Tikrit University

The College of Petroleum Processes Engineering

Petroleum Systems Control Engineering

Department

Petroleum Refining Processes

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Lecture 6

By

Jasim I. Humadi

Well Fluid Compositions

Fluid flow from a well can include gas, free water, condensable vapors (water or hydrocarbon), crude oil, and solid debris (basic sediment). The proportion of each component varies in different well streams. When water is produced with crude oil, it is mixed in either or both of the following forms:

1. Free Water/Produced Water: Water mixed with the oil but will separate easily into a clear layer when the mixture is allowed enough time to settle.

2. Emulsion: Water can also be mixed with the oil in the form of very small droplets of water coated with oil. A mixture like this is called emulsion. Water in this case cannot be easily separated from oil and need to undergo **demulsifications process** in order to remove the water content in crude. The waste water may be used as utility or discharged as water effluents to the sea. In either case, the water must be treated for solid particles removal, de-oxygenation, bacteria and hydrocarbon recovery at skimmer pit. As for the gas, it can be found in the well as:

1. Solution Gas: Gas dissolved in the well fluids under the effect of pressure of the reservoir. As the fluids flow from the reservoir into the well and up to the surface, the pressure of the fluid decreases. The capacity of the liquid to hold gas in solution also decreases and gas starts to separate out of the oil.
2. Free Gas: Gas that is not held in the oil under reservoir conditions.
3. Associated Gas: Total gas produced with the oil in a crude oil well. This type of gas is separated in the three phase gravity separator and will under further treatment to be converted into Liquefied Petroleum Gas (LPG product), sales

gas to petrochemical industries or used as a fuel gas for burner/heater at the production facility.

Crude Processing & Treatment

Oil well fluids are produced normally in two phases - vapor and liquid. These two phases require entirely different handling, measuring and processing methods. Reservoir pressure are generally much higher than atmospheric pressure. As well fluids reach the surface, pressure on them is decreased. The liquid ability to hold gas in solution decreases and the liquids begin to release 'Solution Gas'. Light fluids begin to separate naturally when the pressure on them is lowered. The solution gas released as 'Free gas' is held by the surface tension of the oil. This free gas is released from the oil when the well fluids are warmed to reduce the surface tension of the oil. After the well fluid has been extracted from various oil well/well platform/subsea manifold, it will undergo primary separation to remove free water and any solid impurities (sand, wax etc.) at the surface production facilities (offshore platform). Well fluid extracted from the well is received in the production manifold. Demulsifier chemicals is dozed in production manifold to promote breaking up of Water-Oil emulsion.
Three phase well fluid is received from wells/well platforms and processed at large process platform generally consisting of the following four major processing module :

a. Separation (Oil, gas and produced water) & oil dispatch
b. Gas compression & dehydration
c. Produced water conditioning
d. Sea water processing & injection system

Special corrosion inhibitor might be injected into the pipeline stream as to avoid the waxy formation and corrosion inside the pipeline. Upon reaching onshore, the inlet crude will undergo further separation process **(crude stabilization process)** as to separate the oil mixture into three phase (oil-gas-water) streams.

Crude Oil Stabilization

The fluids existing in a hydrocarbon are usually under high pressure and may be in a liquid or gaseous state. The hydrocarbon fluids in the reservoir are usually in contact with water, which is normally salty. Each reservoir is unique : and all of its individual characteristics, listed below, will have an effect on how the fluid will be produced and how they must be treated when they reach the surface.

a. Pressure
b. Temperature
c. Density of the fluids
d. Type and quantity of fluid that it contains
e. Whether the fluid contains components considered to be undesirable (e.g., hydrogen sulphide, H_2S and carbon dioxide, CO_2
f. Amount of free water in the crude

The hydrocarbon fluids to be found in the reservoir range in a composition from nearly pure methane gas to a crude so heavy that it is essentially asphalt. The job of a production facility (oil & gas production terminal) is to separate the well stream into three components, typically called ‘phases’ (oil, gas and water), and process these phases into some marketable product(s) or dispose them in an environmentally acceptable manner. In a typical onshore oil and gas processing facility, separation is the heart of the process. Separation is a process to separate the gas from the liquid and the water from the oil. This is usually done in a separator which is an unfired pressure vessel. The well stream flows into the separator and allow the gas, oil and water to separate because the of the gravity. During the separations: crude oil stabilization process, gas is flashed from the liquids and 'free water' is separated from the oil. These step remove enough light hydrocarbons to produce a stable crude oil with the volatility (vapor pressure) to meet sales criteria. The gas that is separated must be compressed and treated for sales, while the free water produced will undergo further hydrocarbon recovery process as to reduce the oil proportion below 10 mg/L before being discharged as water effluents to the sea.

Separation is often accomplished in two or three stages of decreasing pressure : especially is this true in production from high-pressure wells. Staged separation is desirable for the following reasons as per below:

a. It promotes more efficient separation. Less of the intermediate and heavier hydrocarbons is carried away by the gas : thus they remain in the liquid phase and a larger volume is retained. The liquid will also have a higher API gravity, increasing its value. Furthermore, less effort is required to remove the heavier hydrocarbons from the gas to condition it for pipeline transmission.

b. Less horsepower is required to compress the gas to pipeline pressure. The existing separator design is capable of processing heavy crude oil and has been used widely over the world for so many years, however there is still need to improve the crude stabilization system as to achieve higher separation efficiency and cost effective.

In summary, the main description of crude oil stabilization processes as follow:

- Dissolved gas in the crude oil must be removed to meet pipeline, storage, or tanker RVP specification.
- Removal of the dissolved natural gas components is called oil stabilization.
- Crude oil can be stabilized by passing it through multiple separators in series where the volatile components will vaporize.
- A stabilization column might replace the simple flash-separation stages to achieve the required RVP, but these columns are rarely found offshore.
- Crude oil separation depend on the composition of the fluids, and on their pressure and temperature.
- The pressure of the fluids is controlled by the back - pressure regulator and the temperature may be regulated by expanding the fluid through a choke, by addition of heat in a furnace or by heating or cooling in a heat exchanger. Therefore, separators can be designed to handle fluids according to the fluid composition.
- The main principle used to achieve physical separation of gas and liquids are : Gravity Settling and Coalescing. Any separator may employ one or more of these principle, but the fluid phases must be 'immiscible' (cannot mix), and have different densities for separation to occur.
- In summary, these are variables which aid in the separation of a fluid stream, which are:

  a. Temperature of the fluids

  b. Pressure on the fluids.

  c. Density of the components.
- In addition to using the force of gravity, modern separators make use of other forces to get the best possible separation of oil and gas. The gas that is separated must be

compressed and treated for sales.

Stabilization of the crude oil often requires:

Heat to be added or removed at certain points in the processing train. Crude heating may be required for:

- Emulsion breaking and improved separation of oil and produced water.
- Adjustments of final product vapor pressure and H_2S content.

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 below:

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 2 shows a typical flow scheme of 3 stages separation.

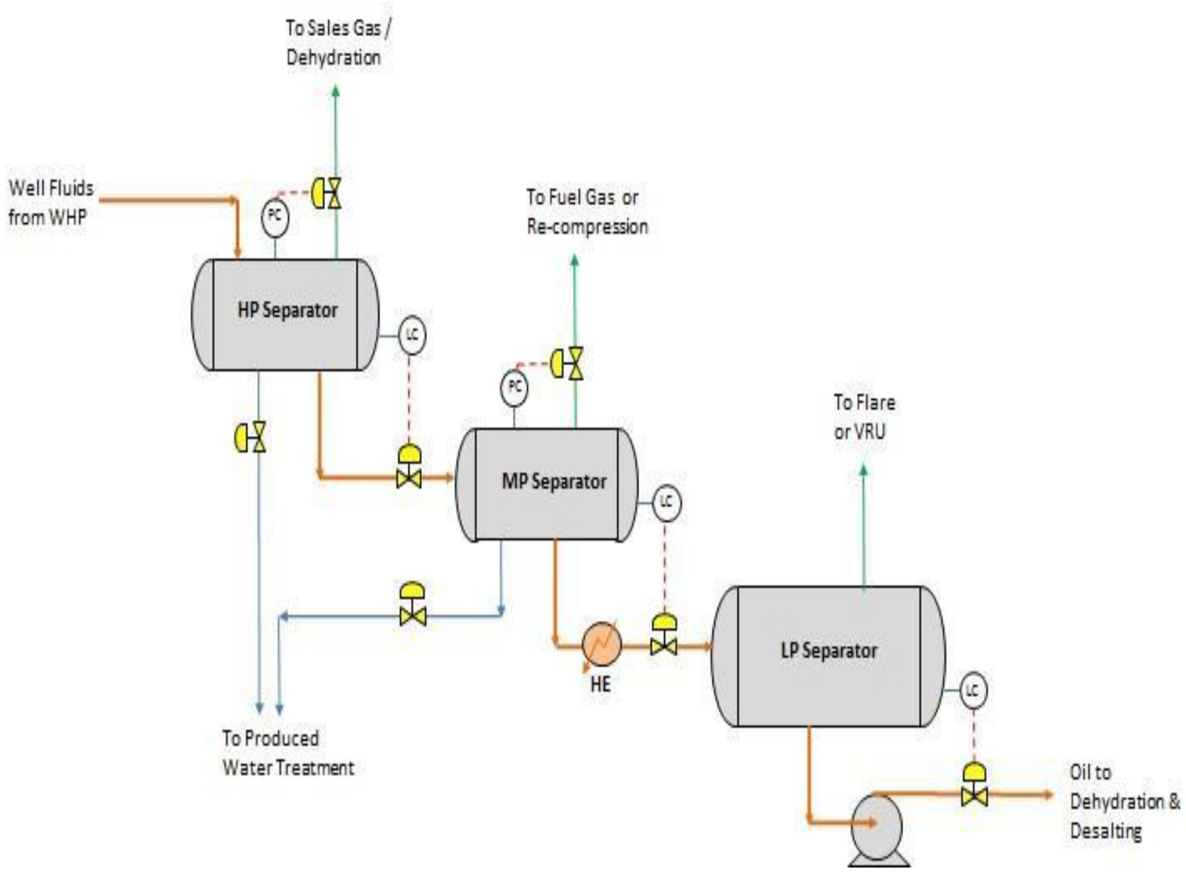

Figure 4. Typical 3 Stages Separation.

- 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).