University of Khartoum
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Downhole Separation Technology

A project submitted in partial fulfillment of requirement as a part of honor degree of bachelor in petroleum engineering

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DEDICATION

This thesis is dedicated to all the people who assisted and motivated us through our journey of education.

To our lovely parents who supported us from the very beginning, to our families and friends whose love and encouragement sustained us through our life.

To the University of Khartoum in general and to the Petroleum Department in particular which gave us the education and knowledge to reach this point.
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ABSTRACT

Production management of produced water has become a major issue of hydrocarbon production, since the produced water increases as the field grows older and the cost of water handling, such as separation, treatment and repair is dramatically increasing. Management of produced water presents challenges and costs to operators. If the entire process of lifting, treating, and re-injecting can be avoided, costs and environmental impacts are likely to be reduced.

With this idea in mind, during the 1990s, downhole separation emerged, in which the oil or gas rich stream is produced to the surface, while the water-rich stream is injected to an underground formation without ever being lifted to the surface or it can be produced separately to the surface. These devices are known as downhole oil/water separators (DOWS) and downhole gas/water separators (DGWS).

Liquid-Liquid Hydro-Cyclones is an integral part of a down-hole oil water separation system. Despite performance and functionality of cyclones not being fully understood, they have created new ways for separating fluid down-hole for the producing formation and injecting separated water far away from the production interval.

This study provides a full description of downhole separation technology, showing the types, advantages, requirements and limitations of the technology. The report also provides data on a wide range of field trails and from different locations.

Computational Fluid Dynamic (CFD) was used to understand the behavior of the liquid-liquid hydro-cyclone in downhole conditions. It was also used to simulate the applicability and efficiency of separation using Liquid-Liquid Hydro-Cyclones in Well-04 in Heglig field in Sudan.
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1. CHAPTER ONE: INTRODUCTION

1.1 Produced water problems

Water is by far the largest waste stream associated with oil and gas production and it is nearly impossible to find an oil reservoir absolutely free from connate water. Separation of water from oil and gas is the oldest practice in the petroleum industry.

When oil is produced from underground wells, it is often accompanied by significant amounts of water, called produced water. Produced water refers to the water brought up from the hydrocarbon bearing strata during the extraction of oil and gas. This water can include formation water, injection water, and any (waste) surfactants added down-hole or during the oil/water separation process. Produced water always contains dispersed and dissolved oil and other varieties of dissolved inorganic and organic compounds, suspended solids such as formation fines, sand, scales and corrosion products. This mixture of oil and water needs to be separated and the water disposed of or re-injected into the reservoir before the oil can be exported to refineries.

Water management has become an important issue of hydrocarbon production; since the produced water increases as a field matures and because of the increasing cost of water handling. In addition, the withdrawal of water contributes to the reduction of pressure and water re-injection is required to maintain reservoir pressure in order to enhance oil recovery.

Figure 1-1: Water and oil production in western Canada
Traditionally, large, heavy gravity vessels have been used to separate oil and water. Due to the slug flow of the oil/water interface these separators are not stable and separation efficiency is reduced, making it difficult to produce only oil, thus creating economic and environmental challenges.

As the oil concentration changes, such as in oily wastewater containing more than 90% of water, oil content can be as low as 50 ppm or as high as 500 ppm. In a mature oilfield, oil content can vary between 2% and 10%, depending on the oilfield’s characteristics. The separation process varies based on the oil-water mixture. Most commercially available oil-water separators rely on the gravity movement but this separation method is not effective in less-dense oil in down-hole oil-water separation.

With their compact size, Hydro-cyclone can be used to replace large surface separators, both on newly built platforms and existing ones with water-handling problems that usually occur in mature fields. Before putting cyclones into operation, one has to investigate fluid properties, well geometry, well completion and characteristics of the formation.

1.2 Hydro-cyclone operation downhole

The hydro-cyclone is a static separator which utilizes fluid pressure energy to create rotational fluid motion. The hydro-cyclone separates lighter components from a liquid medium which is usually water. It was due to this water medium that the name “hydro-cyclone” was introduced. Hydro-cyclones have no rotating parts and necessary vortex is produced by pumping the fluid tangentially into a stationary cone-cylindrical body. The vessel at the point of entry is usually cylindrical. It can remain cylindrical over its entire length; though it is usually tapered. figure (1.2) shows what is generally accepted as the normal design of the hydro-cyclone.

The cylindrical part is closed at the top by a cover, through which the liquid overflow pipe, or vortex finder, provides outlet for lighter components. Classification of the hydro-cyclone is often in terms of the cylindrical section diameter. Individual hydro-cyclone diameters range from 10 mm to 2.5 m.
1.3 CFD application in petroleum engineering

Computational Fluid Dynamics (CFD) is a part of fluid mechanics that brings to perfection for experimental and analytical fluid engineering. CFD is the science of predicting fluid flow, heat and mass transfer, chemical reactions and related phenomena by solving numerically sets of governing equations. Its capabilities and application have been widely expanded, giving, experts in the petroleum industry confidence to use this predictive tool in many applications ranging from drilling to production and processing.

CFD models were applied to simulate the hydrodynamics of complex machinery and Equipment involving moving parts, erosion, heat transfer, chemical reactions and multiphase flow. Fluent models have been developed and tested with applications such as; drill bits, pumps, static mixers, and distillation trays, separators, packed beds, fluidized beds, reactors and multistage compressors. Fluent solves transport equations needed for each application. It is capable of solving a fast array of a complex phenomenon using a storehouse of physical models. We can apply CFD to many problems in petroleum engineering, such as:

- Drilling fluids, such as mud (non-Newtonian viscosity laws)
- Production in oil fields, including flow around down-hole injectors
- Flow involving two-phase and three-phase (gas-solids, liquid-solids or liquid-liquid mixtures).
Compressors, pumps, propellers and impellers.
Flow in refinery equipment such as crude oil desalters and reactors.
Erosion and other effects of particle-laden flows (comprehensive particle-tracking algorithm).

Computational fluid dynamic (CFD) simulations and modeling were conducted to understand the behavior of the liquid-liquid hydro-cyclone (LLHC) in down-hole conditions. CFD is a tool that can predict fluid flow, split ratio, total separation efficiency, pressure drop, heat and mass transfer, chemical reactions and related phenomena by solving sets of governing equations.
1.4 OBJECTIVE OF THE STUDY

The objective of this study is to investigate the performance and efficiency of a liquid-liquid hydro-cyclone in down-hole conditions. The specific aim of this study is as follows:

• To describe the concept of downhole separation technology
• To develop a Hydro-cyclone performance model using CFD.
• To simulate the model into conditions of Well-04 in Heglig field, Sudan
• To test and verify this model and compare it with published field trails.
2. CHAPTER TWO: LITERATURE REVIEW

The traditional production process involves producing both oil and gas to the surface and separating them at the surface. This separation occurs through the use of gravity settlers such as vessel, plate coalescence and hydro-cyclone. However, as a field matures and oil and gas production peaks, there is often an associated increase of produced water and a corresponding increase in both lifting and water disposal costs, that leads to an additional increase in maintenance of equipment and downhole treatment for corrosion, bacteria, scale and naturally occurring radioactive material.

2.1 Description of downhole separation technology

Downhole separation technology is a relatively new method that separates oil and gas from produced water at the bottom of the well, and re-injects most of the produced water into another formation which is usually deeper than the producing formation, while the oil and gas rich stream is pumped to the surface, or produce water stream separately to the surface.

Downhole separation effectively removes solids from the disposal fluid and thus avoid injectivity decline caused by solids plugging. Simultaneous injection using downhole separation minimizes the opportunity for the contamination of underground sources of drinking water through leaks in tubing and casing during the injection process.

Down-hole separation principles are similar to traditional surface separation governed by Stoke’s Law of droplet settlement.

2.2 Background of the technology

Down-hole oil-water separation technology has been in the oil and gas industry since the 1990s. Despite offering an economic and environmental advantage, only a limited number of this system has been installed in oil and gas wells.

When the concept of downhole separation was first introduced, there was a huge amount of interest, peaking during the 1990s, as everyone in the industry noticed the potential that reducing the volume of produced water could bring. However, the main concerns at the time included high costs and the complexity of the system together with the low reliability of the Initial DOWS, the ongoing concern regarding exactly what was being injected, and the fact that there was no way to verify separation efficiency, the end result was a low confidence that
the systems could deliver as designed. Therefore, despite widespread initial interest and the obvious benefits, attention to the technology Faded and the number of installations tailed off such that in the five years prior to 2010, no installations transpired.

Today, a remarkable number of downhole separation systems are installed in sites around the world as it will be shown later on this research.

2.3 Downhole oil water separation (DOWS)

A DOWS system is installed at the bottom of an oil well, it separates oil and water at the bottom of the well. The oil rich stream is brought to the surface while the water rich stream is pumped into an injection formation without ever coming to the surface or it could be produced separately. A DOWS system includes many components but the two primary components are an oil/water separation system and a pumping/injection system used to lift oil to the surface and inject the water into a deeper formation.

Figure 2-1: typical design of a DOWS
Two basic types of DOWS systems have been developed, one type uses hydro-cyclones to mechanically separate oil and water and the other relies on gravity separation that takes place in the wellbore. Three basic types of pumping/injection systems are used with the DOWS technology. These include electrical submersible pumps, progressive cavity pumps and sucker rod pumps. Table (2.1) shows the capacity limits of different pump types. Hydro-cyclone separators are usually used with the electrical submersible pumps because of higher drawdown created with effective injection of water into the lower zone.

<table>
<thead>
<tr>
<th>Pump type</th>
<th>Casing size (inch)</th>
<th>Total volume (bbl/day)</th>
<th>Maximum volume to surface (bbl/day)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric submersible pump</td>
<td>5.5</td>
<td>3,800</td>
<td>440</td>
</tr>
<tr>
<td></td>
<td>7.0</td>
<td>10,000</td>
<td>940</td>
</tr>
<tr>
<td>Progressive cavity pump</td>
<td>5.5</td>
<td>2,200</td>
<td>450</td>
</tr>
<tr>
<td></td>
<td>7.0</td>
<td>3,800</td>
<td>1,360</td>
</tr>
<tr>
<td>Rod pump</td>
<td>5.5 (85% watercut)</td>
<td>1,700</td>
<td>530</td>
</tr>
<tr>
<td></td>
<td>5.5 (97% water cut)</td>
<td>1,200</td>
<td>70</td>
</tr>
<tr>
<td></td>
<td>7.0 (85% watercut)</td>
<td>2,500</td>
<td>790</td>
</tr>
<tr>
<td></td>
<td>7.0 (97% water cut)</td>
<td>1,900</td>
<td>190</td>
</tr>
</tbody>
</table>

Table 2-1: capacity limits for hydro-cyclone type DOWS

DOWS systems can take different configurations. The system illustrated in Figure (2.2) is referred to as a push-through system. In this design, the injection pump discharge is connected directly to the inlet of the separator. The injection pump provides the pressure required to operate the separator and inject the separated water. In some cases, where the pressure required to inject the water is equal to or higher than the pressure required to lift the oil stream to surface, the injection pump can serve both purposes and only one pump is required. Where injection pressure is low, it is normal practice to use a second pump to lift the oil stream. If two pumps are used, a common motor normally drives both. Reduced power
requirement is the primary justification for using two pumps in a push-through system. Significant power savings can result if the injection pressure is low and the water cut is high. In this situation, the total production volume is pumped only to the pressure required for injection, while the production pump boosts only a fraction of the produced fluid to the pressure required to reach the surface. This reduction in power requirement has been used to either install lower horsepower motors—reducing energy requirement and extending motor life—or to increase total draw-down and oil production without an increase in the motor size or energy consumed, as compared to a conventional lift system.

![Figure 2-2: push through type DOWS](image)

Figure (2.3) shows a pull-through system. In this configuration, the suction of the injection pump is connected to the water outlet of the separator. The pump draws separated water from the separator and boosts pressure to a level suitable for injection. Unless the well is free flowing (i.e. does not require an artificial lift system to produce to the surface), a second pump is required to lift the oil stream to the surface (Bower et al, 2000)
Down-hole oil-water separation may offer several reservoir benefits. This technology may reduce the hydrostatic column, which is significant for low-pressure reservoirs, the life of the reservoir may be extended, and production will be increased. Gas lifting will be postponed by applying this system.
2.3.1 DOWS completion designs

To attain a successful downhole separation using a combination of a downhole pump and a downhole separator, good completion designs must be applied. A number of new completion technologies and equipment designs are available which help to expand the application of downhole separation technology.

The different completion design can vary depending on the location of production and injection zones, the well completion data and the lift method.

The completion design must accomplish the following:

- Separate oil from water
- Provide energy to dispose the water and insure oil can flow to the surface
- Provide zone isolation for water injection

A packer is to be installed to provide isolation from the injection zone to the production zone. A second packer needs to be installed to ensure the fluid is only going through the separating assembly (and not upthrough the annulus).

Figures (2.4) and figure (2.5) shows two types of reservoir configuration existing, the oil producing layer above the water injection zone and vice versa. Also the distance between these two zones influences the completion design of the separator assembly. In figure (2.4) the distance between the two zones is larger than the separator assembly. in figure (2.5) the distance between the two zones is smaller than the separator assembly.

An advantage of reservoir configuration having the production zone below the injection zone is the benefit of the "free" extra pressure due to the producing zone being below the injecting zone.
Figure 2-4: different completion design

Figure 2-5: different completion design
2.3.2 Types of DOWS

(1) Gravity separators

Gravity separation can happen when two immiscible liquid phases or liquid and gas phases are separated by the differences of their densities. Sufficient retention time must be provided in the gravity settler to allow the gravity separation to take place. In two phase liquid separation, heavy liquid droplets will settle out of the light liquid phase if the gravitational force acting on the heavy liquid droplets is greater than the drag force of the light phase flowing around the droplet. The oil-water separation process is generally explained by particle dynamics. It is thought to be governed by Stokes Law for terminal velocity of spheres in a liquid medium using Newton’s basic drag equation. Gravity separator-type DOWS are designed to allow the oil droplets that enter a well bore through perforations to rise and form a discrete oil layer in the well. Most gravity separator tools are vertically oriented and have two intakes, one in the oil layer and the other in the water layer. This type of DOWS uses rod pumps. As the sucker rods move up and down, the oil is lifted to the surface.

Figure 2-6: gravity separation
(2) Hydro-cyclone separators

Hydro-cyclones use centrifugal force to separate fluids of different specific gravity; they operate without any moving parts. A mixture of oil and water enters the hydro-cyclone at a high velocity from the side of a conical chamber. The subsequent swirling action causes the heavier water to move to the outside of the chamber and exit through one end, while the lighter oil remains in the interior of the chamber and exits through a second opening. The water fraction, containing a low concentration of oil (typically less than 500 mg/L), can then be injected, and the oil fraction along with some water is pumped to the surface.

Hydro-cyclone-type DOWS have been designed with electric submersible pumps (ESPs), progressing cavity pumps, gas lift pumps, and rod pumps. As the fluid moves to the underflow outlet, the narrowing diameter increases the fluid angular velocity and the centrifugal force. It is due to this force and the difference in density between the oil and the water that the oil moves to the center where it is caught by the reverse flow and separated flowing into the overflow outlet. Instead, if the dispersed phase is the heaviest, like solid particles, it will migrate to the wall and exit through the underflow.

The separation of fluids in a hydro-cyclone is not 100% complete: some oil is carried along with the water fraction, and a significant portion of water (typically 10% to 15%) is brought to the surface with oil and gas production. Nevertheless, hydro-cyclones can rapidly and effectively separate most of the oil from the water fraction. For example, wells with a water-to-oil ratio in the range of 5–100 can typically achieve water-to-oil ratios between 1.0 and 2.0 with the help of a hydro-cyclone-type DOWS.

Hydro-cyclones used in DOWS tend to be narrow and tall. Hydro-cyclones can be smaller than 50 mm in diameter and 1–2 m in length. If a single hydro-cyclone does not provide enough capacity to handle the total fluid volume, several hydro-cyclones can be installed in parallel.
There are three types of hydro-cyclones used in down-hole separation:

1. Bulk hydro-cyclones.
2. De-watering hydro-cyclones.

These hydro-cyclones are more or less the same design but operate differently.

The bulk hydro-cyclone splits the mixture of oil and water produced from the reservoir into one oil-rich flow and one water-rich flow. The oil-rich flow goes to the de-watering hydro-cyclones where most of the water is removed resulting in clean oil phase. The water flow from the bulk hydro-cyclone goes to de-oiling hydro-cyclones where oil is removed. De-oiling and de-watering hydro-cyclones prioritize one phase, water or oil respectively. Thus one clean phase and one polluted phase exit the de-oiling hydro-cyclone and de-watering hydro-cyclone, respectively.

The physical separation conditions down-hole are quite different from the surface conditions. Temperature and pressure drop as the fluid flows to the surface. Due to high temperature and pressure, fluid viscosity is at the minimum at the bottom of a well. Low viscosity improves separation and reduces pressure loss in the hydro-cyclone. High pressure and temperature also

Figure 2-7: flow inside a hydro-cyclone
reduce shear forces. A droplet collapses easier if shear forces are small, resulting in improved hydro-cyclone efficiency.

Hydro-cyclones are widely used in produced water treatment. An analysis of physical separation conditions both surface and down-hole suggests that hydro-cyclones can be used successfully for down-hole separation.

THE PERFORMANCE FACTORS OF THE CYCLONES

Hydro-cyclone operation is influenced by a number of parameters, some of which are not fully understood at this moment. The parameters that are affecting efficiency of Separation are as follows:

(a) The split ratio (F):

Defined as the ratio of the over flow rate (oil) to the total inlet flow rate (liquid). Previously researchers thought F>5% was average, but now using small upstream outlet diameter, F can be reduced to about 1%.

The split ratio is expressed as:

\[ F = \frac{q_{\text{overflow}}}{q_{\text{inlet}}} \times 100\% \]

Where:

- \(q_{\text{overflow}}\) = the total oil flow rate at the upper outlet of the hydro-cyclone, m3/s
- \(q_{\text{inlet}}\) = the total inlet flow rate (oil + water), m3/s

(b) Oil Separation Efficiency (\(\varepsilon_{\text{eff}}\)):

It is the practical interpretation of separation of the purity of individual discharge streams. Many references quantify the relative phase composition of the separated streams in the form of a percentage by volume measurement.
It is expressed as:

\[ e_{ff} = \frac{q_{oil-overflow}}{q_{oil-inlet}} \times 100\% \]

Where:

\[ q_{oil-overflow} = \text{the flow rate of oil at the overflow} \]

\[ q_{oil-inlet} = \text{the flow rate of the oil at inlet.} \]

(c) The pressure drop:

It affects pumping requirements, and represents energy required to spin the incoming fluid. The pressure drop of individual cyclones ranges from 5 to 90 psi, with smaller units usually operated at a higher pressure drop than the large ones. Under normal operation there are two measured pressure drops across a hydro-cyclone. One is the difference between inlet and rejected pressure and the other is the difference between inlet and outlet pressure. The first one is always greater than the second. The relationship between two different pressure drops is called pressure difference ratio (PDR) and is defined as:

\[ PDR = \frac{P_{in} - P_{rej}}{P_{in} - P_{out}} \]

Where:

\[ P_{in} = \text{inlet pressure} \]

\[ P_{rej} = \text{the rejected pressure or overflow outlet (oil)} \]

\[ P_{out} = \text{the pressure of underflow outlet (water)} \]

(d) Flow rate:

Minimum flow rate is necessary in order to establish the vortex motion and create the central core. Generally, as flow rate increases, the efficiency of separation increases. Lower flow rates create longer residence times but lower acceleration forces. Conversely, higher flow
rates result in higher acceleration forces and smaller residence times. Hydro-swirl performance is independent of flow rate.

(e) The density difference:
This is the biggest driving force for the separation. The bigger the difference, the more rapid is the separation.

(f) The temperature:
A temperature increase will affect density and also lower viscosity, resulting in better separation.

(g) The particle cut size:
This is the size of a particle that would have a 50% chance of exiting at either the underflow or overflow. In a liquid-liquid separation, the mean droplet size is very important since large droplets will move more rapidly to the central flow or outflow, depending on their density.

2.3.3 Advantages of DOWS

1. Lower cost of oil production: DOWS technology reduces more than 70% of the water that was supposed to be produced thereby reducing the total cost of lifting, treating, re-injecting and disposal of produced water, the cost of production of oil is greatly reduced.

2. Reduction of environmental impact of oil and gas operations: Standard injection well operations pose a significant but manageable risk of environmental pollution. The highest risks occur due to surface spills during re-injection of the separated brine. By reducing the amount of brine brought to the surface and re-injected the environmental risks associated with re-injection wells can be reduced.

3. Pollution of underground sources of drinking water: produced water in most cases contains brines. With DOWS technology, dissolved impurities are not allowed to get to the surface hence they do not pass through intervals containing underground sources of drinking water (USDW). Also, since the water does not require re-injection from the surface, it will not pass
through intervals of USDWs then, either. Therefore, the risks posed by large volumes of these fluids passing USDWs both exiting and re-entering the well upon injection are minimized.

4. Because DOWS technology uses underground equipment, surface brine disposal operations, which may involve pumps, pipes, tank batteries, and other storage facilities may also be reduced in size and extent if not altogether eliminated.

5. The DOWS system is used for re-injection thereby increasing the drawdown pressure which can result in increased production rate

2.3.4 Limitations of DOWS

DOWS technology is very complex and premature. All field tests show that few existing installations are successful. The technology cannot be used in just any field as there are some restrictions for its use. Down-hole hydro-cyclone separators cannot produce both clean water and dehydrated oil streams at the same time. Hydro-cyclones require some fluid properties for an effective separation and not all oil fields meet the requirements. Some of the limitations are related to the system itself while others are inherent to the usage of the system. Technological progress may reduce limitations. The following are some of the limitations of the system:

1. Well-bore space is very limited; Hydro-cyclone designed in this particular operation or in down-hole must be narrow and tall; therefore, minimum casing size requirement must be 5-1/2 inch.

2. ESP-DOWS- the engine must be installed below the productive area to allow its refrigeration; otherwise, an engine sleeve must be used when the casing size allows it.

3. Based on previous experience, the system worked better in carbonates compared to sandstone formations so it is advisable to avoid sandstone formations.

4. Reservoirs that have a history of sand producing may not be suitable for this system due to plugging within the system.

5. This system can be applied to wells producing high volume of water-oil ratio (WOR).

6. Oil density must be higher than 985.052 kg/m³ (12º API).

7. Minimum difference of specific gravity between oil and water should be 0.05.

8. Oil content (typically between 10 and 200 ppm of oil) in the injecting water can damage the formation
9. Impossible to effectively stimulate the areas below the pump without of pulling.

10. It is preferable not to apply this technology to deviated wells especially those that do not have oil residual saturation.

2.3.5 Problems of DOWS

The problems encountered during DOWS applications are either due to the hardware or the formation conditions.

INJECTIVITY DECLINE

For DOWS technology to function properly, the injection zone must have sufficient permeability and porosity to accept brine at a pressure within the capability of the pump. Inappropriate fluids contacted sensitive sands and damaged part of the permeability. Particles in the produced water clogged the injection zone. In fact, injectivity decline caused by the various contaminants in the water phase widely exists in water flooding operations. This phenomenon is referred to as formation damage which can lead to serious loss in productivity or injectivity. It is a big challenge to fit the separator inside a well. In particular, channels to bypass oil flow around the pump and motor assembly must be fitted into a very small cross-section, and are exposed to very high flow rates. This creates risks of erosion/corrosion. Additionally, because these flow bypass channels are normally formed from thin walled tubing and often attached to the outside of the pump assembly, there is a high potential of damage to these tubes in the course of installation, especially when the well is deviated.

SOLIDS PLUGGING

Excessive sands not only damage the injection zone, they also result in premature mechanical failure of the separator, pumps, or bypass tubing. In at least two cases, solids production was so excessive that the entire pump/separator assembly was packed with solids when inspected at the surface. In one case the solids were formation solids, and in the second case the solids were iron sulfide scale.

ISOLATION PROBLEMS

To protect the producing reservoir, the injection zone must be adequately isolated by an integral confining zone and sound cement behind production casing. If isolation is not sufficient, the separated water can migrate into the producing zone and then short-circuit into
the producing perforations. The result will be recycling of the produced water, with oil production rates dropping to nearly zero.

### 2.3.6 Well Candidate for DOWS

It is attractive to reduce produced water handling and disposal costs, and possibly produce more oil through installation of a DOWS; however, not all wells are good candidates for a cost-effective DOWS installation. Several authors have indicated the criteria they have used in selecting candidate wells for installations of hydro-cyclone-type DOWS systems.

Matthews et al (1996) described the selection criteria used to site three hydro-cyclone-type DOWS systems in the Alliance Field in east-central Alberta, Canada. From a production standpoint, wells had to have a water-to-oil ratio of eight or higher and productivity of greater than 1,260 bbl/day. The reservoir had to contain sufficient incremental reserves and provide a suitable disposal zone. The casing had to be at least 5.5” in diameter, and the wellbore had to have good mechanical integrity and a minimum separation of about 24 m (80 ft) between the production zone and disposal zone. The wellbore had to be already open below the production zone so that additional drilling would not be necessary.

Peats and Schrenkel (1997) described the selection criteria used to site a hydro-cyclone-type DOWS in the Swan Hills Unit One Field in Alberta, Canada. Only wells having a water cut of 94% (a water-to-oil ratio of about 16) were considered. Since a DOWS sized to fit in a 5.5” casing would be very long and costly, a well with 7” casing was preferable to maximize the rate of production and allow for better clearance. Wells with a history of asphaltene and scale problems or wells with high gas to oil ratios were avoided. Stuebinger et al (1997) identified several screening criteria for DAPS. The most important is the availability of a suitable injection zone that is isolated from and at least 3 m (10 ft) deeper than the production zone. The pressure required to inject water cannot be excessive. The injection pressure gradient must be less than 0.45 psi per foot of depth. The chemistry of the produced water must be compatible with the injection zone; it is usually inadvisable to mix water from carbonate and sandstone formations. As with all other types of DOWS, the casing must be in sufficiently good condition to withstand setting of a packer and the pressures needed for injection. To promote proper gravity separation of oil and water, the wellbore should be as vertical as possible between the upper and lower intakes. Wells producing cold, heavy crude oil with an API gravity of 10° or less may not be good candidates for gravity separation. An API gravity of 15° may be a more appropriate cut off for gravity separation type DOWS.

To sum up, a good candidate well for DOWS application should meet the following requirements:
1- A compactable injection zone—the injection zone needs to have sustainable permeability for long-term water disposal, which is the most important requirement for DOWS applications. The injection zone should also be compactable with the injected water, which means the chemical properties of the injected water will not cause severe permeability damage. Due to the uncertain separation efficiencies for various DOWS systems, and the different solids specifications from various production zones, there is no clear criteria for cut-off permeability; however, formations that produce no or little sand are favorable.

2- Production requirement—the oil should have a gravity of 15°API or higher. The total production should be less than 1,200 bbl/day for a gravity-type DOWS, or higher flow rates for a hydro-cyclone-type DOWS with water cut of at least 90%.

3- Well requirement—the well has to be straight or slightly deviated. The casing has to be at least 5.5” in diameter, and the wellbore has to have good mechanical integrity and a minimum separation of about 24 m (80 ft) between the production zone and disposal zone. There is no connection between production zone and injection zone.

2.3.7 Reasons for DOWS

Produced-water lifting, treatment, and disposal costs are important components of operating costs. A DOWS can save operators money by reducing these costs.

DOWS installations reduced water volume brought to the surface in 29 of the cases examined in field case studies, the reduction ranged from 14 to 97%, with most installations exceeding a 75% reduction in water brought to the surface.

In more than half of the North American wells in which DOWS have been installed, the oil production rates increased following installation. The increased oil production rates ranged from 11 to more than 1,100%, although oil production decreased in a few wells.

In some cases in which surface processing or disposal capacity is a limiting factor for further production within a field, use of a DOWS to dispose some produced water may allow additional production in that field.

A DOWS provides a positive but not quantifiable environmental benefit by minimizing the opportunity for underground sources of potable water to become contaminated through tubing and casing leaks during the injection process. Likewise, DOWS installations minimize spillage of produced water onto the soil at the surface because less produced water is handled at the surface.
2.4 Downhole gas water separation (DGWS)

Since the difference in specific gravity between natural gas and water is large, separation occurs naturally in the well. The purpose of the DGWS is not so much one of separation of the fluid streams but of disposing the water downhole while allowing gas production. The technology is somewhat different than DOWS technology, for which the fluid separation component is very important.

Bypass tools are installed at the bottom of a rod pump. On the upward pump stroke, water is drawn from the casing-tubing annulus into the pump chamber through a set of valves. On the next downward stroke, these valves close and another set of valves opens, allowing the water to flow into the tubing. Water accumulates in the tubing until it reaches a sufficient hydrostatic head so that it can flow by gravity to a disposal formation. The pump provides no pressure for water injection; water flows solely by gravity. Bypass tools are appropriate for water volumes from 25 to 250 bbl/d and a maximum depth in the 6,000- to 8,000-ft range.

Modified plunger rod pump systems incorporate a rod pump, which has its plunger modified to act as a solid assembly, and an extra section of pipe with several sets of valves located below the pump. On the upward pump stroke, the plunger creates a vacuum and draws water into the pump barrel. On the downward stroke, the plunger forces water out of the pump barrel to a disposal zone. This type of DGWS can generate higher pressure than the bypass tool, which is useful for injecting into a wider range of injection zones. Modified plunger rod pump systems are better suited for moderate to high water volumes (250 to 800 bbl/d) and depths from 2,000 to 8,000 ft.

ESP systems are commonly used in the petroleum industry to lift fluids to the surface. In a DGWS application, they can be configured to discharge downward to a lower injection zone. A packer is used to isolate the producing and injection zones. ESPs can handle much higher flow rates (greater than 800 bbl/d) and can operate at great depths (more than 6,000 ft). They do require a substantial supply of electricity that is not always available in the field. ESPs are available from many suppliers. GRI (1999) reported that Centrilift and REDA (now part of Schlumberger) both offered DGWS systems using ESPs at that time. GRI also noted that another company, Petrospec Engineering, Ltd., had introduced an ESP that was deployed on coiled tubing for shallow and low-power-demand applications. Few ESP-type DGWS tools have been installed.

The fourth type of DGWS uses progressive cavity pumps (also referred to as progressing cavity pumps). This type of pump has been used throughout the petroleum industry. For DGWS applications, the pump is configured to discharge downward to an injection zone, or the pump rotor can be designed to turn in a reversed direction. In an alternate configuration, the progressive cavity pump can be used with a bypass tool. Then the pump would push water
into the tubing, and the water would flow by gravity to the injection formation. Progressive cavity pumps can handle solids (e.g., sand grains or scale) more readily than rod pumps or ESPs. GRI (1999) reported that Weatherford Artificial Lift Systems offered a DGWS system using progressive cavity pumps. The GRI study did not identify any actual applications of progressive cavity pump DGWS systems in use.

### 2.4.1 Downhole gas separator design recommendations

The following summary recalls some of the most important concepts about down hole gas separator design that have been developed over numerous years of field experience and laboratory testing:

- Maximize the size of the separator annular area to maximize the separator liquid capacity.
- Using a mud anchor with thin walls increases the size of the separator annular area. But efforts should be made to ensure that the mud anchor walls have the necessary strength.
- For gravity-driven separators in low viscosity fluid applications, good gas-liquid separation occurs when the superficial downward liquid velocity inside the separator is 6 in/second or less. The separator pump fillage factor decreases rapidly when this liquid velocity is exceeded.
- Excessive gas velocity in the casing annulus reduces the separator performance since it prevents liquid from entering the separator openings. The annular area between casing and separator should be large enough so that gas velocity in the casing annulus is less than 10 ft/sec.
- A long dip tube can be detrimental. A 5.5 ft long dip tube is enough for efficient gas separation for gravity-driven separators. The dip tube should extend about 4-5 feet below the separator inlet openings.
- The inner diameter of the dip tube should be sufficient to minimize the overall pressure drop through the separator.
- Under laboratory conditions, increasing the total area of the openings into the separator to over 65% of the separator outer barrel-dip tube annular area does not considerably improve the separator efficiency.
- Multiple rows of opening are not necessary. Additional rows should only be considered if port plugging is anticipated, based on the chemical evaluation of the fluids.
2.5 Downhole Water Sink (DWS)

Downhole Water Sink (DWS) is a completion/production technique for producing water-free hydrocarbons from reservoirs with bottom water drive and strong tendency to water coning. DWS eliminates water cutting the hydrocarbon production by employing hydrodynamic mechanism of coning control in-situ at the oil-water or gas-water contact.

The mechanism is based upon a local hydraulic drainage generated by a controlled downhole water sink installed in the aquifer beneath the oil or gas-water contact. Figure (2.8) shows principles of two basic variants of the DWS systems, drainage-injection and drainage-production.

In DWS system, a well is dual-completed in the oil and water zones and the two completions are separated by a packer set inside the well at depth of the oil-water contact. The water sink completion comprises a submersible pump and the water drainage perforations. The submersible pump drains the formation water around the well and controls the water cone growth and it’s breaking through the oil column into the oil-producing completion. The fluids produced by the top completion are either free of water or have small water content. In the result, the well’s productivity potential can be fully utilized to maximize oil production.

![Diagram of DWS water injection and production](image)

**Figure 2-8: DWS water injection and production**
Fate and quality of the drained formation water depend upon configuration of the DWS system. In the drainage-injection systems the drained water, free from oil contamination, is re-injected downhole into a deep injection zone. In the drainage-production systems, the water is lifted to the surface for disposal or beneficial use – if applicable.

The system applies to the offshore oil wells operating in the “clean water” range such that the drained water is free of oil and readily discharged overboard. The systems can also be used in gas wells with water coning problem to eliminate liquid loading and maximize gas production. In this application the top completion produces water-free gas and the bottom (water sink) completion drains the water with small amount of gas. The design involves inversing the water cone to create gas breakthrough into the water sink completion. At the completion, the liberated gas is produced to surface while the water pumped into a disposal zone.

2.6 Case study

2.6.1 Background

DOWS and DGWS technologies received a great deal of attention in the late 1990s. Over the past few years, few installations of either technology have been made. The U.S. Department of Energy asked Argonne National Laboratory to compile a database of as many DOWS and DGWS trials as possible and determine what set of production formation geology and injection formation geology offered the greatest chance for a successful installation. We provide here data on DOWS trials and DGWS trials from around the world (Table (1) to table (4) in the appendix). The data are taken from the literature, vendor web sites, and material directly provided by operators or vendors.
2.6.2 Worldwide field trials

Despite not including all worldwide field trials, the data compiled here represent the largest and most complete set of information on downhole separation that is publicly available. We further note that in some columns in the data tables, data are lacking for many trials.

Probably the most important factor is ensuring that the injection formation has good injectivity and that the injection process does not introduce materials that could clog the pores of the injection formation and reduce its injectivity. Another important parameter is good vertical and mechanical separation between the production and injection formations. The candidate well should be located in a formation that has sufficient remaining reserves to allow payback of the investment.

The DGWS success rate is not dependent on the geology of the source zone or disposal zone, but rather on site-specific properties of the disposal zone at individual wells. In general, disposal zones that are favorable for DGWS have high permeability, high porosity, and are underpressured.
DOE (U.S. Department of Energy) has actively promoted DOWS technology. With DOE funding, Argonne National Laboratory conducted an independent evaluation of the technical feasibility, economic viability, and regulatory applicability of DOWS technology in 1999 (Veil et al. 1999). That report provides information on the geology and performance of 37 DOWS installations representing most of the installations that had been made worldwide through 1998. Some of the key findings from those installations are summarized below:

*More than half of the installations were hydro-cyclone-type DOWS (21 compared with 16 gravity-separator-type DOWS.

*Twenty-seven installations were in Canada, and 10 were in the United States.

*Of the 37 DOWS trials described, 27 were in four producing areas: southeast Saskatchewan, east-central Alberta, the central Alberta reef trends, and East Texas.

*Seventeen installations were in 5.5-in. casing, 14 were in 7-in. casing, one was in 8.625-in. casing, and five were unspecified.

*Twenty of the DOWS installations were in wells located in carbonate formations, and 16 were in wells located in sandstone formations. One trial did not specify the lithology.

*The rate of oil production increased in 19 of the trials, decreased in 12, stayed the same in two, and was unspecified in four. The top three performing hydro-cyclone-type wells showed oil production increases ranging from 457% to 1,162%, while one well lost all oil production. The top performing well improved from 13 to 164 bbl/d. The top three gravity separator-type wells showed oil production increases ranging from 106% to 233%, while one well lost all oil production. The top-performing well in this group improved from 3 to 10 bbl/d.

*All 29 trials for which both pre-installation and post-installation water production data were provided showed a decrease in water brought to the surface. The decrease ranged from 14% to 97%, with 22 of 29 trials exceeding a 75% reduction.

**DOWS Installations**:

Table 1 and table 2 (APPENDIX) contains information on DOWS type installations.

**DGWS Installations**:

Table 3 and Table 4 (APPENDIX) offers limited data on DGWS type installations.
3. CHAPTER THREE: METHODOLOGY

3.1 Introduction:

Computational fluid dynamics, abbreviated as CFD is a branch of fluid mechanics that uses numerical analysis and algorithm to solve and analyze problems that involve fluid flow in specific geometries.

The major focus of CFD modeling of industrial process equipment is to simulate the industrial performance of the equipment with reasonable accuracy.

In this study, ANSYS 15 CFD software is used to model the flow of oil and water in a liquid-liquid hydro-cyclone for Well-04 in Heglig field, Sudan, using a complete data for Well-04 necessary to complete the CFD model. The well data used in this study is tabled in the appendix.

3.2 Procedure steps

The preprocessing software is used to build geometry and generate an unstructured mesh around the body of the hydro-cyclone, which could then be analyzed using CFD. Figure (3.1) shows the CFD modeling structure. The modeling structure is used to define modeling goals and identify its modeling domain, then create grid cells and ensure the quality of the grid.

Figure 3-1: modelling structure
Numerical model is set up, the solution is monitored and finally the results are examined to consider revision of the model if needed. The creation of liquid-liquid hydro-cyclone model consists of set of integrated cylindrical and conical sections for fluent analysis. Before meshing could be applied the geometry should be checked and cleaned if needed.

The steps of preprocessing procedure used for modeling hydro-cyclone behavior with CFD are:

1. Create Hydro-cyclone geometry.
2. Generate mesh.
3. Examine mesh quality.
4. Assign boundary zones (inlet, outlet and walls).
5. Set up numerical solution.
6. Analyze and modify solution if needed (post-processing).

### 3.2.1 Hydro-cyclone geometry

The design for a cyclone has four sections: inlet chamber, reducing section, tapered section and tail pipe. Inlet chamber and reducing section are designed to achieve higher tangential acceleration of fluid while reducing pressure drop and shear stress to an acceptable level. The reducing section has to minimize droplet breakup, the leading reduction of separation efficiency. Tapered section is where most of separation is achieved. The low angle of this part keeps swirl intensity high.

The last part (tailpipe) is where the smallest oil droplets immigrate to reverse flow core at the exit. Another important parameter in hydro-cyclone geometry is the inlet configuration. Most often rectangular and circular, single and twin inlets have been used. The main idea is to inject the fluid with higher tangential velocity, avoiding the rupture of the droplet.
The overflow outlet section of the hydro-cyclone has a very small diameter and it plays a major role in the split ratio-defined relationship between the overflow and inlet flow rate. The cyclone geometry used in the first part of the study is given in figure (3.2).

Figure 3-2: Hydro-cyclone dimensions

3.2.2 Mesh generation

For a given boundary mesh with some two dimensional (2D) quadrilateral or three dimensional (3D) hexahedral cells, TGrid (preprocessor) generates an unstructured triangular or tetrahedral (hybrid) grid. In 2D, boundary mesh consists of nodes and straight edges, whereas in 3D mesh consists of nodes and triangular and or quadrilateral faces. Boundary
mesh file can be obtained from Gambit. This file can be read into the solver where solution process and post-processing can occur. The basic steps of grid generation are:

1. Read a boundary mesh file containing some 2D quadrilateral or 3D hexahedral cells.

2. Examine boundary mesh for topological problems such as free edges and duplicate nodes. Once the boundary mesh is topologically correct, a 3D surface mesh can be checked for poor face quality. Many quality-related problems can be solved easily with edge swapping but more difficult problems may require direct manipulation of the faces and node.

3. Generate the volume mesh. We can perform this automatically or by proceeding through a series of steps. For hybrid grids we first generate any prism or pyramid and then generate triangular or tetrahedral volume cells. We can then extend them computational domain by generating more prisms, if desired. For grids containing only triangles and tetrahedrals, we can perform automatic mesh generation procedure or perform each step at a time.

4. Check the mesh problems or quality of mesh. We have to look carefully at the worst cells both for their quality and their location. The presence of degenerated cells will prevent us from obtaining solution and very poor cells in critical areas will cause serious accuracy and convergence problems. If bad cells cannot be removed or improved we need to generate a new mesh by modifying boundary mesh or using different mesh parameters.

5. Finally, we need to write the mesh to a new file for input to the solver.

Generating different grid systems depends on complexities of geometry and flow. Also, we need to know if we have enough computer memory, how many cells are required and how many models will be used (one-stage separation model or two-stage separation model). For simple geometries, quad/hex mesh can provide higher quality solutions with fewer cells than compared to tre/tet mesh. For complex geometries, quad/hex shows no numerical advantage and one can save meshing effort by using a tri/tet mesh.
3.2.3 Fluent modeling overview

For given problems, it is desirable to select appropriate physical models such as turbulence and multiphase models. The solver allows the user to specify various parameters associated with the solution method to be used in calculations like space (2D or 3D) dimensionality of domain, time (steady or unsteady), porous formulation and the velocity formulation. Figure (3.3) presents Fluent modeling overview. The solver uses two numerical methods:

☐ Segregated solver
☐ Coupled solver

Using either method, Fluent will solve the governing integral equation for conversion of mass, momentum and energy (if needed) and other parameters such as turbulence and chemical species.

Figure 3-3: CFD modelling overview
3.2.4 Solver selection

Coupled solver (implicit) is recommended if strong interdependency exists between density, energy, momentum and species; for example, high-speed reaction compressible flow and finite rate reaction flows. In general segregated solver (explicit) is recommended over the coupled (implicit) solver for the following reasons:

- Time required for coupled solver runs roughly twice the time required for segregated solver.
- Coupled solver requires large memory compared to segregated solver
- Segregated solver is preferred because it provides flexibility in solution procedure.

3.2.5 Solution algorithm

The best technique for speeding convergence is to tackle the problem one step at a time. CFD automatically solves each equation that applies to the selected problem. The mixture and volume of fluid models solve the transport equation for volume fraction, momentum equation, continuity equation, slip velocity and draft velocity.

![Solution Procedure Diagram](image-url)

**Figure 3-4: solution procedure**
3.3 Model setup

3.3.1 Physical model

In this study, a 2.8 inch liquid-liquid hydro-cyclone model is used. The model consists of a set of integrated cylindrical and conical sections. As shown on table (3.1) and figure (3.2) the created dimensions of the mixture inlet section was 2 inches in diameter and 1.5 inch in length, oil outlet pipe was 1 inch in diameter and 1.5 inch in length. At the bottom of tapered section where most of separation is achieved a cone is used and connected to a water outlet pipe with 1.6 inch diameter and 6 inch length.

<table>
<thead>
<tr>
<th>Section</th>
<th>Radius (inch)</th>
<th>Length (inch)</th>
<th>Shape</th>
</tr>
</thead>
<tbody>
<tr>
<td>Inlet chamber</td>
<td>1.4</td>
<td>2.5</td>
<td>Cylinder</td>
</tr>
<tr>
<td>Mixture inlet</td>
<td>1</td>
<td>1.5</td>
<td>Cylinder</td>
</tr>
<tr>
<td>Oil outlet</td>
<td>0.5</td>
<td>1</td>
<td>Cylinder</td>
</tr>
<tr>
<td>Tapered section</td>
<td>1.4</td>
<td>6</td>
<td>Cone</td>
</tr>
<tr>
<td>Water outlet</td>
<td>0.8</td>
<td>2</td>
<td>Cylinder</td>
</tr>
</tbody>
</table>

Table 3-1: dimensions of physical model

The geometry was designed using solid work 3D design depending on Well-04 completion data (complete data in appendix) so that the cyclone can fit perfectly in the completion design. The designed hydro-cyclone geometry is shown in figure (3.5) and figure (3.6).
Figure 3-5: Hydro-cyclone geometry

Figure 3-6: Hydro-cyclone geometry
Since a complex geometry was considered, hybrid mesh was generated in volume meshing and thousands of tetrahedral cells were created. The boundary types were specified as inlet velocity, outlet pressure and wall. Fluid was selected as a continuum and the resulting mesh was exported to the solver. The mesh file created with fluent option (3d, pbns, mixture, rngke) and case file was run and the grid was checked. Particular attention was paid to the reported minimum volume to make sure it was a positive number.

Segregated solver was set up and the selection of mixture and volume of the fluid multiphase model was made after studying the characteristics of different parameters such as volume fraction, Stoke’s number and turbulence. Dispersed oil and continuous phase (water) were also specified. Since incompressible flow (constant density) was used. Gravitational acceleration values were 0.0 and 9.81m/s² for x, y and z directions, respectively. Fluid velocity specification method and turbulence specification method was used in the model.

Wall was assumed to be a stationary wall since hydro-cyclone doesn’t have a rotating part. Back pressure was applied at hydro-cyclone underflow in order to force oil phase into the overflow outlet, otherwise, all the flow exits the underflow and no separation will occur. The discrete numerical solution algorithm was selected.

Figure 3-7: created mesh
3.3.2 Defining materials

After selecting the physical model for the cyclone, separation problem such as solver, multiphase model and viscous model the material properties required for the active physical models were selected. Oil from the well and its physical properties that are relevant to the scope of the problem, these properties include density or molecular weights, viscosity and API oil gravity. Reservoir temperature was assumed to be constant as 300 °F throughout the study. Solubility of gas was neglected since two phases (oil water) were considered. These properties were obtained from the PVT data for Well-04, however, viscosity value was assumed as it wasn’t included in PVT data. The water cut was 97% as reported in the well data. Well-04 properties used in the study are summarized in table (3.2)

<table>
<thead>
<tr>
<th>API</th>
<th>Specific gravity</th>
<th>Density, Kg/m³</th>
<th>Viscosity, cp</th>
</tr>
</thead>
<tbody>
<tr>
<td>28.9</td>
<td>0.88216</td>
<td>882.1</td>
<td>26</td>
</tr>
</tbody>
</table>

Table 3-2: PVT data for well-04
The hydro-cyclone was assumed to be placed in the middle of zone Bentaiu 1 (the production zone) near the production perforations at a depth of 1640 m. The zone pressure value was 2313 psia.

### 3.4 Conducting runs

Once iterations are completed and convergence was achieved, velocity, pressure and volume fraction profile were drawn and mass flow rate in both oil outlet and water outlet were studied and analyzed.

The results are presented and discussed in the following chapter.
The CFD modeling was successfully completed and various results are obtained. The CFD modeling and complete result of the study along with the data used for the modeling is given in a CD submitted with the thesis final draft.

Pressure profile:

Based on the results of pressure, Figure (4.1), there was a pressure difference between water and oil outlet and the mixture inlet. Water outlet pressure showed a low value. Oil outlet also shows a low pressure value but remains larger than the water outlet pressure. The pressure is not sufficient to inject water to the injection zone nor to lift the oil or water to surface. This problem can be handled with an application of a good pumping configuration.

Figure 4-1: pressure profile
Velocity profile:

Water velocity profile, figure (4.2), for the outlet section yielded lower values compared to water velocity profile in oil outlet, due to acceleration forces or rotations acting on the inlet chamber. On the other hand, results obtained for mixture velocity profile indicates that oil has a velocity value of nearly 101 m/s compared to mixture velocity of 19 m/s. The velocity profile also indicates that the velocity increases near the walls of the hydro-cyclone.

Figure 4-2: velocity profile
Mass flow:

Result obtained from the simulation showed that the fraction of oil in oil outlet increased compared to water outlet. Since the inlet chamber and reducing section have encountered more turbulence and higher tangential acceleration, oil was forced into the overflow outlet. The mixture mass flow rate in the inlet was 143.95 $m^3/s$ and the oil mass flow rate through the oil outlet was 37.50 $m^3/s$, and the water mass flow rate through the water outlet was 105.45 $m^3/s$.

![Swirl motion](image)

Figure 4-3: swirl motion

Hydro-cyclone efficiency:

Hydro-Cyclone efficiency defined as the ratio of total water in the water outlet to the total water in the mixture inlet. Efficiency was calculated using the mass flow rate through the mixture inlet and water outlet and it was found to reach 75.61%.

The efficiency is acceptable but it could be improved by a number of methods:

- A multi hydro-cyclone system could be designed to increase the efficiency
- Chemical additives such as emulsion breakers could be injected either in the inlet chamber or in the producing formation
The split ratio was also calculated using the following equation:

\[ F = \frac{q_{\text{low}}}{q_{\text{inlet}}} \times 100\% \]

And it was found to be 24.39%.
5. CHAPTER FIVE: CONCLUSIONS AND RECOMMENDATIONS

5.1 CONCLUSIONS

1- In this research, the CFD model was successfully used to represent the hydro-cyclone separators in downhole conditions.

2- The downhole separation is much more economic than conventional surface separation as it saves the cost of water handling, water production and water treatment. Downhole processing reduces the size and weight of surface facilities, which is desirable for offshore and remote areas. Remote wells may be drilled far from existing production facilities, requiring transportation of fluids at significant operational and capital cost.

3- Downhole process control is more challenging than control of surface equipment because; the equipment development is less mature and the equipment is remote from the surface, also the space in a well is very restricted

4- Most of the trials and previous instillations did not succeed because it was made in poorly chosen candidate wells. Companies often offered wells near the end of their useful lives for trials rather than wells that had a good chance of success. In some cases, equipment suppliers designed and installed systems on the basis of formation data supplied by operators. The data were not always accurate, and the systems failed because they were designed for conditions other than those actually present in the formation.

5- Downhole separation can be used to increase well production, water can be separated and re-injected downhole to unload gas wells and improve hydraulics. Gas may also be separated from oil streams downhole to improve tubing hydraulics at very high gas fractions.

6- Separation is more difficult for heavier (low API gravity) oils because the density difference between low API gravity oil and water is small. The minimum density difference is 2 API or 0.02 g/cm³. Separation is also more difficult when droplet sizes are small, such as in water-polishing applications. Small droplets experience high viscous forces, which retard separation, compared to the density difference.
7- Gas fraction is limited to approximately 10% by volume. If more gas is present, it must be separated upstream of the hydro-cyclone.

8- The water cut must be high enough so that the mixture forms a water-external emulsion. This water-cut level varies with individual oil and water properties, but normally occurs at relatively high water-cut levels—greater than 50%. Manufacturers of downhole hydro-cyclones recommend that the water cut be 75% or higher.

9- Hydro-cyclones transform pressure energy into rotational kinetic energy to centrifuge the fluid. Because of this, some pressure drop is required. This is typically in the range of 50 to 200 psi. High bottomhole pressures caused by surface production bottlenecks are favorable.

10- Available downhole separation equipment provides only partial separation of oil and water. As a result, some water must be produced to the surface with the oil, and so water handling on the surface is not completely eliminated.
5.2 RECOMMENDATIONS

The following points should be considered if any future work is to be done regarding this study:

1- Effect of different cyclone geometry on efficiency of oil separation needs to be studied.

2- Separation efficiency of more than one cyclone installed in series needs to be studied.

3- Further research is needed to determine the optimum pressure setting of downhole hydro-cyclone.

4- Nodal analysis should be used to predict the operating conditions for downhole separation with or without downhole injection. This analysis combines the hydrocarbon-zone productivity, the injection-zone injectivity, and tubing/annulus multiphase hydraulics to predict the operating state of the well.

5- As part of the hydraulics and nodal analysis modeling, the pressure changes of the fluid as it flows through the separator, pump, or compressor assembly are required. Pump and compressor curves must be generated and integrated into the hydraulics modeling. These calculations are also required to evaluate the feasibility of the desired outcome and equipment sizing for each application. Normally, these will be generated and provided by the equipment vendor.

6- Materials for the downhole equipment must be chosen to withstand a corrosive wellbore environment if water is produced.

7- The expected life and frequency of repair/replacement of the equipment must be estimated. Then, the cost of replacing the equipment must be calculated. This will result in a projected operation and maintenance cost that can be combined with the capital cost for an overall economic evaluation.

8- Future work should consider the effect of geological conditions on the performance on the downhole separation technology, also the chemistry of both produced water and injection zone should be further studied to be compatible with injected water to avoid injectivity decline.
6. CHAPTER SIX: REFERENCES


* Bradley, D., the Hydro-cyclone, edited by P. V. Danckwerts, Pergamon Press, Oxford, 1965


* Centrilift (Voss 2004a).

* Coleman, D.A., Thew, M.T., “The concept of hydro-cyclones for separating light dispersions and comparison of field data with laboratory work “, paper F2, 2nd Int. Conf. on Hydro-cyclones, Sep. 1984

* Flow Modeling Solution for Oil and Gas Industries


* Pericleous, K. A., Rhodes, N., “A mathematical model for predicting the flow field in a hydro-cyclone classifier”, Paper B1, 2nd Int. Conf. on Hydro-cyclones, Sept. 1984


* Veil et al. (1999).
Table 1 well information:

<table>
<thead>
<tr>
<th>Well name and #:</th>
<th>Heglig 04</th>
</tr>
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<tbody>
<tr>
<td>Perforations:</td>
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<tr>
<td>Zone:</td>
<td>Bentiu 1</td>
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Table 2 completion data:

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<th>Tubulars:</th>
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<th>Grade</th>
<th>Set at</th>
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<td>Conductor:</td>
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<td>139.9</td>
<td>K-55</td>
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<tr>
<td>Surface Casing:</td>
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<td>101.2</td>
<td>S-80</td>
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<td>Intermediate Casing:</td>
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<td>Production Casing:</td>
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Table 3 production data:

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<th>Month</th>
<th>Structure</th>
<th>Well</th>
<th>Type</th>
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<th>CD Oil</th>
<th>CD Water</th>
<th>CD Liq</th>
<th>PD Oil</th>
<th>PD Water</th>
<th>PD Liq</th>
<th>Prod. Zone</th>
<th>WC%</th>
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Table 4 PVT data:

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# DOWS instillations

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<tr>
<th>Operator and Well Name</th>
<th>Field</th>
<th>State/Province</th>
<th>Type of DOWS</th>
<th>Pre-DOWS Oil (bpd)</th>
<th>Pre-DOWS Water (bpd)</th>
<th>Post-DOWS Oil (bpd)</th>
<th>Post-DOWS Water (bpd)</th>
<th>% Increase in Oil</th>
<th>% Decrease in Water</th>
<th>Casing Size (in.)</th>
<th>Production Formation</th>
<th>Injection Formation</th>
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<tr>
<td>Imperial Redwater #1-26</td>
<td>Redwater</td>
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<td>Ellerslie-Dina</td>
<td>Dina</td>
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<td>Dina</td>
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<td>Texas</td>
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Table 2

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<th>Operator and Well Name</th>
<th>Lithology</th>
<th>Injectivity (bpd/psi)</th>
<th>Injection Pressure Differential (psi)</th>
<th>Prod. and Inj. Formation Separation (ft)</th>
<th>Trial Starting Date</th>
<th>Trial Ending Date</th>
<th>Comments</th>
<th>Source of Information</th>
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<tr>
<td>Pinnacle-Alliance (originally PanCanadian) 7C2</td>
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<td>Mathews et al. (1996)</td>
</tr>
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<td></td>
<td></td>
<td>Dec-95</td>
<td></td>
<td>Problems with sand plugging.</td>
<td>Florence (1998)</td>
</tr>
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<td></td>
<td>Dec-95</td>
<td></td>
<td>Problems with sand plugging.</td>
<td>Florence (1998)</td>
</tr>
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<td>PanCanadian 00/16-05</td>
<td>Sandstone/ sandstone</td>
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<td>Jan-96</td>
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<td>Problems with sand plugging.</td>
<td>Florence (1998)</td>
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<tr>
<td>Talisman Energy 4-27-5 3W1</td>
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<td></td>
<td></td>
<td>May-96</td>
<td></td>
<td></td>
<td>Naylor (1998)</td>
</tr>
<tr>
<td>PanCanadian 00/02-09</td>
<td>Carbonate/ carbonate</td>
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<td></td>
<td></td>
<td>May-96</td>
<td></td>
<td>Problems with H2S and scale.</td>
<td>Florence (1998)</td>
</tr>
<tr>
<td>Talisman Energy Tidewater Parkman 4-27</td>
<td>Carbonate/ carbonate</td>
<td>6</td>
<td>0</td>
<td></td>
<td>Jul-96</td>
<td>May-97</td>
<td>Corrosion problems to pump and tubing.</td>
<td>Wright (1998)</td>
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<td>Anderson 08-17</td>
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<td></td>
<td>Problems with well bore and scale formation.</td>
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<td>Texaco Salem #85-40</td>
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<td>1,137</td>
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<td>Aug-96</td>
<td>Apr-97</td>
<td>Pumps damaged by corrosion.</td>
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<td>0</td>
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<td></td>
<td>Aug-96</td>
<td></td>
<td>May have been recycling water? Under sized pump.</td>
<td>Hild (1997)</td>
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## DGWS instillations

### Table 1

<table>
<thead>
<tr>
<th>State/Province/County</th>
<th>Type of DGWS</th>
<th>Pre-DGWS Gas (mstd)</th>
<th>Post-DGWS Gas (mstd)</th>
<th>% Increase in Gas</th>
<th>Production Formation</th>
<th>Lithology</th>
<th>Injection Formation</th>
<th>Lithology</th>
<th>GRI's Qualitative Measure of Performance</th>
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<tr>
<td>Alberta</td>
<td>Bypass seating nipple, Harbison Fischer</td>
<td>Shut in</td>
<td>51</td>
<td>150</td>
<td>Lower Cretaceous</td>
<td>Clastics</td>
<td>Lower Cretaceous</td>
<td>Clastics</td>
<td>Success</td>
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<tr>
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<td>Bypass seating nipple, Harbison Fischer</td>
<td>Shut in</td>
<td>125</td>
<td>200</td>
<td>Cottage Grove</td>
<td>Sandstone</td>
<td>Lower Cretaceous</td>
<td>Sandstone</td>
<td>Success</td>
</tr>
<tr>
<td>OK</td>
<td>Bypass seating nipple, Harbison Fischer</td>
<td>Shut in</td>
<td>250 (before shut in)</td>
<td>220</td>
<td>Council Grove (Wolfcampian)</td>
<td>Shallow shelf carbonate</td>
<td>Lower Cretaceous</td>
<td>Shallow shelf carbonate</td>
<td>Success</td>
</tr>
<tr>
<td>OK</td>
<td>Bypass seating nipple, Harbison Fischer</td>
<td>Shut in</td>
<td>50</td>
<td>150</td>
<td>Council Grove (Wolfcampian)</td>
<td>Shallow shelf carbonate</td>
<td>Lower Cretaceous</td>
<td>Shallow shelf carbonate</td>
<td>Failure</td>
</tr>
<tr>
<td>TX</td>
<td>Bypass seating nipple, Harbison Fischer</td>
<td>Shut in</td>
<td>140</td>
<td>100</td>
<td>Council Grove (Wolfcampian)</td>
<td>Shallow shelf carbonate</td>
<td>Lower Cretaceous</td>
<td>Shallow shelf carbonate</td>
<td>Success</td>
</tr>
<tr>
<td>Alberta</td>
<td>Downhole water injection tool (Chirisco)</td>
<td>Shut in</td>
<td>706</td>
<td>143</td>
<td>Mannville</td>
<td>Sands</td>
<td>Mannville</td>
<td>Sands</td>
<td>Success</td>
</tr>
<tr>
<td>Alberta</td>
<td>Downhole water injection tool (Chirisco)</td>
<td>Shut in</td>
<td>353</td>
<td>142</td>
<td>Mannville</td>
<td>Sands</td>
<td>Mannville</td>
<td>Sands</td>
<td>Success</td>
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<td>87</td>
<td>Mannville</td>
<td>Sands</td>
<td>Mannville</td>
<td>Sands</td>
<td>Success</td>
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<td>Downhole water injection tool (Chirisco)</td>
<td>Shut in</td>
<td>194</td>
<td>244</td>
<td>Mannville</td>
<td>Sands</td>
<td>Mannville</td>
<td>Sands</td>
<td>Success</td>
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<td>Alberta</td>
<td>Downhole water injection tool (Chirisco)</td>
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<td>141</td>
<td>71</td>
<td>Mannville</td>
<td>Sands</td>
<td>Mannville</td>
<td>Sands</td>
<td>Success</td>
</tr>
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<td>Electric submersible pump (Centrifit and Recta)</td>
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<td>1,500</td>
<td>10,000</td>
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<tr>
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<td>Electric submersible pump (Centrifit and Recta)</td>
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<td>0</td>
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<td>Sandstone</td>
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<tr>
<td>State/Provincial Country</td>
<td>Type of DGWS</td>
<td>Pre-DGWS Gas (mcfd)</td>
<td>Pre-DGWS Water (bpd)</td>
<td>Post-DGWS Gas (mcfd)</td>
<td>Post-DGWS Water Injected (bpd)</td>
<td>% Increase in Gas</td>
<td>Production Formation</td>
<td>Lithology</td>
<td>Injection Formation</td>
</tr>
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<td>--------------------------</td>
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<td>350</td>
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<td>750</td>
<td>300</td>
<td>114</td>
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<td>343</td>
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<td>300</td>
<td>100</td>
<td>300</td>
<td>-50</td>
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<td>60</td>
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<td>266</td>
<td>-75</td>
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<td>Sands</td>
<td>Tonkawa sand member of Douglas Group</td>
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<td>125</td>
<td>640</td>
<td>-50</td>
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<td>200</td>
<td>100</td>
<td>-43</td>
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<tr>
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<td>Modified plunger rod pump (DH)</td>
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<td>40</td>
<td>220</td>
<td>260</td>
<td>88</td>
<td>Upper Prue (aka Lagonda)</td>
<td>Sandstone</td>
<td>Lower Prue</td>
</tr>
</tbody>
</table>