Phase Behavior Study for Chemically Enhanced Waterflooding

Chinmoy Dutta[*]
Bidisha Borah[*]
Suraiya Rahman [**]
Ranjan Phukan[*]
Bhaskarjyoti Saikia [**]

Abstract

During chemical based enhanced oil recovery (EOR) process, ultralow oil-water interfacial tension (IFT) (less than 10^{-2} mN/m) should be achieved to mobilize the residual oil left behind after conventional recovery methods. This research work studied the phase behaviour of surfactant systems with a view to screen formulations for chemically enhanced waterflooding with ultralow IFT. The phase behaviour tests help to determine the optimum salinity, which is one of the most important parameter in the surfactant flooding because it is at this salinity at which maximum oil recovery can be obtained. The phase behaviour studies of (surfactant + brine + crude oil) systems were performed with various combinations of chemicals with crude oil (31 ^{0}API) of an Upper Assam oilfield at reservoir temperature (70 ^{0}C). The surfactants considered for the experimental works were Sodium Dodecyl Sulphate (SDS, anionic), TritonX-100 (TX-100, non-ionic) and Black Liquor (BL, natural). Five core flood experiments were done to determine the EOR potential of the surfactants used and to validate the chemical formulations that performed well in phase behavior experiments. Mixed surfactant systems were found to perform better in the phase behavior tests and recovered higher residual oil during core flooding due to synergistic effect.

Keywords:

Enhanced Oil Recovery;
Microemulsion;
Phase behaviour;
Black Liquor;
Core Flooding.

Author correspondence:

Chinmoy Dutta
M.Tech. Program, Department of Petroleum Technology
Dibrugarh University, Assam, India
Email: chinmoydutta.petro@gmail.com

1. Introduction

The major part of the world's crude oil production currently comes from aging oil fields. With the discovery of new reserves steadily declining over the years, it is pertinent to strive for increasing the recovery factors of the producing oilfields to meet the ever increasing energy demand. On an average, the worldwide recovery factor from hydrocarbon reservoirs is about a third of what was originally present in the reservoir. The remaining 2/3 of the original resource being substantial is an attractive target for enhanced oil recovery (EOR) technologies. Technically, the EOR processes can mobilize or recover the oil left behind or that cannot be produced economically from mature and depleted oil reservoirs. Although more expensive in implementation, EOR methods are implemented successfully in many parts of the world. Among the EOR techniques, chemical flooding is one of the widely used methods capable of recovering an additional 35% of the original oil in place (OOIP) after conventional waterflooding [1]. These methods are based on the injection of water containing chemical additives like surfactants, polymers, alkalis, salts, nanoparticles etc. depending upon the specific application. Currently, alkaline-surfactant-polymer (ASP) is considered as the most promising chemical method in EOR because it integrates the advantages of alkali, surfactant and polymer.

---

[*]Department of Petroleum Technology, Dibrugarh University, Assam, India.

[**] Department of Petroleum Engineering, DUIET, Dibrugarh University, Assam, India.

Because of the synergy of these three components, ASP has the ability to improve microscopic displacement as well as the volumetric sweep efficiency.

Injection of surfactants solution into the reservoir leads to the formation of microemulsions (ME) at the interface between crude oil and water. ME are thermodynamically stable, isotropic dispersions of oil and water stabilized by surfactants (and/or cosurfactants). By creating a middle phase ME using brine, oil, surfactant, and/or cosurfactant, it is possible to obtain ultra-low IFT [2]. The formation & phase behaviour of ME when brine, oil & surfactant are mixed was first described by Winsor (1954). The phase behaviour of ME are dependent on the nature & concentration of surfactants, co-surfactant, oil, brine, co-solvents, temperature etc. [3-5]. For particular ME system, phase behaviour is strongly affected by the salinity or concentration of electrolyte. ME phase behavior is described as Winsor type I, type II, and type III. The middle phase ME or Winsor type III is important in EOR because of its ultra-low IFT ($<10^{-2}$ mN/m). By systematically varying the salinity at a particular temperature and pressure, phase transition from Winsor type I to Winsor type II through Winsor type III can be observed.

Phase behavior tests are inexpensive, quick and effective means to screen chemical formulations, minimizing the need for relatively expensive core flood tests [6]. These are performed with various combinations of surfactants, co-solvents and alkalis with a particular crude oil at the reservoir conditions. Phase Behavior tests includes the aqueous stability test & salinity scan. Salinity scan helps to determine the optimum salinity, which is one of the most important parameter in the surfactant flooding process. It is salinity at which IFT between ME & water is equal to the IFT between ME & oil. Healy et. al. 1977 concluded that the optimum salinity is also the salinity at which maximum oil recovery was obtained from core flooding experiments [7].

The success of chemical EOR processes in recovering extra oil will depend on the use of correct chemical formulations that will best recover oil under current reservoir conditions. In this work, phase behaviour studies were performed with various combinations of chemicals with crude oil (31 ^{0}API) of an Upper Assam oilfield at reservoir temperature (70 ^{0}C). The objective was to investigate the compatibility and combination of surfactants that would display favourable phase behaviour and also recovery higher residual oil during chemically augmented waerflooding.

2. Research Method
2.1 Materials

An anionic surfactant Sodium dodecylsulphate (SDS), a non-ionic surfactant Triton X-100 (TX-100), and a natural surfactant Black Liquor (BL) were used. SDS (with 98% purity), was purchased from Merck (India). Triton X-100 was purchased from Sisco Research Laboratories Pvt. Ltd., Mumbai. The natural surfactant Black Liquor (BL) used was an anionic water soluble surfactant and an effluent from Nagaon Paper Mill, Jagiroad, Assam. Sodium carbonate (Na_2CO_3), a conventional alkali was purchased from Merck Specialities Pvt. Ltd., Mumbai was used in the study. Sodium chloride (NaCl) adjusts the brine salinity which was purchased from Merck Specialities Pvt. Ltd., Mumbai. Co-solvents used in phase behaviour study are generally small carbon chain (C_3 to C_5) alcohols. Alcohol reduce ME viscosity; prevents formation of gels, liquid crystals and precipitates, IFT reduction and allow greater penetration of the oil due to increased mobility of the hydrocarbon tail. Pentanol (PA), used as a co-solvent in the experiments was purchased from Sisco Research LaboratoryPvt. Ltd., Mumbai. The crude oils of an Upper Assam oilfield were used having a dead oil viscosity and gravity of 4.1 x10^{-3} Pa and 31 ^{0}API, respectively. The core plugs used for core flooding were prepared from reservoir rock samples of the same oilfield from depths of (2500-2600) meters.

2.2 Procedure
2.2.1 Phase Behavoir Tests

The concentrated stock solutions of surfactants, PA, Na_2CO_3 and NaCl were initially prepared. The stock solutions and distilled water (DW) were mixed in different ratios to obtain the solutions with a range of salinities. The solutions were mixed in the following particular order to prevent phase separation [3, 8, 9]: (i) NaCl, Na_2CO_3 & IPA; (ii) Distilled Water; (iii) Surfactant Solution. 2 ml of the mixed aqueous solutions were dispensed in 5 ml borosilicate pipettes (tips of which were heat-sealed) over which 2 ml of crude oil was added (WOR=1:1). The pipettes were sealed and arranged in order of increasing salinity in racks and placed in an oven. After 20-30 minutes when the samples reached the temperature of the oven (maintained at average reservoir temperature of 70 ^{0}C, the pipettes were gently inverted several times in order to facilitate mixing of oil and aqueous phase [8, 10]. The pipettes were then left in the oven to equilibrate and the fluid interfaces were inspected at intervals of hours, days and weeks. Prior to adding crude oil to pipettes, an aqueous stability tests were conducted to determine the clarity and homogeneity of all dispensed aqueous solutions. After dispensing in each pipette, aqueous volumes were agitated and settled for one hour, and aqueous stability was tested by visually inspecting any cloudiness and/or phase separation. Only those mixtures were selected for phase behavior studies which were found to be stable without cloudiness or precipitation occurring.

Initially coarse salinity increments between pipettes were used to identify the optimal salinity region. Then additional test with different combination of chemicals with finer salinity increments were conducted. In

addition, performance evaluations of the phase behaviour tests were made by comparing the microemulsion parameters i.e. optimal solubilisation ratio, equilibrium time, gellation etc. Chemical formulation having optimal solubilisation ratio greater than 10, gel free and quick equilibrium time were selected.

2.2.3 Core Flooding Experiments

Based on the phase behaviour test, the core flooding experiments were designed. The formulations screened by the phase behviour tests are validated with the core flooding experiments in their ability to recover residual oil after waterflooding [6]. These flooding tests, done at reservoir pressure and temperature, measure the oil recovery efficiency by injecting a fluid into core plugs containing reservoir fluid. The schematic of the core flooding system is shown in the Figure 1. The system is composed of a Hassler Core Holder, liquid pumps for chemical slugs and crude oil, pressure pump for applying overburden pressure, back pressure regulator (BPR) for applying a back-pressureof 400 psi on the core, heat chamber for maintaining reservoir temperature and measuring cylinders for collecting the samples. The measuring and control system consist of different pressure transducers and computer.
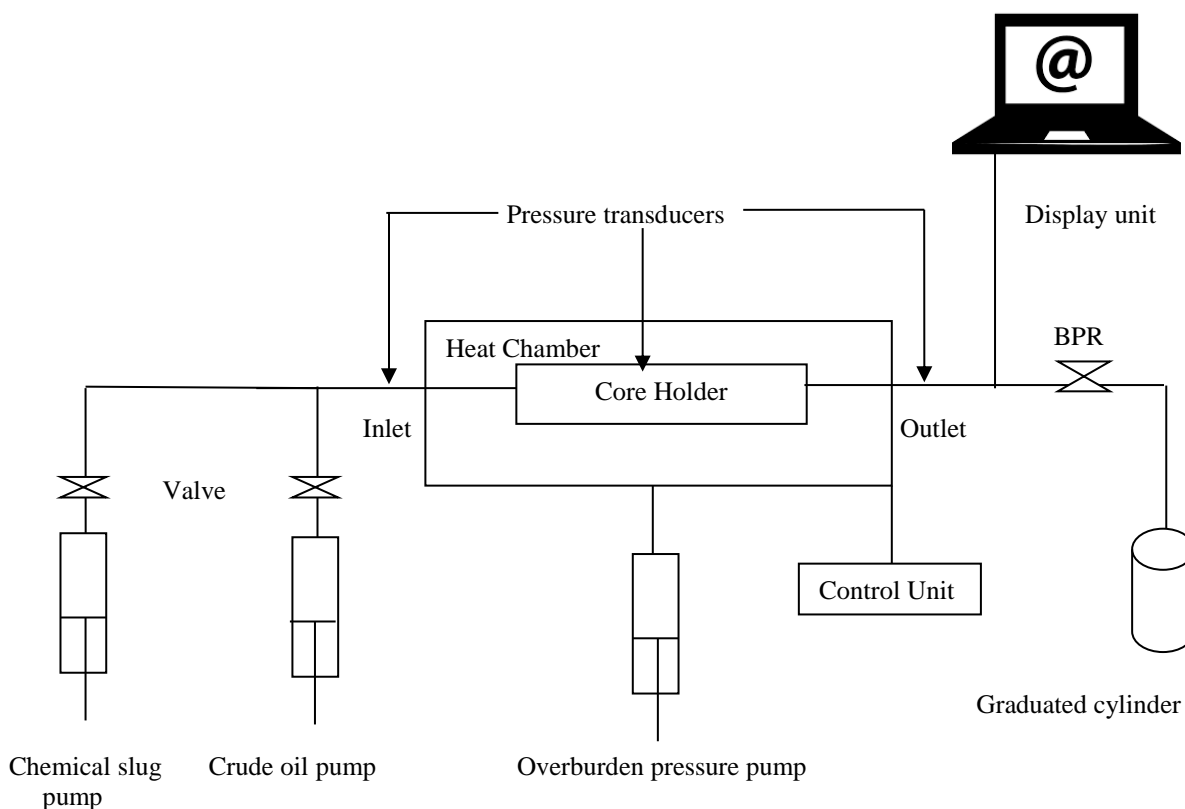

Figure 1. Schematic of the Core Flooding system

The core flooding experiments were conducted by the following procedure [3, 11, 12]: (i) Pore Volume(PV) determination: After cleaning & drying the core plugs, their porosity was determined with Coretest TPI-219 Helium porosimeter. The PVs were then determined from their dimensions and porosity; (ii) Brine flooding: Brine (4000 ppm NaCl) was injected into the core holder to saturate the core plug at room temperature (about 26 °C). Sufficient quantity of brine was injected through the core at a constant flow rate until flow stabilization and permeability of the core to brine was determined. The core saturated with brine was left for 24 hours; (iii) Crude oil flooding: Crude oil was injected into the brine saturated core plug until the effluent is 100% oil. At the end of oil saturation, oil relative permeability at S_{wr} (i.e. K_{orw}) are calculated. The oil-saturated core plugs were maintained at reservoir temperature for 60 hours to allow for possible wettability alteration; (iv) Water flooding: The water flood was carried out with the same brine (4000 ppm) as used to saturate the core. At the end of waterflood, water effective permeability at S_{or} (i.e. K_w) was calculated. From the volume of crude oil collected in the measuring cylinder, the oil recovery was determined; (v) Chemically enhanced waterflooding: The chemical formulations were injected at a constant rate until no more oil was produced. This was followed by injection chase water. The incremental oil recovery during the process was noted.

3. Results and Analysis

3.1 Phase Behavoir Tests: Chemical Formulation Design

A series of phase behaviour tests were performed with different formulations prepared by changing the concentrations of surfactant, co-surfactant, co-solvent and alkali within a range of salinities (Table 1). The pipettes were observed for Type III microemulsion formation and the solubilisation parameters were calculated. The solubilization parameters are defined as: (V_o/V_s and V_w/V_s). V_o/V_s is defined as the volumetric ratio of solubilized oil to surfactant, and V_w/V_s is water to surfactant in the microemulsion phase. V_o/V_s increases with salinity, while V_w/V_s decreases with salinity. The solubilisation ratios were plotted against salinity and the optimum salinity concentration was obtained from the intersection of the two curves. At optimum salinity, the amount of oil and brine solubilized in the surfactant phase are approximately equal and the corresponding solubilisation ratio is the optimal solubilization ratio. The combinations and concentrations of the chemicals were varied to obtain formulations having optimal solubilisation ratio greater than 10 (IFT ≈ 0.003 mN/m by Huh's equation). Huh's equation (1979) gave the relationship between IFT (λ) and optimal solubilization ratio (σ^*), with the value of C around 0.3 mN/m.

$$\lambda = \frac{c}{\left(\sigma^*\right)^2} \tag{1}$$

Table 1. Summary of the Phase Behaviour Study

Expt. No.	Surfactant wt%	Type	Surfactant wt%	Type	Co-solvent PA (wt%)	Alkali Na$_2$CO$_3$ (wt%)	Salinity NaCl (ppm NaCl)	Opt. Sol. Ratio (cc/cc)	Opt. Salinity NaCl (wt%)	Eq. Time (days)
1	0.1	SDS			0.5	0.5	0 to 30000	4	15000	<10
2	0.3	SDS			0.5	0.6	0 to 30000	7	16500	12
3	0.5	SDS			0.5	0.6	0 to 30000	5	17000	14
4	0.02	TX-100			0.5	0.6	0 to 30000	6	13500	8
5	0.03	TX-100			0.5	0.6	0 to 30000	7	14700	12
6	0.05	TX-100			0.5	0.6	0 to 30000	5	14700	<14
7	1	BL			0.5	0.7	0 to 30000	2	2000	10
8	2	BL			0.5	0.7	0 to 30000	4	3500	12
9	3	BL			0.5	0.7	0 to 30000	3	4000	<14
10	0.3	SDS	2	BL	0.5	0.7	0 to 30000	9	14000	12
11	0.3	SDS	3	BL	0.5	0.7	0 to 30000	8	15500	14
12	**0.3**	**SDS**	**1.5**	**BL**	**0.5**	**0.7**	**0 to 30000**	**11**	**15000**	**10**
13	0.03	TX-100	2	BL	0.5	0.6	0 to 10000	7	17500	15
14	**0.03**	**TX-100**	**3**	**BL**	**0.5**	**0.6**	**0 to 10000**	**10**	**19500**	**12**
15	0.03	TX-100	4	BL	0.5	0.6	0 to 10000	8	19000	14

From the aqueous stability tests, it was observed that at higher salinities (greater than 40000 ppm) the chemicals used were unstable showing precipitation with visible signs of cloudiness. Below 30000 ppm, no

precipitation or visible signs of cloudiness was observed confirming the compatibility of chemicals in the aqueous solution within the salinity range from 0 to 30000 ppm. Alkali concentration of 0.5 to 1 wt% was found sufficient to provide suitable pH and satisfy alkali consumption in the core by previous authors [6]. Co-solvent concentration should be low to reduce overall chemical costs so the PA concentration was kept minimum at 0.5 wt%. The IFT of surfactant solutions decrease with concentration until a point after which any increase in surfactant concentration has relatively has no effect on the IFT, this surfactant concentration is called Critical Micelles Concentration (CMC). During the phase behavior tests, the concentration of the surfactants was kept close to their CMC values. BL concentration in the range of 1 to 4 wt% was tested in the formulation. BL, being a weaker surfactant, was used as a co-surfactant with two other surfactants. TX-100 concentrations were kept at 0.01 & 0.05 wt% whereas the SDS concentrations in the range of 0.1 to 0.5 wt%. Higher solubilization ratio with the crude oil was obtained with mixed (SDS+BL) & (TX-100+BL) surfactant systems than SDS, BL or TX-100 alone. This indicates synergism of the surfactants when surfactants are compounded at particular concentrations. The most promising formulation for this crude oil was a mixture of 0.3 wt% SDS, 1.5 wt% BL, 0.7 wt% Na_2CO_3 and 0.5 wt% PA. The equibrium time for this formulation was less than 10 days with a solubilisation ratio of 11 at optimal conditions. Another formulation that displayed good phase behaviour results was a mixture of 0.03 wt% TX-100, 3 wt% BL, 0.6 wt% Na_2CO_3 and 0.5 wt% PA. The optimum solubilisation ratio for this formulaton was 10 and the equilibrium time was about 12 days. The above two chemical formulations displayed better phase behaviour results and were selected for futher investigation (Table 2). The higher solubilization ratio is probably due to the identical chain length of the compounded surfactant system and crude oil. The optimal salinity was observed to increase with the total surfactant concentration. Co-solvent like alcohol lowered optimum solubilization ratio and so its concentration was kept at the minimum. The photographs of the phase behaviour tests were shown in the Figure 3 and the solubilisation data in the Figure 2.

Table 2. Summary of selected chemical formulation

Formulation	Formulation ID	Optimum Salinity (ppm NaCl)	Optimum Solubilization Ratio (cc/cc)	IFT (Huh's formula, (mN/m)
0.3 wt% SDS + 1.5 wt% BL + 0.7 wt% Na_2CO_3 + 0.5 wt% PA	**F1**	15000	11	2.4 x 10^{-3}
0.03 wt% TX-100 + 3 wt% BL + 0.6 wt% Na_2CO_3 + 0.5 wt% PA	**F2**	19500	10	3 x 10^{-3}

(a) Formulation 1 (F1)   (b) Formulation 2 (F2)

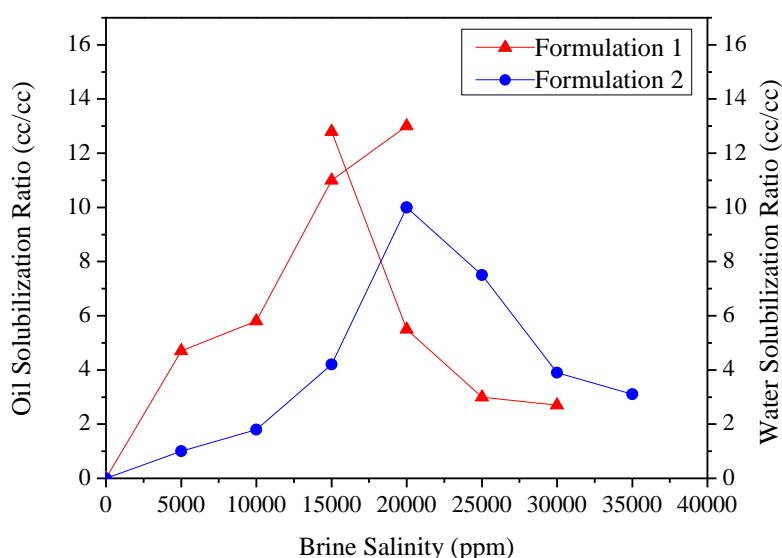Figure 2. Phase behaviour test of Formulation 1 & Formluation 2 with crude oil at 70 ^{0}C

Figure 3. Solubilization data of Formulation 1 & Formluation 2 with crude oil at 70 ^{0}C

3.2 Core Flooding Experiments: Chemical Formulation Validation

Five core flooding experiments were performed whose details & results are summarized in Table 3. The flooding experiments were done with 1.5 inch diameter core plugs with having porosities around 25%. Prior to core flooding, the porosities of the core plugs were measured with TPI-219 Helium Porosimeter, Coretest Systems, Inc, USA. Two core plugs of lengths 6.87 cm and 7.33 cm were used for all the experiments. After each flooding experiment, the core plugs were cleaned & dried before reusing.

From the Figure 4 & Table 3, it can be observed that by conventional waterflooding about 27 % of original oil in place (OOIP) was produced after injection of 1.5 PV of brine in all the experiments. So, the residual oil saturation was similar for all experiments prior to chemical enhanced waterflooding and their recovery was the main focus of the experiments. In Experiment 1, the core plug was waterflood to residual oil saturation, and further flooded with 0.3 wt% SDS surfactant solution until no more oil production occurred. The additional oil recovery after waterflooding was 17.67 % of the OOIP after 1.75 PV chemically enhanced water injection. Experiment 2 was conducted with 2 wt% BL solution injection after conventional waterflooding, which resulted in the residual oil recovery of 4.91 % of the OOIP after 2.25 PV fluid injection. In Experiment 3, extra oil recovery with 2 PV of 0.03 wt% TX-100 solution injection after waterflooding was 9.33 wt% of the OOIP. The additional oil recovery occurred because it is well known that small amount of surfactants added to the aqueous solution decreases the interfacial tension (IFT) between crude oil & formation water which lowers the capillary forces to mobilize residual oil. BL was found to be a weak surfactant compared to SDS & TX-100 as reflected by its lowest extra oil recovery. Anionic surfactant SDS recovery was more than non-ionic surfactant TX-100 due to the possible reason that negatively charged anionic surfactant are adsorbed less by the negative sites of the sand grains. Adsorption of surfactants from aqueous solutions on the rock solid matrix results in the loss and reduction of surfactant concentrations. This diminishes the effectiveness of the chemical solution to reduce oil-water IFT and decreases the EOR ability of the surfactant. The minerals mostly found in the reservoir rocks are quartz, clays, etc., which generally display a net negative charge [13]. Anionic surfactants are negatively charged and are mostly used EOR chemical for sandstone reservoirs because of their relatively low adsorption.

In Experiment 4, the core plug with residual oil after wateflooding was flooded with formulation1 prepared by mixing SDS+BL surfactants with alkali and brine at optimum salinity. The residual oil recovery was the highest of all the experiments with a recovery of 29.20 % of OOIP after injection of PV of chemical slug. The formulation 1with optimum solubilisation ratio of 11 corresponds to an IFT of 2.4 x 10^{-3} mN/m from the Huh's equation. This ultra-low oil-water IFT was high enough to mobilize more amount of residual oil leading to its highest oil recovery. Experiment 5 also employed mixed surfactant system. This time the formulation 2 was prepared by mixing BL & TX-100 surfactants with alkali and brine at optimum salinity. The extra oil recovery was 22.89 % of OOIP after injecting 1.75 PV of the formulation. This recovery was better than oil recovery with single surfactant sytems. The optimum solubilisation ratio for formulation 2 was 10 based on the phase behavior test, which corresponds to an ultra-low IFT of 3 x 10^{-3} mN/m from the same Huh's

equation.The ultra-low IFT & better recovery from the two selected formulations can can be attributed to a number of favorable effects. These include the synergistic effect of mixed surfactants and the favourable interaction of BL with crude oil and reservoir rock. BL is known for its applicable in EOR because of its ability to decrease oil-water IFT [14]. BL main component lignosulphonate was also reported to act as sacrificial adsorbate during surfactant flooding reducing surfactant adsorbtion by being preferentially adsorbed by rock grains [15, 16]. Another reason for the better performance of the screened formulations during core flooding was the association of alkali (Na_2CO_3). Alkali injection can recover additional oil after waterflooding due in situ formation of surfactant produced by reaction of acidic components of oil with alkali which causes reduction of oil-water IFT. Other beneficial effects of alkali addition that help in EOR are wettability alteration and improvement of sweep efficiency by emulsification and entrapment etc. [17]. The success of the formulations in recovering the higher additional oil proved the competency & synergism of the chemicals used to prepare the formulation.
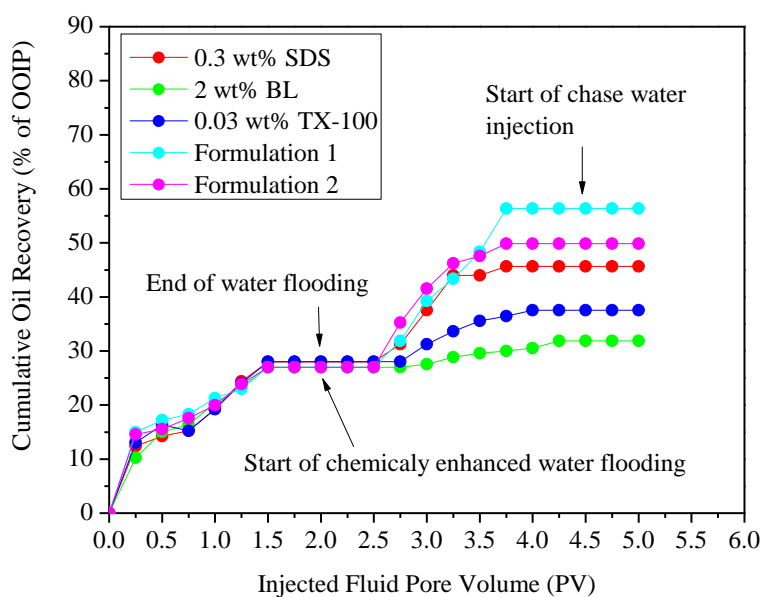

Figure 4. Cumulative oil recovery (% of OOIP) for the core flood experiments

Table 3. Summary of core flooding experiments

Expt. No.	Porosity (%)	Permeability (mD)		Saturations (%)		Experimental Procedure	Recovery (% wt% OOIP)
		K_w at $S_w=1$	K_o at S_{wc}	S_{wc}	S_{oi}		
1	25.25	29.68	18.45	19.35	81.65	Water Flooding	27.98
						0.3 wt% SDS flooding + chase water	17.67
2	25.13	28.75	17.34	18.76	81.24	Water Flooding	26.98
						2 wt% BL flooding + chase water	4.91
3	25.19	30.15	16.50	18.53	81.47	Water Flooding	28.23
						0.03 wt% TX-100 flooding + chase water	9.33
4	25.09	29.87	18.52	17.76	82.24	Water Flooding	27.16
						Formulation 1 flooding + chase water	29.20
5	25.15	29.98	17.84	18.35	81.65	Water Flooding	26.98
						Formulation 2 flooding + chase water	22.89

4. Conclusion

This paper presented a laboratory method to successfully screen chemical formulation using phase behavior studies & validation of the EOR potential of these formulations in the process of chemically enhanced waterflooding. The phase behaviour studies performed with various combinations of surfactants with crude oil (31 ^{0}API) of an Upper Assam oilfield at reservoir temperature (70 ^{0}C) were used to screen best performing chemical formulations. The anionic surfactant SDS, non-ionic Triton X-100 and natural surfactant BL have shown good performance when blended in appropriate proportions. The selected formulation demonstrated high residual oil recovery in the lab-scale core flood experiments. The interaction of the natural anionic surfactant, Black liquor, with crude oil and reservoir rocks was tested successfully for its ability to form three phase microemulsion and to recover additional oil when blended with commercial surfactants.

References

1. Mandal, A., *Chemical flood enhanced oil recovery: a review.* International Journal of Oil, Gas and Coal Technology, 2015. **9**(3): p. 24.
2. Sheng, J.J., *Status of surfactant EOR technology.* Ke Ai Advancing Research Evolving Science, 2015: p. 9.
3. Liu, S., *Alkaline Surfactant Polymer Enhanced Oil Recovery Process*, 2007, Rice University.
4. Achinta Bera, K.O., Ajay Mandal, T. Kumar, *Interfacial tension and phase behavior of surfactant-brine–oil system.* ELSEVIER, 2011: p. 114-119.
5. Bera, A., et al., *Phase Behavior and Physicochemical Properties of (Sodium Dodecyl Sulfate + Brine + Propan-1-ol + Heptane) Microemulsions.* Journal of Chemical and Engineering data, 2012. **57**: p. 7.
6. Flaaten, A.K., et al., *A Systematic Laboratory Approach to Low-Cost, High-Performance Chemical Flooding*, in *SPE/DOE Improved Oil Recovery Symposium*2008, SPE: Tulsa, Oklahoma, U.S.A.
7. Healy, R.N. and R.L. Reed, *Immiscible Microemulsion Flooding.* Society of Petroleum Engineers, 1976: p. 32.
8. M.Srivastava, et al., *A Systematic Study of Alkaline-Surfactant-Gas Injection as an EOR Technique.* SPE, 2009. **124752**: p. 15.
9. Levitt, D.B., et al., *Identification and Evaluation of High-Performance EOR Surfactants.* SPE Reservoir Evaluation & Engineering, 2009: p. 11.
10. Nelson, R.C. and g.A. Pope, *Phase Relationships Chemical Flooding.* Society of Petroleum Engineers, 1978: p. 14.
11. Samanta, A., et al., *Surfactant and Surfactant-Polymer Flooding for Enhanced Oil Recovery.* Advances in Petroleum Exploration and Development, 2011. **2**(1): p. 6.
12. Levitt, D.B., *Experimental Evaluation of High Performance EOR Surfactants for a Dolomite Oil Reservoir*, 2006, The University of Texas at Austin. p. 160.
13. Lv, W., et al., *Static and dynamic adsorption of anionic and amphoteric surfactants with and without the presence of alkali.* Journal of Petroleum Science and Engineering, 2011. **77**: p. 10.
14. Gogoi, S.B. and B.M. Das, *Use of an Effluent for Enhanced Oil Recovery.* Indian Journal of Chemcial Technology, 2012. **19**: p. 5.
15. J.Novosad, *Laboratory Evaluation of Lignosulphonate as Sacrificial Adsorbate in Surfactant Flooding.* Journal of Canadian Petroleum Technology, 1984. **May-June 1984**: p. 6.
16. Hong, S.A., J.H. Bae, and G.R. Lewis, *An Evaluation of Lignosulfonate as a Sacrificial Adsorbate in Surfactant Flooding.* SPE Reservoir Engineering, 1987. **February 1987**: p. 11.
17. Samanta, A., et al., *Comparative studies on enhanced oil recovery by alkali–surfactant and polymer flooding.* Journal of Petroleum Exploration & Production Technology, 2012. **2**: p. 8.