ASSESSING PRODUCTIVITY IMPAIRMENT OF SURFACTANT-POLYMER EOR USING LABORATORY AND FIELD DATA

by

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ABSTRACT

Surfactant-polymer (SP) flooding is an enhanced oil recovery (EOR) technique used to mobilize residual oil by lowering the oil-water interfacial tension, micellar solubilization, and lowering the displacing phase mobility to improve sweep efficiency. Surfactant-polymer flooding, also known as micellar flooding, has been studied both in the laboratory and field pilot tests for several decades.

Surfactant polymer flooding is believed to be a major enhanced oil recovery technique based on laboratory experiments; however, its applications to field has not met the expectations of laboratory results. Successful field applications of SP flooding have been limited because of a number of obstacles, which include the large number of laboratory experiments required to design an appropriate SP system, high sensitivity to reservoir rock and fluid characteristics, complexity of reservoirs, infrastructure required for field implementation, and lack of reliable statistics on successes of field applications. In other words, there are many variables that affect reservoir performance.

Traditionally, in SP flooding, a tapered polymer solution follows the injected surfactant slug. However, in recent years co-injection of surfactant and a relatively high concentration of polymer solution have been used in several field trials. Despite significant increase in oil recovery at early times in several surfactant-polymer floods, the increase in oil production period has had short duration followed by significant reduction in oil production. Thus, this research primarily relied on field test data to understand the problem, hoping that an improved solution strategy can be developed for new field applications. Second, current numerical models do not correctly predict the performance of surfactant-polymer floods and tend to over predict. Thus the second objective of this research was to develop a methodology to use combined field and laboratory data in commercial simulators to improve their predictive capability.
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CHAPTER 1
INTRODUCTION

In this research, I designed several experiments to address the productivity loss observed in the field. Some of the experiments (such as, crude oil tendency to generate emulsions with and without surfactants) are not part of the routine chemical EOR protocol in the industry. However, I studied the importance of emulsion formation in crude oil, brine and polymer at different salinities. Additionally, I used a numerical simulator to model and to evaluate the laboratory experiments and the field test.

Historically, the majority of surfactant EOR projects were implemented when the oil price was relatively high. Nonetheless, surfactant EOR could be viable oil recovery method to recover part of the residual oil left behind by waterflood because surfactant EOR has worked in the laboratory experiments. This thesis highlights the complexity of surfactant-polymer EOR in the field.

1.1 Organization of the Thesis

This dissertation has six chapters. Chapter 1 describes the research motivation, objectives and methodology. Chapter 2 is a literature review. Chapter 3 discusses a field pilot test reservoir properties, chemical injection strategy and performance evaluation of the pilot test. Chapter 4 presents laboratory experiments and engineering analysis to address the poor pilot performance. Chapter 5 presents numerical modeling and history matching of corefloods and the pilot. Also this chapter includes surfactant-polymer modeling issues in commercial simulators and practical approaches used by engineers. Chapter 6 presents research results, conclusions and recommendations.

1.2 Objectives

The objectives of this research are summarized as follows:

- Demonstrate the typical oil recovery characteristics of surfactant-polymer injection in a sandstone reservoir.
- Assess the causes of productivity impairment from the performance results of a pilot test.
• Evaluate the efficiency of numerical simulators to model laboratory experiments and pilot tests.
• Develop a methodology to improve prediction of oil recovery in surfactant-polymer EOR.

The most significant contribution of this research includes experimental data and a methodology to properly scale laboratory results to field. Furthermore, the main cause of productivity impairments was identified and guidelines for successful laboratory experiments and modeling were developed.

1.3 Motivation of Research and Contribution

Surfactant polymer flooding is believed to be a major enhanced oil recovery technique based on laboratory experiments, however its applications to field have not met the expectations of laboratory results. This research is intended to use field data to shed light on this issue hoping that an improve solution can be developed for field applications.

This research will provide the following main contributions to the industry:

• Properly scale laboratory results to field
• Develop workflow for proper use of commercial simulators in predicting performance of chemical EOR
• Convey field and laboratory experience to future users

1.4 Method of Study

The methodology followed to achieve the objectives of this study can be broken into three main sections: field evaluation; laboratory experiments; and numerical modeling.

1.4.1 Field Evaluation

Field evaluation consists of field description, compilation/understanding of oil and water properties, and analysis of field performance results under the water flooding and surfactant-polymer injection. The field implementation and chemical injection strategies (along with
possible observed productivity loss) are discussed in detail. The pilot for this study is located in the Illinois basin with an area of 20 acres and four 5-spot patterns.

1.4.2 Laboratory Experiments

Laboratory experiments include preparation of brines, polymer, surfactant-polymer formulations, rheological characterization, interfacial tension (IFT) measurements and coreflooding tests. The coreflood experiments may be grouped based on their respective injected chemicals. The corefloods are intended to replicate the field productivity loss impairment. In the first group of corefloods, polymer was injected into a core filled with only water (single phase). In another test, polymer was injected into a two phase core (water-oil driven to Sorw). Both tests were done to study the polymer-rock and polymer-oil interactions. The second group includes injection of a surfactant polymer slug into the core to mimic actual field implementation. The final group entailed injection of microemulsions with and without polymer into the core to study the polymer-surfactant and oil interactions.

1.4.3 Numerical Modeling

Numerical modeling involved the assessment of several commercial simulators for surfactant polymer injection. The key laboratory input data necessary to run the surfactant-polymer functionality were evaluated. The difficulties in measuring the laboratory input data are also addressed. The surfactant-polymer modeling issues of each simulator were evaluated in detail. Based on laboratory data and observed field responses, several guidelines and improvements to these commercial simulators were proposed and some of them have been implemented. These contributions/modifications include guidelines to both laboratory protocol as well as commercial simulators.
CHAPTER 2
LITERATURE REVIEW

This chapter reviews literature related to the objective of this study. It is broken into two parts – (a) Chemical Enhanced Oil Recovery (CEOR) in sandstone reservoirs, (b) productivity loss in field applications of CEOR.

2.1 Chemical EOR in Sandstone Reservoirs

Chemical EOR methods were at their historic peak in the 1980s, most of them in sandstone reservoirs (Needham and Doe, 1987). Total active projects peaked in 1986 with polymer flooding being the most often chosen method of chemical EOR (Figure 2.1). However, since the 1990s oil production using chemical EOR methods has been negligible around the world except for China (Chang et al. 2006a; Delamaide et al. 1994; Han et al. 1999; Li et al. 2009a and 2009b; Wang et al. 2002; Wang et al. 2009a and 2009b; Xiaoqin et al. 2009). Furthermore, chemical flooding has been shown to be sensitive to volatility of oil markets despite recent advances (i.e., low surfactant concentrations) and lower costs of chemical additives.

Figure 2.1 EOR projects in the United States (Oil & Gas Journal EOR Surveys, 2014).
Polymer flooding is considered as a mature technology and is still the most important chemical EOR method in sandstone reservoirs based on the review of full field case histories. Based on the EOR survey presented by Moritis (2008) there are ongoing pilots or large scale polymer floods in Argentina (El Tordillo Field), Canada (Pelican Lake), China with approximately 20 projects (i.e., Daqing, Gudao, Gudong and Karamay Fields, among others), India (Jhalora Field), and the U.S. (North Burbank). It is important to mention that a commercial polymer flood was developed in North Burbank during the 1980s (Moffitt and Mitchell, 1983) demonstrating that this method of CEOR may still have potential to increase oil recovery in mature basins. North Burbank reinitiated polymer flooding on a 19 well pattern in December 2007 (Chaparral Energy Inc., 2009). Other countries with reported polymer flooding projects include the Brazilian Carmopolis, Buracica, and Canto do Amaro Fields (Shecaira et al. 2002). India also reports a polymer flood in Sanand Field (Pratap et al. 1997; Tiwari et al. 2008). Oman documented a polymer flood pilot developed in Marmul Field (Koning et al. 1988) and almost twenty years later a large scale application was underway (Moritis, 2008). Additionally, Pirawarth field in Austria (Poellitzer et al. 2009), Argentina (El Tordillo Field), Brazil (Voador offshore Field), Canada (Horsefly Lake Field) and Germany (Bochstedt Field) announced plans to implement polymer flood projects (Moritis, 2008). The listed ongoing and planned polymer floods provide a representative sample of field experiences that validates EOR potential using this recovery method.

While polymer flooding has been the most commonly applied chemical EOR method in sandstone reservoirs (Manning et al. 1983), the injection of alkali, surfactant, alkali-polymer (AP), surfactant-polymer (SP) and Alkali-Surfactant-Polymer (ASP) have been tested in a limited number of fields. Micellar polymer flooding had been the second most used chemical EOR method in light and medium crude oil reservoirs until the early 1990s (Lowry et al. 1986). Although this recovery method was considered as a promising EOR process during the 1970s, the high concentrations and cost of surfactants and co-surfactants, combined with the low oil prices during mid 1980s limited its use. The development of ASP technology since the mid-1980s and the development of surfactant chemistry have brought a renewed attention for chemical floods in recent years, especially to boost oil production in mature and waterflood fields.
Several chemical EOR floods, other than polymer floods, have been widely documented in the literature during the last two decades. However, at the present time Daqing field represents one of the largest, if not the largest, ASP flood implemented as of today. ASP flooding has been studied and tested in Daqing for more than 15 years though several pilots of different scales (Chang et al. 2006a; Demin et al. 1999; Hongfu et al. 2003; Pu and Xu, 2009). The Gudong (Qu et al. 1998), Karamay (Gu et al. 1998; Qiao et al. 2000), Liahoe, and Shengli (Chang et al. 2006) fields are other examples of Chinese ASP projects documented in literature. Additional chemical EOR flooding reported during the last decade include:

- ASP flooding in Viraj field, India (Pratap and Gauma, 2004) and West Kiehl (Meyers et al. 1992), Sho-Vel-Tum (French, 1999), Cambridge Minnelusa Field (Vargo et al. 2000), and Tanner (Pitts et al. 2006) fields in the U.S.

- AP flooding in Xing Long Tai Oil Field (Zhang et al. 1999), China and David Pool Canada (Pitts et al. 2004).

Based on the EOR survey presented by Moritis (2008) there are ongoing ASP pilots in Delaware Childers field (Oklahoma) as well as the Lawrence field (Illinois). The survey also referred to planned ASP floods in Lawrence field, Midland Farm Unit (Texas), Nowata field (Oklahoma), and an SP flood in Minas Field, Indonesia (Bou-Mikael et al. 2000). These planned floods were eventually implemented. However, the number of ASP and SP floods are much higher than the ones reported in literature as well the EOR survey presented by Moritis (2008) because not all operators necessarily respond to this survey. Despite the volatility of oil prices, it is fair to conclude that operators are showing a growing interest on chemical EOR flooding. This trend is also supported by the increase of screening studies to evaluate or re-estimate the EOR potential of chemical flooding in different basins (Alvarado et al. 2008; Costa et al. 2008; Fletcher and Morrison, 2008; Pandey et al. 2008).

In recent years, increase in the price of oil and improvements in surfactant technologies have helped commence several pilot tests in the Illinois basin. Sharma et al. (2013) reported an Alkaline-Surfactant-Polymer (ASP) pilot test in Lawrence field in 2010. Nathan et al. (2012) reported the suitability of application of ASP technology in the Illinois basin based on the success of ASP pilots in the two most productive reservoirs in the Lawrence Field. The ultimate objective of this project was to expand the employment of ASP flood technology from small,
limited pilots in the Bridgeport and Cypress sandstones to the remainder of the Lawrence Field. Past surfactant polymer flood application in the Illinois basin is summarized in Table 2.1.

Table 2.1 Micellar field projects in Illinois basin (Thomas, S, 2006)

<table>
<thead>
<tr>
<th>Field</th>
<th>Year</th>
<th>Stage</th>
<th>Acre</th>
<th>Rec., %OIP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dedrick (IL)</td>
<td>1962</td>
<td>Secondary</td>
<td>2.5</td>
<td>49.7 (a)</td>
</tr>
<tr>
<td>Robinson, 119-R (IL)</td>
<td>1968</td>
<td>Tertiary</td>
<td>40</td>
<td>39</td>
</tr>
<tr>
<td>Benton (IL) Shell</td>
<td>1972</td>
<td>Tertiary</td>
<td>160</td>
<td>29</td>
</tr>
<tr>
<td>Robinson, 219-R (IL)</td>
<td>1974</td>
<td>Tertiary</td>
<td>113</td>
<td>27</td>
</tr>
<tr>
<td>Robinson, M1 (IL)</td>
<td>1977</td>
<td>Tertiary</td>
<td>407</td>
<td>50</td>
</tr>
<tr>
<td>Salem Unit (IL)</td>
<td>1981</td>
<td>Tertiary</td>
<td>200</td>
<td>47</td>
</tr>
<tr>
<td>Louden (IL)</td>
<td>1977</td>
<td>Tertiary</td>
<td>40</td>
<td>27</td>
</tr>
<tr>
<td>Louden (IL)</td>
<td>1977</td>
<td>Tertiary</td>
<td>80</td>
<td>37</td>
</tr>
</tbody>
</table>

(a) Recovery for Dedrick is calculated as a percentage of OOIP

ASP flood test laboratory results have demonstrated that an estimated 130 million barrels (bbl) of oil could potentially be extracted by employing ASP flood technology in the reservoirs within the Lawrence Field. However, ASP flooding was an untested technology in the Illinois Basin. This project presented an exceptional opportunity to perform and document field testing of this recovery technique in two of Illinois’ most prolific reservoirs: the Lawrence Field-located Bridgeport and Cypress sandstones.

Additional evaluation of similar Pennsylvanian and Chesterian reservoirs shows that it is likely that ASP flood technology can be successfully applied to similar reservoirs in the Illinois Basin as well as to other U.S. reservoirs.

With successful ASP flooding projects in Bridgeport and Cypress sandstones, Pennsylvanian-age, and Chesterian-age reservoirs (respectively), may be considered candidates for ASP flooding. There are many shallow sandstone reservoirs with limited or depleted pressure in the Illinois basin that are better suited for ASP than for CO₂ enhanced recovery techniques. Most oil fields in the Illinois basin are candidates for ASP flooding as a tertiary recovery technique.

The other interior cratonic basins in the United States with significant oil production include the Williston, Michigan and Forest City basins. Most of the oil reservoirs in these basins are
hosted in carbonate rocks. The implementation of ASP can be potentially extended to carbonate reservoirs with the experience gained in ASP floods in sandstone formation.

2.2 Productivity Loss in Field Applications of CEOR

Chemical EOR techniques improve oil recovery both in secondary or tertiary floods in variety of reservoir conditions (Demin et al. 1997; Hernandez et al. 2002; Pandey et al. 2008; Shutang et al. 1996; Vargo et al. 2000; Wyatt et al. 1995).

In ASP/SP flooding, surfactant lowers interfacial tension (IFT) between the displacing aqueous phase and the trapped oleic phase (Liu et al. 2010; Liu et al. 2008).

In the early days of surfactant flooding, a low-concentration surfactant brine (low-tension flooding), followed by a polymer solution, was injected to mobilize residual oil and improve sweep efficiency. It was common to flush the reservoir with low-salinity brine prior to low-tension flooding to reduce surfactant retention and reaction with divalent ions. In low-tension flooding, Type I microemulsion is expected to be the dominant microemulsion phase with IFT in the order of $10^{-2}$ dynes/cm and low viscosity.

Nelson, 1982, and Hirasaki et al. (1983) proposed the negative-salinity gradient method to maximize oil recovery and minimize surfactant retention in ASP or SP flooding. In this method, first brine, with salinity greater than the upper salinity limit of Type III microemulsion, is injected ahead of the surfactant. Next, surfactant is injected followed by tapered lower salinity brine. Hence, the expected phase transformation path is from Type II to Type III to Type I. In the negative-salinity gradient method, the initial Type II microemulsion could have large viscosity, which is not desirable.

Productivity loss during ASP/SP/P flooding can be attributed to the following causes:

- High polymer concentration (Polymer-oil emulsions)
- Mineral precipitation common in ASP interaction – causing pore plugging/permeability impairment due to scale formation or stabilizing in-situ emulsions (Pickering effect)
- Polymer-microemulsion-mineral interaction – causing large viscosity of in-situ microemulsion
- Surfactant loss causing change in displacement mechanism – Type III to Type
II phase transformation

Despite promising oil recovery from chemical EOR applications in the field, productivity loss is a major issue in most projects (Sharma et al. 2013, Hashmi et al. 2013, Christopher et al. 1988). Well productivity loss not only is associated with SP/ASP flooding, it is also associated with polymer flooding (Hashmi et al. 2013, Standnes and Skjevrak, 2014, Al Kalbani et al. 2014). In fact, productivity problems are not well documented in the open literature. Specifically, there is a disparity of research to investigate the cause of productivity impairments. Much of the recent studies focused on rheology studies and microemulsion flow in corefloods only (Humphry et al. 2013; Walker et al. 2012). This is why my research is focused on understanding the causes of the productivity loss observed in the field.
CHAPTER 3
PILOT AREA STUDY

The following is a summary of some information about the reservoir and fluids in the pilot study. Figure 3.1 shows a simple schematic of the well configuration for the pilot.

- Reservoir
  - Depth – shallow
  - Size – 20 acres
  - Development (Four 5-spot patterns)
    - 9 Producers, 4 injectors
    - 2 observation wells
    - 2 logging wells
  - Temperature – 28 °C
  - Net pay – 20 to 25 ft
  - Average porosity – 18%
  - Average permeability – 400 md

- Oil
  - Viscosity – 9 cP
  - Density – 37 °API
  - Acid number – 0.1 mg KOH/g

- Formation and produced water (PW)
  - Salinity – 62,000 ppm

Figure 3.1 Pilot study configuration (P stands for producers, I stands for injectors, O stands for observer wells and L stands for logging wells).
The log for the central producer (P5) is shown in Figure 3.2. This log is typical for other wells in the pilot area. This pilot area has been under waterflood for more than 40 years with current water cut of 99.1% (Figure 3.3). Surfactant-polymer injection in the pilot area started in June 2011.

![Well logs for producer well.](image)

**Figure 3.2** Well logs for producer well.

![Historical water cut for the area of the study.](image)

**Figure 3.3** Historical water cut for the area of the study.
A comprehensive laboratory study was performed to design appropriate chemicals and protocols for the project. This study considered reservoir rock and fluid properties, rock fluid interaction, chemical concentrations and salinities, injection slug sizes, and general protocol to be performed in the field pilot. Several coreflood experiments were conducted to test the design, validate the formulation, and help determine expected results from the upcoming pilot. A laboratory history matched model was used to optimize the design (chemical blends) and volumes to be injected to the field pilot test. The polymer chosen is a partially hydrolyzed polyacrylamide (HPAM), with a low-molecular weight, while the surfactant is a blend of three anionic components – internal olefin sulfonate, alkyl propoxylated-sulfate, and alkylbenzene-sulfonate. The surfactant concentration was 0.7 weight percent (0.7 wt%) with a polymer concentration of 2,500 ppm.

Before commencing the pilot test, a numerical simulation model was developed to predict field scale performance, using the results and parameters obtained from the laboratory study. This provided a set of expected results from the pilot study. From the optimal laboratory design, the operation protocol used for the pilot test was as follows:

- Injection of formation water – 418,000 bbl (0.3 PV); salinity ≈ 60,000 ppm
- Injection of SP slug – 566,000 bbl (~ 0.4 PV); salinity ≈ 51,000 ppm
- Injection of Polymer slug – 597,000 bbl (~ 0.4 PV)
  - 0.3 PV; Salinity ≈ 45,000 ppm
  - 0.1 PV; Salinity ≈ 35,000 ppm
- Injection of water
  - 0.3 PV; salinity ≈ 35,000 ppm
  - 1.8 PV; salinity ≈ 55,000 ppm
  - 0.3 PV; salinity ≈ 8,000 ppm

During implementation of the pilot test, the surfactant concentration was held constant at 0.7 wt%, while varying the polymer concentration and injection salinity. The varying parameters are shown in Figure 3.4. These parameters were varied in order to follow a negative salinity strategy, as well as observe the influence of increased viscosity-ratios and displacement efficiencies of fluids in the reservoir.
Figure 3.4 Polymer concentration and injection salinity in pilot wells.

Figure 3.5 and Figure 3.6 shows water injection, production rate and bottom whole pressure for central producer (P5). As shown in the figures, there was a clear increase in oil production; however, this increase was not sustained due to well productivity issues. The liquid rate in the well dropped from 1,200 bpd to 600 bpd. This was not predicted in the simulation and modeling work performed prior to the pilot test. This unexpected result is the main motivation for this research study. It is important to identify and adjust critical parameters used in design and numerical modeling, in order to better predict field performance.
Figure 3.5 Production and injection rate for central producer (P5).

Figure 3.6 Water production rate and bottom hole pressure for central producer (P5).
This chapter provides experimental data and procedures that have been performed to achieve an objective of this study. Experiments were designed and conducted to address the unexpected productivity losses that occurred during the pilot test. This was done to better understand the characteristics of surfactants used, and their effects on oil production in both lab and field scale. The results and learning from the laboratory experiments can be used to improve the numerical modeling and future predictions of field performance. This chapter is broken into materials, surfactant phase behavior, core flood experiments, results and oil-water interactions.

4.1 Materials

We used two sets of sandstone core plugs in the flow experiments (Table 4.1). The first set is from an oil-bearing formation in the pilot area and the second set is Berea core plugs. Because of limited availability of formation cores, Berea sandstone cores were used in most of experiments. Oil used in the study was a dead crude oil from the formation with viscosity of 9 cP, API gravity of 37 at 28 °C, and acid number 0.1 mg KOH/g oil. Formation and produced water (PW) are synonymous and have TDS of ~62,000 ppm (Table 4.2). Table 4.2 also report the composition of fresh water (FW) used in this study. Polymer used in this study was hydrolyzed polyacrylamide (HPAM) Flopaam 3330S with about 6 million Dalton molecular weight and 30% degree of hydrolysis. The Surfactant blend was composed of three anionic components – internal olefin sulfonate, alkyl propoxylated-sulfate, and akylbenzene-sulfonate with concentration of 0.7 wt%. To prepare the SP blend predetermined weights of surfactants, required to make 0.7 wt% solutions, were dissolved first in the aqueous phase and then polymer was added to the solution and the sample was mixed for one day.

To prepare the microemulsion phase for the coreflooding experiments, a surfactant-polymer blend, consisting of 0.7 weight percent surfactant and 2,500-ppm polymer, was in contact with the reservoir oil at a 1:1 ratio and aged for one week. The solution test tube was gently turned at least once a day during the aging period. After a week, a Type III microemulsion formed in the middle of the test tube, which was separated from the lower dense phase and the upper lighter phase. The separated middle phase microemulsion was used in core flood experiments. The
microemulsion phase viscosity was measured using MCR102 Anton Paar Rheometer.

Table 4.1 Core properties used in experiments

<table>
<thead>
<tr>
<th>Experiment</th>
<th>Core properties</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Length (cm)</td>
</tr>
<tr>
<td>SP1</td>
<td>23.82</td>
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<td>SP2</td>
<td>29.72</td>
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<tr>
<td>P1</td>
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<td>P2</td>
<td>30.48</td>
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<tr>
<td>ME1</td>
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<td>ME2</td>
<td>30.48</td>
</tr>
<tr>
<td>ME3</td>
<td>30.48</td>
</tr>
</tbody>
</table>

Table 4.2 Produced and Fresh water composition

<table>
<thead>
<tr>
<th>Ion</th>
<th>Produced water Concentration (ppm)</th>
<th>Fresh water Concentration (ppm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Na⁺</td>
<td>20,420</td>
<td>21</td>
</tr>
<tr>
<td>Ca²⁺</td>
<td>2,238</td>
<td>29</td>
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<tr>
<td>Mg²⁺</td>
<td>847</td>
<td>11</td>
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<tr>
<td>Cl⁻</td>
<td>38,024</td>
<td>27</td>
</tr>
<tr>
<td>SO₄²⁻</td>
<td>7</td>
<td>47</td>
</tr>
<tr>
<td>HCO₃⁻</td>
<td>204</td>
<td>94</td>
</tr>
<tr>
<td>TDS</td>
<td>61,839</td>
<td>228</td>
</tr>
</tbody>
</table>

4.2 Surfactant Phase Behavior

The phase behavior study is performed to screen for the presence of oil and water microemulsions that are stabilized by surfactant formulations, which produce low interfacial tension between an aqueous phase and an oil phase. Phase behavior experiments are used as a screening process to identify effective surfactant formulations with reservoir oil and injection
water. Effective formulations produce a Type III microemulsion with low interfacial tension. Preliminary determination of a surfactant formulation is based on the surfactant’s chemical structure. Additional components such as a co-solvent can be added to decrease microemulsion viscosity and formation of viscous microemulsions. Salinity and surfactant scans can be designed to identify an effective formulation.

Usually phase behavior studies are performed to screen surfactant formulation and obtain which formulation provides the widest range of Type III region. Phase behavior studies are prepared at different salinities with fixed surfactant concentrations. Each surfactant formulation is mixed in tubes with water and oil at increasing intervals of salinity. These tubes are mixed thoroughly and allowed to equilibrate at reservoir temperature for a period of two weeks. Figure 4.1 shows an example of phase tubes versus salinity for surfactant concentration of 0.5 wt%. The development of a middle phase is observed and the volume of oil and water dissolved in the middle phase are carefully noted. Based on these data, solubilization ratio curves are calculated and shown in Figure 4.2.

Oil and water solubilization ratios (SR) are the ratio of the solubilized oil and water phase volumes to the surfactant volume.

\[
\text{Oil Solubilized Ratio} = \frac{V_{so}}{V_s} \tag{4.1}
\]

\[
\text{Water Solubilized Ratio} = \frac{V_{sw}}{V_s} \tag{4.2}
\]

Where, \(V_{so}\) is solubilized oil volume, \(V_{sw}\) is solubilized water volumes and \(V_s\) is surfactant volume.

**Optimum salinity is the salinity at which oil and water solubilization ratios become equal.**

Type I lower-phase microemulsion (also known as Type II-) consists of a lower dense phase with excess oil and surfactant. Type II upper phase microemulsion (also known Type II+) have excess brine plus surfactant. Type III middle phase microemulsion consists of excess brine, excess oil, plus surfactant (Figure 4.3). The optimum salinity of this blend at a surfactant concentration of 0.5 wt% is approximately 51,000 ppm, and Type III region extends between 48,000 and 60,000 ppm – a relatively wide interval. The window of salinity where Type III is forming or disappearing is called lower (\(C_{SEL}\)) and upper (\(C_{SEU}\)) salinity bounds. The optimum salinity,
lower and upper effective salinity limits for SP blends used in this field are plotted in Figure 4.4. As surfactant concentration decreases, the optimum salinity decreases.

The solubilization ratio data may correlate to the IFT (interfacial tension) of the surfactant formulation as a function of salinity. Some correlation has been developed to relate the IFT to solubilization ratio. For example Chun Huh Correlation (Huh, 1979) is as follows:

\[
IFT = \frac{C}{SR^2}
\]

(4.3)

Where IFT is in dynes/cm, C is a constant, which is usually 0.3 dyne/cm, and SR is the solubilization ratio. A value of optimal solubilization ratio greater than 10 implies an IFT of less than 0.003 dyne/cm. For example IFT measured using spinning drop tensiometry and the one calculated from the Chun Huh correlation is compared in Figure 4.5. The actual measured values differ from Chun Huh correlation. IFT measurements are not a practical way to screen surfactants. This indicates Chun Huh correlation is a good tool for screening different surfactant and obtain the best formulation; However, using the IFT data obtained from this correlation in numerical models needs to be validated with actual laboratory measurements.
Figure 4.2 Solubilization ratio curves of the surfactant blend at different concentration.

Figure 4.3 Surfactant oil phase behavior Winsor Type (Modified from Lake, 1989).
Figure 4.4 Optimum salinity, lower and upper effective salinity versus surfactant concentration.

Figure 4.5 Measured laboratory IFT and Chun Huh correlation comparison.
4.3 Experiments

Several experiments were designed to determine the cause of the productivity loss in a recent SP pilot test. Table 4.3 summarizes core flood characteristics. The experiments were divided into three categories: polymer flood (P), surfactant polymer flood (SP), and microemulsion flood (ME) experiments. The SP1 experiment mimics the pilot test conditions. The summary and objective of each corefloods is presented in Table 4.4 (i.e. Page 23). The details and procedure of these experiments are summarized in Appendix A.

Table 4.3 Corefloods experiments

<table>
<thead>
<tr>
<th>Experiment</th>
<th>Chemicals &amp; Injected</th>
<th>Water Saturation</th>
<th>Oil Saturation</th>
<th>WaterFlood</th>
<th>Microemulsion</th>
<th>Surfactant Polymer</th>
<th>Polymer Flood</th>
<th>WaterFlood</th>
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<tr>
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<td></td>
<td>Surfactant Conc. Ppm</td>
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<td>3.5</td>
<td>0.4</td>
<td>1</td>
<td>2</td>
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<td>P1</td>
<td>Salinity</td>
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<td>Pore Volume</td>
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<td>0.4</td>
<td>1.7</td>
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<td>51000</td>
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<td>35000</td>
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</tr>
<tr>
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<td>Polymer Conc. ppm</td>
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<td></td>
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<td>7000</td>
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<td>0.4</td>
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<td>51000</td>
<td>45000/35000</td>
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</tr>
<tr>
<td></td>
<td>Polymer Conc. ppm</td>
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<td>Surfactant Conc. Ppm</td>
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<td>7000</td>
<td>0</td>
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<td></td>
</tr>
<tr>
<td></td>
<td>Pore Volume</td>
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<td>3</td>
<td>2</td>
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<td>0.4</td>
<td>0.4/2</td>
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<td>ME3</td>
<td>Salinity</td>
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<td>62000</td>
<td>51000</td>
<td>45000</td>
<td>35000</td>
<td></td>
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<tr>
<td></td>
<td>Polymer Conc. ppm</td>
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<tr>
<td></td>
<td>Pore Volume</td>
<td>3</td>
<td>4</td>
<td>2</td>
<td>0.4</td>
<td>0.4</td>
<td>1.7</td>
<td></td>
</tr>
</tbody>
</table>

4.3.1 Surfactant Polymer (SP) Experiments

Two surfactant polymer (SP) experiments were conducted. The first coreflood experiment (SP1) was designed to mimic the actual field design (decreasing salinity strategy). Four reservoir core plugs with similar air permeability were stacked together to make a 9.38-inch
composite core. Then the composite core was saturated using degassed produced water with TDS of 62,000 ppm and aged for two days at 28°C. At the end of the aging period, the flow rate was changed from 1.0 to 2.0 cc/min gradually and the stabilized pressure drop at each flow rate was recorded. Then, this data was used to calculate the brine permeability of the core using Darcy's law. For this experiment, the calculated permeability was 102 mD. After measuring the permeability, the filtered crude oil was injected until the water cut became zero and the pressure drop stabilized at 5.5 PV. After 11 days aging with the crude oil at 28°C, the produced water was injected through the core until oil production ceased (oil cut < 1.0 percent). To mobilize the residual oil at the end of waterflood, 0.4 PV of the SP slug (0.7 wt% total surfactant and 2,500 ppm HPAM in 51,000 ppm blended brine, which contains 82% produced water and 18% fresh water) was injected. Then, it was chased with 0.4 PV of 2,500 ppm polymer at TDS of 45,000 ppm (73% produced water + 27 % fresh water). In the end, water with salinity of 31,000 ppm (50% producer water + 50% fresh water) was injected until no more oil was produced. The flow rate was kept constant at 1.0 ft/day during water, chemical and post-brine injection. In this experiment, the viscosities of SP and polymer push were 14.5 and 15.5 cP, respectively at 28°C and 10 sec\(^{-1}\) shear rate. Effluent samples were collected throughout the experiment for further analysis.

The second experiment (SP2) was designed to study the effect of over optimum salinity strategy on possible productivity loss. The flooding procedure of this experiment mimics Experiment 1 with the following changes: the salinity of SP, polymer push and post-brine injection was changed to 51,000, 56,000 and 60,000, respectively to keep the salinity above the optimum salinity. Also the viscosities of SP and polymer solutions were decreased to 4 and 7.5 cP, respectively. The reason behind the viscosity reduction in this test was to reduce the impact on SP/P viscosity on the pressure drop and focus more on the W/O emulsion viscosity and its attribution on productivity loss.

4.3.2 Polymer (P) Experiments

Two polymer flood experiments (P1 and P2) were designed to investigate the effect of polymer on productivity loss by polymer-rock (P1) and polymer-oil (P2) interaction. In P1, polymer solution was injected into the brine-saturated core to study the pressure drop response due to the polymer injection in the absence of crude oil. In P2, the polymer solution was injected
into the core at residual oil saturation (Sorw) to determine whether polymer-oil interaction may cause any abnormal pressure drop in absence of surfactant.

4.3.3 Microemulsion (ME) Experiments

Three microemulsion experiments (ME1, ME2, and ME3) were conducted. In ME1 the core flooding procedure was the same as in the SP1 experiment, but instead of the SP blend, a microemulsion-polymer (MEP) blend was injected. The second microemulsion experiment (ME2) was similar to the ME1 experiment, except that the MEP was chased with brine instead of polymer solution. The salinity of the injected brine was identical to the ME1 experiment in which 45,000 ppm brine was injected for 0.4 PV followed by 35,000 ppm for the rest of experiment.

Unlike the ME1 and ME2 experiments, in the third microemulsion experiment (ME3), the microemulsion phase was injected at a constant rate and the polymer concentration reduced from 2,500 ppm to 1,000 ppm during the MEP and polymer push injection.

Table 4.4 Corefloods summary

<table>
<thead>
<tr>
<th>Test</th>
<th>Description</th>
<th>Objective / Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>SP1</td>
<td>SP with negative salinity gradient</td>
<td>Implemented in field</td>
</tr>
<tr>
<td>SP2</td>
<td>SP injection over optimum salinity</td>
<td>Induce Type II ME</td>
</tr>
<tr>
<td>P1</td>
<td>Single phase polymer flooding (PF)</td>
<td>Polymer - rock interactions</td>
</tr>
<tr>
<td>P2</td>
<td>Two phase PF (@ Sorw)</td>
<td>Polymer - oil interactions</td>
</tr>
<tr>
<td>ME1</td>
<td>ME (0.4 PV) with negative salinity, polymer (0.4 PV) and water</td>
<td>Polymer slug concentration of 2,500 ppm</td>
</tr>
<tr>
<td>ME2</td>
<td>ME (0.4 PV) with negative salinity followed by water</td>
<td>Effect of polymer (mobility control)</td>
</tr>
<tr>
<td>ME3</td>
<td>ME Negative salinity followed by Polymer</td>
<td>Polymer concentration of 1000 ppm</td>
</tr>
</tbody>
</table>

4.4 Oil-water Interaction

In addition to coreflooding experiments, oil-water interactions were studied in test tubes. Several emulsions were prepared by homogenizing deionized water (DW), produced water
(PW), fresh water (FW) and mixture of PW/FW at the ratio of 82/18% (MW) with crude oil. Analyzing emulsions with different compositions and different water-to-oil ratios shows that, at 1:1 water-oil ratio, the oil forms relatively stable water-in-oil emulsions (Figure 4.6). The micrographs show that DW and FW form more stable emulsions than MW and PW and droplets are more spherical with DW and FW. The conclusion is that \textit{as the salinity decreases, more stable water-in-oil macroemulsion forms.}

![Figure 4.6 Water-in-oil emulsions after 4 days of aging for four increasing salinity brine-oil systems. The four fluid systems are 1:1 water-oil mixtures with different brine salinities.](image)

Figure 4.7 shows the viscosity of oil-water mixture. At a 50% oil ratio, water-in-oil macro-emulsion is formed and exhibits higher viscosity, however, it was noticed that in the presence of polymer the formation of macro-emulsion was inhibited. These results suggest that large polymer molecules help keeping fresh water in the water phase rather than in the oil phase. Figure 4.8 shows microemulsion viscosity with (MEP) and without (ME) polymer at 51,000 ppm TDS. The presence of polymer results in a highly viscous microemulsion.

Figure 4.8 also indicates that the viscosity of the MEP solution is much higher than the ME – specifically at the low shear rates. This suggests that far away from the injection well, where the shear rate is low, the MEP solution can cause productivity loss due to high viscosity.
Figure 4.9 shows polymer viscosity versus shear rate and polymer concentration at 51,000 ppm TDS. Shear-thinning is present for all concentrations.

Figure 4.7 Fluid mixture viscosity versus oil-water ratio.

Figure 4.8 Microemulsion viscosity with and without polymer at 51,000 ppm TDS; Microemulsion: 2,500 ppm polymer and 0.7% wt surfactant.

Figure 4.9 Polymer viscosity versus shear rate and polymer concentration at 51,000 ppm TDS.
4.5 Emulsion Sizes and Pore Size Distribution

Emulsion is defined as dispersion of water droplets in continues oil phase (water-in-oil emulsion), oil droplets in continuous water phase (oil-in-water emulsion), or a mixture of both (Kokal, 2005). Kokal provided size distribution for water in oil emulsion (Figure 4.10). The smaller the size of the emulsion the longer the time required to separate oil and water phase.

![Emulsion Size Distribution](image)

Figure 4.10 Emulsion size distribution of produced oilfield emulsions (Kokal, 2005).

Most of the papers on emulsions only address the separation and demulsification issues once emulsions are produced (Kokal, et al. 2005, Wang, et al., Alvarado, et al., 2008, Yee, et al., 2013) and not the reasons for productivity loss observed in both polymer and SP or ASP flooding. In this thesis, I address blockage of micro-emulsion in the formation.

Figure 4.12 and Figure 4.11 present two photo-micrographs of microemulsions that exist in Type II and Type III. An Olympus BX53 transmitted-light microscope, with 40X magnification and 0.42 μm resolution, was used to capture the images. I have also provided the pore size distribution (Figure 4.13) of the formation and a Berea core plug that were used in this thesis. The microemulsion diameter and/or conventional emulsion size is at least in order of 10 μm, which is within the range of pore size distribution of the reservoir rock. Therefore, Type II microemulsions cause blockage during filtration which I believe is the cause of productivity loss observed in the pilot test.
Figure 4.11 Microemulsion sizes at TDS of 4.53 wt%, Winsor Type II (very high salinity, water in oil micro-emulsions).

Figure 4.12 Microemulsion sizes at TDS of 4.12 wt%, Winsor Type III (intermediate salinity, water in oil micro-emulsions).
4.6 Coreflood Results and Discussions

Pressure drop and recovery factors were constructed to analyze the coreflooding experiments. In the surfactant-polymer experiment SP1, the negative salinity gradient was honored. The water flood recovered 52.4% OOIP and the surfactant-polymer injection, followed by the polymer push, recovered 90% of the remaining oil (Figure 4.14). Because of negative salinity gradient, phase inversion from Type III to I occurred in the late phase of the experiment. The pressure gradients did not show any abnormal behavior throughout the experiment. On the other hand, in the surfactant-polymer experiment SP2, the negative salinity gradient was not honored and injected salinity was maintained above the optimal salinity throughout the flood. As a result, pressure drop was very large and the tertiary oil recovery factor was low because of phase inversion to Type II microemulsion during the experiment, suggesting that the sub-optimal salinity gradient might have caused large pressure gradients and low oil recovery. SP1 and SP2 results, suggests that inappropriate salinity gradient may cause productivity loss and low incremental oil recovery. Due to the heterogeneity of the reservoir and complex rock-fluid and fluid-fluid interactions, maintaining the salinity is not an easy task in the field; therefore, precaution should be taken to avoid Type II occurrence during chemical injection.
Figure 4.14 Oil recovery factor and pressure drop for SP1 (left) and SP2 (right) core flood experiments.

Figure 4.15 pertains to polymer flood experiments P1 and P2; Experiment P1 is a single phase flow while P2 is oil-water flow. In P1, the negative salinity gradient was honored for a single-phase polymer injection (without surfactant), which did not cause any abnormal pressure drop. This suggests that the polymer-rock interaction is not the cause of the high-pressure drop when surfactant is used with the polymer. Unlike P1, which is single-phase only, the P2 experiment involves water-oil at irreducible oil conditions (i.e. the field under the study), which indicates that when polymer is injected in tertiary mode, even after switching to brine, the pressure drop remains very high (Figure 4.15- right). This indicates that a high-viscosity phase forms due to the oil-polymer-water interactions. It is interesting to note that residual resistance factor (RRF) in P1 experiment is 2.5 whereas in P2 experiment it is 8.6.

Figure 4.15 Pressure drop for Experiment P1 (left) and oil recovery, pressure drop for Experiment P2 (right).
The injection rate and pressure drop for microemulsion experiments ME1, ME2 and ME3 are presented in Figure 4.16 and Figure 4.17. The viscosities of the injected microemulsion fluids were 25, 25 and 14 cP for experiments ME1, ME2 and ME3, respectively. In the ME1 and ME2 experiments, 0.4 PV of microemulsion was injected at constant injection rate, followed by brine/polymer injection at a constant pressure. In the ME1 experiment, the injection pressure was increased to 27 psig to accommodate a 0.05 ml/hr flow rate. However, in the ME2 experiment, an injection pressure of 9 psi was required to inject fluid at the same rate as ME1. Figure 4.16 and Figure 4.17 indicate that the microemulsion-polymer interaction could cause significant pressure drop across the core, even though large amounts of additional oil were recovered in the ME3 experiment as shown on Figure 4.18.

Figure 4.10 shows the waterflood oil recovery of 58, 56 and 47 % of the OOIP for experiments ME1, ME2 and ME3, respectively. Injection of 0.4 PV of microemulsion followed by 0.4 PV of the polymer, increases oil recovery to 78% and 91 % of the OOIP for experiments ME1 and ME3. However, in ME2, 67% of the OOIP was recovered. Comparing the recovery factors for all three experiments suggests that there is a need for mobility control (polymer push) and that might be the cause of low incremental oil recovery of ME2. One possible reason for lower incremental recovery factor in the coreflood ME2 could be the polymer concentration.

Figure 4.16 Pressure drop and injection rate for Experiment ME1 (Left) and ME2 (Right).
Figure 4.17 Pressure drop and injection rate for Experiment ME3.

Figure 4.18 Oil recovery for Experiments ME1, ME2 and ME3.
CHAPTER 5
NUMERICAL SIMULATION

5.1 Chemical EOR Commercial Models

In chemical flooding, chemicals are added to the water phase to improve water displacement efficiency by increasing viscosity, reducing interfacial tension and increasing water wettability. For instance, polymer is used to increase water viscosity and surfactant/alkaline is used to increase wettability and reduce the interfacial tension between oil and water.

Polymer rheology and transport is well understood. In the last four decades several chemical flooding simulators have become commercially available. These simulators can be categorized in two groups: the first group includes simulators UTCHEM and REVEAL which model formation of microemulsions while the second group such as CMG-STARS and Eclipse do not model formation of microemulsions. However, the latter group uses a chemical modeling procedure to track viscosity and interfacial tension changes. These models are easier and more practical to use than UTCHEM and REVEAL. For instance, CMG models flow by viscosity increase and relative permeability shift to accommodate oil mobilization. These models generally use Capillary and Bond numbers to decide on relative permeability shift. The Capillary number is a ratio of viscose to interfacial tension forces and Bond number is ratio of gravity to interfacial forces.

Capillary number is:

$$ NC = \frac{\mu V}{\sigma} \quad (5.1) $$

Where, $\mu$ (Unit: N.S/m$^2$ ) is viscosity of fluid $V$ (m/s) is velocity and $\sigma$ (N/m ) is interfacial tension between two fluid phases.

Bond number is also defined:

$$ NB = \frac{\Delta \rho g L^2}{\sigma} \quad (5.2) $$

Where, $\Delta \rho$ (kg/m$^3$ ) is difference in density of two phases, $g$ (m/s$^2$ ) is gravitational force constant, $L$ (m ) is characteristic length and $\sigma$ (N/m ) is interfacial tension between two fluid phases.
In UTCHEM, surfactant partitioning coefficient, which controls the behavior of microemulsion phase, is a strong function of water composition, but it is very difficult to quantify. This includes cation exchange reaction parameters between surfactant and divalent cations. To get around the difficulties in measuring these parameters, in this thesis we measured and correlated interfacial tension, polymer solution viscosity, surfactant and polymer adsorption/retentions and optimum salinity. Our modeling approach is based on the measurable laboratory data, understanding its limitations and honoring these data in the simulation models.

Dynamic phase behavior, flow properties and stability of microemulsion in porous media are more complex than can be accurately extracted from bottle test results. In fact, the fluid rheology of the chemical system is not well understood or easily extracted from experiments.

5.2 Governing Equations for Surfactant-Polymer Modeling

The governing equations for the two phase flow of surfactant-polymer system include mass balance of individual chemical component. The mass balance equation accounts for the relevant physical properties such as: gravity, capillarity, rock and fluid compressibility, molecular diffusion, chemical partitioning between phases, and chemical adsorption on the rock surface.

5.2.1 CMG-STARS Governing Equations

In this section we present the mathematical formulation used in STARS simulator (CMG-2013). The mass balance equation for component i, is:

\[
\frac{\partial}{\partial t} \left[ V_i \left( \rho_r S_w w_i + \rho_o S_o x_i + \rho_g S_g y_i \right) + V_i A_i \right] = \\
\sum_{k=1}^{n_i} \left[ T_{w} \rho_{w} w_i \Delta \Phi_{w} + T_{o} \rho_{o} x_i \Delta \Phi_{o} + T_{g} \rho_{g} y_i \Delta \Phi_{g} \right] + V \sum_{k=1}^{n_i} (s_{ki} - s_{ki}) r_k \\
+ \sum_{k=1}^{n_i} \left[ \phi D_{w} \rho_{w} \Delta w_i + \phi D_{o} \rho_{o} \Delta x_i + \phi D_{g} \rho_{g} \Delta y_i \right] + \delta w \sum_{k=1}^{n_i} \rho_{w, qaq w_k} w_k \\
+ \rho_{w, qw w_k} w_i + \rho_{o, qw o_k} x_i + \rho_{g, qw g_k} y_i \right] \left[ \text{well layer} k \right] \quad (i = 1, 2, ..., nc) \tag{5.3}
\]

Where,

\[
V = V_r + V_o + V_w + V_g \tag{5.4}
\]

\(V\)=volume, \(r\)=rock, \(s\)=solid, \(w\)=water, \(o\)=oil \(g\)=gas
$V_f = V_w + V_o + V_g$  \hspace{1cm} (5.5)

$V_f$ = fluid volume, f=fluid

$V_v = V - V_e = V_f + V_s$  \hspace{1cm} (5.6)

$V_v$ = void volume

$\phi_v = V_v / V$  \hspace{1cm} (5.7)

$\phi_v$ = void porosity

$\phi_f = V_f / V$  \hspace{1cm} (5.8)

$\phi_f$ = is fluid porosity

$n_f$ is the number of neighboring regions or grid block faces.

$T_j$ is the phase transmissibility

$$T_j = T \left( \frac{k_{nj}}{\mu_j r_j} \right) \quad j = w, o, g \quad r_j = \text{phase resistance factor}$$  \hspace{1cm} (5.9)

$D_{ji}$ (j=w,o,g) are the dispersion coefficients in individual phases.

$q_{aq}$ is a volumetric water flow rate through a block face k to/from the adjacent aquifer.

The reaction source /sink term for component $i$ is

$$V \sum_{k=1}^{N_c} (s'_k - s_k) r_k$$  \hspace{1cm} (5.10)

$s'_k$, is the product stoichiometric coefficient of component $i$ in reaction $k$.

$s_k$, is reactant stoichiometric coefficient of component $i$ in reaction $k$.

$r_k$, is the volumetric rate of reaction $k$, calculated from reaction kinetics
\[ y_i = K_i^{sw} x_i \quad ; \quad x_i = K_i^{og} y_i \]
\[ x_i = K_i^{sw} w_i \quad ; \quad w_i = K_i^{wo} x_i \]
\[ w_i = K_i^{rg} y_i \quad ; \quad y_i = K_i^{gw} w_i \]  \hspace{1cm} (5.11)

Where \( K \) is partitioning coefficient

In STARS, the user defines chemical components in the aqueous phase. In polymer modeling, the water viscosity is input into the model, as a function of polymer concentration, shear rate, and salinity. Beside the polymer viscosity, high molecular weight of polymer generates resistance to flow. The resistance factor is obtained with the following equations:

\[ R_{kp} = 1 + (RRF - 1) \frac{Ad(C_i, Sal, T)}{Ad_{\text{max}}}, \quad \varphi = w, o, g \]  \hspace{1cm} (5.12)

\[ k_{r\varphi_p} = \frac{k_{r\varphi}}{R_{kp}} \]  \hspace{1cm} (5.13)

Where \( 1/R_{kp} \) is the permeability reduction factor of each phase and \( k_{r\varphi_p} \) is the reduced phase relative permeability due to resistance factor. \( RRF \) is the residual resistance factor and is measured from corefloods experiments. \( Ad \) is adoption and is a function of concentration (\( C_i \)), salinity (\( Sal \)) and temperature (\( T \)). \( Ad_{\text{max}} \) represents the maximum adsorption. \( k_{r\varphi} \) is the relative permeability of each phase.

For surfactant modeling, tabular interfacial tension (IFT) is input to the model and tabular relative permeability is defined as a function of the capillary numbers. The model will calculate a capillary number and interpolate from tabular relative permeability curves and subsequent relative permeability tables.

Basically pragmatic commercial simulators (STARS, Eclipse) use the above governing equations to model a surfactant-polymer system. Eclipse uses the above equation in black oil mode, treating each chemical as a tracer and modifying phase properties (relative permeability, viscosity, adsorption, among others) as a function of component concentrations. The surfactant material balance equation calculates the surfactant concentration and adsorption in each grid block. These concentrations will be used in the calculation of a capillary number and relative permeability shift and value determination. The polymer material balance equation is used to obtain the polymer concentration in each grid block to obtain the water viscosity and the
resistance factor. Later this resistance factor will be used in the relative permeability section to reduce the relative permeability of water phase.

5.3 How to Use CMG-STARS in Surfactant Polymer Modeling

In this section we explain how CMG-STARS can be effectively used to model the surfactant polymer system. The current limitations and solution are also discussed. The focus of this section is mostly related to how measured laboratory data can be used effectively in the simulator. We will cover four important essential laboratory data that are required in chemical modeling: polymer solution viscosity, interfacial tension and capillary number interpolation parameter, relative permeability shift at high and low capillary numbers and finally surfactant and polymer adsorption/retention.

In STARS, the chemical components need to be defined by users. However, it is important to properly define each component property. We suggest at a minimum three components are needed for a surfactant polymer system. These components can be defined as: Surfactant, Polymer and Salinity. For example, the Polymer component is used to increase the viscosity of water phase, the Surfactant component is needed to define interfacial tension and subsequent relative permeability curves. The Salinity component is required to model its effects on viscosity and interfacial tension.

5.3.1 Polymer Solution Viscosity Modeling

Polymer solution viscosity is a function of concentration, shear rate and salinities. Currently STARS is using nonlinear mixing rule to model polymer viscosity as follows:

\[
\ln \mu_a = f(x_a) \ln(\mu_a) + \frac{1 - f(x_a)}{1 - x_a} \sum_{i \neq a} x_i \ln \mu_i
\]

Where, \(a\) is the polymer component that has the pure viscosity of \(\mu_a\) and \(x_a\) is the component \(a\) mole fraction, \(f(x_a)\) is the mixing function which depend on \(x_a\).

Polymer shear modeling is velocity dependent; however, the laboratory measures this data as a function of Sec\(^{-1}\) in the rheometer. STARS uses the following equation to relate the effective porous media shear rate and Darcy velocity.
\[ \gamma = \frac{\gamma_{fac}|u_i|}{\sqrt{kk_{rl}k_{rel}\phi S}} \]  

(5.15)

Where, \( k \) is absolute permeability, \( \phi \) is porosity, \( u_i \) is phase Darcy velocity, \( k_{rel} \) and \( S_i \) is relative permeability and saturation.

\( \gamma_{fac} \) is the shear rate factor and is usually assumed to be 4.8 for most of the polymers. It also can be calculated from following equation

\[ \gamma_{fac} = C \left[ \frac{3n + 1}{4n} \right]^{n-1} \]  

(5.16)

Where, \( n \) is the shear rate thinning power law exponent, \( C \) is constant value, usually is equal to 6.

The most challenging part of polymer solution viscosity modeling is shear rate modeling. Velocity is grid size dependent and there is a need to define fine grid sizes to capture the field velocity. In most of the field simulation projects, refining small grid sizes won’t be possible due to the computation speed. Using the high grid sizes results in lower velocity, therefore higher polymer solution viscosity in the simulation model. This will result in inejectivity issues in the simulation model. In other words, can Eq. 5.15 model velocity shear dependency for all the polymer types and different porous media? Therefore it is important to consider these uncertainties in modeling polymer viscosity. We suggest local grid refinements around injectors and negative skins to overcome some of these issues.

### 5.3.2 Interfacial Tension Modeling

The interfacial tension data needs to be measured as a function of surfactant concentration and water salinity. These data are input to STARS in tabular format using the keywords IFTTABLE, 2CMPW. STARS uses this information in the calculation of capillary numbers. Capillary number equation can also be rewritten in the following format using Darcy law in velocity calculation

\[ NC = 2.23 \times 10^{-3} \frac{k\nabla P}{\sigma} \]  

(5.17)

Where, \( k \) (darcy) is permeability and \( \nabla P \) (psi/ft) is pressure gradient and \( \sigma \) (N/m) is interfacial tension between two fluid phases.
For example for experiment SP1 we calculate the capillary number using above equations and core properties shown in Table 5.1

Table 5.1 Core properties of experiment SP1

<table>
<thead>
<tr>
<th>L, ft</th>
<th>Area, ft²</th>
<th>Rate, ft³/day</th>
<th>ρw, cp</th>
<th>k, md</th>
<th>krw</th>
<th>σ (dynes/cm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.307742</td>
<td>0.015420</td>
<td>0.00208498</td>
<td>0.902</td>
<td>100.9</td>
<td>0.048</td>
<td>22.1</td>
</tr>
</tbody>
</table>

From Darcy law \( \nabla P \) is calculated

\[
\nabla P = \frac{\Delta P}{L} = \frac{q \mu}{0.006328 \times k k_{rw} A} = \frac{0.00208498 \times 0.902}{0.006328 \times 100.9 \times 0.048 \times 0.01542} = 3.98 \text{ psi/ft}
\]

Using Eq. 5.17 the capillary number can be calculated as \( NC = 4.1 \times 10^{-7} \). The same calculation will be performed for every grid block to obtain the capillary number. Later this capillary number will be used for relative permeability shift and value determination.

It is important to mention in mechanistic models (UTCHEM, REVEAL) IFT data cannot be directly inputted to the model and is calculated from correlations and do not always correspond to measured IFT data (Figure 4.5).

5.3.3 Relative Permeability Shift

Relative permeability shift is the main driver that allows oil mobilization with surfactant. In STARS, the user needs to define tabular relative permeability at a given capillary number. These capillary numbers and related relative permeability curves are obtained from the coreflood experiments. For instance for experiment SP1, the relative permeability end points and capillary number inputs to the model are reported in Table 5.2.

Table 5.2 Capillary number and relative permeability shift for experiment SP1

<table>
<thead>
<tr>
<th></th>
<th>NC</th>
<th>SORW</th>
<th>Krw</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rel perm 1</td>
<td>1.00E-05</td>
<td>0.337</td>
<td>0.048</td>
</tr>
<tr>
<td>Rel perm 2</td>
<td>3.16E-04</td>
<td>0.15</td>
<td>0.208</td>
</tr>
<tr>
<td>Rel perm 3</td>
<td>0.03162</td>
<td>0.048</td>
<td>1</td>
</tr>
</tbody>
</table>

Based on the capillary number in the grid block, the simulator will interpolate from defined relative permeability curves and obtain the values that will be used for oil and water relative...
permeability determination. For instance, if the NC is less than 0.03 the relative permeability will be used.

5.3.4 Adsorption Modeling

The adsorption data in the laboratory are measured by analysis of chemical effluent data obtained during the coreflood experiments. These data can be input to the model using a tabular format or Langmuir coefficients. STARS can model adsorption as a function of chemical concentration, water salinity and temperature. As an example, in experiment SP1 the adsorption of 0.158 mg/g rock obtained and used as input to the simulation model. For adsorption modeling, we measure the maximum adsorption and we also measure the adsorption a function of chemical concentration in the laboratory. A set of adsorption isotherms (adsorption level as a function of component concentration) at a constant temperature is defined in the model. The equation shown below is the Langmuir adsorption equation, where \( \frac{A}{B} \) is the slope of the Langmuir type curve and it quantifies the adsorption sensitivity.

\[
Ad_i = \left( \frac{A}{B} \right) \frac{Bz_i}{1 + Bz_i}
\]  

(5.18)

5.3.5 Discussion and Limitation

In this section we elaborate on the capability of the current version of STARS (2013.1) for surfactant polymer modeling and also discuss some of the limitations and difficulties that exist.

A process mechanism for modeling surfactant is shown in Figure 5.1. As surfactant is injected to the core and is propagated, (Figure 5.1. (a)) the interfacial tension (Figure 5.1 (b)) as well as a log of capillary number (Figure 5.1 (c)) changes, later this log of capillary number is used as a lookup for the relative permeability values depending on water and oil saturation(Figure 5.1 (d)). The IFT reduces as result of surfactant injection, causing lower residual oil saturation and allows oil to be mobilized and start moving through the porous media.

Currently, modeling surfactant polymer is done via relative permeability shifts and increasing the water phase viscosity. The current version of STARS cannot model the microemulsion phase or its effects due to the complex characteristics of the microemulsion. Beside this limitation, relative permeability up-scaling from the lab to field is also challenging. The grid sizes and field simulation model velocities are different from the corefloods models. The relative permeability
curves and interpolations from lab coreflood models cannot be used directly to the field simulation model. Proper upscaling based on the grid sizes is needed.

Since CMG-STARS is a compositional simulator and allows the definition of multiple components in the aqueous phase and model reactions, it will provide the ability to track and model more complex physical phenomena. For example although STARS is missing the microemulsion phase, it can be used to model the microemulsion effects by minimally manipulating the software and introducing some new correlations to model microemulsion viscosity. This allows us to better model the viscosity of oil and water phase based on the type of microemulsion. Besides the viscosity modeling, we suggest including the ability to input and model IFT as a function of microemulsion type.

![Figure 5.1 Process mechanisms for modeling surfactant: (a) surfactant concentration vs pore volume injected, (b) IFT vs pore volume injected, (c) Log of capillary number vs pore volume injected, (d) relative permeability shift.](image)
5.4 Coreflood History Matching

In this section, we present a reservoir simulation match of the experimental results, using the CMG-STARS surfactant polymer simulator. The objective is to interpret the pressure drop and oil recovery characteristics of coreflood experiments. The simulator accounts for surfactant adsorption, using a correlation between surfactant concentration and oil-water IFT, and shifts the relative permeability with the capillary number. A nonlinear viscosity-mixing rule determines aqueous phase viscosity. Polymer solution viscosity is modeled using polymer concentration, shear rate and brine salinity.

After history matching waterflooding honoring relative permeability endpoints at low capillary number conditions, to history match both oil recovery and pressure drop during chemical flooding and post waterflood, in addition to the relative permeability parameters (intermediate to high capillary number), there was a need for a high RRF (higher apparent viscosity) for the experiments that exhibit high productivity loss. Figure 5.2 presents input variables for modeling surfactant and polymer flow in the experiments. These inputs are the key parameters required for modeling a SP process.

In this test, the calculated dynamic retention of surfactant was 0.158 mg/g rock which is a relatively low number. To match the trend of oil recovery and produce surfactant during chemical flood, surfactant adsorption needs to be defined partially reversible.

Figure 5.3, Figure 5.4 and Figure 5.5 are history matches of Experiments SP1, SP2 and P2. In all successful surfactant-polymer flood experiments, surfactant mobilizes residual oil effectively without phase trapping. In such experiments, pressure drop decreases after switching to the final water injection. However, in experiment SP2 (Figure 5.4) the pressure stays higher than water flood pressure (approx. 10 times). The experiment SP2 pressure drop cannot be matched with polymer viscosity and typical RRF. Two cases were defined where, RRF of 12.1 is able match the pressure drop values.

Usually in chemical flooding the permeability reduction factor associated with polymer injection is less than 3 for a variety of experiments (Table 5.3).

Table 5.3 summarizes polymer adsorption and RRF for several laboratory and field studies reported in the literature. Figure 5.5 also illustrate that to match the pressure drop, a RRF of 9.8
is needed. Similarly, to history match the pressure responses and oil recovery, higher apparent viscosity (high RRF) was needed.

![Graphs showing IFT, polymer viscosity, surfactant adsorption, and polymer adsorption](image)

Figure 5.2 Input variables for modeling surfactant and polymer flow. (a) IFT as a function of salinity and concentration, (b) Polymer viscosity as function of concentration, (c) surfactant adsorption versus surfactant concentration, and (d) polymer adsorption versus polymer concentration.

Table 5.4 summarizes the important input parameters utilized in studied cases.

Extensive evaluation of the models revealed that polymer flow modeling would benefit from the use of residual resistance factor (RRF), which varied from 1.0 to 10. The higher resistance factor was needed for the experiments that show productivity loss or higher pressure drop than what was expected.

Current modeling technique cannot model the effect of microemulsion phase viscosity. Due to lack of microemulsion phase in STARS, the beta version of STARS called STARS-ME was used to history match microemulsion experiments. Similarly, to history match the pressure responses and oil recovery, higher apparent viscosity (high RRF) was needed.

The history matching of these corefloods reveals that there is a need to capture the microemulsion effects in numerical simulations of surfactant polymers systems.
Figure 5.3 History match of experiment SP1: (a) oil recovery and pressure drop, (b) effluent surfactant concentration.

Figure 5.4 History match of Experiment SP2: (a) oil recovery (b) and pressure drop. The calculated surfactant retention is 0.158 mg/g rock.

Figure 5.5 History match of Experiment P2: (a) oil recovery, (b) pressure drop.
<table>
<thead>
<tr>
<th>Experiment</th>
<th>Case</th>
<th>Polymer Viscosity (cP)</th>
<th>RRF</th>
<th>Krw@$^{wf}$</th>
<th>SOR@$^{WF}$</th>
<th>Krw@$^{SP}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>SP1</td>
<td></td>
<td>15</td>
<td>1.7</td>
<td>0.048</td>
<td>0.34</td>
<td>0.3</td>
</tr>
<tr>
<td>SP2</td>
<td>Case1</td>
<td>9.0</td>
<td>2.3</td>
<td>0.087</td>
<td>0.30</td>
<td>0.11</td>
</tr>
<tr>
<td></td>
<td>Case2</td>
<td>2</td>
<td>12.1</td>
<td>0.087</td>
<td>0.30</td>
<td>0.110</td>
</tr>
<tr>
<td>P1</td>
<td></td>
<td>2</td>
<td>2.3</td>
<td>NA</td>
<td>NA</td>
<td>1</td>
</tr>
<tr>
<td>P2</td>
<td>Case1</td>
<td>3</td>
<td>2.6</td>
<td>0.07</td>
<td>0.25</td>
<td>0.08</td>
</tr>
<tr>
<td></td>
<td>Case2</td>
<td>1</td>
<td>9.8</td>
<td>0.07</td>
<td>0.25</td>
<td>0.08</td>
</tr>
<tr>
<td>ME1</td>
<td></td>
<td>15</td>
<td>10</td>
<td>0.05</td>
<td>0.311</td>
<td>0.669</td>
</tr>
<tr>
<td>ME2</td>
<td></td>
<td>15</td>
<td>1.15</td>
<td>0.026</td>
<td>0.333</td>
<td>0.1</td>
</tr>
</tbody>
</table>
Table 5.4 Example of experiments reporting polymer adsorption and residual resistance factor (RRF)

<table>
<thead>
<tr>
<th>Adsorption mg/g</th>
<th>RRF</th>
<th>Comment(s)</th>
<th>Ref.</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.007 - 0.013 (a)</td>
<td></td>
<td>Silica sand in 100% water (a) and in presence of oil (b); Berea in 100% water (c) and in presence of oil (d)</td>
<td>Szabo, 1975</td>
</tr>
<tr>
<td>0.004 - 0.008 (b)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>0.029 (c)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>0.005 - 0.010 (d)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>0.055 - 0.070</td>
<td></td>
<td>Berea core using sheared and un-sheared polymer in 2% NaCl</td>
<td>Szabo, 1979</td>
</tr>
<tr>
<td>≥ 0.03</td>
<td></td>
<td>Typical values reported in the laboratory. For field cases reported adsorption ranged from 20 to 500+ lb/acre-ft</td>
<td>Chang, 1978</td>
</tr>
<tr>
<td>2.3 - 4.4</td>
<td></td>
<td>Tensleep sandstone Fm., Wyoming</td>
<td>Castango, et al.</td>
</tr>
<tr>
<td>0.020 – 0.060</td>
<td>1.3</td>
<td>Polymer flood in Courtenay Field (laboratory and simulation data)</td>
<td>Putz, et al. 1988</td>
</tr>
<tr>
<td>1 - 7 (Avg. = 2.96)</td>
<td></td>
<td>Berea and Bentheim cores using different polymers (MW = 5 to 20 x106), injection rates (0.1 to 60 cc/min) and synthetic sea water (average reported from 22 corefloods)</td>
<td>Stvland, et al. 1988</td>
</tr>
<tr>
<td>0.025</td>
<td></td>
<td>East Bodo polymer flood, Lloydminster sandstone Fm.</td>
<td>Wassmuth, et al. 2009</td>
</tr>
<tr>
<td>0.024</td>
<td></td>
<td>David Lloydminster sandstone Fm.</td>
<td>Hawkins, et al. 2004</td>
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<tr>
<td>0.040 - 0.050</td>
<td>1.25 - 2</td>
<td>Laboratory study in unconsolidated sandstone</td>
<td>Wassmuth, et al. 2007</td>
</tr>
<tr>
<td>2.87</td>
<td></td>
<td>Bohai Bay polymer flood. Lab test with sandstone core and pre-sheared Hydrophobically Associative Polymer</td>
<td>Ming, et al. 2006</td>
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<tr>
<td>0.010 - 0.030</td>
<td>1.7 - 2.3</td>
<td>Dalia polymer flood, offshore Angola</td>
<td>Morel, et al. 2008</td>
</tr>
<tr>
<td>0.030</td>
<td>1 - 1.5</td>
<td>Polymer flood simulation study for Nigerian Delta reservoir</td>
<td>Mogbo, 2011</td>
</tr>
<tr>
<td>0.035 - 0.160</td>
<td></td>
<td>Dynamic adsorption in Berea and Ottawa sand packs</td>
<td>Mungan, 1969</td>
</tr>
<tr>
<td>0.028 (a)</td>
<td></td>
<td>Static adsorption in pure quartzite (a) and crushed reservoir rock (b) after 24 hours using a 2,000 ppm HPAM in a 2% KCL</td>
<td>Chappa, 1999</td>
</tr>
<tr>
<td>0.20 (b)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
5.5 Pilot History Matching

In this section, we present a reservoir simulation match of the pilot test results, using CMG-STARS. The objective is to understand the parameters that were used to obtain a reasonable match. The simulator doesn’t account for the generation of microemulsions. In this section two models are discussed. Model1 (before history matching model) is the original model that was initially used for pilot design and prediction of SP flooding performance in this field. Model2 (After history matching model) is a modified version of Model 1 where the microemulsion effects were introduced. To achieve the approach used in Model2 an extensive number of simulation cases with different modification were made and tested.

Figure 5.6 compares the oil response in observation well O1 in both models. The oil responses predicted in both models are in good agreement with the historical data in well O1. This was mainly before the productivity losses were occurred in any producers. The observation well O1 is located in the middle of injector/producer pair. In this relatively short distance the oil bank was formed as expected and is moving toward the producers. However, this oil bank was not able to be transferred to the producer due to possible high viscous microemulsion phase (confirmed by model 2 approach).

Figure 5.7 compares the history matching results of the oil production rate in the entire pilot area. The original simulation model over predicted the oil production due to lack of microemulsion phase modeling. However, in model 2, the history matching was achieved by considering the microemulsion effects.

The main history matching modification can be summarized as follows:

- Microemulsion effect was considered by introducing
  - Regional residual resistance
  - Viscosity regions
- Permeability changes in some selective areas. Detecting thief zones is the key in matching polymer concentrations.
- Relative permeability curves for water flooding following by SP and Polymer are relatively adjusted compared to the original sets (Three relative permeability curves are using in the model as function of capillary number)
- Capillary number interpolation was slightly modified.
- Viscosity tables and corresponding shear rate are modified
Figure 5.6 Simulation versus field oil production rate comparison in O1 well.

Figure 5.7 History match results pilot oil production rate.
Figure 5.8 and Figure 5.9 compare the oil rate and injected/produced water salinity of producer (P4) for both simulation and field data. The observed high salinity in P4 can justify the need for introducing the higher viscous microemulsion phase due to existence of Type II microemulsion.

Figure 5.8. Simulation versus field oil production rate comparison in P4 well.

Figure 5.9 Water salinity comparison: simulation versus field for well P4.
Figure 5.10 and Figure 5.11 shows the water viscosity as well as residual resistance factor at the end of polymer injection (Feb-2012). Higher viscosity fluid around the producers P1, P5, and observation well O1 were required to history match these areas.

![Figure 5.10 Water viscosity at the end of polymer injection.](image)

Figure 5.10 Water viscosity at the end of polymer injection.

Beside viscosity regions, in some area high residual resistance factor was required to obtain the match. These are mainly between injectors I1, I3 and producer P5. Similar behavior is considered between injector I1 and producer P1, P4.

We can conclude the main history matching parameters were introducing additional viscosity regions and regional residual resistance factors. Residual resistance factor was around 10 and that is consistent with coreflood laboratory experiments. History matching suggests the existence of Type II microemulsion phase, where surfactant is present mainly in oil phase. To better understand the existence of Type II microemulsion in the field, fresh water injection was performed at the end of pilot test. Figure 5.12 shows the surfactant and polymer concentration in offset producer P5. This figure illustrates that an enormous amount of surfactant was released after fresh water injection commenced. Real field data also confirmed the existence of Type II microemulsion as a possible cause of productivity impairments in the field.
Figure 5.11 Water resistance factor at the end of polymer injection.

Figure 5.12 Field surfactant and polymer concentration in producer P5.
5.6 Proposed Modeling Approaches

History matching both coreflood and pilot test suggests a need to include the microemulsion effects in surfactant polymer modeling. This might be one of the main reasons that pragmatic simulators (ECLIPSE, STARS) over predict the oil recovery of surfactant polymer system. Although mechanistic models (UTCHEM, REVEAL) can predict the microemulsion phase generation, running these models in field scale simulation is not feasible due to run times, complexity and required amount of lab data. In these models propagation of the microemulsion phase in the reservoir remains uncertain due to the many assumptions that need to be taken in regards to the input data to these models.

Based on laboratory and pilot test results, it can be observed that salinity is an important parameter in chemical injection floods; it has a tremendous effect on interfacial tension, adsorption, phase relationship, and viscosity of the solution. The chemical flood is designed based on salinity. Patrick et al.1986 has done a statistical study on salinity effect on recovery efficiency of 21 micellar field projects. The salinity of connate water for this pilot tests ranges from 2,500 to 150,000 ppm. Their statistical projects reviews show the connate water salinity has an important effect on recovery efficiency of surfactant floods. Also it is important to emphasize that they have suggested if the design of chemical injection salinity differs from the reservoir salinity, surfactant flood might cause inefficiency due to high adsorption/retention. The laboratory design salinity strategies might change due to mixing the injected salinity with rock and reservoir water as well as ion exchange from clays with injected water.

Currently in the mechanistic simulators, the IFT is calculated based on the effective salinity, Winsor type and surfactant ternary phase diagram through correlations obtained from solubilization ratios. It is not easy to obtain these correlation input data with laboratory phase behavior study. A tremendous amount of phase behavior studies need to be run in order to obtain surfactant ternary phase diagram that can be used for IFT determination and capillary desaturation model. In contrast, in pragmatic models, (STARS, Eclipse) the IFT is a direct input to the model. Therefor we are suggesting an analysis of the phase tubes to obtain the salinity limits for Type III as a function of surfactant concentration (Figure 4.4) and measure IFT and aqueous and oil viscosity. These data will be used to properly model the microemulsion effects in the simulator.
In this research we are proposing to introduce microemulsion effects in pragmatic models (STARS, ECLIPSE) as a function of salinity and surfactant concentration. For example the surfactant blends used in this field reveal the salinity windows shown in these effects and can be summarized as follows:

- Define lower and upper salinity limits to track the effective salinity regions in which Type III microemulsion is formed and disappeared.
  - This can be done by defining a tracking component with reactions where it can track surfactant and salinity in which both coexist.
- Modify the current oil viscosity model in STARS by defining a viscosity that can be a function of salinity, phase behavior type and surfactant concentration.
- Include additional IFT tables to model the IFT as function of surfactant, salinity and Winsor types. Currently, IFT is only a function of surfactant concentration and salinity, which is one of the main reasons that pragmatic models over predict the oil recovery.

![Effective salinity window for surfactant blend used in this field](image)

Figure 5.13 Effective salinity window for surfactant blend used in this field
CHAPTER 6
CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions

Chemical EOR design typically is based on phase behavior and coreflood measurements. These designs, however, are not adequate in providing the necessary information for field applications. The laboratory and field study conducted in this thesis supports these allegations. Specifically, this research focuses on fluid-fluid interactions and emulsion formation that typically cause productivity loss.

We conducted laboratory studies including core flood experiments to determine causes of productivity loss in application of surfactant-polymer flood in a specific field in the Illinois basin. We then conducted numerical simulation to evaluate coreflood experiments as well as the capabilities to history match these tests using commercial simulators. Coreflood and the pilot test history matching suggest that there is a need to formulate a mechanism for emulsion formation in numerical simulators. However, this was beyond the objective of this thesis, but is an issue to be studied by other researchers.

The main conclusions are:

1. Reservoir oils, in general, have a tendency to form emulsions during waterflooding even in the absence of surfactants.
2. For the field pilot studied in this research, water-in-oil emulsion formation is attributed to the high salinity and sub-optimal salinity gradient of the chemical design. The high-viscosity microemulsion formed in presence of polymer is similarly attributed to the sub-optimal salinity gradient design.
3. The microemulsion diameter and/or conventional emulsion size is at least in order of 10 \( \mu m \), which is within the range of pore size distribution of the reservoir rock. Therefore, microemulsion flow cause blockage due to filtration effects that can explain productivity losses observed in the pilot test.
4. For this reservoir, in absence of surfactant, high polymer concentration causes undesirable oil-polymer-water interactions, which create large mixture viscosities.
5. Injection of middle phase microemulsion in core experiments indicated the need for optimizing and adding polymer to improve sweep efficiency.
6. Evaluation of the field pilot test indicates that chemical flooding is very complex, and
existing theories do not explain the cause of field failures. While we could not develop a reliable theory, SP field pilot results provides insight into the causes of chemical flood field failures.

7. Laboratory evaluations of chemical flood design must include the evaluation of emulsion tendencies with polymer, surfactants and its combinations at different oil-water rations and salinities.

6.2 Recommendations

Based on the results of this research we recommend the following, hoping to better characterize microemulsion formations to be used as a next step in numerical modeling of chemical flooding.

- Once the surfactant formulation is selected, perform additional phase behavior tests in the laboratory to obtain the effective salinity limits in which Type III microemulsion forms and disappears.

- Evaluation of pore size and droplet size (micro/macro) distribution of different emulsion should be part of the laboratory protocol for the design of the chemical flood

- Effective salinity limits need to be obtained as function of surfactant concentration and oil water ratio. It has been shown that oil water ratio also has tremendous effects on the effective salinity bounds.

- Use the above salinity window to model the microemulsion viscosity as a function of brine salinity and microemulsion types in the modeling of surfactant polymer system.

- Introduce the microemulsion effect in modeling surfactant polymer systems by tracking effective salinity and modifying the oil and water phase viscosity as well as IFT as a function of microemulsion types.

- Prior field application of surfactant polymer injection, monitor injection and production salinity and water composition of the formation for several months. This is to primarily understand the salinity behavior in each producer. These data will be compared against the optimum salinity window of the selected formulation, as well as initializing the model with salinity data. The robustness of the surfactant formulation need to be verified prior field application.
Perform rock mineralogy X-Ray Diffraction (XRD), Scanning Electron Microscopic (SEM) analysis and consider them in the surfactant formulation for adsorption /retention as well as possible reaction and changes in water chemistry. For example, presence of iron will impact the polymer solution viscosity.
NOMENCLATURE

\(a_s\) Adsorption, milligram/gram (ppm) nomenclature
\(B_\phi\) Formation volume factor of phase \(\phi\), rb/STB
\(c_t\) Total system compressibility, psi\(^{-1}\)
\(c_\phi\) Compressibility of phase \(\phi\), psi\(^{-1}\)
\(c_\phi\) Pore compressibility, psi\(^{-1}\)
\(C_{\phi s}\) Surfactant concentration in phase \(\phi\), micro-gram/gram (ppm)
\(C_{SEL}\) Lower boundary effective salinity
\(C_{SEU}\) Upper boundary effective salinity
\(D\) Depth, ft
\(D\) Diffusivity, ft\(^2\)/day
\(k\) Absolute permeability, md
\(k_{t\phi}\) Relative permeability to phase \(\phi\), dimensionless
\(P_\phi\) Pressure of phase \(\phi\), psi
\(P_{cwo}\) Water-oil capillary pressure, psi
\(q_\phi\) Flow rate for phase \(\phi\), ft\(^3\)/d
\(\bar{q}\) Source/sink term per volume of grid block, 1/day
\(S_\phi\) Saturation of phase \(\phi\), fraction

Greek Letters
\(\gamma_\phi\) Fluid gravity gradient for phase \(\phi\), psi/ft
\(\lambda_\phi\) Mobility of phase \(\phi\), cp\(^{-1}\)
\(\lambda_t\) Total system mobility, cp\(^{-1}\)
\(\rho_r\) Rock density, lb/ft\(^3\)
\(\bar{\tau}\) Turtuasity, dimensionless

Operators
\(\nabla\) Gradient operator

Subscript
max Maximum
\(o\) Oil
t Total system
\(w\) Water
\(\phi\) Fluid phase (\(\phi = o, w, g\) respectively)

Abbreviation
ASP Alkaline Surfactant Polymer
DW Deionized Water
<table>
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<tr>
<th>Abbreviation</th>
<th>Full Form</th>
</tr>
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<tbody>
<tr>
<td>EOR</td>
<td>Enhanced Oil Recovery</td>
</tr>
<tr>
<td>FW</td>
<td>Fresh Water</td>
</tr>
<tr>
<td>IFT</td>
<td>Interfacial Tension</td>
</tr>
<tr>
<td>ME</td>
<td>Microemulsion</td>
</tr>
<tr>
<td>ME1</td>
<td>Microemulsion Experiment #1</td>
</tr>
<tr>
<td>ME2</td>
<td>Microemulsion Experiment #2</td>
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<tr>
<td>ME3</td>
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<td>Microemulsion-Polymer</td>
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<td>Original Oil in Place</td>
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<tr>
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<td>Oil in water emulsion</td>
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<tr>
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<td>Polymer Flood Experiment #1</td>
</tr>
<tr>
<td>P2</td>
<td>Polymer Flood Experiment #2</td>
</tr>
<tr>
<td>PV</td>
<td>Pore Volume Injected</td>
</tr>
<tr>
<td>PW</td>
<td>Produced Water</td>
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<tr>
<td>RRF</td>
<td>Residual Resistance Factor</td>
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<tr>
<td>SR</td>
<td>Solubilization Ratio</td>
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<tr>
<td>Sorw</td>
<td>Residual Oil Saturation to Water</td>
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<tr>
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<td>Surfactant Polymer</td>
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<tr>
<td>SP3</td>
<td>Surfactant Polymer Experiment #3</td>
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<tr>
<td>TDS</td>
<td>Total dissolved solid</td>
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<tr>
<td>(V_{PW})</td>
<td>Volume of Produced Water</td>
</tr>
<tr>
<td>(V_{FW})</td>
<td>Volume of Fresh Water</td>
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<td>W/O</td>
<td>Water in oil emulsion</td>
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<td>wt%</td>
<td>Weight percentage</td>
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APPENDIX A
LABORATORY EXPERIMENTS PROCEDURES AND DETAILS

All experimental procedures are summarized in this section. The coreflooding apparatus used in running these experiments was Chandler FRT (Formation Response Tester) model 6100 shown in Figure A.0.1. This device consists of pumps, a core holder, back pressure regulator and accumulator. FRT is designed to accurately measure the pressure drop across the core and different location along the core, when exposed to variety of test fluids.

A.1 Experiment SP1

Coreflood procedure for the experiment SP1 is as follows:
1. Measure air permeability of each core plug, and choose the ones that have similar permeability and stack them together to make a 8-12 inch long core.
2. Saturate the core with de-gassed produced water (~62,000 ppm TDS) at 25 °C.
3. Flood the core with filtered reservoir oil at reservoir temperature (28 °C) until the water cut is zero (Measure of Swi), and age it for 11 days.

4. Flood the core with produced water (~62,000 ppm TDS) at reservoir temperature (28 °C) at 1 ft/day until the oil cut reaches zero (Measure of Sor).

5. Inject 0.4 PV of SP slug (0.7% total surfactant, 2500 ppm HPAM 3330S) in blended water (82% produced water blending 18% fresh water, 51,000 ppm TDS) at reservoir temperature (28 °C).

6. Inject 0.4 PV 2500 ppm HPAM 3330S in blended water (73% produced water blending 27% fresh water, 45,000 ppm TDS) at reservoir temperature (28 °C).

7. Inject blended water (50% produced water blending 50% fresh water, 31,000 ppm TDS) at reservoir temperature (28 °C) until the oil cut is zero.

8. Collect and analyze effluent to get data for oil recovery, surfactant retention, polymer retention, and effluent salinity.

The permeability of core is calculated using Darcy law as follows:

\[ k = 122.7842 \frac{q \mu L}{\Delta P D^2} \]  \hspace{1cm} (A.0.1)

Where \( k \) (md) is permeability, \( q \) (ml/min) is flow rate, \( L \) (inch) is core length, \( \Delta P \) (psi) is the pressure drop across the core, and \( D \) (inch) is the core diameter.

For example the brine permeability for experiment SP1 is calculated and shown in Table A.1.

<table>
<thead>
<tr>
<th>( q ), (ml/min)</th>
<th>( \mu ), cp</th>
<th>( L ), inch</th>
<th>( \Delta P ), psi</th>
<th>( D ), inch</th>
<th>( k ), md</th>
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<td>1</td>
<td>1</td>
<td>9.38</td>
<td>5.01</td>
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</table>

The following figures show pressure drop data during different stages of experiment: Figure A.0.2, Figure A.0.3, Figure A.0.4 and Figure A.0.5 shows pressure drop for the following steps: the brine saturation step, oil saturation step, waterflood step and chemical injection.
Figure A.0.2 Pressure drop versus pore volume injected across the core for brine saturation step.

Figure A.0.3 Pressure drop versus pore volume injected across the core for oil saturation step.

Figure A.0.4 Pressure drop versus pore volume injected across the core for waterflood step.
Figure A.0.5 Pressure drop versus pore volume injected across the core for chemical flood and post waterflood step.

A.2 Experiment SP2

Coreflood procedure for experiment SP2 is as follows:
1. Saturate the Berea core with de-gassed produced water (~60,000 ppm TDS) at 25°C
2. Flood the core with oil at reservoir temperature (28°C) until water cut is zero (Measure of Swi), and age it for two days at reservoir temperature. After aging inject about 2 PV of the fresh oil into the core.
3. Flood the core with produced water (~60,000 ppm TDS) at reservoir temperature (28°C) and injection rate of 2 ft/day until no more oil is produced (Sorw).
4. Inject 0.4 PV of surfactant polymer slug (1000 ppm polymer, 0.7% surfactant, 93% PW & 7% FW) and evaluate pressure drops and residual oil recovery (Sorw) at reservoir temperature (28 °C) and constant injection rate of 2 ft/day.
5. Continue injecting 2 PV of HPAM 3330S at 2000 ppm in blended water (93% pw + 7% FW salinity of 56,000 ppm) using constant rate mode to monitor oil production, pressure drops and possible changes in productivity.
6. Continue injecting produced water also using constant rate mode until the oil cut is zero.

The following figures show pressure drop data during different stages of experiment: Figure A.0.6, Figure A.0.7, Figure A.0.8 and Figure A.0.9 shows pressure drop for the following steps: the brine saturation step, oil saturation step, waterflood step and chemical injection.
Figure A.0.6 Pressure drop versus pore volume injected across the core for brine saturation step.

Figure A.0.7 Pressure drop versus pore volume injected across the core for oil saturation step.

Figure A.0.8 Pressure drop versus pore volume injected across the core for waterflood step.
Figure A.0.9  Pressure drop versus pore volume injected across the core for chemical flood and post waterflood step.

A.3  Experiment P1

Coreflood procedure for experiment P1 is as follows:

1. Saturate the Berea core with de-gassed produced water (~60,000 ppm TDS) at 25°C and calculate brine permeability.
2. Inject multiple PV of HPAM 3330S at 2,500 ppm in blended water (93 % PW + 7% FW salinity of 60,000 ppm) using constant rate mode to monitor oil production, pressure drops and possible changes in productivity.
3. Continue injecting produced water using constant rate mode.

A.4  Experiment P2

The procedure for this coreflood is as follows:

1. Saturate the Berea core with de-gassed produced water (~60,000 ppm TDS) at 25°C and calculate brine permeability.
2. Flood the core oil at reservoir temperature (28°C) until water cut is zero (measure of Swi), and age it for 2 days at reservoir temperature.
   a. Start with the injection rate of 0.5 cc/min and increase it gradually until the total pressure drop across the core is about 35-40 PSI.
   b. Measure the oil permeability and calculate kro.
c. After aging inject about 2 PV of the fresh oil into the core.

3. Flood the core with produced water (~60,000 ppm TDS) at reservoir temperature (28°C) and injection rate of 2 ft/day until no more oil is produced (Sorw).

4. Inject multiple PV of HPAM 3330S at 2,500 ppm in blended water (73% pw + 27%) using constant rate mode to monitor oil production, pressure drops and possible changes in productivity.

5. Flood the core with water (56.5% produced water - 43.5% fresh water) at constant flow rate (0.15cc/min) until no more oil is produced.

A.5 **Experiment ME1**

Experimental procedure for ME1 is as follows:

1. Saturate the core with de-gassed produced water (~62,000 ppm TDS) at 25°C.

2. Flood the core with oil at reservoir temperature (28°C) until water cut is zero (Measure of Swi), and age it for 1 week at reservoir temperature.

3. Flood the core with produced water (~62,000 ppm TDS) at reservoir temperature (28°C) and injection rate of 2 ft/day until no more oil is produced (Sorw).

4. Inject 0.4 PV of microemulsion (input WOR =1) prepared at optimal salinity (0.7% total surfactant, 2500 ppm HPAM 3330S, in 82% produced water blending 18% fresh water, 51,000 ppm TDS) and evaluate pressure drops and residual oil recovery (Sorw) at reservoir temperature (28°C) and constant injection rate of 2 ft/day.

5. Continue injecting 0.4 PV of HPAM 3330S at 2,500 ppm in blended water (73% produced water and 27% fresh water at total salinity of 45,000 ppm) using constant pressure mode to monitor oil production, pressure drops and possible changes in productivity.

6. Inject blended water (56.5% produced water and 43.5% fresh water at 35,000 ppm TDS) also using constant pressure mode until the oil cut is zero.

Composition of microemulsion is shown in Figure A.0.10. Figure A.0.11, Figure A.0.12, Figure A.0.13,

Figure A.0.14 and Figure A.0.15 shows pressure drop for the following steps: the brine saturation step, oil saturation step, waterflood step, chemical injection and post waterflood step:
Surfactant concentration: 0.39 wt%

**1 week aging**

**Microemulsion composition**

<p>| | | |</p>
<table>
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<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
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<td>Oil</td>
<td>58.1</td>
<td>Volume %</td>
</tr>
<tr>
<td>Water</td>
<td>41.9</td>
<td>Volume %</td>
</tr>
<tr>
<td>Surfactant Concentration (assuming all surfactant in microemulsion phase)</td>
<td>2.67</td>
<td>wt%</td>
</tr>
<tr>
<td>Surfactant Concentration (assuming surfactant equally in liquid phase)</td>
<td>0.29</td>
<td>wt%</td>
</tr>
<tr>
<td>Polymer Concentration (assuming polymer equally in liquid phase)</td>
<td>1,048</td>
<td>ppm</td>
</tr>
<tr>
<td>Viscosity</td>
<td>22.1</td>
<td>cP</td>
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</table>

Figure A.0.10 Composition of microemulsion Phase.

Figure A.0.11 Pressure drop versus pore volume injected across the core for brine saturation step.
Figure A.0.12 Pressure drop versus pore volume injected across the core for oil saturation step.

Figure A.0.13 Pressure drop versus pore volume injected across the core for waterflood step.
A.6 Experiment ME2

The procedure for experiment ME2 is presented as follows:

1. Saturate the core with de-gassed produced water (~62,000 ppm TDS) at 25°C and injection rate of 1 cc/min.

2. Flood the core with oil at reservoir temperature (28°C) and injection rate of 0.5 cc/min until water cut is zero (Measure of Swi), and age it for one week at reservoir temperature.

3. Flood the core with produced water (~62,000 ppm TDS) at reservoir temperature (28°C) and injection rate of 2 ft/day until no more oil is produced (Sorw).

4. Inject 0.4 PV of microemulsion (input WOR = 1) and evaluate pressure drops and residual oil recovery (Sorw) at reservoir temperature (28 °C) and constant injection rate of 2 ft/day (We need to confirm PV to be injected).

5. Inject 0.4 PV blended water (73% produced water and 27% fresh water at 45,000 ppm TDS) followed by water drive (56.5% produced water and 43.5% fresh water at 35,000 ppm TDS) using constant pressure mode until the oil cut is zero.
a. Although this test will not consider the injection of 0.4 PV of polymer same water strategy was kept to modify as less as possible salinity contrast as of ME1

b. Inject at constant pressure starting with ΔP at the end of waterflood (evaluate possible productivity losses due to ME injection and its changes as flow through the Berea core plug).

The following figures show pressure drop data during different stages of the experiment. Figure A.0.16, Figure A.0.17, Figure A.0.18, Figure A.0.19 and Figure A.0.20 shows pressure drop for the following steps: the brine saturation step, oil saturation step, waterflood step, chemical injection and post-waterflood step:

![Graph showing pressure drop versus pore volume injected across the core for brine saturation step.](image)

Figure A.0.16  Pressure drop versus pore volume injected across the core for brine saturation step.

### A.7 Experiment ME3

The procedure for experiment ME3 is presented as follows:

1. Saturate the core with de-gassed produced water (~62,000 ppm TDS) at 25°C and injection rate of 1cc/min
2. Flood the core with oil at reservoir temperature (28°C) and injection rate of 0.5 cc/min until water cut is zero (measure of Swi), and age it for one week at reservoir temperature
3. Flood the core with produced water (~62,000 ppm TDS) at reservoir temperature (28°C) and an injection rate of 0.15 cc/min until no more oil is produced (Sorw1)
4. Inject 0.4 PV of microemulsion (input WOR = 1) prepared at optimal salinity (0.7% total surfactant, 10000 ppm HPAM 3330S, in 82% produced water blending 18% fresh water, 51,000 ppm TDS) and evaluate pressure drops and residual oil recovery (Sorw) at reservoir temperature (28 °C) and constant injection rate of 0.15 cc/min.

5. Inject 0.4 PV blended water (73% produced water and 27% fresh water at 45,000 ppm TDS) followed by 1.7 PV water drive (56.5% produced water and 43.5% fresh water at 35,000 ppm TDS) using constant pressure mode until the oil cut is zero (Swor2) at injection rate of 0.15 cc/min.

Figure A.0.17 Pressure drop versus pore volume injected across the core for oil saturation step.

Figure A.0.18 Pressure drop versus pore volume injected across the core for waterflood step.
Figure A.0.19 Pressure drop versus pore volume injected across the core for microemulsion step.

Figure A.0.20 Pressure drop versus pore volume injected across post waterflood step.