COMPREHENSIVE EXPERIMENTAL STUDY ON FOAM FLOODING
FOR ENHANCING HEAVY OIL RECOVERY

A Thesis
Submitted to the Faculty of Graduate Studies and Research
In Partial Fulfillment of the Requirements
For the Degree of

Master of Applied Science
in
Petroleum Systems Engineering
University of Regina

by
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August, 2017

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Jing Zhao, candidate for the degree of Master of Applied Science Petroleum Systems Engineering, has presented a thesis titled, *Comprehensive Experimental Study on Foam Flooding for Enhancing Heavy Oil Recovery*, in an oral examination held on August 29, 2017. The following committee members have found the thesis acceptable in form and content, and that the candidate demonstrated satisfactory knowledge of the subject material.

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ABSTRACT

At present, thermal method, such as steam injection and in-situ combustion are the best for recovering heavy oil. However, some reservoirs in Canada and the United States with ultra thin oil formations saturated with lower viscous heavy oil (50~200 cp), chemical flooding is more attractive compared with conventional thermal methods. This study is aimed to explore the effectiveness and potential application of foam flooding for enhancing moderately viscous oil recovery.

The effects of surfactant type and concentration on surfactant properties were examined in terms of bulk foam ability and foam stability by the Ross-miles method and Warning blender method. Foam stability in the presence of experiment heavy oil was determined on the basis of a mechanistic understanding of foam propagation in porous media, combined with “Pseudoemulsion-film model” theory.

The effects of foam quality and flow rate on foam mobility were determined by performing a series of steady-state foam flow experiments in oil-free sandstone porous media.

Oil displacement experiments were conducted to determine the effectiveness of immiscible foam as a tertiary recovery method in recovering heavy oil and to make a comprehensive evaluation of oil displacement efficiency of foam generated by different surfactants. Mobility Reduction Factor (MRF) in the presence or absence of oil were determined to reveal the destabilize effect of oil on foam stability in porous media and investigate the sensitive degree of different types of foam to oil.

Results show anionic surfactants had the best comprehensive foaming ability, followed by nonionic, cationic surfactants. The optimum foaming concentration was found to be 1.0 wt%. To
generate stabilized foam, BIO-TERGE AS-40, STEPANTEX VT-90, Triton X-100 were selected as representatives of anionic, nonionic, and cationic surfactants, respectively. Co-injection of CO$_2$/foaming agent was manifested as a reasonable injection strategy, and the highest recovery factor (RF) was obtained at 80% foam quality with the flowrate of 2.5 cm$^3$/min (at ambient condition). VT-90 foam, as a cationic surfactant, surprisingly presented the highest resistance to flow compared with foam generated by other two surfactants at the same foam quality and gas/liquid flow velocities.

Results of this study showed that foam flooding can be used as an effective tertiary method for enhancing heavy oil recovery. One order decrease in MRFs of the three tested surfactants after interacting with water-flood residual oil proved that experiment heavy oil undoubtedly destabilizes foam texture. VT-90 foam, again exhibited extraordinary foam strength with oil despite its poor bulk foam ability. The ultimate oil recovery of as high as 73% of residual oil in place (ROIP) by VT-90 foam coincides with its lowest sensitive degree to heavy oil. It is speculated that, commercial microemulsions, such as STEPANTEX VT-90 solution, have the potential to recover more oil by emulsifying oil droplets in the Plateau borders and transporting them with bubbles.
ACKNOWLEDGEMENTS

Firstly, I would like to express my appreciation to my supervisor, Dr. Farshid Torabi, for his kindness and professional guidance during my graduate studies at the University of Regina.

I would like to express my appreciation to my thesis examiner and committee members: Dr. Na Jia and Dr. Mehdi. Mohammadpoor, for their valuable suggestions. I would also thank Ruth Engler for proofreading.

I gratefully express my gratitude to the Petroleum Technology Research Center (PRTC) for providing us comfortable and safety study spots.

I genuinely thank Dr. Zeng’s research group, for their kindness help with my laboratory tests.
DEDICATIONS

To my beloved parents,
for supporting me to finish my study.

To Jun Yang,
for giving me encouragement to overcome difficulties.

To Lucy,
for giving me courage to pursue my dream.
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Notations

\( A \)  
\text{cross section area of the sandpack, cm}^2

\( k \)  
\text{absolute permeability of the sandpack, D (10}^{-2}\ \text{µm}^2\)

\( L \)  
\text{length of the sandpack, cm}

\( \Delta P \)  
\text{pressure drop, kPa}

\( Q \)  
\text{flowrate, cm}^3/\text{min}

\( V_p \)  
\text{pore volume, cm}^3

\( V_b \)  
\text{bulk volume, cm}^3

\( W \)  
\text{weight of the samples, g}

\( W_b \)  
\text{weight of the beaker, g}

\( PV \)  
\text{pore volumes of liquid injected into the sandpack, cm}^3

Greek Symbols

\( \sigma \)  
\text{interfacial tension of gas-liquid phase, gas-oil phase and oil-liquid phase}

\( \rho_o \)  
\text{dead oil density, kg/m}^3

\( \rho_w \)  
\text{water density, kg/m}^3

\( \phi \)  
\text{porosity of the sandpack}

\( \mu \)  
\text{fluid viscosity, cp}

\( \lambda \)  
\text{disturbance wavelength}

\( \omega \)  
\text{growth-rate factor}

\( \gamma \)  
\text{dimensionless equilibrium entry interfacial curvature}

\( \Pi \)  
\text{conjoining/ disjoining pressure}
Subscripts

\( E_D \) oil displacement efficiency
\( F_q \) summing up foam ability
\( P_c \) capillary pressure
\( C_m \) sum of the inverse of two principal radii of curvature of the interface
\( N_{ca} \) capillary number
\( R \) circumferential radius of curvature of the pendular wetting liquid in the corner
\( R_T \) radius of the largest inscribed circle
\( R(z) \) radial location of the interface
\( R(\zeta) \) transverse/longitudinal curvature at the specific radial location
\( H_0 \) initial foam height (Ross-Miles method)
\( t_{1/2} \) half decay time
\( F_m \) foam ability (Warning blender method)
\( F_r \) foam stability (Warning blender method)

Abbreviations

B Bridging coefficient
CAPP Canadian Association of Petroleum Producer
CHOPS Cold Heavy Oil Production with Sands
CMC Critical Micelle Concentration
CSS Cyclic Solvent Injection
E Entering coefficient
IEA International Energy Agency
IFT Interfacial Tension
MRF Mobility Reduction Factor
GOR        Gas Oil Ratio
OOIP       Original Oil in Place
OPEC       Organization of the Petroleum Exporting Countries
PTRC       Petroleum Technology Research Center
PV         Pore Volume
FRF        Foam Resistance Factor
RF         Oil Recovery Factor
S          Spreading coefficient
SAGD       Steam Assisted Gravity Drainage
VAPEX      Vapor Extraction

Units

1 inch = 2.54 cm

1 Psi = 6.89475 kPa
CHAPTER 1
INTRODUCTION

1.1 Background

It is well known that fossil fuel is limited, non-renewable resources, and over 85% of the world’s energy is supplied by fossil fuels (Egbogah et al, 1985). According to the “Peak Oil Theory” proposed by Hubbert (1962), the rate of petroleum production of the reserve over time follows a “bell” curve, which means the oil production rate will experience a dramatic decrease after peaking. Since last decade, a large amount of the developed oil reserves are aging and less new oil reserves can be developed and the oil production rate has exceeded the newly increased or explored reserves every year. The discovery rate of giant oil fields in the Organization of the Petroleum Exporting Countries (OPEC) which accounts for approximately 44% of world’s oil production rate (OPEC 172nd meeting, 2017) and dominates the world crude oil market had already peaked in the late 1960s and early 1970s (Watkins, 1985). Even in most non-traditional production areas, their reserve to production ratios (R/P) are now exceeding the empirical critical value of 10 and reaching 17~18. Many countries attempt to discovery new reservoirs in offshore or environmentally-unfavorable areas which will lead to an increase in gasoline retail price eventually (Simjoo, 2012).

Enhanced oil recovery (EOR) is defined as a process to produce recoverable oil after primary or secondary recovery which aims to extend oil field’s production life cycle and to recover more of the remaining oil (Yassin, 1988) (Fig.1.1). Worldwide, for heavy oil, primary oil production only produces 3~10% of the original oil in place (OOIP) on average (Luke, 1989). As reported by worldwide EOR surveys of the Oil and Gas Journal (2007), the global conventional oil
reserves will be expanded by 88 billion barrels if there is an increase of 1% in oil recovery efficiency. Currently, the ability of EOR techniques to boost the oil production rate is receiving more interest from governments because EOR process contribute to the approximately 4% of the world’s daily oil production (Moritis, 2010).

The conventional oil recovery methods are summarized in Fig. 1.2.

1.2 Foam Flooding in Enhanced Oil Recovery

Foam is generated by injecting gas (e.g. nitrogen, CO$_2$, air, natural gas) and foaming agents (an aqueous solution containing a surfactant) simultaneously or intermittently into the porous media (Holm, 1968). Foam is effective in modifying the unfavorable mobility ratio by reducing the relative permeability of porous media to gas and improving the sweep efficiency, especially in loose sands (Yang, 1989; Bernard and Holm, 1964). It has been reported that foam mobility (the total mobility of CO$_2$/foaming agent) decreased with increasing gas fractional flow ratio and increased with increasing flow rate (total flow rate of CO$_2$/foaming agent) (Chang and Grigg, 1999).

Foam flooding within a formation is a promising tertiary recovery method for its effectiveness in improving oil displacement efficiency and sweep efficiency than its separate constituents and has achieved many successful field applications. However, foam flooding has its disadvantages. At present, the design for standard foam flooding construction parameters such as injection mode, slug size, fluid injection velocity is not well-developed. In field applications, the unavoidable occurrence of viscous fingering and channeling during foam flooding lowers the predicted oil recovery factor. Although foam combination flooding and enhanced foam flooding
Figure 1.1  Production life time of a typical oil field (reconstructed from Ali and Thomas, 2000)
have modified the poor stability of foam to some degree, the addition of polymer prohibits foam flooding being implied in the high temperature and high salinity reservoirs. Moreover, N₂ and O₂ in the air strongly destroy polymer properties in an air-foam system. Alkali corrosion leads to the emulsification of output liquid, reducing pump efficiency and decreasing the oil production rate. Several methods have been proposed to optimize foam flooding. For instance, foam can be injected into the reservoirs alternatively with the designed slugs which have better oil-water interfacial tension reduction ability and better oil displacement efficiency. Nevertheless, flue gas foam and air foam should be studied further to reduce the cost of foam flooding.

1.3 Research Methodologies and Objectives

Through conducting bulk foam experiments and sandpack tests by using different types of surfactants, the objectives of this research can be concluded as follow.

1. To undertake a comparative study on foam ability and foam stability generated by various foaming agents, and to determine the surfactant concentration which shows the best summing-up foaming ability.

2. Based on the above study on bubble column experiments, evaluate the mobility reduction ability of different types of CO₂-foams by conducting steady-state foam flow experiments, and to determine the influencing factors of the foam resistance factor such as foam quality (gas fraction in the whole foam system), gas/liquid volumetric flow rates.

3. To study the oil displacement efficiency of different types of CO₂-foams by conducting oil recovery experiments and determining the residual oil saturation at the end of each test by using the weighting method to verify the accuracy of oil recovery experiments.
The goal is to select a promising commercial foaming agent that effectively improves ultimate oil recovery.

1.4 Thesis Outlines

This thesis consists of six parts. More specifically, Chapter 1 provided the current situation of world petroleum industry and the importance of enhancing heavy oil recovery, and the research objectives and methodologies. Chapter 2 contains the structurally review of thermal and non-thermal EOR methods for enhancing heavy oil recovery on the basis of the previous work, and the mechanisms of the increment of oil recovery by foam flooding. Chapter 3 supplies the comparative evaluation of bulk foam properties generated by different types of surfactants using different experimental methods. Chapter 4 describes the detailed information about the steady-state foam flow experiments, including the description of the typical experimental procedures, experimental equipments, and the sandpack model properties. Chapter 5 discusses the performance of different types of CO₂-foam in oil displacement experiments. The analysis and discussions of the experimental results of each experiment are given at the end of each chapter. Chapter 6 contains the major conclusions and recommendations for the future work.
Figure 1.2  Summary of EOR methods (reconstructed from Ali and Thomas, 2000)
CHAPTER 2
LITERATURE REVIEW

2.1 Heavy Oil Recovery Process

The world’s oil resources are currently in decline, and Canada is no exception. However, as the sixth largest producer of crude oil in the world with extensive oil and natural gas reserves across the country (CAPP), Canada has the fortune to have 6 trillion barrels heavy oils in place (IEA, 2005). Conventional heavy oil productions only expect to produce up to 5% OOIP (Batycky, 1997). Thus, a large amount of oil except for the immobile oil remains in oil fields. Applying enhanced oil recovery methods in heavy oil is urgent and a most critical step to sustain the oil production rate.

The reduction of the mobility ratio is essential to improve heavy oil recovery efficiency. It can be realized by means of improving the viscosity of the driving fluid and reducing the oil viscosity. Heavy oil recovery methods are classified into two methods: thermal and non-thermal methods.

2.1.1 Thermal Methods

Thermal energy is used to heat the OOI to reduce the viscous force that retains the oil (Denney, 2012). Although the amount of heat actually spent on the oil is unavoidably small, its economic effects can be obtained by heat recuperation (Dietz, 1975).

1) Cyclic Steam Stimulation (CSS)

Cyclic Steam Stimulation (CSS) is a commonly used thermal recovery method in which steam is injected constantly to the well at a relatively high rate for a few weeks until it reaches a
desirable volume. The high steam injection rate is to minimize the heat losses. Then, a shut-in period is followed for several days to promote partial condensation of steam as well as achieve an even distribution of the injected heat. After opening the well, the oil production rate declines with the passage of time because of the heat losses and heat production on its way towards the production well.

2) Steam Assisted Gravity Drainage (SAGD) and Solvent Vapor Extraction (VAPEX)

Steam Assisted Gravity Drainage (SAGD) is originally developed for the in-situ recovery of bitumen in several main Canadian reservoirs such as Athabasca, Cold Lake, and Peace River. It is the most successful commercial technique in recovering oil from Canadian oil sands (Butler, 1994). In the typical SAGD process, two parallel horizontal wells are drilled in the reservoir. Steam is produced from the bottom well (Bybee, 2001). There is a wide application of SAGD method because the formed steam chamber significantly increases the hot steam sweep efficiency and the temperature of the steam chamber does not cool during its propagation which is unlike CCS.

Solvent Vapor Extraction (VAPEX) is evolved from the SAGD concept. In VAPEX, a hydrocarbon vapour (methane, ethane, propane, butane) or a mixture of vapours, along with a carrier gas (CO$_2$, N$_2$) are injected into the well. A vapour chamber is also formed and propagates laterally. However, compared with SAGD, this method is less efficient in reducing oil viscosity (Naderi, 2015).

2.1.2 Non-thermal Methods

Undoubtedly, thermal methods enhance the heavy oil recovery efficiency extraordinarily. However, the application of thermal methods is unfavourable in some oil fields. For instance, too
thin (< 30 ft) or too deep (> 3000 ft) formations; very dense layers (<1 Darcy) and other factors (Ali, 1976). In this case, non-thermal methods are employed.

1) Cold Heavy Oil Production with Sand (CHOPS)

Conventional cold production increases the oil recovery factor to 5%~20%. Among them, Cold Heavy Oil Production with Sand (CHOPS) is the primary cold production technique in Canadian oil production industry. Sand is allowed to be produced deliberately with heavy oil. Over the last 35 years, it has been reported that Canadian crude oil production has increased by more than 2.4 million barrels per day due to the growth in oil sands supply. Generally, sand is produced with oil at concentration of 0.23% to 10% of the volume. Wormholes, which have a positive effect on recovering oil, are created by the production of sand (Rangriz and Babadagli, 2012).

2) Waterflooding

Conventional waterflooding usually has poor oil displacement efficiency and sweep efficiency. Nevertheless, it is favoured in heavy oil recovery because it is economical and easier to conduct. It has been reported that in the common five-spot pattern, the oil recovery efficiency was not satisfactory with over 30% recoverable viscous oil remaining after waterflooding (Layton, 1970). Field operators are dedicated to investigating effective waterflooding schemes for heavy oil recovery and have achieved some acknowledgement such as prior injection gas followed by injection pattern rotation.

3) Polymer flooding

Polymer increases the water apparent viscosity and improves the injection profile. It has been reported that polymer flooding is effective in recovering moderately viscous oil, especially within the range of 10 to 150 cp oil viscosity. Polymer flooding recovered more viscous oil at the
earlier stage of the field life cycle with a relatively lower water-to-oil ratio (WOR) (Sandiford, 1964).

4) Surfactant Flooding

Surfactant flooding has been extensively employed as a tertiary recovery method to lower oil-water interfacial tension (IFT) sufficiently and increase sweep efficiency in conventional oil reservoirs since the early 1980s.

Surfactants are polymeric, amphiphilic molecules, containing hydrophilic and hydrophobic parts (Fig. 2.1). The hydrophilic “head” prefers a polar environment while the hydrophobic “tail” favors non-polar environment. Seen from their chemical expression, the hydrophobic part (figuratively illustrated as “-O”), is called the hydrocarbon chain, while the hydrophilic part is an asymmetrical group. Surfactants are classified into three types according their hydrophilic parts: anionic, cationic, and nonionic surfactants. The detailed classification of surfactants is summarized in Table 2.1.

Anionic surfactants in water are typically alkaline metals such as sodium (Na$^+$) or potassium (K$^+$), including alkylbenzenes sulfonates, fatty acid, di-alkyl sulfo succinate, and lauryl sulfate. Anionic surfactants are most widely used in EOR because of their lower adsorption on reservoir rocks (Green and Willhite, 1998). Anionic surfactants such as petroleum sulfonates, synthetic sulfonates and exthoxylates sulfonates can be manufactured economically. Many oil companies prepared petroleum sulfonates by a crude oil sulfonation process. Synthetic sulfonates are produced by the sulfonation of the prepared alkylates with sulfuric acid. Alkylates are made of olefin or aromatic hydrocarbons. Exthoxylates sulfonates are a mixture of above two types of surfactants which exhibit stronger salinity tolerance (Donaldson, et al., 1989).
Generally, cationic surfactants are not favoured in the oil production industry because of their strong adsorption on reservoir rocks. Nevertheless, EOR processes based on a cationic surfactant have yielded higher ultimate oil recovery from limestone (Wu et al., 2008). The most widely used cationic surfactants is cetrimide which has tetradecyl trimethyl ammonium bromide with a minimum amount of dodecyl and hexadecyl compounds (Carter, 2008).

Non-ionic surfactants present a good tolerance of high-salinity environment and are commonly used as a co-surfactant in EOR. They are classified into polyol esters, polyoxyethylene esters and poloxamers.

The mechanisms of surfactant flooding to recover oil are IFT reduction and wettability alteration. With the additive of an amphiphilic surfactant solution, surfactant molecules tend to assemble spontaneously onto the water-oil interface, which causes polarity disparity reduction over the interface. Accordingly, the IFT is reduced.

Rock surfaces alter spontaneously from oil-wet to water-wet during surfactant-solution imbibitions (Ali, 1976). Following the field experiences and lab experiments, the alternation degree mainly depends on rock properties, surfactant type and concentration (Wagner and Leach, 1959). More specifically, when the surfactant solution concentration is below critical micelle concentration (CMC), water-wet rock turns into oil-wet rock with the increasing of surfactant concentration because of “monomolecular layer adsorption”. When the surfactant concentration is above CMC, the oil-wet rock turns into water-wet again with the increasing surfactant concentration because of “bi-layer adsorption” based on the “polarity affinity” principle.

5) Carbon dioxide flooding

Carbon dioxide (CO₂) is very cheap in terms of its availability and it is used in two forms in the EOR industry: CO₂ miscible flooding and carbonated waterflooding.
CO₂ has the advantageous quality of dissolving in heavy oil and reducing its viscosity. Miscible flooding sweep efficiency is strongly influenced by minimum miscible pressure (MMP) which is proportional to the specific gravity of oil (Sebastian et al., 1985). Although heavy oil has high MMP, CO₂ can extract hydrocarbons within the C₅-C₃₀ range when contacting with oil and concentrate a solvent miscible bank (Holm and Josendal, 1974). However, during CO₂ miscible flooding, the precipitation of asphaltenes will lead to the reduction of reservoir permeability.

Apart from the above mentioned non-thermal EOR methods, caustic and emulsion flooding, hot water flooding, etc., have also been extensively investigated (Selby and Alikhan, 1989). It has been reported that immiscible carbon dioxide water-altering-gas (WAG) method is applicable in recovering viscous oil especially oil viscosities within the range of 500 to 5000 mPa (Thomas, 2001). After carefully examination of the experimental tests and field trials, it can be concluded that non-thermal methods hold promise for recovering moderately viscous oils.

2.2 Foam Flooding

The application of foam as a mobility control agent was first proposed in 1958 (Bond and Holbrook, 1958). The first recorded successful foam flooding trial was in Siggins oil field, Illinois by Unocal Corporation from 1964 to 1967. During the trial, the water oil ratio decreased from 15% to 12% (Holm, 1970). In 1994, British and Norway conducted studies on three pilot projects in the North Sea oilfield for four years to study the improving effects of foam on gas fingering in high gas/oil (GOR) production wells (Aarra and Skauge, 1994). Furthermore, Suffridge et al. (1989) proposed that the destabilize effect of more viscous alkanes are less than that of light alkanes and Schramm (1994) speculated that the slower emulsification of heavy oil may delay the breakage of foam lamellae which provide a chance for foam to enhance oil recovery.
2.2.1 Mechanisms of Oil Recovery by Foam Flooding

1) Increase the Oil Displacement Efficiency (E_D).

For water-wetting core, whether the residual oil is able to flow after water flooding depends on the combination of the driving force and resisting force applied on the oil drops. For a rock with specific wetting characteristics and capillary radius, the oil displacement efficiency can be represented by capillary number (N_{ca}).

\[
N_{ca} = \frac{k\Delta P}{\sigma L}
\]  \hspace{1cm} (2.1)

where \( k \) is permeability, \( \Delta P \) is pressure drop and \( \sigma \) is the interfacial tension between the displaced and displacing fluids. By transforming Darcy’s equation, the pressure gradient can be expressed as the function of fluid viscosity \( \mu \) and velocity \( v \), so the capillary number is re-written as:

\[
N_{ca} = \frac{\nu \mu}{\sigma}
\]  \hspace{1cm} (2.2)

The higher apparent viscosity of foam and strong IFT reduction ability of the surfactant solution increase the capillary number, so as to increase the oil displacement efficiency. As the foam system is composed of bubbles of different interfacial curvatures which create multiple forces, there is a possibility for the combination of some of these forces to act as a driving force to move oil drops. Furthermore, for specific surfactant formulas, oil can be produced with foam by being emulsified into the Plateau borders between bubbles (Heins, 2014).

2) Reduce the Mobility Ratio and Increase the Sweep Efficiency.

Gas flooding is characterized by poor sweep efficiency caused by frontal instability. Foam greatly reduces the gas relative permeability and thus reduces the mobility ratio. Two foam types
are distributed in the porous media: trapped foam and mobile foam. Trapped foam plugs the pore channels and constrictions through which gas otherwise travel. Furthermore, with the constantly changing foam gas-liquid interfaces, mobile foam suffers significant drag force during its propagation which contributes to mobility reduction (Kovescek et al., 1994).

3) Reduce the Reservoir Heterogeneity

During the foam flooding process in a heterogeneity reservoir, most of the gas and foaming agents go preferentially into the more permeable layer and generate foam there which causes the following liquids to change their flow paths and flow into the less permeable layer because of high foam resistance. In real oil production fields, waterflooding is often conducted again to obtain incremental oil after foam flooding because foam can plug some pore channels and force water to flow into some layers with lower permeability.

2.2.2 Limitations of Foam Flooding

Foam is sensitive to oil in porous media (Bernard and Holm, 1964). Foam stability after contacting with oil varies from foam types. From the work of Schramm et al. (2003), based on foam stability in the presence of oil, foam is graded into three levels: (1) less sensitive, (2) moderate sensitive and (3) severe sensitive foam. For less sensitive foam, oil tends to be pinched off into bigger oil drops and carried by the Plateau borders. For moderate sensitive foam, oil tends to be emulsified into smaller oil droplets in the Plateau borders. Oil drops are carried by lamellae for some distance and released. They are later collected and carried again by the sequence foam lamellae. For highly sensitive foam, oil tends to be emulsified into very small oil droplets: filling even thin foam liquid films and causing rupture frequently (Schramm and Stasiuk, 2003).
Three coefficients were introduced to predict the effect of surfactant types on foam stability with oil: (1) the entering coefficient (E), (2) the spreading coefficient (S), and (3) the bridging coefficient (B). E represents the ability of oil drops to enter the liquid film (Robinson and Wood, 1948), while S exhibits whether oil drops can spread inside the lamella (Harkins, 1941). This condition only occurs when oil drops enter the lamella successfully and it is largely responsible for foam stability; while bridging occurs as long as oil spreading is not favorable (Simjoo, 2012). Oil tends to form a lens at the gas-liquid interface, and an oil layer exists further, causing the eventually rupture of bubbles.

These three coefficients are calculated by the combination of the gas-surfactant solution surface tension ($\sigma_{gl}$), the oil-surfactant solution interfacial tension ($\sigma_{ol}$) and the oil-gas interfacial tension ($\sigma_{og}$), as shown in Eq. (2.3) to Eq. (2.5).

$$E = \sigma_{gl} + \sigma_{ol} + \sigma_{og} \quad (2.3)$$

$$S = \sigma_{gl} + \sigma_{ol} - \sigma_{og} \quad (2.4)$$

$$B = \sigma_{gl}^2 + \sigma_{ol}^2 - \sigma_{og}^2 \quad (2.5)$$

Table 2.1 was drawn to illustrate the foam stability with oil presented by the E, S, and B coefficients. In this table, positive E (i.e., E is “+”) represents the entering condition is favourable, and vice versa. The rest can be reasoned in the same manner.

Surfactant loss is another problem. Many mechanisms contribute to the loss of surfactant, such as surfactant adsorption at the solid-liquid and oil-water interfaces, precipitation (Milner, 1973), chemical degradation (Rodriguez, 1981), and partition into oil. So, the screening of novel foaming formulas which have a strong foaming ability, foam stability, oil tolerance ability and low surfactant adsorption is of great importance.
Figure 2.1  (a) Schematic of a surfactant molecule; (b): schematic of a surfactant molecular in an oil-surfactant-water system (Green and Willhite, 1998)
# Table 2.1 Classification and chemical structures of surfactants

<table>
<thead>
<tr>
<th></th>
<th>Hydroxy acid salt</th>
<th>Sulfate</th>
<th>Sulfonate</th>
<th>Phosphate</th>
<th>Polyoxyethylene (polyethylene glycol, ether)</th>
<th>Polyhydric alcohol</th>
<th>Ester ether</th>
<th>Oxygen containing type</th>
<th>Primary ammonium salt</th>
<th>Secondary ammonium salt</th>
<th>Tertiary ammonium salt</th>
<th>Quaternary ammonium salt</th>
</tr>
</thead>
<tbody>
<tr>
<td>Anionic surfactant</td>
<td>R-COONa</td>
<td>R-OSO₃Na</td>
<td>R-SO₃Na</td>
<td>R-OPO₃Na</td>
<td>R-O-(OCH₂CH₂)ₙH</td>
<td>R-NHCH₂CH₂C</td>
<td>R-O-R’COOR’</td>
<td>RCONH-R’OH</td>
<td>R-NH₂HCl</td>
<td>R-NH(CH₃)HCl</td>
<td>R-N(CH₃)₂HCl</td>
<td>R-N(CH₃)₃Cl</td>
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<tr>
<td>No-ionic surfactant</td>
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<tr>
<td>Cationic surfactant</td>
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2.2.3 Foam Performance Models

By far, predicting foam flow behavior is a challenging task. Foam models are used to predict foam performance in porous media. Currently, various models are used to predict foam performance under the field condition such as population balance models, fractional flow models, the fixed-\(P^*\) models, percolation models (Rossen and Zeilinger, 1994). Population balance models are the most popular although they only successfully model the steady-state in real applications. This kind of model addresses the concept of “foam mobility”. From a realistic perspective, the concept of “foam mobility” does not exist because the gas and liquid phase move separately in porous media. Nevertheless, foam mobility is still considered to simplify the modeling procedures. Population balance models incorporate the relationship between foam mobility and foam texture, and take foam generation and destruction mechanisms into account. Recently, Zitha et al. proposed an alternative stochastic bubble population model which is physically and mathematically useful in previous simulation studies.
Table 2.2 Foam stability predicted by the sign of E, S and B coefficients (Simjoo, 2012)
2.3 Chapter Summary

From the extensive literature review in this chapter, it can be seen that thermal heavy oil recovery methods have achieved great success in field applications. Many non-thermal methods such as waterflooding, carbon dioxide flooding, polymer flooding, etc., for recovering the moderately viscous oil was under investigation. An intensive mechanism study of different EOR methods was conducted, and their advantages and disadvantages are analyzed. Foam flooding was emphatically studied for its potential in recovering moderately viscous oil in terms of its unique attribute of higher apparent viscosity. Besides, the limitations of foam flooding such as foam poor stability after contacting with oil and surfactant adsorption were discussed and remedy methods proposed. Moreover, several typical foam models were established to better exhibit the foam propagation process inside the porous media. However, the study of foam immiscible flooding is still at the early stage and limited studies have been conducted on foam flooding in moderately viscous heavy oils. Hence, this study is aimed at screening surfactants by taking both bulk foam and sandpack experimental results into consideration; analyzing the effects of influencing factors such as gas fraction ratio, surfactant types, and liquid injection velocity on mobility reduction ability of different CO₂-foam types in the absence of and in the presence of oil; and comparatively evaluating the performance of different foam types on recovering moderately viscous oil.
CHAPTER 3

FOAM ABILITY AND FOAM STABILITY

In this experiment, seven classes of surfactants were used: two non-ionic surfactants Triton X-100 and BIO-SOFT N1-3; three anionic surfactants STEPANOL WA-EXTRA, BIO-TERGE AS-40, BIO-SOFT D-62 LT, and two cationic surfactants STEPAN TEX VT-90 and BTC 1210-80%. Many methods have been used to evaluate surfactants in terms of their foaming ability and foam stability such as the Ross-miles method, Waring method, and geometric method. In this study, we adopt the first two methods.

Based on the experimental results of the Ross-Miles method and Warning blender method, a comprehensive analysis on the foam quality of different surfactants was conducted to screen the surfactants. Although foam flow properties are more complicated in oil production fields, this study presents the basic evaluation of foaming characteristics of different surfactants and provides a reference for future work.

Note that, in this study, foam is specifically named after the foaming agents (Table 3.1).

3.1 Ross-Miles Method (Pouring Method)

A Ross-Miles experiment was conducted to determine two principal indicative parameters: Initial foam height ($H_0$) and half-decay time ($t_{1/2}$). Foaming volume is the volume of the generated foam, and the half-decay time is defined as the time at which bubbles destruct to half of the initial volume. In the petroleum industry application, surfactant concentrations are generally above critical micelle concentration (CMC) but within a reasonable range (not too high). In this case, surfactant concentrations used in this test are 0.1 wt%, 0.5 wt%, and 1.0 wt%.

21
<table>
<thead>
<tr>
<th>Surfactant</th>
<th>Foam name</th>
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</thead>
<tbody>
<tr>
<td>STEPANOL WA-EXTRA</td>
<td>SLS foam</td>
</tr>
<tr>
<td>BIO-SOFT D-62 LT</td>
<td>SBS foam</td>
</tr>
<tr>
<td>STEPANTEX VT-90</td>
<td>VT-90 foam</td>
</tr>
<tr>
<td>BTC 1210 -80%</td>
<td>DDAC foam</td>
</tr>
<tr>
<td>BIO-SOFT N1-3</td>
<td>AE foam</td>
</tr>
<tr>
<td>Triton X-100</td>
<td>TX-100 foam</td>
</tr>
<tr>
<td>BIO-TERGE AS-40</td>
<td>AOS foam</td>
</tr>
</tbody>
</table>
3.1.1 Experimental Setups

1. The Ross-miles foam test apparatus (LG-3941-100, VWR Inc., Canada) (Fig. 3.1) is composed of two parts: foam pipet and foam receiver. The foam receiver is made from double-decked, chemical resistance glass tubing with a $5 \pm 0.08\text{cm}$ internal diameter (I.D.). It is kept vertical by two stainless holders (VWR Inc., Canada) throughout the experiment. A stopcock is located at the downstream of the tube to control fluid flowing in and out. Three calibration marks are distributed on the foam receiver wall. The first mark is at 50 mL point, which instructs the foaming agent volume initially in the foam receiver. The second mark is at the 250 mL point, which allows researchers to gain a rough estimation of the foaming volume. The third mark is $90 \pm 0.5 \text{ cm}$ above the 50-mL mark, and the bottom of the foam pipet should be paralleled with this mark. The total length of the foam receiver is $100 \pm 0.5\text{cm}$ to ensure the foaming agent inside generates sufficient foam after crushing with the surfactant solution that pours out of the foam pipet. The foam pipet is also constructed from standard-wall glass tubing which consists of two parts: (1) a bulb with a $4.5 \pm 0.05 \text{ cm}$ outside diameter (O.D.) and (2) a stream with a $0.7 \pm 0.05 \text{ cm}$ O.D. It is maintained straight exactly in the centre of the foam receiver throughout the pouring process. A red mark on the upper stream mark 200ml to illustrate that the pipet contains $200 \pm 0.05 \text{ mL}$ foaming agent. The switch at the upper stream is used to control the fluid flow.

2. A thermostatic water bath (Cole-Parmer Polystat Inc., USA) is used during the experiment to not only simulate the oil reservoir temperature and shorten the experiment period because an increase in temperature speeds up the foam decay process. The thermostatic waterbath is tightly connected to the foam receiver using two rubber tubes to
ensure a continuous water circulation inside the double-deck of the foam receiver. The target temperature (50°C) is set at the control panel of the waterbath.

3. Precise balance and glass beakers are used to weigh the surfactants.

4. An air pump is used to suck the foaming agent into the foam pipet.

### 3.1.2 Experimental Procedures

The whole experiment was conducted at ambient temperature (20°C) and atmosphere pressure (101 kPa).

1. The foam receiver was tightly kept vertical on the stand hold by a suitable holder tightly. Distilled water was used to rinse down the walls of the foam receiver before the start of each test until no remaining surfactant solution was attached to the walls (no foam bubbles appear) before closing the stopcock at the downstream of the foam receiver.

2. After heating the circulated water to 40°C by the thermostatic waterbath, the foaming agent was slowly stirred into the foam receiver to avoid excessive foam formation until reaching to the 50 mL mark.

3. Foam receiver was kept vertical on the stand and held in place tightly by a suitable holder. Distilled water was used to rinse down the walls of the foam receiver before each test until no remaining surfactant solution was attached to the walls (no foam appeared in this process) before closing the stopcock at the downstream of the foam receiver.

4. The foaming agent was aged for 20 minutes.
Figure 3.1  Ross-miles foam test apparatus: foam pipet (left) and foam receiver (right) (Active Standard ASTM D1173)
5. 200ml foaming agent was sucked carefully by an air pump into the foam pipet. The downstream stopper was closed to avoid foaming agent to flow out. As the foam pipet was transferred to right above the foam receiver. The stopper was open immediately. The measurement of the initial foam height started immediately when the foaming agent in the foam pipet running out completely.

6. The foaming height ($H_0$) was recorded as soon as the foaming agent in the foam pipet ran out. As bubble surface is an uneven surface, the reading of the top of the foam column was taken as the average of the highest height and rim of the foam had reached.

7. Foam volumes were recorded with time to better exhibit the foam decay process. The time interval was chosen according to the decay rate of different types of foam. For instance, the interval time for the stable AOS-foams is much longer than that of the fastest destructed BLC 1210-80%-foams.

8. The half decay time ($t_{1/2}$) was recorded when the residual foam volume reached $\frac{1}{2}H_0$.

### 3.2 Waring Blender Method

As its name implies, the Warning blender method generates foam by blending the foaming agent in a beaker. The experiment was conducted at ambient condition, and the surfactant concentration was at 1.0 wt%.

#### 3.2.1 Experimental Apparatus and Procedures

The apparatus for the experiment consisted of a 4000 ml beaker (effective volume: 3500 ml), a ruler (30 cm), a mixer (Model 6000, Arrow Inc., Canada), and a second chronograph. The experiment procedures are not complex. Firstly, 1500 ml surfactant solutions were prepared at
surfactant concentration of 0.5% in weight in the beaker (Appendix A.2). The original height of
the surfactant solution (I) was the same at 8.5 cm. Next, the surfactant solution was blended by
the mixer at 6000 rpm for 30 seconds. Lastly, the initial foam height (M) was measured as soon
as the switch was turned off. The foam height after standing for 5 minutes (R) was measured.

Fm and Fr are defined as the parameters to reflect the foam ability and foam stability of
different surfactants, respectively. They were calculated by Eq. (3.2) and Eq. (3.3).

\[ F_m = M - I \]  \hspace{1cm} (3.2)

\[ F_r = R - I \]  \hspace{1cm} (3.3)

3.2.1 Results and Discussions

Two surfactants: BIO-TERGE AS-40 and STEPANOL WA-EXTRA were chosen randomly
to generate foam at the concentration of 0.5 wt%. Each test was run in duplicate (at least three
times). The foaming heights of AOS-foam were 14.7 cm, 14.7 cm, 14.6 cm; and for SLS-foam
they were 15.3 cm, 15.2 cm, 15.2 cm, which refers that the Ross-Miles method performed good
reproducibility with negligible error within ±0.2 mm.

Figure 3.2 illustrates the variation of the foaming ability for various surfactant types at
different concentrations. Foam heights of each surfactant rose smoothly during the course of the
experiment as the surfactant concentration increased during the course of the experiments. From
Fig 3.3, it can be observed that foams generated at higher surfactant concentrations were more
stable.

From Fig. 3.3, anionic surfactants show exceptional foaming ability within the whole range
of concentrations studied, followed by nonionic and cationic surfactants. Among three anionic
surfactants, SLS generated more foam than the other two candidates. This finding can be
attributed to the differences in surfactant type and chemical structure. Generally, sulfate-type surfactants have better foam ability than sulfonate-type surfactants. The chemical structures of STEPANOL WA-EXTRA, BIO-SOFT D-62 LT and BIO-TERGE AS-40 are $CH_3(CH_2)_{10}CH_2OSO_3Na$, and sodium $C_{14-16}$ olefin sulfonate, respectively. Carbon chains in the hydrophobic groups of these three surfactants are all straight (Borchardt and Bright, 1985). In this study, SLS possesses shorter carbon chain but exhibited the best foaming ability which is consistence with the conclusion drawn by Wu and Pan (2010) that surfactants with smaller carbon number have a tendency to have better foaming ability.

Figure 3.4 presents the change of AOS, TX-100, and VT-90 foam heights with time. The dense, highly uniform AOS foam column decayed rapidly at the beginning, and the foam column exhibited a metastable state with a practically stabilized foam height for a certain period of time, followed by a second decay regime. Bubbles started to rupture at a faster coalescence rate from the apex of the foam column. Foam column gradually became sparse and disappeared. The initial mechanism for foam decay is gravity drainage. In latter stages when the generation foam was heterogeneous with broad bubble sizes, the dominate mechanisms are bubble coalescence and Ostwald ripening. TX-100 foam was characterized by bigger bubbles with various diameters. And its foaming ability was also satisfactory with the maximum initial foaming height of 14 cm. Unlike AOS foam, TX-100 foam destructed fast at the very beginning and reached half of the initial foaming height in less than 3 minutes. The profile kept a flat-flying varying tendency for a long period after six minutes. With regard to STEPANTEX VT-90, although it performed weak in foaming ability, it showed extraordinary foam stability. The fine VT-90 foam experienced a small and rapid decay, and then kept a low coalescence rate for the rest of the measurement.
As for two cationic surfactants STEPANTEX VT-90 and BTC 1210-80% (DDAC), STEPANTEX VT-90 generated the least foam but had the longest half-decay time while DDAC generated more initial foam but with so poor foam texture that bubbles coalesced as soon as they were generated. The weak foaming ability of STEPANTEX VT-90 is probably due to the lower carbon number in STEPANTEX V-90 (shorter carbon chain generally has lower intermolecular force).

The Ross-Miles method provided an external direct-viewing impression on the foaming ability of various surfactants. However, the Ross-Miles generated foam by the method of pouring and lashing. The generated bubbles were normally uniformly distributed with various sizes and had shorter longevity, accordingly. In this case, the Blender method was conducted to verify the accuracy of the Ross-Miles method.

Figure 3.5 shows that the experimental results of the Blender method were in good agreement with those of the Ross-miles method. Three anionic surfactants generated more initial foam volume compared with the other two types. In this experiment, cationic surfactant BTC 1210-80% exhibited the best foaminess but the worst foam stability.
Figure 3.2  Effects of surfactant type and concentration on bulk foam heights
Figure 3.3  Effects of surfactant type and concentration on bulk foam half decay time
Figure 3.4  Bulk foam decay time curves of BIO-TERGE AS-40 (blue line), STEPAN TEX VT-90 (green line), and Triton X-100 (red line)
Figure 3.5  Bulk foam heights generated by different surfactants in Waring Blender experiment at ambient condition
Foam ability and stability should be taken into equal account when evaluating surfactant properties. Thus, a coefficient $F_q$ was introduced to comprehensively evaluate foaming ability of surfactants (Wu and Pan, 2010). $F_q$ can be calculated by Eq. (3.1).

$$F_q = \frac{3}{4} \frac{t_{1/2}}{H_0}$$

(3.1)

where $t_{1/2}$ is the half decay time; $H_0$ is the initial foam height.

The summing up foaming ability of each surfactant is shown in Fig. 3.6. Three anionic surfactants BIO-TERGE AS-40, BIO-SOFT D-62 LT and STEPANOL WA-EXTRA showed an overall better performance in the pouring experiments, especially BIO-TERGE AS-40. STEPANTEX VT-90 had better comprehensive foaming ability than BTC 1210-80%. Both of the nonionic surfactants exhibited poor summing up foaming ability. The closely packed adsorption films cannot form because the polyoxyethylene ether group in this type of surfactants presents meander structure in aqueous solution. Furthermore, the polyoxyethylene ether group is not capable of forming double electricity layers because of its poor hydration capacity.

In conclusion, in oil-free bulk foam experiments, the optimal foaming concentration was found to be 1.0 wt%. BIO-TERGE AS-40, Triton X-100, and STEPANOLTEX VT-90 were selected as representatives of anionic, nonionic, and cationic surfactants for the further sandpack tests.

However, the presence of oil has a great impact on foam stability. The critical micelle concentrations (CMC) of the selected surfactants are all below 0.2 wt%. It is accepted that when surfactant concentrations are lower, say below CMC, the dominate mechanism of foam stability is surface rheology, while when surfactant concentrations are much above CMC (0.5 wt%, 1 wt %), foam stability is governed by micellae stratification (Wasan and Koczo, 1994). Also, it is
reported the stability of pseudoemulsion film increases with surfactant concentration. When surfactant concentration is above CMC, the disjoining pressure increases and the foam film experiences a stepwise layer-to-layer thinning process. So, the surfactant concentration of 1 wt% was selected for further study.

Bulk foam experiments are widely used for surfactant screening. Whereas, foam performance characteristic by studies on the laboratory condition has a fundamental difference from foam flow behavior in porous media. In this case, pore-level foam generation and destruction events should be studied in order to better understand foam flooding process.
**Figure 3.6**  Summing up foaming ability ($F_q$) of different surfactants.
3.3 Foam Generation and Transportation in Porous Media

The above experiments are based on bulk foam performance in the laboratory condition. As there is no such equipment like foam generator outside the sandpack in the following sandpack experiments, foam generation only occurs inside the sandpack. Pore-level CO$_2$-foam flow needs to be exploration in-depth.

Foam is defined as a dispersion of gas in the liquid. Gas phase is made discontinuous by lamella. The liquid phase presents three forms inside the porous media: (a) occupying the smallest pore channels; (b) coating the pore walls which are originally filled with gas; (c) becoming lamella. Lamella is defined as the liquid films which make the gas phase discontinuous. A large proportion of the liquid phase is inside the pore channels. A majority of the gas phase becomes trapped gas when it flows through intermediate pore channels (Kovscek, 1993).

3.3.1 Foam Generation

Foam generation in porous media is controlled by three mechanisms: leaving behind, capillary snap-off and division.

Leaving-behind (Fig. 3.6 (a)) normally occurs at a lower gas flow rate. When two gas fronts from two directions covers the same pore body initially filled with liquid. Interstitial liquid is extruded and a lens is left behind. The lens later drains into a thin film. Only a continuous-gas foam will be formed if leaving-behind is the only mechanism to generate foam.

Snap-off (Fig. 3.6 (b)) is the dominate mechanism to generate foam in porous media (especially when the gas and foaming agent are injected simultaneously). Two models were used
to simplify snap-off process: (1) snap-off in straight cylinder pores and (2) snap-off in constricted pores.

1) Straight cylinder capillary

Figure 3.7 illustrates a gas bubble advancing inside the porous media. During its propagation, due to thermal fluctuations, even a slight disturbance may raise interface ripples. The Young-Laplace Equation can be expressed as shown in Eq. (3.4).

\[ P_C = P_{\text{non-wetting}} - P_{\text{wetting}} = P_G - P_L = 2\sigma C_m \]  

(3.4)

where \( \sigma \) is the interfacial tension between liquid and gas. \( C_m \) denotes the sum of the inverse of two principal radii of the curvature of the interface.

Combined with Eq. (3.5), Gauglitz (1988) proposed an equation to better illustrate the relationship between capillary pressure difference and interfacial curvature.

\[ P_{L_2} - P_{L_1} = \sigma \left[ R^{-1}(1) - R^{-1}(2) - R_{zz}(1) + R_{zz}(2) \right] \]  

(3.5)

where \( R(z) \) represents the radial location of the interface; \( P_{L}(z) \) denote liquid pressures at the specific radial location of the interface; and \( R_{zz}(z) \) reflects the transverse or longitudinal curvature at the specific radial location of the interface.

According to Eq. (3.6), the liquid pressure gradient between Point 1 and Point 2 drains out the liquid originally in Point 2 into Point 1 (Fig. 3.7). Besides, the diminishing of \( R(1) \) requires more liquid to flow in. After a drainage process, a liquid film was left behind on the pore wall. Assume that the initial thickness of this uniform liquid film is \( h_0 \) which is written as a function of the capillary radius (r) and the capillary number (\( N_{ca} \)).
Figure 3.7  Foam generation mechanisms: (a) leave behind, (b) snap-off, (c): division (reconstructed from Kovscek, 1993).
A large number of experimental and theoretical results reflects that, only when the liquid film thickness and capillary radius ratio is bigger than 0.1 ($h_0/r > 0.1$), the growing collars touch each other on opposite sides to form a lens (Fig. 3.8).

The thickness of this liquid film changes with time and space. Gauglitz (1986) put forward an equation to reflect the stability of the liquid film.

\[
\frac{h_0}{r} = 1.337 N_f^{\frac{2}{3}}
\]  

(3.6)

where $R_T$ denotes the radium of the largest inscribed circle; $3\nu \omega / \sigma$ is the characteristic time for inside rearrangement of a thin liquid film; $\omega$ denotes the growth-rate factor which reflects the stability of the liquid film ($\omega > 0$, unstable; $\omega < 0$, stable); and $\lambda$ is the wavelength of the disturbance. From Eq. (3.7), the collars are unstable when $\lambda > 2\pi r$ (Fig. 3.8) which means when the growth wavelength of the collar is bigger than $2\pi r$, a lens is created.

1) Neck constricted snap-off

The straight cylinder capillary is an ideal model that fails to reflect the realistic diagnostic feature of pores. In this case, constricted cornered capillaries model (Fig. 3.6 (c)) was used as an analogy with real pores. Combined with Eq. (3.4), Ransohoff, et al. (1987) derived an equation to determine the relationship of capillary pressure difference and interface curvature in constricted cornered capillaries as shown in Eq. (3.8).

\[
P_{L4} - P_{L3} = \sigma \cdot \gamma \cdot \left( \frac{1}{R_{f3}} - \frac{1}{R_{f4}} \right) = \sigma \left( \frac{1}{R_3} - \frac{1}{R_4} \right)
\]  

(3.8)
where \( R \) denotes the circumferential radium of the curvature of the wetting liquid in the corners. \( \gamma \) is the equilibrium entry interfacial curvature.

In the beginning, a gas front enters the pore throat initially filled with water and expands into the downstream pore body. From Fig. 3.9 and Eq. (3.8) the radius of the pore throat (Point 3) is smaller than that of pore body (Point 4). The capillary pressure gradient drives the liquid to flow into the pore constriction. In the stable state, \( R_6 > R_5 \), and \( P_{L5} > P_{L6} \), liquid flows out from a higher saturation state to heal the disturbance. In an unstable state liquid flows into the higher saturation part and amplifies the disturbance which requires \( R_6 < R_5 \). When \( R \) reaches the maximum inscribed circle radius, the corresponding interfacial curvature becomes \( \gamma \) and thus the capillary pressure difference increases to the critical capillary pressure. The instability grows faster than that in circular pores because the cornered constriction is non-axisymmetric. As a result, no stable collar grows. Snap off occurs only when the critical pore body to the pore throat aspect ratio is larger than 2, snap off occurs, otherwise snap off process is not admitted (Roof, 1970).

Whether snap-off events can successively occur at the same location or not depends on the gas saturation on the downstream pore body. High gas saturation translates into low capillary pressure on the downstream. Thus, the decreasing driving force of liquid rearrangement causes less liquid residents in the pore constriction.

Division requires the pre-existence of and the branching of lamella in the flow path. Larger bubbles are easier to divide than smaller ones (Kevin and Thomas, 1990). Hirasaki (1989) proposed that lamellae division is the predominate mechanism for generating lamellae under a large pressure gradient. When the initial bubble reaches the branch point, it divides into two separate bubbles and continues to move downstream (Kovscek, 1993).
Figure 3.8  Schematic of capillary snap-off in a cylindrical pore
Figure 3.9  Schematics of evolution of a stable collar (left) and lens (right) (Gauglitz, 1986)
Figure 3.10  Schematic of capillary snap-off in a constricted pore (reconstructed from Kevin and Radke. 1991)
3.3.2 Foam Destruction

From microscopic perspective, surfactants are used to stabilize the lens created by the snap-off mechanism. Apart from gravity drainage, two primary factors dominate during foam breakage: capillary suction and gas diffusion.

1) Capillary suction

“The Plateau borders” are defined as regions where lamellae terminate. At the Plateau border, the liquid pressure is lower than the gas pressure, while inside the lamellae, the liquid pressure is equal to the gas pressure. A capillary suction process occurs because of this liquid pressure gradient (Fig. 3.10). In this case, additional force ($\Pi$) must exist to balance capillary force (Derjaguin, 1939). Positive $\Pi$ indicates disjoining pressure while negative $\Pi$ indicates conjoining pressure and only positive $\Pi$ can balance the capillary suction force. Disjoining pressure is written as a function of film thickness ($h$), and results from intermolecular interaction (Van der Waals dispersion) and repulsive force (Knoll and Prud’homme, 1987). Different from capillary snap-off, capillary suction destruction is strongly affected by a surfactant solution.

Jimenez et al (1989) proposed an augmented Young-Laplace equation to describe the relationship between local capillary pressure $P_c$ and $\Pi$.

$$P_c = 2\alpha Cm + \Pi(h)$$ (3.9)

Also, they sketched an S-shaped isotherm to illustrate the relationship between $\Pi$ and $h$ (Fig. 3.11(a)) (Jimenez and Radke, 1989). For static foam, a new equation was derived by combining Eq. (3.4) and Eq. (3.5).

$$P_{L6} - P_{L5} = \alpha h_{zz} (6) / 2 - \alpha h_{zz} (5) / 2 - \Pi(6) + \Pi(5)$$ (3.10)
where \( h_{zz} \) denotes \( h \) differentiation with respect to the axial distance. \( \Pi (5) \) and \( \Pi (6) \) are the disjoining pressure at the locations of Point 5 and Point 6, respectively.

The first two terms on the right of equation can be neglected. In Fig. 3.11(a), assume \( r \) is slightly less than \( h_c \). A bigger film thickness translates to a larger \( \Pi \), which results in lower liquid pressure at Point 5. In this case, liquid is drained out of Point 6 to Point 5. This phenomenon proves that film is unstable when \( d\Pi/dh \) is positive and, vice versa. During the drainage process, the capillary pressure inside the porous media increases. The film thickness decreases until \( \Pi \) reaches \( \Pi_{\text{max}} \). Then, \( \Pi \) becomes \( \Pi_{\text{rup}} \) for a slight increase of the imposed capillary pressure. The capillary pressure that results for the \( \Pi_{\text{rup}} \) is defined as the “critical capillary pressure”.

The process of dynamic foam destruction is more complicated than that of static foam. The specific pressure for dynamic foam to coalescence is called the limiting capillary pressure (\( P^* \)). The coalescence process is illustrated in Fig. 3.11 (b). The lamella is moving from left to right. It is squeezed when it reaches the pore constriction. In order to conserve the liquid mass, the film thickness increases. Thus, the disjoining pressure decreases. The pressure gradient between the capillary pressure on the Plateau borders and the disjoining pressure drive the liquid inside of the lamella to put the system in an equilibrium state. The lamella then moves out of the pore throat and stretches. The film thickness decreases and the liquid fills into the lamella to equalize \( P_c \) and \( \Pi \). However, when the film thickness decreases to \( h_c \), and the surfactant fails to heal the coalescence of the lamella, rupture ensues.

Gas diffusion is the other mechanism for foam coalescence. Gas diffusion normally occurs from smaller bubbles to bigger bubbles after the bubbles have contacted with each other for a certain period of time. Taking a system consisting of two bubbles have contacted with each
other for a certain period of time. Taking a system consisting of two bubbles with different sizes as an example, according to the Young-Laplace equation the gas pressure inside of the bubble is higher than that outside the bubble (inside the bigger bubble). So, it is obvious that the chemical potential inside the smaller bubble is bigger than that outside, which results in gas diffusion from the smaller bubble to bigger one. With the shrinking of the smaller bubble, its curvature increases accordingly. Thus, the escape of more gas eventually causes the rupture of the smaller bubble.
Figure 3.11  Schematic of the breakage of a foam lamella (reconstructed from Kevin and Radke. 1991)
Figure 3.12  (a) Schematics of film thickness and disjoining pressure isotherm; (b) and dynamic foam in a periodically constricted pore (reconstructed from Kovscek, 1993)
3.4 Chapter Summary

After all surfactant tests, it can be concluded that: Anionic surfactants had the best comprehensive foaming ability, followed by non-ionic, and cationic surfactants. To generate stabilized foam, three types of surfactants, namely, BIO-TERGE AS-40, Triton X-100, and STEPANTEX VT-90 were selected as representatives of anionic, nonionic, and cationic surfactants, respectively. The optimal surfactant concentration was found to be 1 wt%.

In addition, the relevant foam theories are proposed guidance for foam generation, destruction, propagation in porous media.
CHAPTER 4
THE EVALUATION OF CO$_2$-FOAM MOBILITY REDUCTION

Foam is extensively used as a mobility control agent in enhancing oil recovery. Improvement in the unfavourable mobility ratio is the ultimate goal to enhance heavy oil recovery.

Foam mobility depends strongly on bubble sizes and foam texture (Rossen, 1999). It is a huge task if we study foam mobility from these aspects. Researchers proposed that foam mobility can be simply expressed as an empirical function of flow rate, foam quality and surfactant concentration. Traditionally, the Foam Resistance Factor (FRF) is introduced as an index to evaluate the foam mobility reduction ability. It is originally defined as the ratio of the brine mobility to foam mobility, and it is further simplified as the ratio of the pressure drop for the foam flow to the corresponding pressure drop for the water flow at the same superficial velocity after the foam system reaches a steady-state (Zang and Li, 2015).

In this chapter, a series of foam drive tests were conducted with foaming agents of different foam qualities and at different gas or liquid volumetric injection rates. Note that foam quality is defined as the gas fraction in the whole foam system. A foam quality of 60% corresponding to a gas fraction of 0.6, which means the gas-liquid volumetric flow ratio is 3:2. The objective is to assess the magnitude of the mobility reduction of different types of foam and to analyze the effects of the foaming agent type, foam quality and fluid injection rate on the foam resistance factor. Co-injection of CO$_2$ and the foaming agent was manifested as a reasonable injection strategy in this study after the comprehensive consideration of experimental apparatus.

Although foam is not advancing in the porous media as a single fluid, we are still encouraged to use Darcy’s equation to calculate the entire foam flow.
The steady-state FRF is derived as follow (Minssieux, 1974).

\[ FRF = \frac{\dot{\Lambda}w}{\dot{\Lambda}f} = \frac{kw}{uw} / \frac{kf}{uf} \quad (4.1) \]

For foam flow, Darcy’s equation

\[ Q = -\frac{k \cdot A \cdot \left( \frac{\Delta P}{100} \right)}{\mu L} \quad (4.2) \]

In terms of mass,

\[ w_{foam} = Q \gamma_{foam} \]

\[ \gamma_{foam} = 1 + f_g (\gamma_g - 1) \]

\[ u_{foam} = \frac{\left( \frac{\Delta P_f}{100} \right)}{\Delta L} \cdot \frac{kA}{w_{foam}} \left[ 1 + f_g (\gamma_g - 1) \right] \quad (4.3) \]

The weight of the gas phase can be neglected,

\[ u_{foam} \approx \frac{\left( \frac{\Delta P_f}{100} \right)}{\Delta L} \cdot \frac{kA}{w_{foam}} (1 - f_g) \]

\[ u_{foam} \approx k \cdot A \cdot \frac{\left( \frac{\Delta P_f}{100} \right)}{\Delta L} \cdot \frac{1}{\frac{Q_f}{60}} \]

For conventional waterflooding, combined with Darcy’s equation,

\[ \frac{\Delta P_W}{14.7} = \frac{\left( \frac{Q_f}{60} \right) \cdot \mu}{kA} \]

Substituting in Equation 4.1, FRF can be determined by
\[ FRF = \frac{\Delta P_f}{\Delta P_w} \cdot \frac{Q_w}{Q_f} \]

\[ FRF = \frac{\Delta P_f}{\Delta P_w} \cdot \frac{Q_w}{Q_f} \]

If \( Q_w = Q_f \)

\[ FRF = \left[ \frac{\Delta P_f}{\Delta P_w} \right] \quad (4.4) \]

where \( k \) is the absolute permeability of the sand pack, \( D \); \( \mu_{foam} \) denotes the foam viscosity, \( \text{cp} \);

\( f_g \) represents foam quality; \( \gamma_g \) is gas gravity, \( m/s^2 \); \( Q_w, Q_f \) are injection rates of water and foam solution, respectively, \( \text{cm}^3/\text{min} \); \( L \) is the effective length of the sandpack, \( \text{cm} \); \( A \) is the cross-section area of the sandpack, \( \text{cm}^2 \); where \( \Delta P_f \) and \( \Delta P_w \) are pressure different across the sandpack during waterflooding and foam flooding, respectively, \( \text{kPa} \);

\[ 4.1 \text{ Experimental Equipment and Apparatus} \]

The experiments were conducted at ambient conditions (20°C and 101 kPa).

1. The brine was prepared following the procedures stated in Appendix A.1.

2. A consolidated sandpack with an effective length of 27.43 cm (0.9 ft) is contained in a stainless-steel tubing with a 2.41 cm (0.95 in.) inside diameter. The sandpack properties are illustrated in Table 4.1.

3. A syringe pump (500D, TELEDYNE ISCO Inc., USA) with a maximum working pressure of 13790 kPa and a maximum volume of 500 cm\(^3\) along with a transfer cell were used to inject fluid into the sandpack at various flowrates. Ten valves were used to control the injection process.
4. A pressure transducer was connected into the system to monitor the pressure gradient automatically across the sandpack during each flooding process by recording pressure data in a data acquisition computer. The range of the pressure transducer was from 0~7000 kPa with a reading accuracy of ±0.08%. In addition, two highly sensitive digital pressure gauges were connected to the inlet and outlet ends of the sand pack to verify the accuracy of the pressure transducer.

5. A CO₂ cylinder connected with a nitrogen gas type flow mass controller (EL-FLOW® Select Series Mass Flow Controller, Bronkhorst Inc., The Netherlands) with the reading accuracy of ±1.0% full scale was used to inject CO₂ into the sandpack at a constant flow rate. The calibration procedures of the gas flow controller are explained in Appendix B.

6. Nitrogen gas, stored in the nitrogen storage vessel, was used for leakage tests in the experiments.

7. Three commercial surfactants (Triton X-100, STEPAN TEX VT-90 and BIO-TERGE AS-40) selected by bubble column experiments were used. The detailed surfactant information is illustrated in Appendix A.2. The surfactant concentration was 0.5% in weight.

### 4.2 Experimental Preparations

1) Sand Packing

Silica sand (Bell & Mackenzie Co. Ltd., USA) was wet packed in this experiment. A vibrator was connected to the air tube and the sandpack was vibrated at 800 kPa for 8 hours.
in order to further compact the sand pack. During the shaking stage, brine was added into the sandpack occasionally until the sandpack was completely saturated with brine. Finally, the air tube was connected again to either end of the sand pack to dry the sandpack system until no water came out.

2) Leak Test and Evacuation

A nitrogen cylinder (Praxair, with purity of 99.99%) was connected to the gas outlet line to pressurize the sandpack to 344.74 kPa. The system was considered leak-free when the reading differential pressure was within a reasonable range (normally 0~20.68kPa) even after leaving it for 24 hours. If not, a leak detective by a soapy liquid detector was required to determine the leak locations. Then, a vacuum pump (M16C Single Phase, Fisher Scientific Inc., USA) was used to vacuum the system at -94 kPa for 40 minutes to remove the gas and liquid inside.

3) Pore Volume and Porosity Measurement (Gravity Imbibition)

A beaker was filled with distilled water and the total volume of water was recorded as $V_1$. Then, the beaker was placed about 90 cm higher than the sandpack model. A long plastic tube was connected between the either end of the sandpack and the beaker. Water imbibitions occurred because of the wet-loving property of the sand used in this study. The remaining water volume $V_2$ was recorded when no water was sucked into the sand pack. The pore volume of the sandpack could be calculated as the D-value of $V_1$ and $V_2$ ($V_1-V_2$). The bulk volume of the sandpack model was known. The porosity was calculated by Eq. 4.5.

$$\phi = \frac{V_p}{V_b}$$  \hspace{1cm} (4.5)
where $\phi$ is the porosity of the sandpack, %; $V_p$, $V_b$ are the pore volume and bulk volume of the sandpack, cm$^3$, respectively. The detailed sandpack properties in this test are shown in Table 4.1.

4) Absolute Permeability Measurement

Brine was injected at various flow rates (0.5 cm$^3$/min, 1 cm$^3$/min, 1.5 cm$^3$/min, 2 cm$^3$/min, 2.5 cm$^3$/min) into the evacuated sandpack by pump for permeability determination. The corresponding pressure drops were recorded by two pressure gauges. According to Darcy’s equation (Eq. 4.2), the differential pressure should be proportional to the aqueous flow rate. The permeability of the sandpacks used in this experiment was 9.8 D.

4.3 Experimental Procedure

Details of the experiment are summarized as follow.

1. As standard foam test procedures, the sandpack was pre-flushed with CO$_2$ before starting the test to displace gases that are insoluble in water.

2. CO$_2$ was injected concurrently with foaming agents at various gas-liquid volumetric injection ratios. The steady-state pressure differences across the inlet and outlet of the sandpack were measured by pressure transducer at various gas/liquid injection rates. After each foam drive experiment, 2 PV brine was injected to displace the CO$_2$ and foaming agents remaining inside the sandpack. In most cases, the tests lasted until a steady-state pressure across the pack was achieved. The foam qualities in this study are defined at ambient conditions and range from 50% to 94.1% for the flowrates of 2.5 cm$^3$/min, 3 cm$^3$/min, 4 cm$^3$/min, 4.5 cm$^3$/min, 5 cm$^3$/min, 6 cm$^3$/min, 8 cm$^3$/min, 8.5 cm$^3$/min, 10 cm$^3$/min. Note that CO$_2$ is compressible, the gas flowrate at ambient
condition and in the porous media after foam flooding attaining steady state are different. Besides, surfactant adsorption and desorption equilibrium cannot be obtained in many laboratory experiments, especially in short flooding period, so they are ignored in this study.

3. After foam flooding, 2 PV brine was injected to flush the sandpack. Waterflooding was conducted then as a baseline experiment. The brine injection rate was the same as the total injection rate in the porous media. The steady-state pressure differences across the inlet and outlet of the sand pack were measured by pressure two taps at various brine injection rates.

The experiment setup is illustrated in Fig. 4.1.
Table 4.1 Sandpack properties in foam flooding in the absence of oil experiment

<table>
<thead>
<tr>
<th>Sand type</th>
<th>OD, cm</th>
<th>Length, cm</th>
<th>Initial pore value, cm$^3$</th>
<th>Initial porosity, %</th>
<th>Initial water permeability, D</th>
</tr>
</thead>
<tbody>
<tr>
<td>Silica</td>
<td>3.3</td>
<td>27.43</td>
<td>45.5</td>
<td>27</td>
<td>9.8</td>
</tr>
</tbody>
</table>
Figure 4.1 Experimental schematic of foam flooding: (1) brine injection pump, (2) CO₂ pump, (3) oil/ surfactant solution, (4) gas mass flow controller, (5) pressure transducer, (6) sandpack model, (7) graduated cylinder, (8) data acquisition system;
4.4 Results and Discussions

From Figures 4.2~4.12, most foam flooding pressure response curves experienced repeatedly up and down before achieving a constant pressure drop. Note that the sharp increase on the pressure response curves at the very beginning of the first couple of waterflooding tests was probably due to the existing of multiphase flow in the system. In this study, after carefully examining the pressure fluctuant during foam propagation in porous media, it can be concluded the pressure gradient curves experienced a steep rise when foam moved as a “continuous” bubble cluster while no obvious change (0 ± 0.69 kPa) was observed when foam moved slug by slug as sectional flows of gas and liquid. In this case, it can be predicted that the cyclical trend of the pressure response curves is probably because foam films were not distributed uniformly throughout the sand pack. This observation is in conformity of the conclusion proposed by Holm and Bernard (1986) that foam is not propagating as a single fluid. Gas and liquid moves separately through the sandpack even they were injected simultaneously at the same flow rate. Liquid moves through the porous media in the form of bubble film while gas phase is trapped by the constantly breakage and reformation of liquid films.
Figure 4.2  Pressure drop response curves of waterflooding and the TX-100 foam experiment, 50% foam quality and 4 cm$^3$/min total injection rate versus time
Figure 4.3  Pressure drop response curves of waterflooding and the VT-90 foam experiment, 50% foam quality and 4 cm$^3$/min total injection rate versus time
Figure 4.4  Pressure drop response curves of waterflooding and the AOS foam experiment, 50% foam quality and 4 cm³/min total injection rate versus time
Figure 4.5  Pressure drop response curves of waterflooding and the TX-100 foam experiment, 66.7% foam quality and 3 cm$^3$/min total injection rate versus time
Figure 4.6  Pressure drop response curves of waterflooding and the VT-90 foam experiment, $66.7\%$ foam quality and $3\text{ cm}^3/\text{min}$ total injection rate versus time
Figure 4.7  Pressure drop response curves of waterflooding and the AOS foam experiment, 66.7% foam quality and 3 cm$^3$/min total injection rate versus time
Figure 4.8  Pressure drop response curves of waterflooding and the TX-100 foam experiment, 80% foam quality and 5 cm$^3$/min total injection rate versus time
Figure 4.9    Pressure drop response curves of waterflooding and the AOS foam experiment, 80% foam quality and 5 cm³/min total injection rate versus time
Figure 4.10 Pressure drop response curves of waterflooding and the VT-90 foam experiment, 80% foam quality and 5 cm³/min total injection rate versus time
Figure 4.11  Pressure drop response curves of waterflooding and the TX-100 foam experiment, 94.1% foam quality and 8.5 cm³/min total injection rate versus time.
Figure 4.12  Pressure drop response curves of waterflooding and the AOS foam experiment, 88.9% foam quality and 4.5 cm$^3$/min total injection rate versus time
4.4.1 The Effect of Foam Quality on Foam Resistance Factor

The pressure gradient curves were difficult to reach the steady state when foaming agents are of lower foam quality (50%). When CO$_2$ fraction was of 0.67, TX-100 foam flooding was still difficult to reach the steady state with the pressure gradient curves presenting cyclical trend with the peak to bottom values varying from 27.6 to 41.4 kPa. The pressure gradient curve of VT-90 also cycled up and down and failed to reach a state of equilibrium. However, AOS foam successfully obtained a constant pressure difference at 24.8 kPa.

Although the sandpacks used in these tests are homogenous with no gas blocking phenomenon, it is still acceptable that although the foam flooding pressure gradient sometimes cannot reach a steady state because the foam is unstable with constant breakage and reformation, it still partially reflect foam capacity ability by taking an average of the maximum and minimum pressure differences. Under this circumstance, a minimum foam resistance factor was found at 50% foam quality because of the low gas fraction. Foam of 50% foam quality is regarded as “wet foam”, which consists of smaller bubbles (Holm, 1968). As stated previously, gas diffusion from smaller bubbles to bigger ones is the primary mechanism for foam destruction. Besides, the sandpack is short (27.43 cm) in this experiment. Those small bubbles may not rupture throughout the foam propagation process. As bubbles which destruct and reform continuously offered more resistance to flow compared with those offered by stable bubbles (Bernard and Jacobs, 1965). In this case, the foam resistance factor is lower at 50% foam quality. From Fig. 4.9~4.12, when the foam quality was 80%, the pressure response curves of all three surfactants were very smooth and reached the steady-state successfully in the later stage. This was also the case with foam experiments with foam qualities of 88.9% and 94.1%. It can be predicted that at high foam
quality, bubbles are closely assembled and cannot move independently as easily as foam with lower foam quality. The foam mobility can be calculated by Eq. (4.6).

\[
\lambda = \frac{Q \cdot L}{A \cdot \left( \frac{\Delta P}{100} \right)}
\]  

(4.6)

Q is the total flow rate of the foam system (cm\(^3\)/s); L is the length of the sandpack (cm); A is the cross-section area of the sandpack (cm\(^2\)); \(\Delta P\) denotes the differential pressure across the sandpack (kPa).

From Fig. 4.13, Fig. 4.14 and Table 4.2, \(FRF\) was highest at 80% foam quality at the same liquid flow rate although there appears to be some uncertainties for some tests conducted at a very high total injection rate (10 cm\(^3\)/min). The trend was the similar at the same gas flow rate. So it can also be speculated that foam quality has no significant effect on foam mobility at high total injection rates. Combined with the pressure response curves analysis results, foam with 80% foam quality reached the steady state easier. So, this specific foam quality was chosen in the later oil displacement experiments.

### 4.4.2 The Effect of Flow Rate on Foam Resistance Factor

After carefully examining the results shown in Table 4.2, it can be concluded that the \(FRF\) decreased with increasing flow rate at a fixed foam quality which is consistent with the conclusion drawn by Chang et.al. (1999). Besides, the FRF attained highest values at 2.5 cm\(^3\)/min total injection rate. Also, at the same foam quality, at the lowest gas injection rate (2 cm\(^3\)/min), the \(FRF\)s were the highest which indicates that the foam textures are extraordinary fine at 2 cm\(^3\)/min gas injection rate. Thus, an increase in the gas flowrate results in greater
pressure gradient when holding the liquid flowrate constant which means more fine-textured foam was generated.

4.4.3 The Effect of Foaming Agent Type on Foam Resistance Factor

Surfactants can be ranked as follows in terms of cationic surfactant (STEPANTEX VT-90) > nonionic surfactant (Triton X-100) > anionic surfactant (BIO-TERGE AS-40). Interestingly, the experimental results are not in consistence with those in bulk foam experiments. BIO-TERGE AS-40 was endowed with the best performance of generating foam on bulk foam experiment but had the worst foam sealing capacity; STEPANTEX VT-90, which was proved less effective in the previous study showed the best blocking ability. However, as illustrated from pressure response curves, BIO-TERGE AS-40 reached the steady-state condition in most cases which indicates the distribution of AOS-foam films are uniform and the pore channels and paths through which AOS-foams flow are probably occupied by large bubbles (trapped gas inside) generated by gas diffusion from smaller bubbles.
Figure 4.13 The effects of foam quality on foam mobility for different surfactants
Figure 4.14 The effects of flowrate on foam mobility for different surfactants
### Table 4.2 Summarize of Foam Resistance Factor at various foam qualities and gas/liquid flowrates

<table>
<thead>
<tr>
<th>Foam quality</th>
<th>Flowrate (g: CO₂; s.s.: surfactant solution)</th>
<th>Foam Resistance Factor (FRF)</th>
</tr>
</thead>
<tbody>
<tr>
<td>@ 101kPa</td>
<td>in porous media</td>
<td>TX-100 AOS VT-90</td>
</tr>
<tr>
<td>TX-100</td>
<td>AOS</td>
<td>VT-90</td>
</tr>
<tr>
<td>50%</td>
<td>8 (4 g+4 s.s.)</td>
<td>5</td>
</tr>
<tr>
<td>40%</td>
<td>45%</td>
<td>4.6</td>
</tr>
<tr>
<td>41%</td>
<td>46%</td>
<td>5.7</td>
</tr>
<tr>
<td>46%</td>
<td>8 (4 g+4 s.s.)</td>
<td>9</td>
</tr>
<tr>
<td>4 (2 g+2 s.s.)</td>
<td>10.7</td>
<td></td>
</tr>
<tr>
<td>66.7%</td>
<td>6 (4 g+2 s.s.)</td>
<td>12.2</td>
</tr>
<tr>
<td>59%</td>
<td>61%</td>
<td>7.3</td>
</tr>
<tr>
<td>58%</td>
<td>65%</td>
<td>14.3</td>
</tr>
<tr>
<td>2 (2 g+1 s.s.)</td>
<td>15.7</td>
<td></td>
</tr>
<tr>
<td></td>
<td>11.4</td>
<td></td>
</tr>
<tr>
<td>80%</td>
<td>5 (4 g+1 s.s.)</td>
<td>15.7</td>
</tr>
<tr>
<td>74%</td>
<td>76%</td>
<td>13.5</td>
</tr>
<tr>
<td>76%</td>
<td>70%</td>
<td>8.3</td>
</tr>
<tr>
<td>79%</td>
<td>13.7</td>
<td></td>
</tr>
<tr>
<td>73%</td>
<td>2.5 (2 g+0.5 s.s.)</td>
<td>20.1</td>
</tr>
<tr>
<td>74%</td>
<td>10 (8 g+2 s.s.)</td>
<td>7.4</td>
</tr>
<tr>
<td>88.9%</td>
<td>4.5 (4 g+0.5 s.s)</td>
<td>8.5</td>
</tr>
<tr>
<td>86%</td>
<td>87%</td>
<td>6</td>
</tr>
<tr>
<td>88%</td>
<td>19.3</td>
<td></td>
</tr>
<tr>
<td>87%</td>
<td>13.5</td>
<td></td>
</tr>
<tr>
<td>8.5 (8 g+0.5 s.s.)</td>
<td>1.7</td>
<td></td>
</tr>
<tr>
<td>94%</td>
<td>94%</td>
<td>13.5</td>
</tr>
<tr>
<td>91%</td>
<td>90%</td>
<td>11.1</td>
</tr>
</tbody>
</table>
4.5 Chapter Summary

In this chapter, the most effective surfactant type, foam quality and gas/liquid flowrate were determined by steady-state foam flow experiments which give a direction for the following oil recovery experiments optimization. Several conclusions are drawn as follow.

1. The foam resistance factor increase with increased foam quality ranging from 50%~80%, and reached the highest level at the foam quality of 80%.

2. The foam mobility increased with the increasing flow rate at a constant total fluid injection rate. Thus, at the same foam quality, foam mobility is the lowest at lower gas injection rate (2cm³/min). This conclusion proves that the reliance of high flowrates and high foam quality to achieve “strong foam” is unrealistic.

2. VT-90 foams exhibited the highest foam resistance factor while AOS foams exhibited the lowest. This ranking differs from the one concluded from bulk foam experiments which further illustrates the fundamental difference between bulk foams and foams in porous media.
CHAPTER 5

FOAM FLOODING IN ENHANCED OIL RECOVERY

The objective of this chapter is to evaluate the oil displacement efficiency of different types of CO₂-foams as a tertiary enhanced oil recovery method. The types of foam are: TX-100 foam, VT-90 foam and AOS foam. In addition, CO₂ and foaming agent were co-injected at 2 cm³/min and 0.5cm³/min, respectively. The reason to use this strategy is that the foam quality of 80% is necessary to initiate foam formation and oil transportation (Manngardt, and Novosad, 2000) which is in consistence with the previous conclusions drawn in Chapter 4 that foam used in this study obtained the lowest mobility at 80% foam quality with the total injection rate of 2.5 cm³/min.

5.1 Experimental Equipment and Apparatus

1. See Appendix A1 for brine and oil preparation procedures.

2. The properties of the sandpack models used in four oil displacement tests are the same as that used in the foam mobility reduction experiments except for the porosities and permeabilities for each test.

3. A syringe pump (500D, TELEDYNE ISCO Inc., USA) along with transfer cell were used to inject fluid into the sand pack at various flowrates.

4. A pressure transducer was connected to the system. Also, two highly sensitive digital pressure gauges were connected to the inlet and outlet ends of the sand pack. A CO₂ cylinder was connected with the gas flow controller to inject CO₂ into the sandpack at a constant flow rate.
5. Three commercial surfactants (Triton X-100, STEPANTEX VT-90 and BIO-TERGE AS-40) of the same concentration (0.5 wt %) were used.

6. Oil recovery apparatus was installed at the outlet end of the sandpack. Oil produced during water flooding and foam flooding was collected at the outlet of the sand pack every 5 or 10 minutes by a plastic beaker. Wet phase (brine) was at the bottom of the beaker while non-wetting phase (oil) was at the top because of the density difference. A centrifugal separator (Fisher Scientific Inc., USA) was used to separate the oil and brine collected in each beaker completely at 6500 rpm for at least 1 hour because the boundary of oil and brine was obscure and a certain amount of oil was attached to the beaker wall. The oil volume is determined as the D-value between the recorded total liquid volume and brine volume after centrifugation.

5.2 Experimental Procedures

1. The whole system was maintained at an ambient temperature (20°C) and pressure (101 kPa) throughout the experiments. Typical sand packing, leak test and evacuation; the measurements of sandpack pore volume, porosity, and permeability were performed. Between experiments, these procedures were repeated for the next test.

2. After determining the basic sandpack properties, the original oil saturation measurement was conducted before the start of each test. Oil was added into the transfer cylinder and injected into the sandpack at a constant injection rate (0.1 cm$^3$/min). A graduated flask with a sealer to prevent water from vaporizing was placed at the outlet end of the sandpack to collect the displaced brine for a period of time until no additional brine was produced, which represents the sandpack reached the residual brine status. Then, the
produced brine volume was recorded in the tube as the initial oil saturation. This value is equal to the original oil saturation. The sandpacks used in this study were consolidated and the oil injection rate was lower, so the original oil saturation of each test was approximately the same around 96%. The detailed information is illustrated in Table 5.1.

3. Five experiments were performed to determine the oil displacement efficiency of different types of surfactants. At the first stage, water flooded the sand pack at 0.4 cm$^3$/min flowrate until the water cut was greater than 95%. Then, foam flooding was conducted immediately as a tertiary EOR by co-injecting CO$_2$ and the foaming agent containing BIO-TERGE AS-40 into the pack until no oil was produced. The gas, liquid volumetric injection rates were 2 cm$^3$/min and 0.5 cm$^3$/min, respectively. According to the previous research, in steady-state foam flow experiments, foam quality that shows the highest resistance factor is consistent with foam that has the greatest drive efficiency (Minssieux, 1974). A foam quality of 80% with a lower gas flowrate and total fluid flow rate (2.5 cm$^3$/min) was chosen. In addition, a 0.4 cm$^3$/min brine injection rate was set to avoid oil being displaced too fast so that less experimental data could be analyzed. It should be emphasized that the sandpacks used were similar except for permeability and porosity, and the fluid flowrates were unchanged in the five tests.
Table 5.1 Sandpack properties in oil recovery experiments

<table>
<thead>
<tr>
<th>Experiment No.</th>
<th>Porosity (%)</th>
<th>Pore Volume (cm³)</th>
<th>Permeability (D)</th>
<th>Initial oil saturation (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
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<td>9</td>
<td>97</td>
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<tr>
<td>5</td>
<td>33.0</td>
<td>45</td>
<td>10.5</td>
<td>96</td>
</tr>
</tbody>
</table>
5.3 Discussions and Results

1) Experiment # AOS

In Experiment # AOS, the porosity of the sand pack was 34.8% and the permeability was 9 D. The foaming agent used was 0.5 wt% BIO-TERGE AS-40.

The oil Recovery factor (RF) can be expressed as the ratio of the volume of oil collected after enhanced oil recovery to that of oil originally saturated in the sand pack. Figure 5.1 contains the relationship between the total pore volume of the displacing agent injected and the oil recovery factor. At the beginning of waterflooding, the oil RFs increased smoothly. Although the water injection rate was controlled at a low level, it is still difficult to observe the exact water breakthrough time. The growth rate then decreased after injecting 0.7 PV of brine. Forty-three percent (43%) of original oil in place (OOIP) had been recovered after 2 PV of brine was injected when the water cut reached 95%. Another 1 PV of brine was injected to ensure no additional oil was produced. Foam flooding was performed next. During the first 12 minutes, the oil RFs curve experienced a sharp increase to 53%. Then, it increased moderately and reached maximum (68%) after injecting 18PV of the total fluid. 25% of extra oil was recovered by AOS foam flooding.

The variation tendency of Fig. 5.2 was in consistent with that shown in Fig. 5.1. There were two time points with better displacement performance: (1) at the very beginning of the waterflooding period, and (2) BIO-TERGE AS-40 and CO₂ co-injection period with the oil productions of 0.28 cm³/min and 0.32 cm³/min, respectively. Figures 5.1 and 5.2 prove that foam flooding can efficiently reduce oil saturation in the sand pack below waterflood residual.
Figure 5.1  Oil RFs and oil production rate during waterflooding (WF)/ AOS foam flooding (FF) plotted with PV.
Figure 5.2  Oil RFs and oil production rate during waterflooding and BIO-TERGE AS-40 foam flooding plotted with production time
2) Experiment # TX-100

The experimental procedures were similar to Experiment # AOS except that the surfactant used this time was Triton X-100. The porosity of the re-packed sand pack was 34.4% and the permeability was 8.5 D.

During this experiment, the sand pack was reduced to residual oil saturation after brine injection. It was further reduced by the co-injection of foaming agent containing Triton X-100 and CO₂ until no oil was produced.

The characteristics of oil RFs during the EOR process are shown in Fig. 5.3, it is observed that the shape of curves of Experiments # AOS, and Experiment #TX-100 are similar. The oil RFs increased constantly after 2 PV of brine injected. The slope of the oil RF curve decreased to almost zero when the oil RF reached 50%. Foam injection stopped after injecting in total 26.5PV of liquid when water cut was higher than 99%. The ultimate oil RF at the end of foam floods was 82%. Sixty-four percent of the oil left behind by water flooding was produced by foam flooding.

By plotting the relationship between the displacing agent injected volume and the oil production rate (Fig. 5.4), it can be observed that, during the waterflooding period, the oil production rate curve increased steeply to 0.33 cm³/min in less than 30 minutes. Then, the rate decreased with some little fluctuations until it reached zero, followed by a sharp increase to 0.18 cm³/min by foam flooding.

The lower oil production rate compared with that of 0.33 cm³/min during water flooding shows that Triton X-100 is less effective in enhanced oil recovery.
Figure 5.3  Oil RFs and oil production rate during waterflooding (WF)/ TX-100 foam flooding (FF) plotted with PV
Figure 5.4  Oil RFs and oil production rate during waterflooding/ Triton X-100 foam flooding plotted with production time
3) Experiment # **STEPANTEX VT-90**

The foaming agent used in the third test was **STEPANTEX VT-90**. The porosity of the re-packed sand pack was 34.4% and the permeability was 8.5 D.

Figure 5.5 shows the cumulative oil recovery over the water flooding and foam flooding processes. The waterflooded oil recovery factor was 48% after 3.5PV of brine was injected, followed by another 1.5PV brine injection to ensure that residual oil saturation was achieved at the end of the water flooding process. Thirty-eight percent (38%) extra oil was obtained with 8.75 PV of fluid injected at the end of foam flooding.

Figure 5.6 illustrates that the highest oil production rate during water flooding and foam flooding was of the same value at 0.26cm$^3$/min.

Until now, it is hard to confirm that foam flooding contributes to the increasing oil recovery efficiency. Gas drive or continuous water drive may also be capable of recovering extra oil. In this case, two base run were carried out.

4) **Experiment # CO$_2$ + brine**

The permeability and porosity of the sand pack used in Experiment # CO$_2$ and brine were 10 D and 32%, respectively.

This experiment consists of two stages: (1) conventional water flooding at the flow rate of 0.4 cm$^3$/min, (2) co-injection of brine and CO$_2$ at the flow rate of 0.5 cm$^3$/min and 2 cm$^3$/min, respectively. The porosity of the sand pack was 32%. This test was designed to prove that the increase in oil recovery factor is to a large extent due to foam rather than CO$_2$.

Figure 5.7 and 5.8 demonstrate that the oil RFs were about 46% after water flooding. CO$_2$ and brine were injected simultaneously until the water cut was above 99%. The cumulative oil
RF was only 63%, which means that, after brine and CO\textsubscript{2} co-injection, only 17% additional oil was recovered. Obviously, it proves that foam is more efficient in oil production when used as a tertiary recovery option than CO\textsubscript{2}-brine co-injection.

5) Experiment # Waterflooding

Continuous water drive was conducted as the second baseline experiment. The permeability and porosity of the sand pack used in this experiment are 10.5 D and 33\%, respectively. There is a possibility that waterflooding recovers more oil than foam flooding because oil can destabilize foam, sometimes causing a lower foam viscosity than that of water during foam flow (Minssieux, 1974). This base run was set to prove the appreciable gain in oil recovery provided by foam flooding is more than the appreciable gain provided by waterflooding alone.

In the first stage, brine was injected at a 0.4 cm\textsuperscript{3}/min flowrate until the sandpack was waterflooded to immobile oil saturation. Later, brine was injected at a 1.68 cm\textsuperscript{3}/min flowrate. The experiment was continued until no additional oil was produced. The average pressure drop during AOS, TX-100, and VT-90 foam flooding processes was approximately 10 psi (69 kPa). Considering the compressibility of CO\textsubscript{2}, the density of CO\textsubscript{2} at atmosphere pressure (101 kPa) is approximately 0.0018 g/cm\textsuperscript{3}, while at 24.7 psi (170 kPa), the density is 0.0031 g/cm\textsuperscript{3} (NIST Chemistry WebBook, SRD 69). So, in the experimental condition, when the real injection rate of CO\textsubscript{2} is 1.18 cm\textsuperscript{3}/min, the corresponding set value of the mass flow controller is 2 cm\textsuperscript{3}/min. In this situation, the total injection rate was the sum of the injection rates of CO\textsubscript{2} (1.18 cm\textsuperscript{3}/min) and the surfactant solution (0.5 cm\textsuperscript{3}/min).

From Fig. 5.9, it is observed that the oil RF reached 0.42 after injecting brine for 6 hours. Then, the injection rate was increased which results in a higher pressure gradient and thus higher
relative permeability of the sandpack to brine. Another 15% oil was produced after 5 PV of brine was injected. The additional oil recovery during the second period was probably due to the continuous water channels after the first-stage waterflooding provided low resistance to water injected during the second waterflooding period.
Figure 5.5  Oil RFs and oil production rate during waterflooding/VT-90 foam flooding plotted with production time.
Figure 5.6  Oil RFs and oil production rate during waterflooding/ VT-90 foam flooding plotted with production time.
Figure 5.7  Oil RFs and oil production rate during waterflooding (WF)/ co-injection of brine and CO₂ plotted with PV and production time
Figure 5.8  Oil RFs and oil production rate during waterflooding/co-injection of brine and CO2 plotted with production time
Figure 5.9  Oil RFs and oil production rate during brine injection plotted with PV
Figure 5.10  Oil RFs and oil production rate during only brine injection plotted with production time
5.4 Determine the Residual Oil Saturation by Weighing Method

The weighing method was used to determine the residual oil saturation after the whole oil displacement process to verify or refute the accuracy of the oil recovery factor.

5.4.1 Experimental Apparatus

Five 25mL beakers along with an analytical balance (AG204, Mettler Toledo Inc., Canada) were used to weigh the weight of the samples. A roller Oven (507ET, Fann Inc., U.S.A) was used to dry the sample out of water and kerosene at different temperatures.

5.4.2 Experimental Procedures

1. The physical sand pack was evenly divided into four segments (Fig. 5.11). Sand containing fluids were sampled from five different test points: A₁, A₂, A₃, A₄, and A₅. Among them, A₁ is the inlet end of the sand pack, while A₅ is the outlet end of the sand pack. The length of each segment is 14.478 cm.

2. The weight of the five original samples from the specific locations mentioned above was measured and recorded as W₁.

3. The samples were placed into the oven to remove the water at the constant temperature of 105 °C for 24 hours. The weight of the water-free sample was measured and recorded as W₂.

4. Kerosene was used to rinse the oil repeatedly until the sands became colorless. Again, the sand was put into the oven to dry the kerosene at 120°C for 12 hours. The weight of the water and oil free sands was recorded as W₃.
5. The experimental procedures were repeated in the following three experiments. The density of water, oil and sand is known as 1 g/cm$^3$, 0.81 g/cm$^3$, and 2.3 g/cm$^3$. Combined with the known porosity, the residual oil saturation can be calculated by Eq. (5.1).

$$S_{or} = \left( \frac{W_2 - W_b}{\rho_{oil}} \right) \frac{1 - \phi}{\phi} \frac{W_3 - W_b}{\rho_{sand}}$$

where $\phi$ is the porosity of the sandpack, %; $W_b$ is the net weight of the beaker, g; $W_1$ is the weight of sand containing fluids (oil+water), g; $W_2$ is the weight of sand containing oil, g; $W_3$ is the weight of the dried sand, g; $\rho_o, \rho_w$ is the density of oil and water, respectively, g/cm$^3$.

5.4.3 Results and Discussions

Table 5.2 lists the detailed information of each residual oil saturation determination test.

In Experiment No.ROS-1, the average residual oil saturation of the five samples after AOS foam flooding was 34%. The ultimate oil recovery factor was 74%. The error is about 8% which within the limits of system error.

Similarly, in Experiment No.ROS-2, the average residual oil saturation at the end of TX-100 foam flooding was 26%, while the oil recovery factor was 82%. The error is also around 8%.

In Experiment No.ROS-3, the average residual oil saturation was 22%, which is in good agreement with the oil recovery factor which was 86%.

The residual oil saturation was 48% in Experiment No.ROS-4 which is the highest among all oil displacement tests, while the oil recovery factor of this test was 63%. Although the results are to some extent not convincing, they still reflect that foam flooding obviously increases the oil recovery efficiency.
In Experiment No. ROS-5, the average residual oil saturation was 41% which perfectly matched and the oil recovery factor which was 58%.

All experimental results analyzed here match those of the oil recovery experiments with reasonable error. In conclusion, CO₂-foam induced by STEPANTEX VT-90 recovered more residual oil after water flooding, while AOS foams failed to perform as robust as they were supposed to perform.
Figure 5.11  (a) Diagrammatize of Locations of samples in the sandpack; (b) digital photographs of samples during the course of the experiments (1: original sample; 2: water-free samples; 3: water and oil-free sample)
Table 5.2 List of average residual oil saturation at the end of each oil displacement experiment

<table>
<thead>
<tr>
<th>Exp No.</th>
<th>Sample</th>
<th>(W_1, g)</th>
<th>(W_2, g)</th>
<th>(W_3, g)</th>
<th>(V_{\text{oil}}, \text{cm}^3)</th>
<th>(V_{\text{water}}, \text{cm}^3)</th>
<th>(S_{\text{or}}, %)</th>
<th>Average (S_{\text{or}})</th>
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<td>A₁</td>
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<td>A₂</td>
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<tr>
<td></td>
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<td>29.87</td>
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<td>B₁</td>
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<td>B₄</td>
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<td>D₅</td>
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5.5 Mobility Reduction Ability of Different CO₂-foams with and without Oil

In previous studies, the Foam Resistance Factor (FRF) was introduced to evaluate the foam mobility reduction ability in the absence of oil. Similarly, the mobility reduction factor (MRF) is introduced as a measure of foam effectiveness in this section.

Parameter \( \text{MRF}_{\text{with-oil}} \) is defined as the ratio of measured pressure drop during the foam flooding to the corresponding pressure drop during waterflooding at the same injection rate in oil recovery experiments Eq. (5.2). \( \text{MRF}_{\text{no-oil}} \) is defined as the ratio of measured pressure drop during foam flooding to the corresponding pressure drop during waterflooding at the same injection rate in oil-free steady-state foam flow experiments Eq. (5.3). Note that as stated in Experiment# Waterflooding, 2.5 cm³/min total flowrate at ambient conditions is equal to a 1.68 cm³/min total flowrate in experimental condition.

\[
\text{MRF}_{\text{with-oil}} = \left( \frac{\Delta P_{\text{foam}}^{\text{with-oil}}}{\Delta P_{\text{brine}}^{\text{with-oil}}} \right)_u
\]  

(5.2)

\[
\text{MRF}_{\text{no-oil}} = \left( \frac{\Delta P_{\text{foam}}^{\text{no-oil}}}{\Delta P_{\text{brine}}^{\text{no-oil}}} \right)_u
\]  

(5.3)

Figure 5.12 shows the pressure response curves during oil displacement processes by different foaming agents. The \( \text{MRF}_{\text{with-oil}} \) and \( \text{MRF}_{\text{no-oil}} \) of different foaming agents are presented in Table 5.3.

As expected, the MFRs of each test were lowered by an order of magnitude which proves that oil deleteriously affects foam stability. STEPANTEX VT-90 still owns the highest foam mobility reduction factor with oil (3.5) compared to those of Triton X-100 (3.06) and BIO-TERGE AS-40 (1.1). These results are in good agreement with the trend of FRFs measured.
Table 5.3 Comparisons of the mobility reduction factor in foam flooding in the absence and in the presence of oil

<table>
<thead>
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<th>Oil phase</th>
<th>Surfactant</th>
<th>VT-90</th>
<th>TX-100</th>
<th>AOS</th>
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<td>Without oil</td>
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<td>33</td>
<td>25</td>
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<tr>
<td></td>
<td>TX-100</td>
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<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>AOS</td>
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<td>11</td>
<td>8.3</td>
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<tr>
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<td>VT-90</td>
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<td>57</td>
<td>29</td>
</tr>
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<td></td>
<td>TX-100</td>
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<td></td>
<td></td>
</tr>
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<td>AOS</td>
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</table>
Figure 5.12  Differential pressure characteristics during oil displacement by AOS foam, TX-100 foam, and VT-90 foam and baseline waterflooding
during foam flow experiments in the absence of oil. The sensitive degree of different types of foam to oil is defined as the ratio of the pressure gradient during foam flooding to the corresponding pressure gradient in oil free foam flow experiments, and the lower the ratio, the more sensitive a foam to oil (Mannhardt, 2000). From Table 5.3, it can be concluded that AOS foam is the most sensitive to oil while VT-90 foam is the least sensitive. This results fails to support the prediction that the oil used in this study stabilize the VT-90 foam. However, at least we can confirm that VT-90 foam is the least sensitive to oil.

5.6 Capillary End Effects

In conventional oilflooding processes, capillary end effects are a concern. Essentially, it is capillary effect arised at the outlet end of a porous media through which a two-phase fluids flow. It is characterized by an increase in water saturation within a certain distance from the outlet end of the sandpack. Before brine arrives at the outlet end, the distribution of the water saturation keeps being normal, the oil-water interface is concave towards the outlet, and the capillary pressure exists as the driving force for water flooding. However, as the water flows out of the sandpack, the capillary pressure intends to block the outflow as the result of the deformation of the interface and the wettability reversal, leading to higher water saturation in the vicinity of the sandpack outlet and a transient hysteresis before the outlet end witnesses a breakthrough of water.

Water saturation at breakthrough was difficult to determine because the sandpack used was short and the total injection rate was relatively high in this study. Water breakthrough occurred at the very early time so that we cannot see whether there was a delay in the breakthrough of water during oilflooding process. However, it is a normal practice for researchers to eliminate end effects in heavy oil displacement because of the adverse mobility ratio. Viscous fingering results
in much earlier water breakthrough time. Thus, in this study, we did not consider the outlet end effects.

5.7 Chapter Summary

In Chapter 5, a series of oil recovery experiments were implemented. The objectives were to determine whether foam flooding is a promising tertiary recovery method to improve oil recovery efficiency; to determine which type of CO₂ foam is more efficient in producing oil; and furthermore to study foam blocking ability with and without oil by introducing two parameters: MRFₜₜₜ with-oil, and MRFₜₜₜ no-oil. The following conclusions are drawn:

1. After conventional waterflooding, foam flooding is more efficiency and CO₂ foam generated by STEPANTEX VT-90 yielded less residual oil than AOS foam and TX-100 foam.

2. Through comparing the MRFₜₜₜ with-oil and MRFₜₜₜ no-oil, we can conclude that oil destabilizes foam because the MRFₜₜₜ with-oil of each foaming agent was significantly lower than the MRFₜₜₜ no-oil. More specifically, the presence of oil strongly destabilizes AOS foam, followed by TX-100 foam and VT-90 foam.

3. Although in bulk foam experiments, STEPANTEX VT-90’s comprehensive foaming ability was not satisfactory, it performed the best in modifying the mobility ratio and recovering oil.
CHAPTER 6

CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions

From the bulk foam experiments and sandpack flooding tests in the study, it can be concluded that:

1. In the foaming agent screening experiments, anionic surfactants showed the ability to generate fine foam with better foam ability and foam stability, followed by nonionic surfactants and cationic surfactants. BIO-TERGE AS-40 (anionic surfactant), STEPANTEX VT-90 (cationic surfactant), and Triton X-100 (nonionic surfactant) were selected for foam flooding. Besides, 0.5 wt% was chosen as the most suitable foaming concentration.

2. In the steady-state foam flow experiments, foam mobility was lower at foam quality of 80%, and the lowest foam mobility was obtained at the total flow rate of 2.5 cm³/min. VT-90 foam had the strongest blocking ability with the highest foam resistance factor.

3. In oil recovery experiments, immiscible foam was efficient as a tertiary recovery method. VT-90 foam was capable of recovering more water-flood residual oil, followed by TX-100 foam and AOS foam. The MRF decreased by one order of magnitude proves the experimental oil is detrimental to foam.
6.2 Recommendations

Based on the comprehensive studies on immiscible foam in enhancing oil recovery by bulk and porous media experiments, several recommendations are proposed for future study.

1. In bulk foam experiments, surfactant chemical properties such as carbon number, the length of carbon chain, etc., should be further studied in order to better evaluate surfactant properties. Foam stability in the presence of oil should be studied by the sign of entering (E), spreading (S), and bridging (B) coefficients by measuring the interfacial tension between different interfaces. More novel foaming formulas for CO₂-flood flooding such as gel-enhanced foam, and nano-particles enhanced foam should be explored.

2. In sandpack flooding experiments, foam propagation inside porous media should be further studied by using X-ray CT. The gas phase should be collected by during the courses of sandpack test to explore the mechanisms of gas and liquid in the porous media to establish foam micro-models. In addition, surfactant adsorption and the effect of salinity on surfactant properties should be considered.

3. Foam is not widely used in enhancing heavy oil recovery because of the unfavorable mobility ratio and the oil destabilizing effect on foam. However, in this study, immiscible foam flooding proves to be effective as a tertiary recovery method in the moderately viscous heavy oil (184 cp), studies should be performed to investigate foam effectiveness in different oil viscosities, and to find a critical oil viscosity that immiscible foam flooding is no longer practical.
APPENDIX A

EXPERIMENTAL PREPARATIONS

1. Brine Preparation

A 500 ml beaker was used to prepare the 0.2 wt% brine. 1 g sodium chloride was weighed by the precious balance, and 499 g distilled water was added to dissolve it. The brine was diluted completely by a magnetic stirrer hotplate (Fisher Scientific., USA).

2. Surfactant Solution Preparation

Seven different classes of surfactants were used in this study: STEPANOL WA-EXTRA, BIO-SOFT D-62 LT, BIO-TERGE AS-40, STEPANTEX VT-90, BTC 1210 -80%, BIO-SOFT N1-3 (Stepan Inc., Canada), and Triton X-100 (Sigma-Aldrich Inc., Canada). Surfactants of various concentrations in the aqueous condition (0.1 wt %, 0.5 wt %, 1.0 wt %) were prepared by mixing them with the prepared brine.

Surfactants are in different conditions in ambient environment. STEPANOL WA-EXTRA, BIO-TERGE AS-40, BTC 1210 -80%, and BIO-SOFT N1-3 are clear or slightly hazy liquid and soluble in brine; Triton X-100 is high viscous liquid which dissolves in brine after standing for 1-2 hours. STEPANTEX VT-90, and BIO-SOFT D-62 LT are saponaceous, which means they must be stirred for a period of time until no suspension surfactant particles appears in the solution. It should be noticed that the stirring process of STEPANTEX VT-90, and BIO-SOFT D-62 LT should be done slowly and carefully to avoid foam generation, thus influencing their foam ability.
All surfactant solutions were prepared at most 5 hours before use and discarded after two day. The surfactant information is shown in Table A.1.

After surfactant screening experiments, three surfactants were selected for the following sandpack flooding experiments: BIO-TERGE AS-40, Triton X-100 and STEPANTEX VT-90. The physical appearances of these three surfactants at 20°C and in water are shown in Fig. A.1, and their chemical properties are illustrated in Table A.2.
<table>
<thead>
<tr>
<th>Surfactant</th>
<th>Company</th>
</tr>
</thead>
<tbody>
<tr>
<td>Anionic surfactant</td>
<td></td>
</tr>
<tr>
<td>STEPANOL WA-EXTRA (Sodium Lauryl Sulfate)</td>
<td></td>
</tr>
<tr>
<td>BIO-SOFT D-62 LT (Sodium C_{10-16} benzenesulfonate)</td>
<td>Stepan</td>
</tr>
<tr>
<td>BIO-TERGE AS-40 (Sodium C_{14-16} olefin sulfonate)</td>
<td></td>
</tr>
<tr>
<td>Cationic surfactant</td>
<td></td>
</tr>
<tr>
<td>STEPANTEX VT-90 (Quaternary ammonium salts)</td>
<td></td>
</tr>
<tr>
<td>BTC 1210 -80% (Didecyl dimethyl ammonium choride, DDAC)</td>
<td></td>
</tr>
<tr>
<td>Nonionic surfactant</td>
<td></td>
</tr>
<tr>
<td>BIO-SOFT N1-3 (Poly(oxy-1,2-ethanediyl), alpha-undecyl-omega-hydroxy-)</td>
<td>Sigma-Aldrich</td>
</tr>
<tr>
<td>Triton X-100 (Octylphenol ethylene oxide condensate)</td>
<td></td>
</tr>
</tbody>
</table>
Table A.2 Detailed properties of surfactants used in steady-state foam resistance factor and oil displacement experiments

<table>
<thead>
<tr>
<th>Property @ 20°C</th>
<th>Name</th>
<th>BIO-TERGE AS-40</th>
<th>Triton X-100</th>
<th>STEPANTEX VT-90</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chemical description</td>
<td>Sodium C\textsubscript{14-16} olefin sulfonate</td>
<td>Octylphenol ethylene oxide condensate</td>
<td>Quaternary ammonium salts</td>
<td></td>
</tr>
<tr>
<td>Appearance</td>
<td>Liquid, clear</td>
<td>Liquid, slightly hazy, colorless</td>
<td>Paste</td>
<td></td>
</tr>
<tr>
<td>Specific gravity (γ)</td>
<td>1.06</td>
<td>1.065</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Viscosity (cp)</td>
<td>125</td>
<td>240</td>
<td>200-300</td>
<td></td>
</tr>
</tbody>
</table>
Figure A.1  (a) Digital photos of surfactants used in surfactant screening experiments. (b) Physical appearance of Triton X-100, BIO-TERGE AS-40, and STEPANTEX VT-90 (left: appearance @ 20°C; right: appearance in solution)
3. Oil Preparation

The dead oil sample used in this study was tested by the Saskatchewan Research Council (SRC) with the original viscosity and density of 132000 cp and 996.98 kg/m$^3$, respectively at ambient conditions (20°C, atmospheric pressure). A certain amount of kerosene was added into the crude oil to reduce its viscosity. A viscometer (DV2T Touch Screen Viscometer, BROOKFIELD, USA) was repeatedly used to measure the oil viscosity. The final oil viscosity in this study was 184 cp, and the oil density was 0.82 g/cm$^3$. 
APPENDIX B

GAS FLOW CONTROLLER CALIBRATION

A Nitrogen gas type mass flow controller (EL-FLOW® Select Series Mass Flow Controller, Bronkhorst Inc., The Netherlands) was used to control the flowrate of CO₂.

From the theoretical gas correction factors for various gases with respect to nitrogen provided by Bronkhorst, the conversion factor for CO₂ is 0.74 at 20°C, 1atm. However, considering the gas compressibility and the difference in measuring apparatus used, experiments were conducted to determine a more reliable conversion factor.

Seven gas flow rates (14 cm³/min, 17.5 cm³/min, 25 cm³/min, 35 cm³/min, 40 cm³/min, 45 cm³/min, 55 cm³/min) were set to enter into the gas flow controller, and the flow rate at the outlet of the flow controller were measured by a flowmeter.

By plotting the relationship between the set gas flowrate and real gas flowrate together with the trend line (Fig. B), the output values were linearly proportional to the set values. The gas conversion factor from nitrogen to CO₂ is defined as the slope of the trend line which is 0.2.
Figure B  Relationship between designed and real gas flowrate.


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