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MOBILITY CONTROL OF CHEMICAL EOR FLUIDS USING FOAM IN HIGHLY FRACTURED RESERVOIRS

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MOBILITY CONTROL OF CHEMICAL EOR FLUIDS USING FOAM IN HIGHLY FRACTURED RESERVOIRS

by

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Dedication

To my mother and friend, Lourdes, with her everlasting love and generosity toward her children, has always been by my side regardless the distance. To my siblings, Luly, Sofía, and Jorge, always the first to learn about my adventures, with their love and advice supported me through thick and thin. To my father, Oscar, who made the impossible to support me for 24 years. And especially to Laura, my beloved confidante and friend, to whom I deeply appreciate her love, support and patience this past year.

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Abstract

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Highly fractured and vuggy oil reservoirs represent a challenge for enhanced oil recovery (EOR) methods. The fractured networks provide flow paths several orders of magnitude greater than the rock matrix. Common enhanced oil recovery methods, including gases or low viscosity liquids, are used to channel through the high permeability fracture networks causing poor sweep efficiency and early breakthrough. The purpose of this research is to determine the feasibility of using foam in highly fractured reservoirs to produce oil-rich zones. Multiple surfactant formulations specifically tailored for a distinct oil type were analyzed by aqueous stability and foam stability tests. Several core floods were performed and targeted effects such as foam quality, injection rate, injection type, permeability, gas saturation, wettability, capillary
pressure, diffusion, foam squeezing, oil flow, microemulsion flow and gravity segregation. Ultimately, foam was successfully propagated under various core geometries, initial conditions and injections methods. Consequently, fluids were able to divert to unswept matrix and improve the ultimate oil recovery.
# Table of Contents

List of Tables ........................................................................................................... xiii

List of Figures ............................................................................................................ xiv

Chapter 1: Introduction .............................................................................................. 1
   Enhanced Oil Recovery: Gas injection ................................................................. 1
   Foam Principles and Applications ...................................................................... 3
      Gas Mobility Reduction .................................................................................. 3
      Liquid Mobility Reduction ............................................................................ 3
      Low-Tension Gas Process ............................................................................. 4
   Research Motivation ......................................................................................... 5
   Research Objectives ......................................................................................... 5
   Thesis Organization ......................................................................................... 6

Chapter 2: Literature Review .................................................................................... 7
   Foam Principles ................................................................................................. 7
   Foam in Porous Media ...................................................................................... 8
      Mechanisms of Foam Generation .................................................................. 8
         Snap-Off ..................................................................................................... 8
         Lamella- division ....................................................................................... 9
         Leave-behind ............................................................................................. 10
      Mechanisms of Foam Destruction ............................................................... 11
   Macroscopic Effects of Foam in Porous Media ................................................. 12
      Effect of Permeability Contrast in a Dual Porosity System ......................... 12
      Effect of Trapped Gas .................................................................................. 12
      Effect of Capillary Pressure Between Gaseous and Liquid Phases .......... 13
      Effect of Injection Mode: Co-injection vs. SAG ........................................ 14
   Fluid Flow in Fractured Reservoirs ................................................................. 15
Transport Properties of Rock Fractures ........................................ 15
Characterization of Fluid Flow in Fractures ................................. 15
Multiphase Flow in Fractures ...................................................... 16
Fluid Transfer from Fracture to Matrix ........................................ 18
Foam Flow in Fractured Reservoirs ............................................ 18
Effect of Fracture Permeability ................................................... 18
Effect of Fracture Surface Roughness ........................................ 20
Foam apparent viscosity in Fractures ........................................ 20
Enhanced Oil Recovery Foam .................................................... 21
Recovery Mechanisms during Low-Tension Gas Flooding ............ 21
  Diffusion .............................................................................. 22
  Wettability alteration .......................................................... 23
  Natural Water Imbibition at High Interfacial Tension ............... 23
  Natural Water Imbibition at Low Interfacial Tension .............. 24
Chapter Summary ..................................................................... 25

Chapter 3: Development of a Chemical Formulation for Low-Tension Gas Flooding ................................................................. 26
  Introduction ........................................................................... 26
  Experimental Description ...................................................... 26
    Materials ........................................................................... 26
      Brines ............................................................................ 26
      Crude Oil ....................................................................... 27
      Surfactants ...................................................................... 27
    Experimental Procedure .................................................... 28
      Aqueous Stability Test .................................................... 28
      Foam Stability .................................................................. 29
      Phase Behavior ............................................................... 30
  Experimental Results ............................................................ 31
    Foaming Surfactant .......................................................... 31
    Aqueous Stability ............................................................. 31

x
List of Tables

Table 1. Chemicals analysis of brines used .................................................................27
Table 2. Surfactants tested during the screening. Company agreements prohibit disclosure of some surfactant details .................................................................28
Table 3. Surfactant tested for low tension properties ..................................................28
Table 4. Salinity Scan Results (C=Clear, P=Precipitate) .........................................31
Table 5. Salinity Scan Results (C=Clear, P=Precipitate) .........................................33
Table 6. Main surfactant at 1% mixed with C_{7-8}(EO)_{5}-sulfate at 1%. Tested at only Synthetic Sea Water (SSW) and Synthetic Formation Brine (SFB) (C=Clear, P=Precipitate) .................................................................33
Table 7. Core Flood Schedule and Permeabilities .......................................................45
Table 8. Low Tension Surfactant Formulation .............................................................60
Table 9. Reservoir core properties (from Dr. Pope’s unpublished work) .................61
List of Figures

Figure 1. Possible effects of foam on transport of gas in porous media (a) gravity override (b) viscous fingering (c) flow diversion to low permeability zones (Sharma and Shah 1989) ...................................................... 2

Figure 2. Snap-off mechanism of lamellae generation. (a) gas enters the liquid filled pores (b) liquid film swells bridging the throats together (c) the process is repeated after snap-off (Kovscek and Radke 1994) ................. 9

Figure 3. Lamella division mechanisms of lamellae generation (a) lamella stretches at a branch point (b) two lamellae form (Kovscek and Radke 1994) ... 10

Figure 4. Leave-behind lamellae generation mechanism. (a) Non-wetting phase starts to displace wetting phase (b) wetting phase residues bridge neighboring pores creating lamellae parallel to flow direction (Kovscek and Radke 1994) .................................................................................................. 10

Figure 5. Comparison of gas-liquid relative permeability models in fractures (Shad and Gates 2010) .............................................................................................................. 17

Figure 6. Surfactant Functions Cycle ................................................................................. 21

Figure 7. Criteria used to determine the results of an aqueous stability test .......... 29

Figure 8. Graphs showing the foam column inside a pipette as a function of time. This test was performed at both 20 °C and 95 °C using IOS C_{15-18} and C_{7-8} (EO)_{5}-sulfate for the first two columns, and a ratio 1:1 of surfactant solution and oil for the last two columns in each time period. ........ 35
Figure 9. Graphs showing the foam column inside a pipette as a function of time. This test was performed at both 20 °C and 95 °C using AOS C$_{12-16}$ and C$_{7-8}$ (EO)$_5$ sulfate for the first two columns, and a ratio 1:1 of surfactant solution and oil for the last two columns in each time period. ..........35

Figure 10. Graphs showing the foam column inside a pipette as a function of time. This test was performed at both 20 °C and 95 °C using a non-ionic surfactant and C$_{7-8}$ (EO)$_5$ sulfate for the first two columns, and a ratio 1:1 of surfactant solution and oil for the last two columns in each time period. .................................................. 36

Figure 11. Solubilization Ratio as a function of Salinity for AKL-412 (Lu, Solairaj et al. 2011). .................................................................37

Figure 12. Foam stability comparison between the best foaming surfactant formulation and the best low tension surfactant formulation ..........38

Figure 13. Different core geometries used..........................................................43

Figure 14. Experimental setup used for the core floods ..................................44

Figure 15. (In-1-7) Mobility Reduction Factor during foam injection for the case of medium vug density ....................................................47

Figure 16. (In-1-6) Mobility Reduction Factor during foam injection at various rates and foam qualities in a high overlapping vugs case .......................49

Figure 18. (In-1-7) Mobility Reduction Factor during foam injection for the medium vug density case at 75% foam quality and 1 ft/d .........................51

Figure 19. Compressibility of nitrogen gas from SRK EOS from inlet to outlet conditions proving the presence of gas expansion ..................52
Figure 20. (In-1-10) Mobility Reduction Factor during foam injection at various rates and foam qualities in a high overlapping vugs case after nitrogen injection.................................................................53

Figure 21. Comparison of MRF for the cases of overlapping high vug density core flood with and without a dry fracture .................................................................54

Figure 22. Foam for a fixed liquid slug of 0.1 PV. Gas Varied from 0.1, 0.3, to 0.5 PV at a constant rate of 0.75 ft/d.................................................................55

Figure 24. CT scan images done on reservoir core (images taken by Dr. Pope’s group) ...........................................................................................................62

Figure 25. (In-2-4) Simultaneous injection of nitrogen and brine at 1.5 ft/d and 50% gas fraction.........................................................63

Figure 26. Mobility Reduction Factor of In-2-4 of foam at 1.5 ft/day and 50% foam quality ........................................................................................................64

Figure 27. Image of fracture surfaces after experiment ........................................65

Figure 28. Pressure drop of Res-2a during water flood followed by co-injection of N₂ and brine at 38,000 PPM TDS ........................................66

Figure 29. Pressure drop of Res-2a during co-injection of N₂ and surfactant at 38,000 PPM TDS ........................................................................................................67

Figure 30. Oil recovery of Res-2a during co-injection of N₂ and surfactant at 38,000 PPM TDS ........................................................................................................67

Figure 31. Pressure drop of Res-2b during co-injection of N₂ and brine at 26,000 PPM TDS ........................................................................................................69

Figure 32. Pressure drop of Res-2b during co-injection of N₂ and surfactant at 26,000 PPM TDS ........................................................................................................69
Chapter 1: Introduction

This section will give a general overview of foam principles and applications. To better understand where foam stands in the oil production cycle, a description of Enhanced Oil Recovery techniques is given first. Then, common methods, like gas injection, are described along with its challenges. Next, foam is introduced as a way of solving these challenges. Finally, application of foam as a novel method for mobility control in highly fractured reservoirs is introduced.

Enhanced Oil Recovery: Gas Injection

Gas injection is the most common Enhanced Oil Recovery technique these days because of its low cost per incremental barrel of oil. EOR or Improved Oil Recovery (IOR), is the last phase of an oil development plan and consists of injecting any foreign chemical or fluid into the matrix, except water injection. The importance of EOR has increased in the last few years due to a dramatic increase in the oil price which makes previously uneconomic projects to life. Common EOR techniques include: Gas injection, chemical injection and thermal recovery methods, among other innovative techniques such as microbial and nanoparticle injection.

Gas injection has been widely used as a way of improving oil recovery. Common gases include hydrocarbon gas, nitrogen and carbon dioxide. Its use is mainly influenced by its availability in the field. Gas injection may aid in more ways than just maintaining reservoir pressure. Immiscible gases may lower the viscosity of the oil, or cause it to swell out of the matrix. Miscible gases would lower capillary pressure between the
phases and thus recover the oil as one phase, this process usually work best at high pressures and is dependent on the type of crude oil and gas being used.

Common problems encountered during conventional gas injection are shown in Figure 1. Gravity override occurs when the lighter fluid flows on top and ride over the liquid phases below. Viscous fingering occurs because of the differences in viscosity between the injected gas and the native liquids. In heterogeneous reservoirs, the injected gas flows preferentially through the high permeability layers. All these issues cause gas-early breakthrough, and significantly reduces the efficiency of these processes.

Figure 1. Possible effects of foam on transport of gas in porous media (a) gravity override (b) viscous fingering (c) flow diversion to low permeability zones (Sharma and Shah 1989).
FOAM PRINCIPLES AND APPLICATIONS

By injecting surfactant solution capable of creating foam, the gas mobility is reduced, which in turn decreases the gravity override, viscous fingering, and channeling to higher permeability layers. Foam increases trapped gas, increasing gas saturation and thus decreasing oil saturation. Foam may also have an effect on the liquid mobility by reducing it.

Gas Mobility Reduction

Gas exists in foam surrounded by liquid lamellae. The efficiency of the foam process relies on this principle. The lamellae exert resistance on the flowing gas due to their contact with the pore walls. Some of the gas may be retained by immobile lamellae, which block some of the flow paths. The reduced gas flow paths in turn reduce gas relative permeability. Although, the actual gas viscosity is unchanged, the gas shows an apparent increase in gas viscosity because of its reduced flow rate.

Liquid Mobility Reduction

Liquid in the presence of foam behaves in different ways than gas. Liquid flow paths may be connected through lamellae. During foam propagation, the gas saturation increases and behaves as additional rock matrix by blocking the liquid flow paths. The reduced flow paths decrease liquid relative permeability. In other words, liquid saturation decreases due to the increase in gas saturation which in turn affects the liquid relative permeability.
Low-Tension Gas Process

Alkaline Surfactant Polymer (ASP) has been widely used in old near-depleted reservoirs. ASP uses polymer as a way of controlling mobility. There are various disadvantages to polymer: 1) high molecular weight polymers can be large and plug rocks, 2) polymer may be unstable at high temperature and high salinity 3) high flow rates may degrade polymer performance. A novel approach has been evaluated by Srivastava et al. (2009) which substitutes the polymer with gas to create foam. Successful core floods using Alkaline-Surfactant-Gas (ASG) were conducted on low to medium permeability sandstone and dolomite. Using a negative salinity gradient, they were able to mobilize trapped surfactant and increase foam strength during the drive slug to improve mobility ratio and conformance control. The work done by Srivastava et al. (2009) is relevant to this thesis except for the use of alkaline which is not evaluated here.

Low-Tension Gas Process employs a dual-purpose surfactant formulation that work together to improve the oil recovery in fractured or non-fractured media. The first surfactant characteristic provides mobility control by using gas to create foam. The produced foam increases the apparent viscosity of the solution, thus reducing its mobility. The second surfactant characteristic reduces the interfacial tension between oil and water to emulsify these two phases and produce them by gravity drainage. In the case of a fractured reservoir, foam provides mobility control in the fractures and diverts the surfactant solution into the matrix where it emulsifies the oil and allows it to flow out of the matrix to be produced. The combined effect of these two mechanisms is known as Low-Tension Gas Process.
**RESEARCH MOTIVATION**

Fractured carbonate fields are an enormous source of oil. However, the channels created by these natural fractures are several orders of magnitude more permeable than the contiguous matrix. Most of the oil recovered from carbonate reservoirs comes from the fractures leaving most of the oil in the matrix unswept. Other problems with these types of reservoirs include the downward movement due to depletion of the gas-oil contact, water encroachment caused by an active aquifer, and the upward movement through fracture network of the water-oil contact.

Common secondary and tertiary recovery methods like gas injection are not suitable because of these fractures. Any attempt to control fluid mobility using polymers is limited because of the extreme conditions encountered in some of these reservoirs. The high salinity, temperature and pressure limit the potential of polymers. An enhanced oil recovery method capable of plugging the fractures and capable of diverting fluids into the matrix is needed to increase production from these problematic reservoirs. Once the injected fluids are able to divert into the matrix a surfactant blend may be injected which may reduce the interfacial tension between oil and water and recover oil by gravity segregation as well as by altering the wettability of the rock.

**RESEARCH OBJECTIVES**

1) Develop a surfactant formulation capable of producing foam in extreme conditions of high temperature, pressure and salinity.
2) Understanding of foam behavior in highly fractured reservoirs at extreme conditions of high temperature, pressure and salinity in the absence of oil.

3) Recognize the mechanisms of oil recovery during low-tension gas flooding in highly fractured reservoirs at extreme conditions of high temperature, pressure and salinity.

**THESIS ORGANIZATION**

This thesis is organized in six chapters. After this introduction, Chapter Two will review the current literature available up to date on the topic of foam, briefly describing the basics of foam and then focusing on available studies of low-tension flooding in fractures. Chapter Three will cover the development of a chemical formulation for low-tension gas flooding, covering the brine chemical analysis as well as the various tests done to identify multiple surfactant formulations capable of producing foam and lowering the interfacial between oil and brine. Chapter Four will describe the extensive experimental work done on cores, the innovative core drilling techniques to successfully represent a fractured reservoir, the sophisticated equipment used in core floods and the interpretation of the results. Finally, Chapter Five will cover the experimental work and interpretations done on low-tension gas flooding core floods in the presence of oil.
Chapter 2: Literature Review

FOAM PRINCIPLES

Foam is a dispersion of gas in a liquid solution. The gas is known as the discontinuous phase, while the liquid is known as the continuous phase. Gas bubbles are separated by thin liquid films called lamellae. Foam can vary based on multiple factors: foam quality, texture, and rheology (S. S. Marsden 1967).

Foam quality is defined as the ratio of volume of gas over the volume of liquid present. The ranges of quality that may be obtained depend on the foaming surfactant as well as the method of foam generation. Two common ways of naming foam quality is by either wet or dry. The actual foam quality range for each type of foam quality varies from author to author, however, wet foam refers to low foam quality, while dry foam refers to high foam quality.

Foam texture refers to the bubble size and bubble size distribution. These are described in terms of the average bubble diameter. Texture depends on the foaming surfactant, foam generation method, foam quality, and foam conduit. An increase in surfactant concentration and decrease in foam quality will result decreased bubble size. Also, foam depends on the medium size through which it is flowing. Bubbles may shape depending on the medium diameter.

Foam rheology is of great importance when considering foam applications. Foam behaves as a non-Newtonian fluid. Its true viscosity is difficult to quantify due to its constant coalescence rate, and in porous media, regeneration rate. It is common to
express foam in terms of foam mobility, calculated from Darcy’s law, i.e., the ratio of effective permeability to apparent viscosity.

**FOAM IN POROUS MEDIA**

**Mechanisms of Foam Generation**

Understanding foam generation in porous media requires pore-level study of lamellae behavior. Based on visual observations, there are three well-known lamellae generation mechanisms: *snap-off*, *lamella-division*, and *leave-behind*.

**Snap-Off**

This phenomenon was first explained by Roof (1970). Also known as capillary snap-off, it is one of the most observed lamellae generation mechanisms in microscopic models. When liquid is driven by capillary pressure into a pore throat, the liquid covers the walls of the pore (Falls, Hirasaki et al. 1988). If sufficient liquid is accumulated so that the pore throat is completely blocked by the liquid, a lense or lamellae is formed (see Figure 2). Given enough capillary pressure to push gas into the pore and through the lamellae a new bubble is formed downstream (T.C. Ransohoff 1988). This is the only foam mechanism that is completely mechanical and may occur in the absence of surfactant. The role of the surfactant is to stabilize the developed bubble and prevent it from promptly coalescing. (Kovscek and Radke 1994).
Figure 2. Snap-off mechanism of lamellae generation. (a) gas enters the liquid filled pores (b) liquid film swells bridging the throats together (c) the process is repeated after snap-off (Kovscek and Radke 1994)

**Lamella-division**

Lamella or bubble division occurs when one lamella divides into two separate ones at branch points in porous media (see Figure 3). This method requires pre-existing bubbles. The frequency of lamella division depends on: branch points, bubble sizes, local capillary pressure fluctuation. Lamella-division is a contributor to the gas viscosity because of the force required to push lamellae through the pores.
Leave-behind

Leave-behind occurs when a non-wetting phase displaces a wetting phase, leaving behind wet surfaces that may bridge together to form lamella (see Figure 4). This method contributes the least to gas viscosity since no effort is required to push the lamellae through the porous media because of their parallel alignment to the flow direction. On the other hand, the lamellae created by leave-behind mechanism may reduce gas permeability by blocking flow paths to gas.

Figure 3. Lamella division mechanisms of lamellae generation (a) lamella stretches at a branch point (b) two lamellae form (Kovscek and Radke 1994)

Figure 4. Leave-behind lamellae generation mechanism. (a) Non-wetting phase starts to displace wetting phase (b) wetting phase residues bridge neighboring pores creating lamellae parallel to flow direction (Kovscek and Radke 1994)
Mechanisms of Foam Destruction

In the absence of oil, two main mechanisms of foam destruction exist: capillary suction and gas diffusion (Chambers and Radke 1991). Capillary suction as well as gas flow rate causes lamellae to move and coalesce when their bodies are quickly stretched beyond a critical film thickness. Capillary pressure is affected by the liquid saturation, absolute permeability and surface tension. A limiting capillary pressure exists above which coalescence is significant while below it is minimal. (Khatib, Hirasaki et al. 1988). Moreover, gas diffusion does not play an important role as that of capillary suction and pertains mainly to stagnant, trapped bubbles. The Young-Laplace equation describes a difference in pressure and hence chemical potential between the inside and outside of a bubble. Driven by this difference, gas dissolves in the liquid and escapes the bubble until the thermodynamically-stable state of zero curvature is reached, i.e., no more foam exists (Chambers and Radke 1991).

In the presence of oil, Raterman (1989) proposed a three-part mechanism for foam destabilization: oil penetration, disturbance propagation, and lamellae rupture. Oil may penetrate foam either by solubilization or emulsification. Solubilization occurs only if the surfactant concentration is above the critical micelle concentration (CMC). In this case, micelles are present as a structured layer in foam films and cause foam films to thin in stepwise transition. Solubilized oil increases the rate of film thinning. Moreover, emulsified oil forms pseudoemulsion films between the oil and gas. When these films break, oil may enter, spread and destabilize the gas and water films. The destabilizing effect of oil depends on the type of oil and surfactant used.
MACROSCOPIC EFFECTS OF FOAM IN POROUS MEDIA

Effect of Permeability Contrast in a Dual Porosity System

All types of injected fluid flow through the fractures bypassing the matrix because of the high permeability contrast between the matrix and the fracture. Also, fracture systems have a broad distribution of fracture thicknesses. Thus, the thicker fractures will act as thief zones for the injected fluids, leaving the thinner fractures untouched. Although, few studies have been reported on foam in fractures, analogous research has been done on dual permeability systems. The permeability contrast is one of the most important factors governing diversion of fluids from a high permeability layer to a lower one (Siddiqui and Islam 1997; Quoc P. Nguyen 2003). Capillary contact during foam flow in two different layers makes foam fronts travel at the same rate. However, if the two layers are not communicated, i.e., crossflow does not occur, gas flow is blocked at the high permeability zone and diverted towards the low permeability core where it travels faster (H.J. Bertin and O.G. Apaydin 1999).

Effect of Trapped Gas

Permeability has a strong effect on foam strength (H.O. Lee 1991; Parlar 1995; Martinez 1996; Rossen 1997). After sufficient gas injection, this may be attributed to the amount of trapped gas in a given permeable configuration. Absolute gas mobility at limiting capillary pressure shows three kinds of relationships: (1) a decreasing function at low permeability values, (2) neutral at medium permeability values, and (3) sharp increase at high permeability values (Quoc P. Nguyen 2000). In the case of a homogeneous sandstone core of low permeability, foam generation and collapse rates balance throughout the majority of the core. As a result, the average foam texture reveals
a narrow developing zone and a steady plateau for the remainder of the core (Q. Chen 2008). As explained later in the discussion section, a fractured system should present a sharp increase in gas mobility because of the high permeability values.

**Effect of Capillary Pressure Between Gaseous and Liquid Phases**

In a dual permeability system, there exists a threshold injection foam quality below which foam no longer flows to lower permeability layers. This threshold depends on the permeability contrast and foam strength in the high permeability region (Quoc P. Nguyen 2003). Furthermore, two foam flow regimes were identified: a high quality flow regime, where steady-state pressure gradient is independent of gas flow rate; and a low foam quality flow regime, where steady-state pressure gradient is independent of liquid flow rate (Osterloh 1992). The high quality flow regime is dominated by capillary pressure and coalescence (Osterloh 1992), while the low quality flow regime is dominated by fixed size bubble trapping and mobilization (W.R. Rossen 1999).

The rate of cumulative foam strength is directly attributable to its individual lamellae behavior. Lamellae may be destroyed by (1) capillary suction coalescence, (2) gas diffusion, (3) liquid evaporation and condensation, and (4) influence of additional phases (Quoc P. Nguyen 2000). In the case of a heterogeneous highly fractured reservoir, all of these factors reduce foam strength. In the gas cap of a fractured reservoir, the high conductivity channels lead to a dramatic decrease in water saturation by seeping water into the aquifer. Therefore, the high gas saturation in these regions will create a high capillary pressure that will suck most of the liquid in the lamellae and thus destroy the foam. A similar effect may be encountered at the top of the foam injection zone because of gravity drainage. Jiménez and Radke observed a dramatic foam collapse when transferring from a wet upstream micro model (saturated initially with surfactant) to an
identical attached dry micro model (Jiménez and Radke 1989). Gas diffusion, liquid evaporation and condensation will not be considered in this work because capillary suction coalescence plays a larger role in foam destruction. The last factor, the influence of additional phases, is as important as capillary pressure and will be the focus of a subsequent study.

**Effect of Injection Mode: Co-injection vs. SAG**

Different foam injection strategies need to be taken into account because of stratigraphic differences, foam behavior and operational concerns. Co-injection of surfactant and gas should be used if foam needs to be created in the near-well region or to ensure that both gas and liquid enter the same zones in a heterogeneous reservoir. In a fractured reservoir, it is important to study the possibility of injecting surfactant alternating gas (SAG) because of the risk associated with not intersecting a fracture. If the well hits a zone of low permeability matrix, injectivity may decrease to the point that co-injection may no longer be an option anymore. SAG injection has been studied by Shi and Rossen who showed some of the advantages of using SAG injection in a homogeneous reservoir, such as improved gas injectivity and corrosion avoidance by minimizing contact between gas and water in the surface facilities and pipes. Water is displaced from the near-well region by gas allowing one-phase flow and weakening foam near the well thereby increasing gas injectivity and mobility. Shan and Rossen showed that sweep efficiency is maximized using a constant-pressure single large slug injection (D. Shan 2004).
FLUID FLOW IN FRACTURED RESERVOIRS

Transport Properties of Rock Fractures

Most of the research done on fractures has been in the form of numerical simulation due to the complexity of the experimental study. Vilarrasa (2011) studied the effect of mechanical shearing on fluid flow anisotropy and solute transport in rough rock fractures. Their numerical studies were based on two surface fractures generated by laser scan. They studied the motion of solute particles in a rough fracture under shear. Shear-induced channels yield a transport behavior where advection is the main factor in direction parallel to shear and dispersion dominates in direction perpendicular to shear. Their finding is relevant when considering transport properties of rock fractures.

Characterization of Fluid Flow in Fractures

The simplest way of describing flow in a fracture is by using the Poiseuille law through parallel plates along with Darcy’s law to yield the permeability values as a function of the fracture thickness as shown in Equation 1 below, where H is the gap between fracture walls.

\[ K = \frac{H^3}{12} \]

Equation 1. Permeability value for a constant thickness fracture

Fluid flow and transport in a single fracture is of extreme importance for this research study to fully understand foam in fractures. Flow in a single fracture could be investigated using the Navier-Stokes Equation (Zimmerman and Bodvarsson 1996). However, due to its complexity, various approximations are commonly used. The
acceleration terms in the Navier-Stokes Equation may be discarded, yielding the Stokes equation. This is only valid below Reynolds Numbers of 10 (Zimmerman and Bodvarsson 1996). Another simplification is to replace the Stokes equation by the local cubic law (Brown 1987; Zimmerman, Al-Yaarubi et al. 2004). This local cubic law states that the fluid volumetric flow rate in a fracture is proportional to the fracture aperture to the power of three, and it works best for Darcian flow in a smooth and parallel single fracture. See Equation 2 below, where $g$ is the acceleration of gravity (m/s$^2$), $e$ is the average aperture (m), $\nu$ is the kinematic viscosity (m$^2$/s).

\[
q = \frac{g e^3 \nu}{12}
\]

Equation 2. Local Cubic Law is based on this formula.

Since field observations indicate that natural fractures are rough and not smooth (Meheust and Schmittbuhl 2001), additional studies are needed on the local cubic law to confirm its validity for rough surface fractures. Special attention should be placed on the Reynolds Number, for instance, the local cubic law is not valid for Reynolds Number above 10, and different power indexes should be used in such case (Qian, Chen et al. 2011).

**Multiphase Flow in Fractures**

Multiphase flow in fractures is still unclear. It is important to use an accurate relative permeability curve in reservoir simulators to accurately predict oil recovery. Shad and Gates (2010) derived a simple flow model to determine analytic functions for relative permeability curves. They found that the relative permeability is a function of fluid
saturation, fluid properties and flow pattern within the fracture itself. The effect of lubrication is emphasized as a factor leading to exceeding unity of a relative permeability of a certain phase. They also gathered much of the literature on multiphase flow relative permeability analysis and constructed a graph comparing several methods (Fourar and Bories 1995; Persoff and Pruess 1995; E. Rangel-German 1999; Chen, Horne et al. 2004) (see Figure 5).

![Figure 5: Comparison of gas-liquid relative permeability models in fractures (Shad and Gates 2010)](image)

From Figure 5 above it is clear that there is significant disagreement on the physics of multiphase flow in fractured media. Several analytical models have been used to calculate the relative permeability curves but at this point it is impossible to identify one that will successfully describe every flow regime.
**Fluid Transfer from Fracture to Matrix**

Chakravarthy *et al.* (2004) used X-ray CT to investigate CO$_2$ and WAG injection in fractured reservoirs. They found that injection rates played an important role in the recovery process in the presence of fractures. At higher injection rates they observed faster CO$_2$ breakthrough and higher oil bypass than at low injection rates. This may be attributed to diffusion (A. Jamili 2010). Chakravarthy *et al.* (2004) used gel to obtain mobility control and discovered that their recovery rates were improved.

Babadagli (2000) studied steam flooding in naturally fractured reservoirs and also found that the injection rate plays a very important role in the transfer of heat from the steam into the matrix oil. The higher the rate the lower the heat transfer. Through a series of core floods, they evaluated the critical rate concept for different horizontal fractures and steam qualities. This concept is analogous to that of Chakravarthy in the sense that there is a transport phenomenon in the form of heat or mass, from the fracture to the matrix. Injection rate plays an important role in this transport phenomenon.

**FOAM FLOW IN FRACTURED RESERVOIRS**

**Effect of Fracture Permeability**

Yan *et al.* (2006) found that foam flow can be diverted from thicker to thinner fractures because of an increase in apparent viscosity as gas fractional flow increases in thicker fractures. They were able to confirm their observations experimentally and by modeling.
Knowledge of fracture thicknesses can lead to a better understanding of production reservoir characteristics. Attempts are being made to quantify these in actual reservoirs (Narr 1996). The significance to this study lies on a better understanding of fractured reservoirs to improve experimental work in the laboratory.

Graue (2002) studied the impact of fracture permeability on oil recovery from moderately-water-wet chalk. An oil saturated chalk block under Nuclear Tracer Imaging was used to study fluid saturations while water flooding. Their observations led to the conclusion that spontaneous imbibition was the dominant oil recovery mechanism, but viscous oil recovery significantly improved oil production. Fracture permeability was decreased by increasing confinement pressure, but the process was not reversible. Oil recovery was a strong function of permeability ratio between the fractured system and the matrix, aggravating as the fracture permeability increased.

Haugen (2010) also observed that the best rate of recovery results at the lowest fracture/matrix permeability ratio. Fractured oil-wet low permeability limestone was studied by Haugen in 2010, who created a base case by injecting surfactant solution and gas individually. This method recovered mostly oil from the fractures (10% OOIP). Oil recovery was significantly improved (up to 80% OOIP) by injecting stable pre-generated foam. The injected surfactant solution entered the fractures, which in the presence of stable foam diverted fluid into the matrix and released the oil. However, simultaneous injection of gas and surfactant solution to generate foam in-situ was not as promising. In this case, foam was not able to propagate, thus no improvement in recovery was perceived.
Effect of Fracture Surface Roughness

Kovscek et al. (1995) were the first to study foam flow through a transparent replica of a natural rough-walled rock fracture. Their experimental setup provided a means of flow visualization, adjustment of fracture aperture, and measurement of pressure drop. Their design consisted of a transparent epoxy fracture replica mounted horizontally between two pieces of clear Plexiglas. Bolts on each of the four corners allowed control of the fracture aperture. Different injection schemes were tested by varying foam quality and total rate. By considering bubble morphology and its effect on flow resistance, they observed that low quality foam (below 0.91) is more mobile than high quality foam (above 0.91) because of the availability of liquid to lubricate the rough fracture surfaces. Both types of foam effectively reduced gas mobility in fractures. Dispersing gas as foam in fractures increased gas flow resistance 100-540 times.

Foam apparent viscosity in Fractures

Yan, W., Hirasaki, G. et al. (2006) studied the apparent viscosity and found that viscosity is the sum of contributions from the liquid between bubbles and the bubble resistance to deformation as they pass through the fracture. They found that the apparent viscosity increases for thicker fractures, indicating that foam can divert flow towards the thinner fractures. Yan et al. (2006) found that the number of lamellae per unit length is the main factor affecting foam viscosity in smooth uniform fractures. The higher the gas fractional flow and ratios of aperture thickness to bubble size, the larger the apparent viscosity.
**Enhanced Oil Recovery Foam**

**Recovery Mechanisms during Low-Tension Gas Flooding**

Low-Tension Gas Flooding employs two main components: gas and surfactant. Each plays a very important role in the process. Gas is employed mainly as a way of providing mobility control in the form of foam. Surfactant solution (first property) mixes with the gas to create foam which reduces liquid relative permeability. (This process was described in Foam Principles in this chapter.) In addition, gas has a finite miscibility with the oil. Diffusion of gas into the oil makes it swell out of the matrix. Surfactant solution (second property) lowers the interfacial tension between the oil and brine to produce oil by emulsification and gravity drainage. Also, the surfactant solution (third property) may alter the wettability of the rock, which promotes additional imbibition. Figure 6 below summarizes the surfactant functions cycle.

![Figure 6. Surfactant Functions Cycle](image)
**Diffusion**

Although diffusion is not a predominant mechanism of mass-transfer between the fracture and the matrix during the entire mass-transfer process, its importance lies at the beginning when other mechanisms like wettability alteration or interfacial tension have not been activated. Diffusion of surfactant into the matrix will trigger the other mechanisms. For gases in the absence of surfactant, the following studies found that diffusion plays an important role.

Morel et al. (1993) and Le Romancer et al. (1994) performed oil recovery experiments on fractured one-dimensional chalk cores involving nitrogen and carbon dioxide flow in a fracture. Based on these experiments, Jamili et al. (2010) developed a model which describes the mass transfer in one dimension between gas flowing in a fracture and a horizontal matrix block. They found that diffusion is the main mass-transfer mechanism between matrix and fracture during nitrogen injection, while diffusion and convection were both important during carbon dioxide injection.

Fjelde et al. (2008) studied the effects of a CO$_2$–foaming agent on the rate of oil production in fractured chalk one-dimensional cores. The pressure decay method was used to measure the CO$_2$ bulk diffusion coefficients for synthetic seawater, stock tank oil and aqueous foaming solution. They found that the oil produced may be attributed to CO$_2$ gas and the CO$_2$–foaming agent solution initially diffusing from the fractures into the matrix, slowly altering the rock wettability and reducing CO$_2$–oil and CO$_2$–aqueous foaming agent interfacial tensions, enabling capillary imbibition into the matrix. Similar results were reported by Hirasaki et al. (2004), Ayirala et al. (2006), and Zuta et al. (2009).
Wettability alteration

Wettability alteration in fractured carbonate reservoirs is an important oil recovery mechanism. For water-wet carbonates, water flooding is sufficient to recover large quantities of oil. However, water flooding is not efficient for oil-wet carbonates especially when the reservoir exhibits high permeability fractures and low permeability matrix. Since the oil-wet carbonate surfaces are positively charged, cationic surfactants have been known to change the wettability to mixed or water–wet significantly improving oil recovery. Austad et al. (1997) did a series of experiments and proved that the cationic surfactant dodecyltrimethylammonium bromide (DATB). In his experiments, he was able to obtain spontaneous imbibition of water to nearly oil-wet chalk. He noticed that the flow was countercurrent which suggested the chalk used turned water-wet. Seethepalli et al. (2004) identified a series of anionic surfactants, such as alkyl aryl ethoxylated sulphonate and proposylated sulfates ranging from 3 to 8 PO groups, which were able to alter the wettability of the calcite surface to intermediate-/water-wet condition.

Natural Water Imbibition at High Interfacial Tension

Enhancing water imbibition by capillarity is accomplished by chemical wettability alteration. Wettability modifiers such as surfactants have been widely studied (Standnes and Austad 2000; A. Seethepalli 2004; Ayirala, Vijapurapu et al. 2006; Leslie Zhang, Liu et al. 2006; M.T. Tweheyo 2006; Chinedu Agbalaka, Abhijit Y. Dandekar et al. 2008). In carbonate reservoirs, the rock surface is positively charged and thus cationic surfactants exhibit a stronger wettability alteration (Standnes and Austad 2000).
However, other studies have proven similar or better alteration by using anionic surfactants (Anita Seethepalli 2004; George Hirasaki 2004; Leslie Zhang, Liu et al. 2006). In addition, non-ionic surfactants result in higher capillarity driven natural imbibition because of the higher oil/water interfacial tension.

**Natural Water Imbibition at Low Interfacial Tension**

Zhang et al. (2008) evaluated water imbibition induced by emulsification at low IFT by submerging oil-saturated plates into surfactant solutions to form Winsor Type I, III, or II microemulsions. They found that formation of microemulsion strongly promotes water imbibition. The rate was highest for Winsor Type II microemulsion because of the water loading into the matrix oil by formation of a water-in-oil emulsion. Significant water loading may swell the oil and expand it out of the matrix. Winsor Type III microemulsion suppressed capillary pressure and slowly recovered oil by emulsification. A similar but slower mechanism was observed for Winsor Type II microemulsion.

Babadagli (2001) performed experiments on sandstone cores with different boundary conditions in order to isolate the effects of gravity and capillary forces on oil recovery. In one case, an oil-saturated core with an open top face (upward flow is achieved by both capillary and gravity forces) and one with a closed top face (upward flow against gravity is only achieved by capillary forces) were submerged in a surfactant solution. The surfactant lowered the IFT between the crude oil and the aqueous solution. As the capillary pressure is reduced due to the lowered IFT, the gravity forces dominate. This relationship can be observed by the inverse Bond number as shown in Equation 3 below, where if \( N_B^{-1} > 5 \), imbibition is driven by capillary forces (countercurrent flow), and if \( N_B^{-1} \ll 1 \) imbibition is driven by gravity forces (vertical cocurrent flow) (Austad
Since the closed top face had the gravity forces ‘disabled’, its oil recovery was less than that of the open top face. The oil in the disabled-gravity case could have been recovered by oil emulsification (Jieyuan Zhang 2008).

\[
N_B^{-1} = \frac{c}{\sigma} \frac{\sqrt{\phi/k}}{\Delta \rho gh}
\]

Equation 3. Inverse Bond Number

**CHAPTER SUMMARY**

This chapter presented a review of the most relevant literature available describing foam principles, applications, its use in porous media and in fractured reservoirs. Emphasis was made on the literature available on low-tension gas flooding. Although the process is fairly new and literature is scarcely available, this chapter presented a review of what is available.
Chapter 3: Development of a Chemical Formulation for Low-Tension Gas Flooding

INTRODUCTION

This section will describe the fluids used in the core floods in the next chapters. Brines and surfactants were used in the core floods on Chapter 4 and brine, crude oil and different surfactants were used in the core floods on Chapter 5. Various tests were performed to identify the foaming capacity and interfacial tension reduction and these are described below.

EXPERIMENTAL DESCRIPTION

Materials

Brines

Three types of synthetic brines were used. The formation brine has a TDS of about 117,000 ppm, while the sea water has a TDS of about 39,000 ppm. A softened version of sea water without any calcium or magnesium ions, substituted with sodium chloride to maintain the same salinity. Table 1 below gives a detailed chemical analysis.
Table 1. Chemicals analysis of brines used

<table>
<thead>
<tr>
<th></th>
<th>Sea Water</th>
<th>Soft Sea Water</th>
<th>Formation Brine</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>IW</td>
<td>SIW</td>
<td>FB</td>
</tr>
<tr>
<td>TDS ppm</td>
<td>38618</td>
<td>38618</td>
<td>117164</td>
</tr>
<tr>
<td>Na⁺ mg/L</td>
<td>12188.87</td>
<td>14,010.78</td>
<td>41473</td>
</tr>
<tr>
<td>Ca²⁺ mg/L</td>
<td>480</td>
<td>0</td>
<td>3880</td>
</tr>
<tr>
<td>Mg²⁺ mg/L</td>
<td>1341.91</td>
<td>0</td>
<td>145</td>
</tr>
<tr>
<td>Fe mg/L</td>
<td>78</td>
<td>0</td>
<td>78</td>
</tr>
<tr>
<td>Cl⁻ mg/L</td>
<td>21200</td>
<td>23,021.91</td>
<td>70971</td>
</tr>
<tr>
<td>SO₄²⁻ mg/L</td>
<td>3250</td>
<td>3,250.00</td>
<td>500</td>
</tr>
<tr>
<td>CO₃⁻ mg/L</td>
<td>24</td>
<td>0</td>
<td>--</td>
</tr>
<tr>
<td>HCO₃⁻ mg/L</td>
<td>54.9</td>
<td>0</td>
<td>117</td>
</tr>
<tr>
<td>Density (g/cc)</td>
<td>1.03</td>
<td>1.03</td>
<td>1.08</td>
</tr>
<tr>
<td>pH</td>
<td>8.34</td>
<td>--</td>
<td>6.9</td>
</tr>
</tbody>
</table>

**Crude Oil**

The crude oil was provided by our sponsoring company and was used as given. It has a viscosity of 6.452 cp and a density of 0.718 g/cm³ at reservoir conditions.

**Surfactants**

A meticulous surfactant screening was conducted to identify a surfactant formulation that could produce enough foam and lower the interfacial tension between oil and water. Anionic surfactants and non-ionic surfactants were studied. Table 2 below shows the foaming surfactants tested for this screening. Table 3 shows the surfactant formulation used for the low tension experiments. This formulation was identified by Dr. Pope’s group.
Table 2. Surfactants tested during the screening. Company agreements prohibit disclosure of some surfactant details.

<table>
<thead>
<tr>
<th>Trade Name</th>
<th>Type</th>
<th>Hydrophobe</th>
<th>Lot #</th>
<th>Activity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Petrostep S2</td>
<td>IOS</td>
<td>C15-18</td>
<td>16920-113005-1.15</td>
<td>21.25%</td>
</tr>
<tr>
<td>Petrostep S-3A</td>
<td>IOS</td>
<td>C20-24</td>
<td>18239-091907</td>
<td>60.72%</td>
</tr>
<tr>
<td>Petrostep C2</td>
<td>AOS</td>
<td>C12-C16</td>
<td>3298-88</td>
<td>41.63%</td>
</tr>
<tr>
<td>Petrostep C3</td>
<td>AOS</td>
<td>C16-18</td>
<td>3153-026</td>
<td>10.90%</td>
</tr>
<tr>
<td>Petrostep C4</td>
<td>AOS</td>
<td>C20+</td>
<td>3153-027</td>
<td>10.43%</td>
</tr>
<tr>
<td>Enordet 0342</td>
<td>IOS</td>
<td>C19-23</td>
<td>27130-36A</td>
<td>18.50%</td>
</tr>
<tr>
<td>Enordet 0352</td>
<td>IOS</td>
<td>C24-28</td>
<td>26956-36</td>
<td>24.60%</td>
</tr>
<tr>
<td>CS1050A</td>
<td>non-ionic</td>
<td>--</td>
<td>--</td>
<td>100.00%</td>
</tr>
<tr>
<td>CS1050B</td>
<td>non-ionic</td>
<td>--</td>
<td>--</td>
<td>100.00%</td>
</tr>
<tr>
<td>Neodol</td>
<td>Sulfate</td>
<td>C12-15(EO)12</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Petrostep ES-65A</td>
<td>Sulfate</td>
<td>C12-15(EO)5</td>
<td>--</td>
<td>--</td>
</tr>
</tbody>
</table>

Table 3. Surfactant tested for low tension properties

<table>
<thead>
<tr>
<th>Surfactant</th>
<th>C_{19-23}(0.5%) and C_{24}(EO)<em>{56}(PO)</em>{25} Carboxylate (0.5%)</th>
</tr>
</thead>
</table>

Experimental Procedure

Aqueous Stability Test

Aqueous stability refers to a surfactant that dissolves in brine and forms a clear solution. A surfactant must be chemically stable in the presence of salt ions to pass this test. When a surfactant does not pass aqueous stability, it precipitates or separates from solution. This separation may cause problems during the core flood stage by plugging in the pores, or even worse in the field, by increasing its absorption to the rock and increasing production costs.
Figure 7 below shows the criteria used to determine results of an aqueous stability test. A clear solution shows that a surfactant can tolerate the temperature and salinity tested. A precipitation is usually an early indication of separation. The precipitation may precede a separation, which depends on the density of the component coming out of solution.

![Figure 7. Criteria used to determine the results of an aqueous stability test](image)

**Foam Stability**

Foam stability tests are a simple and quick indication of the foaming capabilities of a surfactant formulation. In a pipette, aqueous solution consisting of surfactant and brine are mixed. Equal amounts of oil are added if the effect of oil wants to be studied. The pipettes are sealed to prevent evaporation during heating to reservoir temperature. After temperature equilibration in the oven, the pipettes are shaken with equal intensity resulting in the formation of a foam column. All pipettes should be shaken with the same
intensity to improve reproducibility of the test. Finally, the foam collapse is measured as a function of time. The surfactant with the lowest rate of destruction shows the best foaming capability. This test is a quick indication of foam stability, but it should not be the only criteria for surfactant selection. Foam strength strongly depends on its destruction and generation rate in porous media, where factors such as, capillary pressure, absorption and dispersion, are taken into account.

**Phase Behavior**

The phase behavior of a microemulsion is complex and depends on multiple factors: surfactant concentration and type, cosurfactant concentration and type, hydrocarbon type, brine salinity, temperature and pressure. The only method of measuring phase behavior is experimentally, there is so far not a single universal equation of state to represent even simple microemulsion.

The effect of salinity on phase behavior of a microemulsion is widely studied because increasing salinity of the aqueous phase significantly decreases the solubility of an ionic surfactant. As the electrolytes increase, the surfactant is driven out of solution until it precipitates. Precipitation reduces the working effect of the surfactant as well as poses plugging issues in laboratory studies.

For an ideal system, the multiphase behavior divides into three basic classes. At low brine salinity, oil-in-water (o/w) phase and excess oil appears (Type I). Since the O/W phase is denser than the oil itself, it appears at the bottom and it is called a lower phase microemulsion. At high brine salinity, water-in-oil (w/o) phase and excess water appears (Type II). Since the W/O phase is lighter than water itself, it appears at the top and it is called an upper phase microemulsion. At intermediate salinity, a three-phase
region exists; microemulsion, water and oil exist in equilibrium. Since the microemulsion is lighter than water but heavier than oil it lays at the middle and it is thus called middle-phase microemulsion.

**EXPERIMENTAL RESULTS**

**Foaming Surfactant**

**Aqueous Stability**

Surfactants were tested as received with no adjustments. Only Petrostep C2 an AOS with a hydrophobe C_{12-16} was able to tolerate 95°C at both synthetic sea water (TDS 38,000 ppm) and synthetic formation brine (TDS 117,000 ppm).

To broaden the number of foam candidates, a C_{12-15} (EO)_3-sulfate was introduced as a co-surfactant to increase the solubility of higher hydrophobe length surfactants. Targeting larger molecule surfactants is crucial for IFT reduction purposes, but not for foaming. Since our formula should ideally have both properties, targeting larger molecule surfactants seemed correct. The C_{12-15} (EO)_3-sulfate was tested at 1% along with the Enordet 0342, an IOS C_{20-24} also at 1%. Both hard and soft sea water were scanned. The case of hard synthetic sea water showed only solubility up to TDS 17100 ppm for 30 minutes at room temperature and precipitated immediately at 120°C. For the case of soft sea water, the solution was able to remain stable for more than 48 hours up to a TDS 32300 ppm. The high concentrations of calcium and magnesium ions decrease the salinity tolerance. Table 4 summarizes the results for different dilutions of both hard and soft sea water.

Table 4. Salinity Scan Results (C=Clear, P=Precipitate)
Two mechanisms aid solubilization of a heavy surfactant: 1) lower hydrophobe length, 2) higher ethylene oxide (EO) groups. In order to solubilize more surfactants, a co-surfactant with 12 EO groups was used. That increases the number of EO groups by 9 as compared to the previous co-surfactant. A C_{12-15}(EO)_{12-15} sulfate was introduced to increase the solubility of longer carbon chain surfactants. The results were disappointing because of precipitation of the surfactant in the presence of both sea water and formation brine. The pH was measured and found to be very basic, around 10-11. This fact suggested that the calcium and magnesium ions may have hydrolyzed and thus created the observed separation. To prevent hydrolysis of hardness ions, further tests were done at neutral pH. Results at neutral pH show that the C_{12-15}(EO)_{12-15} sulfate was stable at 120 °C for more than 12 hours.

Other surfactants were mixed with C_{12-15}(EO)_{12-15} sulfate to improve their stability. Again, Enordet 0342, an IOS C_{20-24} at 1%, mixed with C_{12-15}(EO)_{12-15} sulfate at 1%, were tested at sea water. However, the solution showed a destabilizing trend with time as salinity increased. After 24 hours at 120°C the solution was stable only up to TDS 38,000 ppm. In order to improve the stability, the hardness ions were removed and the solution remained clear for more than 48 hours at reservoir conditions. This result, suggest that
hardness ions affect in great extent solubility of potential foaming surfactant. Table 5 shows the detailed results for all these tests.

Table 5. Salinity Scan Results (C=Clear, P=Precipitate)

<table>
<thead>
<tr>
<th>Salinity (ppm):</th>
<th>Synthetic Sea Water (SSW)</th>
<th>Softened Synthetic Sea Water (SSSW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Time (hrs)</td>
<td>Temp (°C)</td>
<td>Time (hrs)</td>
</tr>
<tr>
<td>0.5</td>
<td>30</td>
<td>0.5</td>
</tr>
<tr>
<td>3</td>
<td>120</td>
<td>3</td>
</tr>
<tr>
<td>6</td>
<td>120</td>
<td>6</td>
</tr>
<tr>
<td>12</td>
<td>120</td>
<td>12</td>
</tr>
<tr>
<td>24</td>
<td>120</td>
<td>24</td>
</tr>
</tbody>
</table>

To broaden the available surfactants, another co-surfactant was tested, C₇-₈(EO)₅-sulfate. Surfactants showed in Table 2 were mixed at 1% with this new co-surfactant also at 1%. To improve efficiency only two salinities were targeted, synthetic sea water and synthetic formation brine. Results show (see Table 6) that the IOS C₁₅-₁₈, AOS C₁₂-₁₆ and a non-ionic surfactant were able to solubilize at 95°C and up to TDS 117,000 ppm.

Table 6. Main surfactant at 1% mixed with C₇-₈(EO)₅-sulfate at 1%. Tested at only Synthetic Sea Water (SSW) and Synthetic Formation Brine (SFB) (C=Clear, P=Precipitate).
**Foam Stability**

Preliminary results using the foam stability method show IOS C\(_{15-18}\) and a non-ionic surfactant combined independently at 1% / 1% with C\(_{7-8}\)(EO)\(_5\)-sulfate. Akal oil reduces the foam column height by half compared to the test done on the surfactant solution with no oil. AOS C\(_{12-16}\) with C\(_{7-8}\)(EO)\(_5\)-sulfate shows a decrease of only 15% in the foam column height in the presence of Akal oil compared to the test done on the surfactant itself. Thus, so far a solution of AOS C\(_{12-16}\) with C\(_{7-8}\)(EO)\(_5\)-sulfate creates the strongest foam in contact with Akal oil. Figure 8, Figure 9, and Figure 10 show the foam column heights as a function of time for three surfactant solutions.

<table>
<thead>
<tr>
<th>Trade Name</th>
<th>Type</th>
<th>Hydrophobe</th>
<th><strong>20°C</strong></th>
<th><strong>95°C (12 hrs)</strong></th>
<th><strong>95°C (24 hrs)</strong></th>
<th><strong>95°C (48 hrs)</strong></th>
<th><strong>95°C (72 hrs)</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Petrostep S2</td>
<td>IOS</td>
<td>C(_{15-18})</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
</tr>
<tr>
<td>Petrostep S-3A</td>
<td>IOS</td>
<td>C(_{19-23})</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
</tr>
<tr>
<td>Enordet 0342</td>
<td>IOS</td>
<td>C(_{20-24})</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
</tr>
<tr>
<td>Enordet 0352</td>
<td>IOS</td>
<td>C(_{24-28})</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
</tr>
<tr>
<td>Petrostep G2</td>
<td>AOS</td>
<td>C(_{12-16})</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
</tr>
<tr>
<td>Petrostep C4</td>
<td>AOS</td>
<td>C(_{20+})</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
</tr>
<tr>
<td>CS1050A</td>
<td>nonionic</td>
<td>--</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
</tr>
<tr>
<td>CS1050B</td>
<td>nonionic</td>
<td>--</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>P</td>
</tr>
</tbody>
</table>
Figure 8. Graphs showing the foam column inside a pipette as a function of time. This test was performed at both 20 °C and 95 °C using IOS C_{15-18} and C_{7-8}(EO)_{5}-sulfate for the first two columns, and a ratio 1:1 of surfactant solution and oil for the last two columns in each time period.

Figure 9. Graphs showing the foam column inside a pipette as a function of time. This test was performed at both 20 °C and 95 °C using AOS C_{12-16} and C_{7-8} (EO)_{5} sulfate for the first two columns, and a ratio 1:1 of surfactant solution and oil for the last two columns in each time period.
Figure 10. Graphs showing the foam column inside a pipette as a function of time. This test was performed at both 20 °C and 95 °C using a non-ionic surfactant and C_{7-8} (EO)_5 sulfate for the first two columns, and a ratio 1:1 of surfactant solution and oil for the last two columns in each time period.

Low Tension Surfactant

Phase Behavior

The low tension surfactant was identified by Dr. Pope’s group. Its use combined with mobility control using gas is a promising injection technique that will be evaluated in Chapter 5. The graph shown in Figure 11 shows the solubilization ratio as a function of salinity. The optimum salinity is identified at around 38,000 ppm which is also the injection water salinity for the reservoir sponsoring the project. Thus, the convenience of having optimum salinity at the injection water eliminates the need of using preflushes.
Figure 11. Solubilization Ratio as a function of Salinity for AKL-412 (Lu, Solairaj et al. 2011).

Foam Stability on Low-Tension Surfactant

In addition to its low tension properties, AKL-412 was also tested for its foaming capacity. If the foaming capacity proved to be effective, then the surfactant would go to the next phase by itself. If the foaming capacity was not satisfactory, then a blend would be done between AKL-412 and a foamer. This section presents the results done using the foam stability test described before in this chapter.

Since the reproducibility of a foaming surfactant depends on a lot of variables. The best surfactant in terms of foam capacity was used as a baseline to compare the new low tension formula. Figure 12 below shows the foam level as a function of time for both surfactant formulations.
CHAPTER SUMMARY

This chapter provided the necessary materials to perform the core floods described in the next chapter. A systematic analysis was done where surfactant formulations had to pass a series of tests. The first test was the aqueous stability test at reservoir temperature and salinity. If surfactants were able to stay clear for more than 48 hours at reservoir conditions, they were eligible for the next test. The foam stability test followed the aqueous stability test. In the foaming test, surfactants were placed in a pipette and shaken equally. Their foam collapse rate was measured. The surfactant formulation with the lowest rate was then considered for core flood experiments.
Chapter 4: Foam in Fractures in the Absence of Oil

INTRODUCTION

Highly fractured and vuggy oil reservoirs represent a challenge for enhanced oil recovery (EOR) methods. The fractured networks using flow paths several orders of magnitude greater than the rock matrix. Common enhanced oil recovery methods including low viscosity liquids or gases may channel through the high permeability fracture networks causing poor sweep efficiency and early breakthrough. As a result, a considerable amount of oil is left in the bypassed matrix and isolated vugs (J.L. Sánchez 2005). Developing a suitable method of recovery is the motivation for this research. Common methods of mobility control such as polymers, which viscosify the injected liquid, may not be suitable or economically attractive for all reservoir conditions. Specifically, polymers have limited applications in low permeability, vuggy and fractured carbonate rocks. Low molecular weight polymers perform better in these reservoirs, but their cost increases as their molecular weight decreases, so eventually they become uneconomical. Some polymers may mechanically degrade because of the high shear stress in the injection line, or near the wellbore regions of low permeability reservoirs. In addition, high salinity and a severe salinity gradient between injection water and formation brine requires an increase in the amount of polymer to control mobility. This increased quantity of polymer affects the quality and the ability to control viscosity.

Gas can be a potential substitute for polymer as an agent of mobility control for EOR processes. When an aqueous chemical solution flows through a path occupied by gas, its mobility is reduced. Simultaneous flow of two phases results in the mobility reduction of each phase. Water-alternating-gas (WAG) injection and simultaneous water and gas injection (SWAG) are two processes in which mobility control is achieved due to
the simultaneous flow of the two phases. However, when the chemical slug contains surfactant, foam may be generated. The generation of foam films stabilized by surfactant is referred to as foam generation. *Snap-off, lamella-division, and leave-behind* foam generation mechanisms have been well documented (T.C. Ransohoff 1988; Quoc P. Nguyen 2000). The surface tension on individual lamellae, as well as the drag force as foam slides through pore walls causes it to resist movement through the pores. This resistance results in an increased apparent viscosity and gas saturation. The higher gas saturation results in a lower liquid saturation and lower liquid relative permeability.

When combined with traditional chemical EOR methods, such as interfacial tension reduction or wettability alteration, foam may provide an effective means of mobility control. Capillary forces in lower permeability zones debilitate foam by decreasing its liquid saturation. Thus, because of its inherent properties, foam is stronger in higher permeability zones. The viscous pressure gradient generated in these higher permeability zones will divert the chemical solutions that create the microemulsions at ultra-low interfacial tension (IFT) to the lower permeability zones. This process is termed Alkaline-Surfactant-Gas (ASG) and is relatively new. Some work has been done on low to medium permeability sandstone and dolomite cores, which indicates the applicability of ASG in a wide range of reservoirs (Mayank Srivastava 2009; Mayank Srivastava 2010) However, little experimentation in fractured reservoirs has been done. Therefore, this chapter will address these reservoirs by studying the feasibility of foam propagated inside a fracture and its ability to divert chemical treatments into the matrix.

**EXPERIMENTAL DESCRIPTION**

In an effort to effectively study foam in a highly heterogeneous fractured reservoir, common regions and geometries were identified within the reservoir: (1) a tight...
fracture with low vug density (fracture/matrix permeability ratio of 5-10), (2) a tight fracture with medium vug density (fracture/matrix permeability ratio of 50-200) and (3) a wide fracture of high density overlapping vugs (fracture/matrix permeability ratio of $10^3$-$10^4$). Each region and geometry would be individually and independently tested. In terms of geometry, a single fractured core was used as an example of the tightest possible case. The number of vugs in the core was increased to simulate a thicker fracture. Each region is studied by varying injection rates to take into account that rates near the wellbore are higher than rates far from the wellbore. Initial conditions were also varied to understand how foam behaves in dry and wet fractures. The study of foam propagation in the matrix is not necessary since it has been studied before (Srivastava, Zhang et al. 2009). Finally, in an effort to broaden the application of this technique to fields with injectivity issues, two injection strategies are being studied; co-injection and alternating slugs of surfactant and gas (SAG).

**Materials**

**Surfactants**

One surfactant formulation, an (C_{15-18} IOS) at 1% was used along with C_{7-8}(EO)_{5-}

sulfate at 1% which helped its aqueous stability. The high surfactant concentration was used to avoid adsorption problems in our experiments. The selection of these surfactants was based on results from aqueous stability and foam stability tests described in Chapter 3.
**Brines**

The synthetic brines used were described in Chapter 3. The formation brine represents the actual brine in the reservoir. It has TDS of 117,000 ppm, while the injection water which represents sea water has a TDS of 38,000 ppm.

**Cores**

Indiana limestone was used in the core floods. Its homogeneous quality and tight matrix is ideal for our current investigation. The matrix shows an average permeability of 2md. The cores were drilled one foot long and 1.5” diameter. It was then cut in half through its length. Vugs were drilled using a half an inch drill to a depth of 5 mm. After it was prepared the vugs were filled with sand of approximately 700µm. The two slabs were put back together and the sand was maintained consolidated using DI water. The whole core was wrapped in thermal shrinking plastic tube to keep the two slabs together and placed in the oven to dry any excess water in it. To investigate different reservoir geometries and permeability ratios the number of vugs was increased as shown in Figure 13 below. After the core was dried, it was placed in the core holder where porosity and permeability were determined before conducting the experiment.
**Experimental setup**

Figure 14 shows the experimental setup used for conducting the core floods. A nitrogen cylinder provided by Matheson Gas was used. A Brooks mass flow controller was digitally controlled to regulate the amount of gas flowing into the core. A Mity Mite RedQ backpressure regulator prevented backflow into the mass flow controller. Temco stainless steel accumulators containing a piston separated the injected distilled water and the formation brine or surfactant solution. Distilled water was injected to avoid corrosion or any scratched on the equipment walls caused by salts. A dual piston Quizix pump from Ametek Chandler engineering was used to precisely control the rate of injection. The stainless steel core holder was provided by Phoenix Instruments.
Experimental Procedures

Core floods

Foam core flood experiments were conducted after the optimal chemical formulation was identified through the tests described above. Porosity and permeability were determined at room temperature using formation brine. Table 7 below shows the core floods cited in this work along with their geometry, injection scheme and permeability. Cores were divided into three regions where section 1 is the inlet region, section 2 is the middle section and section 3 is the outlet region.
Table 7. Core Flood Schedule and Permeabilities

<table>
<thead>
<tr>
<th>Experiment ID</th>
<th>Geometry</th>
<th>Injection Scheme</th>
<th>Permeability (mD)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>X-core</td>
</tr>
<tr>
<td>In-1-3</td>
<td>Low vug density</td>
<td>Coinjection</td>
<td>11.8</td>
</tr>
<tr>
<td>In-1-7</td>
<td>Medium vug density</td>
<td>Coinjection</td>
<td>132.0</td>
</tr>
<tr>
<td>In-1-6</td>
<td>High overlapping vug density</td>
<td>Coinjection</td>
<td>7639</td>
</tr>
<tr>
<td>In-1-10</td>
<td>High overlapping vug density</td>
<td>Coinjection</td>
<td>7666</td>
</tr>
<tr>
<td>In-1-13</td>
<td>High overlapping vug density</td>
<td>SAG</td>
<td>824.7</td>
</tr>
<tr>
<td>In-2-1</td>
<td>Medium vug density</td>
<td>SAG</td>
<td>183.4</td>
</tr>
</tbody>
</table>

**In-1-3 Low vug density**

The overall brine permeability along the low vug density core increased with the fracture compared to the matrix alone. The low vug density core flood showed a low fracture/matrix permeability ratio. Gas and surfactant solution were co-injected at 50% foam quality at outlet conditions (760 psi and 90°C) for 1.5 ft/day total superficial velocity.

**In-1-7 Medium vug density**

The overall brine permeability started showing the effects of the vugs. The effect of foam quality at injection was targeted. Foam quality was varied from 75% (1.0 ft/day), 50% (1.5 ft/day) down to 25% (1.5 ft/day) at outlet conditions.

**In-1-6 High overlapping vug density**

Fracture/matrix permeability ratio is now on the order of $10^3$. Section 1 shows lower permeability than the other regions due to the space of matrix left from the inlet to the first vug. This case followed exactly the same procedure as that of In-1-7.
In-1-10 High overlapping vug density

Permeability varied in this core from region to region because of the sand variation. However, overall permeability is still comparable to its counterpart In-1-6. The objective of this core flood was to analyze the effect of foam propagation in a dry fracture. Nitrogen was injected at 0.75 ft/day after brine injection bringing down water saturation to 79.2%, the volume of the vugs was calculated to 16.8%, meaning only 4% of the water produced came from the matrix. Co-injection of surfactant solution and nitrogen gas followed to produce a foam quality of 75% at outlet conditions.

In-1-13 High overlapping vug density

Permeability varied in section 3 because of a misaligned vug. However, the core is still useful to study the effect of surfactant alternating gas injection. In this case, after permeability measurement using formation brine, surfactant solution was injected at 0.75 ft/day alternating with gas at 0.75 ft/day.

In-2-1 Medium vug density

Permeability in this core was relatively uniform from region to region. The same procedure was followed here as in In-1-13. The purpose was to study the effect of a decreased fracture/matrix permeability ratio.

RESULTS AND DISCUSSION

Fracture thickness variation and its effect on trapped gas

Foam is a strong function of the trapped gas. As described earlier, there are three regimes of absolute gas mobility (Quoc P. Nguyen 2000). For the lower permeability
range, gas gets trapped in the pores blocking the path of foam. Since the rate is kept constant the local velocity increases in the contiguous flowing spaces. Velocity increases shear rate which increases foam strength. For a higher permeability range, including fractures, trapped gas is not an issue because of the high conductivity channels that will not trap any gas.

Figure 15 shows the case with medium vug density, where the overall absolute permeability is low. As expected, when the same gas and liquid injection rates were repeated at a later time, the MRF did not return to its original value. Since Indiana limestone contains none to low amounts of clays or organic matter (Churcher 1991) that could possibly decrease permeability by particle migration, one attributable cause may be trapped gas in the matrix. The relative permeability of foamed gas is a function of only the flowing foam saturation, where the stationary gas has a relative permeability of zero.
The relative permeability of the aqueous phase is only a function of the aqueous phase saturation (Kovscek, Patzek et al. 1995). This scenario could not be confirmed with saturation profiles based on mass balance because of the high compressibility of nitrogen which caused fluid exchange with the large-volume measuring chambers in pressure transducers.

Although the overall absolute permeability for the medium vug density case increased, the fracture conductivity was not enough to suppress the pressure drop caused by foam in matrix. Therefore, the entire system behaved as a matrix-dominated system, and foam in the fractures could not be decoupled satisfactorily from matrix foam. In a macroscopic overall view, a system with tight fractures and matrix behaves the same way as a system with only matrix. Please note that this does not imply that foam in a tight fracture behaves the same was as foam in matrix. Additional specific studies are needed on systems that satisfactorily decouple pressure drop from foam in a matrix and from foam in a fracture.

The high vug density case (see Figure 16) confirms our hypothesis that trapped gas affects foam strength in a matrix-dominated core by showing a similar core, but with an increase in the fracture permeability. The permeability in this high vug density case is much higher than the medium vug density case (tight fracture case). Therefore, when the same gas and liquid rates were repeated at a later time, the MRF returned to its original value, confirming the absence of trapped gas, and making this system a fracture-dominated system.
Injected gas will not get trapped in the high conductivity channels created by the wide tortuous fracture created in this case (Figure 16). The system is fracture-dominated because of the absence of trapped gas. This observation is confirmed by the mobility reduction factor returning to its original value. We may conclude that the conductivity of a wide fracture is significant to the point that it makes the entire system fracture-dominated and any pressure drop observed may be attributed to foam created in the fracture. Else, if the pressure drop observed is attributed to foam in the matrix, the tight matrix would trap gas and will not be able to return the MRF to its original value. This observation is useful for modeling foam in a fracture by using the local equilibrium criteria (Q. Chen 2008).
Figure 17. (In-1-3) Mobility Reduction Factor during foam injection for the low vug density case

**Mobility Reduction Factor of Foam in Fractures**

As seen on the low and medium density core floods (see Figure 17 and Figure 18), the MRF increases with core position. When foam reaches a steady state pressure drop section three has the highest MRF. During the transient period, foam starts to develop in section one, two and three, respectively. The further from the injection point the more resistance foam exerts. Permeability variation does not have an important influence since all sections are relatively homogeneous. Gas and liquid injection were maintained constant throughout the entire core flood, and the reference foam quality is quantified at outlet conditions. The increase in MRF is attributed to gas expansion due to pressure drop as it traveled through the core. Figure 19 shows the compressibility of nitrogen from inlet to outlet conditions. Nitrogen expands about 7.5% from inlet to outlet conditions, making gas expansion a variable that needs to be considered. In porous
media, bubbles become trapped when their size is increased (Shirley Arthur 1988). This trapping effect may not be apply in this fractured studies because of the high conductivity channels preventing trapped gas as explained in the previous section.

![Graph showing Mobility Reduction Factor during foam injection](image)

Figure 18. (In-1-7) Mobility Reduction Factor during foam injection for the medium vug density case at 75% foam quality and 1 ft/d

In fractured systems, as gas saturation increases towards the end of the core, the available liquid decreases and lubrication to the fracture walls decreases. The fracture surfaces may be thought of a network of crevices that increase friction between the wall and foam. The available liquid in lower quality foam lubricates the rough fracture surface by filling the fissures and increasing foam mobility. (A. Kovscek, D. Tretheway et al. 1995) In addition, as gas expands the gas fractional flow increases creating more lamellae. The number of lamellae is the main factor affecting apparent viscosity (Yan, Miller et al. 2006). When apparent viscosity increases, the mobility reduction factor increases too.
Figure 19. Compressibility of nitrogen gas from SRK EOS from inlet to outlet conditions proving the presence of gas expansion.

In short, the increase in mobility reduction factor towards the end of the cores, shown by Figure 17 and Figure 18 is attributed to two causes: (1) the increase in gas saturation decreases the available liquid to lubricate the fracture walls which increase the bubbles drag, (2) the expansion of gas increases gas velocity creating more shear which in turn increases foam strength by increasing lamellae and apparent viscosity (Yan, Miller et al. 2006).

Effect of capillary pressure in a fracture

Theoretically, capillary pressure should not be an issue in fractured reservoirs because of the high permeability. However, the low permeability in the matrix creates capillary crossflow which affects foam in the fracture. Capillary pressure decreases as water saturation and permeability in a rock increases. Rising capillary pressure has a detrimental effect on foam stability. A case (In-1-10) where nitrogen was injected after
water flood in an effort to decrease water saturation was performed. Residual water saturation after gas injection was 79.2%. Figure 21 shows the resulting MRF along with the previous case (In-1-6) of a wet fracture. The results show that foam in the dry case was able to reach the same strength as foam in the wet case after sufficient injection.

Figure 20. (In-1-10) Mobility Reduction Factor during foam injection at various rates and foam qualities in a high overlapping vugs case after nitrogen injection

Capillary pressure may be responsible for lamellae drainage at the beginning of the dry fracture case flood. As more liquid was injected and the gas saturation in the fracture decreased, foam started to gain strength until it reached the steady-state pressure drop from its corresponding wet core flood.
**Surfactant Alternating Gas Injection in Fractures**

From the pressure drop profiles in Figure 22 and Figure 23, it is evident that the slug size is not an important factor for foam strength. After approximately 3 to 4 PV, foam reached a steady pressure drop fluctuation. The number of cycles and ratio of liquid over gas is important when discussing foam transient behavior, but plays no factor when foam reaches a constant average pressure. Notice how section 1 and 2 pressure drops are out of phase in Figure 22 and Figure 23. Ratio 1 shows this effect at the end which suggests it had not reached a constant average pressure. Ratios 1/3 and 1/5 clearly show section 1 and 2 pressure drops out of phase. Section 3 is harder to observe since it has a significantly different permeability due to the out-phasing of the vugs as discussed earlier. When gas is injected section 1 pressure drop increases, while as we switch to liquid, Sec. 1 decreases, and Sec. 2 increases. To better understand the out-of-phase...
pattern, the geometry of the rock has to be kept in mind. This is a highly permeable fractured rock. The time to observe changes from the fluid injected decreases compared to a conventional matrix flood due to the high conductivity channel that runs through the core.

![Graph](image)

Figure 22. Foam for a fixed liquid slug of 0.1 PV. Gas Varied from 0.1, 0.3, to 0.5 PV at a constant rate of 0.75 ft/d.

As a constant average pressure is reached, foam is propagated throughout the core. However, as the fluid injected varies, the foam quality also varies within the core. As gas is injected the foam quality increases and starts a flowing bank of high foam quality that travels through the core. Likewise, when liquid is injected a flowing slug of low foam quality travels through the core.
Figure 23. Foam for a fixed liquid slug of 0.3 PV. Gas varied from 0.1, 0.3 to 0.5 PV at a constant rate of 0.75 ft/d.

As observed in Figure 22, during the gas injection slug, the pressure drop increased and caused a local state of high foam quality. The reason behind this behavior may by explained by the different flow regimes indentified before in terms of foam quality. The high foam quality slug (gas injection slug) is representative of high rates and low lamella densities are expected. The low lamella densities are described by a decrease in liquid saturation. The high rates are characterized by the local high gas velocity. This flow regime has more flow resistance.

A similar analysis on the lower foam quality slug proves the previous discussion. The local low foam quality slug results during liquid injection and in Figure 22 by low pressure drops. The flow regime governing here needs low gas rates and large lamella densities. The increased liquid saturation increases the lamella density. While the liquid
freely flows through the lamella, which act as low resistance pathways, responsible for the lower observed pressure.

**CONCLUSION**

This chapter addresses the feasibility of foam propagated in a highly fractured system of varying permeability ratios between the fracture and the matrix. Through experimentation the following conclusions were determined:

1) Foam quality is affected by gas expansion as pressure decreases along the core. Foam mobility decreases because of the higher gas saturation at the end section which decreases the liquid available to lubricate the rough surfaces of the fracture (A. Kosscek, D. Tregthewey et al. 1995).

2) Gas trapping has a direct effect on foam strength and its effect is only observed for tight fractures. For the case of wide tortuous fractures, the fracture dominates and any trapped gas in the matrix is negligible. This conclusion helps in modeling foam in fractures by supporting the local equilibrium approximation (Q. Chen 2008).

3) During Surfactant-Alternating-Gas Injection, slug size and slug ratio are independent of foam strength once a constant average pressure drop is reached.
CHAPTER SUMMARY AND FUTURE WORK

This chapter described the feasibility of using foam in highly heterogeneous fractured reservoirs to divert chemical treatments into the matrix. Multiple conclusions were established as described before which lead to the possibility of using foam as method of controlling mobility in a fracture and divert liquids into the matrix. The chemical treatments that will be diverted to the matrix consist of surfactants capable of lowering the interfacial tension between injected fluids and oil, as well as altering the wettability of the rock. The mechanisms responsible of producing oil from the matrix and the effect of the transport of oil or microemulsion through the fractures in the presence of foam need further studies.
Chapter 5: Oil Recovery with Low-Tension Gas Process

INTRODUCTION

This chapter will study the oil recovery mechanisms involved in low-tension gas process in the presence of fractures at residual oil saturation. In the previous chapter, the concept of low-tension gas was tested in cores with varying fracture geometries. We were able to develop foam in multiple fractured cored in the absence of oil. Since oil is known to have a detrimental effect on foam stability (Raterman 1989), this chapter will certainly be a great complement to the last one and a step forward toward the understanding of foam in real fractured reservoirs.

The preparation of these cores was done trying to mimic properties in the gas cap of a fractured/vuggy carbonate formation. Fractures have mostly been depleted of their natural oil and most of the oil is contained in the matrix. Residual oil saturation in the matrix is huge, estimated around 65%. Typical total porosity in the reservoirs is 8%, and more than 25% of it may correspond to secondary porosity. Typical absolute permeability is about 0.3 mD in the matrix blocks and 5 D for the fractures. The rock is believed to be preferentially mixed-wet towards oil-wet. The core floods described in this chapter will attempt to replicate these properties from the reservoir.
EXPERIMENTAL DESCRIPTION

Materials

**Surfactant**

As described in Chapter 3, the low tension surfactant formula is shown in Table 8. Phase behavior analysis determined (see Chapter 3) its optimum salinity at 38,000 ppm.

Table 8. Low Tension Surfactant Formulation

<table>
<thead>
<tr>
<th>Surfactant</th>
<th>(C_{19-23})IOS (0.5 %) and (C_{24}(EO)<em>{56}(PO)</em>{25}) Carboxylate (0.5%)</th>
</tr>
</thead>
</table>

**Brines**

The synthetic brines used were also described in Chapter 3. The formation brine represents the actual brine in the reservoir. It has TDS of 117,000 ppm, while the injection water which represents sea water has a TDS of 38,000 ppm.

**Cores**

Due to the limited availability of reservoir cores, Indiana limestone outcrop was used on the initial core floods for oil recovery. The core (In-2-4) had a porosity of 15.1 and an average permeability of 94 mD. For this case, the core was cut in half through its length and no vugs were present.
The ideal situation would be to use reservoir cores which contained the original wettability in the reservoir (oil-wet ideally). A reservoir core was then used on later tests. Table 9 shows the basic reservoir core properties. Figure 24 shows a CT scan done on the only reservoir core used in this section. These images confirm the presence of vugs and fractures running along the core. Please note some of the fractures were created by applying axial pressure and thus opening fractures through the natural weak stress surfaces. Even though artificial force was used to open the fractures, the core is still representative of the reservoir under study.

Table 9. Reservoir core properties (from Dr. Pope’s unpublished work)

<table>
<thead>
<tr>
<th>Rock type</th>
<th>ZAAP-128</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mass</td>
<td>1188.3 g</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.10</td>
</tr>
<tr>
<td>Length</td>
<td>26.7 cm</td>
</tr>
<tr>
<td>Diameter</td>
<td>4.83 cm</td>
</tr>
<tr>
<td>Area</td>
<td>18.3 cm²</td>
</tr>
<tr>
<td>Temperature</td>
<td>100 °C</td>
</tr>
<tr>
<td>PV</td>
<td>48.8 ml</td>
</tr>
<tr>
<td>(K_{oil})</td>
<td>780 md</td>
</tr>
<tr>
<td>(K_{water})</td>
<td>89 md</td>
</tr>
<tr>
<td>(K_{surf})</td>
<td>1072 md</td>
</tr>
</tbody>
</table>
Experimental setup

The experimental setup used is the same one used and described in Chapter 4. Please refer to that chapter for additional details.

Experimental Procedure

The experimental procedure is similar to that described in Chapter 4. Permeability and porosity measurements are identical to those described in Chapter 4. However, after these measurements, oil flooding was done at reservoir conditions of 100°C and 760 psi (back pressure). In order to place as much oil as possible into the matrix pores, high injection rates were used. Then, the residual oil to either gas or brine was measured by injecting the fluid until zero oil-cut at the effluent. Finally, the foam injection by co-injection of surfactant and nitrogen was performed.
CORE FLOOD RESULTS

In-2-4

After permeability measurement using injection water at 38,000 ppm, oil was injected at different rates until 100% oil cut was achieved. The amount of oil left inside the core was computed by mass balance, giving the initial oil saturation of 42.47%.

The core was then flooded with nitrogen at 0.75 ft/d superficial velocity until 100% nitrogen produced. The oil saturation after nitrogen flood was determined to be 28.5% OOIP. After nitrogen flooding, brine and nitrogen were simultaneously injected at the same rate (1.5ft/d superficial velocity) to establish a baseline pressure profile. The cumulative oil recovery at the end of this fluid stage was 49.93% OOIP. Finally, foam was injected at the same gas and liquid rates at constant injection salinity of 38,000 ppm. The final cumulative oil recovery at the end of surfactant injection was 89.57%.

Figure 25. (In-2-4) Simultaneous injection of nitrogen and brine at 1.5 ft/d and 50% gas fraction
Figure 25 shows the pressure profiles for nitrogen flooding followed with nitrogen-brine flooding. The pressure drop is quite high because the effective core permeability is low. Note that matrix permeability is about 2 md. During surfactant injection stage, foam reduced total fluid mobility by a factor of about 2 as shown in Figure 26. An image of fracture surfaces after core flooding was taken and shown in Figure 27. The oil stain area in Section 2 is significantly larger than that in Section 1 and 3, which may indicate that the sweep efficiency was lower in Section 2 than the other sections.

Figure 26. Mobility Reduction Factor of In-2-4 of foam at 1.5 ft/day and 50% foam quality
Table 9 above shows different core properties. Permeability to oil was calculated at irreducible water saturation. Permeability to water was done at irreducible oil saturation and surfactant permeability shows the absolute permeability done after vacuuming the core to remove any trapped air. Figure 24 shows CT scan images of the core.

The core was previously used on a core flood involving only surfactant without any gas injection. In order to clean any surfactant left in the core without altering the rock wettability, methanol was injected for about 10 PV. Methanol desorbed any surfactant from the rock. To remove the methanol, brine was injected for about 100 PV. This process has been successfully applied in other projects to restore reservoir cores when their availability is limited.

After measuring permeability and porosity with brine at optimum salinity (see AKL-412 phase behavior in Chapter 3), the core was saturated with diluted akal oil (30%
cyclohexane). Oil was injected at high rates to create a pressure gradient large enough to mobilize any residual water and reach deep pores. The initial oil saturation at this point was 65% PV. Water injection followed at a total superficial velocity of 1.5 ft/day. The pressure drop profile for this case is shown in Figure 28. The oil saturation at residual water was 23% PV. Co-injection of nitrogen and brine at 1.5 ft/day and 50% gas quality decreased oil saturation to 13% PV. The pressure drop profile is also shown in Figure 28. Please note that the oil saturation before tertiary oil recovery is low. This is the hardest oil to recover.

Figure 28. Pressure drop of Res-2a during water flood followed by co-injection of N₂ and brine at 38,000 PPM TDS

Co-injection of surfactant solution using AKL-412 and nitrogen gas followed with a total superficial velocity of 1.5 ft/day and foam quality of 50%. Figure 29 shows the pressure drop profile during this case. The oil saturation is lower for this case than for co-injection and thus the lower pressure drop than at the co-injection without surfactant case. Figure 30 shows the oil recovery curve. After 1 PV, only 35% of additional oil recovery was obtained. This percentage comes from the oil left after co-injection without
surfactant. After 2 PV of liquid injection, or 4 PV of total volume injected, the oil recovery reached about 90%.

Figure 29. Pressure drop of Res-2a during co-injection of N₂ and surfactant at 38,000 PPM TDS

Figure 30. Oil recovery of Res-2a during co-injection of N₂ and surfactant at 38,000 PPM TDS
Res-2b

The previous reservoir core flood proved that given enough time the surfactant solution and injection method is capable of recovering most of the oil in the core. Now that the concept has been proven, the optimization phase begins. In an effort to decrease the amount of surfactant injected, salinity was decreased to the point that a Winsor Type I microemulsion would form (see AKL-412 phase behavior from Chapter 3). The idea is to enable capillary-pressure-driven water imbibition from the fractures to the matrix and thus push oil out. Additional core floods are required to test new ideas and optimize oil recovery.

The same cleaning procedure and oil saturation was followed on the same core used for Res-2a. In this case, initial oil saturation was 63%. Oil saturation at residual water was 20%, and oil saturation after co-injection of brine and nitrogen was 14%. Gas injection followed after this phase but did not recover any additional oil. Refer to Figure 31 for a pressure drop profile during this case. At this point, co-injection of surfactant solution and nitrogen started at the same rate as in the previous case (1.5 ft/d total, 50% foam quality). Figure 32 shows the pressure drop profile during this foam development phase. Unfortunately, oil recovery was the same even with the decreased salinity (see Figure 33).
Figure 31. Pressure drop of Res-2b during co-injection of N₂ and brine at 26,000 PPM TDS

Figure 32. Pressure drop of Res-2b during co-injection of N₂ and surfactant at 26,000 PPM TDS
Figure 33. Oil recovery of Res-2b during co-injection of N₂ and surfactant at 26,000 PPM TDS

**DISCUSSION**

**Recovery Mechanisms during Low-Tension Gas Flooding**

*Evidence of liquid diversion into the matrix*

The two reservoir core floods (Res-2a and Res-2b) were done at identical conditions except for the constant injection salinity. The first was injected at optimum salinity (Type III) while the second was injected at lower than optimum salinity (Type I). The fact that both oil recovery curves are identical proves that the recovery mechanism was solely surfactant imbibition into the matrix or liquid diversion into the matrix. Since the injection rates were high, foam was successfully created. Foam is responsible for plugging the fracture network and diverting liquid into the matrix to recover oil. If additional mechanisms which to be targeted a slower injection rate should be used.
Evidence of emulsification as a recovery mechanism

The key idea behind In-2-4 was to test the efficiency of the low-tension surfactant in a core and target emulsification as a recovery mechanism. The lack of reservoir cores at that time forced us to use an outcrop (Indiana Limestone). Although the ultimate recovery is high, the time it took for that recovery is too long. After 8 total PV injected, the recovery reached 89%. At 50% foam quality, this is 4 liquid PV injected to reach 89%. Although more analysis is required on reservoir cores to optimize the final oil production, the collected effluent shows evidence of thick emulsification. As shown in Figure 11, the collected effluent shows little free oil and mostly all of the recovered oil is in the form of a Type III microemulsion.

Figure 34. (In-2-4) Microemulsion collected during foam injection. Left - before heat, Right – after heat
CONCLUSION

Although the experimental evidence is scarce, the following conclusions were made:

1) Foam successfully diverted surfactant into the matrix pores as observed by the high oil recovery.

2) The diversion of liquid into the matrix at high injection rates surpasses the effect of other recovery mechanisms.

CHAPTER SUMMARY AND FUTURE WORK

This chapter explains the oil recovery mechanisms during low-tension gas flooding. Three different core floods are explained: one done on Indiana limestone outcrop rock, and two done on a naturally fractured carbonate reservoir core. The purpose of the Indiana limestone was to analyze the behavior of the low tension surfactant formulation in a core. The floods done on reservoir core were done to optimize the low-tension gas process to recover as much oil as possible. The first reservoir core was done at optimum salinity to use the emulsification process as a recovery mechanism. However, in an effort to strengthen foam and use capillary pressure forces to accelerate the oil recovery, injection salinity was lowered below the optimum value. Both cases yielded the same amount of oil, proving that the main recovery mechanism is independent of interfacial tension.
Future work is needed to truly understand the recovery mechanisms individually. A core flood without any gas injection may eliminate the effect of liquid diversion due to foam mobility control as explained before and may give insight into the mechanism of natural imbibition as well as wettability alteration.
References


