CERTIFICATION OF APPROVAL

Polymeric Surfactant for EOR: Polymeric Sodium Methyl Ester Sulfonate (PMES) Performance in High Brine Salinity

by

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Approved by,

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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.

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ABDUL AFIF BIN OSMAN

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ABSTRACT

The recent successes in the field have confirmed that chemical EOR is a viable technique for oil recovery. Numerous new chemicals and processes have been developed to increase the effectiveness and the economics of chemical EOR towards extreme reservoir conditions. Recently, an alternative chemical formulation using the new polymeric surfactant is developed to improve the conventional alkali/surfactant/polymer. This project evaluates the performance and compatibility of the new formulated Polymeric Sodium Methyl Ester Sulfonate (PMES) in high saline brine environment. The evaluations are made based on the ability of the PMES in viscosity control and in interfacial tension (IFT) reduction between oil and water. The project consist of series of experiments starting with fluid to fluid compatibility test, followed by interfacial tension and viscosity test of various combination of solutions, then lastly core flood tests for oil recovery simulation. Based on the results obtained from the constructive experimental tests, the optimum concentration of surfactant is 0.6% while the optimum concentration for alkali is 0.8%. At this optimum concentration, the interfacial tension of the fluid was significantly reduced while maintaining the desired solution viscosity even in high saline brine environment. By using the optimum surfactant and alkali surfactant concentrations, the tertiary recovery could reach 22.3% of the original oil in place when only 0.5 pore volume of the formulated slug and chase water was injected. In conclusion, it is certain that PMES has good tolerance level in high brine salinity without any momentous effects on its performance in interfacial reduction and viscosity control.

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ABBREVIATION & NOMENCLATURES

PMES	*Polymeric Sodium Methyl Ester Sulfonate*
IFT	*Interfacial Tension*
ASP	*Alkaline Surfactant Polymer*
OOIP	*Oil Originally In Place*
Nc	*Capillary Number*
NP	*No Precipitation*

CHAPTER 1
INTRODUCTION

1.1 Background of study

Chemical flooding has been developed since early 1950s and it is one of the most feasible EOR technique used nowadays. Chemical flooding primary goal is to recover more oil by either one or a combination of the following processes:

1. Interfacial tension (IFT) reduction by using surfactants and alkalis
2. Mobility control by adding or injecting polymers

However, chemical flooding in most cases is proven uneconomical and considered as a complex method. This is due to the fact that there are so many variables affecting the success of a particular chemical flooding such as feasibility of the project and the extreme reservoir conditions. In most cases, combination involving alkali-surfactant-polymer (ASP) is recognized to be a cost-effective chemical flooding process but the success of this process is depending on the compatibility and effective formulation. Due to this matter, a number of researches have been conducted to formulate the best combination of chemical that might cease the existing problems as well as opening up new opportunities into the chemical EOR technique.

Polymeric surfactant is one of the recent approaches made by Elraies (2). In fact, the new formulated polymeric surfactant shows good results in interfacial tension reduction and viscosity control. The new polymeric surfactant which is polymeric sodium methyl ester sulfonate (PMES) was developed using non-edible Jathopra oil through polymerization process (1). Series experimental tests were conducted to evaluate the performance of the new polymeric surfactant in oil recovery. From the result, improvement in final oil recovery was demonstrated when the cores were treated with optimum combination of PMES and alkalis solution. However, the test was conducted using a very low salinity of softened water thus the performance of the new polymeric surfactant in extreme environment such as in high saline brine environment need to be evaluated.

1.2 Problem Statement

Chemical flooding in difficult environments such as high salinity of brine has long been considered as challenging. In fact, high performance surfactants for chemical EOR are mostly anionic surfactant. These types of surfactant typically exhibit limited tolerance to high salinity brines. This is mainly due to the salts cations (Na^+, Ca^+ and Mg^+) in the brine are known to strongly impact the surfactant absorption. In addition, the addition of alkalis might be recommended in soft brine but not in the hard brine due to precipitation issues which will result in poor reservoir integrity. The addition of alkali also might affect the viscosity of system. Thus, in this project, the author will investigate on the tolerance level and performance of the PMES in addressing the high saline brine environments.

1.3 Significance of Project

This research is very significant as the result obtained will predict and evaluate the performance of the PMES in interfacial tension reduction and viscosity control. This research also addresses the tolerance level of the PMES in high salinity brine.

Furthermore, the research helps in evaluating and understanding the PMES behavior before any larger scale of pilot test is done. In addition, the result of this research might foresee some lacking area in the PMES which can be access and modify in the near future to adapt extreme reservoir environment.

1.4 Objectives

The research goal is to evaluate the compatibility and performance of the new polymeric surfactant PMES against high saline brine. Theoretically, salinity affects the performance of any alkaline surfactant polymer solution. Thus, this research aims to:

1. To evaluate the tolerance level of the PMES toward high brine salinity .
2. To find the optimum polymeric surfactant concentration and alkali concentration for oil recovery improvement.

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1.5 Scope of study

The overall research plan is to evaluate the compatibility and performance of the PMES in IFT reduction and viscosity control in oil recovery. In a real situation, varieties of factor affect the performance of chemical EOR. However, due to limited time of Final Year 1 and 2, only some of the factors are taken into account in this research:

1. The compatibility of high saline brine on the PMES.
2. The IFT reduction and viscosity control performance of the PMES in high saline brine.
3. The IFT reduction and viscosity control performance of the PMES with the presence of alkalis in high saline brine.

The other factors which affecting the PMES performance are assume to be constant or negligible to simplify the research.

1.6 Relevancy of the Project

This research will be very relevant judging from certain criteria and circumstances. From the project background, this research will be focused on the new polymeric surfactant PMES performances in oil recovery.

Experimental and laboratory tests are very essential to predict the advantages and disadvantages of a product, in this case PMES. From this research, some of the lacking areas in the formulation can be adjusted or modified to suite the requirement in the oil and gas industry. The PMES might be a perfect candidate of ASP flooding in extreme environment with the help of this laboratory research.

1.7 Feasibility of the Project within the Scope of Time Frame

The development and completion of the project is feasible judging from the objectives and scope of studies stated in the research. The overall period to complete the research is approximately eight month.

The experiments and laboratory tests will consume at maximum of twelve weeks times. The rest of the time will be used to provide detailed analysis on the results obtain and reports presentation. Based on that, the research is feasible as the time allocates is sufficient for the author to achieve the objectives of the projects.

CHAPTER 2
LITERATURE REVIEWAND/OR THEORY

The literature review will theoretically covers every elements and foundation of the research. The objective of this research is to evaluate the compatibility and performance of the new polymeric surfactant PMES on oil recovery in high saline brine environment. Thus, previous studies related to the scope of work of this research will be discussed in this section.

2.1 Background of chemical flooding

Chemical flooding has been proved to be one of the most useful enhanced oil recovery techniques (EOR) for the past decades. It refers to those processes in which additional non-natural components (chemicals) are added to the reservoir in order to stimulate the mobility of oil left behind after primary and secondary recovery (11). Chemical flooding is classified as water based EOR methods (9) and there are two basic principles of chemical flooding techniques which are widely used:

- Surfactant flooding
- Polymer flooding

2.2 Fundamental of Surfactant flooding

Surfactant flooding aims to recover the capillary-trapped residual oil by injecting soap-like chemical solutions to reduce the interfacial tension between the oil and water (10). The mechanism behind surfactant flooding is the non-polar lypophile group and polar hydrophile group. When an anionic surfactant is dissolved in an aqueous phase, the surfactants molecules will starts to dissociate into cation and anionic monomer. Due to the nature of the surfactant molecules, it will tends to accumulate at the interface with lyphophilic (hydrophobic) placed in the oil phase while the hydrophilic in the aqueous phase. Jelmert T.A et al (9) stated that, as the surfactant concentration increases, more surfactant molecules will accumulate at the oil/water interface which dramatically reduced the IFT between oil and water. Figure 1 shows the aggregation of surfactant at the oil/water interface while table 1 shows the conventional surfactant structures.

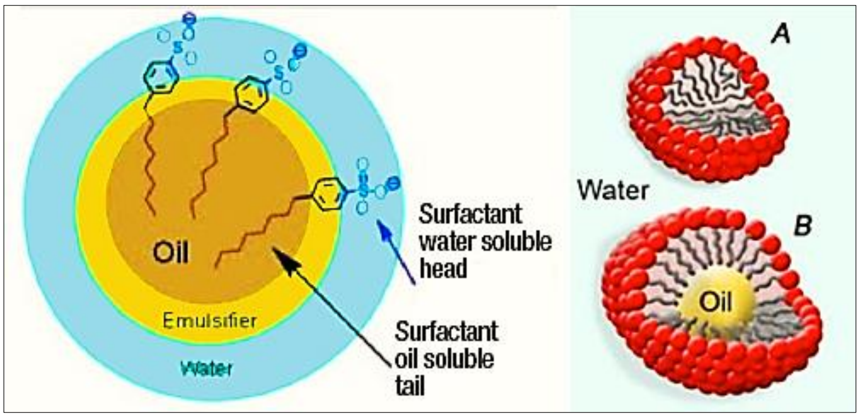
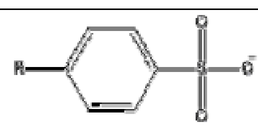
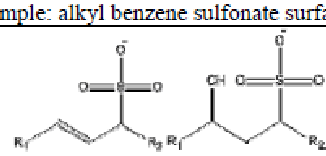
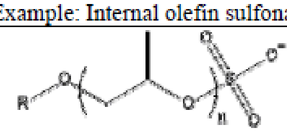


FIGURE1: Mechanism of Surfactant Flooding, (source: retrieved from www.nature.com on 21 Feb 2013)

TABLE 1: Conventional surfactant structures (source: R. Tabari et all, 2013)

Surfactant name	Surfactant structure example	Structural variations
Alkyl Aryl Sulfonates (AAS)	 Example: alkyl benzene sulfonate surfactant	Alkyl benzene sulfonate. Alkyl chain lengths: C12 to C16.
Olefin Sulfonates (OS)	 Example: Internal olefin sulfonate	Alkyl chain lengths: C14 to C28 Either based on alpha or internal olefins (different degree of branching).
Alkyl Ether Sulfates (AES)	 Example: alkyl propoxy sulfate	Alkyl chain lengths: C8 to C17 Different degree of branching Adjustable number and nature of ether groups (PO, EO).

2.3 Fundamental of Polymer Flooding

Polymers are used to achieve favorable mobility ratio during water and surfactant flooding by increasing the viscosity and sweep efficiency of the injected water (12). This is due to the fact that, the reservoir oil is typically more viscous than the injected water for an existing waterflood, causing significant fingering of water between the injector and producing well (13). Hence, the viscosity alteration by the polymer solution is very essential during the flooding period. Based on study by Jelmer T.A et al (9), the viscosity can be mainly be effected by the temperature which either causing changes in the state of energy of the polymer or breakdown of polymer chain. However, high viscous polymer can also reduce the injection rate. Due to this, surfactant flooding is used in combination with polymer flooding to increase the viscosity of water and reduction in relative permeability to water. As a result of those alteration, the mobility ratio reduced leading to more favorable condition for oil recovery. For those reservoirs that have high mobility ratio, improvement in the volumetric sweep efficiency will be likely noticeable (10).

Most of the polymer floods used water-soluble polyacrylamides and biopolymers. By far the major polymer used in the chemical EOR is polyacrylamides (PAM). The intention of these polymer additives when added to the injection water is to aid the sweep efficiency at the waterfront and ensure more oil is pushed to the producing wells. Figure 2 shows the typical structure of polyacrylamides (PAM).

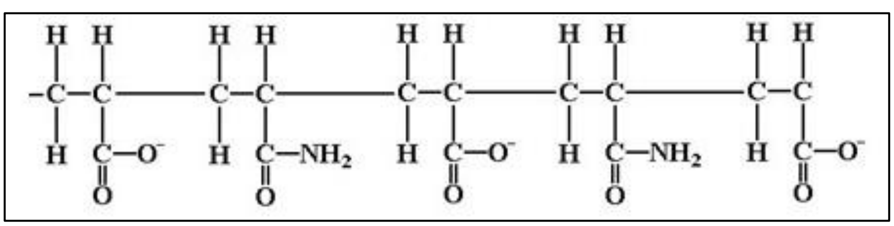


FIGURE2: Typical structure of polyacrylamides (PAM)

2.4 Alkaline-surfactant-polymer flooding (ASP)

One of the most successful combinations of chemical flood in the recent years is combination of alkaline-surfactant-polymer (ASP). In the ASP process, a very low concentration of the surfactant is used to achieve ultra-low interfacial tension between the trapped oil and the injection fluid or formation water (9). The ultra-low interfacial tension also allows the alkali present in the injection fluid to penetrate deeply into the formation and contact the trapped oil globules. Huang et al (4) claims that the alkali will reacts with the acidic components in the crude oil to form additional surfactant in-situ which will continuously providing ultra-low interfacial tension and freeing the trapped oil. In similar study on alkali by Dakuang H, (14), the alkali also helps in reducing the absorption and retention of the surfactant on the rock surface. In the same time, the polymer is used to increase the viscosity of the injection fluid, to minimize channeling, and provide mobility control. The combination of the three chemicals is synergistic as together they are more effective than as individual components. This can be proven by numbers of successful field tests. One of the successful examples in ASP flooding is at the Gudong Oil Field China with an increase in about 13.4% OOIP of ultimate oil recovery (15). Figure 3 shows the basic ASP injection strategy.

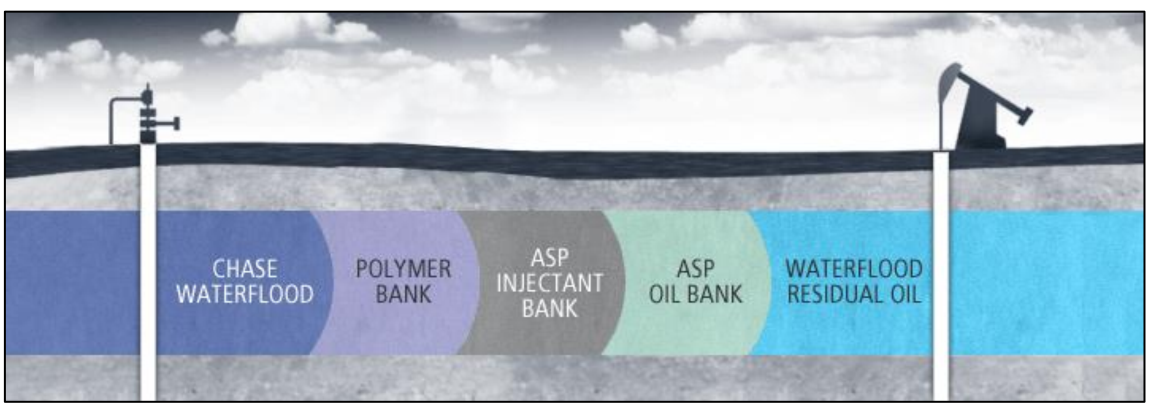


FIGURE 3: Basic injection strategy of ASP flood

2.5 Challenges and limitation of Alkaline-Surfactant-Polymer Flooding

Despites the advantages of ASP flooding in enhance oil recovery, the ASP flooding appear to have some limitations towards the reservoir environments. This is due to the fact that the ASP flooding process required extended studies due to its process complexity. In a paper by Tabary et al (16), most of the surfactant has low tolerance level towards high salinity brine which would significantly lead to high surfactant absorption. This is due to the effect of metallic ions in the brines such as Na^+, Ca^+ and Mg^+ that will absorb the surfactant thus reducing the surfactant effectiveness. However, to overcome this limitation, in most cases, surfactant flooding used low water salinity for injection and some additional absorption inhibitor are added. In order to produce a low salinity of water, water treatment facilities are required which will increase the cost of any particular ASP project.

In addition, in conventional ASP system, the viscosity of the system will reduces as the concentration of alkali increases, Nasr E.D (7). This is mainly due to conventional alkali such as sodium carbonate is known to precipitate high saline brine environment. The alkali also provides additional salts ions which will lead to charge shielding or polymer hydrolysis to happen. Meanwhile, the disadvantage of polymer is mainly due to high possibility to be effected by the reservoir rock. The reservoir rock can retain the polymer molecules through absorption on surface of pore, mechanical entrapping in the pore and precipitation due to accumulation of the polymer molecules (12).

TABLE 2: Conditions encountered in common chemical flooding

	Conditions Encountered
Handling & logistic	Multiple chemicals, shipping and storage of the chemical, tax of chemicals, extra surface equipment.
Salinity optimization	Poor surfactant and polymer performance, might cause corrosion
Water quality	High hardness level of brine
Emulsion	Possible emulsion block, and reduce in water quality
Adsorption	Poor propagation

2.6 Polymeric Sodium Methyl Ester Sulfonate (PMES)

To address the existing ASP challenges and limitations, numerous new chemicals have been formulated and tested. One of the new chemical formulations is polymeric surfactant which is formulated by Elraies et al. 2012 (1). The new polymeric surfactant, polymeric sodium methyl ester sulfonate (PMES) is formulated with a goal to produce new surfactant that will be both economical and effective for interfacial tension reduction and viscosity control.

The PMES is designed at such the hydrophobic group of associated polymer chain is attached to a sulfonate group to produce hydrophobically modified polymers (1). The hydrophobically modified polymers can have either a telechelic structure or more complicated comb like structure where the hydrophopic groups are randomly distributed to the polymer background. A transient network structure is then obtained upon neutralization when the polymer backbone allowing more hydrophobic group to be associated (3).

Based on the paper by Elraies et al. 2012 (1), the PMES is produced using a single step route similar to the method reported by Ye et al. 2004 (4) through polymerization process. Jatropha oil, a non-edible oil, was chosen as the raw material due to its availability and cost effective. Figure 2 describe the flow of PMES production process (1).

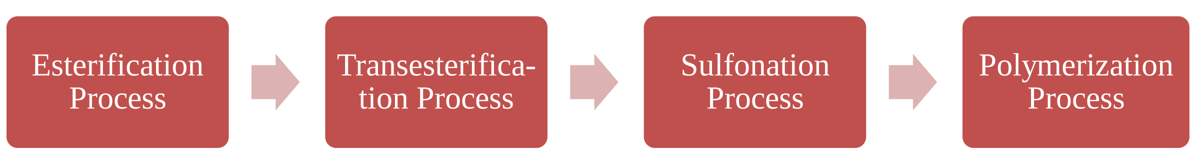


FIGURE 4: PMES surfactant production process

The new polymeric surfactant PMES performance has been evaluated in series of laboratory test (2). The result show tremendous result in IFT reduction and swept efficiency when Angsi crude oil is used as the oil phases. The IFT reduction increases as the concentration of PMES increases. However, the performance of the polymeric surfactant under extreme reservoir environment such as in high saline brine is still not evaluated.

2.7 Interfacial Tension Reduction and Viscosity Control

One of the most important success key attribute in chemical flooding technique is interfacial tension reduction. Interfacial tension (IFT) is defined as the surface tension at the surface separating two non-miscible liquids. In oil and gas industry, this interfacial tension reduction between residual oil and brine are very important in order to recover the trapped oil. Berger and Lee (5) claimed that the use of proper surfactant can effectively lower the interfacial tension resulting in increase in capillary numbers. The capillary number (Nc) is used to express the forces acting on the entrapped droplet of oil within a porous media and is express as the function of the Darcy velocity (υ), the viscosity (μ), of the mobile phase, and the IFT (σ) between the mobile and the trapped oil phase. The relationship can be describe in figure

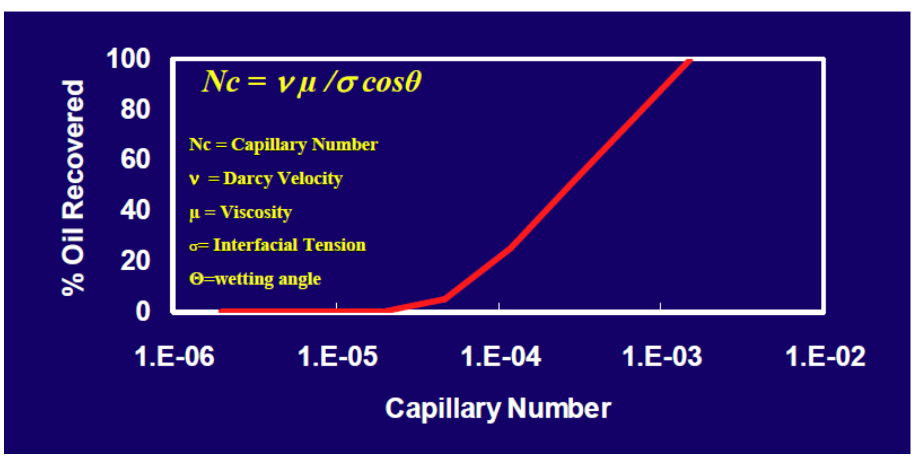


FIGURE 5: Relationship between capillary number and oil recovery (source: Chatzis and Morrow, SPEJ, (1994) 561.)

The theory behind the surfactant-alkali in IFT reduction is their synergetic effect. Surfactant will tend to accumulate at the surface of oil in water thus increasing the surface pressure while decreasing the IFT of both surface of oil and water. Based on research made by Rudin & Wasan (6), this synergetic effect is cause by the mixed micelles and the generated in situ surfactant from the reaction of crude's acid and alkali. The presence of alkali also will helps in reduction of the surfactant absorption on the sand surface which will gradually aid in interfacial tension reduction**.**

Another important key attribute in chemical flooding is viscosity control. Viscosity is defined as the quantity that describes a fluid's resistance to flow. The viscosity of the oil in the reservoir usually higher than the reservoir water, thus mobility of water is more favorable. In this case, it is more likely that more water will be produced at the producing well. At such, additional chemical (usually polymer) must be injected to increase the reservoir water viscosity to change the mobility favor to oil. However, as reported by Nasr E.D (7), the viscosity of conventional ASP will be affected as the concentration of sodium ions increases.

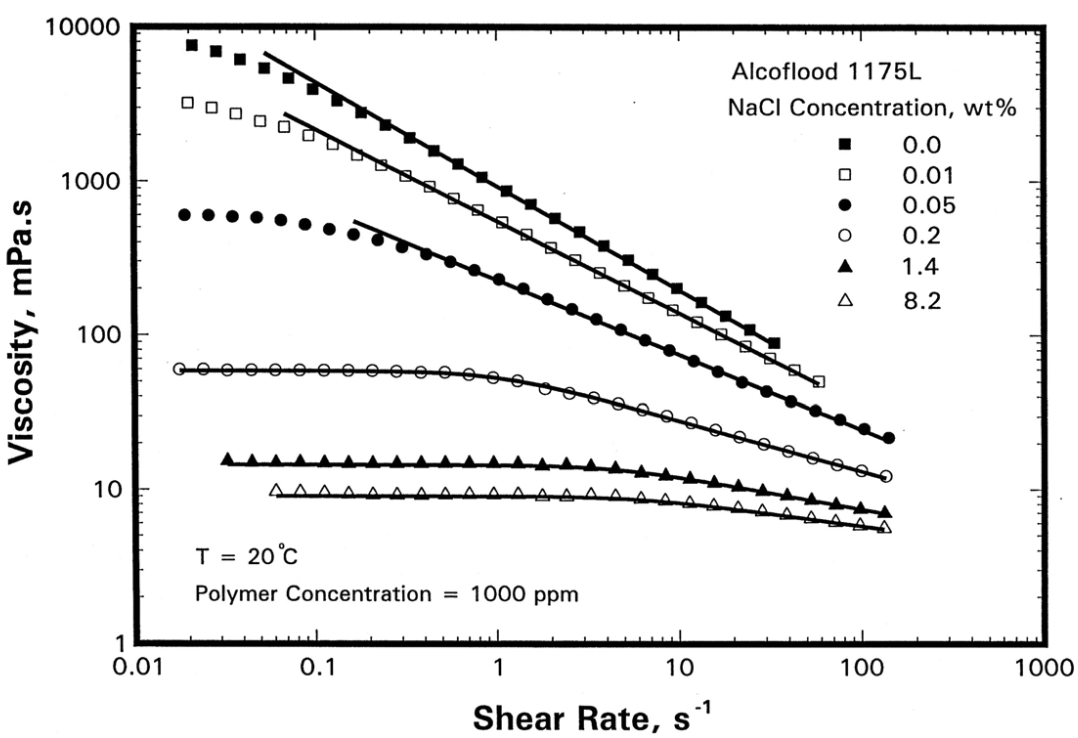


FIGURE 6: Effect of salt on viscosity (Source: Nasr El-Din, SPE21028, 1992)

CHAPTER 3

METHODOLOGY/PROJECT WORK

3.1 Research Methodology

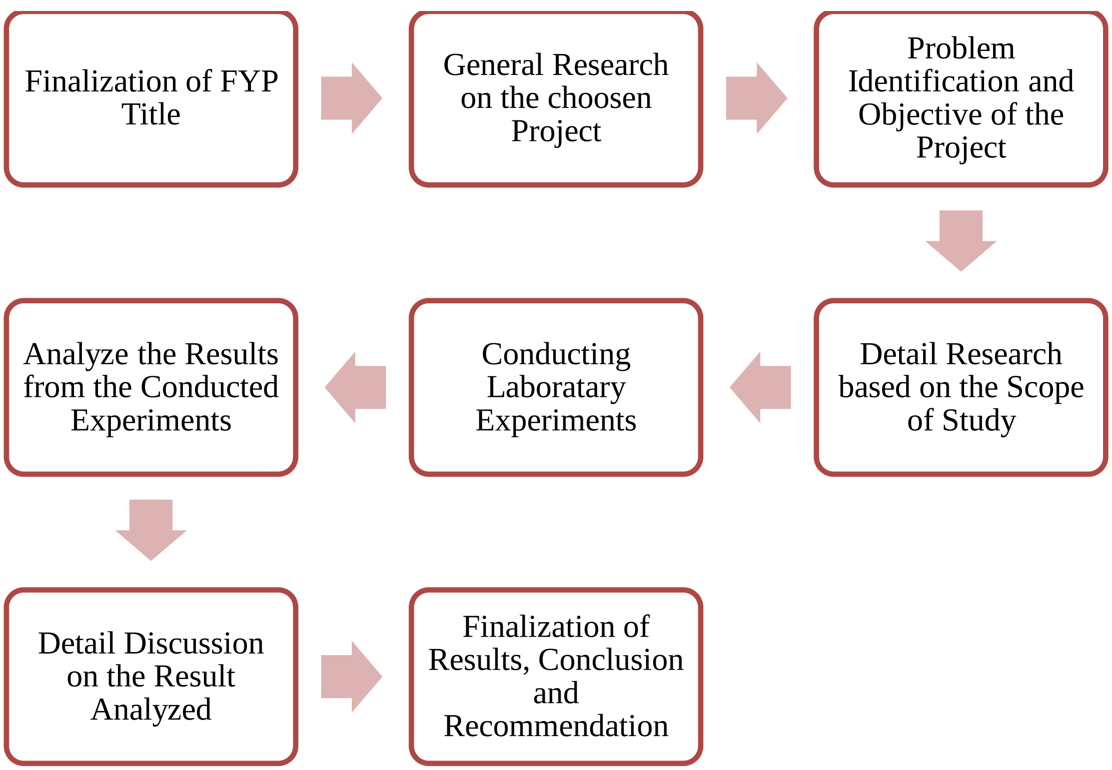


FIGURE 7: Methodology of Research

The methodology of the research is illustrated in the form of flow chart in figure 7. This flow chart explains the flow of the research for whole project duration (FYP1 & FYP2). At the same time, the flow chart will serve as a guideline to ensure the research to be executed in manageable approach in term of time, cost and the quality of the research itself.

3.2 Projects Activities

In the purpose of better research execution, the whole duration of the research will be divided into three main stages; Early Research development, Middle Research Development and Final Research Development.

3.2.1 Early Research Development

In the early research development stage, the activities are mainly focusing in the background research.Technical papers, journal, and books will be the main references for the author to understand the concept of the project as a whole and deciding the scopes of study for the research. Variables to be included in the research and assumptions made to ease the research will be finalized in this stage. Once the scopes of study are narrowed, the author will then proceed on detail research to understand and relate each of the finalized scope. The author will also conduct a routine discussion with project supervisor to clear any uncertainties, getting advices to continue the research and to understand the theory in depth.

3.2.2 Middle Research Development

During the middle research development stage, series of experimental and laboratory tests will be conducted to prove the objective of this project. The experiments will be carried out in stages which are:-

1. Fluid to fluid compatibility test
2. Interfacial tension and viscosity tests for various concentration of PMES
3. Interfacial tension and viscosity tests for optimum PMES concentration with various concentration of alkalis (Na_2CO_3)
4. Core flood test for chosen optimum APS slug for oil recovery evaluation

Fluid to fluid compatibility test	<u>Objective/Goal</u> To evaluate the tolerance level as well as the compatibility of the PMES itself and with the presence of alkali towards high salinity of brine. <u>Material and Apparatus</u> i. Polymeric Sodium Methyl Ester Sulfonate Powder (PMES) ii. Distilled water iii. Sodium Chloride (NaCl) iv. Sodium Carbonate (Na_2CO_3) v. Test Tubes and racks vi. Oven vii. Magnetic Stirrer <u>Procedure</u> 1. In this experiment, various polymeric surfactant (PMES) concentrations of 0.2wt% 0.4wt%, 0.6wt%, 0.8wt% and 1.0wt% are mixed with brine with a total of 30000ppm of salinity. The water will be purely prepared using only sodium chloride powder (NaCl). Then, the mixtures are kept in the laboratory oven with constant temperature of 70 degree Celsius for fifty days. The mixtures will be monitored three times a week to observe if there is any visual changes occurred. 2. The experiment is repeated for compatibility of the alkali mixtures. The same brine solution will be used to prepare various mixtures with different alkaline concentration solution (Na_2CO_3) of 0.2wt%, 0.4wt%, 0.6wt%, 0.8wt% and 1.0wt%, respectively. 3. Lastly, the experiment is repeated again using the optimum PMES concentration with various alkali concentrations. 4. All the results will be tabulated.

Polymeric surfactant performance in high saline brine.	<u>Objective/Goal</u> 1. To evaluate the performance of the PMES itself in high salinity brine. 2. To deduce the optimum PMES concentration for APS slug preparation <u>Material and Apparatus</u> i. Polymeric Sodium Methyl Ester Sulfonate Powder (PMES) ii. Distilled water iii. Sodium Chloride (NaCl) iv. Angsi Crude Oil v. Density meter Model DMA4500M vi. Model SVT 20 spinning drop tensiometer vii. Cannon-Fenske Viscometer and Koehler Viscosity Bath viii. Refractometer <u>Procedure for Interfacial tension test</u> 1. The mixture of brine and PMES with various concentrations of 0.2wt%, 0.4wt%, 0.6wt%, 0.8wt% and 1.0wt% will be prepared. 2. The density of the angsi crude oil and all the prepared mixtures will be determined using the density meter. 3. The refractivity index (RI) of all the mixtures will be determined using refractometer. 4. The Model SVT 20 spinning drop tensiometer equipped with video camera will be used to determine the IFT at 70 deg celcius. Each sample will be introduced into a capillary tube which was first filled with the denser fluid and then closed with Teflon cap having a rubber septum. After that, a drop of less dense fluid (angsi crude oil) will be injected into the tube through the rubber septum using a syringe and will the whole tube-cap assembly will be inserted into the tensiometer. Appropriate rotation speed will be

	adjusted with respect to the suitability of elongation of the oil droplet. The IFT of the two miscible fluid will then calculated using built-in software. 5. The result from the software later will be tabulated and used to deduce the optimum PMES concentration. <u>Procedure for Viscosity test</u> 1. The mixture of brine and PMES with various concentrations of 0.2wt%, 0.4wt%, 0.6wt%, 0.8wt% and 1.0wt% will be prepared. 2. The sample will be first introduced into the Cannon-Fenske viscometer through suction method while the viscosity bath equipment is pre-heated to 70 degree Celcius. 3. The viscometer will be placed into the holder, and inserted into the constant temperature viscosity bath. 4. The time taken for the sample to flow upwards from one point to another point will be taken manually using stopwatch. 5. An approximation of 0.005cst/s will be used to find the sample viscosity. 

Polymeric surfactant performance on the absence and presence of alkalis.	Objective/Goal 1. To evaluate the performance of the PMES in high salinity brine with the presence of alkalis. 2. To deduce the optimum PMES concentration and alkalis concentration for ASP slug preparation Material and Apparatus i. Polymeric Sodium Methyl Ester Sulfonate Powder (PMES) ii. Distilled water iii. Sodium Chloride (NaCl) iv. Sodium Carbonate (Na_2CO_3) v. Angsi Crude Oil vi. Density meter Model DMA4500M vii. Model SVT 20 spinning drop tensiometer viii. Cannon-Fenske Viscometer and Koehler Viscosity Bath ix. Refractometer Procedure for Interfacial tension test 1. The mixture of brine, optimum PMES deduced from previous experiments and sodium carbonate with various concentration of 0.2wt%, 0.4wt%, 0.6wt%, 0.8wt% and 1.0wt% will be prepared. 2. The density of the Angsi crude oil and all the prepared mixtures will be determined using the density meter. 3. The refractivity index (RI) of all the mixtures will be determined using refractometer. 4. The Model SVT 20 spinning drop tensiometer equipped with video camera will be used to determine the IFT at 70 deg celcius. Each sample will be introduced into a capillary tube which was first filled with the denser fluid and then closed with Teflon cap having a rubber septum. After that, a drop of less dense fluid (angsi crude oil) will be injected into the tube through the rubber septum using a

syringe and will the whole tube-cap assembly will be inserted into the tensiometer. Appropriate rotation speed will be adjusted with respect to the suitability of elongation of the oil droplet. The IFT of the two miscible fluid will then calculated using a built-in software.

5. The result from the software later will be tabulated and used to deduce the optimum PMES concentration.

Procedure for Viscosity test

1. The mixture of brine, optimum concentration PMES, and various concentrations of 0.2wt%, 0.4wt%, 0.6wt%, 0.8wt% and 1.0wt% will be prepared.
2. The sample will be first introduced into the Cannon-Fenske viscometer through suction method and the viscosity bath equipment is pre- heated to 70 degree Celcius.
3. The viscometer will be placed into the holder, and inserted into the constant temperature viscosity bath.
4. The time taken for the sample to flow upwards from one point to another point will be taken manually using stopwatch.
5. An approximation of 0.005cst/s will be used to obtain the sample’s viscosity

Core Flood tests	<u>Objective/Goal</u> 1. To evaluate the oil recovery factor when the core is treated with optimum APS deduced from the previous experiments 2. To evaluate the performance of the PMES in high brine salinity. <u>Material and Apparatus</u> i. Polymeric Sodium Methyl Ester Sulfonate Powder (PMES) ii. Distilled water iii. Sodium Chloride (NaCl) iv. Sodium Carbonate (Na_2CO_3) v. Relative permeability system (RPS) vi. Measuring Cylinder vii. Linear Berea sandstone core sample viii. Angsi Crude Oil <u>Procedure of the core flood test</u> 1) The core samples will be first saturated with synthetic brine of 30000ppm of sodium chloride. 2) This followed by injection of Angsi Crude oil until water saturation condition is obtained. 3) Then the core will be water flooded to the residual oil saturation as per designed. 4) After that, the core will be flooded with 0.5PV of Alkaline Polymeric Surfactant (APS) slug. Once all the APS slug are injected, the extended water flood will be initiated until the oil production is negligible. 5) From this test, the optimum APS concentration will be selected based on the total oil recovery percentage.

3.2.3 Final Research Development

In the final research development, the result from the experiments will be finalized and the author will try to improve the range of data of widen the scope of the studies. The result obtain from the experiments will be reviewed with project supervisor for further improvement and necessary changes will be done. A proper documentation will be completed and the research will be open for further improvement.

3.3 Key Milestone

Below are the key milestones that need to be achieved by the author throughout the period of the research which is approximately 26 weeks.

TABLE 3: Key milestones

Milestone	**Week**
Early Research Development • Research Background • Problem statement and Objective • Scope of studies	1-9

Middle Research Development
• Detailed research
    ○ How to conduct the experiment?
    ○ What Parameters are required before testing?
    ○ Expected result from the test
• Experimental and laboratories test
    ○ Fluid to Fluid compatibility test
    ○ Interfacial Tension Test
    ○ Viscosity Test
    ○ Core Flood Test
• Analysing the data and result obtains
	10-21

Final Research Development • Finalizing the results • Completing the documentation	22-26

3.4 Gantt Chart

The key milestones explained earlier are summarized in the Gantt chart in the **Appendix I, II, and III.**

3.5 Material and Apparatus

TABLE 4: Material and Apparatus

Material	1) Polymeric Surfactant PMES Powder 2) Sodium Chloride (NaCl) Powder 3) Sodium Carbonate (Na_2CO_3) Powder 4) Distilled water
Apparatus and Machinery	1) Model SVT 20 spinning drop tensiometer (**Appendix IV**) 2) Relative permeability system (**Appendix V**) 3) Cannon-Fenske Viscometer and Koehler Viscosity Bath (**Appendix VI**) 4) Refractometer 5) Density Meter (**Appendix VII**) 6) Test tubes 7) Oven

CHAPTER 4
RESULTS AND DISCUSSION

This chapter will discuss on the results for both project objectives which are firstly, to evaluate the tolerance level of the PMES toward high brine salinity at a constant temperature and secondly, to find the optimum polymeric surfactant concentration and alkali concentration for oil recovery improvement.

4.1 Sample preparation

Preparation of 30000ppm brine

To demonstrate the effect of high saline brine environment, 30000ppm of only sodium chloride, NaCl brine was used in all of the experiments. The preparation of the 30000ppm of brine was calculated below:

1ppm=1mg NaCl/1 litre of water

30000ppm= 30000mg of NaCl/1 litre of water

Example: For 100ml brine solution,

30000ppm= 3000mg of NaCl/ 100ml of water

Preparation of various concentration of polymeric surfactant with 30000ppm brine

The polymeric surfactant was prepared in different concentration of 0.2%, 0.4%, 0.6%, 0.8% and 1.0%, respectively. Each solution was prepared in 100ml to ease the calculation. Table 4 shows the required polymeric surfactant powder and brine solution to prepare the respective polymeric surfactant concentration solutions.

Example calculation:

0.2wt% of 100ml=0.2ml=0.2g

99.8% of 100ml=99.8ml

Thus, 0.2g of polymeric surfactant powder was dissolved in 99.8ml of 30000ppm brine solution.

TABLE 5: Various polymeric surfactant concentrations solutions

Polymeric Surfactant Concentration, wt%	Polymeric Surfactant Powder, g	Brine solutions, ml
0.2	0.2	99.8
0.4	0.4	99.6
0.6	0.6	99.4
0.8	0.8	99.2
1.0	1.0	99.0

Preparation of various concentrations of sodium carbonate solutions with 30000ppm brine

The sodium carbonate was prepared in different concentration of 0.2wt%, 0.4wt%, 0.6wt%, 0.8wt% and 1.0wt%, respectively. Again to simplify the calculation, each of the solution was prepared in 100ml. Table 5 shows the required sodium carbonate powder and brine solution to prepare the respective sodium carbonate concentration solutions.

TABLE 6: Various sodium carbonate concentration solutions

Sodium Carbonate Na_2CO_3, wt%	Sodium Carbonate Na_2CO_3 Powder, g	Brine solutions, ml
0.2	0.2	99.8
0.4	0.4	99.6
0.6	0.6	99.4
0.8	0.8	99.2
1.0	1.0	99.0

<u>Preparation various sodium carbonate concentration with 0.6% PMES concentration in 30000ppm brine</u>

Sodium carbonate with various concentrations was dissolved in 30000ppm of NaCl brine together with 0.6% polymeric surfactant concentration. Each of the solution was prepared in 100ml to ease the calculation. Table 6 shows the required polymeric surfactant powder, sodium carbonate powder and brine solution.

TABLE 7: Various sodium carbonate concentration with 0.6% PMES concentration solutions

Polymeric Surfactant Concentration, wt%	Polymeric Surfactant Powder, g	Sodium Carbonate Na_2CO_3, wt%	Sodium Carbonate Na_2CO_3 Powder, g	Brine solutions, ml
0.6	0.6	0.2	0.2	99.2
0.6	0.6	0.4	0.4	99.0
0.6	0.6	0.6	0.6	98.8
0.6	0.6	0.8	0.8	98.6
0.6	0.6	1.0	1.0	98.4

4.2 Fluid to fluid compatibility test

In this experiment, the compatibility of the polymeric surfactant and sodium carbonate in high saline brine were determined by observing any physical changes in each sample. The samples were kept in the oven of 70 degree Celsius for 50 days. The results are tabulated below.

TABLE 8: Compatibility test of various PMES concentration and 30000ppm brine mixtures

Day	0.2% PMES + 30000ppm brine	0.4% PMES + 30000ppm brine	0.6% PMES + 30000ppm brine	0.8% PMES + 30000ppm brine	1.0% PMES + 30000ppm brine
1	NP	NP	NP	NP	NP
3	NP	NP	NP	NP	NP
5	NP	NP	NP	NP	NP
8	NP	NP	NP	NP	NP
10	NP	NP	NP	NP	NP
12	NP	NP	NP	NP	NP
15	NP	NP	NP	NP	NP
17	NP	NP	NP	NP	NP
19	NP	NP	NP	NP	NP
22	NP	NP	NP	NP	NP
24	NP	NP	NP	NP	NP
26	NP	NP	NP	NP	NP
29	NP	NP	NP	NP	NP
32	NP	NP	NP	NP	NP
34	NP	NP	NP	NP	NP
36	NP	NP	NP	NP	NP
38	NP	NP	NP	NP	NP
41	NP	NP	NP	NP	NP
43	NP	NP	NP	NP	NP
45	NP	NP	NP	NP	NP
48	NP	NP	NP	NP	NP
50	NP	NP	NP	NP	NP

TABLE 9: Compatibility test of different sodium carbonate concentration and 30000ppm brine mixtures

Day	0.2% Na_2CO_3 + 30000ppm brine	0.4% Na_2CO_3 + 30000ppm brine	0.6% Na_2CO_3 + 30000ppm brine	0.8% Na_2CO_3 + 30000ppm brine	1.0% Na_2CO_3 + 30000ppm brine
1	NP	NP	NP	NP	NP
3	NP	NP	NP	NP	NP
5	NP	NP	NP	NP	NP
8	NP	NP	NP	NP	NP
10	NP	NP	NP	NP	NP
12	NP	NP	NP	NP	NP
15	NP	NP	NP	NP	NP
17	NP	NP	NP	NP	NP
19	NP	NP	NP	NP	NP
22	NP	NP	NP	NP	NP
24	NP	NP	NP	NP	NP
26	NP	NP	NP	NP	NP
29	NP	NP	NP	NP	NP
32	NP	NP	NP	NP	NP
34	NP	NP	NP	NP	NP
36	NP	NP	NP	NP	NP
38	NP	NP	NP	NP	NP
41	NP	NP	NP	NP	NP
43	NP	NP	NP	NP	NP
45	NP	NP	NP	NP	NP
48	NP	NP	NP	NP	NP
50	NP	NP	NP	NP	NP

*NP= No Precipitation

TABLE 10: Compatibility test of various sodium carbonate concentration, optimum PMES concentration and 30000ppm brine mixtures

Day	0.2% Na_2CO_3 + 0.6% PMES + 30000ppm brine	0.4% Na_2CO_3 + 0.6% PMES + 30000ppm brine	0.6% Na_2CO_3 + 0.6% PMES + 30000ppm brine	0.8% Na_2CO_3 + 0.6% PMES + 30000ppm brine	1.0% Na_2CO_3 + 0.6% PMES + 30000ppm brine
1	NP	NP	NP	NP	NP
3	NP	NP	NP	NP	NP
5	NP	NP	NP	NP	NP
8	NP	NP	NP	NP	NP
10	NP	NP	NP	NP	NP
12	NP	NP	NP	NP	NP
15	NP	NP	NP	NP	NP
17	NP	NP	NP	NP	NP
19	NP	NP	NP	NP	NP
22	NP	NP	NP	NP	NP
24	NP	NP	NP	NP	NP
26	NP	NP	NP	NP	NP
29	NP	NP	NP	NP	NP
32	NP	NP	NP	NP	NP
34	NP	NP	NP	NP	NP
36	NP	NP	NP	NP	NP
38	NP	NP	NP	NP	NP
41	NP	NP	NP	NP	NP
43	NP	NP	NP	NP	NP
45	NP	NP	NP	NP	NP
48	NP	NP	NP	NP	NP
50	NP	NP	NP	NP	NP

*NP= No Precipitation

Based on the results obtained, all the samples demonstrate good tolerance level towards high saline brine. All of the samples show no visible physical changes when treated in 30000ppm of brine for 50 days. These results were mainly produced due to the brine which was prepared only using sodium chloride. The sodium ions in the brine have lower tendency to exhibit chemical reaction towards the polymeric surfactant and alkali due to the fact that both of the polymeric surfactant and alkali were also made up from sodium ions. Figures 8, 9 and 10 show the final products of the compatibility tests.

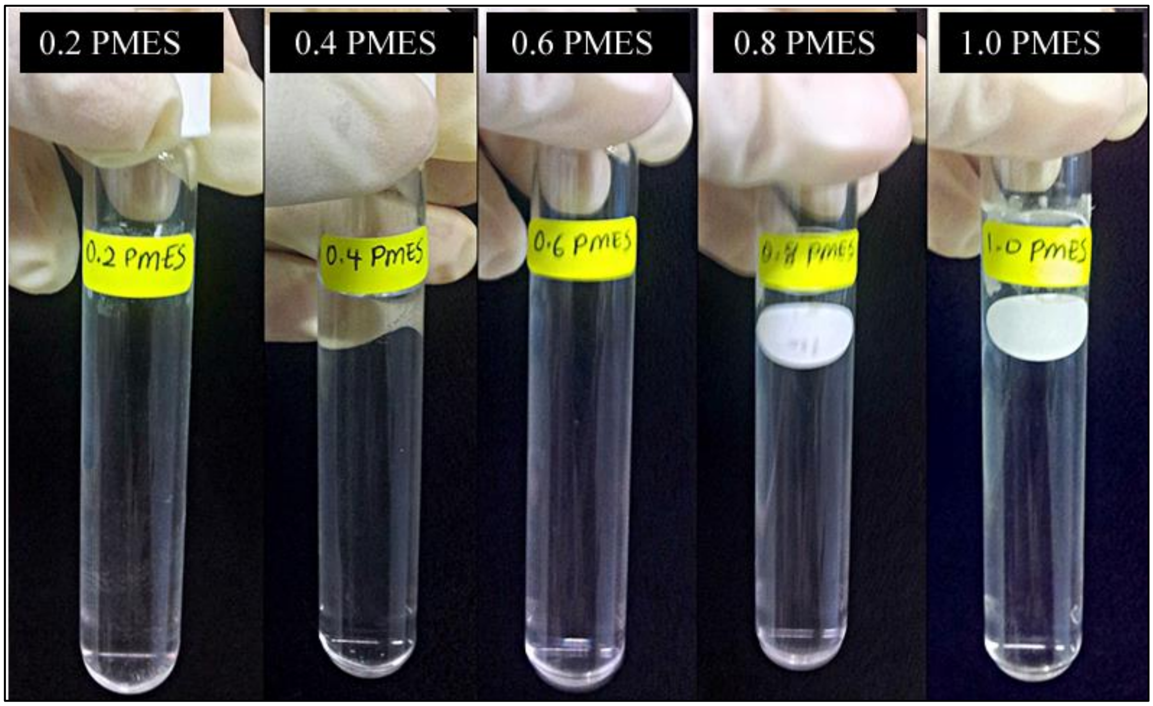


FIGURE 8: Compatibility test of various polymeric surfactant concentrations

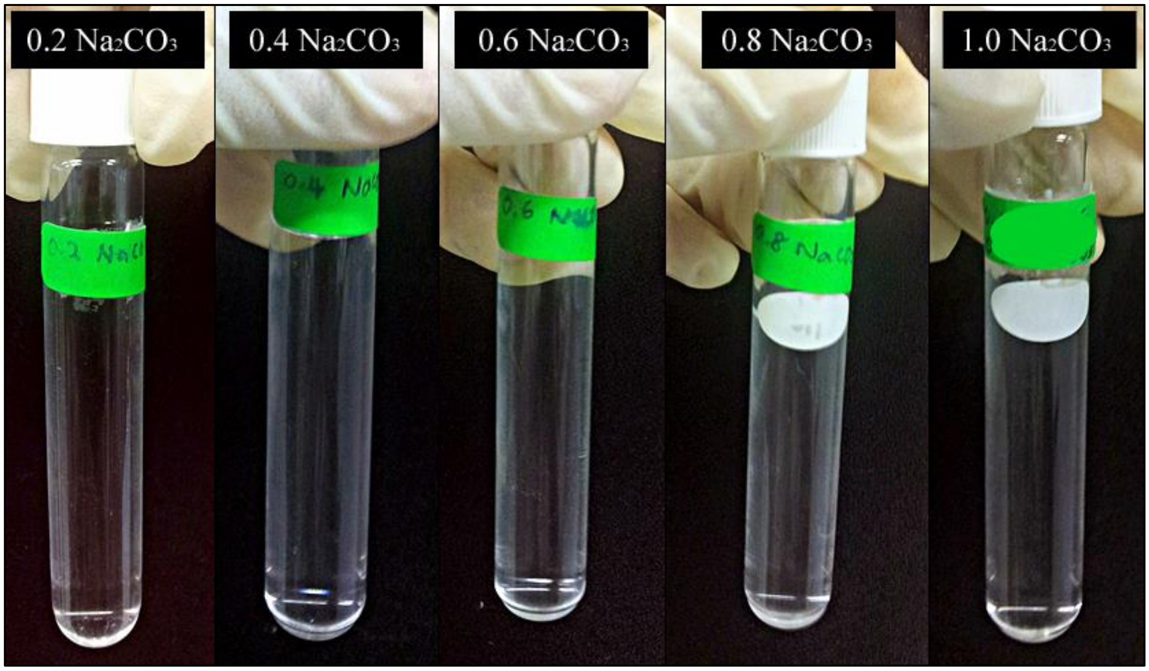


FIGURE 9: Compatibility test of various sodium carbonate concentrations

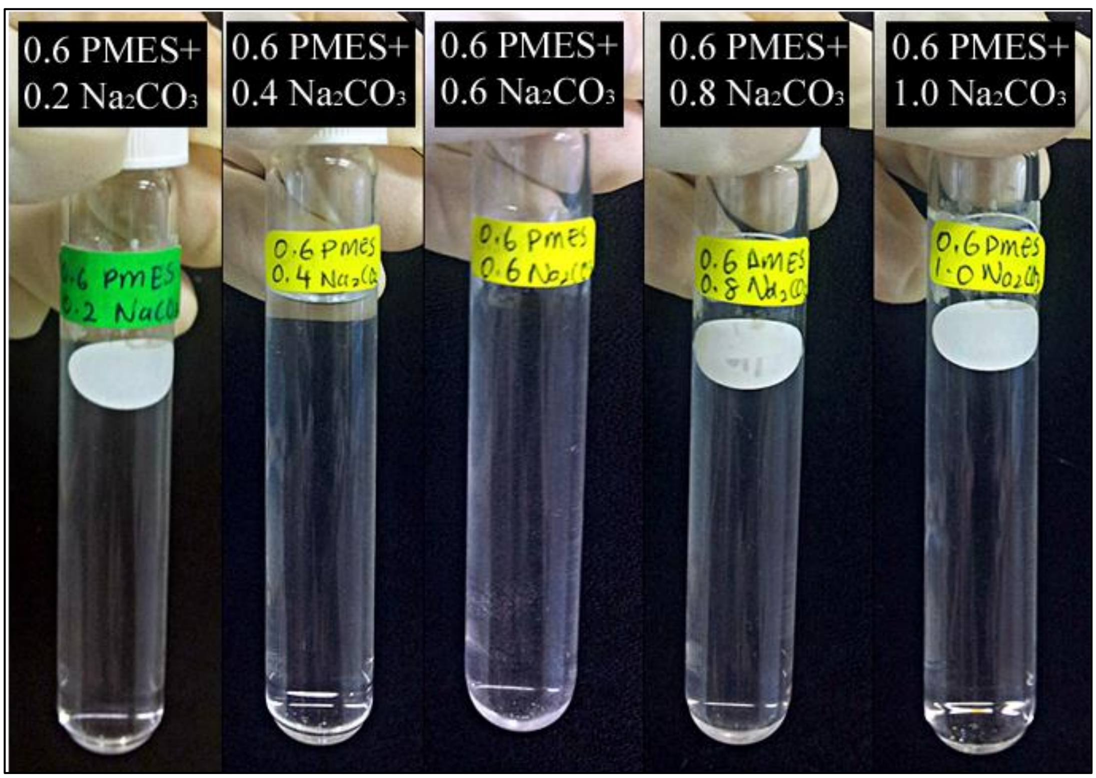


FIGURE 10: Compatibility test of various sodium carbonate concentrations and 0.6wt% PMES concentration

4.3 Polymeric Surfactant performance in high saline brine

The performance of the polymeric surfactant and alkali in high saline brine was evaluated in interfacial tension and viscosity test. The optimum concentration of the polymeric surfactant was deduced from these two experiments. The results of the experiments are tabulated and analysed below.

<u>Interfacial tension (IFT) reduction of various polymeric surfactant concentrations</u>

In this experiment, the interfacial tension reduction of different polymeric surfactant concentrations against Angsi crude oil of average 42 API was measured. Prior to IFT test, the sample properties such as density and refractivity index were measured using Density meter and Refractometer, respectively. Table 10 shows the density and refractivity index of each sample

TABLE 11: Sample properties

Density and Refractivity Index result			
Sample	**Density g/cm^3**	**RI nD**	**Temperature C**
Angsi Crude Oil	0.8222	-	70
30000ppm brine	0.9826	1.33573	
0.2% PMES + 30000ppm brine	0.9995	1.33579	
0.4% PMES + 30000ppm brine	0.9998	1.33589	
0.6% PMES + 30000ppm brine	1.0011	1.33625	
0.8% PMES + 30000ppm brine	1.0015	1.33642	
1.0% PMES + 30000ppm brine	1.0037	1.33700	

The refractivity index of Angsi crude oil was not measured because the value was not necessary in interfacial tension test. From the data collected, the density and RI increases as the concentration of polymeric surfactant increases.

The interfacial tension test of various polymeric surfactant concentrations was measured using the Model SVT20 spinning drop tensiometer. The rotation speed of the overall experiments was ranging around 1200-1500 rpm. The average values of interfacial tension of each sample are tabulated as per table 11.

TABLE 12: Interfacial Tension of various polymeric surfactant concentrations

Solutions	Average IFT mN/m
30000ppm brine	6.73
0.2% PMES + 30000ppm brine	0.610
0.4% PMES + 30000ppm brine	0.378
0.6% PMES + 30000ppm brine	0.259
0.8% PMES + 30000ppm brine	0.175
1.0% PMES + 30000ppm brine	0.115

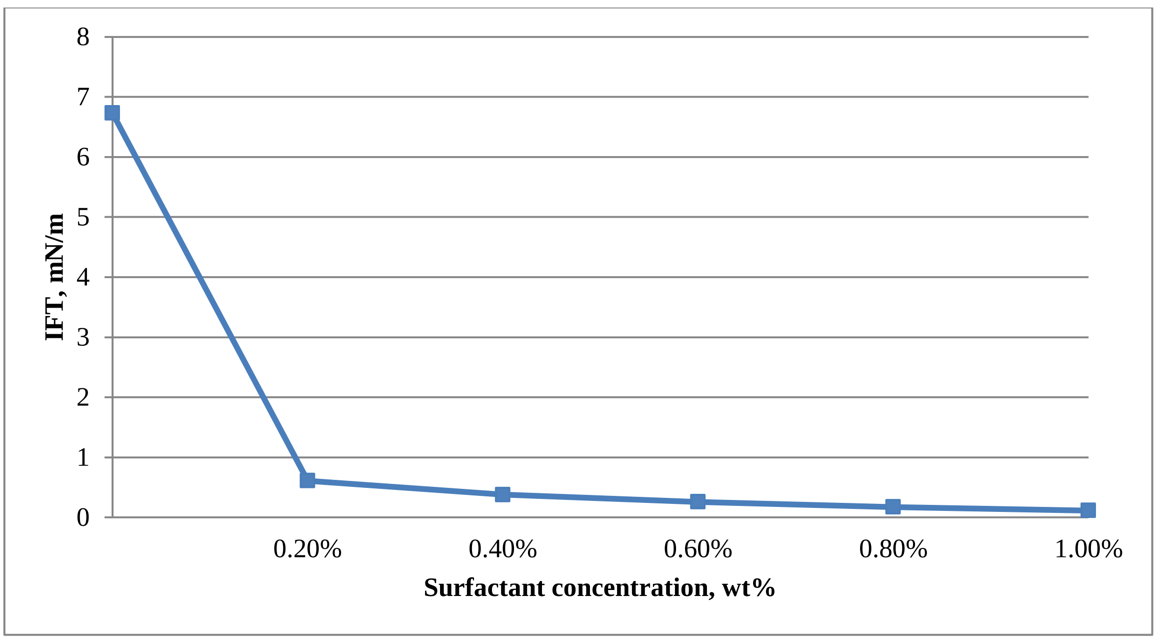


FIGURE 11: IFT performance of various polymeric surfactant concentrations

Based on figure 11, the polymeric surfactant significantly reduced the interfacial tension of the system from 6.73mN/m without any polymeric surfactant to as low as 0.115mN/m when 1.0wt% polymeric surfactant was added to the brine. Similarly, as the concentration of polymeric surfactant increases, the reduction of interfacial tension also increases. This is mainly due to the surface adsorption and aggregative properties of the polymeric surfactant. As the polymeric surfactant concentration increase, more surfactant molecules will be aggregated at the oil/water interface to form micelle solution.

Viscosity of various polymeric surfactant concentration and Angsi crude oil

The viscosity test on various polymeric surfactant concentration and Angsi crude oil were measured using Cannon Fenske viscometer. Time taken for each sample to travel in a desired column is tabulated. A viscosity approximation of 0.005cst/s was then multiplied to the measured time taken to get the sample viscosity. Table 13 shows the viscosity of various polymeric surfactant and Angsi crude oil.

TABLE 13: Viscosity of various polymeric surfactant concentration and Angsi crude oil

Solution	Time taken s	Viscosity mm^2/sec
Angsi Crude Oil	570	2.85
0.2 PMES	383	1.92
0.4 PMES	508	2.54
0.6 PMES	825	4.13
0.8 PMES	1305	6.53
1.0 PMES	1758	8.79

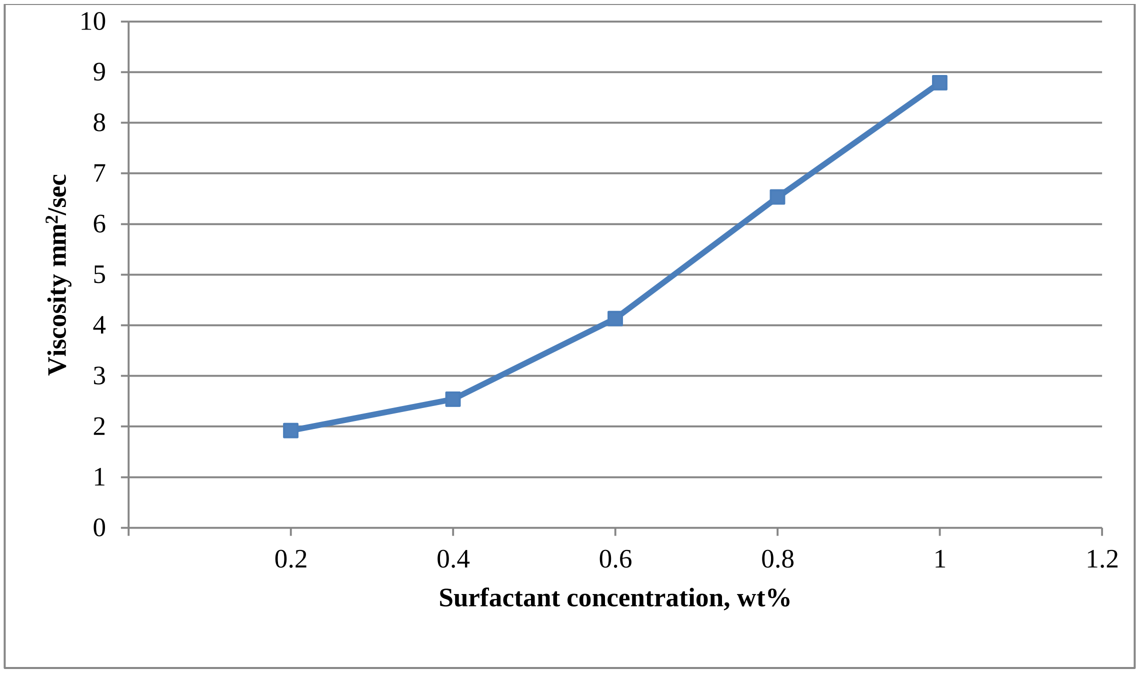


FIGURE 12: Viscosity performance of various surfactant concentrations

Figure 12 shows the viscosity performance of various surfactant concentrations. The viscosity increases as the concentration of polymeric surfactant increases. This can be explained since increasing the polymeric surfactant concentration will increase the polymeric surfactant molecules. As more polymeric surfactant molecules presence in the solution, the solution became more viscous. Since the Angsi crude oil viscosity is 2.85mm^2/sec, the 0.2wt% and 0.4wt% polymeric surfactant concentration with viscosity of 1.92mm^2/sec and 2.54mm^2/sec, respectively, are not economical and acceptable. In order to design the optimum slug concentration, the viscosity of the system must be slightly higher than the viscosity of the crude oil in order to have the desired viscosity control.

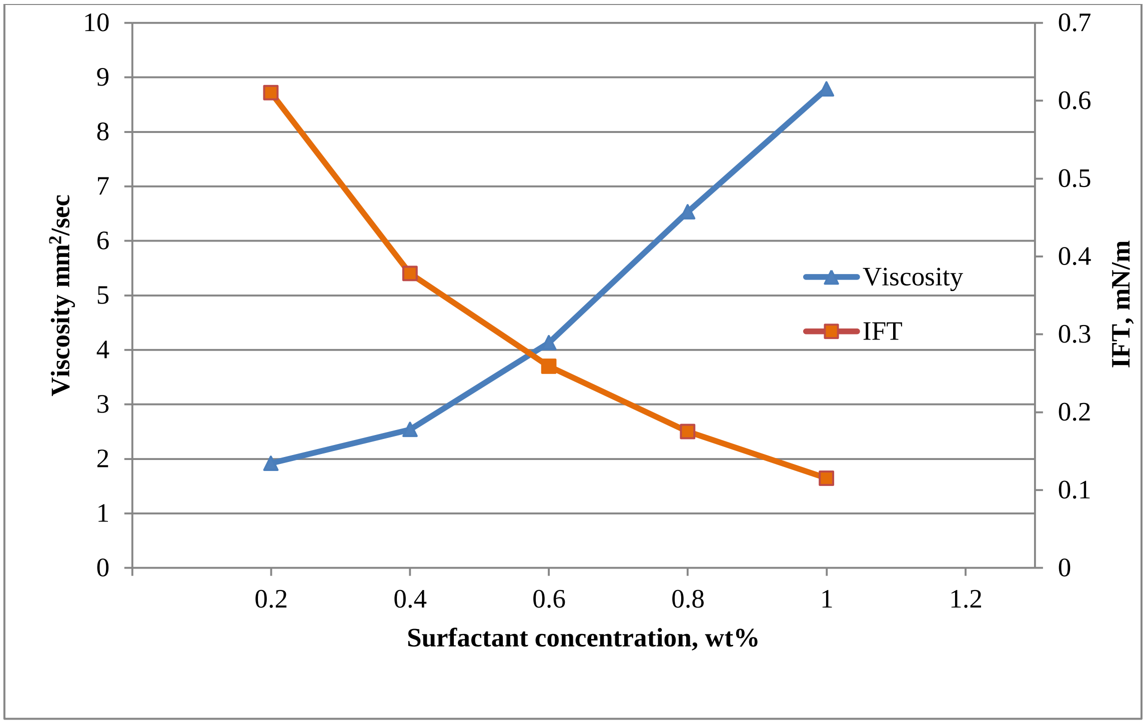


FIGURE 13: IFT and viscosity performance of various surfactant concentrations

Figure 13 shows the interfacial tension reduction and viscosity of various surfactant concentrations. The determination of a cost-effective polymeric surfactant concentration was based on the viscosity and interfacial performance of the surfactant. From the graph, polymeric surfactant of 0.6% is chosen to be the cost-effective concentration due to its performance in interfacial tension reduction and also the viscosity of the system. The optimum surfactant concentration will give favourable mobility ratio for chemical flooding displacement of the crude oil. Furthermore, although 0.8wt % and 1.0wt% polymeric surfactant concentrations shows better results than 0.6wt%, the concentrations are not economical and high viscous fluid might cause some injection issues. The optimum polymeric surfactant concentration 0.6wt% is used to investigate the impact of alkali in the system to deduce the optimum alkali concentration.

4.4 Polymeric Surfactant performance in the absence and presence of alkali

To investigate the effect of alkali on the performance PMES, interfacial tension and viscosity test of optimum polymeric surfactant of 0.6wt% with the presence of various concentration of sodium carbonate were carried out. The tests were also conducted to determine the presence of sodium carbonate in the system would affect the viscosity of the polymeric surfactant solutions.

Interfacial tension test in the absence and presence of various alkali concentrations

In this experiment, the interfacial tension reduction of optimum polymeric concentration in the absence and presence of various alkali concentrations was measured. Prior to IFT test, the sample properties such as density and refractivity index were measured using Density meter and Refractometer, respectively. The sample properties are tabulated in table 14.

TABLE 14: Sample properties of various sodium carbonate concentrations (0.6wt%PMES)

Density and Refractivity Index result			
Sample	**Density g/cm^3**	**RI nD**	**Temperature C**
Angsi Crude Oil	0.8222	-	70
0.6% PMES + 30000ppm brine	1.0011	1.33625	
0.2% Na_2CO_3 + 0.6% PMES + 30000ppm brine	1.0056	1.33714	
0.4% Na_2CO_3 + 0.6% PMES + 30000ppm brine	1.0059	1.33726	
0.6% Na_2CO_3 + 0.6% PMES + 30000ppm brine	1.0062	1.33736	
0.8% Na_2CO_3 + 0.6% PMES + 30000ppm brine	1.0086	1.3375	
1.0% Na_2CO_3 + 0.6% PMES +30000ppm brine	1.0109	1.33821	

The interfacial tension test of optimum polymeric concentration in the absence and presence of various alkali concentrations was measured using the Model SVT20 spinning drop tensiometer. The rotation speed of the overall experiments was ranging around 1200-1500 rpm. The average values of interfacial tension of each sample are as per table 15.

TABLE 15: Interfacial tension of various sodium carbonate concentrations (0.6wt%PMES)

Solutions	Average IFT mN/m
0.6% PMES + 30000ppm brine	0.259
0.2% Na_2CO_3 + 0.6% PMES + 30000ppm brine	0.241
0.4% Na_2CO_3 + 0.6% PMES + 30000ppm brine	0.225
0.6% Na_2CO_3 + 0.6% PMES + 30000ppm brine	0.19
0.8% Na_2CO_3 + 0.6% PMES + 30000ppm brine	0.165
1.0% Na_2CO_3 + 0.6% PMES +30000ppm brine	0.162

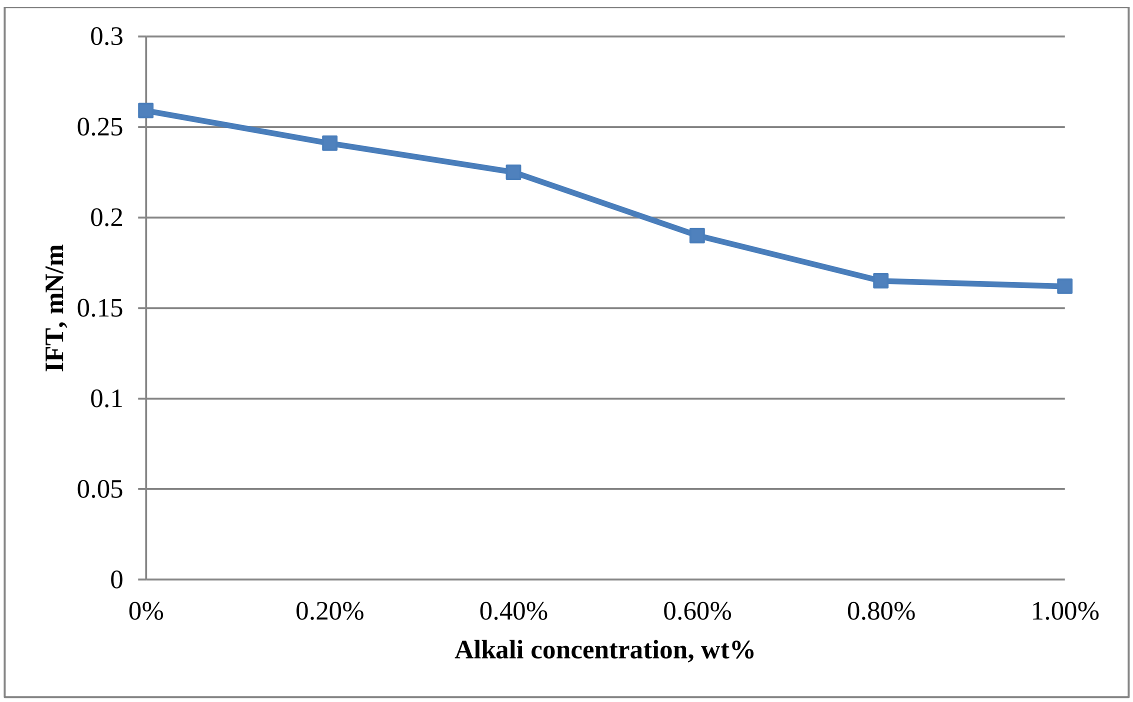


FIGURE 14: IFT performance in the absence and presence of various alkali concentrations (0.6% PMES)

Figure 14 shows the effect of alkali concentrations on the IFT performance of the polymeric surfactant. The IFT decreases significantly with the increment of alkali concentration until it reaches 0.165mN/m when the concentration of sodium carbonate was at 0.8wt%. Above this concentration, the changes in IFT reduction was consider insignificant and negligible. The significant IFT reduction observed when the alkali concentration increases from 0.2wt% to 0.8wt% can be explained by the production of in- situ surfactant due to saponification reaction between the alkali and the acidic groups in the crude oil. These in-situ surfactants are associated with the polymeric surfactant to produce synergistic mixtures which later adsorbed at the oil and water interface.

Viscosity of PMES with the presence of alkalis with different concentration

The viscosity test of optimum polymeric concentration in the absence and presence of various alkali concentrations was measured using Cannon Fenske viscometer. Time taken for each sample to travel in a desired column is tabulated. A viscosity approximation of 0.005cst/s was then multiplied to the measured time taken to get the sample viscosity. Table 16 shows the viscosity of polymeric surfactant with the presence of various concentration of alkali

TABLE 16: Viscosity of various sodium carbonate concentration (0.6wt% PMES)

Solution	Time taken s	Viscosity mm^2/sec
0.6% PMES + 30000ppm brine	825	4.13
0.2% Na_2CO_3 + 0.6% PMES + 30000ppm brine	856	4.28
0.4% Na_2CO_3 + 0.6% PMES + 30000ppm brine	863	4.32
0.6% Na_2CO_3 + 0.6% PMES + 30000ppm brine	871	4.35
0.8% Na_2CO_3 + 0.6% PMES + 30000ppm brine	884	4.42
1.0% Na_2CO_3 + 0.6% PMES +30000ppm brine	893	4.46

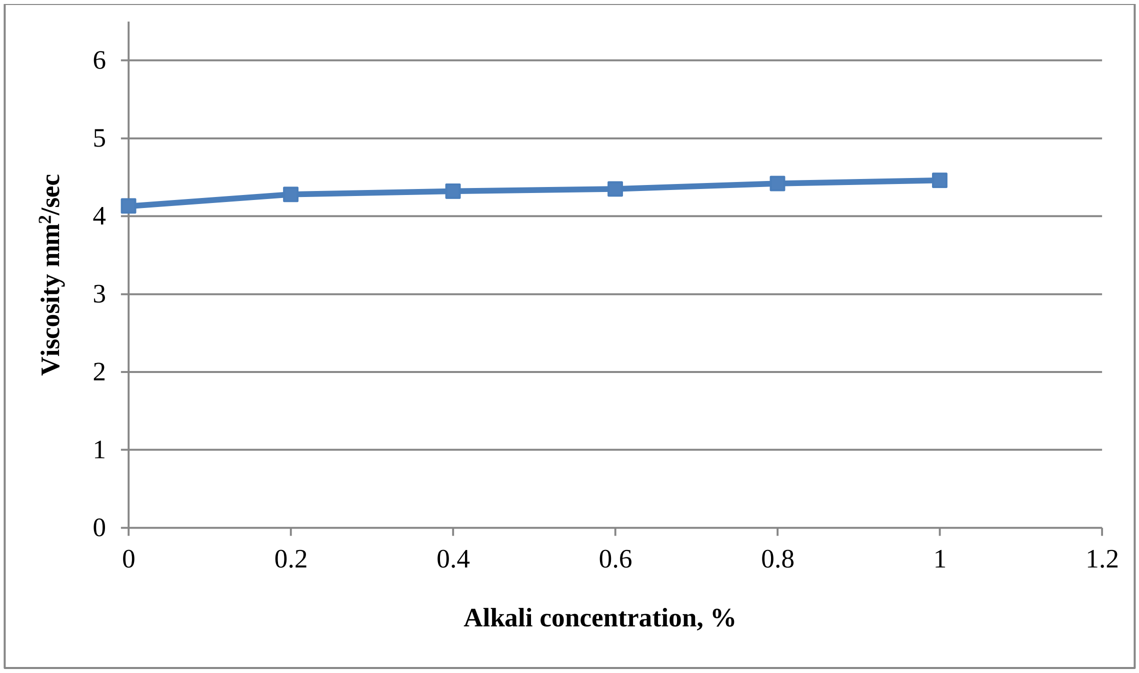


FIGURE 15: Viscosity performance in the absence and presence of various alkali concentrations

Figure 15 shows the viscosity performance in the absence and presence of sodium carbonate at 70◦C. The presence of alkali ranging from 0.2wt% to 1.0wt did affect the viscosity of the system but the rate of increment was low. At 0.2wt% of alkali, the value of the viscosity of the system is 4.28mm^2/sec while at 1.0wt% of alkali, the viscosity is at 4.46mm^2/sec. This increment of viscosity can be explained due to fact that as the sodium carbonate increase, the amount of sodium ions presence in the system also increases. This sodium ion enhanced the viscosity of the system through polymer hydrolysis. As the polymer is hydrolysed, the number of negatively charge group on the polymer increases which lead to increase in electrostatic repulsion. As a result, the polymer chain size increase and so thus the viscosity. However, at high sodium ions concentration, the effect of hydrolysis compensates through charge screening or shielding mechanism which result in the viscosity of the system remains almost constant. Based on the graph, the new polymeric surfactant in the presence of sodium carbonate shows great stability as compared to conventional ASP formula.

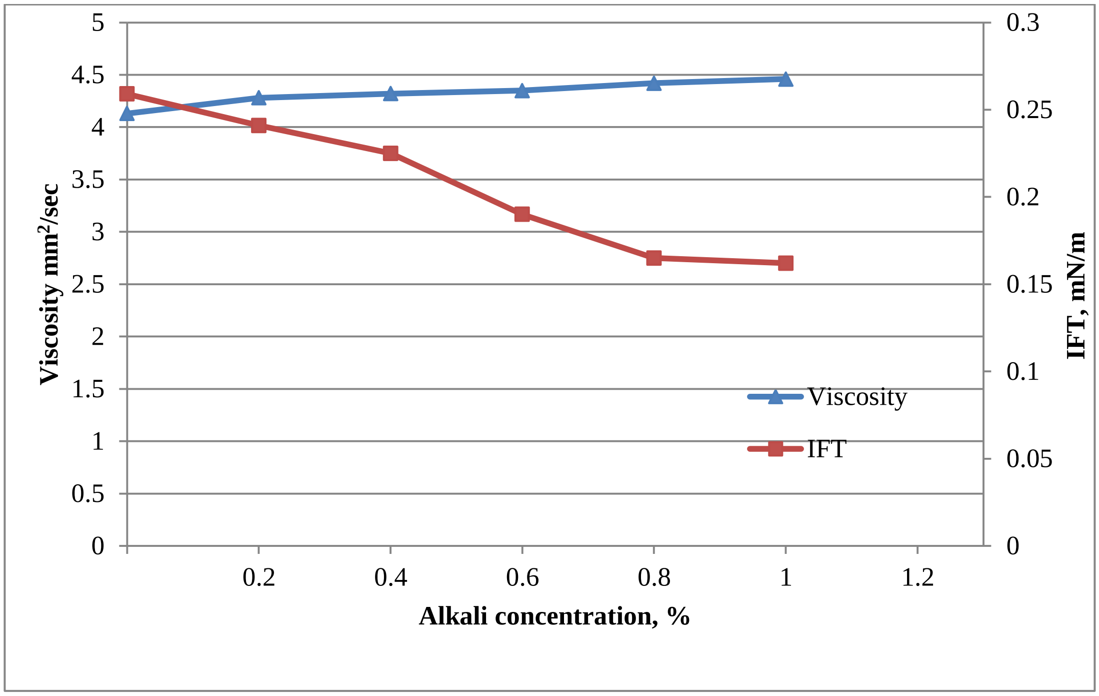


FIGURE 16: IFT and Viscosity performance in the absence and presence of various alkali concentrations

Figure 16 shows the IFT and viscosity performance of the PMES in the absence and presence of various alkali concentrations. From the graph, the IFT reduction improved when the alkali concentration increases until to a certain concentration where the IFT reduction is almost constant. Meanwhile, the viscosity of the system increases as the alkali concentration increases. However, the rate of change in the viscosity reduces as the concentration of alkali increase. In order to design an optimum ASP slugs, the alkali concentration of 0.8wt% is chosen to be the optimum alkali concentration due to good performance in IFT reduction and viscosity stability. As a result, 0.6wt% of polymeric concentration and 0.8wt% alkali concentration are chosen as the optimum concentration of the ASP slug. The optimum ASP slug concentration is used in the chemical flooding displacement of the crude oil used in this project.

4.4 Core Flood Test

To examine the performance of the new polymeric surfactant in enhanced oil recovery application, two core flood test were performed using different polymeric surfactant concentrations of 0.6wt% and 0.8wt% with the addition of 0.8wt% of alkali concentration. For all the core flood experiments, the injection strategy stated with the water flooding as the primary and secondary recovery, followed by 0.5 pore volume of ASP slug and the last step involved water flooding as chase water until production of residual oil is negligible.

4.4.1 Core samples properties

Prior to the core flood tests, the weight, length, and diameter of the core samples were first measured before the core samples were saturated with 30000ppm of brine for a night. After the saturation process was completed, the weight of the core samples was again measured to find the pore volume. From the pore volume, the porosity of the core samples was calculated. The value of permeability of the core samples was measured directly from the relative permeability system built-in software. Table 17 summarises the physical core properties.

TABLE 17: Physical core properties

Properties		
	Core 1	**Core 2**
Length (cm)	6.73	7.13
Diameter (cm)	3.886	3.695
Bulk Volume (cc)	79.81	76.46

Properties	Core 1	Core 2
Dry Weight (g)	167.4	167.1
Wet Weight (g)	180.1	179.5
Weight difference (g)	12.7	12.4
Density of brine (g/cc)	1.020	1.020
Pore Volume (cc)	12.45	12.15
Porosity %	15.6%	15.9%
Permeability (md)	79.4	72.6

4.4.2 Oil Flood

TABLE 18: Oil flood results

	Core 1	Core 2
Injection rate (ml/min)	0.32	0.29
Pore volume (cc)	12.45	12.15
Initial oil in place ,OIIP (cc)	8.97	7.97
Oil Saturation, So (%)	72	66
Irreducible water (cc)	3.48	4.18
Water Saturation, Sw (%)	28	34

Table 18 shows the results of the oil flood. Oil flooding was done to displace as much as water as possible until the irreducible water saturation is achieved. After the oil flood, the core samples were left for a night to allow the oil and water in the cores to stabilize. The initial oil in place (OOIP) for core 1 and 2 were 72% and 66% respectively. Meanwhile, the water saturation was at 28% and 34% for core 1 and 2 respectively.

Figure shows the amount of water collected at the end of oil flooding. However, 5.03ml of the amount of water collected was deducted in order to find the amount the total displaced water in the cores.

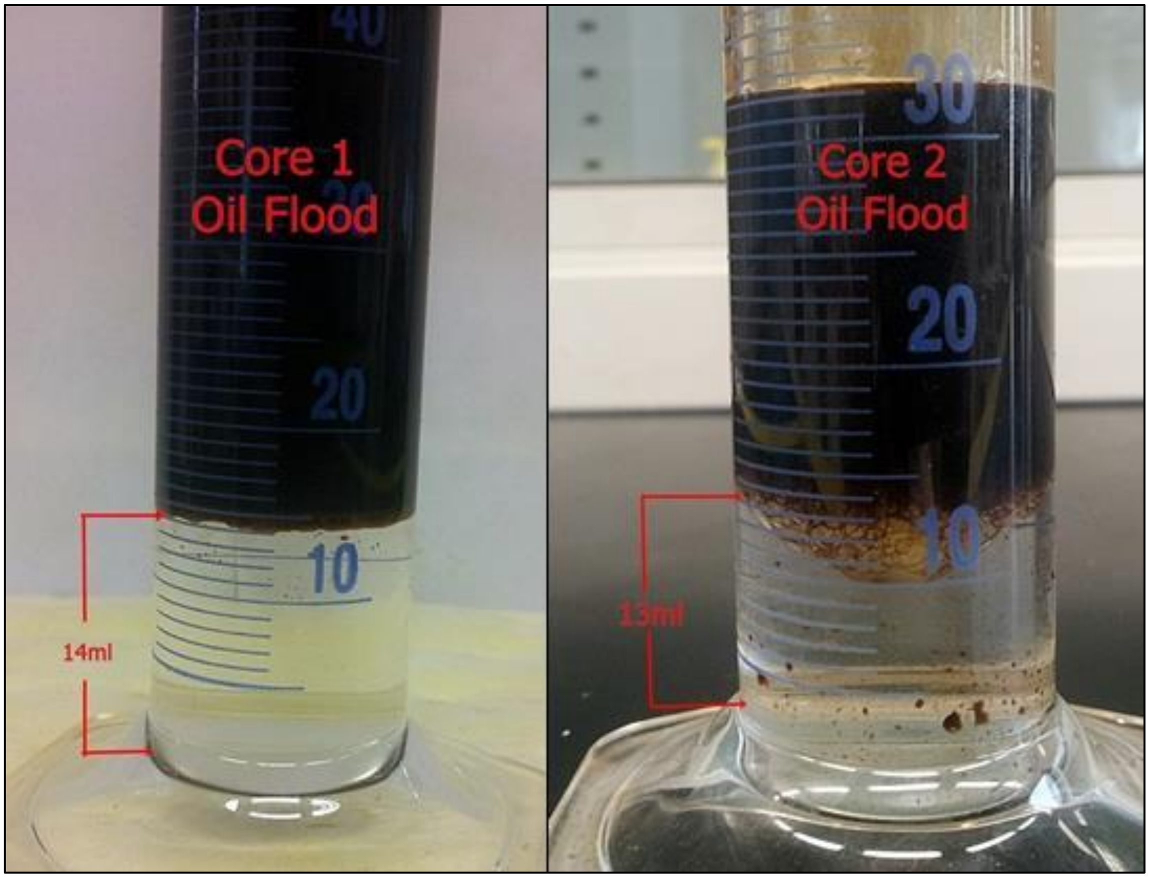


FIGURE 17: Amount of water collected after the oil flood

4.4.3 Water flooding

TABLE 19: Water flood results

	Core 1	Core 2
Injection rate (ml/min)	0.32	0.29
Oil produced	3.97	3.50
Residual oil after water flooding (cc)	5.00	4.47
Residual oil after water flooding (%)	55.7	56.1
Total secondary recovery (%)	44.2	43.9

Table 19 shows the result of water flooding using 30000ppm brine. Water flooding was done to each core sample to act as secondary oil recovery process. The 30000ppm of brine was only prepared using sodium chloride. The total residual oil after water flooding was at 55.7% and 56.1% for core 1 and 2, respectively. The total secondary recovery was almost the same for both core samples with 44.2% and 43.9% for core 1 and 2, respectively. This shows that the ability of the brine to displace the oil is limited due to high value of IFT in the previous experiments. Figure 18, shows the amount of oil collected at the end of water flooding. However, 5.03ml of the collected oil amount is deducted in order to find the amount of displaced oil in the core.

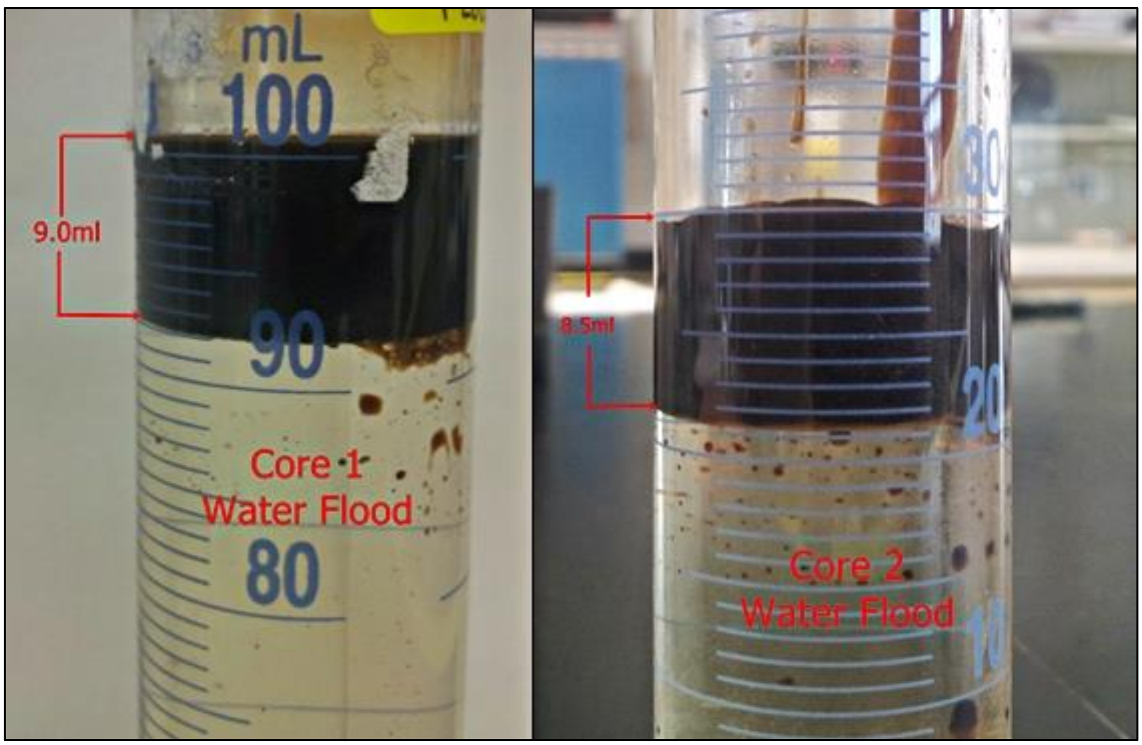


FIGURE 18: Amount of oil collected after water flood

4.4.4 Alkaline-Surfactant-Polymer slug flood

TABLE 20: APS slug and chase water flood results

	Core 1	Core 2
PMES concentration, (wt%)	0.6	0.8
Alkali concentration (wt%)	0.8	0.8
0.5 PV (cc)	6.22	6.08
Injection rate (ml/min)	0.32	0.29
Oil produced	2.0	2.2
Residual oil after APS and chase water (cc)	3.0	2.27
Residual oil after APS and chase water (%)	33.4	28.4
Tertiary oil recovery (%)	22.3	27.6
Total oil recovery (%)	66.5	71.5

Table 20 shows the APS slug and chase water flood results. The core was first injected with 0.5 pore volume of APS slug and followed by chase water until the production of oil is negligible. The total residual oil after APS and chase water was at 33.4% and 28.4% for core 1 and 2, respectively. Figure 19 shows the amount of oil collected after the APS and chase water flood.

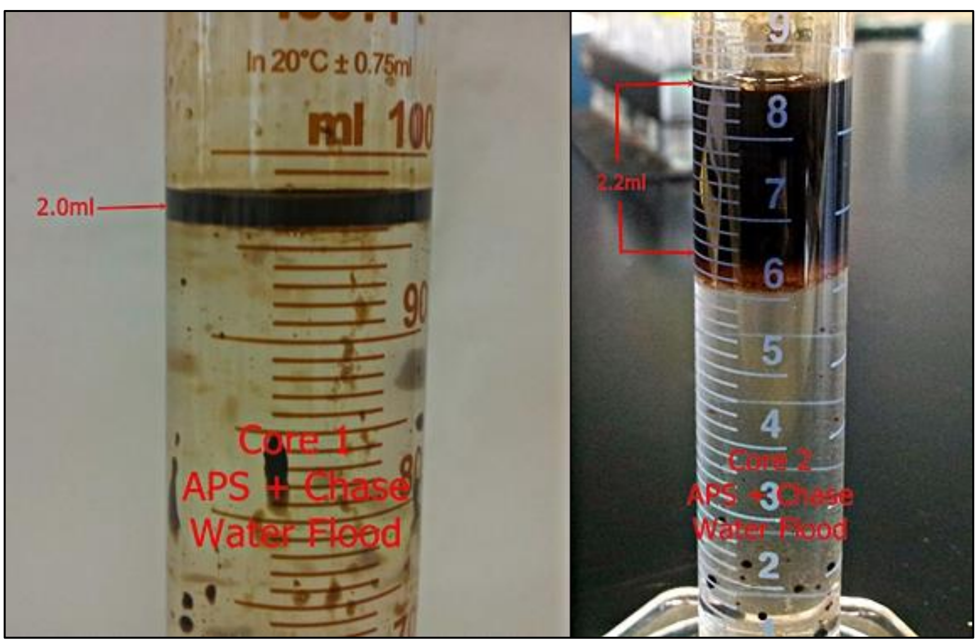


FIGURE 19: Amount of oil collected from APS + chase water flood

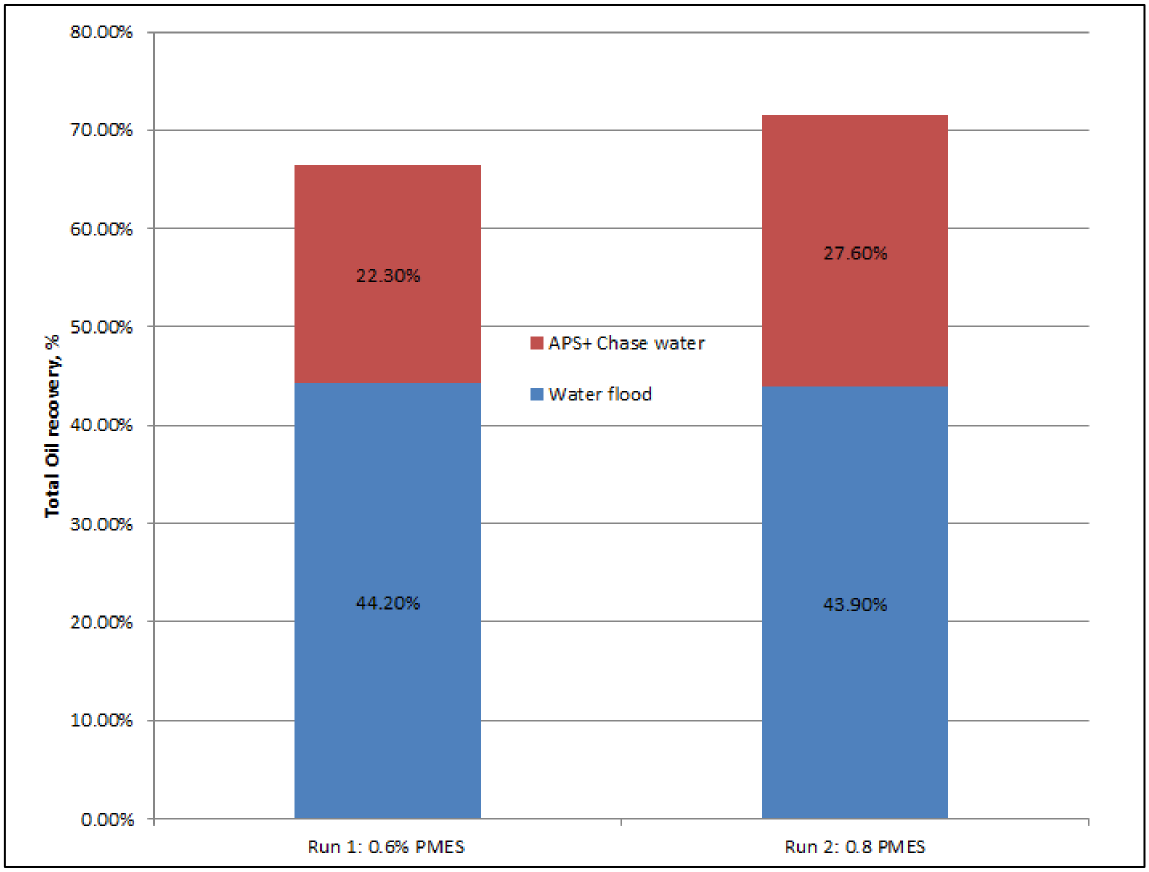


FIGURE 20: Total oil recovery vs polymeric surfactant concentrations

Figure 20 shows the total recovery for both core 1 and 2. For core 1, the optimum polymeric surfactant deduced from previous experiments which is 0.6wt% was used to prepare the APS slug. Meanwhile, for core 2, 0.8wt% polymeric surfactant concentration was used as the APS slug. In both cases, the APS slug show significant increase in the recovery of oil whereby 22.3% and 27.6% of tertiary oil recovery were achieved for core 1 and 2, respectively. The high oil recovery was due to the synergistic effect between the surfactant and alkali to emulsify and mobilize the crude oil. This increases both the microscopic displacement and sweep efficiency. Meanwhile, the 0.8wt% polymeric surfactant concentration shows higher percentage of tertiary oil recovery compared to 0.6wt% polymeric surfactant concentration. This was due to the fact that the 0.8wt% polymeric surfactant concentration contains more surfactant molecules which improved the aggregation process. However, the 5% increase of tertiary oil recovery from 0.6wt% to 0.8wt% polymeric surfactant required additional

0.2wt% polymeric surfactant concentration. In this case, the 5% increment of tertiary recovery did not compensate the cost of additional 0.2wt% polymeric surfactant. Therefore, in order to design a cost and effective slug, the optimum polymeric surfactant of 0.6wt% was selected for this study.

CHAPTER 5
CONCLUSION AND RECOMMENDATION

5.1 Conclusion

A combination of polymeric surfactant and alkali showed good results for interfacial tension reduction and viscosity control in high saline brine when Angsi crude oil was used as the oil phase. However, the interfacial reduction obtained in this project is higher than those interfacial tension obtained in soft brine. This is due to the presence of more salts ions in high saline brine. This salts ions contributes to surfactant absorption which will reduce the effectiveness of the surfactant. Nevertheless, the amount of interfacial tension reduction obtained from this project was sufficient to emulsify and mobilize the crude oil.

Furthermore, the viscosity of the system was slightly affected by addition of alkali. The viscosity of the system increases as the concentration of alkali increases. This increase in viscosity was explained by the charge screening and hydrolysis phenomenon. In contrast with the conventional ASP flooding system, the viscosity is reduced with the addition of alkali.

Based on a series of core flood tests, the final oil recovery was increase as the surfactant concentration increases. The 0.6wt% polymeric surfactant concentration and 0.8% of alkali concentration had the best value to performance in recovering residual oil after water flooding. Tertiary oil recovery of 22.3% OOIP achieved when 0.5PV of APS slug followed by chase water was injected.

From all the conducted tests results, the evaluation of the polymeric surfactant toward high saline brine was successful. The polymeric surfactant shows good tolerance to high saline brine when only sodium chloride was used to prepare the brine. In conclusion, the objectives are achieved.

5.2 Recommendation

Throughout the research, the scopes of studies are limited to only three parameters; interfacial tension reduction, viscosity of the system, and compatibility towards high saline brine. Others factors that will affect the performance of polymeric surfactant are assumed constant for simplicity of the research. In order to improve the project in the near future, there are several recommendations that need to be considered which are:

1. PMES compatibility and performance towards high concentration of divalent ions such as Ca^+ and Mg^+ since the effect of divalent ions is more severe than monovalent ion such as Na^+.
2. Increase the brine salinity from 30000ppm up to 100000ppm to study the trend of surfactant behaviour and performance. Having the salinity range, the optimal salinity could be determined
3. PMES compatibility and performance in high temperature settings. The viscosity and interfacial tension reduction are affected by the temperature.
4. The effect of PH and surfactant adsorption in high saline brine must be evaluated.
5. The performance of the PMES in recovering heavy oil instead of light oil.

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APPENDICES

Appendix I: Gantt chart for FYP 1 and FYP 2

Stage	FYP 1													FYP 2												
	Week																									
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Early Research Developments																										
Research Background																										
Problem statement and Objective																										
Scope of studies																										
Middle Research Developments																										
Detailed research																										
Experimental and laboratories test																										
Analysing data and result obtains																										
Final Research Developments																										
Finalizing the results																										
Completing the documentation																										

Appendix II: Gantt Chart for Final Year Project 1

No.	Detail/ Week	1	2	3	4	5	6	7		8	9	10	11	12	13	14
1	Selection of Project Topic	■	■						Mid-semester break							
2	Preliminary Research Work		■	■	■	■										
3	Submission of Extended Proposal						●									
4	Proposal Defence									■	■					
5	Project work continues											■	■	■		
6	Submission of Interim Draft Report														●	
7	Submission of Interim Report															●

● Suggested milestone

■ Process

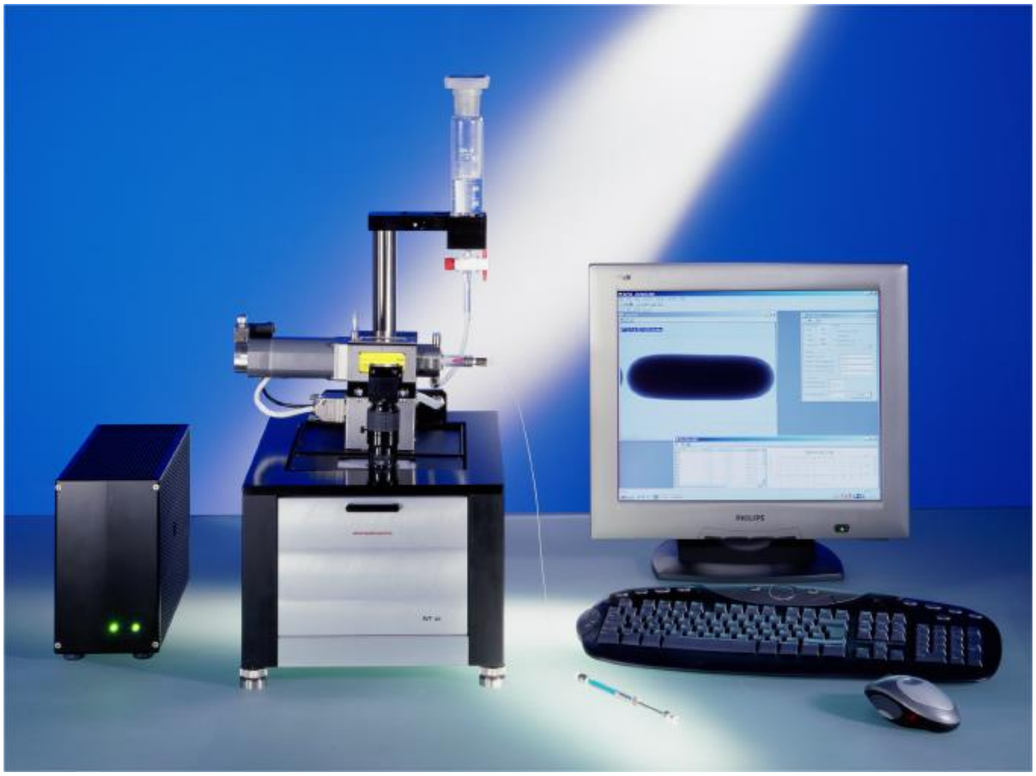
Appendix III: Gantt Chart for final year project 2

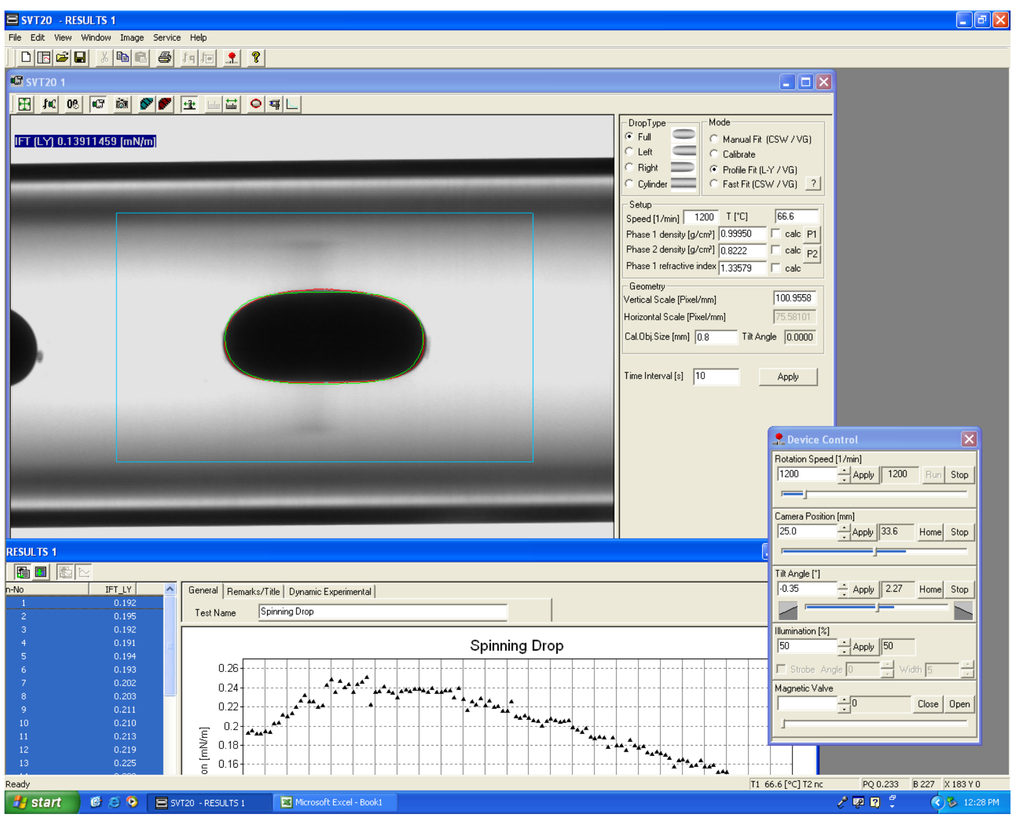
No.	Detail/ Week	1	2	3	4	5	6	7	Mid-Semester Break	8	9	10	11	12	13	14	15
1	Project Work Continues	■	■	■	■	■	■	■									
2	Submission of Progress Report							●									
3	Project Work Continues									■	■	■	■	■			
4	Pre-SEDEX											●					
5	Submission of Draft Report												●				
6	Submission of Dissertation (soft bound)													●			
7	Submission of Technical Paper													●			
8	Oral Presentation														●		
9	Submission of Project Dissertation (Hard Bound)																●

● Suggested milestone

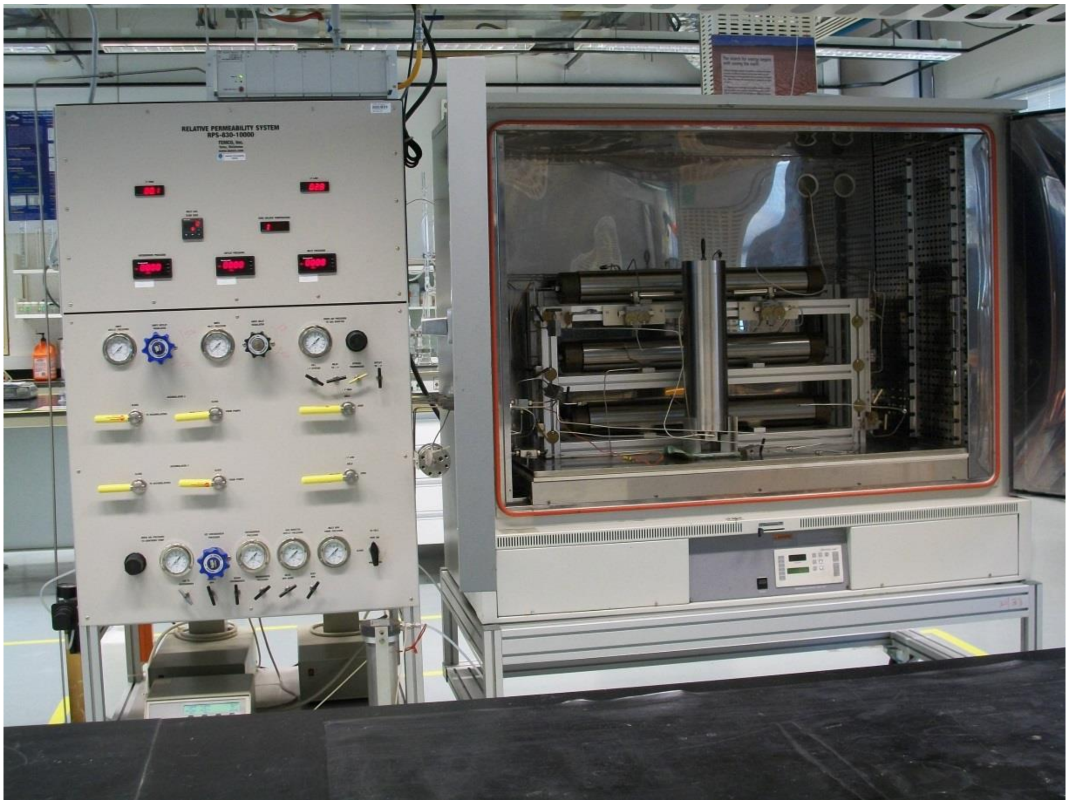
■ Process

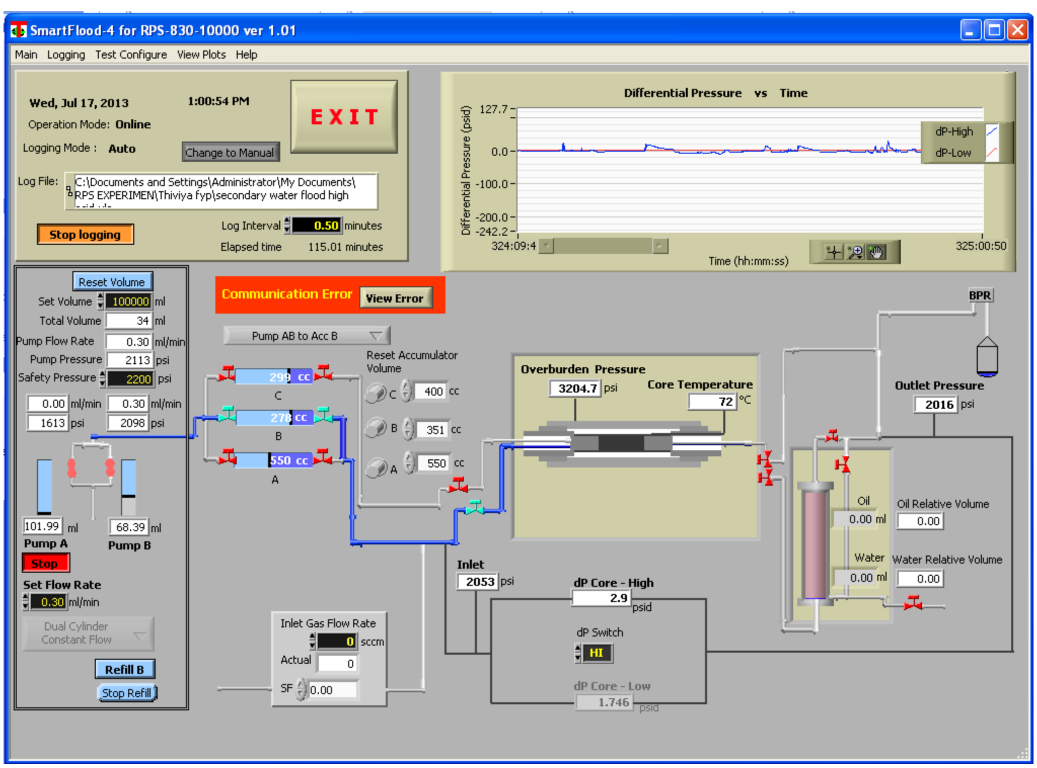
Appendix IV: Model SVT20 Spinning drop Tensiometer



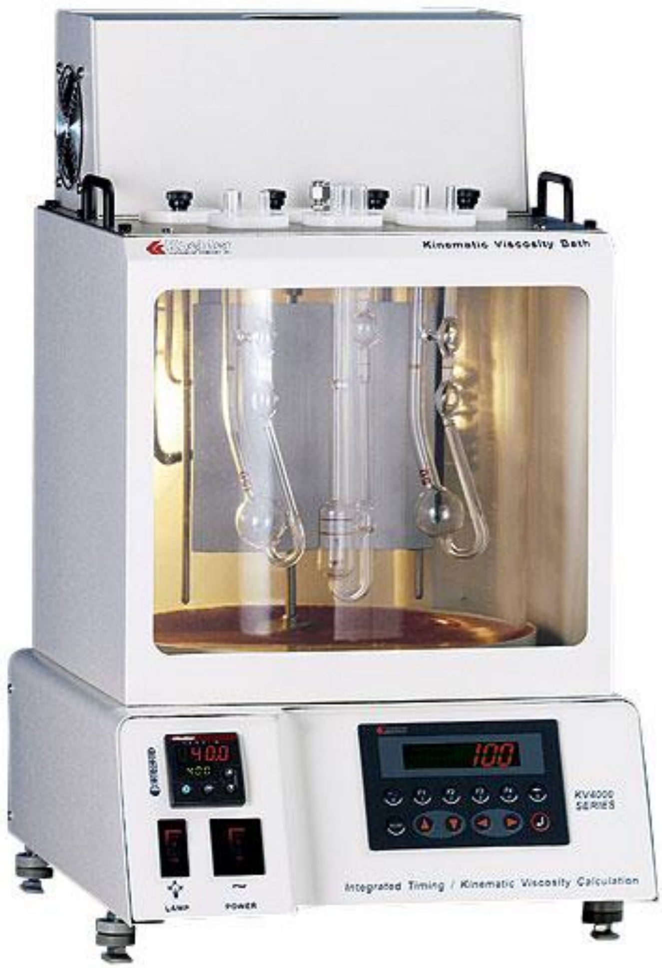


Appendix V: Relative Permeability System RPS





Appendix VI: Cannon-Fenske Viscometer and Koehler Kinematic Viscosity Bath



Appendix VII: Density Meter