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TEZĂ DE DOCTORAT

CONTRIBUŢII LA OPTIMIZAREA PROCESULUI DE SEPARARE A GAZELOR ŞI APEI DIN ŢIŢEI

Autor: **ASHOURI AZAM**

Conducător științific: **Prof.dr.ing. IULIAN NISTOR**

Ploiești 2021

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TEZĂ DE DOCTORAT

Rezumatul tezei de doctorat

CONTRIBUŢII LA OPTIMIZAREA PROCESULUI DE SEPARARE A GAZELOR ŞI APEI DIN ŢIŢEI

Summary

CONTRIBUTIONS TO OPTIMIZATION OF SEPARATION PROCESS OF GAS AND WATER FROM OIL

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Introduction

Oil and gas wells produce oil, condensate, hydrocarbon gas, water with dissolved minerals, usually including a large amount of salt; other gases, including nitrogen, carbon dioxide (CO2), possibly hydrogen sulfide (H_2S); and solids, including sand from the reservoir, dirt, scale, and corrosion products from the tubing.

The aim is to produce oil that meets the criteria that specify the maximum water, salt, or other impurities that are permitted. Similarly, to restrict condensation during transportation, the gas must be treated to meet customer water vapor and hydrocarbon dew point requirements.

Oil recovery could be increased by optimizing each phase of the production of oil from the field to the production unit. To reach this aim, using the high-tech equipment and facilities and integrated optimization of the well to surface facilities would be more efficient. However, in this study, optimization of gas oil separation unit is considered.

To optimize the separation process and maximize liquid hydrocarbon recovery, multi-stage separation at decreasing pressure is required. Then to optimize separation process and recovery at the lowest cost the optimum pressure has to determine.

This thesis provides the separation process optimization for production plants of two light and heavy oil reservoir of an Iranian oil field. To achieve optimized separators pressure in the crude oil production reservoir unit, the steady state simulation model of a multi-stage crude oil production plant was carried out by Hysys software.
Also, software simulation can minimize the associated uncertainties and difficulties during field analysis, and most condition changes can be implemented quickly in the unit.
The field has two gathering manifold. The produced crude will transport to a Gas/Oil Separation Plant (GOSP). The heavy and light crude oils are processed separately. Then processed crudes (contains heavy and light oils) and excess gas export separately about 100 km away to the Booster Station (BS) and a tie-in point near BS, respectively. Freshwater is transports through 20 km pipeline from river to the GOSP.
The process simulate to provide an oil export production rate of 90,000 bbl/d of light crude and 45,000 bbl/d simulated of heavy crude.

Chapter 1

CAUSES OF WATER PRESENCE IN THE OIL, STA- BILITY OF WATER-OIL EMULSION

1- CAUSES OF WATER PRESENCE IN THE OIL, STA- BILITY OF WATER-OIL EMULSION

1.1. Introduction

Hydrocarbon fields and reservoirs usually produce water together with hydrocarbons, either from the aquifer, a zone beneath the hydrocarbon layer, or from the same layer or formation with the oil and gas. Oil producing wells sometimes produce large volumes of water with the oil. The water produced during oil production is either produced as free water, and so it will settle out fairly quickly, or the water may be combined with oil in the form of emulsions.

1.2. Water presence in the oil

In the formation, the mineral matrix pores contain the natural fluids at chemical equilibrium. Because reservoir formation is mainly of sedimentary origin, water was available at the time of rock appearance and trapped in the pores of the rock. Water could also immigrate to the hydraulic pressures lead by geological phenomenon that shapes the reservoirs.

1. 2.1. Primary production

Today oil companies produce an average of 3 barrels of water for each barrel of oil from their depletion reservoir each year more than $40 billion spent dealing with unwanted water. In many cases, innovative water control technology can lead to significant cost reduction, and improved oil production.

1. 2.2. Importance of produced water

Since the produced water is typically not a source of income, the focus on the prediction of water flow, the advancement of technology and the implementation of engineering has not traditionally been a big issue of engineering in oil and gas production.

1.3. Oil Treatment

Crude oil is rarely produced on its own since it usually blends with water. Water causes many issues and typically raises the production cost of oil unit. The water contained in the production unit should be: Separated from the hydrocarbon (oil & gas), Go through treatment process, Disposed and/or injected appropriately. All these steps increase costs.

1. 4. Emulsion

An emulsion is the oil and water mixture which are not separated just by gravity. In normal emulsion, water droplets are dispersed in the oil that continuous phase is oil and water forms the dispersed phase.

1. 4.1. Type of emulsions

Emulsions are normally categorized in three main classes: Water in crude oil, Crude oil in water, Combined, multiple or complex emulsions.

1. 4.2. Emulsion Characteristics

Either the drop size should be small enough in a true emulsion which imposes due to thermal collisions with the molecules of continuous phase create Brownian motion and avoids settling. Alternatively the properties of interfacial surfaces have to be changed by surfactants, dispersed solids, or the other semi-soluble substance that decreases the free energy of the surface sufficiently to avoid it from serving as a driving force.

1. 4. 3. Viscosity of emulsions

Emulsion viscosity could be considerably bigger than both oil or water viscosities since emulsions exhibit non-Newtonian behavior. This activity is a consequence of crowding of droplets or structural viscosity. When the viscosity is a function of shear rate, a fluid is called non-Newtonian. Oil and gas industry emulsions represent the shear thinning or pseudo-plastic fluids at a particular volume fraction of the aqueous phase (water cut) (i.e., as shear rate increase will decrease viscosity).

1.4.3.1. Interfacial viscosity

The last section discussed mainly bulk viscosity of emulsion. Interfacial viscosity or fluid viscosity at the O/W interface is a closely connected and highly prominent property, mainly for demulsification. W-in-O emulsions shape hard interfacial layers encapsulating the water droplets, as described previously. By decreasing IFT and raising interfacial viscosity, such interfacial layers can stabilize the emulsion. During the coalescence of aqueous droplets, the layers delay the rate of oil-film drainage, thus significantly decreasing the rate of emulsion breakdown. The rate of oil drainage relies on the viscosity of interfacial shear. High interfacial viscosities consider- ably lower the rate of liquid drainage and therefore has a stabilizing impact on the emulsion.

Emulsion interfacial viscosity plays too essential function in demulsification.

1. 4.4. Formation of Emulsion

To form crude oil emulsion first oil and water (brine) has to contact with each other than adequate mixing occurs and an emulsifying agent has to present. For the creation of an emulsion, the mixing quantity and the presence of the emulsifier are important.

4.5. Emulsion's Stability

An emulsion is an unstable phenomenon from the thermodynamic point of view, since there is a normal tendency for a liquid / liquid mixture to separate and reduce the interfacial area and thus the interfacial energy. However majority of emulsion systems show kinetic stability (i.e., they are stable in a certain period of time).

1. 4.5.1. Differential Density

One of the factors determining the rate of water droplets settling through the continuous oil process is the density difference between oil and water stages. The higher gravity difference caused the faster settling into oil process as water droplets. Heavy oils prefer to keep water droplets in suspension longer (high specific gravity). Light oils (low specific gravity) tend to cause the bottom of the tank to settle for water droplets. Therefore, the higher the density difference between the oil and water, the easier settling water droplets.

1. 4.5.2. Size of Water Droplets

The rate of moving the water droplets through the oil phase also influences the size of the dispersed water droplets. The bigger droplet will settle more rapidly out of the oil phase. In an emulsion, the water droplet size depends on the degree of agitation that the emulsion is subjected to before treatment. Water droplet sizes can minimize flow through pumps, chokes, valves, and other surface equipment.

1. 4.5.3. Viscosity

As oil viscosity increases, greater agitation is needed in the oil phase to shear the bigger water droplets down to a smaller size. Thus as viscosity increases, the size of the water droplets that must be removed to meet water cut specifications for treatment system increases.

1. 4.5.4. Interfacial Tension

Interfacial tension is the force of holding water surfaces and oil phase together. The interfacial tension between oil and water is low when an emulsifying agent is not present. Water droplets combine quickly upon interaction when interfacial tension is minimal. However, they increase the interfacial tension and prevent water droplets coalescence while emulsifying agents are present. In separation, something that lowers the interfacial stress would assist.

1. 4.5.5. Presence and Concentration of Emulsifying Agents

They become more stable as emulsions age, and separation of the water droplets becomes more difficult. The time required to increase stability change widely and depends on many factors.

1. 4.5.8. Agitation

The water drop size is determined by the form and intensity of agitation applied to an oil-water combination. In a production method, the more turbulence and shearing activity present makes smaller water droplets and the emulsion more stable. The "stability" of emulsions defines the variables above. It can take weeks or months to separate certain stable emulsions if left alone in a tank with no care. In only a matter of minutes, other unstable emulsions can separate into relatively clean oil and water phases. Within the continuous oil process, little water droplets occur.

1. 4.6. Emulsifying Agents

It's should be noted that when studying emulsion stability of crude oil and water mixture, only agitation cannot produce an emulsion without the presence of an emulsifying agent,. When the pure oil and water are mixed and settled in a bottle, they separate easily.

1. 4.6.1. Surface-Active Agents

A material with a surface-active tendency is an emulsifier or emulsifying agent in the process. Compounds that are partially soluble in both water and oil are surface-active agents (surfactants). They have a part that is hydrophobic with an attraction for oil and a part that is hydrophilic with an attraction for water. Surfactants have the tendency to be concentrated at the O-W interface, where they establish interfacial films, because of such a molecular structure. This typically causes a reduction of IFT and triggers the dispersion and emulsification of droplets.

1. 4.6.2. Finely Divided Solids

Fine solid particles could be used as a mechanical stabilizer.

4.7. Demulsification

Due to the large range of crude oils, produced brines, separation vessels, chemical demulsifiers, and product specifications and requirements, demulsification methods are specific. In addition, emulsions and conditions alter by time, which leads to the treatment's complexity. Applying heat and a suitable chemical demulsifiers to promote destabilization is the most common form of emulsion treatment, preceded by a settling time with electrostatic grids to increase gravitational separation.

1. 4.7.1. Thermal Methods

Heat and increasing temperature decrease crude oil viscosity and increases water phase settling rate. Due to decreased interfacial viscosity, higher temperatures also cause the rigid films to destabilize. In addition, due to the obvious higher thermal energy of the droplets, the water droplet coalescence frequency is increase.

1. 4.7.2. Mechanical methods

There is much type of mechanical methods and equipment to break emulsion, like as:

Free-water knockout are used to separate free-water of the produced oil and water. In these drums, a part of gas can be separated. Free-water knockout drums are complementary devices that help the emulsions treatment process.

Three-phase separators are used to separate oil, water and gas. These separators classified as horizontal or vertical. To improve the separation, each separator is sized with a fixed retention time.

1. 4.7.3. Electrical methods

For emulsion treatment, electrostatic field are also used.

1. 4.7.4. Chemical methods

Adding demulsifiers is the usual form of treating emulsion. These chemicals are intended to neutralize the emulsifying agents' stabilizing effect. Demulsifiers are surfacetive compounds that once added to the emulsion, migrate to the O/W interface, rupture or weaken the rigid film, and increase water droplet coalescence. Usually, they are surface-active agents, so their excessive application will reduce the water droplets' surface tension and generate very stable emulsions. A properly specified chemical for the provided emulsion is needed for optimum emulsion breaking and treating with a demulsifiers; sufficient amount of the chemical; sufficient mixing of the chemical in the emulsion; and adequate retention time in separators to settle water droplets.

1. 4.7.4.1. Demulsifiers selection

Bottle Test

From all of the chemical selection tests, this is one of the most common. However, Emulsion-breaking chemicals are most commonly tested with a bottle test that involves mixing and observing the effects of different chemicals with emulsion samples. These tests are useful in removing such chemicals and choosing those that seem to be more effective.

Field Trial

A field trial to assess the chemical's ability to function in a complex system should be performed after selecting a suitable demulsifiers candidate.

Field Optimization

A full-scale field optimization is conducted after a practical field experiment. The chemical output is regularly tracked here, as are the potential side effects of under- or overdosing, such as the build-up of the separators. It could be that for each area, injection positions and dose rates may have to be optimized if the field produces via two or more platforms.

Changing the Demulsifiers

As crude characteristics change over the field life, the chemical demulsifiers output will also change. Usually, it is difficult to break the emulsions when fields first produce water. The emulsion stability and even the emulsifying agents can change as the field ages and water cuts in- crease. It is therefore normal to investigate the output of demulsifiers every 2-3 years. It may be necessary to evaluate demulsifiers output more regularly in certain instances where a step change in water cutting is observed.

In most situations, all that is needed to decide whether the current chemical is still optimal is a simple bottle test. If not, it is possible to perform a full bottle test to find a more successful chemical.

Demulsifiers Troubleshooting

Overdosing is the most common concern with demulsifiers. Poor treatment, dirty water, and the build-up of interface pads are all risk factors of an optimum chemical overdose.

5. Emulsion Treating Methods

Oil-water emulsions have to be isolated quite totally in the summer before cure oil could be transported and further refined. The destabilization of emulsifying films around water droplets certainly requires the separation of the emulsion into oil and water.

1. 5.1. Emulsion prevention:

During oil production, it is almost infeasible to remove emulsions; nevertheless, it is possible to minimize emulsion problems by applying appropriate operational best practices.

In working procedures, the following key considerations must be included.

Solids management: Fine solid particles stabilize emulsions and attempts should be taken during processing to eliminate solid contaminants. These solids include asphaltenes that can be managed by effective management of asphaltenes, dispersants, scales that can be decreased by scale inhibitors, and waxes that can be controlled by applying heat.

C***orrosion management***: With efficient corrosion inhibitors, the corrosion products could be minimized.

Acidizing: Acid stimulation could create very severe emulsions; acid jobs must therefore be planned with detailed planning and engineering design, and the field results should be tested. The acid job design must introduce efficient demulsifiers at reasonably high concentrations, apply shared solvents, and eliminate fines and precipitates in the course of acidizing operations in order to prevent emulsion upsets.

Mixing or turbulence: Before mixing and making turbulence, chokes and all other equipment and devices like pumps must be verified, tested and managed. The degree of fluid mixing that passes through these systems depends on the rate of energy dissipation, i.e. how easily and in what amount this energy is brought to the system. While a medium level of mixing is appropriate and helpful, post water separation, excessive mixing will cause severe emulsions or even reemulsification. Another point of controlling the mixing is in artificial gas lift operation with the optimum gas injection.

Chemicals compatibility: More chemicals are gradually being utilized to enhance oil recovery and process efficiency. The chemical might trigger the emulsion problem itself. Compatibility experiments and analysis must be conducted with candidate chemicals applied during production (from reservoir to separation plants), and their emulsion-forming tendencies have to be investigated and evaluated.

1. 5.2. Emulsion treating guidelines

Highly operations specific: Every producing stream is unique and specific and has to be analyzed separately to determine the best separation strategy. Laboratory experiments with real field samples are recommended; however, data from offset wells and/or fields shall be applied as estimates.

Experience and engineering analysis: The planning and engineering work for future emulsion treatment must begin during the first phase of separation plants design. For instance, if water cut is estimated to increase, preventive and predictive measures must be considered in the design phase to increase water handling capacity.

Data requirements: Operational practices and experience as well as laboratory analysis are necessary to establish and identify emulsion challenges and propose solutions. Pilot and onsite sampling, test and analysis shall define and decide about the appropriate treatment requirements. Bottle tests have certain restrictions in estimating dosage rather are suitable for screening and trend analysis.

Treatment capacities would be improved for current operating separator trains by re-engineering and retrofitting. For instance, internal packing shall be installed in the separator to enhance emulsion resolution.

The Balance between chemical, thermal, mechanical and electrical: Monitor the demulsifiers and other related operating data (e.g. output rate, temperature, water cut, and cost) in a certain time frame for current systems. The acquired data is useful for the study of demulsifiers dosages and unit-demulsifiers costs (e.g. during the summer and winter) and can recognize some behavior associations that could be cause of the emulsion upsets and underlying issues. This data is also really useful for the optimization of the emulsion treatment method.

Optimization: Check regularly the method of emulsion-treatment as conditions change. The frequency of the assessment depends on several factors, such as the relative cost of heating, demulsifiers, capability limitation and the requirements for manpower.

FIGURE 1-12: EMULSION TREATING GUIDELINE

1. 5.3. General Considerations

Until the physical characteristics of oil and water have been determined, and the impact of available chemicals on the emulsion has been studied, treatment procedures and equipment should not be chosen. It is considered that the water remaining in the oil after the free water has settled out is in an emulsified condition. One or more treatment procedures extract emulsified oil. Treatment refers to any procedure for extracting oil from water and foreign pollutants brought along with it.

1. 5.3.1. Chemical Addition

The purpose of the treatment of chemicals is to promote coalescence in order to separate the oil and water quickly. At the oil-water interface, surface-active agents are absorbed; the hard film (skin) around the water droplets is broken and the emulsifying agent is displaced and the emulating agent is pushed back into the oil process.

Amount of Chemical
Bottle tests do not reliably predict the quantity of chemicals required.

The cases where the injection is not recommended
The chemical is normally injected into a connection which is welded to the side of the pipe, but that's not recommended in case flow rate is low (less than 3 ft. /sec) or when the laminar flow regime is experienced.

Bottle Test Considerations
The product that results in the most rapid and complete phase’s separation at a minimum concentration is the best demulsifiers. The output requirements and the actions of the device will deter- mine the significant characteristics of the bottle test.

Water Drop-Out Rate*:* when water cut is high in crude oil, is required a chemical that causes rapid water drop-out rate to operate the plant normally. When FWKOs are used the most important factor can be water drop-out speed. In treatment, chemicals with quick water drop-out properties are often insufficient. The water drop-out rate in selecting the best demulsifiers may be of limited importance in low water volume systems (fields with facilities having longer than aver- age treatment time). The water drop-out rate should be noted and reported in all situations.

Sludge: Crude oil may destabilize in ship tankers over time, because heavier components of crude oil, such as emulsified oil with sands, are separated at the bottom of the storage tank. These components at the bottom of the storage, such as water-in-oil emulsions, sands and insoluble heavy metals, will increase density, increase viscosity and decrease flow capacity. This dense and viscous mixture is known as oil sludge.

Interface*:* One which has shiny oil in contact with water is the desired interface (mirror interface). The interface should be as good as, if not better than that created by the chemical being replaced while using a new chemical.

Water Turbidity*:* The clarity of the water in the bottle test is very difficult to analyze and correlate with the operation of the facility. Any association can be predicted when the chemical effects in the bottle are evident and repeatable. Clearwater is certainly the expected result.

Oil Color: As compared to the bright color of treated oil, emulsions have a hazy look. The color appears to brighten, as oil emulsion separates. Brightening oil could be motivating, but if used as the main requirement for chemical selection, it can also be disappointing.

Centrifuge Results*:* Centrifuge results have a significant quality in the final decision. Making a centrifuge grind out to determine the final amount of BS&W brought into oil correctly is often advisable.

Chemical Selection

Until chemical selection can be made, a deeper overview of process facilities is required to contribution of treatment. A fast-acting chemical is needed if little agitation is available. The water drop-out rate would be very critical if an FWKO vessel is used. The chemical must operate at ambient temperatures if heating is unavailable. Different vessels types need different chemical procedure.

Settling Tank or "Gun barrel": As both tanks typically have a high volume-to-throughput ratio, speed is not very significant. Over a pretty long time, the chemical can continue to function. An interface layer often grows, but at some appropriate thickness, it typically stabilizes. The treatment method is often supported by an interface layer in a Gun barrel in that it serves as a barrier for solids and residual emulsions. New oil including, a demulsifiers that passes through the layer of the interface helps to control the interface and avoids unnecessary accumulation.

Vertical Heater-Treater*:* The velocity of chemical action is significant because the volume-to-through-put ratio is typically lower than the higher-throughput gun barrel or settling tank, the interface layer is more difficult to stabilize, so more complete treatment is required in a shorter period of time.

In controlling the interface, control of solids may be necessary.

Horizontal Heater-Treater*:* Due to the high through-put, the speed of chemical action is important. The wide area and shallow depth of the interface demand that the interface be reasonably clean. Because only very little interface accumulation can be tolerated by this treater, the chemical treatment should be complete. Since solids appear to accumulate at the interface, the chemical must also de-oil any solids efficiently so how they can settle by gravity.

Chemical demulsification mechanisms*:* Chemical demulsification is quite complicated. The physico-chemical mechanism for the performance of chemical demulsifiers is subject to many theories and hypotheses. The only simple generalization of demulsifiers is their high molecular weight (approximately similar to natural surfactants) and appears to produce an emulsion opposite to stabilized by natural surfactants if used as emulsifying agents. There are hundreds of products patented and produced as demulsifiers of oil. However, there is still a lack of good knowledge of the functionality and efficiency of demulsifiers in breaking and treating emulsions, but there are some general rules for demulsifiers and their capabilities to break emulsions.

1. 5.3.2. Settling Time

Settling time is needed after the addition of treating chemicals to facilitate the gravity settling of the coalescing water droplets. Three-phase separators, FWKOs, heater-treater, and gun barrels with an internally or externally gas boot provide emulsion-treating devices designed to provide adequate time for free water to settle. The differential density between oil & water, the oil viscosity, water droplets size and relative consistency of emulsion influence the time taken for free water to settle.

1. 5.3.3. Coalescence

The coalescence process is time dependent in oil treatment systems. Immediate coalescence usually happens when two droplets collide in the dispersion of two immiscible liquids. If turbulent pressure fluctuations are exposed to droplet and kinetic energy of oscillations caused in coalescing droplet is greater than adhesion energy between them, contact will be broken before coalescence is completed.

1. 5.3.4. Heat Effects

The conventional method of separating the phases is heating the incoming oil-water stream. In accordance with Stokes' law of settling, the addition of heat decreases the viscosity of the oil process, allowing faster settling speeds. The addition of heat deactivates or dissolves emulsifier in certain emulsifying agents, such as paraffin and asphaltenes, and thus increases its solubility in the oil process. Treating temperatures usually range from 38-70 ^{o}C (100 to 160o F). The temperature can be as high as 300o F (150 ^{o}C) in treatment of heavy oil.

1. 5.3.5. Electrostatic Coalescers

By exposing w/o emulsion to a high-voltage electrical field, tiny water drops coalescing distributed in the oil can be achieved. In heavy crude oil Due to the high viscosity of the continuous oil phase and the low density difference between oil and water phases, sedimentation of water drops in heavy crude oil is extremely time consuming.

5.3.6. Water Droplet Size and Retention Time

While this term is squared in the settling equation of Stokes' law, the droplet diameter is the most critical single parameter to control to help in water settling. The coalescence equation indicates that the oil–water interface zone is where nearly all of the coalescence occurs. Except for providing some minimal time for initial coalescence to occur, in- creasing retention time in a crude oil treating system may not be very cost-effective.

1. 6. Recommendations

Finding strategies to prevent the issue in the first place is the most successful therapy.

Chapter 2

WATER AND GAS SEPARATION METHODS FROM CRUDE OIL

1. Introduction

Surface produced hydrocarbon and fluids have complex properties and are mixtures of several compounds of hydrogen and carbon, each with uneven and variant densities, vapor pressure and other physical properties. The O/G separators are categorized into horizontal, vertical, or spherical separators depending on the vessel configurations. In terms of fluids to be separated, the O/G separators are grouped into G/L two-phase separator or O/G/W three-phase separator.

Regarding separation operation, the O/G separators could also be classified into primary phase separator, test separator, high-pressure and low pressure separators, de-liquidizer, de-gasser, etc. O/G separator is also called de-liquidizers or de-gassers, depending on a particular application. The de-liquidizer is applied to separate dispersed droplets from a stream of bulk gas, while the de-gasser is designed to remove contained bubbles of gas from the stream of bulk liquid.

This chapter will address the separation methods, the mechanisms of two and three phase separation, multi stage separation, factors effecting on separation and oil production separator.

2. 2 . Separation Mechanisms

Three basic separation methods are: Gravity Separation, Centrifugal separation, Coalescence.

To separate oil from gas: The primary concern is recovering oil from the gas stream as much as possible. The separation is based on the density difference or gravity differential between oil and gas. This difference in density becomes small at the high operating pressure of the separator (gas law). Oil density is about eight times the gas density. For the liquid particles to disperse and settle down, this may be an adequate driving force.

To remove gas from oil: The aim here is to recover and collect any gas that can be trapped or " locked " in the oil without a solution. Settling, agitation, and applying heat and chemicals are suggested methods to accomplish it. **Table2-1** summarizes the primary functions of an oil/gas separator, as well as the methods of separation.

2. 2.1 . Gravity Separation

In order to separate water droplets from the continuous oil phase, most oil-separating equipment depends on gravity, since water droplets are heavier than oil they displace. However, a drag force created by the downward movement of the droplets through the oil resists gravity. A constant velocity is achieved when the two forces are equal that can be determined as **Equation (2-1)** from Stokes' Law.

2. 2.1.1. Advantage and Disadvantage

The most remarkable advantages of the gravitational methods are their cost efficiency and excellent reduction in some instances. Gravity separation is an appealing operation of the unit as it typically has low capital and maintenance costs, uses few if any chemicals that may cause environmental problems, and the recent advent of new equipment increases the potential range of separations.

2. 2.2. Centrifugal Separation

This technique separates oil and water by centrifugation.

Centrifugal O/W separator units are installed to treat waste water and for cleaning of oil spills on river or sea. It is also applied for filtering diesel and lubricating oils by removing the waste particles and impurities.

If a gas flow containing liquid mist flows in a circular motion at reasonable high velocity, centrifugal force displaces the liquid mist outward against the walls of the container. One of the major useful techniques of separating liquid mist from gas is the centrifugal force.

As shown in **Figure 2-1**, the design of this device generally includes a moving cylindrical container inside a lager one which is stationary. The mixed oil-water liquid is pumped with a constant speed, at a certain angle in the system, which creates a spinning vortex1. As a result of rotation, the denser liquid which is water move to outside and the lower-denser one moved to center of rotation.

2. 2.2.1. Advantages and Disadvantages

The centrifugal separator is more efficient than other devices using gravitational forces.

2.3. Coalescence

Coalescing is one of the separation methods that the liquid-liquid and liquid-gas separation process industry use worldwide.

2. 2.3.1. Advantages and Disadvantages

The main advantages of coalescers are low capital and operational expenditures, minimal maintenance work, low energy consumption and compact and less installation space.

2. 2.4. Electrostatic Separation

Electrostatic separation, with a lower percentage of water content, is often used to isolate crude. There is a mesh of wires inside the separator where an electrostatic field is applied to the liquid. Electrostatic grids are an effective and efficient way of breaking and treating emulsions. The droplets move about rapidly and collide with other droplets and coalesce.

2. 2.4.1. Advantages and Disadvantages

This method has many advantages, but also flaws. It is usually applied with chemical and heat addition. It is used with reduced temperature which results in fuel economy, less problems with scale and corrosion products. The use of this technique leads to the reduction of emulsion-breaking chemicals use.

2. 2.5. Chemical Absorption O/W Separators

Chemical absorption O/W separators are being filled with a chemical medium developed to absorb oil while rejecting water molecules. Where the oil is connected to the medium, de-pressurized oily condensate drains into the chemical absorption separator. Afterwards clean water flows to drain.

2. 2.6. Filtration Separation

This is a more prevalent way of separating a liquid from an insoluble solid.

2. 2.7. pH Adjustment Separation

Basic pH provokes O/W emulsions, and acidic pH produces W/O emulsions.

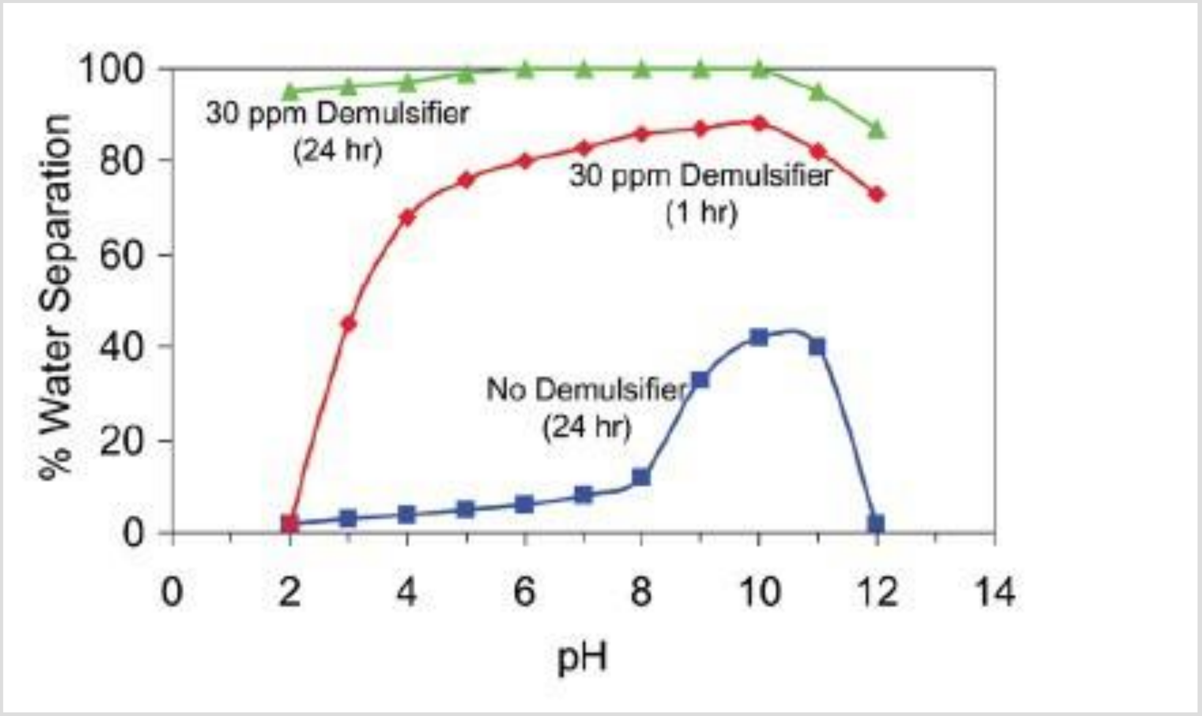


FIGURE 2-3: GRAPH SHOWING THE PERFORMANCE OF DIFFERENT DEMULSIFIERS (31)

2. 2.8. Heating Treatment

The process of heating treatment consists of transforming water into steam by heating the oil to 200°C. Moreover, the heating process reduces the oil viscosity and then facilitates the escape of water steam produced. Heating increases molecular movement, which enhances the coalescence of water droplets. It might accelerate demulsifiers action. It also might increase the gravity difference between oil and water to enhance the gravimetric separation.

2. 2.8.1. Advantages and Disadvantages

Heating accelerates emulsion breaking. A part of the oil is also vaporized. It can be condensed later in the process with the gas. However it still causes a loss of volume. When crude oil is heated, some gas is liberated and causes a problem of treatment and requires appropriated equipment. This process is costly because of the fuel required for the heating and the treatment of the gas liberated.

2. 2.9. Vaporization O/W Separators

Vaporization O/W separators applies an external heat source, for example, an electric or steam heaters, to boil-off the water. The remaining crude is then drained into a container for proper disposal. Vaporization separators will effectively and efficiently separate almost all quantities of oil, however, the design materials O/W separator also have a major impact since the oily waste might cause corrosion issues.

2. 2.10. List of Separation Techniques

Below is the full list of separation techniques for oil, gas and water separation, however, they will not be discussed in more details in this report.

2. 3. Separation Theory

The liquid phase treatment for three-phase separators is, however, different from that used for two-phase separators.

4. Two and Three Phase Separator

In general, well flowing streams are two phases: under a relatively high pressure, vapor and liquid. As an oil and gas mixture which is partly free and partly in solution, the fluid emerges.

Two-phase separators: which are used to separate gas from oil in oil fields, or gas from water for gas fields

Three-phase separators: it is used to separate the gas from the liquid phase, and water from oil.

2. 4.1. Separator Configurations

For separator configuration selection, factors to be considered include:

- How well can international materials (e.g. sand, mud, products of corrosion) are handled?
- How much plot space is needed?
- Is this separator going to be too tall for transport?
- Is there enough interface surfaces for three-phase separation؟
- Can heating coils or sand jets be combining if needed?
- How much surface area is required for the separated liquid degasification?
- Should liquid flow surges be treated without significant level changes?
- Is large volume retention of liquid necessary?

2. 4.2. Two-Phase Separators

Separators are categorized as two phase if they separate gas from the total liquid stream. Majority separators have a conventional design, engineered in either horizontal or vertical configurations.

Horizontal separators are well known as being more size efficient however, they have less flexibility of variations in the inlet stream composition and challenging to install on offshore platforms.

2. 4.2.1. Horizontal Separator

Stream enters the separator and knocks the inlet diverter, leading a sudden variation in momentum and the initial gross separation of gas and liquid. Gravity induces liquid droplets to leave the gas stream and fall to the bottom of the vessel for liquid gathering.

2. 4.2.2. Vertical Separator

When liquid reaches equilibrium condition, the gas bubbles flows counter to the direction of liquid flow and eventually migrate to the vapor space.

2. 4.3.Three-Phase Oil–Water–Gas Separators

Water produced with oil typically exists in part as free water and part as an emulsion of water-in-oil. It should be eliminated or reduced to the minimum in all situations because it affects the price of crude oil, but O/W instead of W/O emulsion will develop in certain instances where the water-oil ratio is very high. The settled water that separate from oil by gravity is known as free water created with the oil.

2. 4.3.2. Vertical Three-Phase Separators

The horizontal separators are usually favored over vertical separators due to the flow geometry that promotes phase separation. However, in some cases, considering the later process related advanced stages, the engineer may be required to choose a vertical separator instead of a horizontal separator.

2. 4.3.3.Internal Parts of a Separator

Separators operate based on the concept that three components have specific densities, allowing them to categories with gas on the top, water at the bottom and oil in the center while travelling slowly.

2. 4.3.3.1.Inlet Device

It's positioned in pre-separation segment for preliminary phase separation that separates the liquid bulk from the gas.

2. 4.3.3.2. Baffles Downstream the Inlet Component

It is the secondary separation section to improve flow distribution. It helps to remove smaller particles of liquid thru gravity settling and it depends significantly on the decreased gas velocity and reduced gas turbulence.

2. 4.3.3.4. Mist Extraction Unit Placed in Gas Space

It helps more to decrease liquid content in the bulk gas stream. Mist extraction segment for removing the entrained liquid drops from gas, which is not separated in the secondary separation segment.

2. 4.3.3.5.Vortex breaker

Vortex breaker is used to avoid gas carry under at the outlet of liquid phase and liquid from sucking any gas into the liquid exit pipe. Typically, the liquid exit pipe is centered at the bottom of the vessel.

2. 4.3.3.6. Liquid level/Interface Detection and Control

Sufficient control devices such as the liquid dump (discharge) valves, gas pressure valves, and safety relief valves.

2. 5.Selection Considerations

The geometry and physical and operating characteristics provide advantages and disadvantages to each kind of separator. In summary, horizontal vessels are more economical for a typical O/W separation, especially in case of issues with emulsions, foam, or high gas–liquid ratios.

2. 6. Methods Applied to Separate Oil from Gas

Currently, some new ideas are being established in which fluids gas are separated at upstream of the main separator. Based on centrifugal and turbine technology, these systems have extra benefits as they are lightweight and motion-in-sensitive, making them suitable for floating production facilities.

2. 6.1. Density Contrast (Gravity Separation)

Natural gas is obviously lighter than hydrocarbon liquids. Tiny liquid hydrocarbon particles momentarily suspended in natural gas streams will if the gas velocity is too slow, settle out of the gas stream by density contrast or gravity force.

2. 6.2. Impingement

If a flowing stream of liquid-containing gas is impacted by mist against a surface, the liquid mist might stick to the surface and coalesce.

2. 6.3. Change of Flow Direction

When the direction of gas stream containing liquid mist is changed suddenly, inertia allows the liquid to proceed in the original direction of flow.

2. 6.4. Change of Flow Velocity

With either a rapid increase or decrease in gas velocity, liquid and gas separation may be done. Both conditions make use of the difference between gas and liquid inertia.

2. 6.5. Centrifugal Force

When a gas stream carrying and transporting liquid mist flows at a sufficiently high velocity in a circular motion, the centrifugal force pushes the liquid mist outward against the container walls. The liquid coalesces into increasingly bigger droplets and gravitates finally to the liquid part underneath.

2. 7. Methods Applied to Remove Gas from Oil

It is necessary to extract all non-soluble gas from oil in the course of field processing due to value of natural gas. Methods used in oil and gas separators to remove gas from crude oil are discussed below:

2. 7.1.Agitation

Moderate, controlled agitation that can be defined as sudden force movement of crude oil is typically helpful in extracting non-solution gas that can be mechanically locked by surface tension and viscosity of oil in the oil. Usually, the agitation will allow the gas bubbles to coalesce in less time and detach from the oil than will be necessary if agitation were not applied.

2. 7.2. Heat

It is an energy that results in a temperature difference when moved from one system to another. This decreases the oil's surface tension and viscosity and thus helps to release gas hydraulically contained in oil. Passing it into a heated-water bath is the more efficient form of heating crude oil. The efficacy of heated-water bath is improved by a spreader plate which can disperse crude oil into small streams or rivulets. The upward flow of oil creates slight agitation thru the water bath that is useful in coalescing and separating entrained gas from oil.

2. 7.3.Centrifugal Force

Centrifugal force that could also be called as a fictional force, peculiar to a circular path particle which has the identical intensity and dimensions as the force which holds the particle in its circular path (centripetal force).

8. Separator Performance

The efficiency of separation can be measured by rates of liquid carrying over and gas reduction, which is determined by several variables, such as: flow rates of phases, fluid physical and chemical properties, vessel design and configuration, internal systems, control system, etc.

2. 8.1. Vessel Internals

Vessel internals will significantly impact the operating performance of an O/W separator thru the following ways: flow distribution, drop/bubble shearing and coalescence, foam creation, mixing.

2. 8.2. Performance Impediments

2. 8.2.1. Foaming

As pressure on some forms of crude oil is decreased, as the gas goes out of the solution, tiny gas bubbles are encased in a thin layer of oil. This can result in the dispersion of foam or froth in oil which produces what is called "foaming" oil.

2. 8.2.2. Paraffin

By partially filling separator and blocking the mist extractor and fluid passages, wax/paraffin deposition in oil/gas separators decreases their performance and can make them unusable. By using steam or solvents, paraffin may be effectively removed from the separators.

2. 8.2.3. Solid Particles and Salt

If sand and other solid particles are generated continuously with the suitable fluids in large amounts, they should be separated before fluids reach pipelines. Salt can be extracted by combining water with oil and water could be separated from oil and drained from separator after the salt dissolution.

2. 8.2.4. Corrosion

Well fluids and streams are normally very corrosive and trigger equipment to fail during development and production phases depending on the composition and components. Hydrogen sulfide and carbon dioxide are the most corrosive components. In the well fluids, the presence of H2S and CO2 might be in amounts up to 40 to 50% of the gas volume, from a sample.

2. 8.2.5. Sloshing

Liquid contents will be excited in an O/G separator due to the action of waves or ocean current on a floating surface, which causes internal fluid sloshing movements. In long horizontal separators, it is especially an issue.

2. 8.2.6. Level Controls

Stable level control of the O/W and G/L interfaces is essential for efficient separation.

9. Factors affecting separation

Many fundamental factors like the influence on the process and L/G separation in a separator: pressure - P, r operating temperature- T, fluid stream composition, x%s

2. 10. Stage Separation

Usually, the single-stage separation is not desirable. By separating the gaseous and liquid hydrocarbons into vapor and liquid phases in two or more equilibrium flash points at progressive lower pressures, a more stable stock tank liquid can be obtained. Also, liquid recovery is enhanced.

2. 11. Separators Application in Oil and gas

A pressure vessel used to separate well fluids formed from oil and gas production into gaseous and liquid stream is defined by the term separator in oilfield terminology.

2. 11.1. Test Separators and Well Test

For comprehensive analysis and low measurement, test separator is applied to isolate the well flow from one or more producing wells.
When the primary process is not working, test separators can also be used to generate fuel gas for power generation. Alternatively, to conserve weight, a three phase flow meter may be used.

2. 11.2.Production Separators

The primary separators shown here are forms of gravity. On the right, around the first stage separator, is the primary components. The manufacturing choke lowers the high pressure manifold and first stage separator well pressure to around 3-5 MPa. Inlet temperature is normally in the range of 100 - 150 ºC.

2. 11.3. Low-Temperature Separator:

Low temperature separator is a special system thru which high pressure production stream is jetted into the vessel via a valve that decreases the choke or pressure to slightly lower the separator temperature below well-fluid temperature. Via the Joule-Thomson effect of expanding fluid, the temperature reduction is achieved when it flows into the separator thru the pressure-decreasing choke or valve. In the vapor state, the lower operating temperature separator condition triggers vapor condensation which will otherwise escape the separator. Produced oil need stabilization to avoid excessive evaporation in the storage tanks.

2. 11.4 Metering Separator:

A single vessel can accomplish the purpose of separating well stream into three phases, oil, gas and water and measuring the liquids. This vessel is generally referred to as metering separator and is available for use in two and in three phase flows. These units are also applied for the precise calculation of foaming and heavy viscous oil.

2. 11.5. Second Stage Separator

The separator for the second stage is kind of similar to the high pressure separator for the first stage. It also handles input from wells connected to the low pressure manifold in addition to output from the first level.

For reheating the O/W/G mixture, an oil heater is normally placed between the first and second stage separators. It makes it easier for water to be separated when initial water cut is high, and the temperature is low. The heat exchanger is usually a type of tube/shell system where oil passes through tubes mounted inside an outer shell in a heating medium.

2. 11.6.Third Stage Separator

A two phase separator, also named a flash drum, is the final separator. The pressure is now decreased to about 100kPa of ambient pressure so that the last components of heavy gas will be released. In some processes with low initial temperature, to obtain good separation of the heavy components, it may be essential to heat the liquid again in a heat exchanger before the flash drum. There are control loops for level and pressure.

As an alternative, the two-phase separator may be a knockout drum when output is primarily gas, and residual liquid droplets must be separated out (K.O. drum)..

2. 11.7.Coalescer

After the third stage separator, the oil will flow to coalescers to remove the final quantities and droplets of water. Water content could be decreased to less than 0.1% in this unit . The coalescers are absolutely filled with liquid: the bottom with water and the top with oil.

2. 11.8.Electrostatic Desalter

If the separated oil contains undesirable concentrations of salt/brine, the electrostatic desalted can be used to remove them. The salt and brine, which can be chlorides of sodium, magnesium, calcium is produced from the formation water and is dissolved in the crude oil as well. Depending on GOR and water cut, desalter is mounted after the first or second stage separators.

2. 11.9. Water Treatment

A large amount of water would be produced during the field development and lifetime where the water cut is high. For example, 40% water cut results a water output of about 4,000 cubic meters per day or 4 million liters which should be treated before any discharge or disposal process. Water also normally carries sand particles that are related to O/W emulsion as well.

2. 11.10. Gas Treatment and Compression

Produced gas must be processed to meet purchaser's water vapor and hydrocarbon dew point specifications to limit condensation during transportation. The gas train includes many stages, each of which takes gas from a sufficient pressure level from the gas outlet of output separator, and from the previous stage

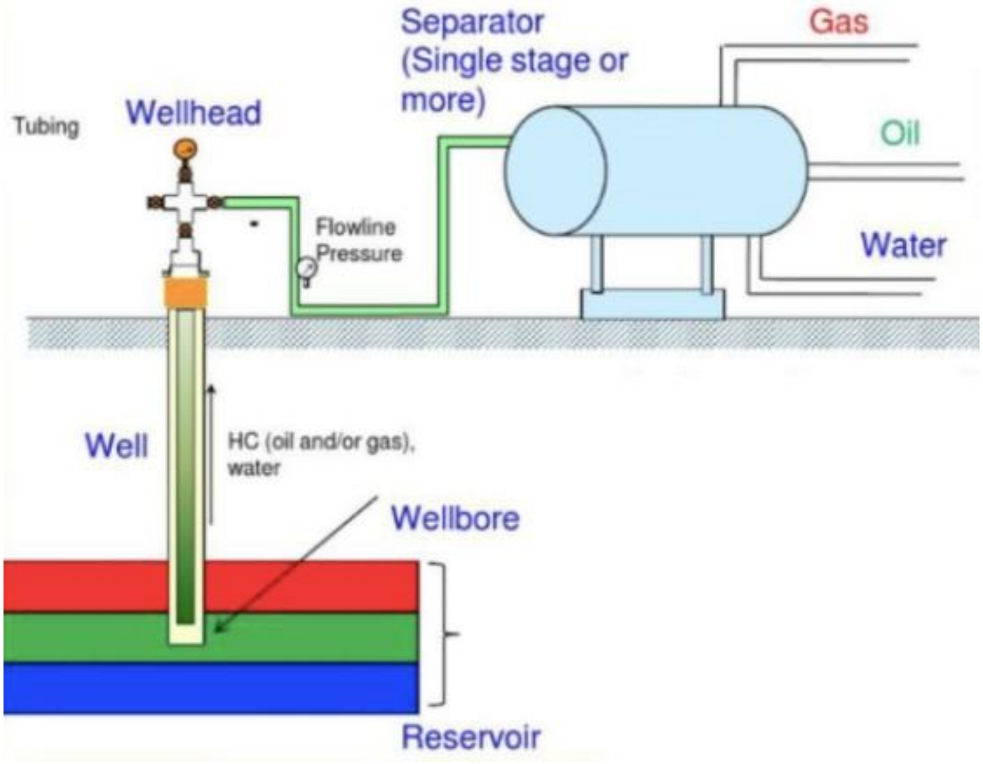
2. 11.11.Scrubbers and Reboilers

There may be mist and some more liquid droplets in the separated gas. As the gas cooling occurs in the heat exchanger, water drops and hydrocarbons also form and should be separated before it enters the compressor. If liquid droplets flow through compressor, the fast spinning blades will erode. A scrubber is applied to remove small fractions of liquid from the gas stream.

Chapter 3

SEPARATION OPTIMIZATION OF WATER AND GAS FROM CRUDE OIL

Case Study for one Iranian Filed



3. SEPARATION OPTIMIZATION OF WATER AND GAS FROM CRUDE OIL (Case Study)

3. 1. Introduction

To obtain an efficient and effective separation of liquid and gas mixtures and to maximize and optimize hydrocarbon liquid recovery, it is essential to apply multi separation stages at decreasing pressures then find optimum pressure at minimum cost.

3. 2. The Concept of Separation Optimization

At the bottom of a production well with high pressure, crude oil contains high amount of dissolved gases. The reservoir fluid weight and friction in the production tube reduces the inlet pressure of gas oil separation unit. Some of the lighter hydrocarbons are going to change phase, and the fluid can create bubbles. The fluid is now unstable and suitable for transport, and it must be equipped with some method of separation.

3. 3. Basis of Design

The field data that are used in the simulation are presented in this section.

3. 3.1. Environmental Data

3. 3.2. Fluid Data

In this study, the model simulates and determines the optimum pressures of multi-stage separators for an Iranian crude oil producing field.

The process has been designed to provide an oil export production rate of 90,000 bbl/d of light crude and 45,000 bbl/d of heavy crude.

Typical Gas Oil Ratio (GOR) ranges are 1,438 - 1,806 scf/bbl for light fluids and 386 scf/bbl for the heavy fluids. Water cut is expected to be up to 10% in light and heavy reservoirs. The minimum flowing wellhead pressure (FWHP) is assumed to be 220 psig for light wells and 400 psig for heavy wells and the estimated flowing wellhead temperature for the heavy oil reservoir is be- tween 45.5ºC to 54.5ºC and for the light oil is between 58.3ºC to 99ºC.

3. 4. Product Specification

All surface facilities shall be designed to process oil and gas in a way to meet the required product specifications which is adopted to N.I.O.C.'s requirements. 3. 4.3. Fresh Water and Disposal Water Specifications

- Produced water and wash water treatment packages shall be designed for sufficient capacity.
- 97% removal of solids greater than 2 microns
- Oxygen less than 7 ppm after treatment
- Oil content not more than 10 ppm

3. 5. Oil production unit Simulation & Optimization

3. 5.1. Process description

Heavy crude from manifolds are combined at the GOSP inlet manifold where it flows to the heavy crude first separator. Light crude from manifolds are combined at the GOSP inlet manifold where it flows to the light crude first separator.

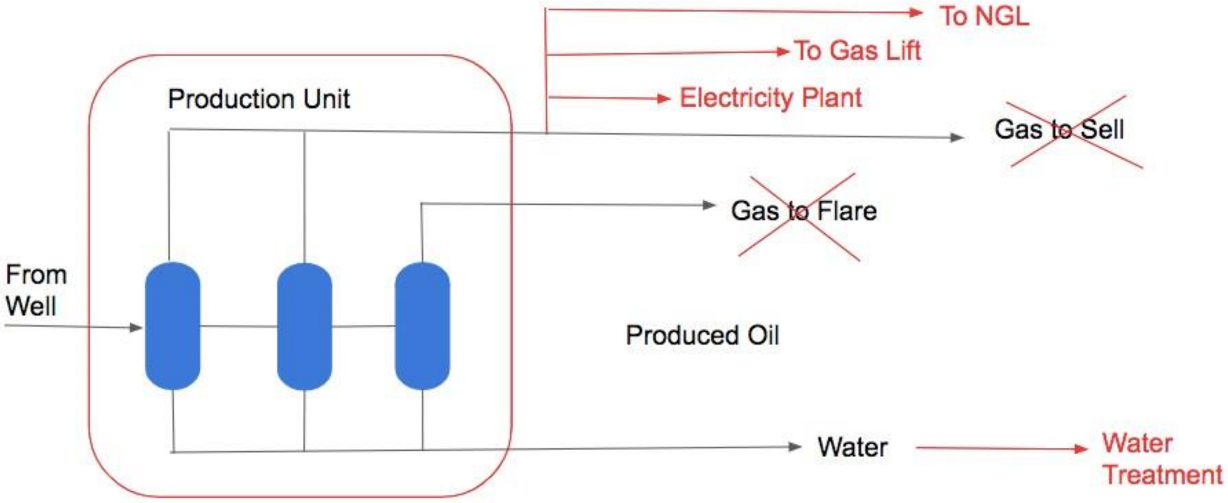


FIGURE 3-7: PROPOSED OPTION S FOR OPTIMIZATION OF LIGHT OIL PRODUCTION UNIT

Figure 3-7 shows the summary of optimized scenario for the light oil production plant.

Based on this scenario, optimization for light crude oil simulated by Hysys software to find the optimum number stages and pressure drop of each separation stages.

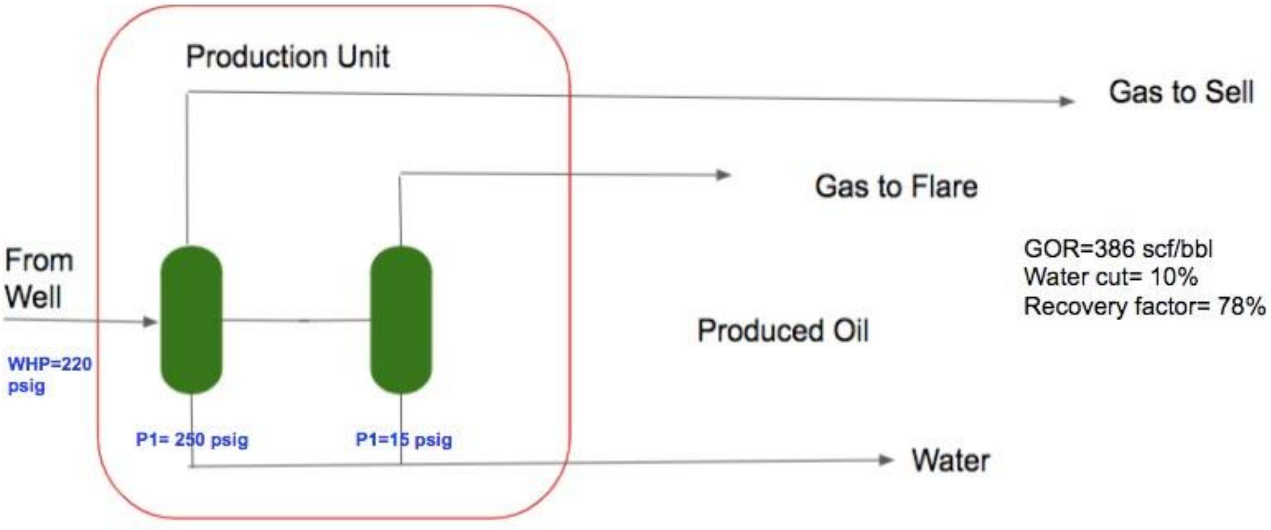


FIGURE 3-8: PREVIOUS SCENARIO FOR HEAVY OIL PRODUCTION UNIT

Figure 3-8 mentioned the previous scenario for heavy oil production unit.

The same concept applies for heavy oil plant. Optimization of separators number and pressure , and preventing of gas flaring and doing water treatment has to consider that mentioned in **Figure 3-9.**

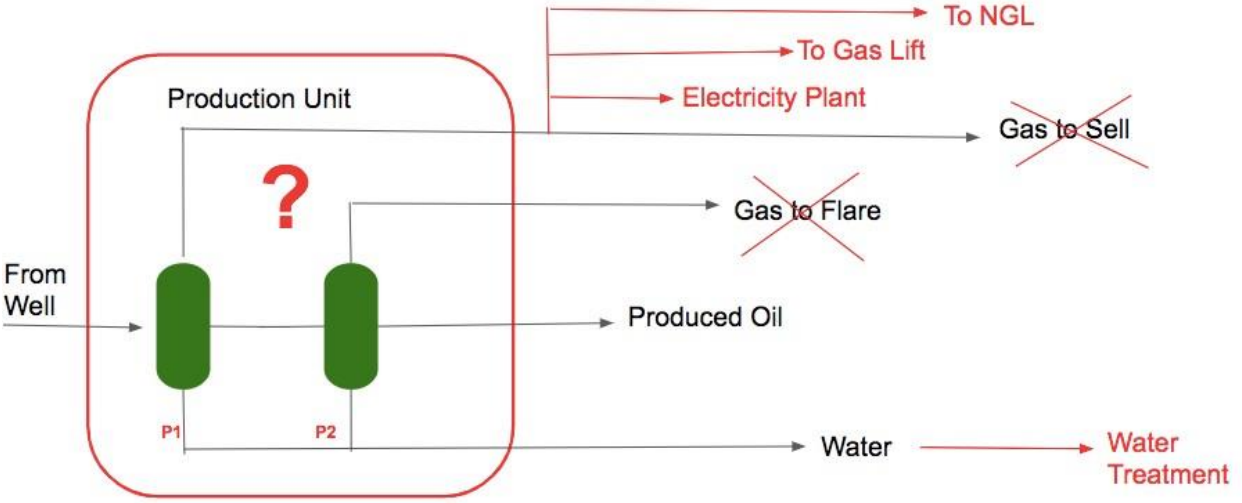


FIGURE 3-9: PROPOSED OPTION FOR OPTIMIZATION OF HEAVY OIL PRODUCTION UNIT

3. 5.2.Water process

The produced water will be cooled down to an acceptable temperature by air cooler and then sent to the water treatment system.

The wash water for the desalting unit is provided by the water supplying system. Oily water requiring treatment can arise from one or more of the following:

- Produced (formation) water from process separators
- Drainage water from miscellaneous process sources
- Ballast water from storage tanks

3. 5.3. Hydrate Formation in GOSP

Under normal operation, the flowing fluid temperature throughout the GOSP is maintained at or above 35°C (based on summer ambient temperatures) which is outside the hydrate formation region.

However, under a process upset and winter ambient conditions, overcooling of the process gas on the inter-stage air coolers could lead to temperatures in the hydrate formation region as it shown in **Figures 3-10** for light crude oil and **Figure 3-11** for heavy crude oil. In this case system design and operational procedures should be implemented to mitigate with this problem. Also, in exposed static areas in the process plant, the fluid temperature may fall within the hydrate formation region during GOSP start-up, hydrate formation conditions are expected downstream of the pressurization - depressurization valves. Operational procedures should be implemented with suitable inhibitor injection points to mitigate hydrate formation.

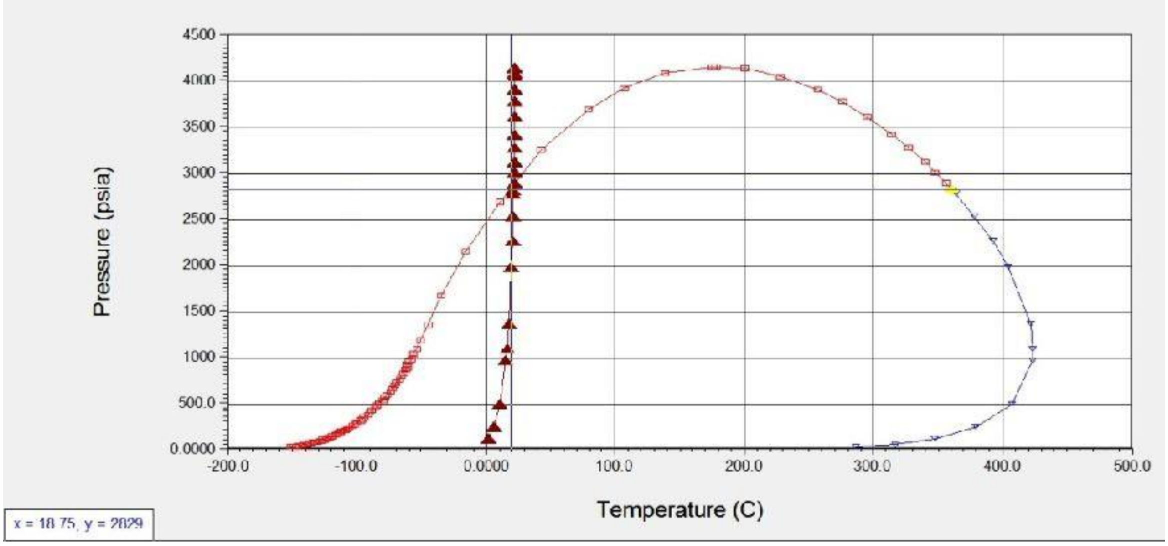


FIGURE 3-10: PHASE DIAGRAM OF LIGHT CRUDE OIL

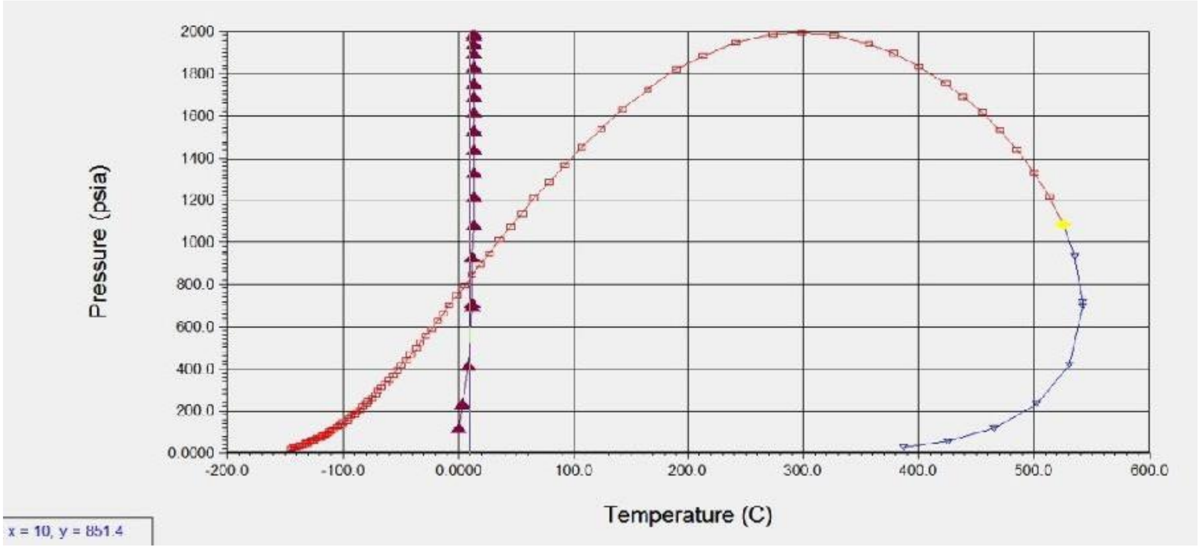


FIGURE 3-11: PHASE DIAGRAM OF HEAVY CRUDE OIL

3.6. Simulation

In this section, in order to maximize oil recovery, the number of separation stages and the pressure of each separator are determined by using Hysys process simulation software.

3. 6.1. Simulation Parameters

3. 6.1.1. Thermodynamic models

There are three main types of thermodynamic models: The viral equations, equations of states and activity coefficient models. The state model equation is also the only model that can be used for both the liquid and vapor phases to estimate thermodynamic properties.
Pressure Range < 100,000 kPa or 15,000 psia

The Soave-Redlich-Kwong (SRK) model offers similar results to Peng-Robinson in many instances, but its range of applications is substantially more limited::
Temperature Range > -143°C or -225°F Pressure Range < 5,000 kPa or 35,000 psia
The ***SRK EOS*** should not be used for non-ideal chemicals such as alcohols, acids or other components. These chemicals are more accurately handled by the Activity Models (highly non-ideal) or the PRSV EOS (moderately non-ideal).

3. 6.1.2. Assumptions and Choice of Model

The fluid contains the polar components: water, hydrogen sulfide and carbon dioxide. For the liquid phases, a method that manages vapor liquid - liquid equilibrium and the activity coefficient model must be used. For systems containing non-polar elements, it is also possible to use the Peng Robinson EOS for the prediction of vapor - liquid phases. It is the technique that will be used for this project.
From the reservoir to the first separator and between the separators a considerable pressure reduction occurs. It is, therefore, reasonable to assume that the fluid separates into three phase oil, gas and water although this is also confirmed to use three phase separators.

3. 6.2. Simulation input

Surface separation pressure and temperature conditions play a major role in the amount of liquid recovery that is realized at the stock tank. Although the temperature of separation is a function of the ambient temperature, which is difficult to control, however, since separators usually work at about the same (surface) temperature, the pressure is typically the key player in optimization studies. The pressure can be controlled through chokes both upstream and downstream of the separator.

For design purposes, the minimum Flowing Wellhead Pressure (FWHP) downstream of the choke valve is assumed to be 15 barg (220 psig) for the heavy crude wells and 27.6 barg (400 psig) for the light crude. Steady State simulations are, generally, created with the following steps:

- *Define the Simulation Basis*

➢ The simulation basis contains all information on components, property package, reactions, etc., that will be used in the simulation. **Figures 3-12** and **3-13**, shows Simulation basis of Hysys interface.

3. 6.3. Simulation Output

As depicted, **Figure 3-17** shows schematic of simulation that made by Hysys for light crude oil.

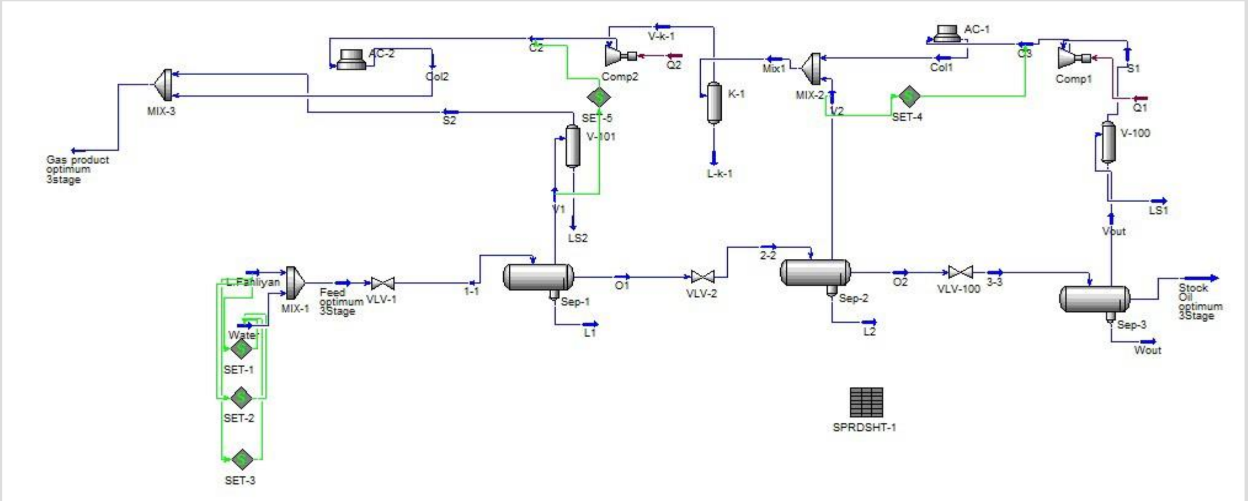


FIGURE 3-17: SIMULATION SCHEMATIC BY HYSYS FOR LIGHT CRUDE.

The results of production unit simulation for light oil with four, three and two stage separations are shown in **Figures 3-19 to 3-20 and Table 3-5 to 3-11.**

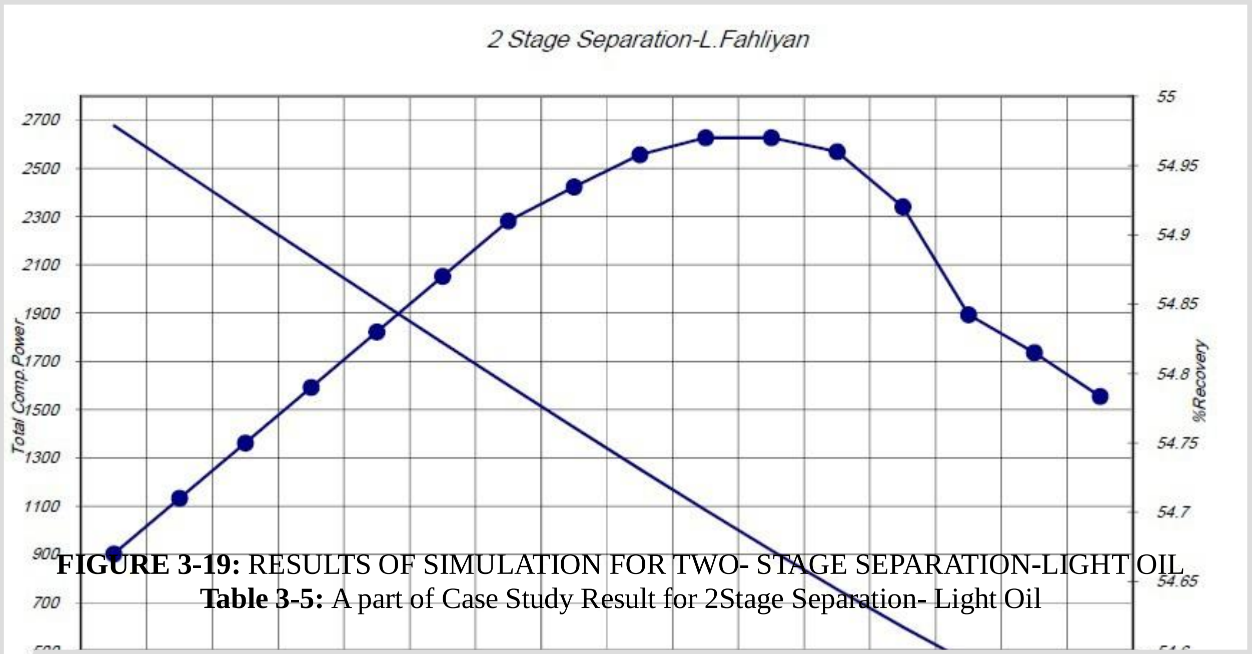
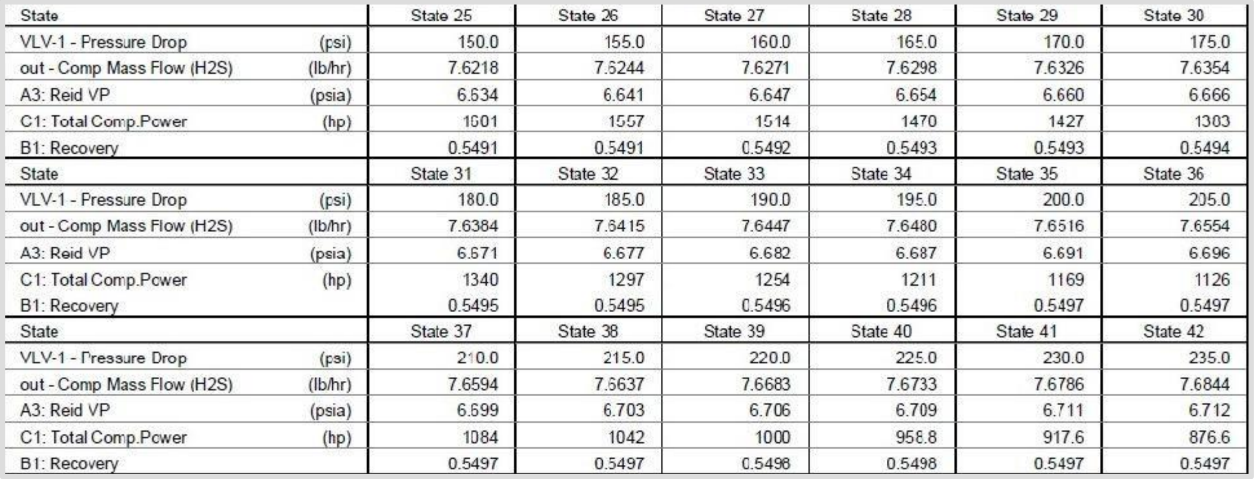


FIGURE 3-19: RESULTS OF SIMULATION FOR TWO- STAGE SEPARATION-LIGHT OIL

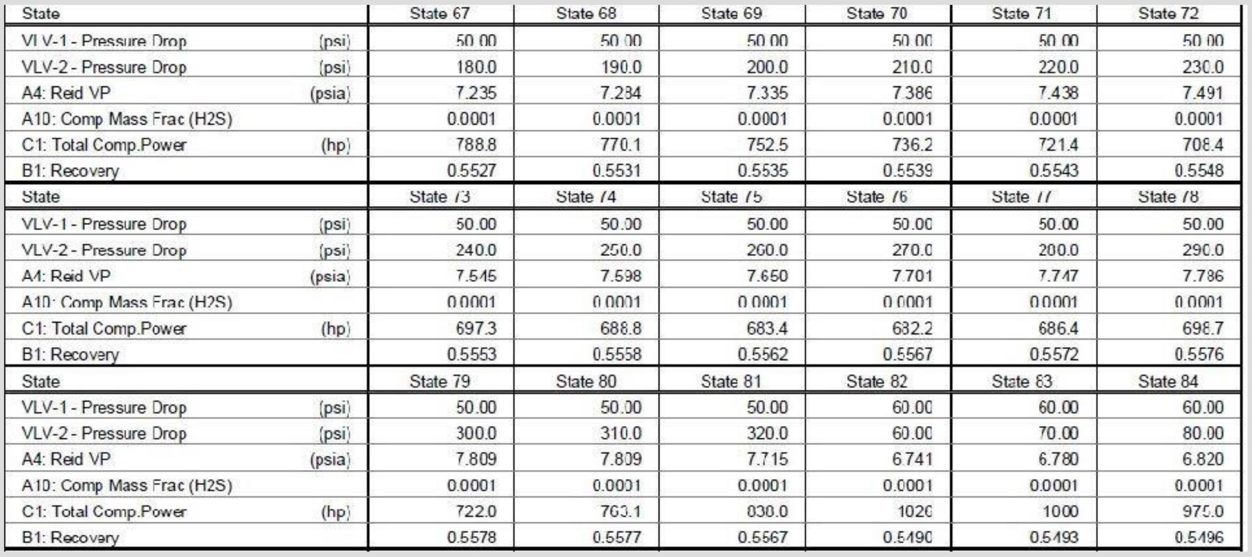
Table 3-5: A part of Case Study Result for 2Stage Separation- Light Oil



State		State 25	State 26	State 27	State 28	State 29	State 30
VLV-1 - Pressure Drop	(psi)	150.0	155.0	160.0	165.0	170.0	175.0
out - Comp Mass Flow (H2S)	(lb/hr)	7.6218	7.6244	7.6271	7.6298	7.6326	7.6354
A3: Reid VP	(psia)	6.634	6.641	6.647	6.654	6.660	6.666
C1: Total Comp.Power	(hp)	1601	1557	1514	1470	1427	1383
B1: Recovery		0.5491	0.5491	0.5492	0.5493	0.5493	0.5494
State		State 31	State 32	State 33	State 34	State 35	State 36
VLV-1 - Pressure Drop	(psi)	180.0	185.0	190.0	195.0	200.0	205.0
out - Comp Mass Flow (H2S)	(lb/hr)	7.6384	7.6415	7.6447	7.6480	7.6516	7.6554
A3: Reid VP	(psia)	6.671	6.677	6.682	6.687	6.691	6.696
C1: Total Comp.Power	(hp)	1340	1297	1254	1211	1169	1126
B1: Recovery		0.5495	0.5495	0.5496	0.5496	0.5497	0.5497
State		State 37	State 38	State 39	State 40	State 41	State 42
VLV-1 - Pressure Drop	(psi)	210.0	215.0	220.0	225.0	230.0	235.0
out - Comp Mass Flow (H2S)	(lb/hr)	7.6594	7.6637	7.6683	7.6733	7.6786	7.6844
A3: Reid VP	(psia)	6.699	6.703	6.706	6.709	6.711	6.712
C1: Total Comp.Power	(hp)	1084	1042	1000	958.8	917.6	876.6
B1: Recovery		0.5497	0.5497	0.5498	0.5498	0.5497	0.5497

FIGURE 3-20: RESULTS OF SIMULATION FOR THREE- STAGE SEPARATION- L.IGHT OIL

Table 3-6: A part of Case Study Result for 3Stage Separation- L.Fahlyan



State	State 67	State 68	State 69	State 70	State 71	State 72
VLV-1 - Pressure Drop (psi)	50.00	50.00	50.00	50.00	50.00	50.00
VLV-2 - Pressure Drop (psi)	180.0	190.0	200.0	210.0	220.0	230.0
A4: Reid VP (psia)	7.235	7.234	7.335	7.386	7.438	7.491
A10: Comp Mass Frac (H2S)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
C1: Total Comp.Power (hp)	788.8	770.1	752.5	736.2	721.4	708.4
B1: Recovery	0.5527	0.5531	0.5535	0.5539	0.5543	0.5548
State	State 73	State 74	State 75	State 76	State 77	State 78
VLV-1 - Pressure Drop (psi)	50.00	50.00	50.00	50.00	50.00	50.00
VLV-2 - Pressure Drop (psi)	240.0	250.0	260.0	270.0	200.0	290.0
A4: Reid VP (psia)	7.545	7.598	7.650	7.701	7.747	7.786
A10: Comp Mass Frac (H2S)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
C1: Total Comp.Power (hp)	697.3	688.8	683.4	632.2	686.4	698.7
B1: Recovery	0.5553	0.5558	0.5562	0.5567	0.5572	0.5576
State	State 79	State 80	State 81	State 82	State 83	State 84
VLV-1 - Pressure Drop (psi)	50.00	50.00	50.00	60.00	60.00	60.00
VLV-2 - Pressure Drop (psi)	300.0	310.0	320.0	60.00	70.00	80.00
A4: Reid VP (psia)	7.809	7.809	7.715	6.741	6.780	6.820
A10: Comp Mass Frac (H2S)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
C1: Total Comp.Power (hp)	722.0	763.1	830.0	1020	1000	975.0
B1: Recovery	0.5578	0.5577	0.5567	0.5490	0.5493	0.5496

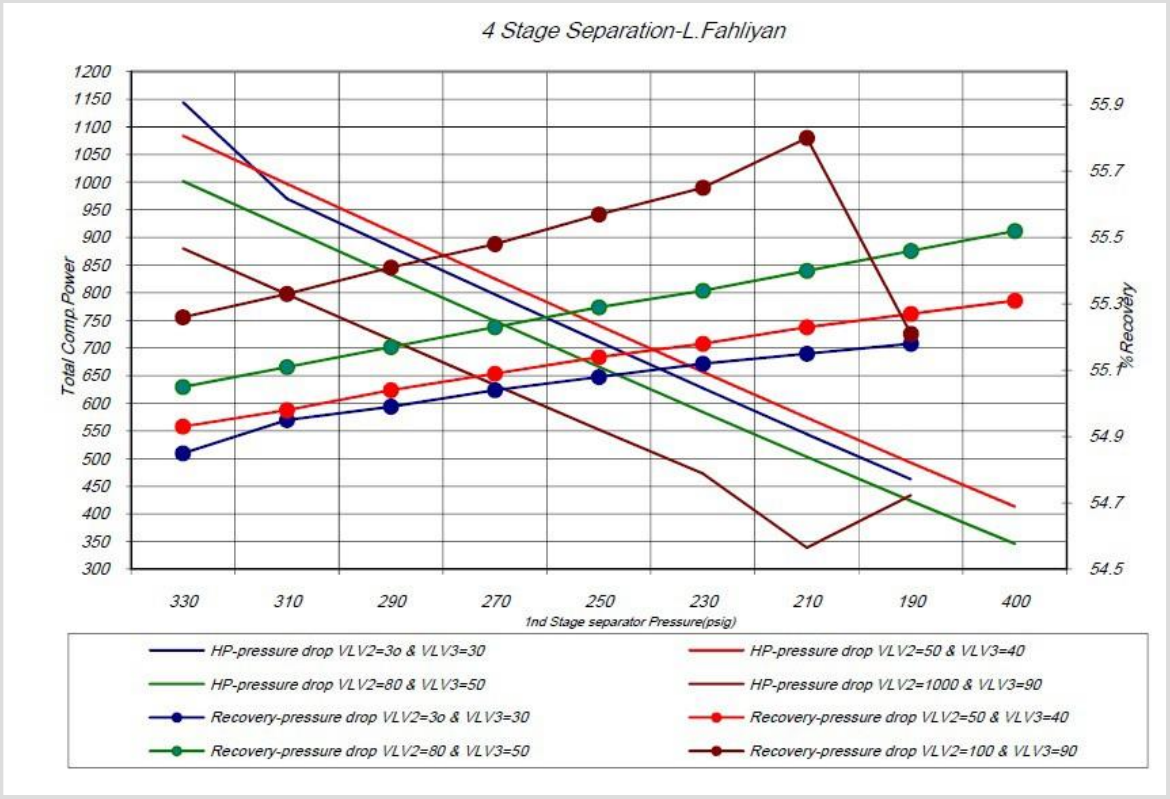


FIGURE 3-21: RESULTS OF SIMULATION FOR FOUR STAGE SEPARATION-LIGHT OIL

Table 3-7: A part of Case Study Result for 4Stage Separation-Light Oil

VLV-1 - Pressure Drop	(psi)	190.0	190.0	190.0	190.0	190.0	190.0
VLV-2 - Pressure Drop	(psi)	80.00	80.00	80.00	80.00	90.00	90.00
VLV-3 - Pressure Drop	(psi)	60.00	70.00	80.00	90.00	30.00	40.00
A2: Comp Mass Frac (H2S)		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
A4: Reid VP	(psia)	7.587	7.673	7.759	7.842	7.419	7.502
B1: Recovery		0.5552	0.5557	0.5563	0.5570	0.5541	0.5546
C1: Total Comp.Power	(hp)	406.1	388.7	372.1	357.5	442.5	424.5
State		State 829	State 830	State 831	State 832	State 833	State 834
VLV-1 - Pressure Drop	(psi)	190.0	190.0	190.0	190.0	190.0	190.0
VLV-2 - Pressure Drop	(psi)	90.00	90.00	90.00	90.00	90.00	100.0
VLV-3 - Pressure Drop	(psi)	50.00	60.00	70.00	80.00	90.00	30.00
A2: Comp Mass Frac (H2S)		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
A4: Reid VP	(psia)	7.588	7.677	7.767	7.853	7.928	7.499
B1: Recovery		0.5552	0.5557	0.5564	0.5570	0.5576	0.5546
C1: Total Comp.Power	(hp)	406.6	388.7	371.4	355.7	344.3	425.7
State		State 835	State 836	State 837	State 838	State 839	State 840
VLV-1 - Pressure Drop	(psi)	190.0	190.0	190.0	190.0	190.0	190.0
VLV-2 - Pressure Drop	(psi)	100.0	100.0	100.0	100.0	100.0	100.0
VLV-3 - Pressure Drop	(psi)	40.00	50.00	60.00	70.00	80.00	90.00
A2: Comp Mass Frac (H2S)		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
A4: Reid VP	(psia)	7.507	7.679	7.772	7.863	7.944	7.909
B1: Recovery		0.5552	0.5557	0.5564	0.5570	0.5576	0.5580
C1: Total Comp.Power	(hp)	407.6	389.3	371.4	354.7	341.7	339.2
State		State 841	State 842	State 843	State 844	State 845	State 846
VLV-1 - Pressure Drop	(psi)	200.0	200.0	200.0	200.0	200.0	200.0
VLV-2 - Pressure Drop	(psi)	30.00	30.00	30.00	30.00	30.00	30.00
VLV-3 - Pressure Drop	(psi)	30.00	40.00	50.00	60.00	70.00	80.00
A2: Comp Mass Frac (H2S)		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
A4: Reid VP	(psia)	7.031	7.096	7.162	7.231	7.303	7.377
B1: Recovery		0.5517	0.5521	0.5525	0.5529	0.5534	0.5538
C1: Total Comp.Power	(hp)	503.5	486.6	469.8	453.1	436.5	420.1

These figures show the recovery factor and total compressor power for four, three and two-stage separations versus separator pressure.

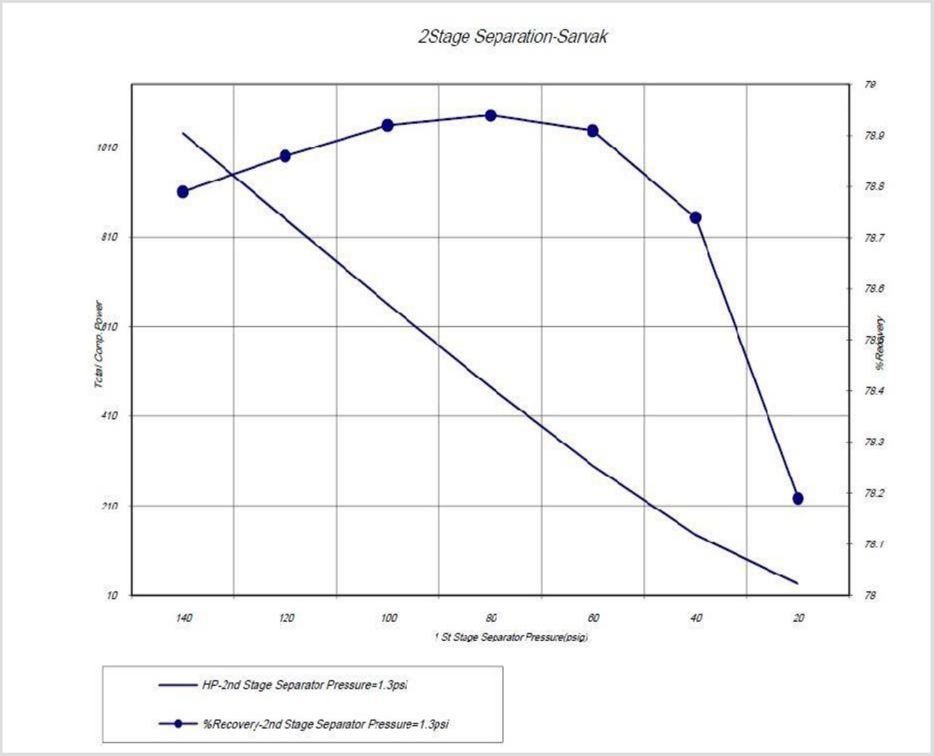


FIGURE 3-22: RESULTS OF SIMULATION FOR TWO- STAGE SEPARATION-HEAVY OIL

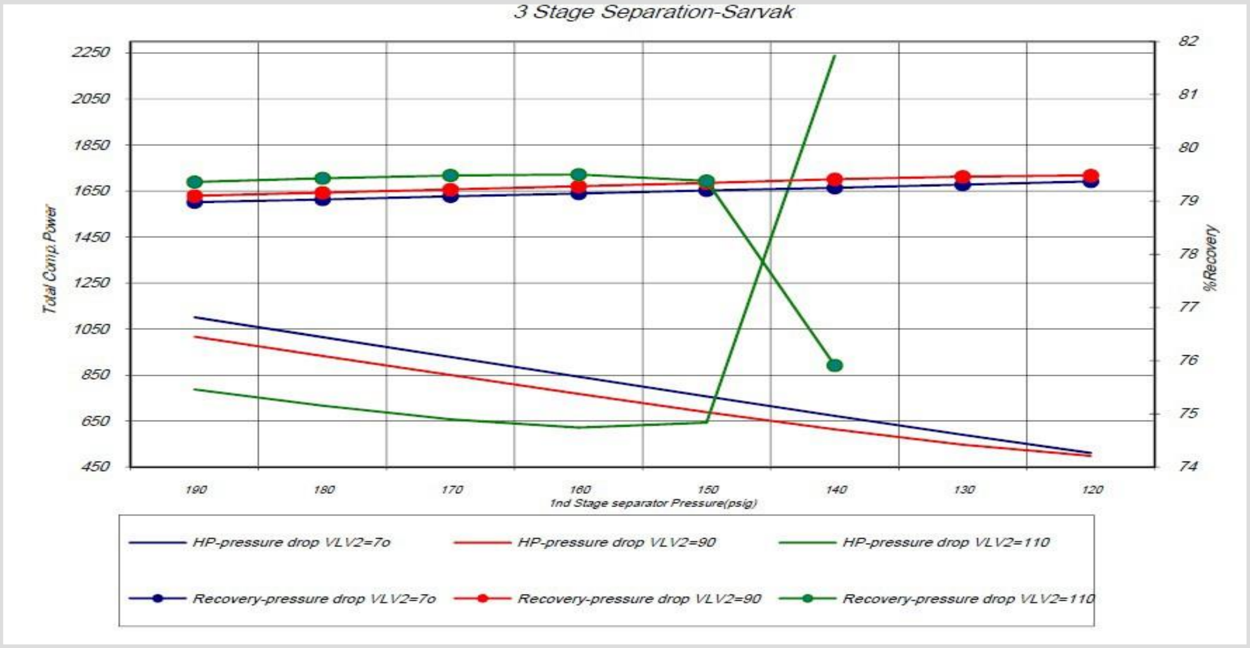


FIGURE 3-23: RESULTS OF SIMULATION FOR THREE - STAGE SEPARATION – HEAVY OIL

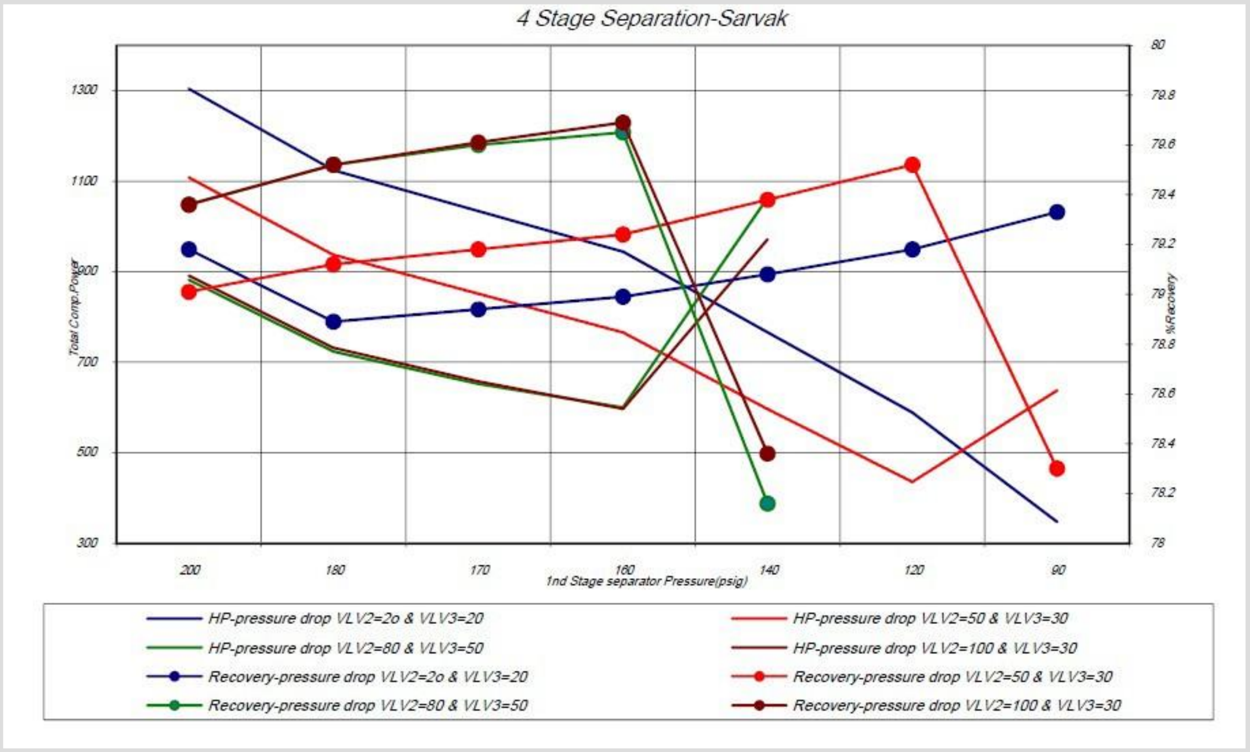


FIGURE 3-24: RESULTS OF SIMULATION FOR FOUR STAGE SEPARATION – HEAVY OIL

These figures show the recovery factor and total compressor power for four, three and two- stage separations versus separator pressure.

In each figure, based on maximum recovery factor and minimum total compressors power, optimum of separators pressure is determined. The results are shown in **Table 3-.12**.

As shown in the mentioned figures and table, the maximum oil recovery is achieved by using a production unit with four-stage separations. On the other hand, considering trivial difference between oil recovery for the production unit with three and four stage separations, and economic point of view, a three-stage separation is recommended.

Therefore the optimum first stage pressure is determined as 140 psig and the second & third stage separators pressure will be 30 psig & atmospheric, respectively.

3. 7. Oil / Gas Export Pipelines

By three export pipelines, the products (Light oil, heavy oil and dry gas) shall be pumped from GOSP / CTEP to Booster Station (BS). The estimated distance between GOSP / CTEP is some 100 Km. The pressure at BS is about 130 psig for both light and heavy oil which is assumed as landing pressure in simulation, and the landing pressure of gas is assumed about 500 psig.

3. 8. Result and Discussion

In this research, the optimization of separation pressure in an Iranian field containing heavy and light crude oils is simulated, and the results are described in details for multiple scenarios. This simulation demonstrated that adaptive separator pressure could increase oil recovery and income from crude oil sale.

Finally, the gas-oil separation and treatment trains for the heavy and light crude are designed on the same basis of 3 stages of separation followed by desalting / dehydration and stabilization as shown in **Figure 3-25**.

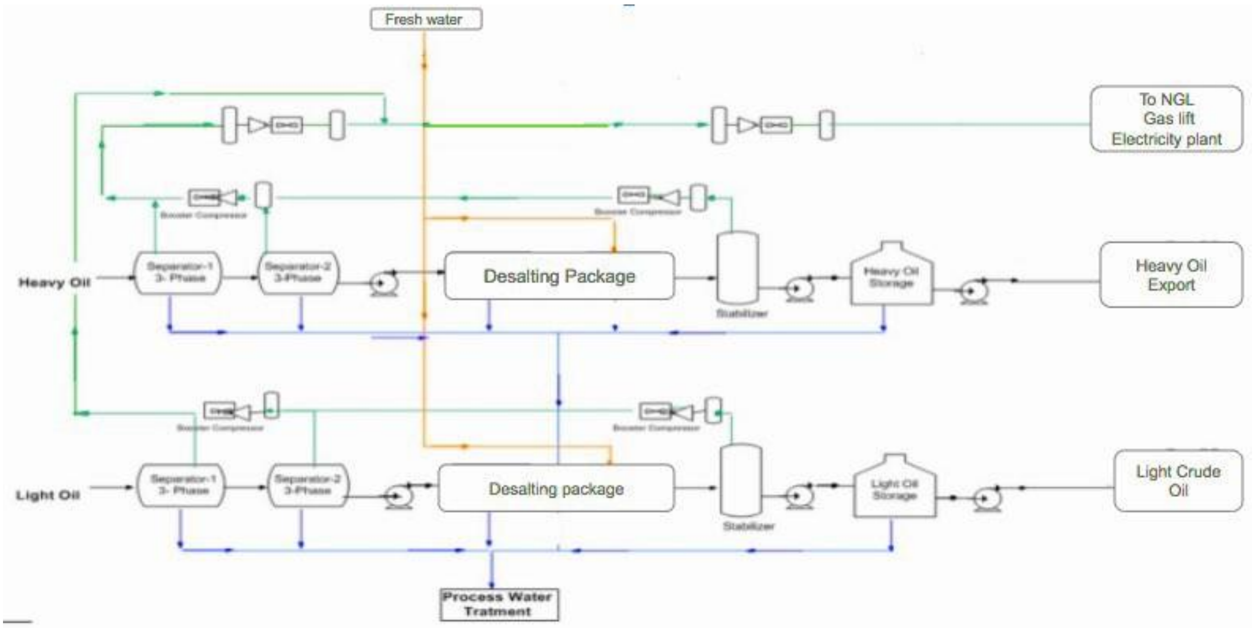


FIGURE 3-25: RESULTS OF SIMULATION FOR LIGHT AND HEAVY OIL PRODUCTION TRAIN

The result of simulation for the field that studied in this research, the separation unit contains three stage of gas-oil separation. Two three-phase separators shall be applied to separate the gas and oil and water and one stabilizer column shall be applied to remove H_2S and to stabilize the oil.

For the field studied in this research the heavy oil recovery about 79.50% has been established (78% in the classical approach) which considering the size of the field and the production volume this achievement could be very substantial and remarkable. A rough estimation shows that the new simulation method can increase the profit by about 27 million dollars per year.

For light crude oil the recovery about 55.78% has been established (54.83% in the classical approach). A rough estimation shows that the new simulation method can increase oil recovery and income from crude oil sale about 16 million dollars per year.

4. Conclusions and Recommendations

Chapter one discussed the emulsion issues in the crude separation process. Oil and water production and processing provides many possibilities to combine the phases intensely and create an emulsion. The process of emulsification may already begin in the reservoir, where narrow pores compress the crude oil and water. When the crude oil flows from the reservoir into the production tubing, and from the wellhead to the manifold, there is usually a substantial pressure reduction with a pressure gradient, especially differential pressure over the chokes and valves where the mixing of oil and water can be intense. After this stage, the production fluid enters the separators, where most of the water is separated from the crude.

Chapter two addressed separators used to separate oil, gas and water, efficient transportation and storage of oil and gas, as they need to be stored separately, prevent corrosion in transportation media by the removal of salts, if present in water.

Chapter three is about the case study and the simulation model. To meet process requirements, the O/G separators are generally engineered in stages, in which the first stage is applied for preliminary phase separation, while the second and third stages are used for further treatment of every particular phase O/G/W.

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