Tikrit University

College of Petroleum Processes Engineering

Department of Petroleum Refining Engineering

Specialized Petroleum Processes

Fourth Class

Lecture 2

By

Jasim I. Humadi

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Crude Oil Processing from Oilfield to Refinery

Crude oil collected from the wells contains sand, mud, and water as impurities which may vary from 20% to 30% by volume. Hence, raw crude is collected in a battery of treatment tanks where both treatment and storage of crude oil are carried out. Treatment steps involve:

- ❖ Removal of sand and water by gravity settling
- ❖ Chemical treatment to remove emulsified water
- ❖ Crude conditioning or stabilizing

- Well fluids are complex mixtures of different compounds of carbon and hydrogen with different densities, vapor pressure and physical characteristics.
- As the well fluids travel from the reservoir to the production facility, it experiences pressure and temperature reduction.
- The characteristics of the well stream continuously changes with the evolving gas from the liquid as the pressure reduces.
- The separation of these phases is one of the basic operations in production, processing and treatment.

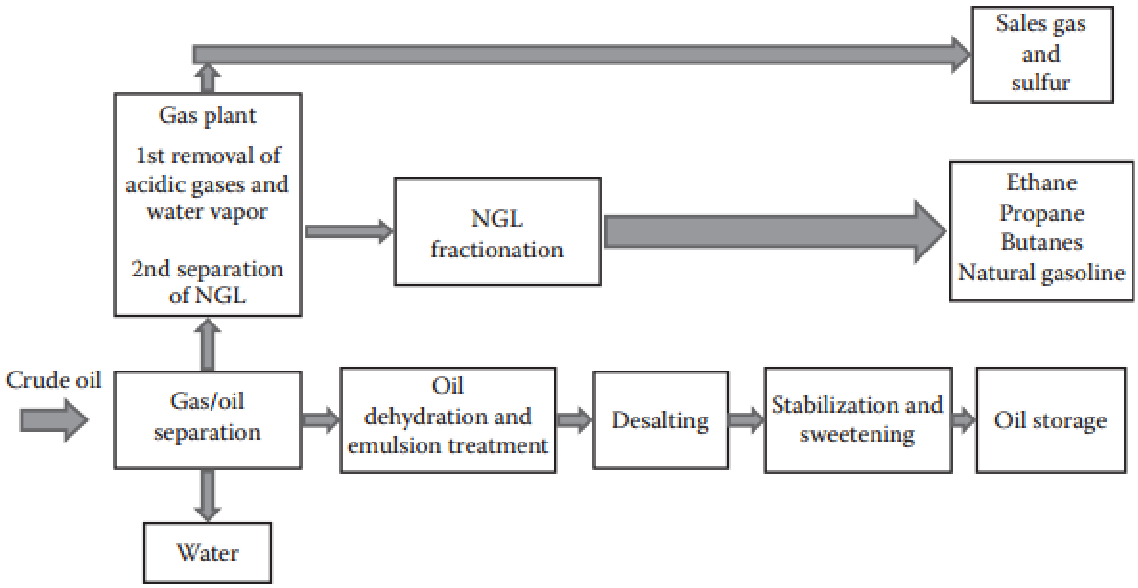

Figure 1: Field processing of well field effluents.

1. Gas–Oil Separation unit

The first step in processing the well stream is to separate the crude oil, natural gas, and water phases into separate streams. A gas–oil separator is a vessel that does this job. Gas–oil separators can be horizontal, vertical, or spherical. **Oil-field separators can be classified into two types based on the number of phases to separate:**

- **Two-phase separators**, which are used to separate gas from oil in oil fields, or gas from water for gas fields
- **Three-phase separators**, which are used to separate the gas from the liquid phase, and water from oil The liquid (oil, emulsion) leaves at the bottom through a level-control or dump valve. The gas leaves the vessel at the top, passing through a mist extractor to remove the small liquid droplets in the gas.

Separators can be categorized according to their operating pressure into:

- **Low pressure units** handle pressures of 10 to 180 psi (69 to 1241 kPa).
- **Medium pressure separators** operate from 230 to 700 psi (1586 to 4826 kPa).
- **High-pressure units** handle pressures of 975 to 1500 psi (6722 to 10,342 kPa).

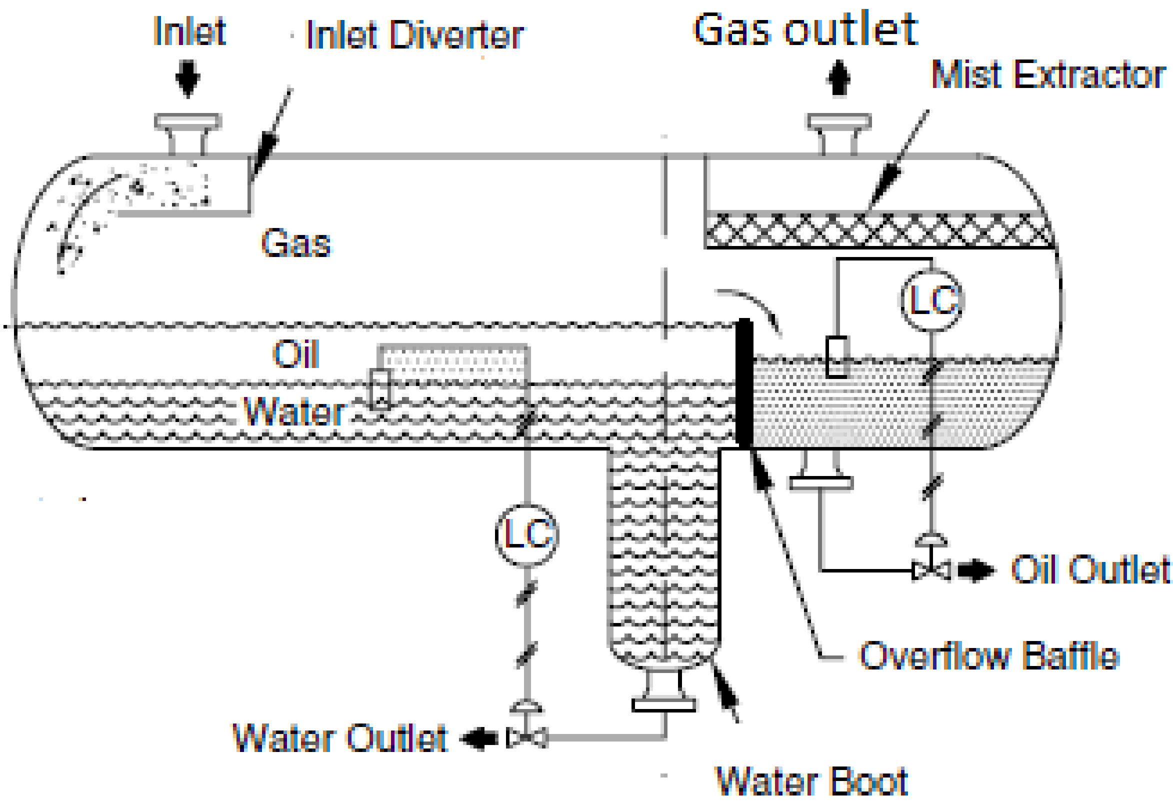

Figure 2: Typical Three Phase Separator (horizontal).

Gravity segregation is the main force that accomplishes the separation, which means the heaviest fluid settles to the bottom and the lightest fluid rises to the top. The degree of separation between gas and liquid inside the separator depends on the following factors:

- Separator operating pressure,
- The residence time of the fluid mixture, and
- The type of flow of the fluid (turbulent flow allows more gas bubbles to escape than laminar flow).

A separator can be either horizontal or vertical configuration

- **Horizontal separator**

Horizontal separator is preferred for low GOR well fluids and three phase separation.

Table below shows the advantages and disadvantages of horizontal separators:

Advantages	Disadvantages
Provide sufficient residence time for liquid-liquid separation	Only part of shell available for passage of gas
Large liquid surface area for foam dispersion generally reduces turbulence	Larger foot print / plot area
Large surge volume capacity	Liquid level control is more critical
Lend themselves to skid mounting and shipping	More difficult to clean produced sand, mud, wax, paraffin. etc.

- **Vertical separator**

Vertical separator is preferred for high GOR well fluids and two phase separation

Table below shows the advantages and disadvantages of vertical separators:

Advantages	Disadvantages
Have full diameter for gas flow at top and oil flow at bottom	Not suitable for bulk liquid-liquid separation
Occupy smaller plot area	Occupy more vertical spacing between decks in offshore
Liquid level control is not so critical	More difficult to skid mount and ship
Have good bottom drain and clean out facilities. Can handle more sand, mud, paraffin, wax, etc.	More difficult to reach and service top-mounted instruments and safety devices

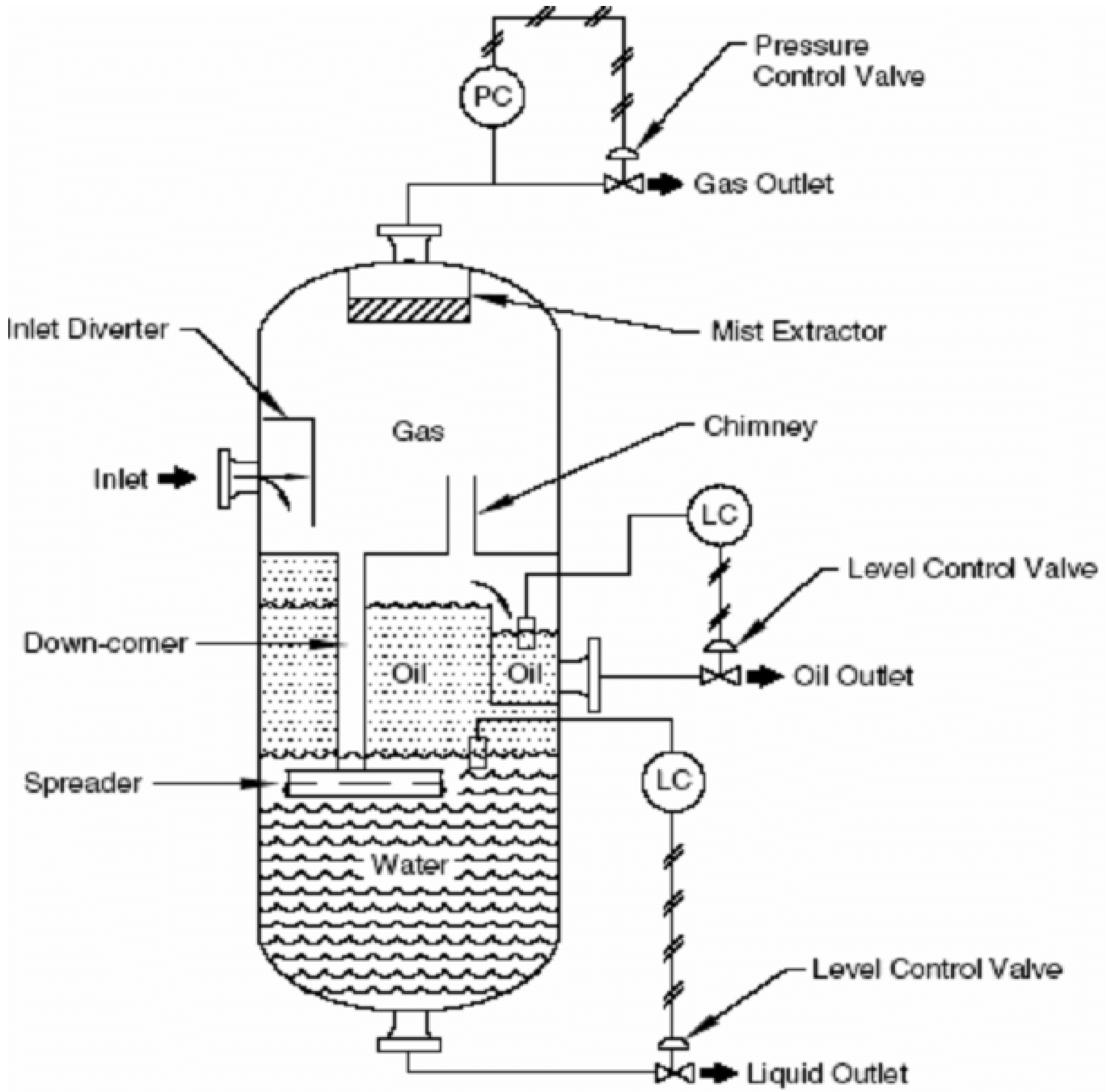

Figure 3: Typical Three Phase Separator (vertical).

Number of Separation Stage

- The well fluid pressure is often reduced in several stages of separation.
- If the reservoir fluid can flow adequately against a wellhead pressure, separation in more than one stage will generally offer an economic advantage.

- The purpose of multi stage separation is to achieve maximum hydrocarbon liquid recovery, to get the liquid stabilized, and minimize compression power required for the gas stream.
- Multi stage separation of oil and gas involves a series of separators operating at sequentially reduced pressures, with liquid flowing from first separator to the next lower pressure separator.
- The optimum number of separation stages varies with Flowing Wellhead Pressure (FWHP), reservoir composition, off-gas compression requirement, and export specification for crude vapor pressure. A quick assessment of separation stages number based on FWHP is given in the Table 1.

Table 1: Separation stages number based on FWHP

FWHP, Bar	Number of Stage
1-20	**1 or 2**
20-70	**2 or 3**
Over 70	**3 or 4**

- The flowing tubing pressure usually decrease during the life of the field, a common practice is to install separate production manifolds for each separator.
- In this case, wells with decreased well pressure would be rerouted to a lower pressure separator, thus maximizing production. Figure 4 shows a typical flow scheme of 3 stages separation.

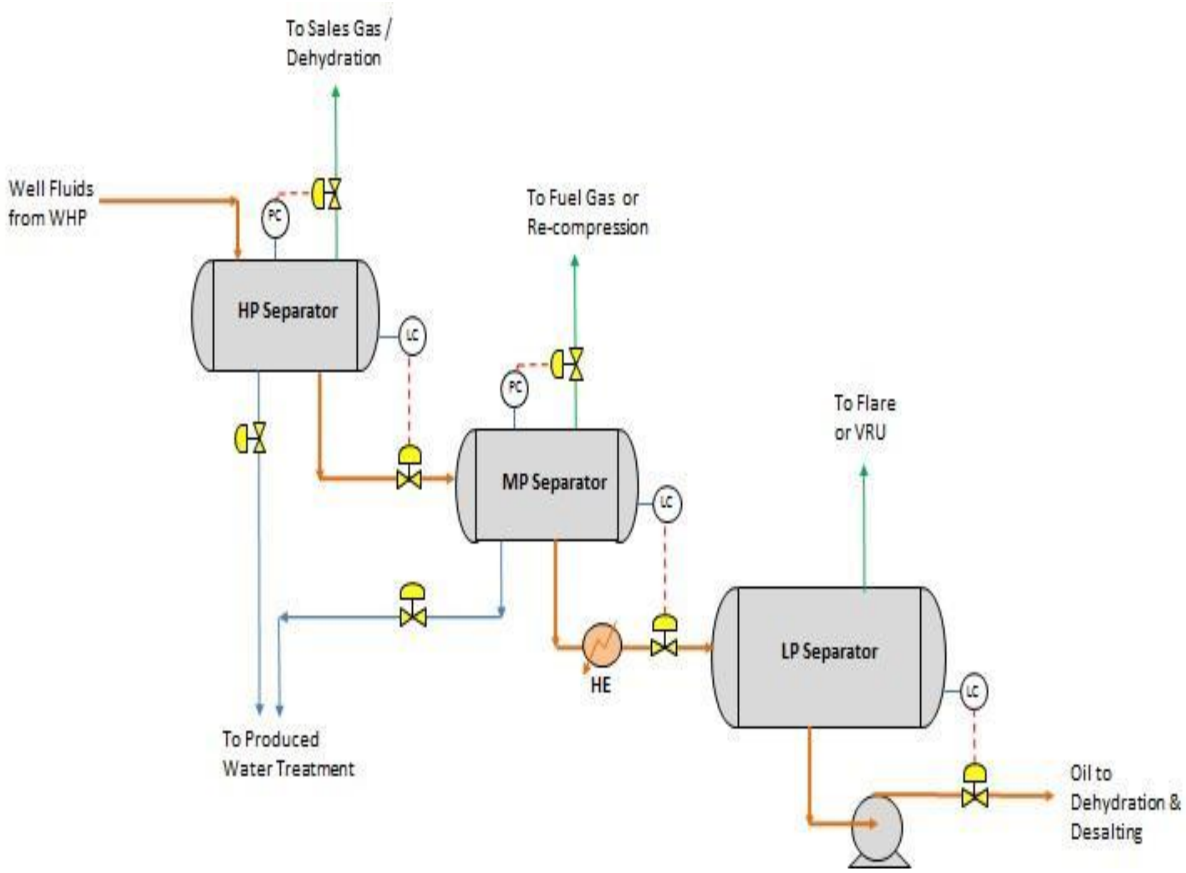

Figure 4: Typical 3 Stages Separation.

- **HP separator** is a 3-phase separator. The separator pressure must be low enough to allow effective choke operation and thus control of well behavior. Therefore, wells with high enough flowing wellhead pressure are routed to the HP Separator. Gas separated from the HP Separator normally flows to the gas compression and dehydration system, and then exported through pipeline.
- **MP separator** is similar to the HP Separator but operates in lower pressure. MP separator receives liquid (oil) from the HP Separator, and due to pressure reduction, the light components of the liquid will vaporize. Gas separated from the MP separator normally flows to an inter-stage compressor and then combines with the gas off from HP separator.
- **LP separator** is a 2-phase (gas/liquid) separator which operates slightly above atmospheric pressure. The operating pressure and temperature of the final gas-oil

separation stage dictates the vapor pressure of the export crude. Generally stable crude (10-12 psia RVP) requires a very low pressure and high temperature.

- **The off gas** from each separation stage can be compressed and treated for use as fuel gas, exported, or flared if quantities are minimal and applicable regulations permit flaring.
- Bulk water in the well fluid is generally removed from the first stage separator, in order to minimize heating/cooling of excess liquid at further processing.
- The removed water is routed to the water treatment plant.

Separators of all types are sized according to the following parameters, to suit product specifications:

- Fluid flow rates.
- Operating Pressure and Temperature.
- Oil in Water Specification (500-1000 ppm).
- Water in Oil Specification (1-3% vol).
- Liquid losses to vapor stream (subject to demister type).
- Liquid droplet size in gas outlet (150 microns and larger droplets can be removed when internals are not used).