$$

The removal of these salts is aimed at providing an economical operating cycle in the refining process of crude oil. The reduction of salt content down to 5 PTB is feasible. Even with this low salt content, it has been reported that the processing of 25,000 bb1/day of crude oil could result in an amount of HCl equal to 65 lb/day (29.5 kg per day) [4].

Description of the desalting process

We cannot economically achieve a satisfactory salt content in oil by using dehydration only (single stage). This is particularly true if the salinity of the water produced with oil is much greater than 20,000 ppm (formation water has a concentration of 50,000–250,000 mg/L). Accordingly, a two-stage system (a dehydration stage and a desalting stage) is shown in Figure 11.1 (a). Under certain conditions, however, a three-stage system may be used which consists of a dehydration stage and two consecutive desalting units as shown in Figure 11.1(b).



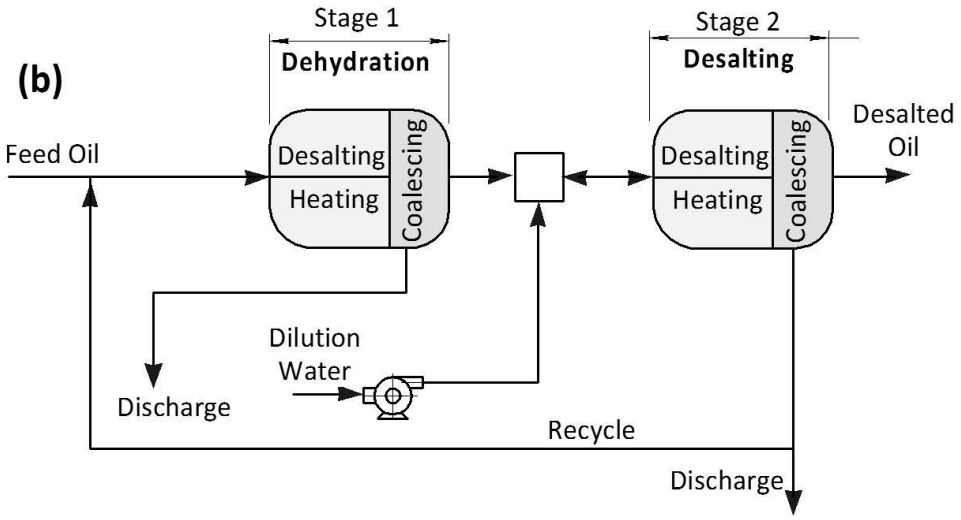


Figure 11.1 – (a) Single-stage desalting system (from Ref. 5). (b) A two-stage desalting system

As shown in Figure 11.1, wash water, also called dilution water, is mixed with the crude oil coming from the dehydration stage. The wash water, which could be either fresh water, or water with lower salinity than the remnant water, mixes with the remnant water, thus diluting its salt concentration. The mixing results in the formation of water–oil emulsion.

The oil (and emulsion) is then dehydrated. The separated water is disposed of through the field-produced water treatment and disposal system. In the two-stage desalting system, dilution water is added in the second stage and all, or part, of the disposed water in the second stage is recycled and used as the dilution water for the first desalting stage. Two-stage desalting systems are normally used to minimize the wash water requirements.

The mixing step in the desalting of crude oil is normally accomplished by pumping the crude oil (which is the continuous phase) and wash water (which is the dispersed phase) separately through a mixing device. The usual mixing device is simply a throttling valve. The degree of mixing can be enhanced if the interfacial area generated upon mixing is increased. A useful device for such a purpose is the application of multiple-orifice-plate mixers (MOMs) shown in Figure 11.2.

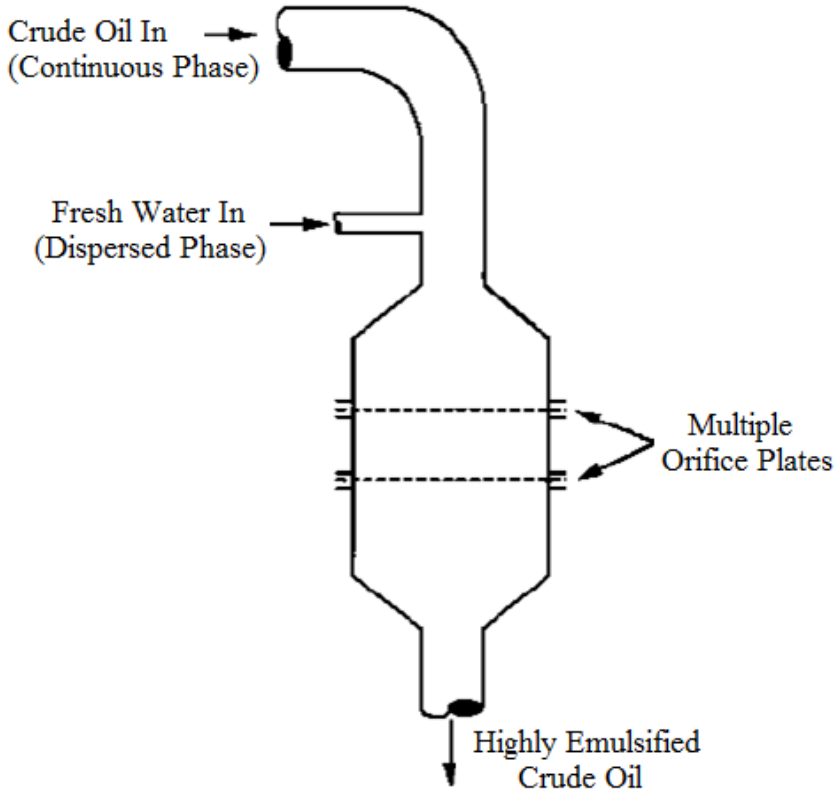


Figure 11.2 – Details of multiple-orifice plate mixers (MOM)

It is of importance to point out that although the theory of dilution of remnant water with fresh water is sound in principle, it can become impossible to implement in actual application. It all depends on the intimate mixing of remnant water with dilution water.

In the emulsion-treating step, a heating, chemical, or electrical demulsifying aid (or a combination of them) is commonly used. The chemical desalting process involves adding chemical agents and wash water to the preheated oil, followed by settling, is shown in Figure 11.3. The settling time varies from a few minutes to 2 h. Some of the commonly used chemical agents are sulfonates, long-chain alcohols, and fatty acids.

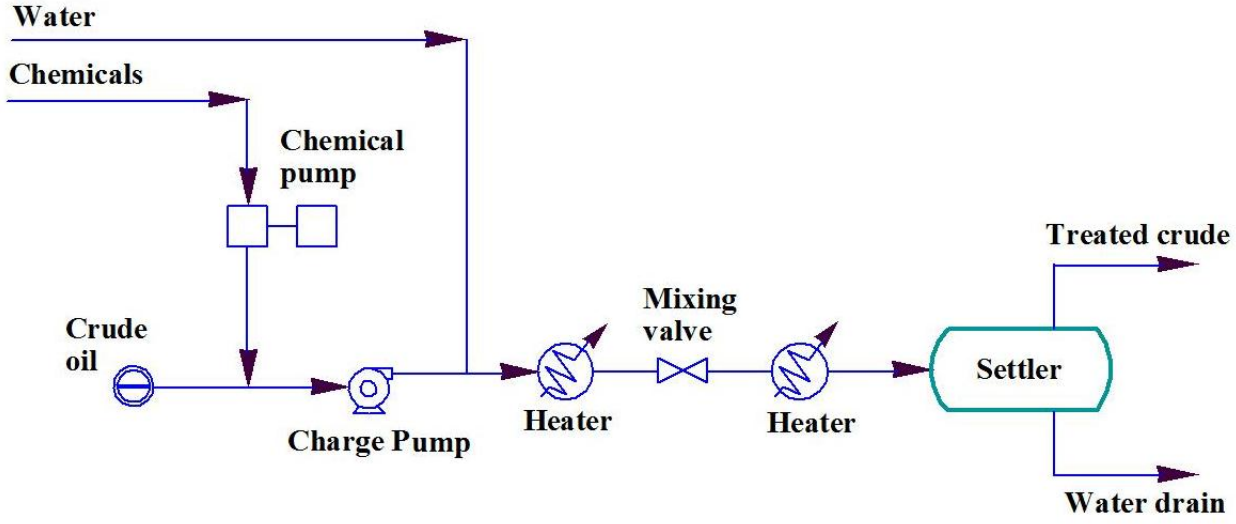


Figure 11.3 – Chemical desalting

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LECTURE 12
ELECTROSTATIC DESALTING

In this case, an external electric field is applied to coalesce the small water droplets and thus promote settling of the water droplets out of the oil. The electric field may be applied in any of the following manners [1]:

1. **ac field devices for water-rich emulsions.** Alternating current (ac) is applied, which alternates the polar water molecule arrangements leading to better coalescence. A schematic diagram of ac electrostatic coalescence is shown in Figure 12.1.

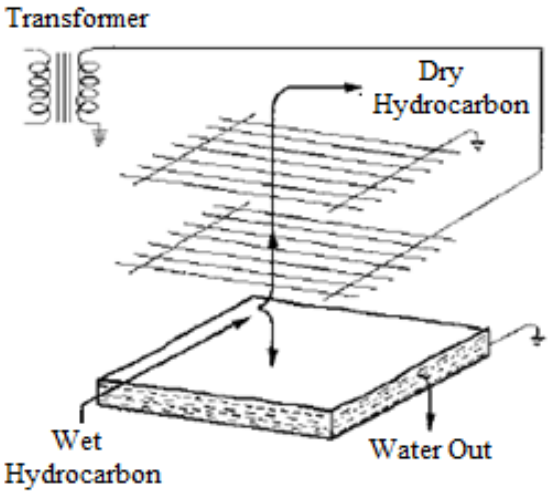

Figure 12.1 – ac electrostatic coalescer

2. **ac/dc field for maximum dehydration**. A combination of ac and dc (direct current) is used in this case. The basic configuration of this process is shown in Figure 12.2. The ac is produced in the zone beneath the electrodes, whereas the dc field is produced between adjacent electrodes. This arrangement achieves maximum water removal.

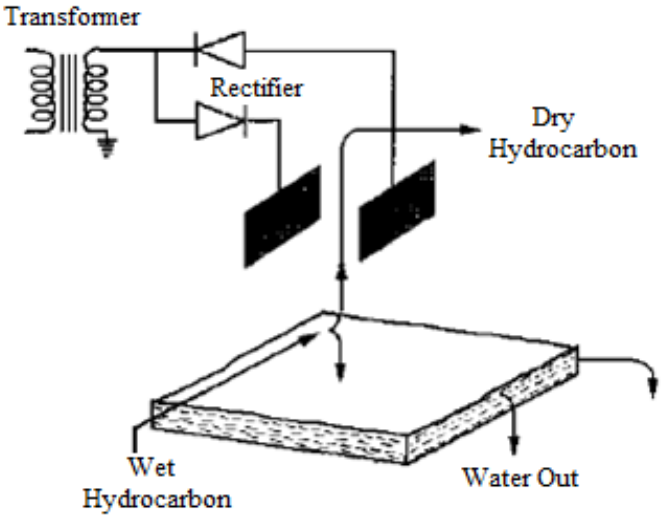

Figure 12.2 – Dual polarity ac/dc field

3. Variable gradient field for maximum salt reduction. If the field gradient is increased beyond a certain limit (Ec), this will shatter the drops; it is expressed as

$$E_c \leq k \cdot \left(\frac{\gamma}{d}\right)^{1/2} \tag{12.1}$$

where k is the dielectric constant, γ is the interfacial tension, and d is the drop diameter. Thus, the drop size can be controlled by the field gradient. The electric field can be used both to mix and separate the drops.

By cycling the field strength, the process can be repeated many times during the retention time of the drops within the electric field. Voltage modulation will create mixing, coalescence, and settling, as shown in Figure 12.3. The electrostatic field causes the dipolar water molecules to align with the field.

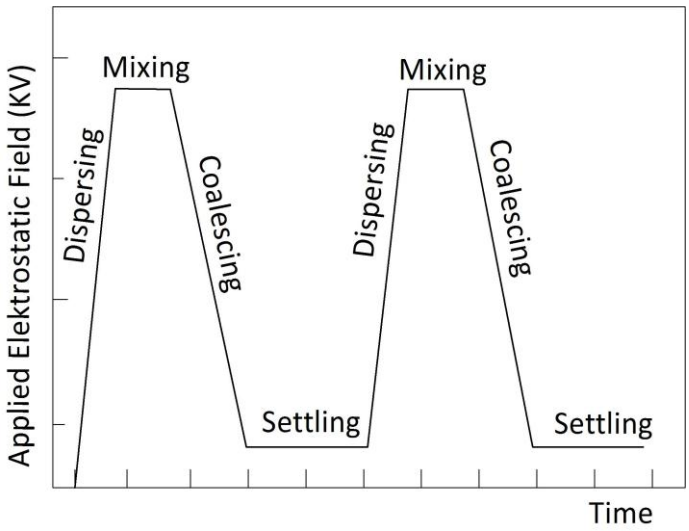

Figure 12.3 – Voltage modulation for electrostatic mixing coalescing

In the electrical desalting process, a high potential field (16,500–33,000 V) is applied across the settling vessels to help coalescence, as shown in Figure 12.4.

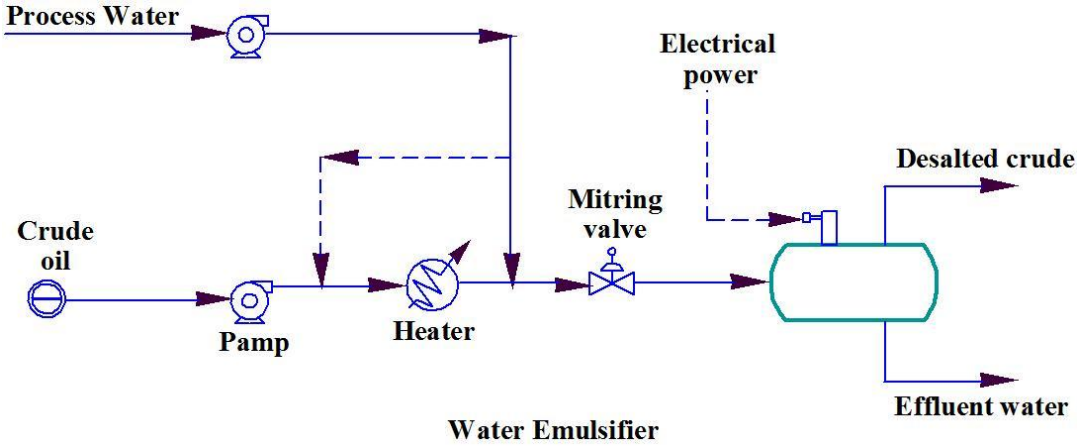

Figure 12.4 – Electrical desalting

The chemielectric concept utilizing both chemical agents and electrical field is schematically illustrated in Figure 12.5. In the desalting process, it is a common practice to apply enough pressure to suppress any loss of hydrocarbon due to vaporization of the oil. The pressure normally used in a desalting process is in the range 50–250 psi.

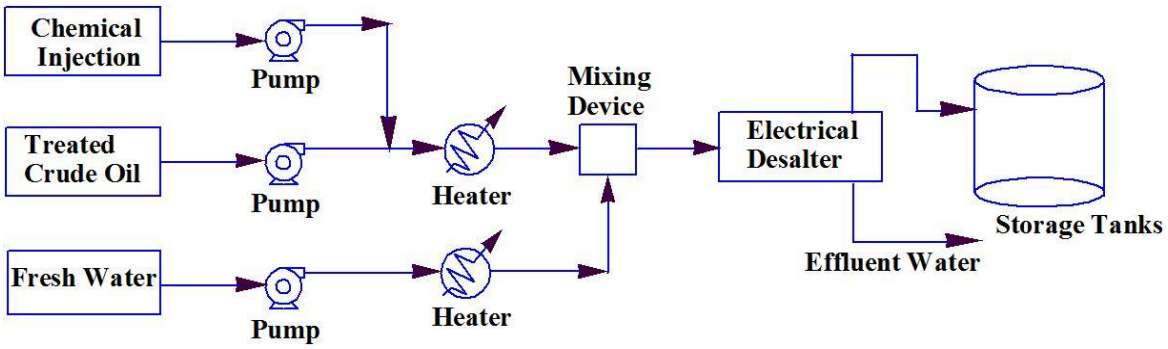

Figure 12.5 – A typical desalting system utilizing chemelectric approach

Determining Dilution Water Requirement

From the operational point of view, it has been reported that the amount of water of dilution WD added in the desalting of crude oils is in the range 5–10% by volume, based on the amount of remnant water and its salinity.

Effect of operating parameters

The efficiency of desalting is dependent on the following parameters [2,3]:

1. Water–crude interface level. This level should be kept constant; any changes will change electrical field and perturbs electrical coalescence.

2. Desalting temperature. Temperature affects water droplet settling through its effect on oil viscosity; therefore, heavier crude oils require higher desalting temperatures.

3. Wash water ratio. Heavy crudes require a high wash water ratio to increase electrical coalescence. A high wash ratio acts similarly to raise temperatures, as illustrated in Table 12.1.

4. Pressure drop in the mixing valve. A high-pressure-drop operation results in the formation of a fine stable emulsion and better washing. However, if the pressure drop is excessive, the emulsion might be difficult to break. The optimum pressure drop is 1.5 bar for light crudes and 0.5 bar for heavy crudes.

5. Type of demulsifiers. Demulsifiers are added to aid in complete electrostatic coalescence and desalting. They are quite important when heavy crudes are handled. Levels ranging between 3 and 10 ppm of the crude are used.

Table 12.1 – Average Desalting Conditions

Crude gravity (°API)	Desalting temperature (°C)	Minimum water ratio (vol%)
>40	110	2–4
30–40	110	4–8
	120	4–7
<30	130	8–10
	140	>10

Design consideration

The following major parameters are considered when designing the desalting system:

1) flow scheme arrangements (conventional one-stage or countercurrent contact desalters);
2) number of desalting stages;
3) dehydration levels achieved;
4) salinity of the brine in the crude;
5) efficiency of valve mixing;
6) salinity of dilution water;
7) target PTB specification.

Trouble shooting

Table 12.2 lists some “tips” that are helpful in solving some of the operating problems or troubles that are of significance to the desalting process.

Table 12.2 – Problems, causes and solutions

Problems	**Causes**	**Solutions**
1	2	3
1. A high salt content in the desalted crude oil	(a)Feed salt content high (b)Wash water injection low (c)Crude oil flow rate exceeds the design flow rate (d)Insufficient mixing of the crude oil and wash water	(a)Increase the wash water rate (b)Reduce the crude oil flow rate (c)Increase the mix value pressure drop
2. Oil in the desalter effluent water	(a)"Interface" level too low (b)Wide emulsion band at the "interface" (c)Excessive crude oil wash water mixing (d)Poor wash water quality (e)Crude temperature too low	(a)Increase the interface level (b)Inject a chemical or dump the emulsion (c)Reduce the mix valve pressure drop (d)Check for any waste in the wash water source
3. High water carry over in desalted crude oil	(a)Wash water flow rate too high (b)Excessive formation water in the crude oil (c)Interface level too high (d)Disturbance in the desalter vessel	(a)Reduce the wash water flow rate and commence or increase chemical injection (b)Reduce the interface level and check the effluent water valve (c)Check for an excessive cause and allow the unit to settle down

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1 Abdel-Aal, H. K. and Shaikh, A. A., Desalting of oil using multiple orifice mixers: An empirical correlation for the water of dilution, presented at the Third Iranian Congress of Chemical Engineering, 1977.

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LECTURE 13
CRUDE OIL STABILIZATION AND SWEETENING

Once degassed and dehydrated–desalted, crude oil is pumped to gathering facilities to be stored in storage tanks. However, if there are any dissolved gases that belong to the light or the intermediate hydrocarbon groups, it will be necessary to remove these gases along with hydrogen sulfide (if present in the crude) before oil can be stored. This process is described as a "dual process" of both stabilizing and sweetening a crude oil.

In stabilization, adjusting the pentanes and lighter fractions retained in the stock tank liquid can change the crude oil gravity. The economic value of the crude oil is accordingly influenced by stabilization. First, liquids can be stored and transported to the market more profitably than gas. Second, it is advantageous to minimize gas losses from light crude oil when stored.

This lecture deals with methods for stabilizing the crude oil to maximize the volume of production as well as its API gravity, against two important constraints imposed by its vapor pressure and the allowable hydrogen sulfide content.

To illustrate the impact of stabilization and sweetening on the quality of crude oil, the properties of oil before and after treatment are compared as follows (Table 13.1).

Table 13.1 – Compare of properties of oil before and after treatment

Before treatment		**After treatment**	
Water content:	up to 3% of crude in the form of emulsions and from 3% to 30% of crude as free water	Water content (B.S.&W.)	0.3% by volume, maximum
Salt content	50,000–250,000 mg/L formation water	Salt content:	10–20 lbs salt (NaCl) per 1000 barrels oil (PTB)
Gas	dissolved gases in varying amounts depending on the gas–oil ratio (GOR)	Vapor pressure	5–20 psia RVP (Reid vapor pressure)
Hydrogen Sulfide	up to 1000 ppm by weight	H_2S	10–100 ppmw

After treatment (dual-purpose operation) sour wet crude must be treated to make it safe and environmentally acceptable for storage, processing, and export. Therefore, removing water and salt, is mandatory to avoid corrosion; separation of gases and H_2S will make crude oil safe and environmentally acceptable to handle.

Crude oil is considered "sweet" if the dangerous acidic gases are removed from it. On the other hand, it is classified as "sour" if it contains as much as 0.05

ft^3 of dissolved H_2S in 100 gal of oil ($3{,}54x10^{-6}$ m^3 of H_2S in 2,77 barrels (440 liters). Hydrogen sulfide gas is a poison hazard because 0.1% in air is toxically fatal in 30 min. Additional processing is mandatory—via this dual operation—in order to release any residual associated gases along with H_2S present in the crude.

Prior to stabilization, crude oil is usually directed to a spheroid for storage in order to reduce its pressure to very near atmospheric, as shown in Figure 13.1.

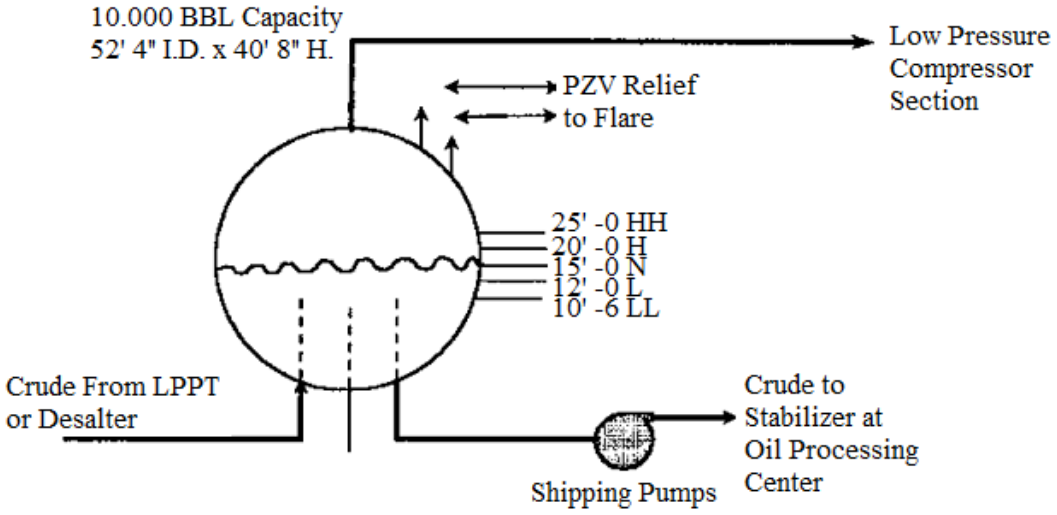

Figure 13.1 – Typical spheroid for oil storage prior to stabilization

Stabilization Operations

The traditional process for separating the crude oil–gas mixture to recover oil consists of a series of flash vessels [gas–oil separation plant (GOSP)] operating over a pressure range from roughly wellhead pressure to nearly atmospheric pressure. The crude oil discharged from the last stage in a GOSP or the desalter has a vapor pressure equal to the total pressure in the last stage. Usually, operation of this system could lead to a crude product with a RVP in the range of 4 to 12 psia (0.27-0.81 bar). Most of the partial pressure of a crude oil comes from the low-boiling compounds, which might be present only in small quantities—in particular hydrogen sulfide and low-molecular-weight hydrocarbons such as methane and ethane.

Now, stabilization is directed to remove these low-boiling compounds without losing the more valuable components. This is particularly true for hydrocarbons lost due to vent losses during storage. In addition, high vapor pressure exerted by low-boiling-point hydrocarbons imposes a safety hazard. Gases evolved from an unstable crude oil are heavier than air and difficult to disperse with a greater risk of explosion.

The stabilization mechanism is based on removing the more volatile components by (a) flashing using stage separation and (b) stripping operations.

As stated earlier, the two major specifications set for stabilized oil are as follows:

- the Reid vapor pressure (RVP)

- hydrogen sulfide content

Based on these specifications, different cases are encountered:

Case 1: Sweet oil (no hydrogen sulfide); no stabilization is needed. For this case and assuming that there is a gasoline plant existing in the facilities (i.e., a plant designed to recover pentane plus), stabilization could be eliminated, allowing the stock tank vapors to be collected [via the vapor recovery unit (VRU)] and sent directly to the gasoline plant, as shown in Figure 13.2.

Case 2: Sour crude; stabilization is a must. For this case, it is assumed that the field facilities do not include a gasoline plant. Stabilization of the crude oil could be carried out using one of the approaches outlined in Figure 13.3. Basically, either flashing or stripping stabilization is used.

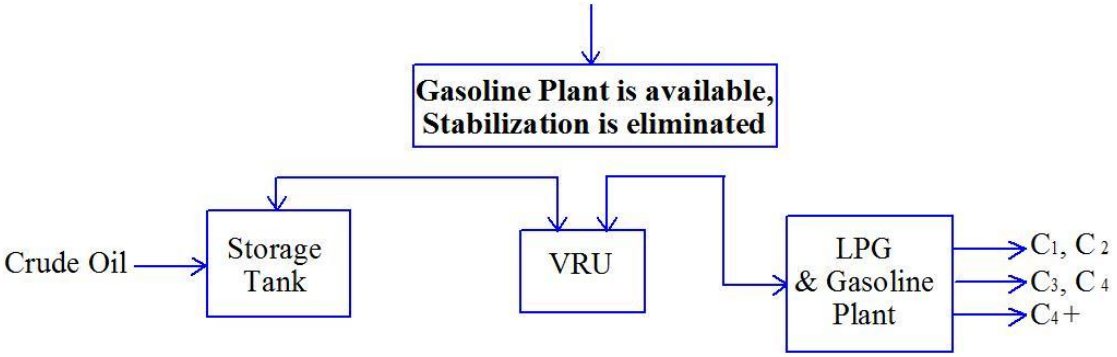

Figure 13.2 – Field operation with no stabilization

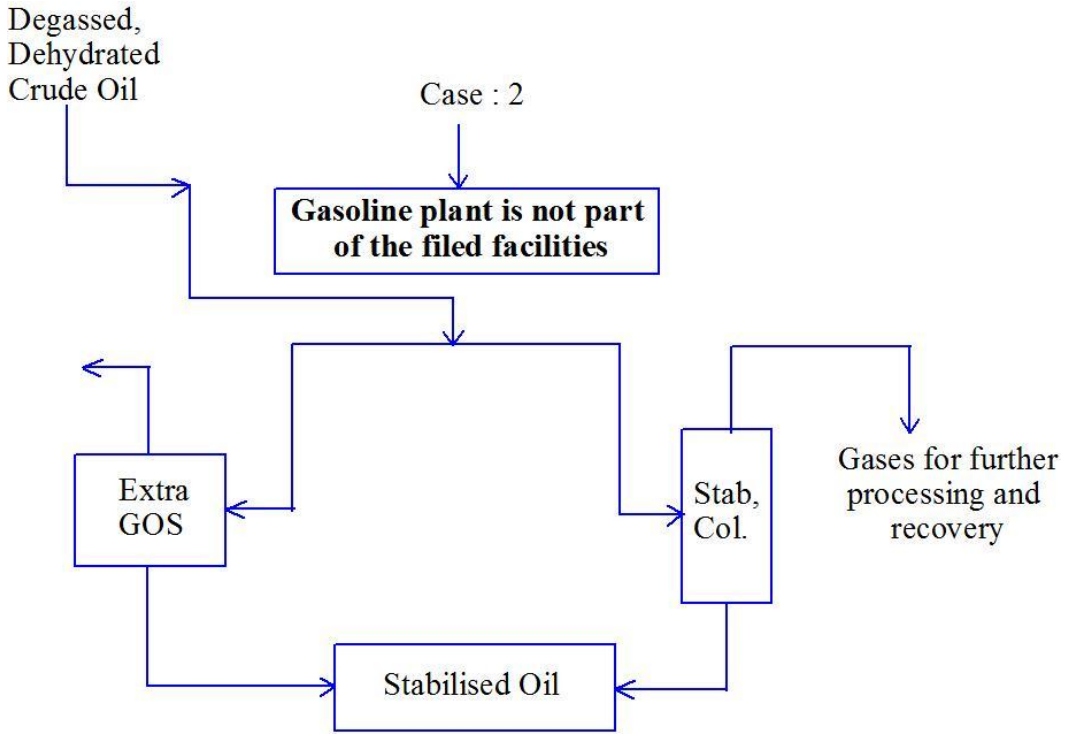

Figure 13.3 – Alternatives for stabilizing crude oil

It can be concluded from the above that the hydrogen sulfide content in the well stream can have a bearing effect on the method of stabilization. Therefore, the recovery of liquid hydrocarbon can be reduced when the stripping requirement to

meet the H_2S specifications is more stringent than that to meet the RVP specified. Accordingly, for a given production facility, product specifications must be individually determined for maximum economic return on any investment.

Stabilization by Flashing (Additional Gas–Oil Separator)

The method utilizes an inexpensive small vessel to be located above the storage tank. The vessel is operated at atmospheric pressure. Vapors separated from the separator are collected using a VRU. This approach is recommended for small-size oil leases handling small volume of fluids to be processed. The principles underlying the stabilization process are the same as for gas–oil separation.

Stabilization by Stripping

The stripping operation employs a stripping agent, which could be either energy or mass, to drive the undesirable components (low-boiling-point hydrocarbons and hydrogen sulfide gas) out of the bulk of crude oil. This approach is economically justified when handling large quantities of fluid and in the absence of a VRU. It is also recommended for dual-purpose operations for stabilizing sour crude oil, where stripping gas is used for stabilization. Stabilizer-column installations are used for the stripping operations.

Types of Stabilizer Employing Energy as a Stripping Agent

Two basic types of trayed stabilizer are commonly used:

- Conventional reflux types normally operate from 150 to 300 psia (10 – 20 bar).

This type of stabilizer is not common in field installations. It is more suitable for large central field processing plants.

- Non-refluxed stabilizers generally operate between 55 and 85 psia (3.7 – 5,7 bar).

These are known as “cold feed” stabilizers. They have some limitations, but they are commonly used in field installations because of their simplicity in design and operation.

Non-refluxed Stabilizers

When hydrocarbon liquids are removed from the separators, the liquid is at its vapor pressure or bubble point. With each subsequent pressure reduction, additional vapors are liberated. Therefore, if the liquids were removed directly from a high-pressure separator into a storage tank, vapors generated would cause loss of lighter as well as heavier ones. This explains the need for many stages in a GOSP. Nevertheless, regardless of the number of stages used, some valuable hydrocarbons are lost with the overhead vapor leaving the last stage of separation or the stock tank.

A maximum volume of hydrocarbon liquid could be obtained under stock tank conditions with a minimum loss of solution vapors by fractionating the last-stage separator liquid. This implies using a simple fractionating column, where the

vapors liberated by increasing the bottom temperature are counter flowed with the cool feed introduced from the top. Interaction takes place on each tray in the column. The vapors act as a stripping agent and the process is described as stabilization.

Equipment and Operation

In general, a conventional fractionating column would require main auxiliaries such as reflux, pumps, condensers, cooling water, and utilities frequently not available on site in oil fields. Stabilizers or stripping columns, on the other hand, can be operated with a minimum of these auxiliaries.

Figure 13.4 depicts a stabilizer in its simplest form.

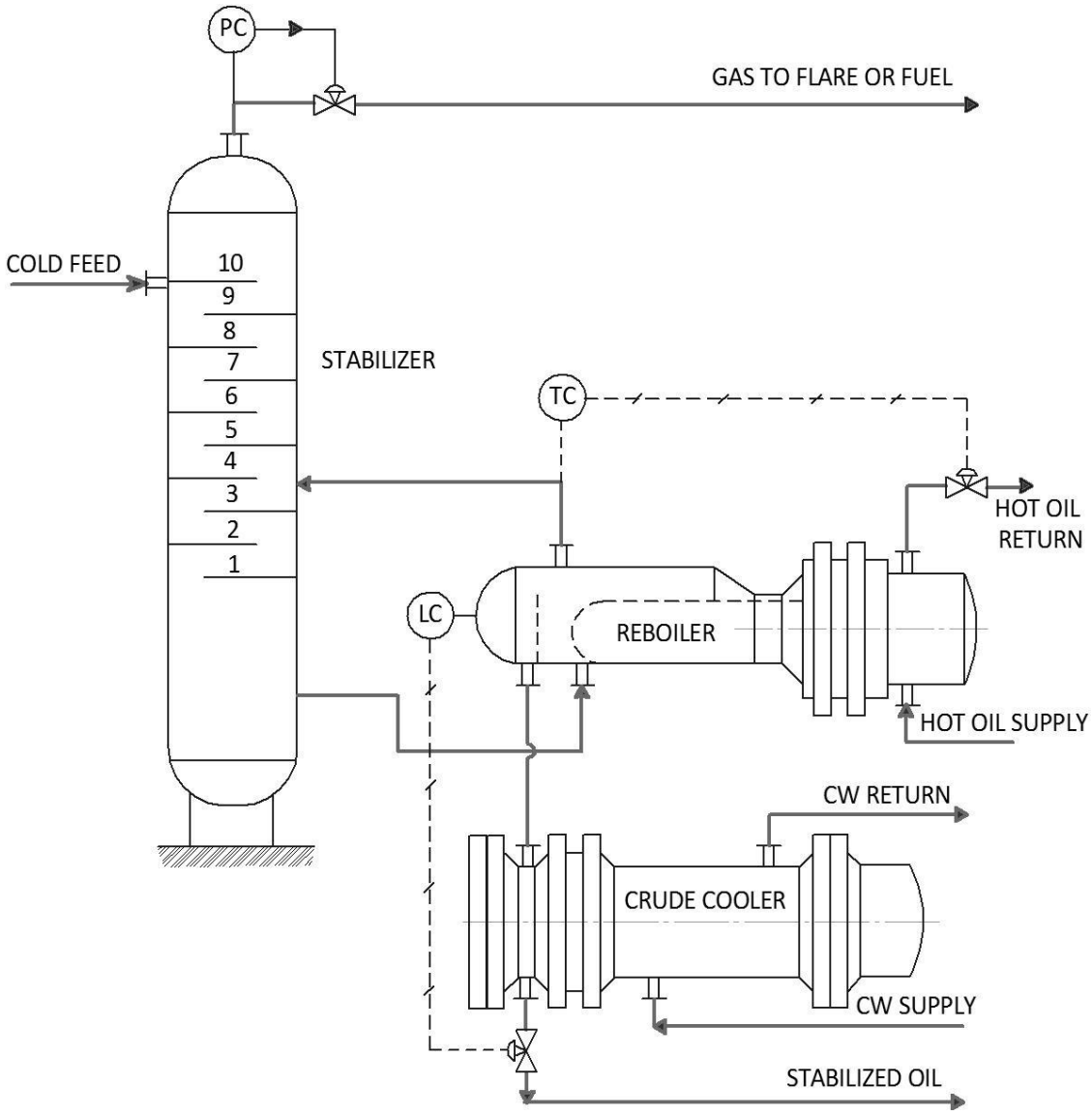

Figure 13.4 – Typical trayed stabilizer

A cold feed stabilizer normally operates with a fixed top and bottom temperatures. The former is kept as low as possible to maximize recovery, whereas the latter is controlled to maintain the product bottom pressure. It is of interest to mention that the overhead gas temperature is identical to the liquid feed

temperature because the ratio of masses of vapor leaving the column to liquid feed entering is rather small.

Most stabilizers operate above 200 psia (13.5 bar) and consist of 20 bubble trays. High-pressure stabilizers have more trays because of the higher temperature gradient between the top and the bottom trays. More trays allow the column to operate closer to equilibrium. Columns less than 20 inches in (50.4 mm) diameter generally use packing rather than trays. A useful rule of thumb is that 1 ft^2 (0.93 m^2) of tower area could handle about 100 bbl/day of stock tank liquid. In some designs, the cold feed is introduced several trays below the top tray, using the upper trays as a scrubber in order to prevent liquid carry over during burping.

Field operation of a stabilizer is described as follows. Relatively cool liquid (oil) exiting the GOSP is fed to the top plate of the column where it contacts the vapor rising from below. The rising vapors strip the lighter ends from the liquid (i.e., acting as a stripping agent). At the same time, the cold liquid—acting as an internal reflux – will condense and dissolve heavier ends from the rising vapor, similar to a rectification process. The net separation is very efficient as compared to stage separation (3–7% more).

To have a stabilized product of certain specifications, in theory a stabilizer can be operated at multiple combinations of tower pressure and bottom temperature. In general, as the tower pressure is increased, more light ends will condense in the bottom. In normal operation, it is best to operate the tower at the lowest possible pressure without losing too much of the light ends at the initial feed flash. This will minimize ‘‘burping’’ and cause the column to operate near equilibrium. In addition, lower operating pressures require less reboiler duty with less fuel consumption. Operating data for a 40,000-bbl/day non-refluxed stabilizer are given in Figure 13.5.

Main Features and Applications of Stabilizers

Stabilizers used for oil production field operations should have the following features:

– They must be self-contained and require minimum utilities that are available in the field, such as natural gas for fuel.

– Stabilizers must be capable of unattended operation and to stand fail-safe operation.

– Stabilizers must be equipped with simple but reliable control system.

– They should be designed in a way to make them accessible for easy dismantling and reassembly in the field.

– Maintenance of stabilizers should be made simple and straight forward.

Stabilizer’s applications, on the other hand, are justified over simple stage separation under the following operating conditions:

– The first-stage separation temperature is between 0 °C and 40 °C.

– The first-stage separation pressure is greater than 1200 psig (81.3 barg).

– The liquid gravity of the stock tank oil is greater than 45 °API.

– Oil to be stabilized contains significant quantities of pentanes plus, even though the oil gravity is less than 45 °API.

– Specifications are set by the market for product compositions—obtained from crude oil—that require minimum light ends.

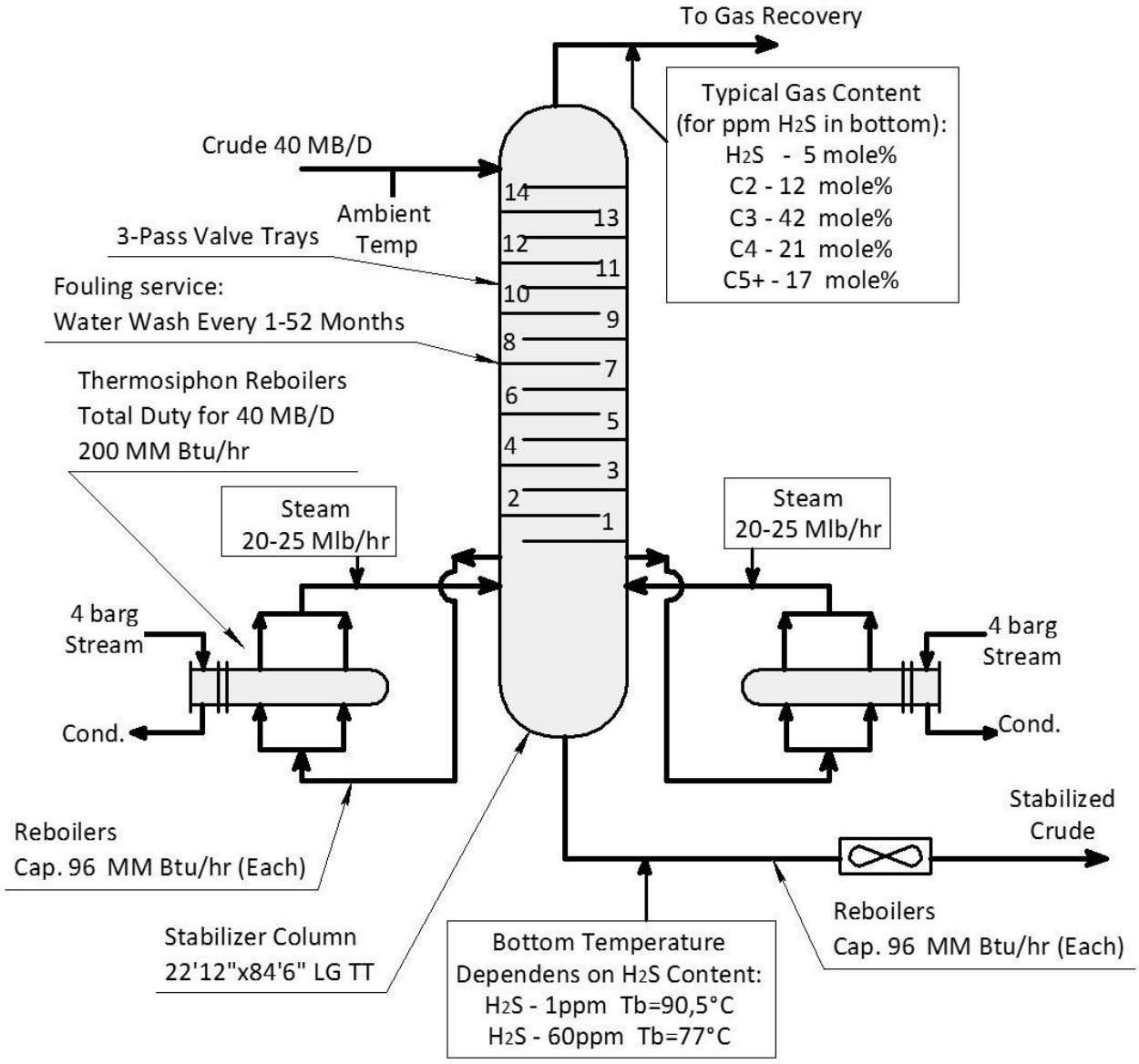

Figure 13.5 – Typical trayed stabilizer with operating data for 40 MB/D of oil

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LECTURE 14
CRUDE OIL SWEETENING

Apart from stabilization problems of "sweet" crude oil, "sour" crude oils containing hydrogen sulfide, mercaptans, and other sulfur compounds present unusual processing problems in oil field production facilities. The presence of hydrogen sulfide and other sulfur compounds in the well stream impose many constraints. Most important are the following:

– Personnel safety and corrosion considerations require that H_2S concentration be lowered to a safe level.

– Brass and copper materials are particularly reactive with sulfur compounds; their use should be prohibited.

– Sulfide stress cracking problems occur in steel structures.

– Mercaptans compounds have an objectionable odor.

Along with stabilization, crude oil sweetening brings in what is called a ''dual operation,'' which permits easier and safe downstream handling and improves and upgrades the crude marketability. Three general schemes are used to sweeten crude oil at the production facilities:

Process	Stripping agent
1 Stage vaporization with stripping gas	Mass (gas)
2 Trayed stabilization with stripping gas	Mass (gas)
3 Reboiled tray stabilization	Energy (heat)

1. Stage vaporization with stripping gas. This process—as its name implies—utilizes stage separation along with a stripping agent.

Hydrogen sulfide is normally the major sour component having a vapor pressure greater than propane but less than ethane. Normal stage separation will, therefore, liberate ethane and propane from the stock tank liquid along with hydrogen sulfide. Stripping efficiency of the system can be improved by mixing a lean (sweet) stripping gas along with the separator liquid between each separation stage.

Figure 14.1 represents typical stage vaporization with stripping gas for crude oil sweetening/stabilization. The effectiveness of this process depends on the pressure available at the first-stage separator (as a driving force), well stream composition, and the final specifications set for the sweet oil.

2. Trayed stabilization with stripping gas. In this process, a tray stabilizer (non-reflux) with sweet gas as a stripping agent is used as shown in Figure 14.2.
Oil leaving a primary separator is fed to the top tray of the column countercurrent to the stripping sweet gas. The tower bottom is flashed in a low-pressure stripper. Sweetened crude is sent to stock tanks, whereas vapors collected from the top of the gas separator and the tank are normally incinerated. These vapors cannot be vented to the atmosphere because of safety considerations. Hydrogen sulfide is hazardous and slightly heavier than air; it can collect in sumps or terrain depressions.

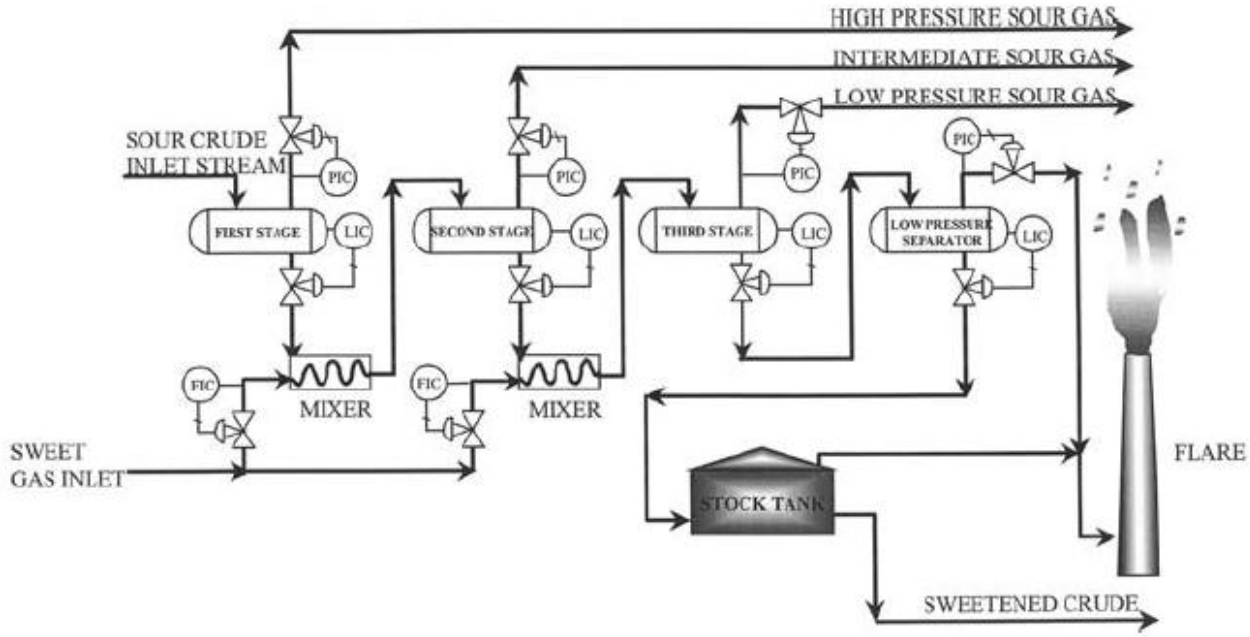

Figure 14.1 – Crude sweetening by stage vaporization with stripping gas

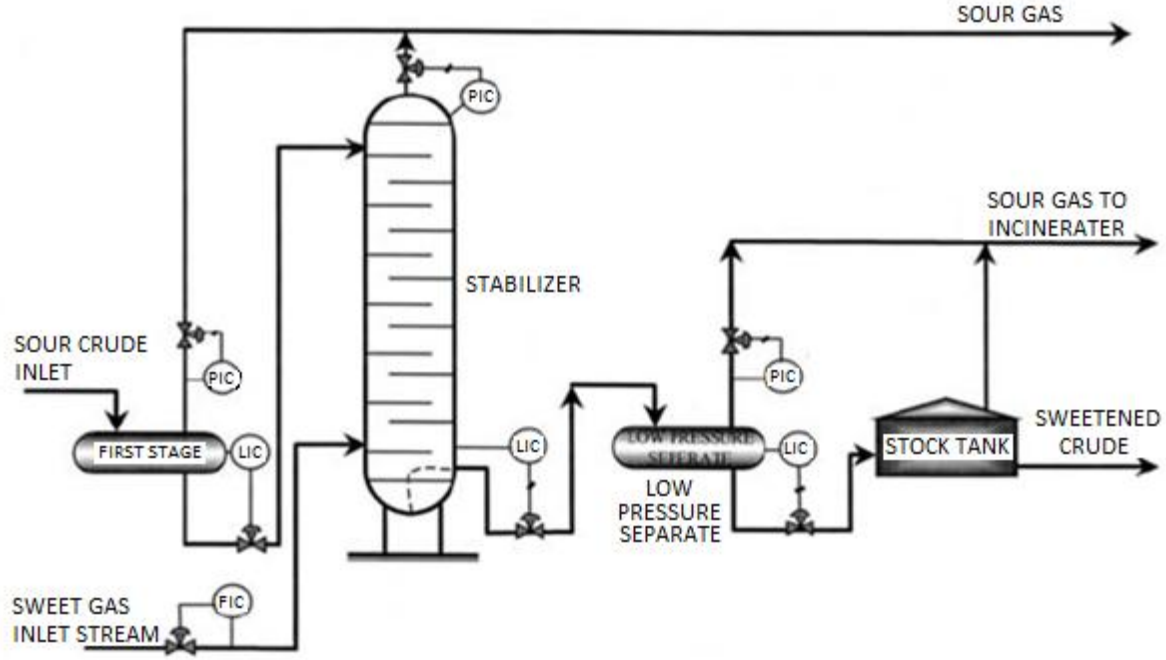

Figure 14.2 – Crude sweetening by trayed stabilization with stripping gas

This process is more efficient than the previous one. However, tray efficiencies cause a serious limitation on the column height. For an efficiency of only 8%, 1 theoretical plate would require 12 actual trays. Because trays are spaced about 2 ft (0.61 m) apart, columns are limited to 24–28 ft (7.3-8.5 m) high, or a maximum of two theoretical trays.

3. Reboiled trayed stabilization. The reboiled trayed stabilizer is the most effective means to sweeten sour crude oils. A typical reboiled trayed stabilizer is shown in Figure 14.3. Its operation is similar to a stabilizer with stripping gas,

except that a reboiler generates the stripping vapors flowing up the column rather than using a stripping gas. These vapors are more effective because they possess energy momentum due to elevated temperature.

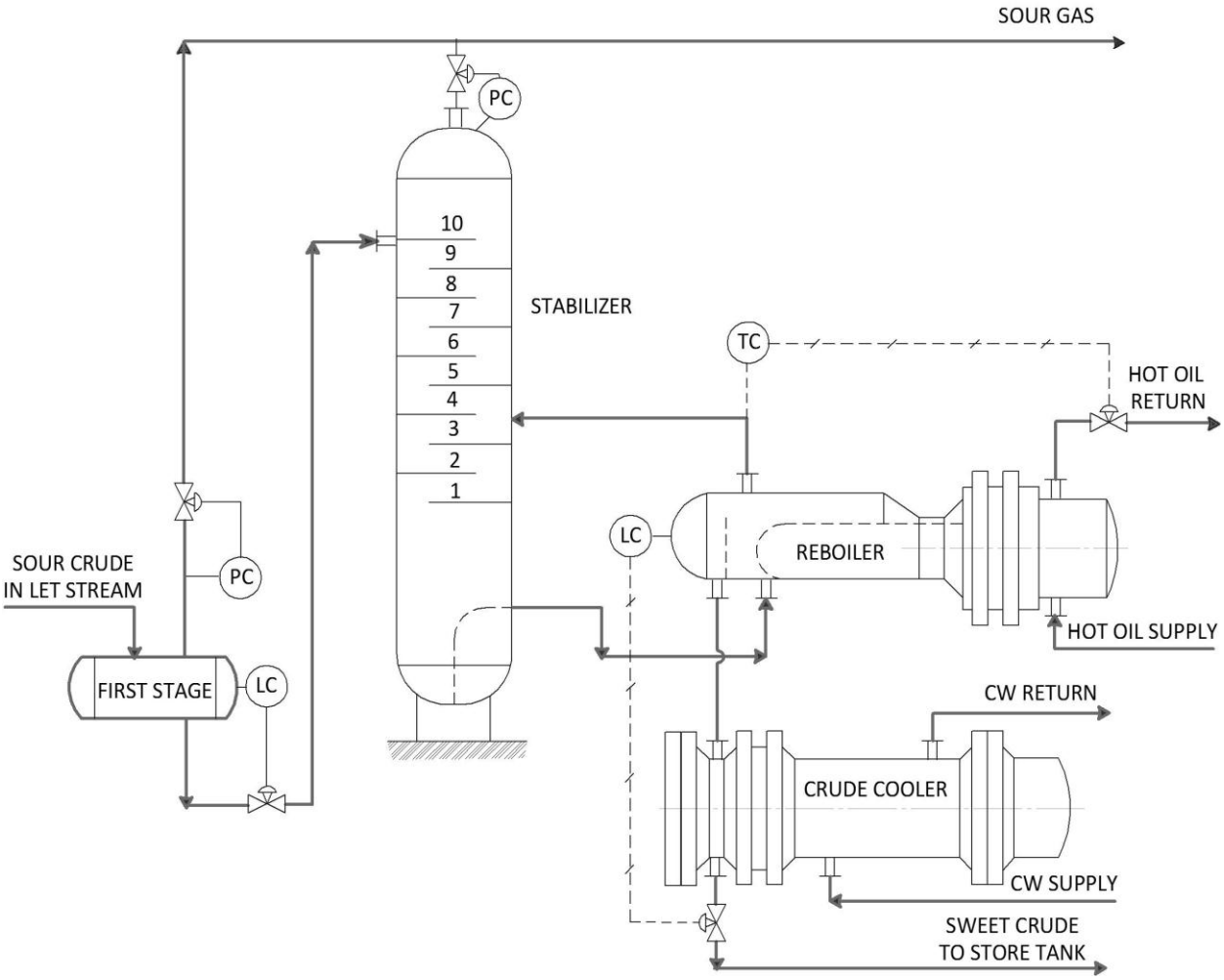

Figure 14.3 – Crude sweetening by reboiled trayed stabilization

Because hydrogen sulfide has a vapor pressure higher than propane, it is relatively easy to drive hydrogen sulfide from the oil. Conversely, the trayed stabilizer provides enough vapor/liquid contact that little pentanes plus are lost to the overhead.

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LECTURE 15
STORAGE TANKS

Storage tanks for crude oil are needed in order to receive and collect oil produced by wells, before pumping to the pipelines as well as to allow for measuring oil properties, sampling, and gauging (figure 15.1).

Figure 15.1 – Storage tanks

The design of storage tanks for crude oil and petroleum products requires, in general, careful consideration of the following important factors:

- the vapor pressure of the materials to be stored;
- the storage temperature and pressure;
- toxicity of the petroleum material.

In order to meet the environmental constraints on air pollution, to prevent fire hazards, and to avoid losses of valuable petroleum products at the same time, it is recommended to adopt the following:

- the use of floating-roof tanks for petroleum materials with a vapor pressure of 1.12–11.5 psia (0.08 – 0.78 bar) at the storage temperature$
- using fixed-roof tanks along with the VRU system (to be described later).

These alternatives are schematically illustrated in Figure 15.2.

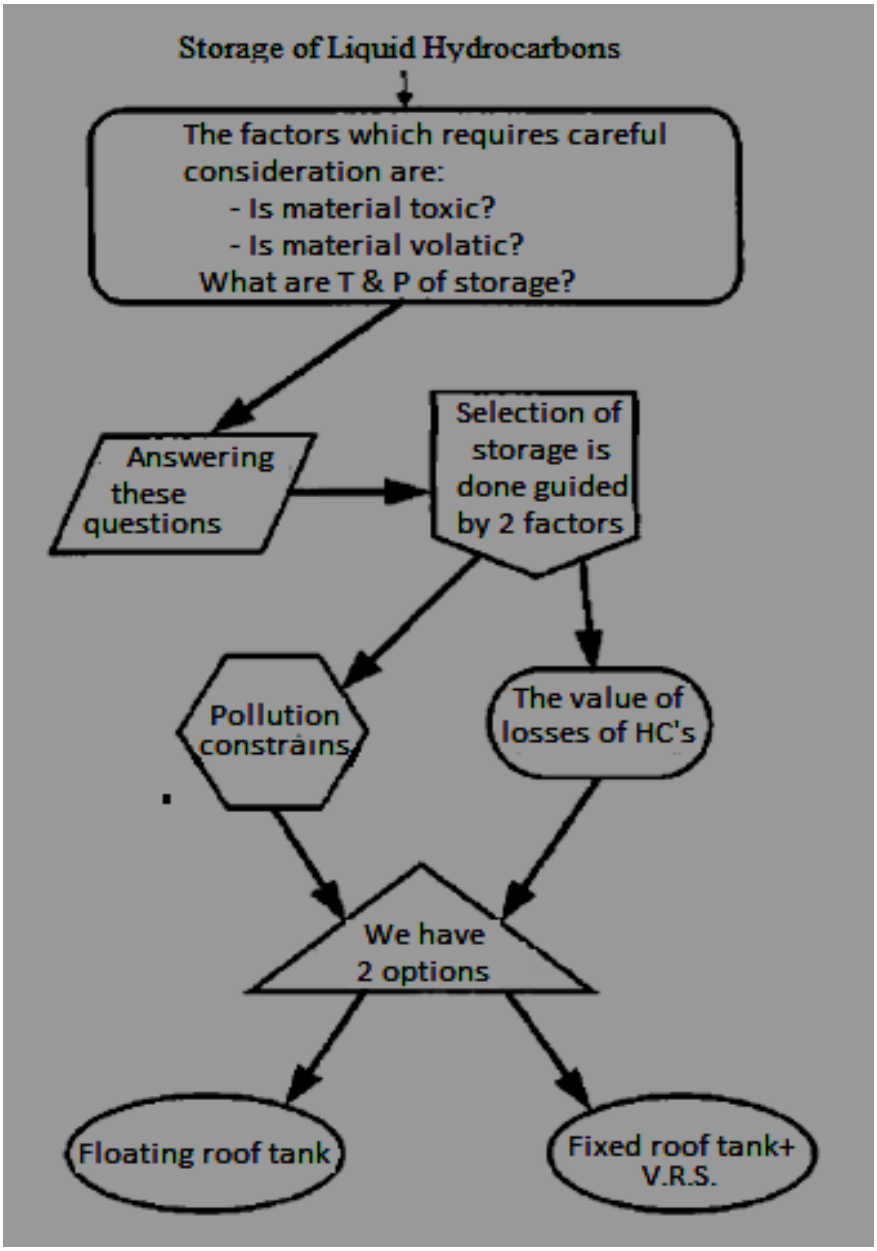

Figure 15.2 – Vapor recovery units are used to minimize the loss of hydrocarbon vapor formed during storage

Types of Storage Tank

The main features of some of the common types of storage tank used by the petroleum industry in general are presented in Table 15.1.

The atmospheric tank, or standard storage tank, is one that is designed to be used within plus or minus a few pounds per square inch of atmospheric pressure. It may be open to the atmosphere (vented) or enclosed.

As will be explained next, an effective method of preventing vent loss in a storage tank is to use one of the many types of variable-volume tank (type II in Table 15.1). These are built under API Standard 650. They may have floating roofs of the double-deck or single-deck type. These are lifter-roof types in which the roof either has a skirt moving up and down in an annular seal or is connected to the tank shell by a flexible membrane.

Table 15.1 – Summary of Refinery Storage Tanks

Characte-ristics	Standard Storage Tanks	Conservation-Type Storage Tanks		
		I (Floating Roofs)	**II (Variable-Vapor-Space)**	**III (Pressure Storage)**
Evaporation losses	High	Significantly reduced	Significantly reduced	Prevented or eliminated
Operating conditions	Recommended for liquids whose vapor pressure is atmospheric or below at storage conditions (vented).	Allow no vapor space above the liquid: level (no venting)	Allow the air-vapor mixture to change volume at constant or variable pressure (no venting)	Allow the pressure in the vapor space to build up. Tanks are capable of withstanding the maximum pressure without venting.
Sub-classification	1.Rectangular 2.Cylinderical: a) Horizontal b) Vertical	-	1. Lifter roof, which is a gas holder mounted on a standard storage tank. 2. Vapor-dome	1.Low-pressure storage normally designed for 2.5-5 psig and up to 15 psig (0.14 – 0.34 bar and up to 1.02 bar) 2.High pressure storage: 30-200 psig (2 – 13.5 bar)
Typical types	Cone-roof-vertical (cylinderical tanks)	Floating-roof. wiggins-Hidek type	Lifter roof tanks. wiggins dry seal type	Spheroids and hemispheroids for low pressure storage, spheres for high pressure storage
Applications	Heavy refinery-products	Sour crude oils, light crude oils, light products.	Light refinery product and distillates	Spheroids are used to store aviation, motor, jet fuels. Spheres are used to store natural gasoline and LPG.

Vapor recovery Units

The loss of hydrocarbon vapors formed above crude oil or its products—when stored—could be minimized using what is called vapor recovery units (VRUs). If allowed to escape to the atmosphere, these vapors will not only cause a loss of income due to loss of hydrocarbon volume and change in the API of the oil but will also lead to pollution and fire hazards.

The three main functions for the vapor recovery system are (as illustrated in Fig. 15.3) as follows:

1) to collect vapor from storage/loading facilities;
2) to reliquefy vapors;
3) to return liquid hydrocarbons to storage.

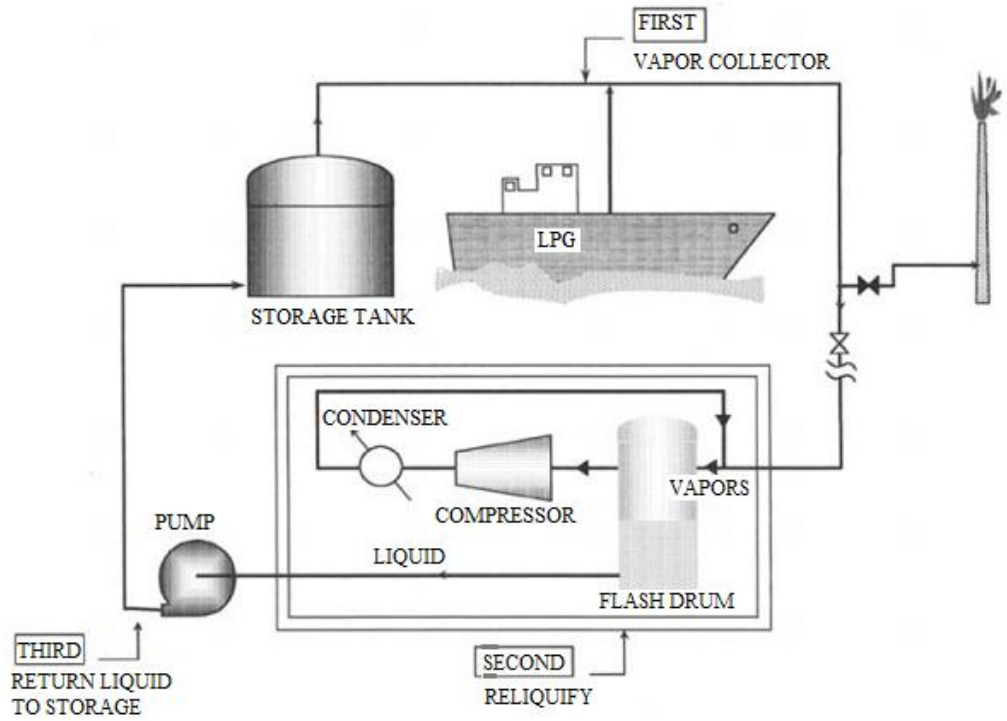

Figure 15.3 – Main functions of vapor recovery system

Basically, when we talk about a VRU, what we are looking for is to hook our storage tanks to a ‘‘breather’’ system such as the following:

- during the day, when the temperature rises and vaporization of the hydrocarbons occur, excess vapors can be released and collected by the VRU;

- at night, when the vapors cool and condensation takes place leading to partial vacuum, vapors from the VRU will be admitted into the tanks;

- while pumping in and pumping out liquids to and from the storage tanks, vapors could be vented, [i.e., collected and drawn in, respectively, by such a breather system (VRU)].

Types of Storage Loss

In general, hydrocarbon losses in storage tanks are identified as follows:

- Working losses:
  (a) Filling;
  (b) Emptying.
- Other losses:
  (a) Breathing;
  (b) Standing;
  (c) Boiling.

Filling losses occur when vapors are expelled from a tank as it is filled, no matter how the vapors are produced. This loss occurs when the pressure inside the tank exceeds the relief-valve pressure. For API tanks, the relief pressure is low and, therefore, filling losses can be relatively high.

Emptying losses are experienced by the vapors that are expelled from a tank after the liquid is removed from it. Because vaporization lags behind the expansion of the vapor space during withdrawal, the partial pressure of a hydrocarbon vapor

drops. Enough air enters during the withdrawal to maintain the total pressure at the barometric value.

However, when vaporization into the new air reaches equilibrium, the increase in the vapor volume will cause some vapor expansion.

Breathing losses occur when vapors are expelled from a tank under one of the following conditions:

1. The thermal expansion of the existing vapors
2. An expansion caused by barometric pressure changes
3. An increase in the amount of vapors from added vaporization in the absence of a liquid level change

Breathing losses take place in most types of tanks and occurs when the tank's limits of pressure or volume changes are exceeded.

The fixed-roof API type tanks used to store stock tank oil are designed for only for a few inches of water pressure or vacuum and suffer relatively large breathing losses.

Standing losses are losses of vapor which result from causes other than breathing or a change in liquid level in tanks. Sources of standing losses are vapor escape from hatches or other openings and from glands, valves, and fittings.

Boiling losses occur when liquid boils in a tank and vapors are expelled. In other words, the vapor pressure of the liquid exceeds the surrounding pressure.

Vapor Recovery Methods

Ideally, it would be best to design a tank or a storage system to operate at pressures high enough to suppress evaporation; hence minimizing evaporation losses. However, this is not generally economical; also, refiners require crude oil to meet maximum vapor pressure specifications.

Various methods can be recommended to recover vapors generated in storage tanks and from other sources such as liquefied petroleum gas (LPG) tankers. These usually involve one or a combination of the following schemes implemented through what is referred to as the VRU:

a) Absorption: Usually carried out under pressure using a liquid solvent of higher molecular weight than that of the vapors being recovered. Vapors are then separated from the rich solvent, which is recycled in the process as ''lean solvent.''

b) Condensation: Vapors can be totally or partially condensed by compression and cooling, as shown in Figure 15.3.

c) Simple cooling: Cooling the vapors without compression may condense the vapors, but it is not normally economical unless refrigeration is applied.

d) Adsorption: Hydrocarbon vapors mixed with non-condensable gases, such as air, can be adsorbed by molecular sieves, activated charcoal, or silica gel. Heat or depressurization will remove the adsorbed vapors from the solid bed. The vapors could then be condensed for recovery.

The basic part of equipment operating the VRU is the vapor regulator setup (see Figure 15.4).

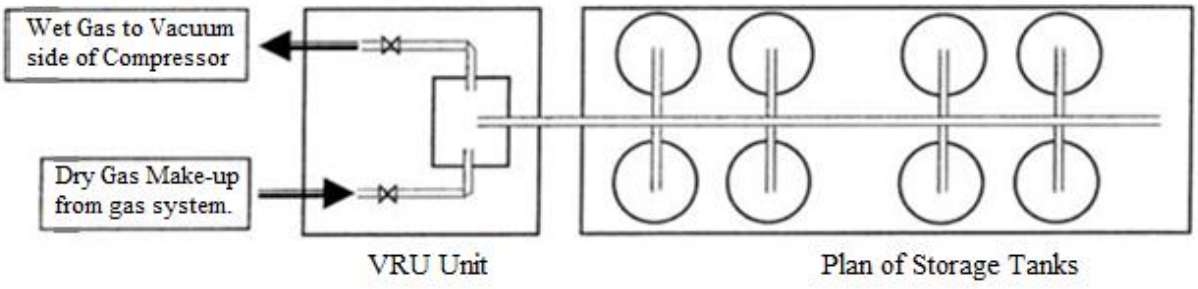

Figure 15.4 – Vapor regulator system connected to storage tanks

The basic functions of the regulator are the following:

1. Release vapor from the storage tank battery when the normal operating pressure within the system increases beyond a preset value

2. Add vapor to the battery system if the normal operating pressure decreases and reaches a preset value

One should mention that, in addition to this vapor regulator, other automatic relief valves are found in the VRU. The system works automatically and in harmony. The breather valve operates if excessive pressure or vacuum exists, whereas the manhole relief functions if abnormal pressure or vacuum is experienced in the system.

Finally, it should be pointed out that the loss of vapors from oil during storage results in the following:

- a decrease in the API gravity of the oil, which degrades its quality;
- a reduction in the volume of oil to be sold.

The loss in volume of oil per degree of API gravity reduction varies depending on the original gravity of the oil. On average, a 2% volume loss is experienced per one degree reduction in the API gravity of the oil, as exemplified in Figure 15.5.

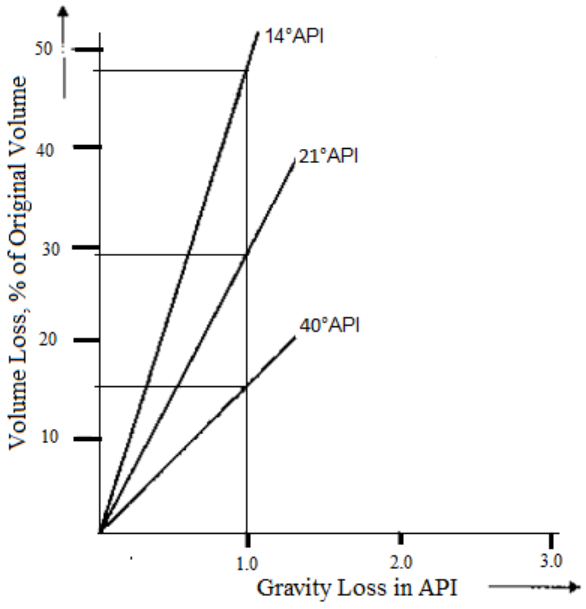

Figure 15.5 – Change of volume with gravity decrease

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LECTURE 16
PRODUCED WATER TREATMENT

Production of crude oil and natural gas is usually associated with the production of water. During the early life of the petroleum fields, water-free production of oil and gas is normally experienced. However, water will eventually be produced later. The produced water may be water that exists within the petroleum reservoir as connate water or bottom water. Alternatively, water may be produced as a result of water-flooding operations, where water is injected into the reservoir to enhance the recovery.

Water production presents serious operating, economic, and environmental problems. Production of water with the crude oil or natural gas reduces the productivity of the well due to the increased pressure losses throughout the production system. This may either result in reduced production or necessitate the installation of costly artificial lifting systems to maintain the desired production levels. Production of water also results in serious corrosion problems, which add to the cost of the operation. Production of water with the crude oil or natural gas requires the use of three-phase separators, emulsion treatment, and desalting systems, which further add to the cost of the operation.

In most situations, the produced water has no value and should be disposed of. In other situations, the produced water may be used for water flooding or reservoir pressure maintenance. The produced water, collected from the separation, emulsion treatment, and desalting systems, contains hydrocarbon concentrations that are too high for environmentally safe disposal. The presence of the hydrocarbon droplets in the water makes it difficult to inject the water into disposal wells or into water-injection-wells for enhanced recovery operations. This is because the hydrocarbon droplets cause severs plugging of the formation. In all cases, the produced water must be treated to lower its hydrocarbon content to acceptable limits. For the heavy oil field, produced water may be used to generate the steam needed for oil recovery. In this case, additional chemical treatment will be needed to reduce the concentration of the salt and other minerals to make the water quality adequate for steam generation.

The purpose of this lecture is to present the concepts and procedures used for selecting and sizing the equipment used for removal of oil from the produced water.

Produced and Treated Water Quality

The quality of treated water (i.e., the maximum allowable oil concentration and maximum allowable oil droplet size) is determined to meet water-injection or disposal requirements. From an environmental point of view, it should be desirable to remove all of the oil from the produced water or at least allow the technically minimum possible. This, however, can impose substantial additional operating costs. Therefore, operators would usually provide the necessary water treatment to achieve the maximum allowable oil content. To properly design an efficient and economical treatment system that achieves this objective, knowledge of the

produced water quality (oil concentration and droplet size distribution) is necessary. This is best determined from laboratory analysis of actual field samples. Such samples, however, are not normally available, especially when designing a treatment system for new field development.

Theoretically speaking, it is possible to determine the droplet size distribution throughout the various components of the production system and the separation and oil treatment equipment. However, most of the parameters needed to solve the governing equations, especially those involving dispersion and coalescence, are normally unknown. The design of separation and oil treatment equipment determines the maximum oil droplet size remaining in the water. Several attempts have been made to determine the oil concentration in water for properly designed separation and treatment equipment. The results showed that the dispersed oil content ranges from 1000 to 2000 μg oil per liter of water. Unfortunately, as the water leaves the separation and treatment equipment, it flows through various restrictions (such as valves and bends) in the piping system before it reaches the water treatment facility. In its journey, the oil droplets are subjected to a series of dispersion and coalescence that makes it difficult to exactly determine the oil droplet size distribution in the water to be treated. Experience showed that a conservative assumption for design purposes would be to represent the droplet size distribution by a straight-line relationship between the droplet size and cumulative oil concentration, with the maximum oil droplet diameter being between 250 and 500 μm.

Produced Water Treatment System

In general, produced water always has to be treated before it is disposed of or injected into the reservoir. The purpose of the treatment is to remove enough oil from the water such that the remaining amount of oil in the water and the oil droplet size are appropriate for the disposal or injection of the water. For example, for water disposal into underground formations and water injection into the producing reservoir, the pore size of the formation determines the allowable oil droplet size in the treated water.

The maximum droplet size of the remaining oil in the water should be less than the minimum pore size of the formation to avoid plugging of the formation by the oil droplets. For water disposal into the sea, as is normally practiced in offshore operations, the amount and droplet size of the oil in the water is governed by environmental constraints.

Depending on the amount and droplet size of the oil in the produced water, the required quality of the treated water, and the operating conditions, water treatment may be achieved through a single or two stages of treatment. The single, or first, stage of treatment is normally known as **the primary treatment stage**; the second stage of treatment is known as **the secondary treatment stage**.

The equipment used for water treatment serves the function of allowing the oil droplets to float to the surface of the water, where they are skimmed and removed. For primary treatment, this may be achieved by using skim tanks for atmospheric treatment or skim vessels for treatment under pressure. Plate coalescers such as the parallel plate interceptor and corrugated plate interceptor are

used to promote coalescence of the oil droplets to increase their size and thus speeds their floatation to the surface. Another device, known as the SP pack, is also used to promote coalescence of the oil droplets. For secondary treatment, plate interceptors, SP packs, and flotation units are normally used.

For offshore operations, water disposal must be through a disposal pile, skim pile, or SP pile. The deck drains normally contains free oil and must be treated before disposal. This can be done either in similar primary treatment equipment or directly through the various disposal piles.

Water Treatment Equipment

The various produced water treatment equipment mentioned are described in this section. The main function of the treating equipment is to separate the free oil droplets from the water. The fluid may contain some dissolved gas, which will be liberated in the treating equipment and must be removed. Therefore, the produced water treatment equipment are, in essence, similar to the three-phase oil–water–gas separators. The main difference is that for water treatment equipment, water is the main and continuous phase and oil represents a small volume of the fluid mixture.

1 Skim Tanks and Vessels

The skim tanks and vessels are the simplest equipment used for primary treatment of produced water. Skim tanks and skim vessels are generally similar in shape, components, and function. However, the designation of skim tanks is associated with atmospheric treatment, whereas skim vessels are used when water treatment is performed under pressures above the atmospheric pressure. These equipment are normally large in volume to provide residence time that is sufficiently long (10–30 min) for the coalescence and gravity separation of the oil droplets.

Pressure vessels are more expensive than atmospheric tanks. However, the choice is controlled by the overall requirements of the water treatment system. Pressure vessels are normally preferred over atmospheric tanks for the following reasons:

1. To avoid the potential gas venting problems associated with atmospheric tanks
2. To eliminate the potential danger of overpressure that may occur in an atmospheric tank
3. To eliminate the need for pumps that may be required to deliver the treated water to other secondary treating equipment or to other locations for disposal

The technical aspects, benefits, and cost should all be considered in deciding on the pressure rating of the skimmers.

Skimmers can be either horizontal or vertical in configuration. The shape and internal components of the skimmers are generally similar to those of the three-phase separators. Figure 1 shows a schematic of a horizontal skimmer. As shown in the figure, the produced water enters the skimmer below the water–oil interface and flows horizontally along the length of the vessel. The oil droplets

coalesce and rise to the oil pad perpendicular to the direction of the water flow. The oil flows over the weir into the oil collection section and out of the skimmer. The height of the oil pad is controlled by the weir as shown in Figure 16.1.

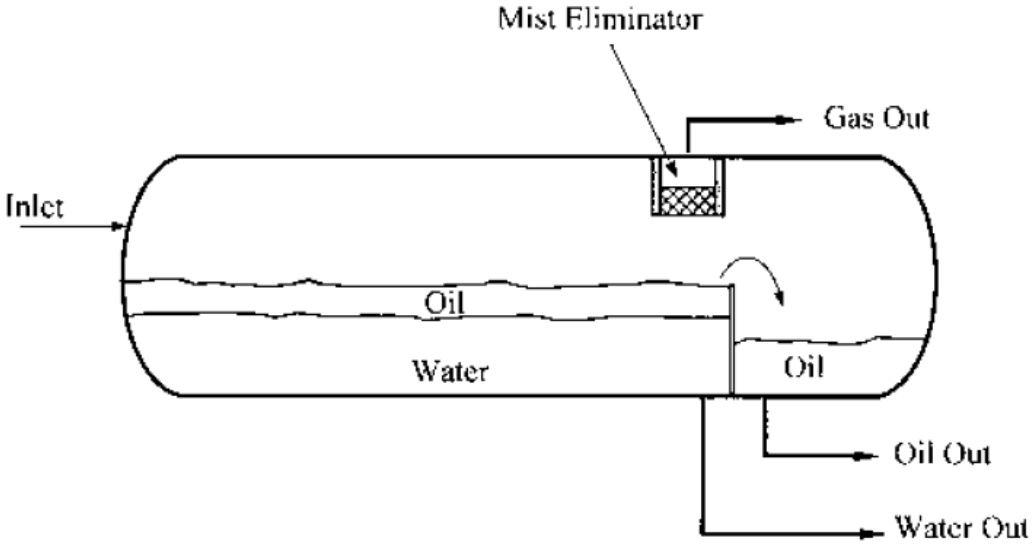

Figure 16.1 – Schematic of a horizontal skimmer [1]

Alternatively, the height of the oil pad may be controlled by an interface level controller or by an external water leg. The treated water is withdrawn from the skimmer at the bottom of the vessel. The liberated gas leaves the vessel at the top through a mist extractor.

Figure 16.2 shows a schematic of a vertical skimmer that is equipped with an inlet spreader and a water outlet collector, which work to even the distribution of the incoming and outgoing flow, respectively. As with the horizontal skimmers, the produced water enters the vessel below the oil–water interface. Water flows downward while the oil droplets rise upward to the oil pad. Because of this countercurrent flow of the water and oil, vertical vessels are generally less efficient than horizontal vessels. The oil is skimmed over the weir into the oil collection section, where it is withdrawn from the vessel. The water outlet is at the bottom of the vessel through the water collector. The liberated gas leaves at the top of the vessel through a mist extractor.

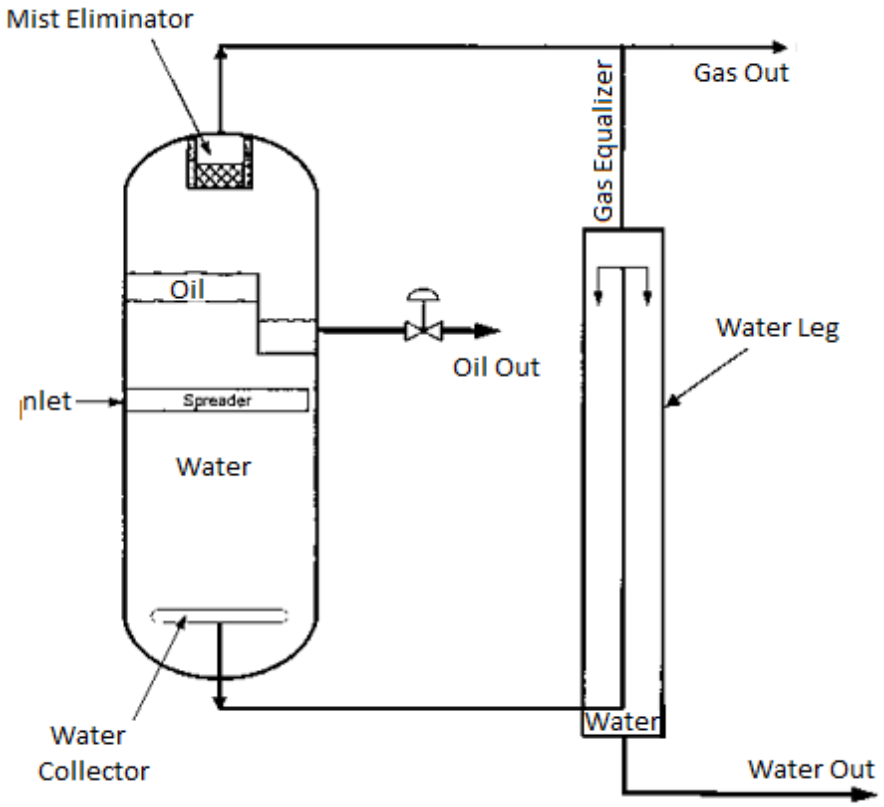

Figure 16.2 – Vertical skimmer schematic

Vertical vessels are preferred over horizontal vessels when treating water containing sand or other solids. A sand drain at the bottom of the vertical vessel always provide a simpler and more effective means for cleaning the vessels as compared to the sand drains in horizontal vessels.

Further, vertical vessels are better than horizontal vessels with regard to handling liquid surges. Surging in horizontal vessels tends to create internal waves, which results in a false indication of a high liquid level within the vessel and leads to false high-level shutdown.

Another type of skimmer is the API separator, which is basically a horizontal, rectangular cross-section tank. This type of skimmer is mostly used for treatment under atmospheric conditions.

2 Plate Coalescers

There are mainly two types of plate coalescer: the parallel plate interceptors (PPI) and the corrugated plate interceptors (CPI). Both types consist of a set of parallel plates that are spaced a short distance apart and are inclined by an angle of 45^{o}.

The PPI was the first form of plate coalescers where a series of inclined parallel plates is installed inside an API separator, as shown in Figure 16.3.

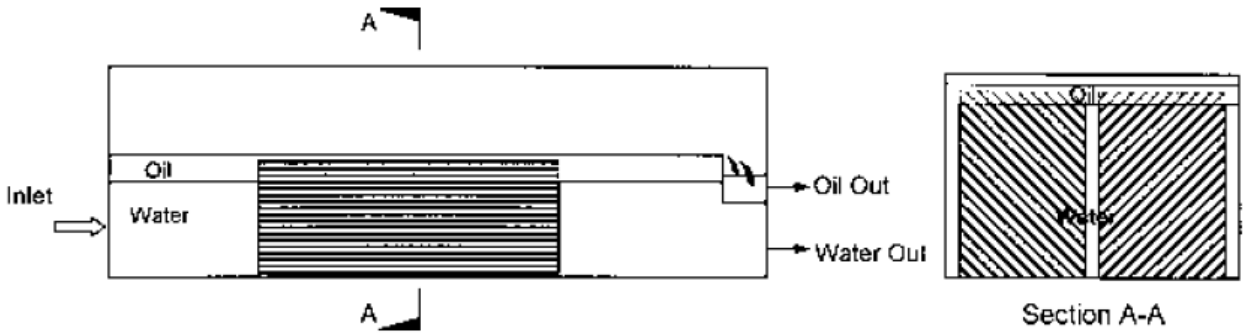

Figure 16.3 – The parallel plate interceptor

The water flow is split between the plates; therefore, the oil droplets need first to rise along the short distance between two consecutive plates where coalescence occurs (Figure 16.4). Due to gravity, the large oil droplets move upward along the bottom surface of the inclined plate and then vertically upward to the oil collection section, where oil is skimmed out of the tank. Sediments in the water move downward to the bottom of the tank, where they can be removed.

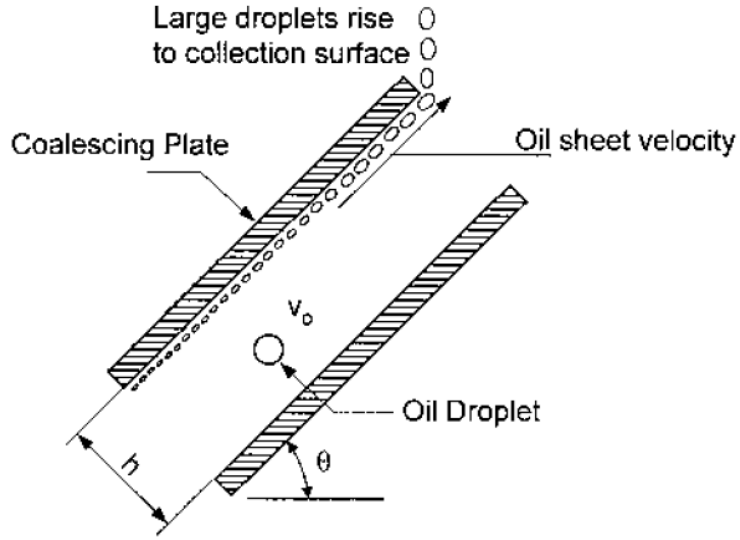

Figure 16.4 – Oil droplets rise between two consecutive plates in the PPI

The CPI is the most commonly used plate interceptor in the industry. The CPI was an improvement over the PPI, where the surface of the parallel plates was made corrugated with the axis of the corrugations being parallel to the direction of water flow. As shown in Figure 16.5, the water to be treated flows downward through the CPI pack. The oil raises upward, counter to the water flow and accumulates at the corrugations. The accumulated oil flows along the axis of corrugations and upward to the oil–water interface.

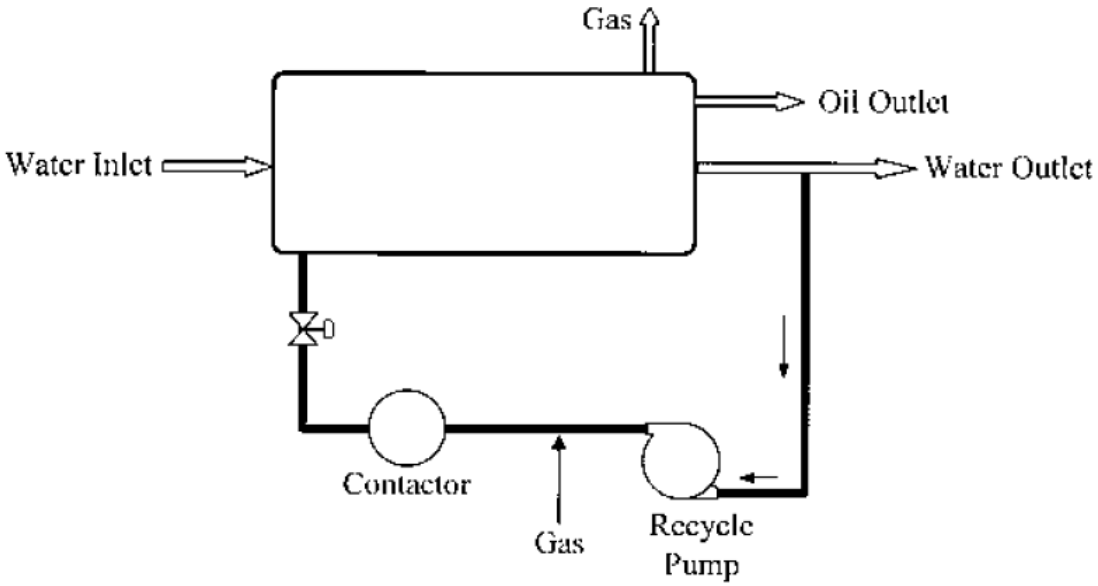

Figure 16.5 – The corrugated plate interceptor

Both PPI and CPI are normally used for water treatment under atmospheric conditions. The 45^{o} inclination of the plates may present a problem when produced water contains appreciable amounts of sediments or sand, particularly oil-wet sand. The solids have the tendency to adhere to the surface of the plates at such an angle of inclination, which may cause clogging of the plates. To avoid such a problem and to enable treatment at pressures higher than atmospheric, modified CPI equipment known as cross-flow devices have been developed. In such equipment, the angle of inclination of the plates is made steeper than 45^{o} (normally $60^{o}$to the horizontal) and the plate pack is placed inside a pressure vessel (vertical or horizontal) such that the water flow is perpendicular to the axis of corrugations in the plates.

Vertical vessels are generally preferred for handling sediments and sand problems. Regular CPI units are less expensive and more efficient than cross-flow devices, but the later should be used for treatment under pressure and for water containing large amounts of sand or sediments.

3 Flotation Units

Flotation units utilize a completely different concept is removing oil droplets from water. In this type of treatment equipment, a large number of small gas bubbles are produced within the water. As the gas bubbles rise upward, they carry the oil droplet to the surface, where they accumulate and are then skimmed out of the unit. Flotation units are classified into two types based on the method by which the gas bubbles are produced. These are the dissolved gas units and the dispersed gas units.

3.1 Dissolved Gas Flotation Units

As shown in Figure 16.6, a portion of the treated water (between 20% and 50% of the effluent) is taken and saturated with natural gas in a contactor at a

pressure between 20 and 40 psi (1.35 – 2.7 bar). The amount of gas used in standard cubic feet (SCF) ranges from 0.2 to 0.5 SCF/bbl of water to be treated (0.23 – 0.36 liters per 1 bbl).

The gas-saturated water is recycled back into the unit, which operates at a pressure lower than that of the gas–water contactor. Due to the reduction in pressure, the dissolved gas breaks out of solution as small bubbles. The gas bubbles carry the oil droplets with them as they move to the surface.

The size and depth of the unit are determined to provide retention times between 10 and 40 min. The equipment manufacturer normally determines the detailed design parameters of the unit based on the specific operating conditions.

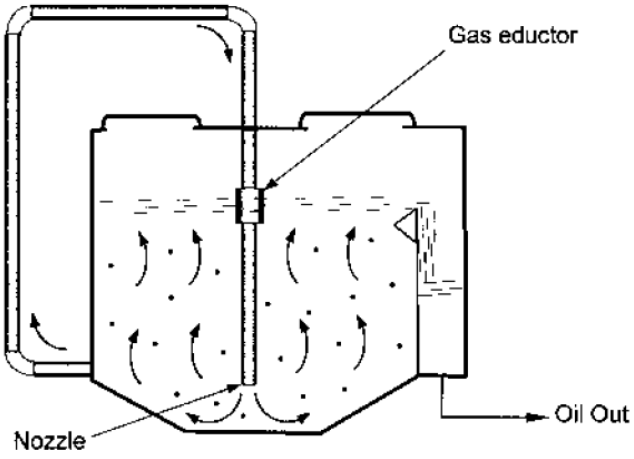

Figure 16.6 – Dispersed gas flotation unit with reduction

3.2 Dispersed Gas Flotation Units

In this type of flotation unit, the gas bubbles are created, introduced, and dispersed into the bulk of the water to be treated. This is basically done by two methods. In one method, the gas bubbles are created and dispersed in the water by inducing a vortex using a mechanical rotor driven by an electric motor. Figure 16.7 shows a schematic cross section of a unit utilizing this method and manufactured by Petrolite Corporation.

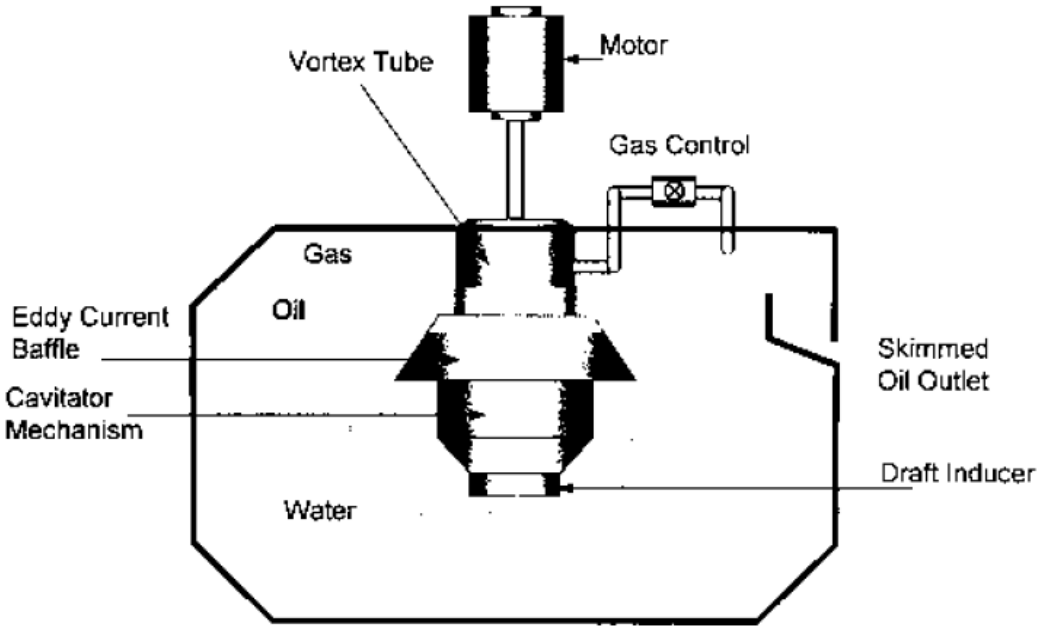

Figure 16.7 – Unit utilizing the method of creating gas bubbles and dispersing them in the water by inducing a vortex [2]

The vortex induced by the rotor creates vacuum within the vortex tube. Due to this vacuum, gas is withdrawn into the vortex and is dispersed in the water. The gas bubbles carry the oil droplets as froth to the surface, where the oil is skimmed and collected in the recovery channel for removal out of the unit.

The other method of creating and dispersing the gas bubbles utilizes an inductor device as shown in Figure 16.8.

As shown in the figure, a portion of the treated water is recycled back to the unit using a pump. The recycled water flows through a Venturi and, due to the reduction in pressure, sucks gas from the vapor space at the top of the unit. The gas is released through a nozzle near the bottom in the form of small bubbles that carry the oil droplets to the surface as they rise. Finally, the oil is skimmed and collected in a chamber for removal out of the unit.

Normally, a dispersed gas flotation unit consists of three or four of the cells described. The water to be treated moves from one cell to the next for further removal of oil. Typically, the oil removal efficiency of one cell is about 50%. Therefore, a three-cell unit will have an overall efficiency of 87%, whereas a four-cell unit will have an overall efficiency of 94%.

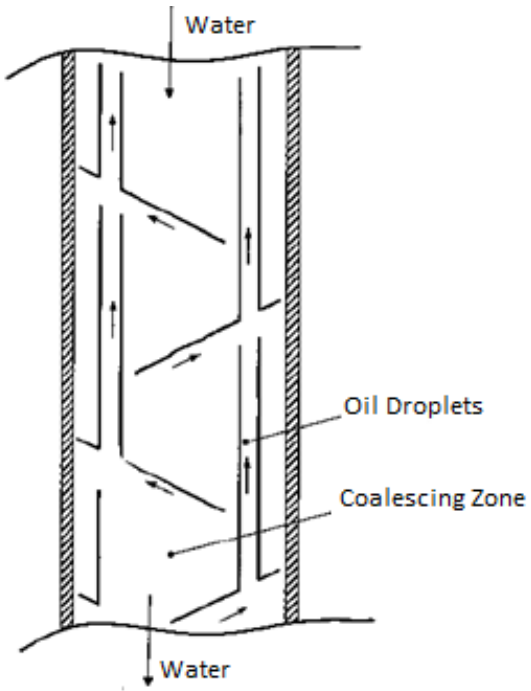

Figure 16.8 – Unit utilizing the method of creating and dispersing gas bubbles using an inductor device

Flotation unit manufacturers have patented design and produce standard units that are typically designed to handle produced water flow rate of about 5000 BPD. For higher flow rates, additional units are added in parallel. Flotation units are capable of removing oil droplets smaller than 30 μm.

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LECTURE 17
OFFSHORE WATER DISPOSAL EQUIPMENT

Produced water in offshore operations should not be dumped directly into the sea after treatment. In addition to the treated produced water, rainwater, and equipment-washdown water represent another source of oil-contaminated water that needs to be disposed of properly. For this purpose, offshore production platforms should be equipped with some form of a disposal device that disposes of the water deep enough below the surface of the sea and away from the wave action to prevent sheens from occurring. The most common of these disposal devices are the disposal piles, skim piles, and SP piles; these are described in the following subsections.

1 Filters

One of the very efficient ways of removing oil droplets from water is the use of filters. In this method of water treatment, produced water is made to flow through a bed of porous medium, normally sand, where the oil droplets are trapped in the filtering medium. At least two filters arranged in parallel are used. As the filter in use gets clogged, the flow is directed to the other filter and the clogged filter is backwashed using water or solvent.

The backwash fluid must be treated or disposed of properly, which adds more complications and cost to the water treatment process. Several onshore successful operations have been reported in which sand filters were used to yield treated produced water with oil content as little as 25 mg/L of water.

Figure 17.1 shows the porous medium for oil-water filters.

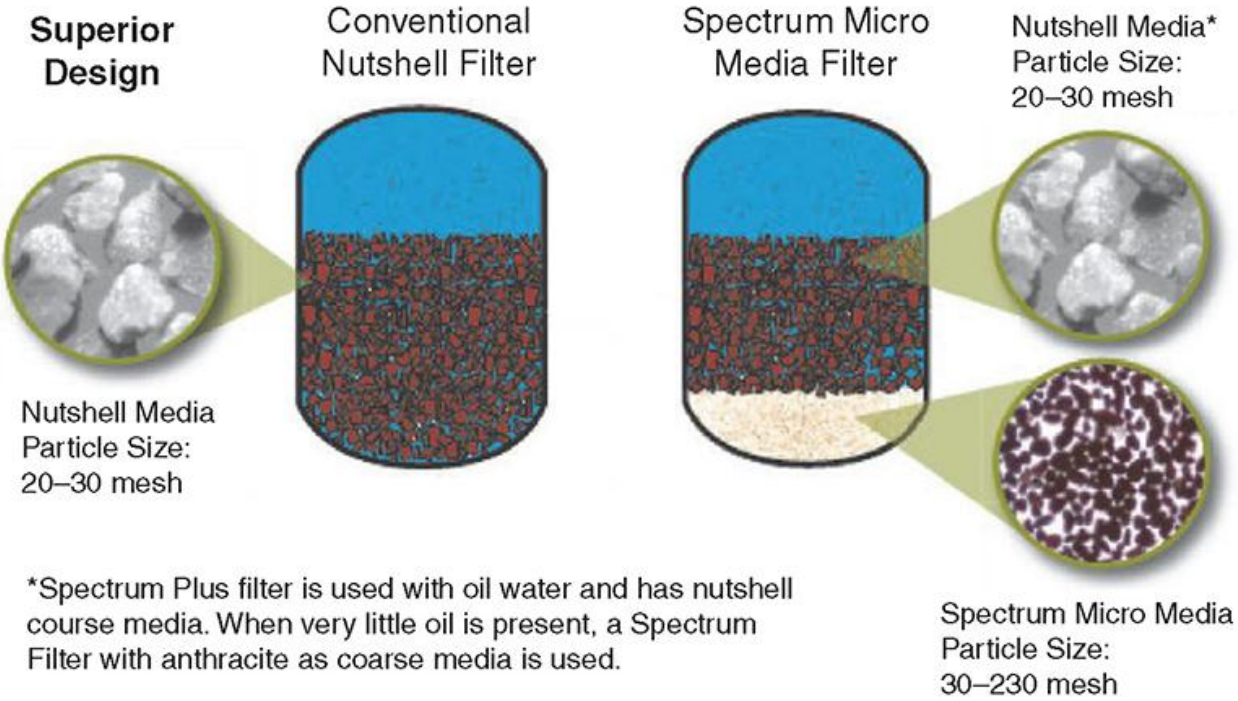

Figure 17.1 – Porous medium for oil-water filters

2 Precipitators

In this method of treatment, the produced water is directed through a bed of porous material, such as excelsior, placed inside a horizontal vessel that is similar in design to the three-phase separator to promote the coalescence of oil droplets. The coalesced large oil droplets flow upward, countercurrent to the downward flow of the water where it can be skimmed out of the vessel. Although this method has been effective in treating produced water to desired quality, clogging of the coalescing medium represented a serious problem, which limited the use of such precipitators. Figure 17.2 represents the process of oil-water separation inside the precipitator.

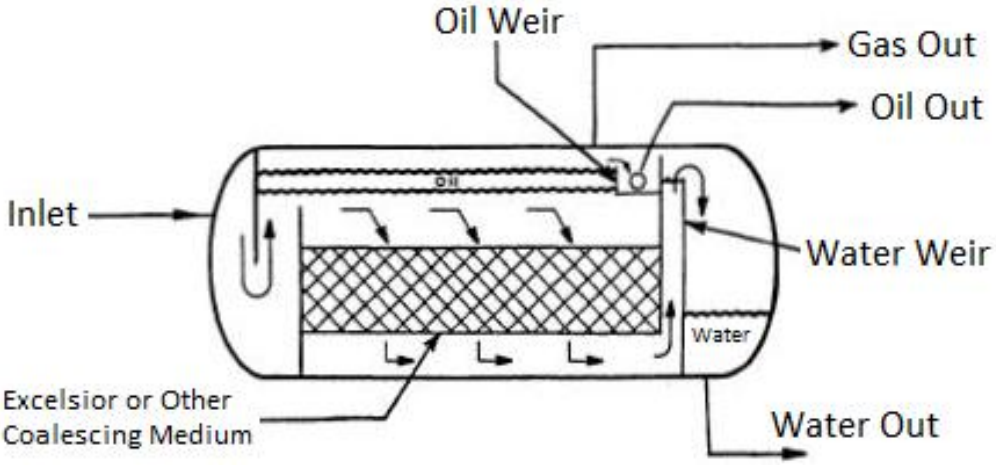

Figure 17.2 – Precipitator schematic

3 Disposal Piles

Disposal piles are the simplest form of offshore water disposal devices. The disposal pile is simply a large diameter open-ended pipe that is attached to the platform and extends to a specific minimum depth below the surface of the sea. The diameter of the pile is determined based on the total flow of water to be disposed of and the water and oil gravities. In shallow water, the disposal pile should extend down to near the seafloor. In deep water, however, the depth of the pile below the normal water level is determined such that a high level in the pile will be sensed and the shutdown signal measured before the oil in the pile comes within 10 ft (3.05 m) of the bottom.

Disposal piles are used to collect treated produced water, deck drains, treated sand, and liquids from drip pans and dispose of them deep below the surface. Disposal piles are also useful as traps for oil in the event of equipment failure or upset operating conditions. The deck drainage, normally rainwater and washdown water, is saturated with oxygen and may contain sand and other solids. Therefore, it should not be treated in the same equipment as produced water to avoid corrosion and plugging problems. Disposal piles are particularly useful for disposal of the platform drainage.

Disposal diagram is represented by figure 17.3.

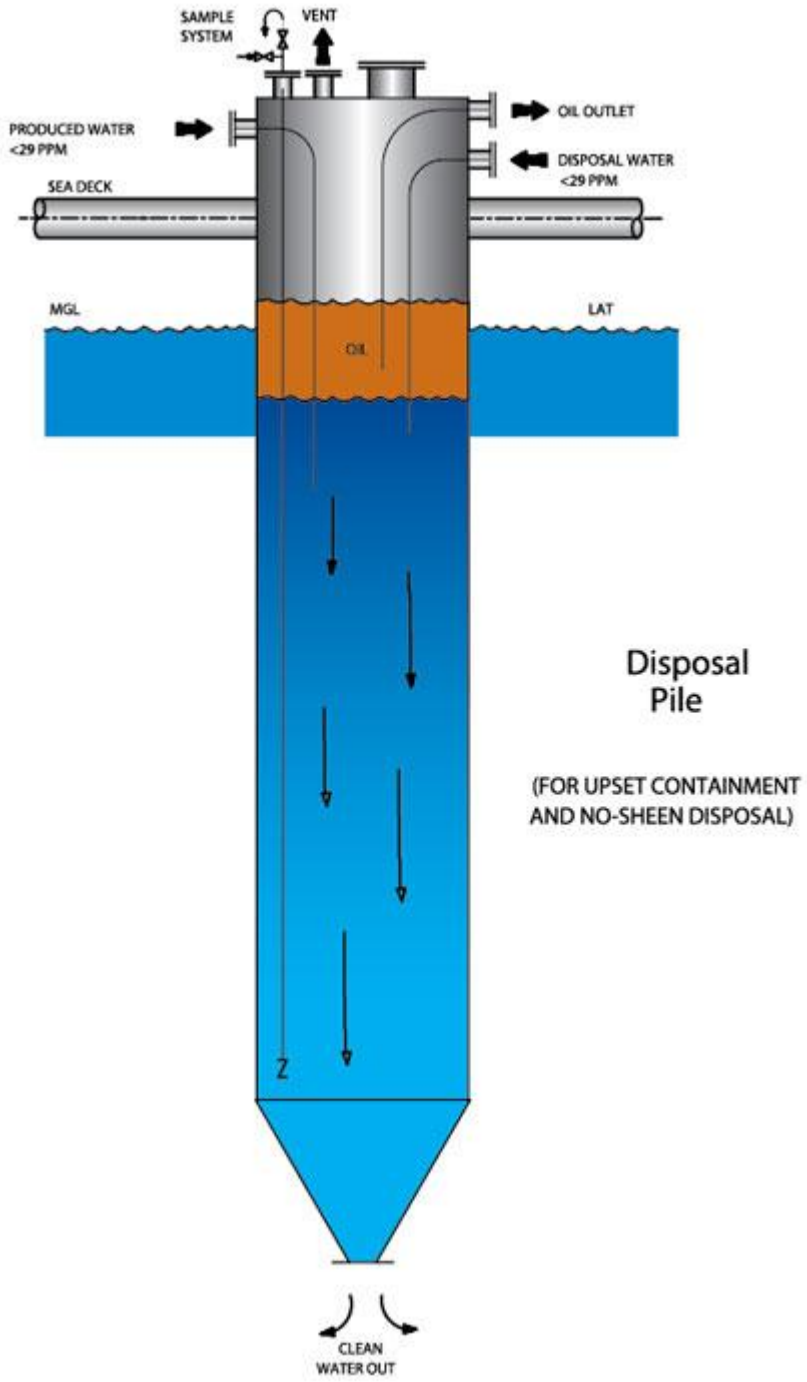

Figure 17.3 – Disposal diagram

4 Skim Piles

The skim pile is basically a disposal pile equipped with a series of inclined baffle plates and oil collection risers, as shown in Figure 17.4.

The presence of these baffles plates serves two functions. It reduces the distance a given oil droplet has to rise to be separated from the water and creates zones of no flow below each plate. The oil droplets rise to the zone of no flow between two successive plates, where coalescence and gravity separation occurs. The coalesced large oil droplets travel up the bottom side of the plate and into the oil collection riser to the surface of the pile where oil could be skimmed out.

Skim piles have two specific advantages over standard disposal piles. Skim piles are more efficient in separating oil from water. Skim piles also provide for some degree of cleaning sand that may be present in the water from oil.

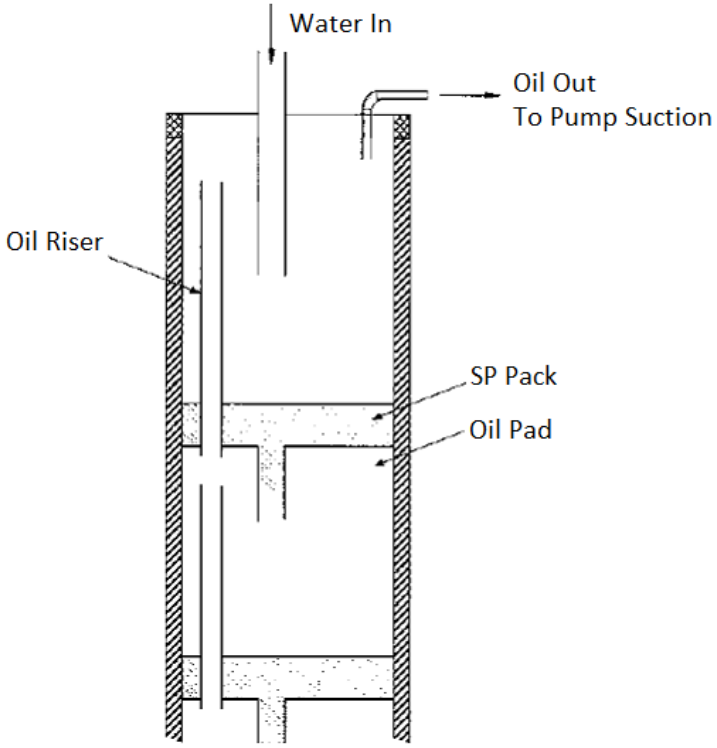

Figure 17.4 – Schematic of a skin pile

5 SP Piles

The serpentine-pipe pack (SP pack) is another device that is used to promote coalescence of the oil droplets and thus facilitates their separation by gravity. The coalescence concept for the SP pack is, however, different from that of the previously described equipment. Water is forced to flow through a serpentine path that is properly sized to create turbulence that is sufficient to cause coalescence without causing shearing of oil droplets below a specified size. The SP packs are available in standard dimensions ranging from 2 to 8 in. (5.1 to 20.3 mm) in diameter for handling water flow ranging from 900 to 73,000 bbl/day (BPD). Such packs are designed to develop a drop size distribution curve with a maximum drop size of 1000 μm. By producing such a drop size distribution, gravity settling becomes very efficient. In fact, SP packs can result in about 50% additional oil removal as compared to gravity settling alone. The SP pack is normally placed inside any gravity settling vessel with the water inlet diameter being the same as the SP diameter. SP packs can be staged in series to allow successive coalescence and removal of oil as the water flows from one stage to the next.

In this type of device, the disposal pile is equipped with a number of equally separated SP packs and oil risers. As water flows through a SP pack, coalescence of oil droplets occurs due to the induced turbulence. As the water travels out of the SP pack to the next SP pack, the larger oil droplets rise to form an oil pad below

the upper SP pack. This continues as the water goes from one SP pack to the next. The oil accumulated below the bottom SP pack rises to the oil pad above through the risers until it reaches the surface to be pumped out.

The SP packs are normally designed to develop oil droplets to a maximum size of 750 μm. The number of SP packs needed is determined from the desired overall efficiency of oil removal.

Skim tank with SP Packs installed is shown at figure 17.5.

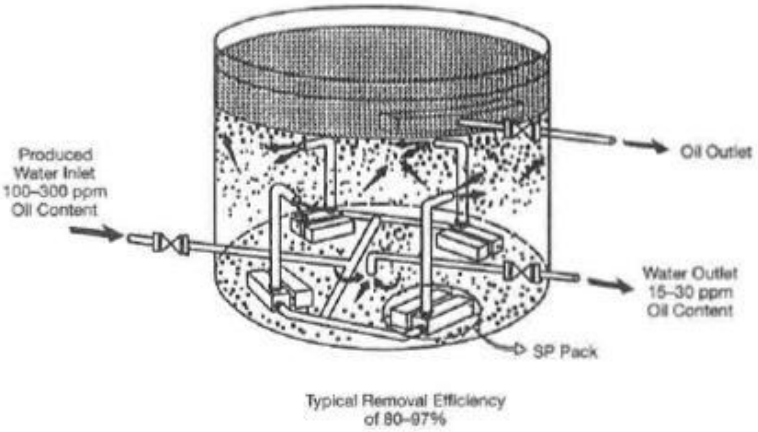

Figure 17.5 - Skim tank with SP Packs installed

The process of water disposal into the sea is the same as for disposal pipe (figure 17.6).

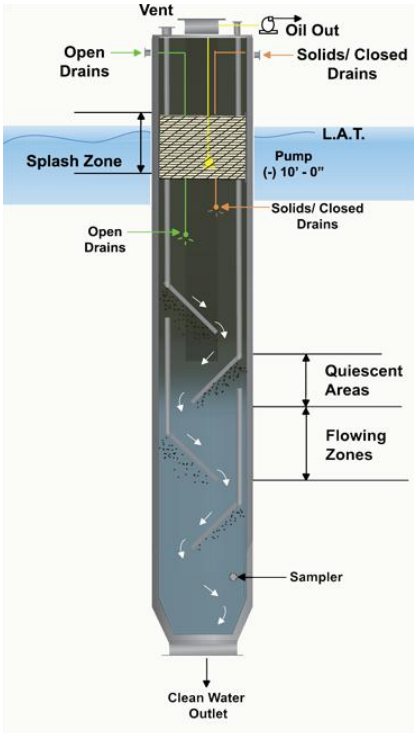

Figure 17.6 – Clean water outlet

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LECTURE 18
SURFACE GATHERING SYSTEMS

Hydrocarbons must be separated from each other and from water before they may be processed into usable petroleum produces. The equipment used for field processing is expensive and is often installed so that several wells are served by a single process facility. The fluids produced from one or more wells are collected in a gathering system and transported to the separation facilities. The gathering system may consist of a single flow-line from a well to its separation equipment or many flow-lines, headers, and process facilities.

Usually the wells are drilled according to specific geographical spacing. Depending on ownership of mineral rights and regulations, wells are drilled within areas called **leases**. The petroleum produced from different leases must be kept separate. Lease restrictions and economics determine the arrangement of gathering systems and the equipment used.

Types of Gathering Systems

One type of gathering system is a radial gathering system (individual flowlines system – figure 18.1). The flow-lines in this system converge at a central point where facilities are located. Flow-lines are usually terminated at a header, a pipe large enough to handle the flow of all flow-lines.

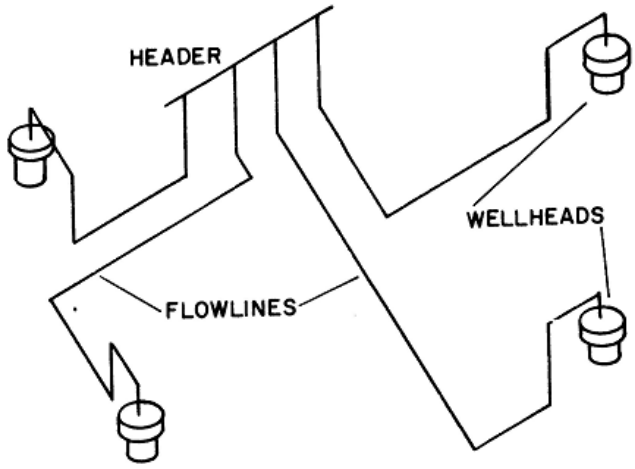

Figure 18.1 – Radial gathering system: all flow-lines brings fluids to a central header

Another gathering system is an axial or trunk-line gathering system (wellhead separation system – figure 18.2). This gathering system is usually used on larger leases, or where it is not practical to build the process facilities at a central point. The remote headers are simply smaller versions of those used in radial systems.

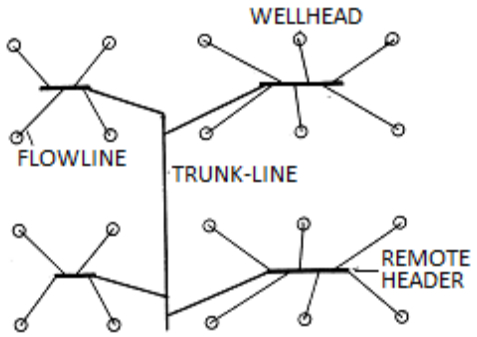

Figure 18.2 – An axial gathering system (trunk-line)

Leases are equipped to process fluids through equipment large enough to handle all wells simultaneously. To measure the production of individual wells simultaneously, a very complex process and metering facility is required. However, unless some method is provided, all fluid is measured at once; no information on individual wells can be gained.

Regulations and good operating practices require that oil, gas, and water production rates be measured for individual wells. Most leases are equipped so that all but one well on a lease are routed through the large process equipment, and the production from this equipment represents the entire lease.

The fluids from one well are routed through other equipment so that the flow rates for that well may be measured singly.

To measure the fluid from a well separately, a method must be provided for routing fluids to the production facility (the equipment used for all wells at once) or the test facility (the system for a single well). This selection is made in a well test header (figure 18.3). To test a single well, the test valve is opened and the production valve closed (figure 18.4). All other well's production valves are open and test valves closed.

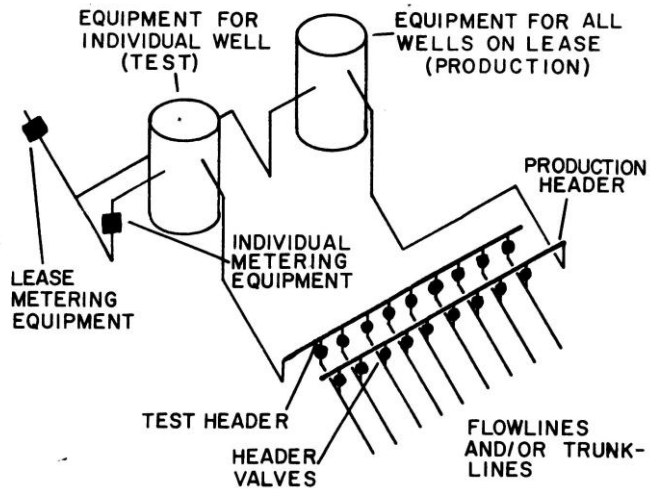

Figure 18.3 – Test and production equipment: by opening and closing selected header valves, an individual well`s fluid flow can be measured in a vessel equipped with metering equipment

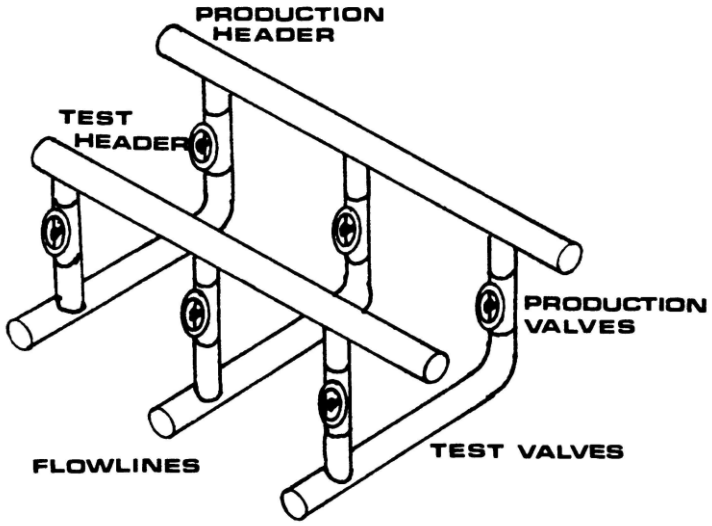

Figure 18.4 – Valves at well test header: for each well to provide routing produced fluids to production or test vessels

When test and production facilities are used with a trunk-line gathering system, both test and production trunk lines are required. The type of gathering system used on an individual lease is determined on the basis of economics. A radial system requires many meters of comparatively small pipe for flowlines. The cost of this pipe may be small in comparison to the cost of the larger pipe required for trunk lines, and the total cost of many long flowlines may be less than that of the same number of short flowlines and one or two long, large trunk lines. The latter is particularly true of the thick pipe used for high-pressure gas production leases.

Another consideration in determining the type of gathering system is the use to which the surface land is put. If the land is rugged pasture land, the flowlines may be laid on the surface and left there permanently. If the land is under cultivation or a populated area, the pipe must be buried 3-5 feet (0.915 – 1.525 m) deep to assure it is below the maximum operating depth of earth-working equipment (like farm machinery). In these areas the flowlines may be required to be buried beneath or adjacent to roads or streets. The length, installation cost, and maintenance costs of the gathering system are influenced by land use, and these factors determine the gathering system type.

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LECTURE 19
CRUDE OIL AND NATURAL GAS METERING

The final stage before the oil and gas leaves the platform or onshore processing facilities consists of storage, pumps and pipeline terminal equipment. But first just after the treatment the volume of produced oil must be metered.

Fiscal metering

Partners, authorities and customers all calculate invoices, taxes and payments based on the actual product pumped or shipped out. Often, custody transfer also takes place at this point, which means transfer of responsibility or title from the producer to a customer, shuttle tanker operator or pipeline operator. Although some small installations are still operated with a dipstick and manual records, larger installations have analysis and metering equipment.

To make sure readings are accurate, a fixed or movable prover loop for calibration is also installed. The illustration at Figure 19.1 shows a full liquid hydrocarbon (oil and condensate) metering system. The analyzer instruments on the left provide product data such as density, viscosity and water content. Pressure and temperature compensation is also included.

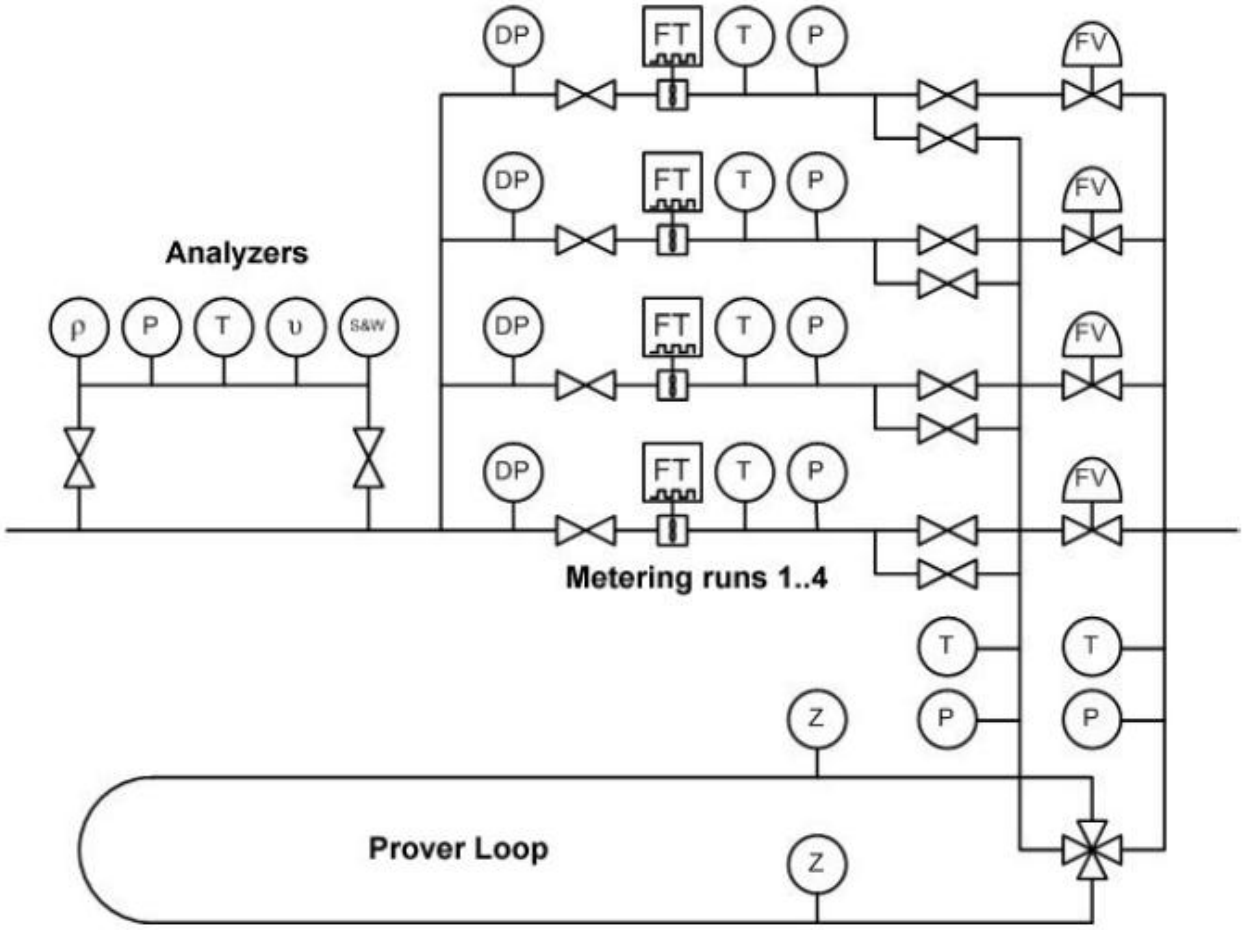

Figure 19.1 – Metering system

For liquids, turbine meters with dual pulse outputs are most common. Alternatives are positive displacement meters (pass a fixed volume per rotation or stroke) and Coriolis mass flow meters. These instruments cannot cover the full range with sufficient accuracy. Therefore, the metering is split into several runs, and the number of runs depends on the flow. Each run employs one meter and several instruments to provide temperature and pressure correction. Open/close valves allow runs to be selected and control valves can balance the flow between runs. The instruments and actuators are monitored and controlled by a flow computer. If the interface is not digital, dual pulse trains are used to allow direction sensing and fault finding.

To obtain the required accuracy, the meters are calibrated. The most common method is a prover loop. A prover ball moves though the loop, and a calibrated volume is provided between the two detectors (Z). When a meter is to be calibrated, the four-way valve opens to allow oil to flow behind the ball. The number of pulses from it passes one detector Z to the other and is counted. After one loop, the four-way valve turns to reverse flow direction and the ball moves back, providing the same volume in reverse, again counting the pulses. From the known reference volume, number of pulses, pressure and temperature the flow computer can calculate the meter factor and provide accurate flow measurements using formulas from industry standard organizations such as API MPMS and ISO 5024. The accuracy is typically ± 0.3% of standard volume.

Gas metering is similar, but instead, analyzers will measure hydrocarbon content and energy value (MJ/scm or BTU, Kcal/scf) as well as pressure and temperature. The meters are normally orifice meters or ultrasonic meters. Orifice plates with a diameter less than the pipe are mounted in cassettes. The pressure differential over the orifice plate as well as pressure and temperature, is used in standard formulas (such as AGA 3 and ISO 5024/5167) to calculate normalized flow. Different ranges are accommodated with different size restrictions.

Orifice plates are sensitive to a buildup of residue and affect the edges of the hole (figure 19.2). Larger new installations therefore prefer ultrasonic gas meters that work by sending multiple ultrasonic beams across the path and measure the Doppler effect.

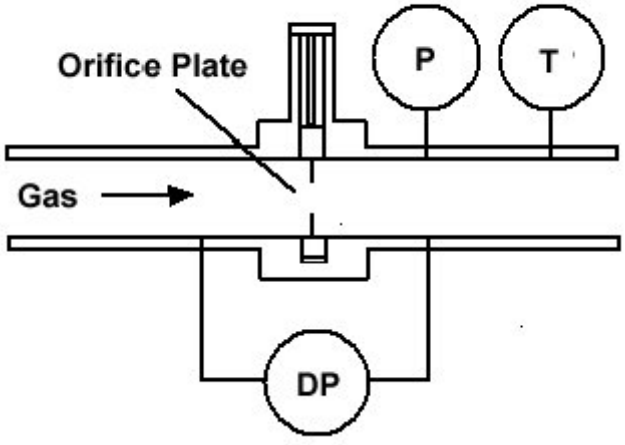

Figure 19.2 – Gas metering

Gas metering is less accurate than liquid, typically ±1.0% of mass. There is usually no prover loop, the instruments and orifice plates are calibrated in separate equipment instead.

LNG is often metered with mass flow meters that can operate at the required low temperature. A three run LNG metering skid is shown below (figure 19.3).

At various points in the movement of oil and gas, similar measurements are taken, usually in a more simplified way. Examples of different gas types are flare gas, fuel gas and injected gas, where required accuracy is 2-5% percent.

Figure 19.3 – LNG metering center

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1 ISO 5024 Petroleum liquids and liquefied petroleum gases – Measurement – Standard reference conditions.

2 ISO 5167 Sizing and flow calculation of differential pressure devices.

LECTURE 20
POTENTIAL OPERATING PROBLEMS

Foamy Crude

The major cause of foam in crude oil is the presence of impurities, other than water, which are impractical to remove before the stream reaches the separator. One impurity that almost always causes foam is CO_2.

Sometimes completion and workover fluids, that are incompatible with the wellbore fluids, may also cause foam. Foam presents no problem within a separator if the internal design assures adequate time or sufficient coalescing surface for the foam to "break."

Foaming in a separating vessel is a threefold problem (figure 20.1):

1. Mechanical control of liquid level is aggravated because any control device must deal with essentially three liquid phases instead of two.

2. Foam has a large volume-to-weight ratio. Therefore, it can occupy much of the vessel space that would otherwise be available in the liquid collecting or gravity settling sections.

3. In an uncontrolled foam bank, it becomes impossible to remove separated gas or degassed oil from the vessel without entraining some of the foamy material in either the liquid or gas outlets.

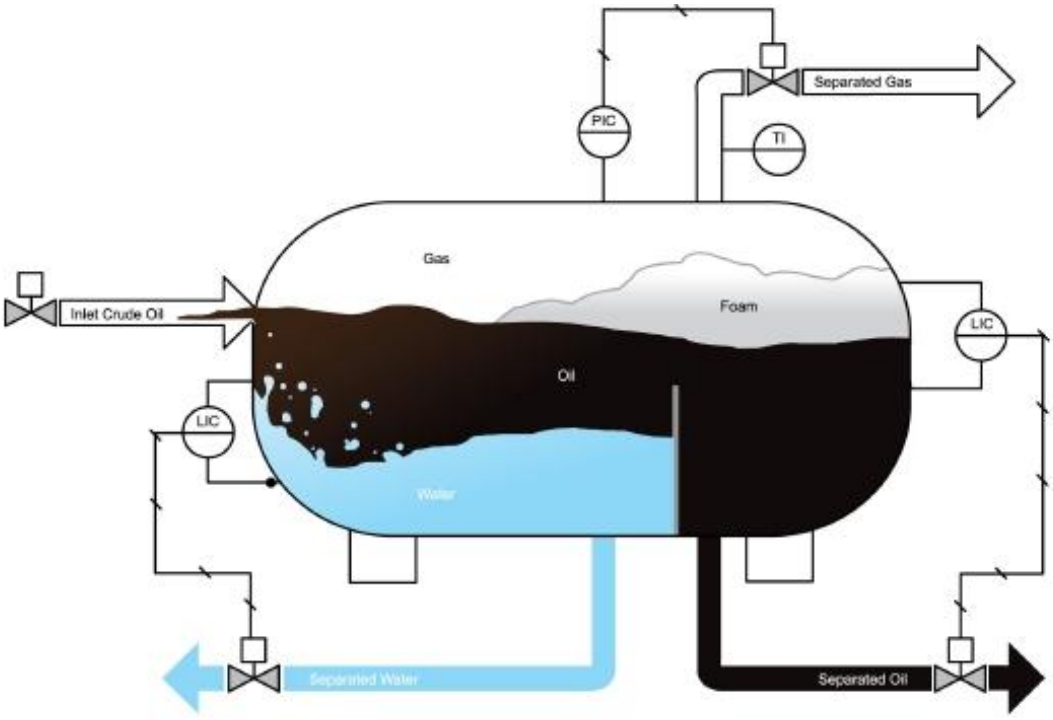


Figure 20.1 – Foam formation

The foaming tendencies of any oil can be determined with laboratory tests.

Only laboratory tests, run by qualified service companies, can qualitatively determine oil's foaming tendency. One such test is ASTM D 892, which involves bubbling air through the oil. Alternatively, the oil may be saturated with its associated gas and then expanded in a gas container.

This alternative test more closely models the actual separation process.

Both of these tests are qualitative. There is no standard method of measuring the amount of foam produced or the difficulty in breaking the foam. Foaming is not possible to predict ahead of time without laboratory tests. However, foaming can be expected where CO_2 is present in small quantities (1–2%). It should be noted that the amount of foam is dependent on the pressure drop to which the inlet liquid is subjected, as well as the characteristics of the liquid at separator conditions.

Comparison of foaming tendencies of known oil to a new one, about which no operational information is known, provides an understanding of the relative foam problem that may be expected with the new oil as weighed against the known oil. A related amount of adjustment can then be made in the design parameters, as compared to those found satisfactory for the known case.

The effects of temperature on foamy oil are interesting. Changing the temperature at which foamy oil is separated has two effects on the foam. The first effect is to change the oil viscosity. That is, an increase in temperature will decrease the oil viscosity, making it easier for the gas to escape from the oil. The second effect is to change the gas-oil equilibrium. A temperature increase will increase the amount of gas, which evolves from the oil.

It's very difficult to predict the effects of temperature on the foaming tendencies of oil. However, some general observations have been made. For low API gravity crude (heavy oils) with low GORs, increasing the operating temperature decreases the oils' foaming tendencies. Similarly, for high API crude (light oils) with high GORs, increasing the operating temperature decreases the oils' foaming tendencies. However, increasing the operating temperature for high API gravity crude (light oil) with low GORs may increase the foaming tendencies. Oils in the last category are typically rich in intermediates, which have a tendency to evolve to the gas phase as the temperature increases. Accordingly, increasing the operating temperature significantly increases gas evolution, which in turn increases the foaming tendencies.

Foam depressant chemicals often will do a good job in increasing the capacity of a given separator. However, in sizing a separator to handle specific crude, the use of an effective depressant should not be assumed because characteristics of the crude and of the foam may change during the life of the field. Also, the cost of foam depressants for high-rate production may be prohibitive. Sufficient capacity should be provided in the separator to handle the anticipated production without use of a foam depressant or inhibitor. Once placed in operation, a foam depressant may allow more throughput than the design capacity.

Paraffin

Separator operation can be adversely affected by an accumulation of paraffin. Coalescing plates in the liquid section and mesh pad mist extractors in the gas section are particularly prone to plugging by accumulations of paraffin. Where it is determined that paraffin is an actual or potential problem, the use of plate-type or centrifugal mist extractors should be considered. Manways, handholes, and nozzles should be provided to allow steam, solvent, or other types of cleaning of

the separator internals. The bulk temperature of the liquid should always be kept above the cloud point of the crude oil. Otherwise paraffin creates solid deposits inside the pipeline during the transportation (figure 20.2).

Figure 20.2 – Paraffin plugins in the oil pipeline

Sand

Sand can be very troublesome in separators by causing cutout of valve trim, plugging of separator internals, and accumulation in the bottom of the separator. Special hard trim can minimize the effects of sand on the valves. Accumulations of sand can be removed by periodically injecting water or steam in the bottom of the vessel so as to suspend the sand during draining. Figure 20.3 is a cutaway of a sand wash and drain system fitted into a horizontal separator fitted with sand jets and an inverted trough.

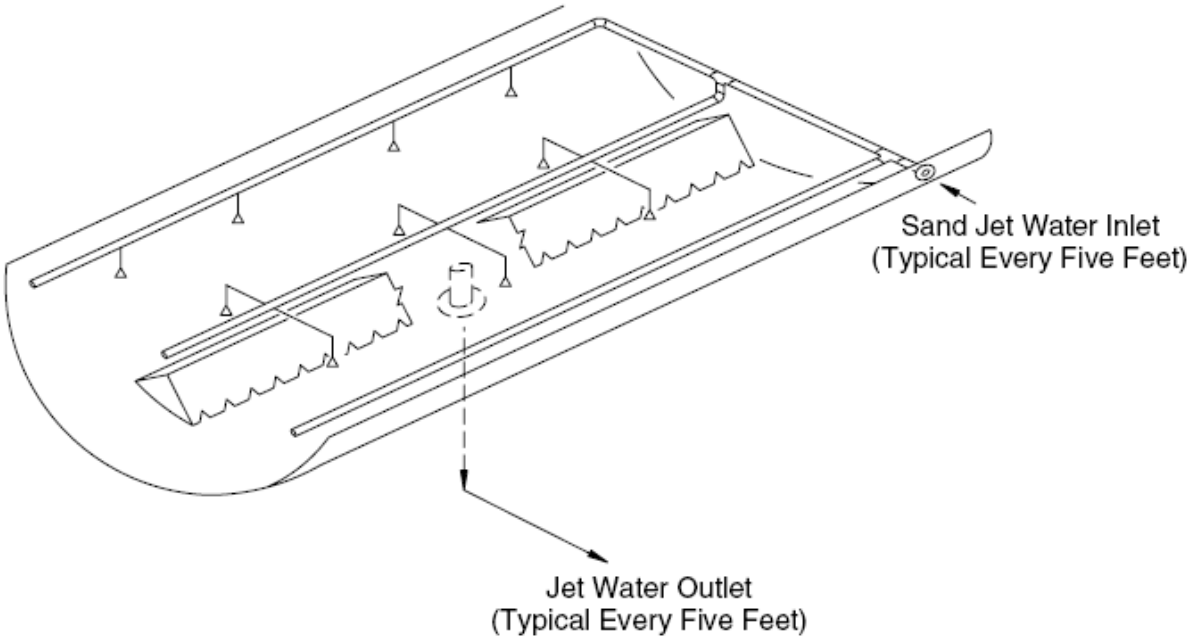


Figure 20.3 – Schematic of a horizontal separator fitted with sand jets and inverted trough

Sometimes a vertical separator is fitted with a cone bottom. This design would be used if sand production was anticipated to be a major problem. The cone is normally at an angle of between 45^0 and 60^0 to the horizontal.

Produced sand may have a tendency to stick to steel at 45^o. If a cone is installed, it could be part of the pressure-containing walls of the vessel (refer to Figure 20.4), or for structural reasons, it could be installed internal to the vessel

cylinder (refer to Figure 20.5). In such a case, a gas equalizing line must be installed to assure that the vapor behind the cone is always in pressure equilibrium with the vapor space.

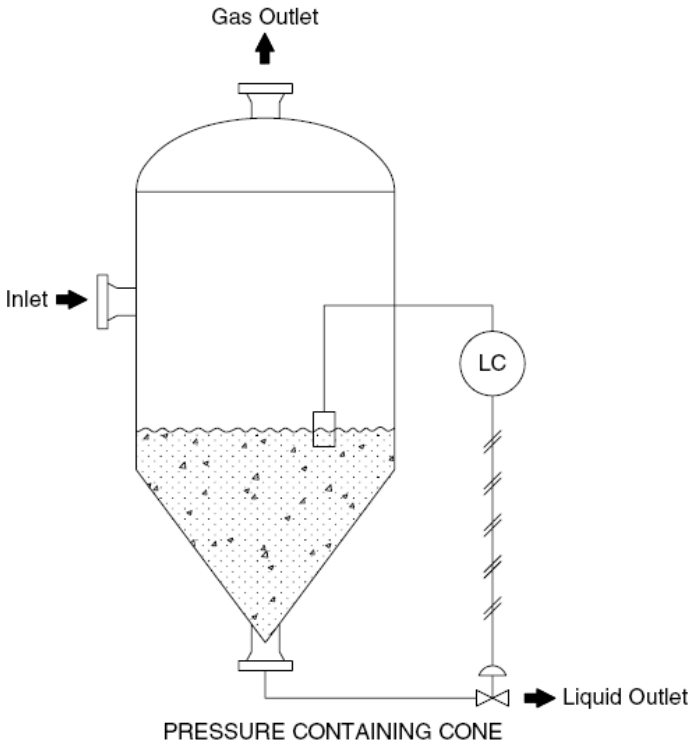


Figure 20.4 – Vertical separator with a pressure containing cone bottom used to collect solids

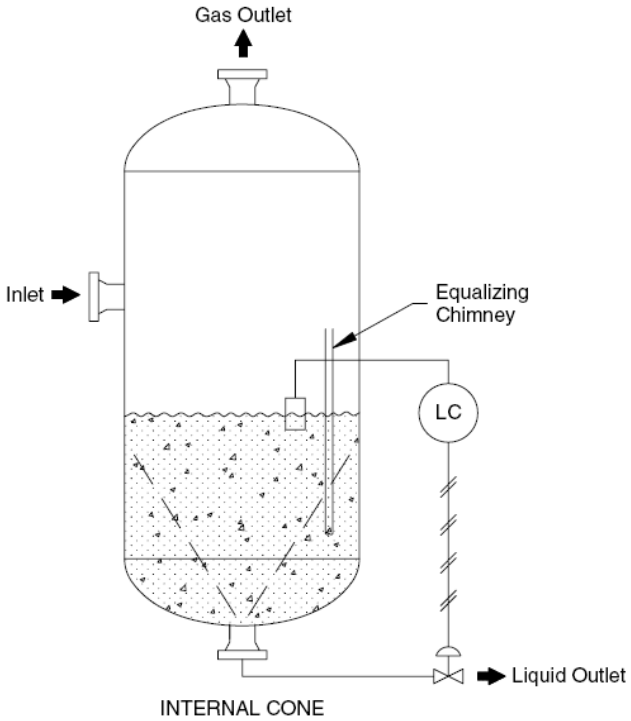


Figure 20.5 – Vertical separator fitted with an internal cone bottom and an equalizing line

Plugging of the separator internals is a problem that must be considered in the design of the separator. A design that will promote good separation and have a minimum of traps for sand accumulation may be difficult to attain, since the design that provides the best mechanism for separating the gas, oil, and water phases probably will also provide areas for sand accumulation. A practical balance for these factors is the best solution.

Liquid Carryover

Usually phases occupy some level inside 3-phase separator respectively to their density (figure 20.6).

Liquid carryover occurs when free liquid escapes with the gas phase and can indicate high liquid level, damage to vessel internals, foam, improper design, plugged liquid outlets, or a flow rate that exceeds the vessel's design rate. Liquid carryover can usually be prevented by installing a level safety high (LSH) sensor that shuts in the inlet flow to the separator when the liquid level exceeds the normal maximum liquid level by some percentage, usually 10–15%.

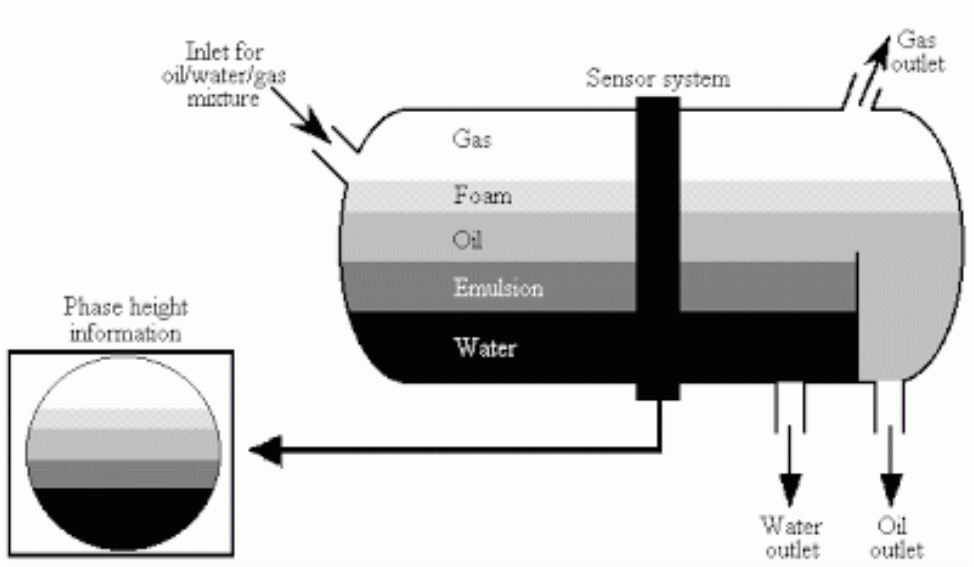


Figure 20.6 – Phase height information

Gas Blowby

Gas blowby occurs when free gas escapes with the liquid phase and can be an indication of low liquid level, vortexing, or level control failure. This could lead to a very dangerous situation. If there is a level control failure and the liquid dump valve is open, the gas entering the vessel will exit the liquid outlet line and would have to be handled by the next downstream vessel in the process. Unless the downstream vessel is designed for the gas blowby condition, it can be over-pressured. Gas blowby can usually be prevented by installing a level safety low sensor (LSL) that shuts in the inflow and/or outflow to the vessel when the liquid level drops to 10–15% below the lowest operating level. In addition, downstream process components should be equipped with a pressure safety high (PSH) sensor and a pressure safety valve (PSV) sized for gas blowby.

During gathering or transportation associated gases can leave crude oil due to the decreasing the operating pressure. Is such gases, gas occupies the upper part of relief large diameter pipeline (picture 20.7).

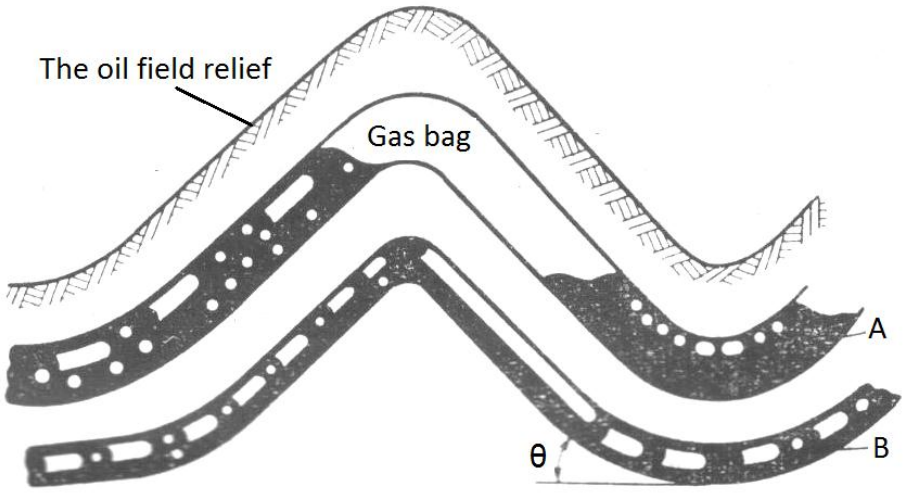
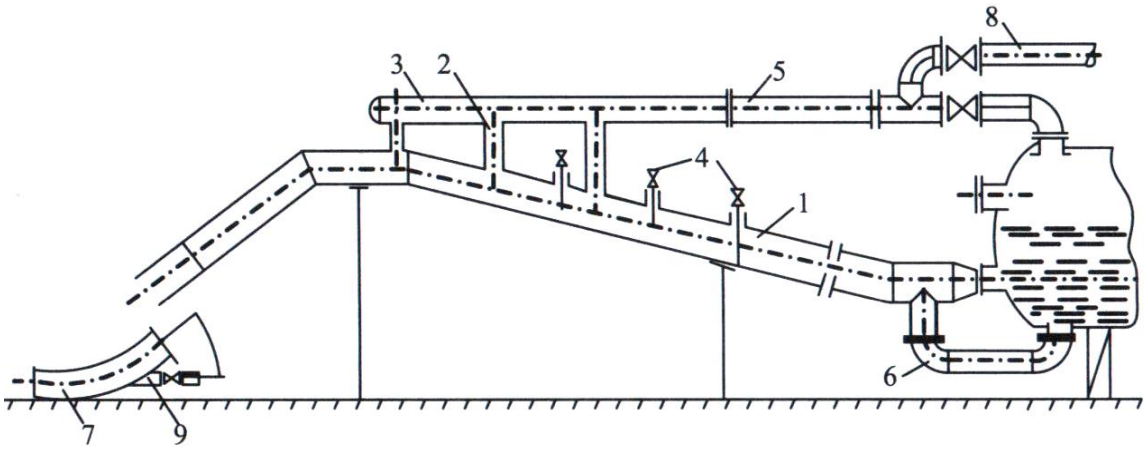


Figure 20.7 – The gas formation in relief pipeline:
a) in large diameter pipeline, b) in small diameter pipeline.

The volume of these gas formations inside the pipeline decreases or increases respectively to the pressure changes (the equation of the state for natural gas). The cycle of the change in gas formation volume leads to the uncontrolled pulsation of inlet pressure and flow rate at the CPF or GOSP. To prevent these uncontrolled pulsation facilities is usually equipped with inlet pressure stabilizers (depulsators – figure 20.8).



1 – inlet pipeline, 2 – outlet tubes, 3 – technological line before inlet separator,
4 – movable safety low sensors, 5 – water drainage system,
7 – the end point of the inlet pipeline, 8 – VRU line, 9 – liquid drainage line.

Figure 20.8 - Inlet pressure stabilizers

Liquid Slugs

Two-phase flow lines and pipelines tend to accumulate liquids in low spots in the lines. When the level of liquid in these low spots raises high enough to block

the gas flow, then the gas will push the liquid along the line as a slug. Depending on the flow rates, flow properties, length and diameter of the flow line, and the elevation change involved, these liquid slugs may contain large liquid volumes.

Situations in which liquid slugs may occur should be identified prior to the design of a separator. The normal operating level and the high-level shutdown on the vessel must be spaced far enough apart to accommodate the anticipated slug volume. If sufficient vessel volume is not provided, then the liquid slugs will trip the high-level shutdown.

When liquid slugs are anticipated, slug volume for design purposes must be established. Then the separator may be sized for liquid flow-rate capacity using the normal operating level. The location of the high-level set point may be established to provide the slug volume between the normal level and the high level. The separator size must then be checked to ensure that sufficient gas capacity is provided even when the liquid is at the high-level set point. This check of gas capacity is particularly important for horizontal separators because, as the liquid level rises, the gas capacity is decreased. For vertical separators, sizing is easier as sufficient height for the slug volume may be added to the vessel's seam-to-seam length.

Often the potential size of the slug is so great that it is beneficial to install a large pipe volume upstream of the separator. The geometry of these pipes is such that they operate normally empty of liquid, but fill with liquid when the slug enters the system. This is the most common type of "slug catcher" used when two-phase pipelines are routinely pigged.

Figure 20.9 is a schematic of a liquid finger slug catcher.

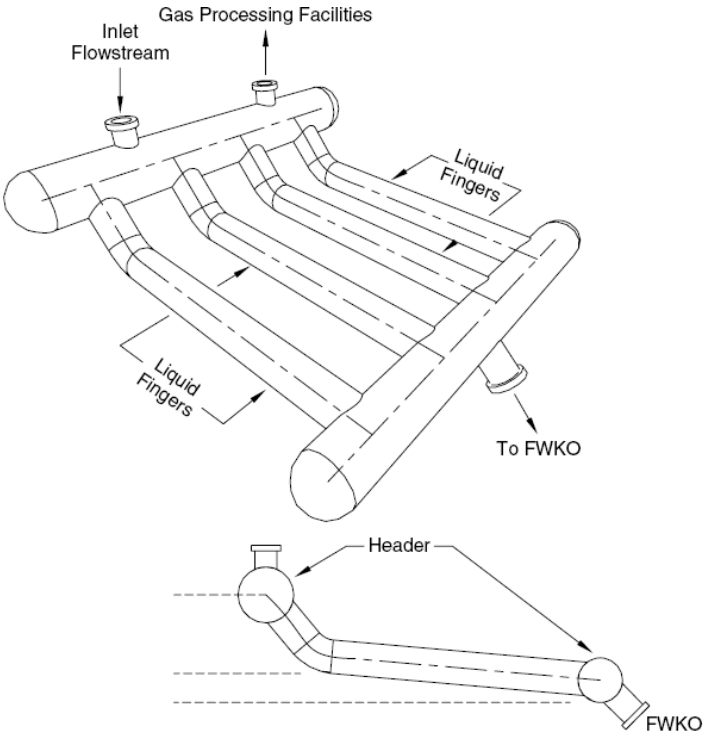


Figure 20.9 – Schematic of a two-phase horizontal slug catcher with liquid "fingers"

Slugging is the main problem in pipeline. Slugging is also called deposits. They reduce oil or gas flow. Sometimes they block the pipeline completely. This slows production. Both gas and oil pipeline must be cleaned by the PIG (figure 20.10). Cleaning means the removing of the all type of deposits inside the pipeline.

The process of removing the deposits requires next steps:

- inspection of pipes and plan pipeline cleaning;
- installation of a launcher and receiver in the pipeline system;
- putting a pipeline inspection gauge (sometimes called – PIG) into the pipeline.

Then the oil or gas pressure in pipeline pushes the pig, the disk and brushes clean the pipe, the pig pushes the deposits out of the pipes. Device is took out from the receiver.

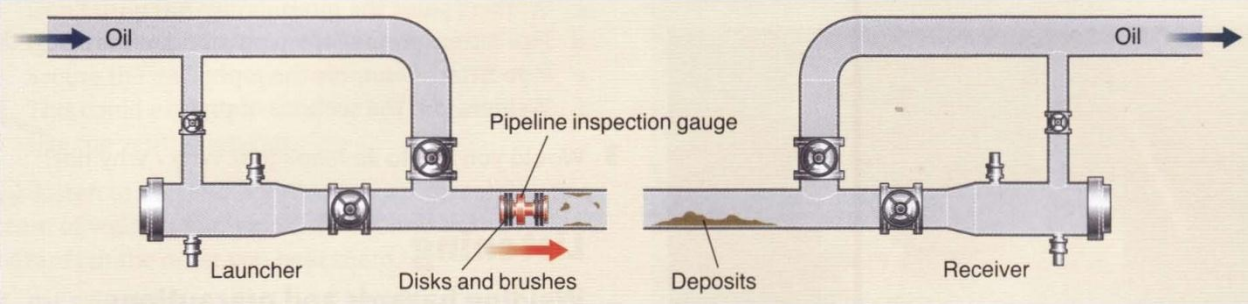


Figure 20.10 – Pigging

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LECTURE 21
CONTROLLING THE PROCESS

A process flowsheet is used to describe the system. Figure 21.1 is a typical flowsheet that will be used as an example for discussion purposes. Another name for a process flowsheet is a process flow diagram (PFD). Regardless what it is called, either a flowsheet or a diagram, the information contained on both is the same. Figure 21.2 defines many of the commonly used symbols in process flowsheets.

Operation of a Control Valve

Control valves are used throughout the process to control pressure, level, temperature, or flow. It is beyond the scope of this lecture to discuss the differences between the various types of control valves and the procedures for their sizing.

This section focuses primarily on the functions of this equipment.

Figure 21.3 shows the major components of a typical sliding-stem control valve. All control valves have a variable opening or orifice. For a given pressure drop across the valve, the larger the orifice is, the greater the flow through the valve will be.

Chokes and other flow control devices have either a fixed or a variable orifice. With a fixed pressure drop across the device (i.e., with both the upstream and downstream pressures fixed by the process system), the larger the orifice is, the greater the flow will be. Chokes are used to regulate the flow rate.

In Figure 21.3 the orifice is made larger by moving the valve stem upward. This moves the plug off the seat, creating a larger annulus for flow between the seat and the plug. Similarly, the orifice is made smaller by moving the valve stem downward. The most common way to effect this motion is with a pneumatic actuator, such as that shown in Figure 21.4.

Instrument air or gas applied to the actuator diaphragm overcomes a spring resistance and moves the stem either upward or downward. The action of the actuator must be matched with the construction of the valve body to assure that the required failure mode is met. That is, if it is desirable for the valve to fail to close, then the actuator and body must be matched so that on failure of the instrument air or gas, the spring causes the stem to move in the direction that blocks flow (i.e., fully shut). This would normally be the case for most liquid control valves. If it is desirable for the valve to fail to open, as in many pressure control situations, then the spring must cause the stem to move in the fully open direction.

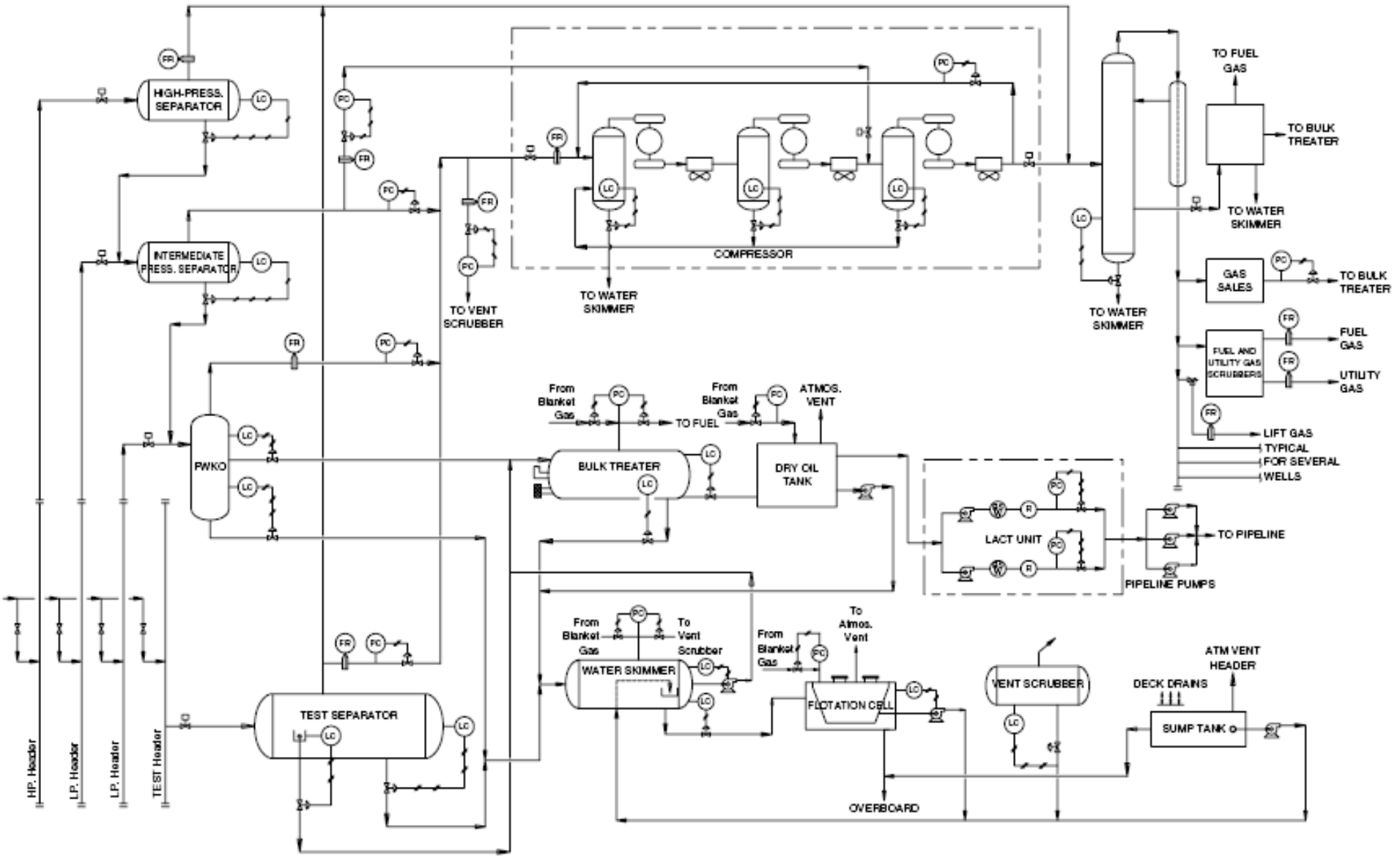

Figure 21.1 – Typical flowsheet

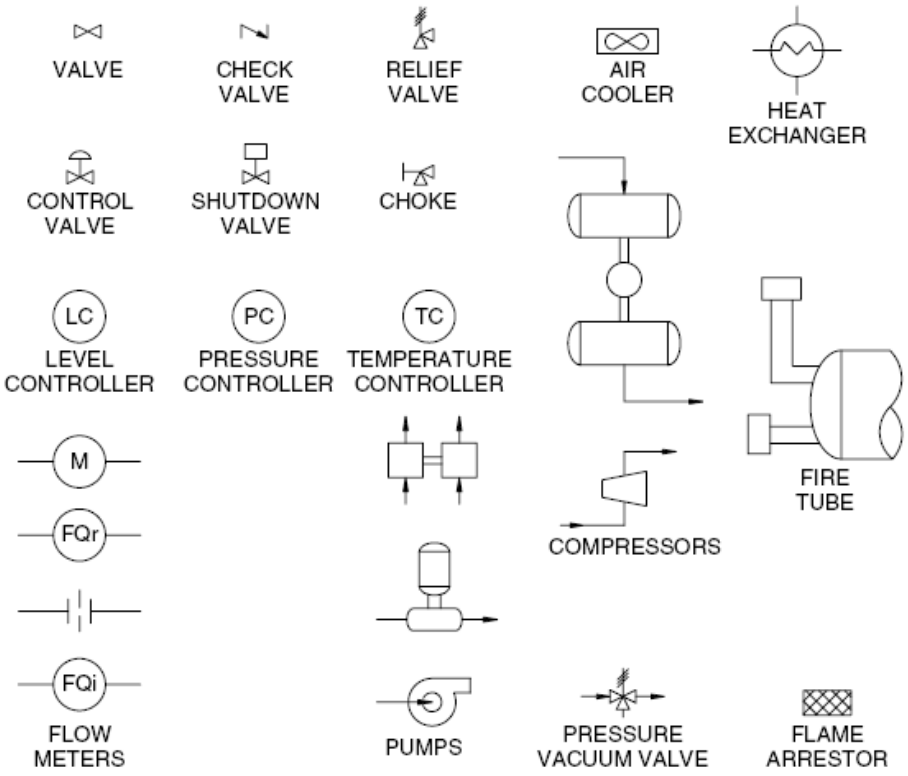

Figure 21.2– Common flowsheet symbols

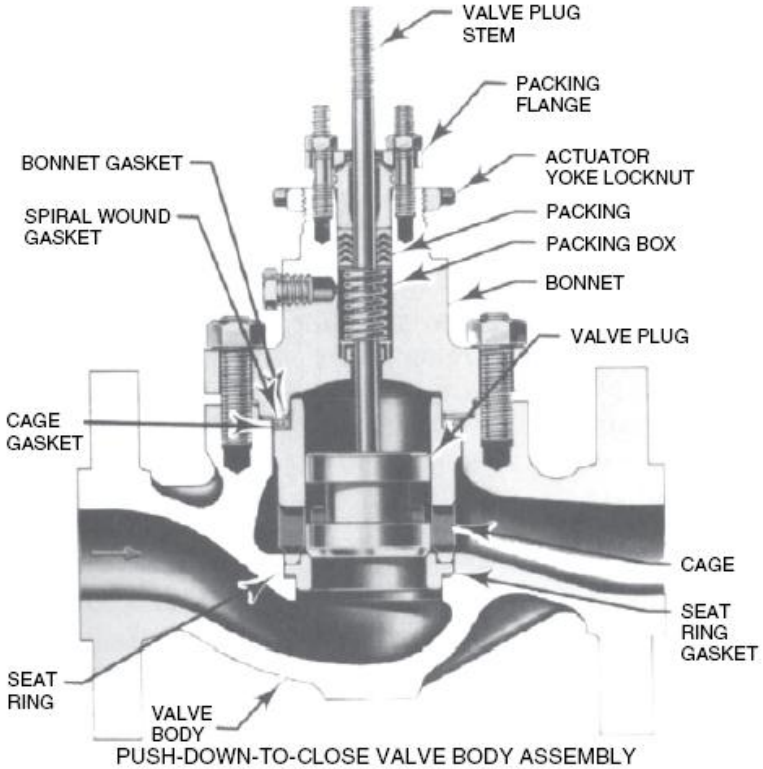

Figure 21.3 – Major components of a typical sliding stem control valve. (courtesy of Fisher Controls International, Inc.)

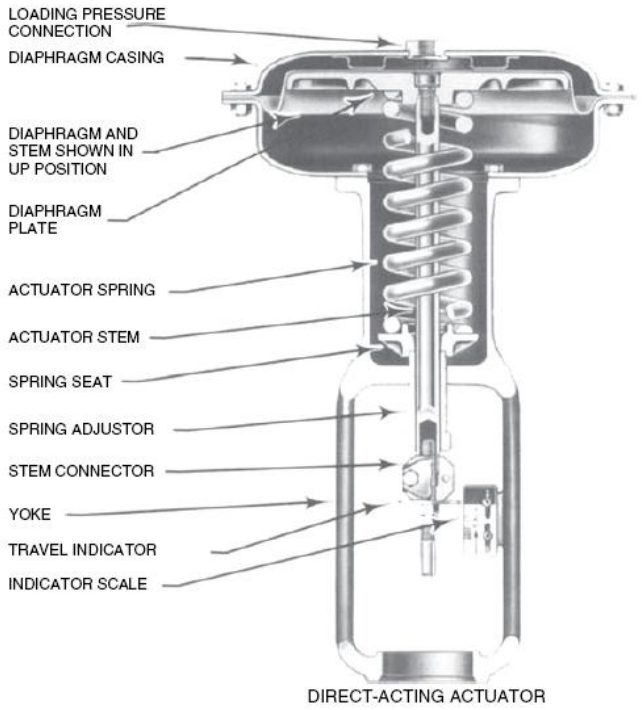

Figure 21.4 – Typical pneumatic direct-acting actuator (courtesy of Fisher Controls International, Inc.)

Pressure Control

The hydrocarbon fluid produced from a well is made up of many components ranging from methane, the lightest and most gaseous hydrocarbon, to some very heavy and complex hydrocarbon compounds. Because of this, whenever there is a drop in fluid pressure, gas is liberated. Therefore, pressure control is important.

The most common method of controlling pressure is with a pressure controller and a backpressure control valve (figure 21.5). The pressure controller senses the pressure in the vapor space of the pressure vessel or tank. By regulating the amount of gas leaving the vapor space, the backpressure control valve maintains the desired pressure in the vessel. If too much gas is released, the number of molecules of gas in the vapor space decreases, and thus the pressure in the vessel decreases. If insufficient gas is released, the number of molecules of gas in the vapor space increases, and thus the pressure in the vessel increases. In most instances, there will be enough gas separated or "flashed" from the liquid to allow the pressure controller to compensate for changes in liquid level, temperature, etc., which would cause a change in the number of molecules of gas required to fill the vapor space at a given pressure.

However, under some conditions where there has been only a small pressure drop from the upstream vessel, or where the crude GOR (gas/oil ratio) is low, it may be necessary to add gas to the vessel to maintain pressure control at all times. This is called "make-up" or "blanket" gas. Gas from a pressure source higher than the desired control

pressure is routed to the vessel by a pressure controller that senses the vessel pressure automatically, allowing either more or less gas to enter the vessel as required.

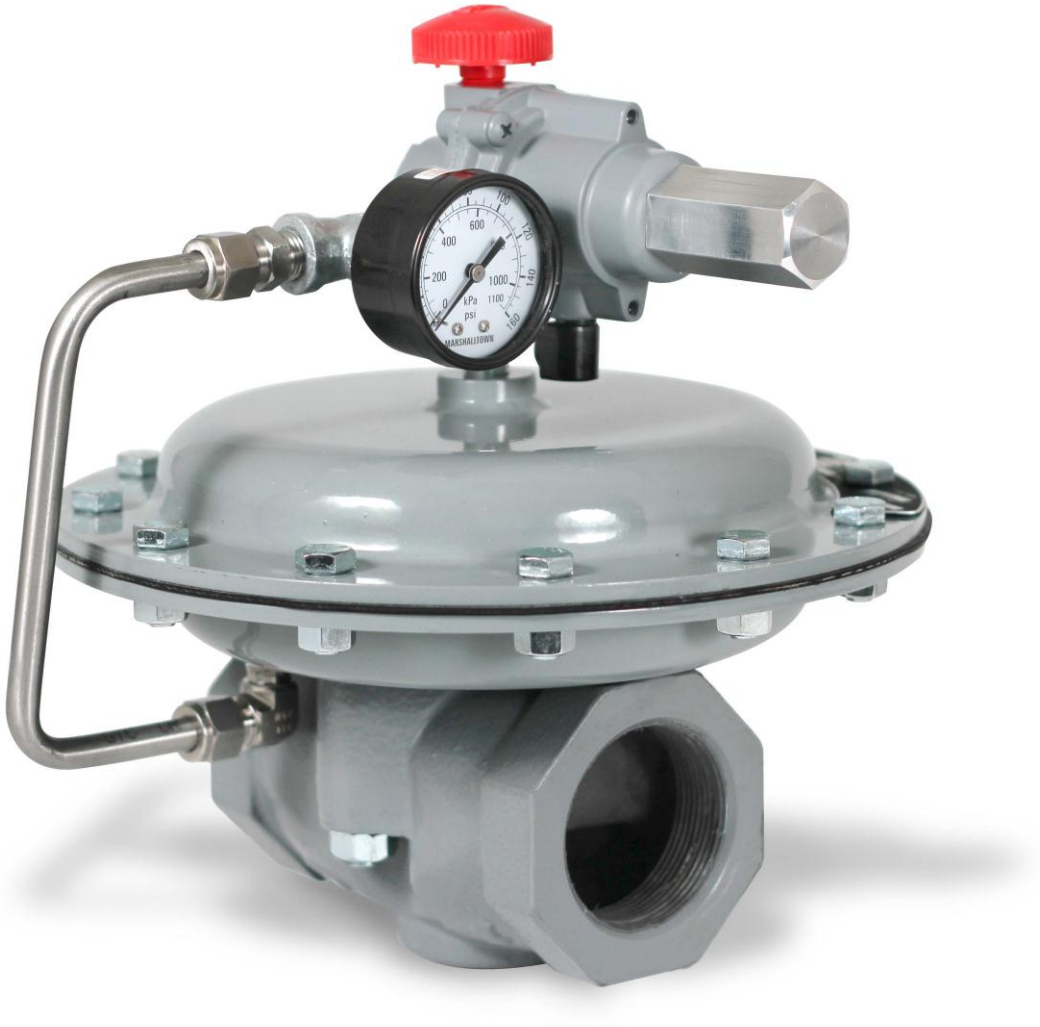

Figure 21.5 – Back pressure valve

Level Control

It is also necessary to control the gas/liquid interface or the oil/water interface in process equipment. This is done with a level controller and liquid dump valve (figure 21.6). The most common forms of level controllers are floats and displacers, although electronic sensing devices can also be used. If the level begins to rise, the controller signals the liquid dump valve to open and allow liquid to leave the vessel. If the level in the vessel begins to fall, the controller signals the liquid dump valve to close and decrease the flow of liquid from the vessel. In this manner the liquid dump valve is constantly adjusting its opening to assure that the rate of liquid flowing into the vessel is matched by the rate out of the vessel.

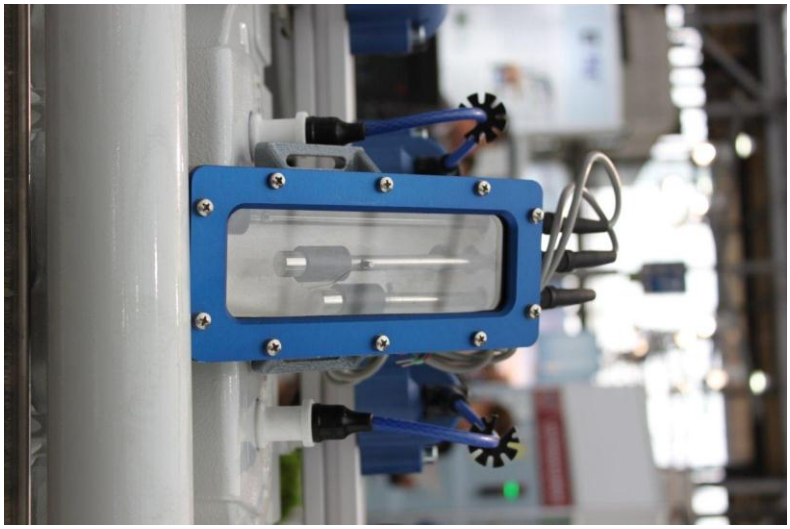

Figure 21.6 – Level contoller

Temperature Control

The way in which the process temperature is controlled varies. In a heater a temperature controller measures the process temperature and signals a fuel valve to let either more or less fuel to the burner. In a heat exchanger the temperature controller could signal a valve to allow more or less of the heating or cooling media to bypass the exchanger. Figure 21.7 shows the controlling the temperature inside storage tanks.

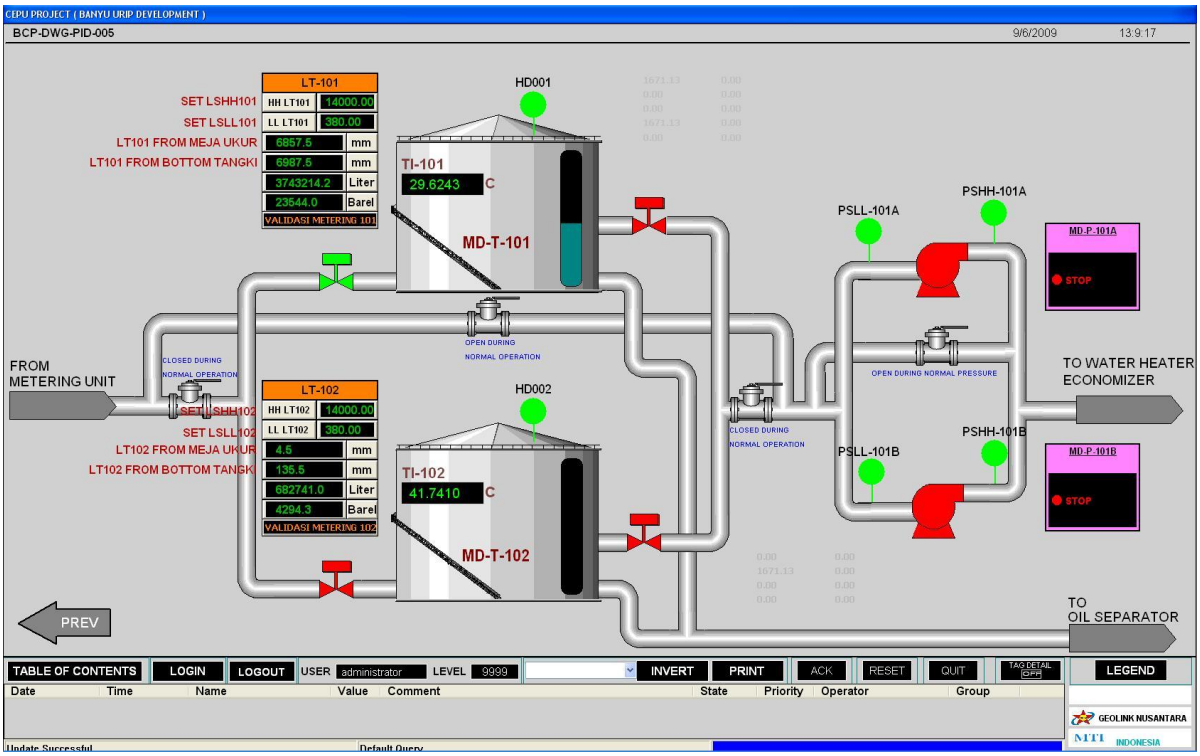

Figure 21.7 – Process oil flow diagram in SCADA

Flow Control

It is very rare that flow must be controlled in an oil field process. Normally, the control of pressure, level, and temperature is sufficient. Occasionally, it is necessary to assure that flow is split in some controlled manner between two process components in parallel, or perhaps to maintain a certain critical flow through a component. This can become a complicated control problem and must be handled on an individual basis.

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CONTENTS