HEAVY OIL WATERFLOODING: EFFECTS OF FLOW RATE

by

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FINAL REPORT

Submitted to the Petroleum Engineering Programme
in Partial Fulfillment of the Requirements
for the Degree
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(Petroleum Engineering)

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CERTIFICATION OF APPROVAL

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Approved:

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UNIVERSITI TEKNOLOGI PETRONAS
TRONOH, PERAK

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CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

SAIFUL IDRUS BIN ZAKARIA

ABSTRACT

The objectives of this final year project are to understand the forces that are present in the reservoir and how they can be used to properly design the heavy oil waterflooing and to determine the effect of water injection rate toward oil recovery. In times of uncertain commodity pricing, it is beneficial to oil and gas industries company to have and examine the potential for low cost, non-thermal oil recovery techniques which are relatively inexpensive and easy to control such as waterflooding.

The problem is that, in waterflooding applications, oil companies still have a problem of understanding the forces that are present in the reservoir and how they can be used to properly design the waterflood which can lead to a better oil recovery. Specifically, proper design and maintenance of waterfloods requires comprehension of how viscous oil can be displaced by water, and how oil recovery can be optimized. Thus, the scope of study should be based on searching for the results for water injection into laboratory core plug containing gas-free heavy oil of high viscosity at different water injection rate. The responses for different waterfloods are compared in order to investigate the mechanisms by which heavy oil can be recovered by water injection. The parameters that will be evaluated is the effect of water injection rate, effect of capillary forces, instability and mobility ratio. This research focus in evaluating affects of water injection rate towards heavy oil recovery by waterflooding. In order to obtain the data, the author use research methodology of identifying and understand the theory of waterflooding in oil reservoir such as understand the instability theory and imbibitions theory. Author also evaluates the effect of viscous forces and capillary forces through laboratory test and make a prediction of heavy oil waterflooding recovery. This final year project presents the finding or results for water injection into laboratory core plug containing gas-free heavy oil at varying water injection rates. The responses for different waterfloods are compared in order to investigate the mechanisms by which heavy oil can be recovered by water injection. Therefore, if the author can prove that waterflooding at lower injection rate is better than high injection rate in term of recovery, Oil Company can increase their profit at significant value.

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LIST OF ABBREVIATIONS

H_2S	Hydrogen Sulfide
CO_2	Carbon Dioxide
SO_4^{2-}	Sulphate ion

CHAPTER 1

INTRODUCTION

1.1 Background of Study

Heavy oil is a type of crude oil which has properties of very viscous, which are not flow easily but provides an interesting situation for the economics of petroleum development. The resources of heavy oil in the worldwide are more than twice those of conventional light crude oil. In October 2009, the USGS updated the Orinoco tar sands (Venezuela) recoverable value to 513 billion barrels (8.16×10^{10} m^3) [1], making this area the world's first recoverable oil deposit, ahead of Saudi Arabia and Canada.

Common characteristic properties for heavy oil are: low hydrogen to carbon ratios, high carbon residues, and high contents of asphaltenes, heavy metal, sulphur and nitrogen, and high specific gravity. A lot of countries in the world contain significant heavy oil deposits. In the reservoirs with viscosity over several hundred mPa·s, waterflooding is not expected to be successful due to the extremely high oil viscosity.

However, in many smaller, thinner reservoirs, or reservoirs at the conclusion of cold production, thermal enhanced oil recovery methods absolutely will not be economic. Waterfloods will still often be employed in high viscosity heavy oil fields because of relatively inexpensive and easy to control and therefore, there are certain parameters which can be used to improve heavy oil waterflooding to make it more effective and efficient.

1.2 Problem Statement

1.21 Problem Identification

In times of uncertain commodity pricing, it is beneficial to oil and gas industries company to have and examine the potential for low cost, non-thermal oil recovery techniques which are relatively inexpensive and easy to control. Waterflooding is often employed, at least initially, in heavy oil reservoirs, both along with or after primary recovery in order to re-pressurize the reservoir and displace oil to producing wells. In these applications, oil companies still have a problem of understanding the forces that are present in the reservoir and how they can be used to properly design the waterflood which can lead to a better oil recovery at low cost. Specifically, proper design and maintenance of waterfloods requires comprehension of how viscous oil can be displaced by water, and how oil recovery can be optimized.

This final year project presents the results for water injection into laboratory sandpacks containing gas-free heavy oil at varying water injection rates. The responses for different waterfloods are compared in order to investigate the mechanisms by which heavy oil can be recovered by water injection. Therefore, if the author can prove that waterflooding at lower injection rate is better than high injection rate, Oil Company can increase their recovery and profit.

1.22 Significant of the Project

There has been some limited experience documented for water-floods in heavy oil reservoirs [3-6] but, in general, the mechanism of viscous oil recovery by waterflooding has not been explored. Recoveries of waterflood are known to be low for high viscosity oil due to the adverse mobility ratio between oil and injected water. Despite the presumed inefficiency of this process, waterflooding is still commonly applied in many of heavy oil fields due to relatively inexpensive and field operators have years of experience designing and controlling waterfloods.

Therefore this final year project is hopefully can increase the level of understanding of mechanism for viscous oil recovery by waterflooding and contribute to the oil company towards high oil recovery.

1.3 Objectives

The ultimate objectives of the project are as follow:

1. To understand the forces that are present in the reservoir and how they can be used to properly design the waterflood.
2. To determine the effect of water injection rate toward oil recovery.

1.4 Scope of Study

This final year project will search for the results for water injection into laboratory core plug containing gas-free heavy oil of varying viscosity of 1500 cp at different water injection rate. The responses for different waterfloods are compared in order to investigate the mechanisms by which heavy oil can be recovered by water injection.

Therefore, the parameters that will be evaluated are effect of viscous forces (oil viscosity and water injection rate), instability and mobility ratio. This research focus in evaluating affects of water injection rate towards high heavy oil recovery by waterflooding.

1.5 Project Relevancy

Waterflooding in heavy oil costs the petroleum industry hundreds of millions of dollars each year. The optimum solution, balancing cost with efficiency of waterflooding in heavy oil production should be an important part of all waterflooding design. An understanding of the forces and mechanism by which heavy oil can be recovered by water injection will ensure the success in heavy oil water flooding such as high oil recovery, high oil production and cost optimization.

In these applications, oil companies still have a problem of understanding the forces that are present in the reservoir and how they can be used to properly design the waterflood, thus the author try to solve this problem by using final year project as a medium.

1.6 Feasibility of the Project

This research is feasible to be conducted within the given time frame due to following factors:

1.6.1 Availability of equipments

The laboratory experiments require three equipments which are Poro/Perm, Sohxlet Extractor, and Relative Permeability System. The equipments are available at Academic Building 15, Universiti Teknologi PETRONAS.

1.6.2 Availability of materials and chemicals

The required chemicals and materials for experimental works are provided at UTP laboratory facilities.

CHAPTER 2

LITERATURE REVIEW

2.1 Heavy Oil

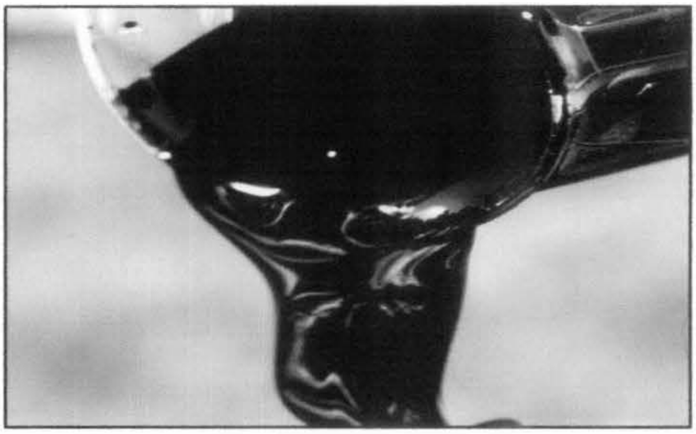


Figure 1: Heavy Oil

Heavy oil accounts for more than double the resources of conventional oil in the world [18]. This type of oil is any type of crude oil which does not flow easily. It is referred to as "heavy" because its density or specific gravity is higher than that of light crude oil. Heavy crude oil has been defined as any liquid petroleum with an API gravity less than 20°[19] ,meaning that its specific gravity is greater than 0.933. This mostly results from the crude oil getting degraded by being exposed to bacteria, water or air resulting in the loss of its lighter fractions while leaving behind its heavier fractions.

Therefore, production, transportation, and refining of heavy crude oil present special challenges compared to light crude oil. The largest reserves of heavy oil in the world are located north of the Orinoco river in Venezuela[20], the same amount as the conventional oil reserves of Saudi Arabia[21], but 30 or more countries are known to have this kind of oil reserves. Actually, heavy crude oil is closely related to oil sands, but the main difference being that oil sands generally do not flow at all. Canada has significant reserves of oil sands, located north and northeast of Edmonton, Alberta.

Physical properties that differentiate between heavy crudes from lighter ones include higher viscosity and specific gravity, as well as heavier molecular composition.

Extra heavy oil from the Orinoco region has a viscosity of over 10,000 centipoise (10 Pa·s)[22] and 10° API gravity [23]. Generally a diluents is added at regular distances in a pipeline in carrying heavy crude to facilitate its flow.

Some of the petroleum geologists categorize bitumen from oil sands as extra heavy oil although bitumen does not flow at ambient conditions. The resources in Canada and the USA are readily accessible to oil companies, and the political and economic environments are seems stable. While these resources in North America only provide a small percentage of current oil production, existing commercial technologies is believed could allow for significantly increased production. These kind of unconventional oils can be profitably produced, but at a smaller profit margin than for conventional oil, because of higher production costs and upgrading costs in conjunction with the lower market price for heavier crude oils. Thus, heavy oil has become an important theme in our industry with an increasing number of operators getting involved or expanding their plans in this market around the world.

Many kind of heavy oil exist and a variety of production processes are being used and developed to recover it. Heavy oil is different, and as a conclusion, many technologies and services used for conventional oil face limitations with these highly viscous oils.

2.2 Waterflooding

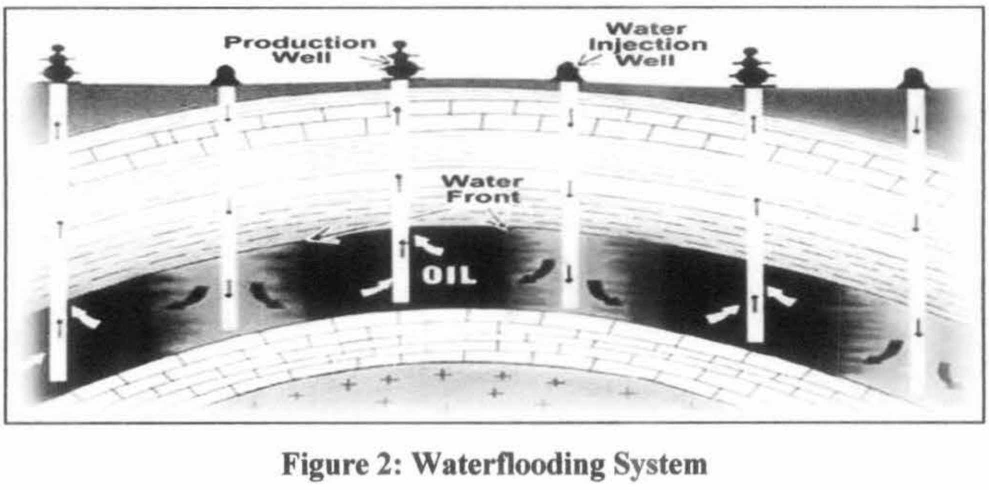


Figure 2: Waterflooding System

Waterflooding is a method of improved recovery in which water is injected into a reservoir to remove additional quantities of oil that have been left behind after primary recovery. Waterflooding usually involves the injection of water through wells specially set up for water injection and the removal of water and oil from production wells drilled adjacent to the injection wells[a]. Therefore it is also secondary recovery mechanism which involves the injection of water into the reservoir through an injector well(s) to maintain the reservoir pressure and drive the oil towards the producing well(s). Secondary or enhanced oil recovery (EOR) methods are needed because only a small fraction of the oil in a reservoir can be produced by primary means (the reservoir's natural drives). Initial recovery ranges from only about 5 per cent (Lloydminster-area heavy oils) up to about 20 per cent [(24)].

These methods must be both economic and effective, or companies may not bother trying to coax more oil from the reservoir. Waterflooding usually become the first secondary method applied to a reservoir--meets both these criteria. In many of situations, it will help recover a significant portion of the oil in the reservoir. Capital costs (CAPEX), mainly for surface facilities to handle the injection and production water, are relatively inexpensive compared with those of most other EOR methods. Operating costs (OPEX) for a waterflood are typically lower than for other EOR techniques.

Where does the water for injection come from? A common misconception is that oil companies use the valuable surface water and, by injecting the water into an oil formation, render it dirty and salty. While a limited number of projects do use some surface water, those practices are now become disappearing. Nowadays, most projects use water from an underground aquifer that is similar to the oil formation's native water, usually quite salty and not suitable for human or animal consumption. Virtually all of the injected water is produced together with the oil. The two fluids are separated at the surface, the oil content remaining in the water is removed, and the water is then reinjected. Thus, in fact most of the water gets repeatedly recycled for only a small amount of 'new' water, roughly equal to the amount of oil produced, is required on a daily basis, Water fractions in the produced fluids can be as high as 99 per cent before water handling costs make the practice uneconomic[24].

Waterflooding already has its advantages as a proven technology for conventional oil, but there is still room to improve. Waterflooding enhancements will be crucial for continuity of productivity for a large number of reservoirs throughout Saskatchewan. While for the other EOR technologies will certainly recover more of the oil from a given reservoir, the economics may not be that favorable to their application in the province. Therefore, the science behind waterflooding must be advanced to sustain the oil industry. Efforts already underway to improve waterflooding technology and also to extend its application to heavy (more viscous) crudes, once thought impractical. One method is involving the addition of a small amount of soap (chemicals) to the water in order to free the oil attached to the reservoir rock. Researchers expect that this technique could recover an additional 10 to 20 per cent of a reservoir's original oil [24]. This can be seen as good as discovering a new reservoir.

The other approaches are being developed to control where the water goes in the reservoir. In many applications, water is less viscous than the reservoir oil, and so tends to flow along the easiest path through the reservoir, missing a large amount of the remaining oil. There are many ways to raise the water's viscosity and get it to flow into areas where there are higher oil concentrations. One of these methods is via creating and injecting micro-bubble solutions. It was recently "tested" by over a thousand school children in "Canada's Largest Science Experiment," held in Regina and Saskatoon [24]. Oil producers and researchers are now working hard to find the best waterflooding practices to increase recovery and to achieve quicker success. Many of the investment opportunities compete for oil companies' attention. For Saskatchewan's reservoirs to be a part of their production strategy, effective and relatively low-cost technology must be "on tap". Doug Soveran is the Manager of Production and Processing for the Saskatchewan Research Council's Energy Division.

However, there are certain potential problems associated with waterflood techniques such as inefficient recovery due to variable permeability, or similar conditions affecting fluid transport within the reservoir, and early water breakthrough that may cause production and surface processing problems [13].

2.3 Permeability

Permeability is ability, or measurement of a rock's ability, to transmit fluids, typically measured in darcies or millidarcies. This term was basically defined by Henry Darcy, who showed that the common mathematics of heat transfer could be modified to adequately describe fluid flow in porous media. Formations which transmit fluids readily, such as sandstones, are described as permeable and tend to have many large and well-connected pores. Impermeable formations such as shales and siltstones are tending to be finer grained or of a mixed grain size and less interconnected pores [14].

Therefore, the absolute permeability is the measurement of the permeability conducted when a single fluid, or phase, is present in the rock and the effective permeability is the ability to preferentially flow or transmit a particular fluid through a rock when other immiscible fluids are present in the reservoir such as effective permeability of gas in a gas-water reservoir. Relative saturations of the fluids as well as the nature of the reservoir affect the effective permeability. Relative permeability is defined as a ratio of effective permeability of a particular fluid at a particular saturation to absolute permeability of that fluid at total saturation. For a single fluid is present in a rock, its relative permeability is 1.0[14]. Calculation of relative permeability allows for comparison of the different abilities of fluids to flow in the presence of each other, since the presence of more than one fluid generally inhibits flow.

2.4 Breakthrough

Breakthrough can be defined as a description of reservoir conditions under which a fluid previously isolated or separated from production, gains access to a producing wellbore [15]. This kind of term is most commonly applied to water or gas breakthrough, which the water or gas injected to maintain reservoir pressure by using injection wells breaks through to one or more of the producing wells.

Water breakthrough is water production from underlying water. This process should be avoided or delayed since there is no value of producing water [16]. Produced water also can change the well and topside environment and it requires treatment and handling to reduce the pollution. The operator will just accept a high water cut in situation where the oil price is high. Therefore, the early water breakthrough will typically occur in bad formation, bad well position, thin oil layer, high production zone and heavy oil production.

The water production of a well designed for oil production will give a new environment in the well and topside equipment too. Even though, formation water has 'no oxygen', but it may change the level of H_2S, CO_2, chloride ions and the others. The important thing is that, bacteria are natural in formation water thus when sulphide reducing bacteria (SRB) can easily produce H_2S from SO_4^{2-} when mixing seawater and formation water. As a conclusion, water breakthrough from seawater pressure support may cause a dramatic increase in H_2S.Therefore if this project can make a longer time production of heavy oil before the breakthrough, it can reduce the problem of high water cut such as corrosion, scale and cracking.

2.5 Waterflooding in Heavy Oil

Waterflooding has long been proven as the simplest and the lowest cost approach to maintain production and increase oil recovery from an oil reservoir. However, all of these benefits may fall far short of the expectations unless the time-tested concepts and practices are clearly understood and judiciously implemented. These concepts and practices aim at process optimization -reducing production cost while minimizing waste and maximizing oil recovery and income [17]. In conventional oil, the waterflooding theory has been well documented. The inherent assumption in conventional oil waterflooding theory is a similarity in viscosity between oil and water [3]. In heavy oil applications this is not the case and even concepts like oil or water relative permeability does not have the same meaning in heavy oil systems where the area of flow for oil and water may be very different at all. However, practitioners often still attempt to apply the same theoretical understanding or concept to their fields. There has been some limited experience in documentation for waterfloods in heavy oil reservoirs but, in general, the mechanism of viscous oil recovery by waterflooding has not been explored yet.

Waterflooding recoveries are low for high viscosity oil because of the adverse mobility ratio between oil and water which injected to the reservoir. Despite the presumed inefficiency of this process, waterflooding is still largely applied in so many heavy oil fields since it is relatively inexpensive and field operators have years of experience designing and controlling the waterfloods. When the period of a conventional oil waterflood come to the end, the residual oil is left in place due to reservoir heterogeneities or capillary trapping. For laboratory core floods of conventional oil, capillary bypassing is one of the main mechanisms responsible for trapping oil [(4)]. For heavy oil systems, however, the high oil viscosity (and hence the poor mobility ratio between displacing and displaced fluids) is the main cause of oil bypassing and residual oil at the end period of the waterflood.

Many of previous investigations usually focused on the oil or water mobility ratio and how it relates to the viscous fingering or instability of displacing water front. All of these analyses focus on the stability of an advancing water front, and how the mobility ratio can be relate to the oil recovery at the point of breakthrough.

2.6 Instability

For heavy oil waterflooding, water is displacing more viscous oil and the displacement front may become unstable. When this happens, viscous fingers are said to have formed. This will lead to premature breakthrough of the displacing phase and reduce the breakthrough oil recovery. Peters and Flock [5] identified the parameters controlling the stability of the system as mobility ratio, displacement velocity, system geometry and dimensions, capillary and gravitational forces, and system permeability and wettability. Their work focused on the performing stability analysis in order to identify the conditions under which a frontal perturbation will grow to become a viscous finger. The instability number (I_{sr}) for a horizontal 1D system, as defined by Peters and Flock [9], is as follows:

$$\boxed{I_{sr} = \frac{(M-1)\,\upsilon\mu_w D^2}{C^*\sigma k_{wor}}} \qquad \text{.......... (1)}$$

The mobility ratio (M) is defined as:

$$\boxed{M = \frac{k_{wor}\mu_o}{k_{oiw}\mu_w}} \qquad \text{.......... (2)}$$

where υ is the injection rate, μ_w is viscosity of water, μ_o is oil viscosity, D is the diameter of the core, σ is the interfacial tension, k_{wor} is the permeability to water at the irreducible oil saturation (S_{or}), k_{oiw} is the permeability to oil at the connate water saturation (S_{wi}) and C^* is the wettability constant. The value for C^* has different values for varying rock wettability and is related to differences in the growth of viscous fingers in oil-wet versus water-wet of porous media. For smaller diameter cores, there is also less potential for fingers to grow, thus in the field, the effect of instability may be more pronounced than in a linear core system. The value of I_{sr} is also directly proportional to the fluid mobility; in heavy oil systems the mobility ratio is very large, which leads to very high values of I_{sr} (i.e. very unstable floods).

At the onset of instability, I_{sr} was found to be π^2 or 13.56(9) and when $I_{sr} < 13.56$, the displacement is stable, indicating that viscous fingers will not grow if a perturbation forms at the displacement front. Therefore, when $I_{sr} > 1{,}000$, the displacement is deemed fully unstable. In the transition zone ($13.56 < I_{sr} < 1{,}000$), the flood will increasingly unstable and breakthrough recovery decreases rapidly as I_{sr} increases. In the 'pseudo stable' region of I_{sr} >1,000, the recovery tends to become constant back. In range of this stage, displacement is actually so unstable that a single finger dominates flow. Most of the injected fluid is passing through this finger and recovery become low and relatively independent of injection rate.

Instability theory shows that before I_{sr} = 1,000, the displacement rate determines the finger properties and during high injection rate in an unstable system, the finger wavelength will be short. Hence, numerous fingers will form and this will lead to even faster breakthrough of water and more bypassing of oil. For low rate condition, the finger wavelength will be long and only a few fingers can form in the porous medium. Multiple fingers will lead to a higher degree of instability. Therefore, it is much recommended to perform waterfloods more slowly under unstable conditions in order to limit the generation and growth of fingers. Peters and Flock[(5)] stressed the importance of the wettability number on the quantification of I_{sr}. This number gives an indication of the ability of the porous medium to imbibe the displacing water, which stabilizing the flood front. For water-wet media, the imbibition forces are strong, where the wettability number will be large (C^* = 306.25) [(5)].

In oil-wet media, the wettability number was found to be much lower due to under drainage, where the water will only move through the largest channels, so the front cannot be stabilized by additional flow into smaller pores. Bentsen [(6)] derived a different version of the instability number based upon force potentials rather than velocity potentials. His version of the instability number is proportional to the one proposed by Peters and Flock [(5)], with an additional factor need to take into consideration; the larger size difference of water and oil fingers. Sarma and Bentsen [(7)] later developed the theory further to predict the recovery at breakthrough for stable displacement and pseudostable (I_{sr} > 1,000) displacement regimes.

The theory of instability is basically based on balance of forces. In the displacement of a higher viscosity fluid, if the combined forces of gravity and capillarity are greater than the viscous force, then the displacement will be stable. If the reverse is true, thus the displacement will be unstable and the degree of instability depends on the rate of injection, with all else being equal. In heavy oil systems, the difference between oil and water viscosity is so great that I_{sr} will always tend to become very large. This theory shows a dominance of viscous forces during waterflooding and explains the low recovery expected. But, after water breakthrough, low-resistance water pathways are present throughout the system and these provide conduits for most of the additional injected water to flow. Therefore, instability theory does not clearly describe how oil is displaced at later times after the water breakthrough occurred.

2.7 Imbibition

When the presence of multiple immiscible fluids in the porous media system occurred, distribution of the fluids at equilibrium is governed by capillary forces. More on deeper, during water injection into a water-wet porous medium (imbibition), capillary forces compete with viscous forces in order to determine the pathways through which water will travel. Therefore, imbibitions act as an important phenomenon during water injection.

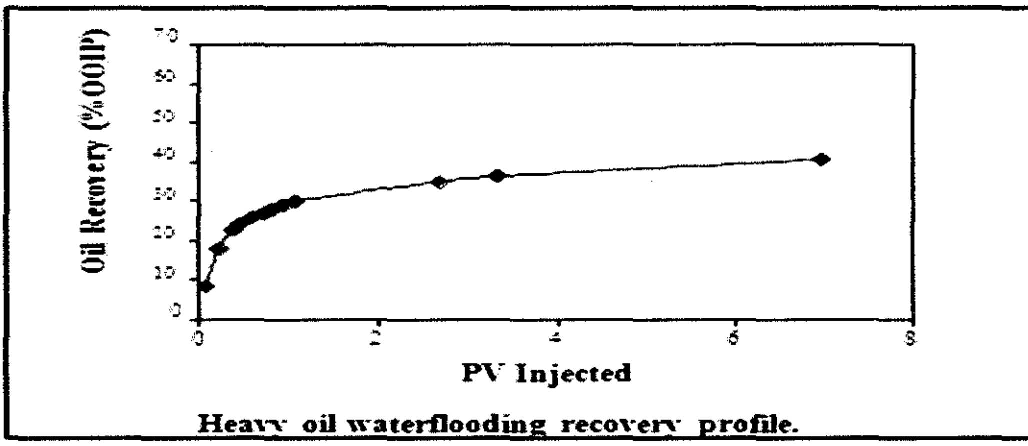
There are so many factors controlling imbibition, such as rock wettability, permeability (pore size), viscosities of the imbibing and displaced fluids, and the initial water and oil saturations in the rock. Wettability is by far the most important parameter in imbibition, as evidenced by the contact angle in the Young-Laplace equation [(8)]. Wettability controls which fluid that will be spontaneously imbibed into the porous medium. Hence, this term governs whether a process is considered to be drainage or imbibition. Therefore, the strength of wettability will also influence the rate of imbibition. Even in viscous heavy oil reservoirs, the porous medium is normally expected to be water-wet for the sand systems.

Li and Horne [(9)] have shown that the capillary pressure is expected to decrease for rocks with higher permeability, since permeability is related to the average pore size in the rock. In a separate study, they verified that the imbibition rate is higher for lower permeability rocks. Rock permeability is therefore another important parameter for quantifying the effect of imbibition. In unconsolidated oil sands, permeability tends to be higher than in conventional oil reservoirs. Therefore, the rate of imbibition is expected to be lower than in consolidated rock.

Zhou et al. [10] found that both the imbibition rate and the final recovery due to imbibition is also affected by the initial water saturation. This is based on the theory of capillary pressure, which indicates that water is expected to exist in the smallest pores and, to a smaller extent, in bypassed larger pores. Therefore, the rate of imbibition is related to the relative fraction of pores which contain mobile water at any given saturation. In heavy oil systems, the relationship between capillary pressure and the water saturation in the rock is poorly defined. At the point of water breakthrough, water has travelled through the least-resistant pore pathways and creating a channel of high water saturation. In the other portions of the core, however, the oil was bypassed and, therefore, the condition of oil and irreducible water still exists or occur. Hence, capillary forces may still be significant, even in the later parts of a waterflood since previously unswept zones are consistently at the irreducible water saturation.

Fischer and Morrow [11] have also shown that the imbibitions rate is a function of oil viscosity and decreases as oil viscosity increases. This result is important, especially for heavy oil systems where the oil and water do not have similar mobility. In order for imbibition to occur, an oil has to be displaced into other pores and displacement of viscous oil will tend to occur much more slowly than in conventional oil. Several researchers have observed that recovery for fixed volumes of water increases in a manner which is proportional to $\sqrt{t}$. In capillary-driven processes, the imbibition rate can be show by:

$$\boxed{\frac{dR}{dt} \propto \frac{1}{\sqrt{t}}} \qquad (3)$$



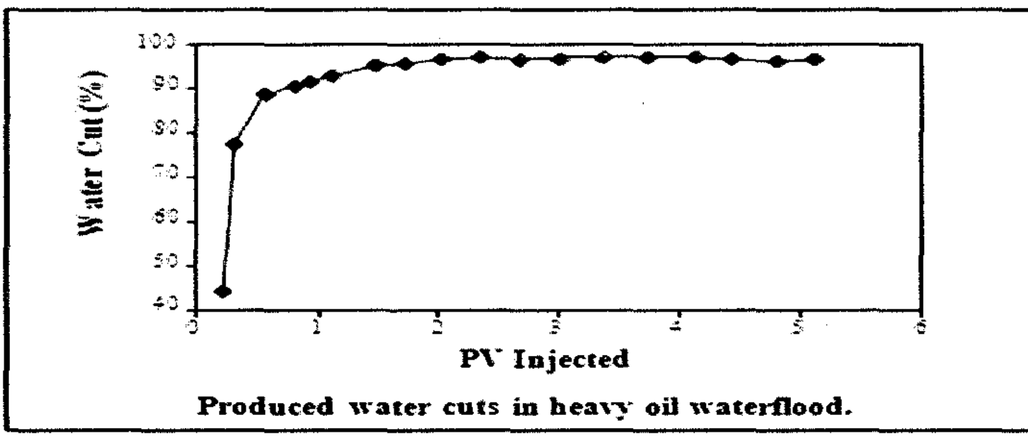


Figure 3: Heavy oil waterflooding recovery profile and Produce water cuts in heavy oil waterflood.

This implies that the imbibition rate or oil production rate is expected to be high at first, and then should decrease with a time. At the early times during injection into heavy oil, however, water is displacing high viscosity heavy oil so the viscous forces are expected to be dominant over capillary forces.

As a conclusion, the imbibition rate decreases with time, increasing permeability and increasing oil viscosity. Conventional knowledge regarding imbibition would shows that it is not expected to hold great importance in oil sands. Hence, this has led to the common assumption that capillary forces and imbibition are insignificant in heavy oil systems in relation to the effect of the viscous forces. Therefore, the examination of the validity of this assumption is one of the main focuses of this final year project research.

CHAPTER 3

METHODOLOGY

3.1 Procedure Identification

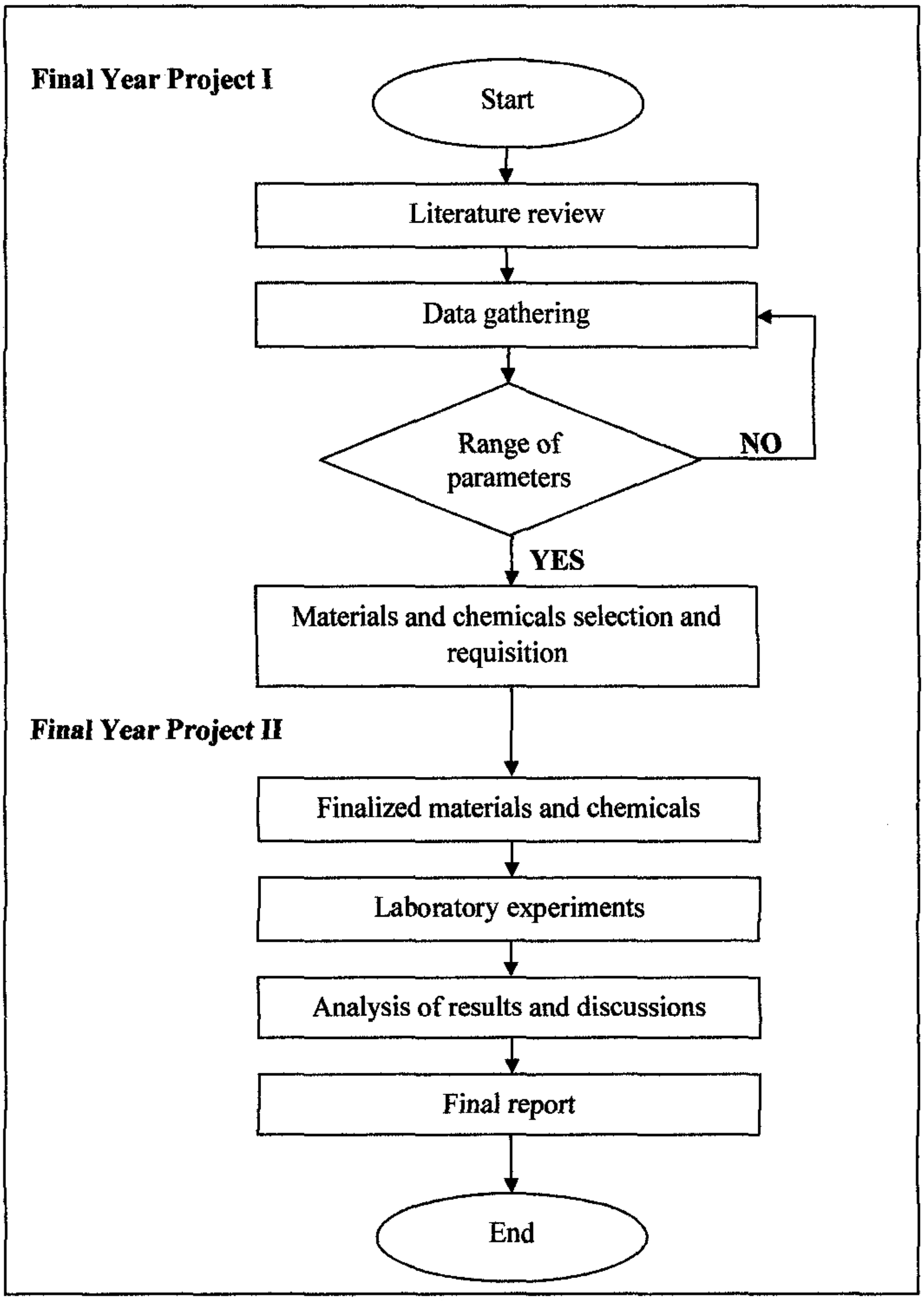


Figure 4: Project flow chart

In brief, the project has been divided into two (2) parts; Final Year Project I and Final Year Project II. **Figure 3** shows the project flow accordance to the sequence to ensure the smoothness and efficiency of the project.

The project will begin with the literature review on heavy oil, waterflooding, permeability, breakthrough, waterflooding in heavy oil, instability and imbibitions which are very crucial parameters for this final year project. Also, some basic review on laboratory work related to studies of waterflooding of high viscosity oil with various water injection rates has been done throughout the first part of the project. All the information were obtained from books, journal, technical presentation and related websites.

Then, all information related to the project is gathered in a proper documentation. Detail review and analysis on the previous works has been conducted to see what have been done so far on this area of study. Based on the analysis, the draft of experimental works was done. Details design of laboratory experiments will be completed during the second part of the project.

The laboratory experiments of waterflooding for core plug of two high viscosity heavy oil of 1500 cp and 2000 cp at varying water injection rates will be carried out using Soxhlet Extractor , POROPERM Instrument , and Relative Permeability System which available at Academic Building 17, Universiti Teknologi PETRONAS. Therefore, Soxhlet apparatus is used to extract and clean the core sample from oil, water and any other materials. Meanwhile, the POROPERM instrument is a permeameter and porosimeter used to determine properties of plug sized core samples at ambiant confining pressure such as the porosity and permeability. At the end of the experiment, waterflooding for different viscosity of core plug with different injection rate are run with largely use equipment called Relative Permeability System. From the obtained results, we can analyze and understand the forces that are present in the reservoir and how they can be used to properly design the waterflood at low cost and know the mechanisms by which heavy oil can be recovered by water injection. Lastly, the study will be documented and compiled to be a proper Final Year Project final report.

3.2 Methodology of the experimental works

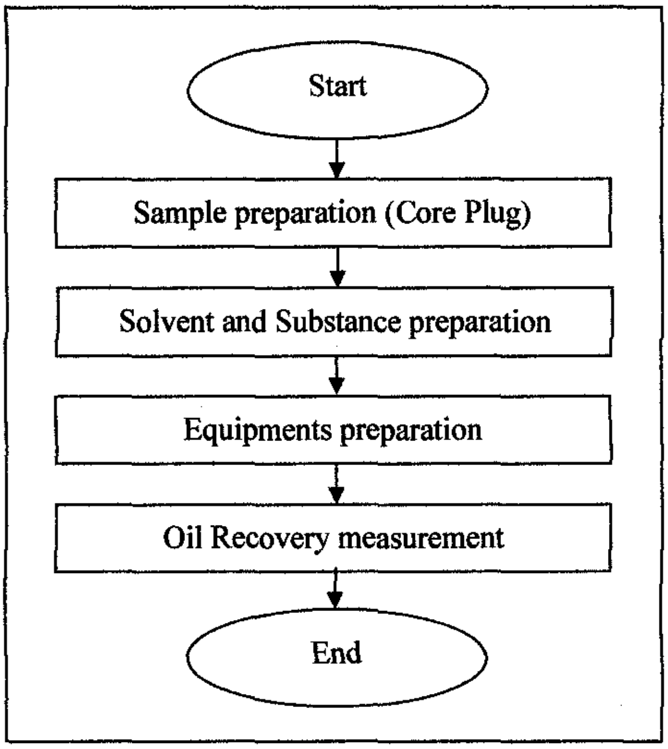


Figure 5: Methodology of the experimental works

3.3 Laboratory works related to waterflooding of core plug

3.3.1 Core Plug Cleaning by using Soxhlet Extractor

The cores used in all experiments are from Petronas Research Sdn. Bhd. For core preparation, author will clean the core by using Soxhlet Extractor Equipment and toluene as s solvent. A Soxhlet extractor is a piece of laboratory apparatus [25] invented in 1879 by Franz von Soxhlet[26].It was originally designed for the extraction of a lipid from a solid material. However, a Soxhlet extractor is not limited to the extraction of lipids.

Typically, a Soxhlet extraction is only required where the desired compound has a limited solubility in a solvent, and the impurity is insoluble in that solvent. If the desired compound has a significant solubility in a solvent then a simple filtration can be used to separate the compound from the insoluble substance. Normally a solid material containing some of the desired compound is placed inside a thimble made from thick filter paper, which is loaded into the main chamber of the Soxhlet extractor. The Soxhlet extractor is placed onto a flask containing the extraction solvent. The Soxhlet is then equipped with a condenser.

The solvent is heated to reflux. The solvent vapour travels up a distillation arm, and floods into the chamber housing the thimble of solid. The condenser ensures that any solvent vapour cools, and drips back down into the chamber housing the solid material. The chamber containing the solid material slowly fills with warm solvent. Some of the desired compound will then dissolve in the warm solvent. When the Soxhlet chamber is almost full, the chamber is automatically emptied by a siphon side arm, with the solvent running back down to the distillation flask. This cycle may be allowed to repeat many times, over hours or days.

During each cycle, a portion of the non-volatile compound dissolves in the solvent. After many cycles the desired compound is concentrated in the distillation flask. The advantage of this system is that instead of many portions of warm solvent being passed through the sample, just one batch of solvent is recycled.

After extraction the solvent is removed, typically by means of a rotary evaporator, yielding the extracted compound. The non-soluble portion of the extracted solid remains in the thimble, and is usually discarded.

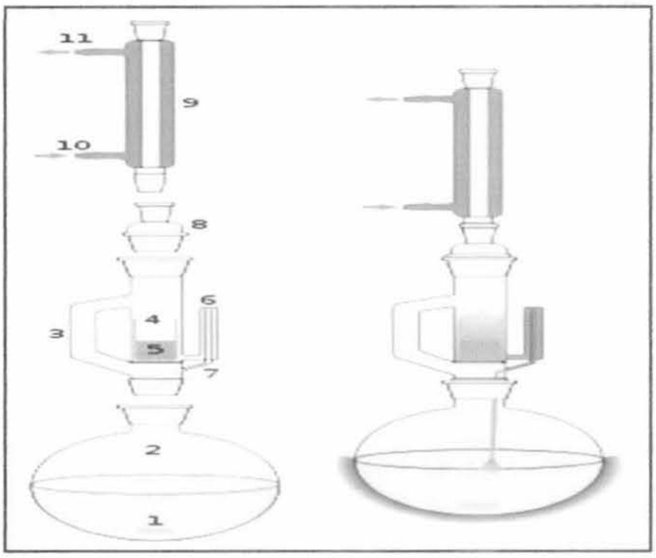


Figure 6: A schematic representation of a Soxhlet extractor

1: Stirrer bar

2: Still pot (the still pot should not be overfilled and the volume of solvent in the still pot should be 3 to 4 times the volume of the soxhlet chamber)

3: Distillation path

4: Thimble

5: Core plug

6: Siphon top

7: Siphon exit

8: Expansion adapter

9: Condensor

10: Cooling water in

11: Cooling water out

Therefore the simplest ways to understand the Soxhlet Extractor Equipment are, Soxhlet apparatus is used to extract and clean the core sample from oil, water and any other materials. The apparatus is based on a heating mantle to boil the solvent, a sample chamber and a water-cooled system to condense the solvent vapors. The core sample is first placed into the sample chamber. Then, the solvent is heated and vaporized. The solvent vapors travel through a lateral way and rise to the top of the glass tube where is the cold trap. At this place, the vapors condense and fall into the sample chamber. The solvent fills the chamber and removes soluble components from the core. Then, the spoiled solvent is evacuated from the chamber through a siphon and goes back to the flask where it will be redistilled.

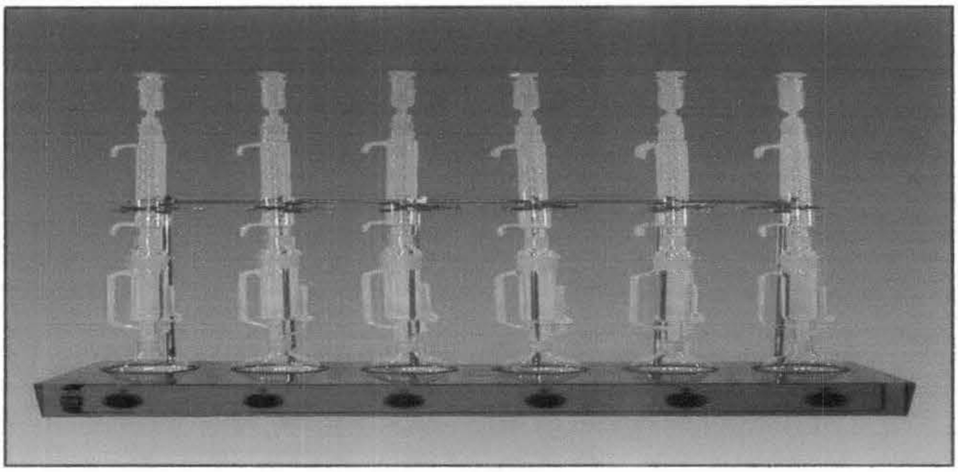


Figure 7: Soxhlet Extractor

3.3.2 Determination Porosity and Permeability of Core Plug by using **POROPERM instrument.**

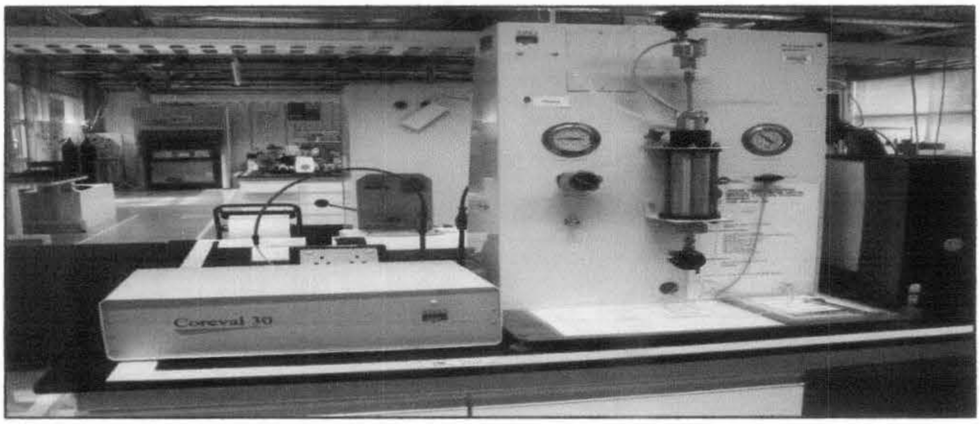


Figure 8: POROPERM Instrument

The POROPERM instrument is a permeameter and porosimeter used to determine properties of plug sized core samples at ambiant confining pressure. In addition to the direct properties measurement, the instrument offers reporting and calculation facilities thanks to its user-friendly Windows operated software. The direct measurements are including of gas permeability (mD), pore volume, core length and diameter. Therefore, the calculated parameters are include of Klinkenberg slip factor "b", Klinkenberg corrected permeability, inertial coefficients, sample bulk volume, sample porosity, grain volume and grain density (assuming sample is weighed).

3.3.3 Waterflooding for different viscosity of core plug with different injection rate.

For this kind of application, Relative Permeability System is largely use.

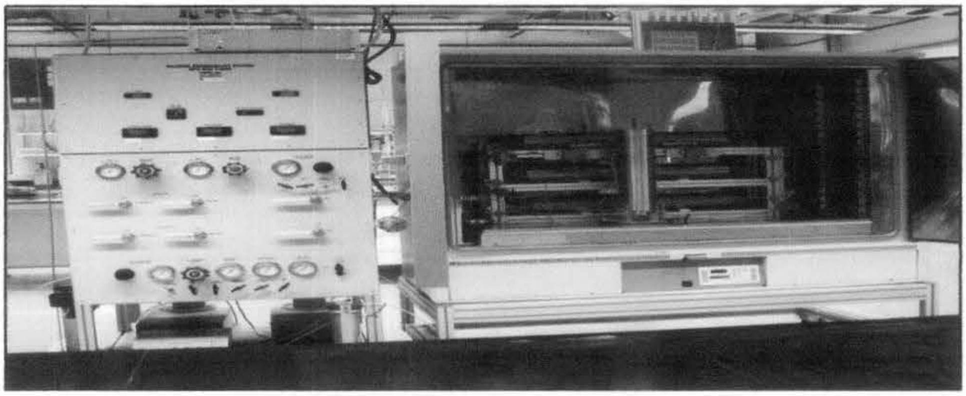


Figure 9: Relative Permeability System

The TEMCO RPS-800-10000 HTHP Relative Permeability Test System can be used for permeability and relative permeability flow testing of core samples, at in-situ conditions of pressure and temperature. Tests that can be performed with the system include initial oil saturation, secondary water flooding, tertiary water flooding, permeability and relative permeability. Brine, oil or other fluids can be injected into and through the core sample. Firstly, the core sample is flooded with brine water (0.02 wt% of NaCl) until 100% saturation of water (S_w). This can be achieved when the volume of inlet is equal to the volume of outlet. After that, the core is flooded with high viscosity of oil until it reached the critical water saturation (S_{wcr}).This can be achieved when 100% oil flow at outlet. Later, let the core stable by put it in core holder for three (3) days. Then, flood the core with brine water (0.02wt% of NaCl) with different rate of injection until 90% of water cut. Therefore, calculate the recovery of the core. Therefore the three table below need to be filled during the experiment. Therefore, author must conduct 5 run experiments for a different viscosity at different rate of injection.

run x (X mL/min and X cp)

Core Name	X

Porosity (%)	x
Permeability (air,mD)	x
Permeability (infinite,mD)	x
Diameter, cm	x
Length, cm	x
Volume Bulk, cc	x
Volume Pore, cc	x
Volume Grain, cc	x
Grain Density, g/cc	x
Bulk Density, g/cc	x
Dry Weight, gm	x

Table 1: Properties of Core Plug

Experiment / run	viscosity (cp)	brine water rate of injection (mL/min)	OOIP (mL)	Critical Water Saturation (S_{wc})	Volume Displace (mL)	Residual Oil (S_{or})	Recovery Factor
1	1500	0.5	x	x	x	x	x
2	1500	1	x	x	x	x	x
3	1500	2	x	x	x	x	x
4	1500	3	x	x	x	x	x
5	1500	4	x	x	x	x	x

Table 2: Recovery

Experiment / run	viscosity (cp)	brine water rate of injection (mL/min)	Recovery Factor
1	1500	0.5	x
2	1500	1	x

3	1500	2	x
4	1500	3	x
5	1500	4	x
6	2000	0.5	x
7	2000	1	x
8	2000	2	x
9	2000	3	x
10	2000	4	x

Table 3: Recovery per pore volume injected

3.4 Project Activities

(*Updated until 4th April 2011)

No.	Subject / Activity	Status/Expected completion
1.	Design laboratory works	Completed
2.	Booking of laboratory	Completed
3.	Preparation of core plug and oil	Completed
4.	Experimental work commences	Completed
5.	Data analysis	Completed
6.	Preparation of progress report	Completed
7.	Preparation of paper/journal	In progress
8.	Preparation of seminar	Week 13
9.	Preparation of poster	Completed
10.	Preparation of final report	Completed
11.	Preparation of oral presentation	Week 15

Table 4: Activity tracking

3.5 Key Milestone

No.	Activities	Date
1.	Design laboratory works	10-23 January 2011
2.	Booking of laboratory	12-14 January 2011
3..	Preparation of core plug and oil	17- 20 January 2011
4.	Experimental work commences	24 January 2011- 9 March 2011
5.	Data analysis	21 February 2011- 25 March 2011

6.	Preparation of progress report	14 -16 March 2011
7.	Preparation of paper/journal	17-25 March 2011
8.	Preparation of seminar	28 March 2011- 8 April 2011
9.	Preparation of poster	28 March 2011- 8 April 2011
10.	Preparation of final report	7 March 2011 - 8 April 2011
11.	*Preparation of oral presentation*	11 – 20 April 2011

Table 5: Key Milestone

3.6 Gantt chart

	Week														
Task/Activity	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Design laboratory works	■	■													
Booking of laboratory	■	■													
Preparation of specimen		■													
Experimental work commences			■	■	■	■	■	■	■						
Data analysis							■	■	■	■	■				
Preparation of progress report										■					
Preparation of paper/journal										■	■				
Preparation of seminar												■	■		
Preparation of poster												■	■		
Preparation of final report									■	■	■	■	■		
Preparation of oral presentation														■	■

Note: Week 1 and 2 is during the semester break (10-23 January 2011)

3.7 Tools / Equipments Required

Apparatus	Quantity
Core Plug – sandstone type	1
PoroPerm System Machine	1
Relative Permeability System Machine	1
Beaker	5
Measuring Cylinder	10

Soxhlet Extractor	1
Densitymetre	1
Chemical	Quantity
Heavy Oil	1000 cc
Brine solution 0.02 w.t %	4000 cc
Toulene	1500 cc

Table 6: Tools and equipments

3.8 Experimental Procedures and Details

3.81 Core Cleaning

Before displacement test can be carried out to measure relative permeability and the oil recovery, it is a must to clean and saturate the core properly to ensure each runs are not affected by any impurities inside the core sample. To restore the native state of the core sample, the core must be clean thoroughly.

Chemicals and Apparatus

Dean-Stark Soxhlet Extractor, Toluene

Procedure:

- *The Soxhlet distillation extraction method is used to dissolve and extract oil and brine from rock core sample by using solvents.*
- *The cleanliness of the sample is determined from the colour of the solvent that siphons periodically from the extractor which must be clear. The samples are placed in the extractor and cleaned by refluxing solvent.*
- *The solvent is heated and vaporized in boiling flasks and cooled at the top by condenser. The cooled solvent liquid falls into the sample chamber. The cleaned solvent fills the chamber and soaks the core sample. When the chamber is full, the dirty solvent which was used to clean the core siphons back into the boiling flask and is redistilled again.*

3.82 Dry Core Properties

Chemicals and Apparatus

Oven, Helium Porosimeter

Nitrogen gas

Procedure:

- *Before the core can be saturated, measurements of air porosity and permeability must be done.*
- After the cleaning process, the core samples are put into oven to dry any residues of toluene which might be still entrapped in the pore spaces.
- Using Porosimeter, nitrogen gas is filled into the core chamber to completely saturate the sample.
- Using suitable confined pressure and setting up the pressure steps for reading purposes, stabilize air porosity and absolute permeability values are obtained.

3.83 POROPERM® MACHINE

Chemicals and Apparatus

POROPERM® MACHINE

Procedure:

- Get two blocks of cleaned core plug
- Measure the diameter, length and weight of the core plug
- Using the POROPERM® device, the core plugs are to be put in the core holder vertically in the machine, confining pressure is applied of up to 1000 psi.
- The system in the computer would automatically display the graphs and characteristics of the core plug.
- Record the porosity and permeability readings in the results section.
- Saturate the core plug with distilled water in a manual pump sucker for at least 6 hours. In the author's experiment, he saturated it for one whole day.

3.8.4 RELATIVE PERMEABILITY SYSTEM (RPS) MACHINE

Chemicals and Apparatus

RELATIVE PERMEABILITY SYSTEM (RPS) MACHINE

Procedure:

- Clean all the tubings by air gun shot thoroughly and make sure it is free of foreign fluid
- Prepare the core holder equipments: put the core plug inside a confining latex tube just about 1 inch deep on one side.
- Plug it close with the core holder closure on one end, while putting all of them inside the metal core holder main enclosure. Lock it thigh using the other end core holder closure using the C-wrench.
- Brine is prepared for 2.0 w.t%. Pour it into the external pump and lock it close. The air vent is pressured to pump the brine into the accumulator B.
- Heavy oil that was heated in the oven at 100 degree C is slowly pour into the accumulator A, close it and lock to its place with half inch wrench..

In the computer interface software for RPS®, follow the steps below:

- Inject brine solution until the permeability reading stabilizes.
    - This step is taken for the purpose of determining the initial permeability or absolute permeability.
- Inject Crude Black Oil.
    - To measure how much volume of oil that has been saturated.
    - Also this is to measure the irreducible water saturation, S_{wir}. Oil is pumped into the core to

displace the water. As more oil is pumped,

- Inject Brine solution.
    - This is done to determine how much volume of oil that has been produced, and how much oil that remains. This is the residual oil saturation, S_{or}.
- Measure the recovery of crude oil manually.
- The experiment would be repeated by using five different brine water injection rate (0.5 mL, 1.0 mL, 2.0 mL, 3.0 mL, and 4.0 mL) for two type of oil viscosity (1500 cp and 2000 cp)

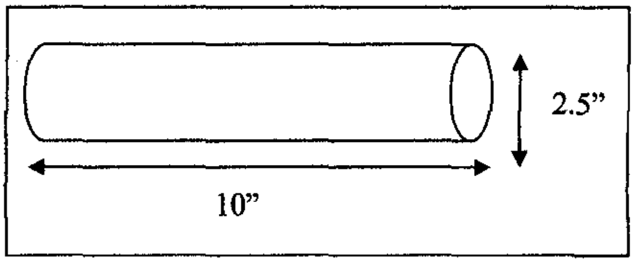


Figure 10: Illustration of core holder

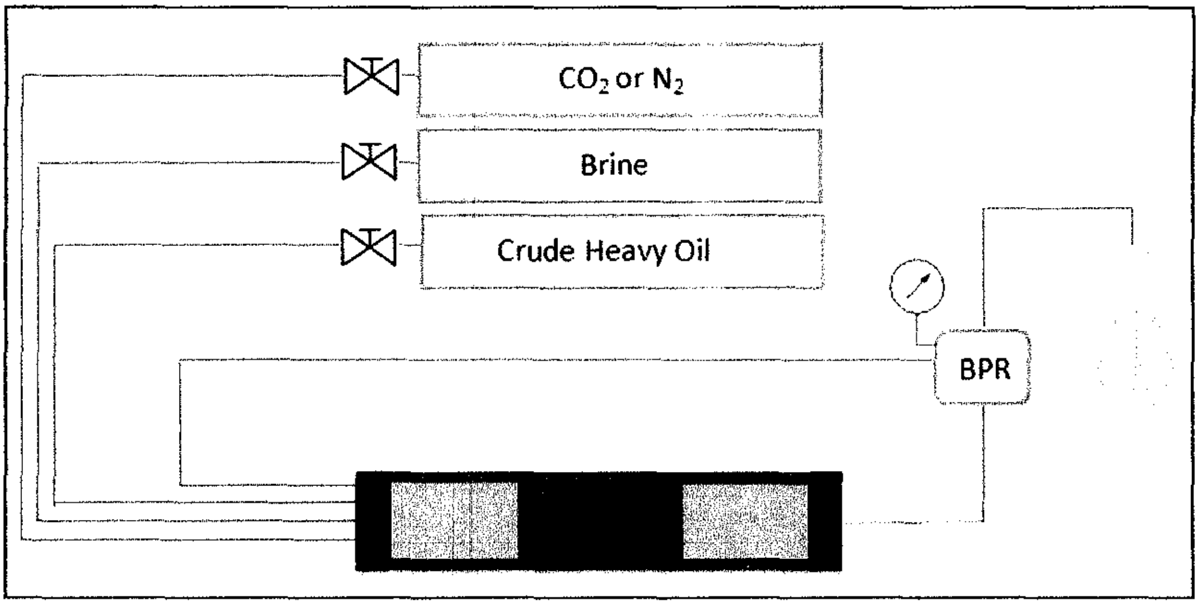


Figure 11: RPS machine equipment's arrangement

Next, all the three pipes or channel would then connected to the core holder which contained the saturated core plug with distilled water with a volume of 82.96 cc. This measurement is obtained from the formula: $\pi r^2 L = \pi \times (3.801/2)^2 \times 7.31$.

Now, since the experiment is focusing on the secondary recovery or waterflooding, we need to waterflood the model first by saturate it with water. Then, brine is injected in at a sufficiently low rate, or 0.5ml/min to attain stabilize model.

At each end of the cylinder model, there would be pressure gauges to measure the pressure reading. At the end of the line, there is BPR equipment to control the inlet and outlet pressure. In this experiment, the author used the following setting:

Inlet pressure: 2000 psi
Outlet pressure: 1900 psi

The whole experiment is kept at a fixed temperature 100°C and then repeated at 100°C.

One end of the cylinder would be the volumetric beaker to measure the heavy oil sample being recovered. The experiment is further continued by changing the brine water injection rate. All of the calculations are done manually by putting the formula in excel spreadsheet such as OOIP, S_{wc}, Volume Displace, S_{or} and RF as tabulated below:

run 1 (0.5 mL/min)

Core Name	x

Porosity (%)	x
Permeability (air,mD)	x
Permeability (infinite,mD)	x
Diameter, cm	x
Length, cm	x
Volume Bulk, cc	x
Volume Pore, cc	x
Volume Grain, cc	x
Grain Density, g/cc	x
Bulk Density, g/cc	x
Dry Weight, gm	x

OOIP (mL)
x

	Volume Displace (mL)
before breakthrough	x
after breakthrough	x
total volume displace	x

Recovery Factor
x

Figure 12: Calculation in Excel Spreadsheet.

* 1) OOIP = measured brine water displaced by heavy oil at outlet – 5.03mL initial water in tubing of outlet equipment)

2) Volume Displace = measured oil displaced during waterflooding

3) Recovery factor =Volume of oil displaced / OOIP

3.9 The Heavy Oil Characteristics

The heavy oil sample used in this experiment is collected from a field in Sudan, for confidentiality, the author named as Field A. Acquired from a Graduate Student from EOR Center, Mr. Sami in the Petroleum Engineering Department at UTP. The properties of the heavy oil applied are as follows:

Characteristics	Value
API No	20.0°
Viscosity(initial), μ_{oi}	230.0 cp
Pressure at bubble point, P_b	208 psi
Density, ρ	0.9330 g/cm^3
Oil compressibility, C_o	4.75 E 10^{-6}
Oil Formation Volume Factor, B_{oi}	1.039 rbbl/STB
Pour Point	36°C

Table 7: The heavy oil characteristics.

Temp. (°C)	48.8	60	71.1	82.2	90	100
Viscosity, μ	1306 cp	610 cp	326 cp	170 cp	85.2 cp	42.6 cp

Table 8: Viscosity (cp) of heavy oil with respect to temperature.

As we could see from the table above, the higher the temperature goes, the lower the viscosity reading of the heavy oil. To be specific, the increment of every 10°C of temperature would result in reduction of half in the viscosity. Putting those values in **Table 8** into graph would look like below:

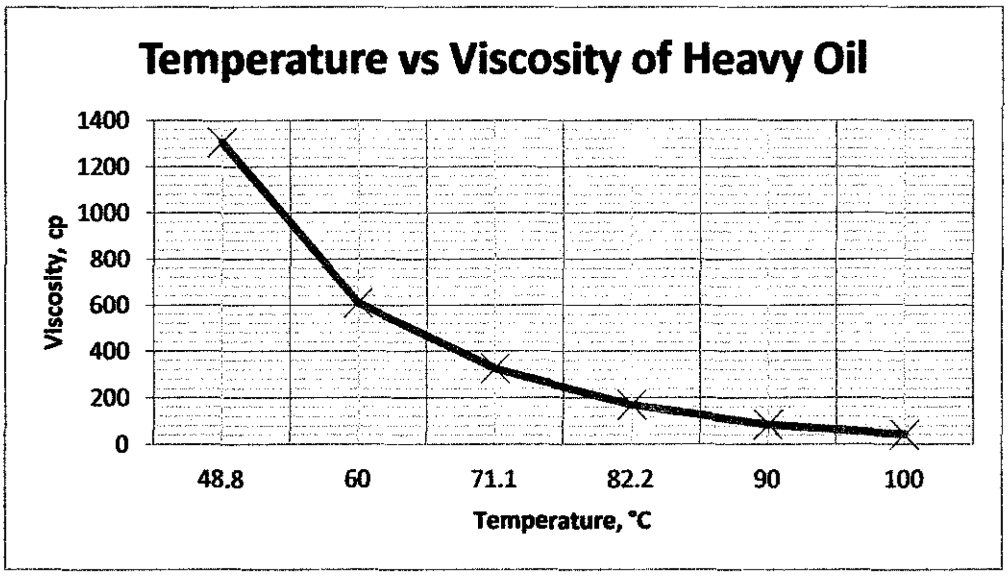


Figure 13: Temperature vs Viscosity of Heavy Oil

CHAPTER 4

RESULTS AND DISCUSSION

4.1 Data Gathering and Data Analysis

In data gathering and data analysis, author shows all the finding of the experimentation result of effect of water injection rate of heavy oil waterflooding towards recovery. Therefore, it will also cover the discussion part which is crucial to relate the literature review and result of this experiment.

4.11 Core Plug information obtained from manual caliper, and PoroPerm machine.

After each of the waterflooding is run towards the core plug by using the RPS machine, information of the core such as diameter, porosity and permeability are collected as to ensure the accuracy of the recovery calculation is obtained. Author already runs the machine for 15 times for 5 reading of tabulated data. After each waterflooding is run, three (3) reading will be collect and author will take the average of the data by summation of three (3) reading divided by 3.The data from the PoroPerm machine is tabulated as below:

run 1 (0.5 mL/min)

Core Name	K-2
Porosity (%)	18.328
Permeability (air,mD)	169.980
Permeability (infinite,mD)	151.155
Diameter, cm	3.802
Length, cm	7.524
Volume Bulk, cc	85.421
Volume Pore, cc	15.656
Volume Grain, cc	69.765
Grain Density, g/cc	2.553
Bulk Density, g/cc	2.085
Dry Weight, gm	178.115

Table 9: Run 1

run 2 (1.0 mL/min)

Core Name	K-2
Porosity (%)	18.328
Permeability (air,mD)	169.980
Permeability (infinite,mD)	151.155
Diameter, cm	3.802
Length, cm	7.524
Volume Bulk, cc	85.421
Volume Pore, cc	15.656
Volume Grain, cc	69.765
Grain Density, g/cc	2.553
Bulk Density, g/cc	2.085
Dry Weight, gm	178.115

Table 10: Run 2

run 3 (2.0 mL/min)

Core Name	K-2
Porosity (%)	18.370
Permeability (air,mD)	169.980
Permeability (infinite,mD)	151.155
Diameter, cm	3.802
Length, cm	7.524
Volume Bulk, cc	85.421
Volume Pore, cc	15.692
Volume Grain, cc	69.729
Grain Density, g/cc	2.553
Bulk Density, g/cc	2.085
Dry Weight, gm	178.115

Table 11: Run 3

run 4 (3.0 mL/min)

Core Name	K-2
Porosity (%)	18.380
Permeability (air,mD)	169.980
Permeability (infinite,mD)	151.155
Diameter, cm	3.802
Length, cm	7.524
Volume Bulk, cc	85.421
Volume Pore, cc	15.700
Volume Grain, cc	69.721
Grain Density, g/cc	2.553
Bulk Density, g/cc	2.085
Dry Weight, gm	178.115

Table 12: Run 4

run 5 (4.0 mL/min)

Core Name	K-2
Porosity (%)	18.360
Permeability (air,mD)	169.980
Permeability (infinite,mD)	151.155
Diameter, cm	3.802
Length, cm	7.524
Volume Bulk, cc	85.421
Volume Pore, cc	15.683
Volume Grain, cc	69.738
Grain Density, g/cc	2.553
Bulk Density, g/cc	2.085
Dry Weight, gm	178.115

Table 13: Run 5

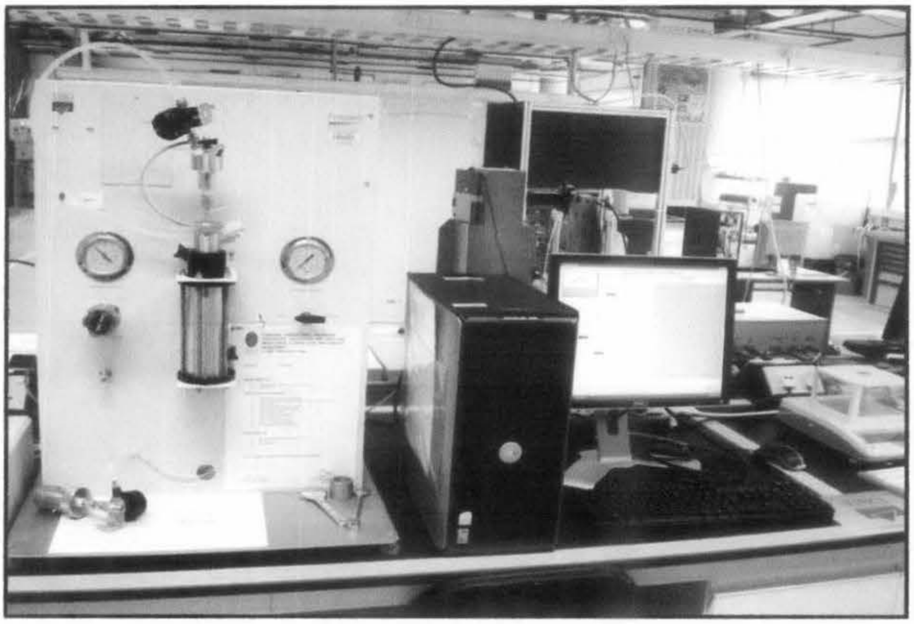


Figure 14: POROPERM Instrument at Core Analysis Lab (Building 15-02-08).

4.12 Waterflooding of heavy oil with different injection flow rate by RPS machine.

Putting all the information above (such as Viscosity, Length and Diameter) into the RPS machine, the author would be running the heavy oil recovery process using computer control. The illustration below shows the input in the control panel on the computer screen:

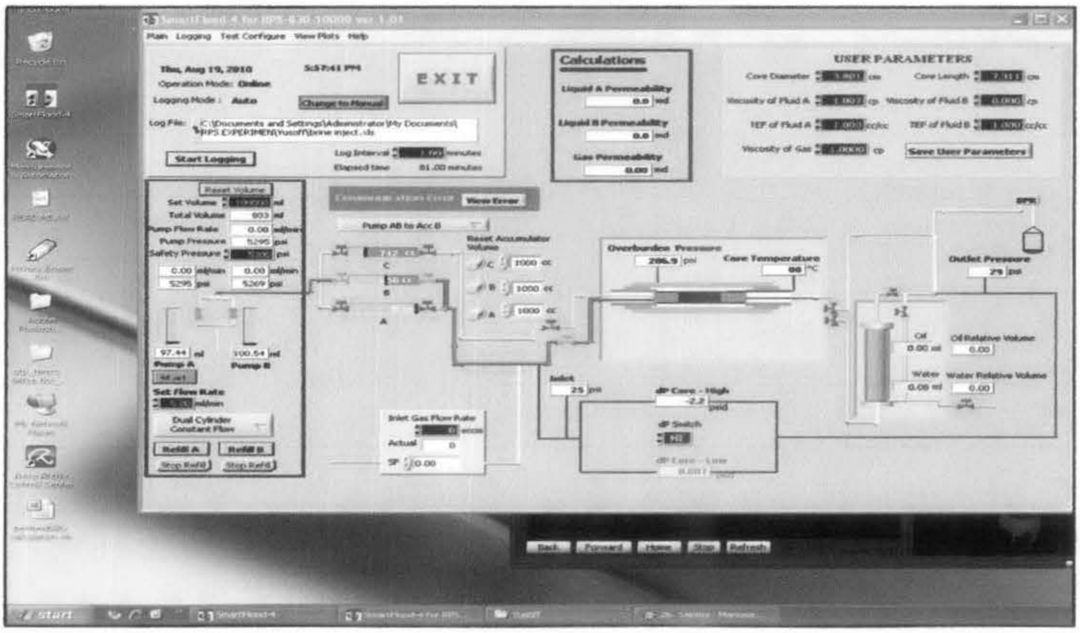


Figure 15: Illustration of RPS machine on-screen control panel.

After all the data is insert in the RPS machine such as the information of core plug, inlet pressure, outlet pressure, overburden pressure, temperature and the others data, author and the laboratory technician ran the machine. At the initial of the waterflooding, it takes a certain period of time to stabilize the pressure.

As stated in the methodology previously, all data will be recorded and tabulated in the excel spreadsheet. At the initial of the flooding, author and the laboratory technician cannot get any oil at the outlet of the machine since the heavy oil is become more viscous due to temperature drop. Thus, they take an initiative by putting a hair dryer at the outlet. Therefore below is the example of the picture which indicates the first heavy oil that has been produce during the waterflooding:

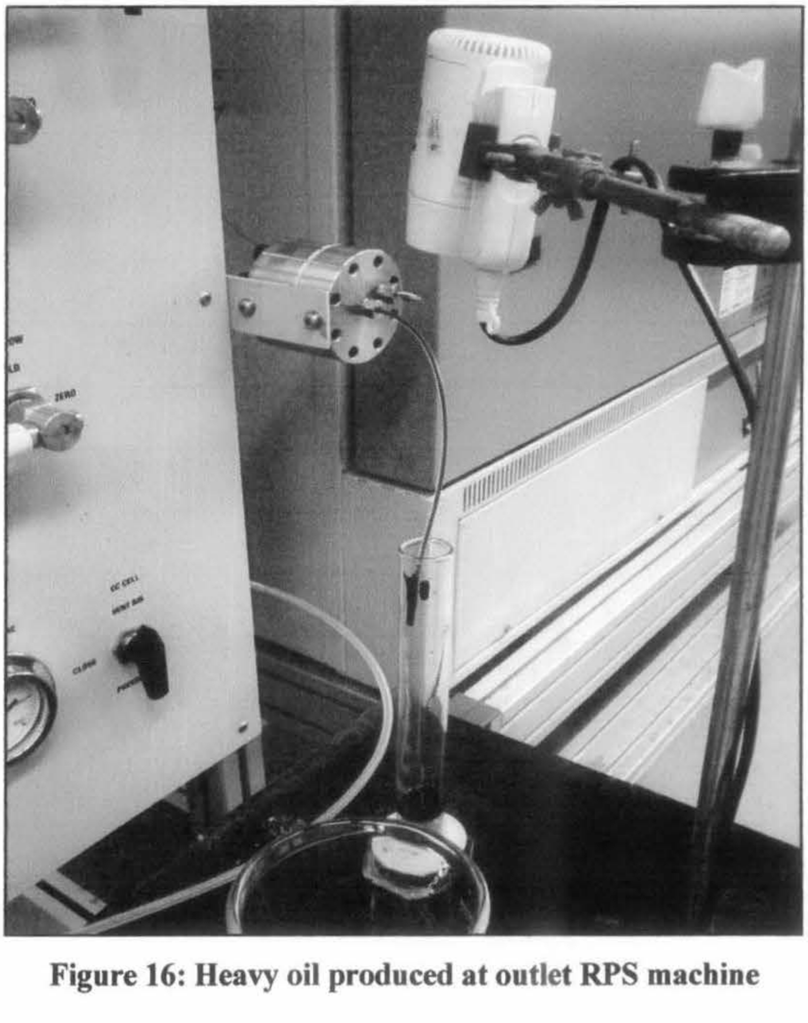


Figure 16: Heavy oil produced at outlet RPS machine

3.2 Findings of heavy oil waterflooding with different water injection rate.

All data are recorded for five (5) run of waterflooding and tabulated as below. Therefore all the calculation for this is formulated in excel spreadsheet.

Experiment / run	viscosity (cp)	brine water rate of injection (mL/min)	OOIP (mL)	Critical Water Saturation (S_{wc})	Volume Displace (mL)	Residual Oil (S_{or})	Recovery Factor
1	1500	0.5	12.97	2.686	11.1	1.87	85.582
2	1500	1	12.67	2.986	9.46	3.21	74.664
3	1500	2	12.55	3.142	9.09	3.46	72.43
4	1500	3	12.93	2.77	8.37	4.56	64.733
5	1500	4	12.87	2.813	7.92	4.95	61.538

Table 14: RPS run in the insulated temperature of 100°C at 36.2 cp viscosity.

Referring to the table above, it can be shown the following:

a) The first column indicates 5 run of heavyoil waterflooding.

b) The second column indicates type of viscosity which are 1500 cp

c) The third column shows the rate of injection for brine water from 0.5 mL/min up to 4.0 mL/min.

d) The forth column and the others shows the further amount of heavy oil being displaced when we inject brine. It can be seen that the heavy oil is **successfully** can be displace for viscosity of 1500 cp but it cannot displace further when using 2000 cp of heavy oil. **The author may failed for the 2000 cp heavy oil experiment, and decided to try it again next time with a high temperature, which is 125°C. This is aimed at reducing the viscosity of the heavy oil, and may solve the problem in the first experiment. The whole RPS tubings were cleaned thoroughly for about three days, before the next same run could be done. However the same result is appeared. Therefore, the time is running out and this situation lead the author to focus on different rate of injection towards recovery compared to different type of viscosity towards recovery.**

run 1 (0.5 mL/min)

Core Name	K-2

Porosity (%)	18.328
Permeability (air,mD)	169.980
Permeability (infinite,mD)	151.155
Diameter, cm	3.802
Length, cm	7.524
Volume Bulk, cc	85.421
Volume Pore, cc	15.656
Volume Grain, cc	69.765
Grain Density, g/cc	2.553
Bulk Density, g/cc	2.085
Dry Weight, gm	178.115

OOIP (mL)
12.97

	Volume Displace (mL)
before breakthrough	8.3
after breakthrough	2.8
total volume displace	11.1

Recovery Factor
85.58211257

Figure 17: Example of calculation in Excel Spreadsheet

The same spreadsheet is used for the other five run. All of the equation is already explained in methodology part. The author gathers all the data and changes it into graph as to ensure it easy to understand the relation between the rates of injection towards recovery and the others parameter which are included in the excel format.Therefore, below are the graph based on the data for 5 run of heavy oil waterflooding:

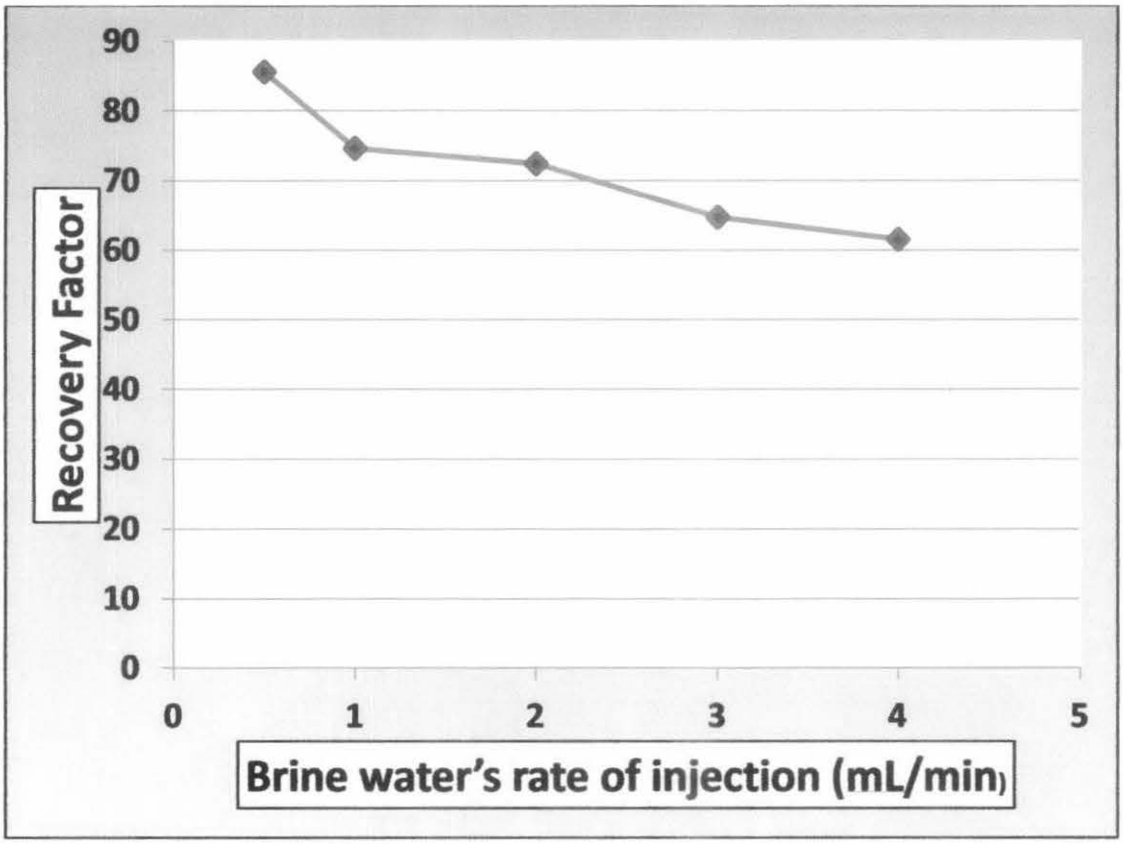


Figure 18: Brine water rate of injection (mL/min) vs Recovery Factor

Referring to the table above, it can be seen that:

a) For brine water with 0.5 mL/ min, it show the optimum recovery factor of 85.582 and sudden drop when the injection being increase up to 1 mL/min

b) The fifth injection of 4 mL/min show the lowest recovery factor of 61.538 compared to the others lower injection of rate.

c) It is clearly show that the recovery factor is decreasing with the increasing of brine water rate of injection (mL/min).

d) Therefore, it also clearly indicate that recovery is high when the decreasing of brine water rate of injection (mL/min)

e) Recovery is high due to waterflooding of linear core sample which is small in size, small in diameter, short in length, and the most important is that the core is homogeneous.

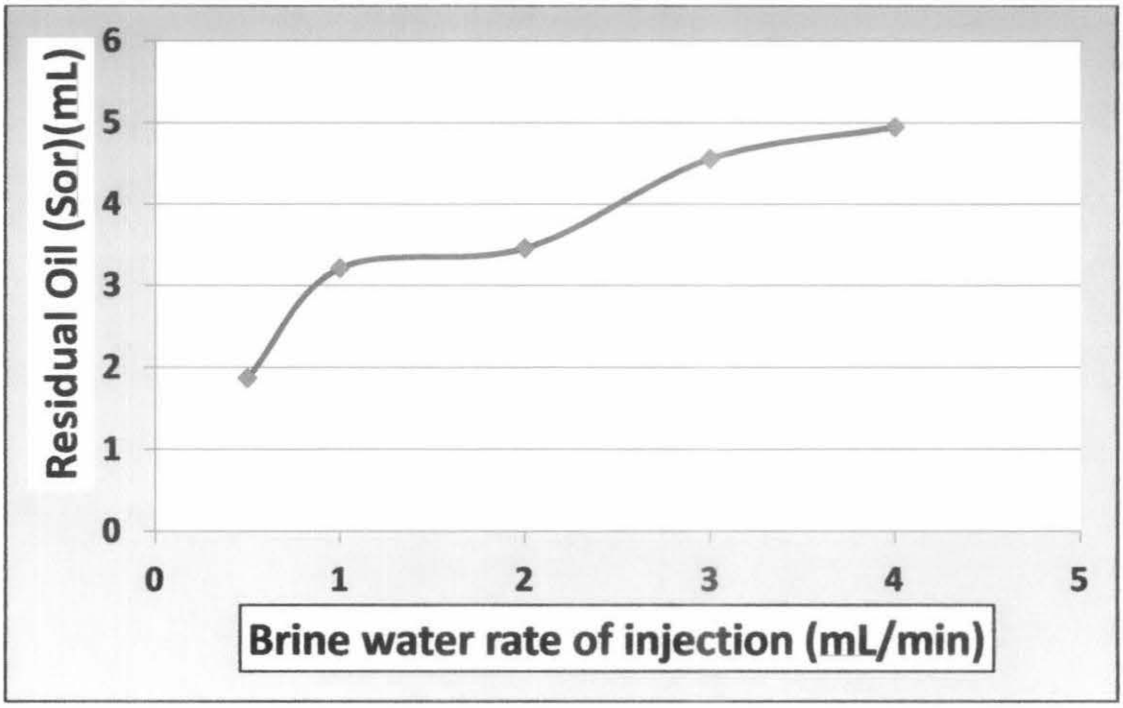


Figure 19: Residual Oil (Sor) vs. Brine water's rate of injection (mL/min)

Referring to the table above, it can be seen that:

a) For brine water with 0.5 mL/ min, it shows the lowest residual oil which is 1.87 mL.

b) The fifth injection of 4 mL/min shows the highest residual oil which is 4.95 mL.

c) It is clearly show that the residual oil is increase with the increasing of brine water rate of injection (mL/min).

d) Therefore, it also clearly indicate that residual oil is high when the increasing of brine water's rate of injection (mL/min)

e) The highest slope is between 0.5 mL/min and 1.0 mL/min. Therefore it indicates that 0.5 mL/min and 1.0 mL/min is the point where the significant residual oil is occurring.

4.3 Discussion

While looking the trend of the graph above, this kind of trend is actually closely relate to the theory that we have discussed before which in the literature review section. It is stated that from conventional theory that heavy oil viscosity will lead to poor mobility ratio. For lab core flood, capillary bypassing and residual oil is one of the main mechanism responsible for trapping oil.

Therefore for smaller diameter core, there is also potential for fingers to grow, thus in the field, the effect of instability may do more pronounced than a linear core system. Instability theory shows that before I_{sr} = 1,000, the displacement rate determines the finger properties and during high injection rate in an unstable system, the finger wavelength will be short. Hence, numerous fingers will form and this will lead to even faster breakthrough of water and more bypassing of oil. For low rate condition, the finger wavelength will be long and only a few fingers can form in the porous medium. Multiple fingers will lead to a higher degree of instability. Therefore, it is much recommended to perform waterfloods more slowly under unstable conditions in order to limit the generation and growth of fingers. Peters and Flock[5] stressed the importance of the wettability number on the quantification of I_{sr}. This number gives an indication of the ability of the porous medium to imbibe the displacing water, which stabilizing the flood front. For water-wet media, the imbibition forces are strong, where the wettability number will be large (C^* = 306.25) [5].

The theory of instability is basically based on balance of forces. In the displacement of a higher viscosity fluid, if the combined forces of gravity and capillarity are greater than the viscous force, then the displacement will be stable. If the reverse is true, thus the displacement will be unstable and the degree of instability depends on the rate of injection, with all else being equal. In heavy oil systems, the difference between oil and water viscosity is so great that I_{sr} will always tend to become very large. This theory shows a dominance of viscous forces during waterflooding and explains the low recovery expected. But, after water breakthrough, low-resistance water pathways are present throughout the system and these provide conduits for most of the additional injected water to flow. Therefore, instability theory does not clearly describe how oil is displaced at later times after the water breakthrough occurred. By referring to the experiment that has been conducted by author, it is shows that, the stability or low injection rate will produce more recovery even after the water breakthrough in high water cut. Therefore, it is a good practice for industrial to inject water at very low injection rate as to stabilize the condition and to avoid early water breakthrough and to produce high recovery.

The author also would like to recommend to UTP to provide core samples with variety in permeability and porosities since it would help much for student to make their experiment more reliable. It is very hard for student to get the cores except they make an order to buy core samples at price around RM2000 and above. Therefore, UTP should also provide the heavy oil for their student since the author found that the searching for heavy oil is very hard even PETRONAS Research Sdn. Bhd. also recommend author to ask from UTP. At last, author managed to get the heavy oil from Sudan's student.

CHAPTER 5

CONCLUSION

5.1 Conclusion

Based on the literature review, there has been some limited experience in documentation for waterfloods in heavy oil reservoirs but, in general, the mechanism of viscous oil recovery by waterflooding has not been explored yet.

Waterflood recoveries are known to be low for high viscosity oil due to the adverse mobility ratio between oil and water that injected to the reservoir. Despite the presumed inefficiency of this process, waterflooding is still commonly applied in so many heavy oil fields since it is relatively inexpensive and field operators have years of experience designing and controlling waterfloods. The challenge is therefore to understand the forces that are present in the reservoir and how they can be used to properly design the waterflood at low cost.

The present work aims to understand the forces that are present in the reservoir and how they can be used to properly design the waterflood at low cost. The ultimate of the study is to investigate the mechanisms by which heavy oil can be recovered by water injection. During the first half of the project, the focus on detail literature reviews about the above matter where it shows the important of mobility ratio, instability and imbibitions parameters during the waterflooding.

Now, in half of the project period, laboratory works already carried out to determine the effect of viscous forces (oil viscosity and water injection rate) toward oil recovery. Therefore the author has proved that water injection rate give the effect to oil recovery which is the low water injection rate will produce high recover through the experimental procedure. The author can said that, this type of experimental finding will lead to not only high recovery, but also the low CAPEX and OPEX for industrial company since they can use or buy low horse power of pumps and low pressure of valves.

5.2 Recommendations

During the experiment, author can see something that can be improved for RPS system, which is we can put heater at the outlet of the RPS since the outlet are not properly heated and lead to the increasing in heavy oil viscosity. When this happen, it will stuck at the outlet tube and restrict the flow of heavy oil which can also lead to the wrong measurement of recovery later. Hence, student may put hair dryer or the other heating element to solve this kind of problem.

Therefore for the industrial practitioner, it is advisable to have water injection of heavy oil at a low rate which is proved by this experiment that it will increase the recovery of the oil. This is crucial since this application can increase the profit and revenue of Oil Company. Therefore author want to stress that even that there are so many other method to produce heavy oil such as combustion which are widely use and believed can increase the recovery, but the author doesn't agree with that method since it will burn the certain amount of oil and it will not follow the sustainability concept. As we already know, as an engineer we need to sustain this non-renewable source of energy.

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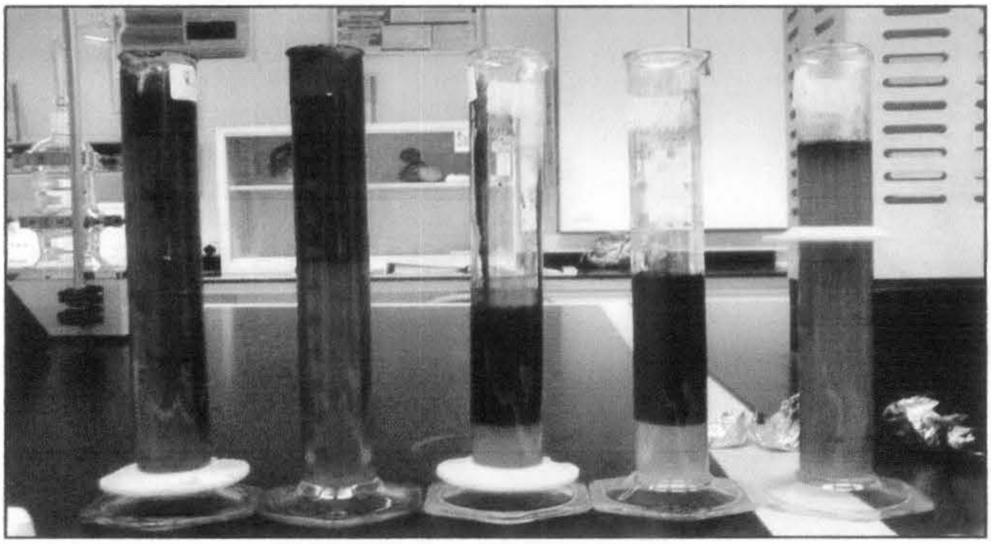
APPENDIXS

Appendix 1: Sample picture of heavy oil waterflooding



Sample picture of heavy oil waterflooding

Appendix 2: Picture of density measurement

Picture of density measurement