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## A strategy for low cost, effective surfactant injection

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## ABSTRACT

Ideally, in a chemical flooding process, one would like to inject a surfactant solution that has good solubility at the relevant conditions, ultralow interfacial tension (efficient oil mobilisation) and low loss of surfactant (better economics) in the porous medium. The key question is – can you have low loss of surfactant, i.e. low retention, at ultralow interfacial tension?

To answer this question, we have undertaken a systematic study of surfactant solubility, phase behaviour, interfacial tension and retention as a function of salinity for a given surfactant formulation. The idea is to explore the interrelationship between these properties and find the best condition(s) for combined low interfacial tension and low retention in a surfactant flooding process.

For the investigated surfactant formulation, ultra-low interfacial tensions ( $< 0.01$  mN/m) can be found in the Winsor III region at optimal salinity. The aqueous solution at optimal salinity is, however, turbid, and retention values are high. On the other hand, for light oils, there are regions in the Winsor I area where (i) interfacial tensions are low ( $0.01$  mN/m  $< IFT < 0.1$  mN/m), but not ultralow, (ii) aqueous solutions are clear and (iii) retention is 10 times lower than at optimal salinity. The search for an optimum surfactant formulation has to consider solution properties and retention in addition to the low interfacial tension. Based on our result, we therefore propose that Winsor I phase behaviour is the best option for a compromise between the properties in question.

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## 1. Introduction

The effectiveness of a chemical flooding process is closely related to the phase behaviour, and consequently interfacial tension, of the brine–oil–surfactant system. The effect of lowered oil–water interfacial tension on residual oil saturation is described by the dimensionless capillary number:

$$N_c = \frac{\mu v}{\sigma} \quad (1)$$

where  $\mu$  is the viscosity of the injected fluid,  $v$  is the linear advance rate and  $\sigma$  is the oil–brine interfacial tension (IFT). The capillary number has been extensively studied for different porous media. Examples include studies by Taber (1969), Stegemeier (1974) and Ganes et al. (1990). By lowering the IFTs by a factor two to four, from the 20–30 mN/m range normally found between a crude oil and brine, residual saturations could be reduced to low values. The capillary desaturation curve (CDC) plots the capillary number

versus residual oil saturation ( $S_{or}$ ), and the capillary number where residual oil saturation starts to decrease is the critical capillary number,  $N_{cc}$ . The value of the critical capillary number, as well as the shape of the CDC, depends on factors such as the pore size distribution and wettability of the porous rock.

When evaluating a surfactant injection process, the cost of chemicals versus the potential gain in recovery is a central issue. High surfactant retention, and the use of high-cost chemicals, can give an uneconomical process by contributing to large chemical costs. High retention will also make the active displacement front in a surfactant injection process advance more slowly than the frontal advance rate of the injected aqueous phase. If retention is high, the result could be that the injected surfactant slug loses its ability to lower the oil–water IFT to values low enough to induce significant mobilisation of capillary trapped oil. Consequently, the best choice of surfactant formulation for a given application has to take other factors than the lowest possible interfacial tension, and thus the highest expected recovery, into account.

## 1.1. Surfactant phase behaviour and oil mobilisation

In the following, we classify microemulsion systems as Winsor I, Winsor II or Winsor III (Winsor, 1948). The Winsor I and II refer to two phase equilibrium between a microemulsion and an excess phase: in a Winsor I system the equilibrium is between an oil-in-water

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microemulsion and an upper excess oil phase, whereas in the Winsor II system the equilibrium is between a water-in-oil microemulsion and a lower excess water phase. The Winsor III system has a middle microemulsion phase in equilibrium with an upper excess oil phase and a lower excess water phase. In general, changing any condition that enhances the oil solubility of the surfactant will cause a shift from Winsor I to Winsor II. This includes changing the surfactant structure, oil properties, brine salinity, temperature and pressure as well as adding co-solvents (Salager et al., 1979).

To increase the solubility of anionic surfactants in saline brines, and avoid the formation of highly viscous phases, alcohols are often added as co-solvents. Hydrophilic straight chain surfactants, such as  $\alpha$ -olefin sulfonates, require large alcohol concentrations to form microemulsion phases instead of highly viscous phases (see for example Hirasaki et al. (2011) and references cited therein).

The solubilisation parameter (SP) indicates the volume of oil or water ( $V_i$ ) solubilised in the microemulsion phase per volume of surfactant:

$$SP_i = \frac{V_i}{V_s} \quad (2)$$

where  $i$  is water or oil. In order to calculate the solubilisation parameter one must assume that there are no volume changes upon mixing, and that all the surfactant is retained in the microemulsion phase. Further, the volume of the surfactant is assumed to be equal to the mass of the surfactant (Skauge and Fotland, 1990). At optimal salinity ( $S^*$ ) the volume of oil and brine per volume of surfactant is equal, i.e. the microemulsion phase contains equal amounts of oil and water:

$$SP^* = \frac{V_o}{V_s} = \frac{V_w}{V_s} \quad (3)$$

here  $SP^*$  is the solubilisation parameter at optimum.

The middle microemulsion phase has been reported to show very low interfacial tensions (IFTs) against oil and water (Healy and Reed, 1976; Reed and Healy, 1977; Huh, 1979). It has been found that a minimum in IFT corresponds to equal volumes of oil and water solubilised in the middle microemulsion phase. When the salt concentration is the key parameter being varied, the condition of equal solubilisation is referred to as the *optimal salinity*. The interfacial tension between oil and water at optimum can be calculated using the Chun Huh relation (Huh, 1979):

$$\sigma = \frac{C}{(SP^*)^2} \quad (4)$$

Where  $C$  is an empirical constant, usually 0.3 mN/m. The numerical value of the empirical constant has been confirmed by comparing phase volumes to direct measurement of interfacial tensions by laser light scattering (Fotland and Skauge, 1986; Skauge and Fotland, 1990).

There is a vast literature on surfactant enhanced oil recovery (EOR) available, much of which is included and discussed in a recent review by Hirasaki et al. (2011). The target for the majority of these studies is to design a system that maintains or passes through the conditions of Winsor III phase behaviour and hence ultralow IFTs. This often involves adding alkali to the surfactant blend, and/or a salinity gradient. Wellington and Richardson (1997), on the other hand, proposed a Winsor I, highly interfacially active blend of anionic ethoxy-propoxy and cationic ethoxylated surfactants to give high oil recovery and low retention.

## 1.2. Effect of salinity on clay stability and surfactant retention

Brine salinity and composition is known to affect surfactant retention (Meyers and Salter, 1984; Friedmann, 1986; Bavière et al., 1993). Traditionally, high surfactant retention has often been

linked to the presence of divalent cations (Meyers and Salter, 1984). Friedmann (1986) measured retention of sulphonate surfactant in fired Berea sandstone cores as a function of brine composition. His results showed that retention decreased by more than 50% as the synthetic reservoir brine was diluted down to 10% of its original concentration. The increase in retention observed for the more concentrated brines was found to be due to an increase in both surface adsorption and total retention. The latter includes loss due to precipitation by divalent ions in the synthetic formation brine in addition to adsorptive losses.

Bavière et al. (1993) on the other hand, studied adsorption of a petroleum sulphonate on powdered sodium kaolinite in the absence of multivalent cations. Their results showed an increase in adsorption with increasing ionic strength. This increase was partly attributed to a salting-out effect of the surfactant, and partly to reduced repulsion between the negatively charged kaolinite surface and the sulphonate anions. Increased adsorption at increased ionic strength due to a salting-out effect of the surfactant would be analogous to the salting-out effect observed in surfactant phase behaviour.

In sandstone reservoirs, possible effects of clay swelling and clay migration, due to changes in the salinity of the brine with which they are in equilibrium, should be taken into consideration. Khilar and Fogler (1984) found a critical salt concentration of around 0.4 wt% for pure NaCl brines in Berea sandstones. Decreasing salinity below this level has the potential for inducing formation damage due to clay destabilisation. It should be noted, however, that this was measured on a completely water-wet, fully brine saturated sample. Clay stability criteria are likely altered at different conditions of wettability and fluid saturations. As an example, Mungan (1965) observed a large difference in response between extracted (cleaned) and non-extracted (fresh) cores, which was ascribed to the presence of protective organic coatings in the latter case. Based on these findings he concluded that the presence of crude oil in Berea may prevent formation damage by fresh water injection. A similar observation was later made by Clementz (1977) who found that formation clays can be stabilised through adsorption of crude oil asphaltenes.

Several studies on the effect of brine salinity on oil recovery have been published over the past decade (see Morrow and Buckley (2011), and references cited therein). The studies have shown a moderate increase in oil recovery during injection of low salinity brine (0.2–0.5 wt% NaCl). Some, but not all, of these experiments have included observations indicating fines migration (see for example Alagic and Skauge, 2010; Gamage and Thyne, 2011; Alagic et al., 2011; Spildo et al., 2012). The factors controlling whether or not fines migration and possible formation damage occurs are not fully understood. However, Alagic et al. (2011) reported a correlation between wettability and fines migration; no indications of fines migration was observed during low salinity injection in aged cores whereas they were observed when unaged, water-wet cores were used. This is in agreement with the results reported by Mungan (1965) and Clementz (1977).

## 1.3. Low salinity surfactant injection

Based on the observed effect of low salinity brine injection on oil recovery, Alagic and Skauge (2010) proposed a new hybrid enhanced oil recovery (EOR) process. This hybrid process combines the effect of low salinity brine injection with reduced capillarity by addition of a suitable surfactant. In their experiments they used aged Berea sandstone cores, and an internal olefin sulphonate surfactant that resulted in a Winsor I microemulsion system at the experimental conditions. The results showed that significantly more oil was mobilised by the hybrid process (IFT reduction and low salinity) compared to what is expected from a

sole reduction in IFT (increase in capillary number) due to the added surfactant. This has later been confirmed by Spildo et al. (2012) and Johannessen and Spildo (2013).

#### 1.4. Scope of paper

The present study explores the interrelationship between solubility, phase behaviour, interfacial tension and retention as a function of brine salinity in a system consisting of anionic surfactant + alcohol co-solvent + NaCl brine + *n*-alkane. The surfactant chosen was an internal olefin sulphonate (IOS). This class of surfactants is considered suitable for a range of sandstone reservoir applications, and is available in quantities for EOR pilot scale trials (Barnes et al., 2010, 2012). The main purpose is to identify a cost-efficient surfactant injection strategy, aimed at applications in sandstone fields with light to medium crude oils. In addition to low chemical consumption and price, cost-efficiency also implies that the process is relatively robust with simple process logistics. The latter is particularly important for an off-shore operation. A key question is – can you have low loss of surfactant at ultralow interfacial tension? Inevitably, if the surfactant formulation forms a Winsor III system with the crude oil in question, its hydrophilic–lipophilic balance (HLB) is such that its aqueous solubility is low. This likely contributes to increased surfactant retention by the salting-out effect and thus poor process efficiency. Consequently, the surfactant formulation that results in the lowest possible interfacial tension, and thus the highest expected recovery, may not always be the best choice.

## 2. Materials and methods

### 2.1. Materials

Test samples were prepared by adding a fixed amount of surfactant (1 wt%) and alcohol co-solvent to sodium chloride brines of varying salinities. The surfactant used was an internal olefin sulphonate with 15–18 carbon atoms in the hydrophobe (IOS 15–18) supplied by Shell Global Solutions International. It should be noted at this stage that the particular surfactant used was not optimised to any specific oil or brine composition. However, as demonstrated by Barnes et al. (2010, 2012), this class of surfactants can be tailored to different crude oils by changing the surfactant hydrophobe. An alcohol co-solvent was added to avoid formation of gel phases and promote formation of type III systems at reasonable salinities. Different types of co-solvents were tested: secondary butyl alcohol (SBA) and isoamyl alcohol (IAA) at 0, 0.5 and 1 wt% concentration. The surfactant solutions were mixed with an equal volume of *n*-alkane, heptane, octane or decane.

The Berea sandstone material used in the retention studies was analysed by *x*-ray diffraction. The mineralogy, clay type and content of a typical core sample from the batch of Berea used is given in Table 1.

Although the present study is limited to a single anionic surfactant, sodium chloride brines, and model oil, we believe that the results obtained are representative of the behaviour that can

be expected for systems consisting of an anionic surfactant, mixed brines and crude oils. This is based on the following: (1) different anionic surfactants are known to show the same overall response to changes in salinity (see for example Salager et al. (1979), and references cited therein). (2) Adapting to a given crude oil generally involves modifying the surfactant hydrophobe (Barnes et al., 2012). Changing the surfactant hydrophobe shifts the overall solubility and phase behaviour, but the response to changes in salinity remains roughly the same only shifted upwards or downwards. (3) Sulphonate surfactants show similar phase behaviour and optimal salinities in pure NaCl brines and mixed NaCl–CaCl<sub>2</sub> brines when salinities are compared on an ionic strength basis (Salager et al., 1979).

### 2.2. Experimental methods

Following the initial solubility evaluation, which was done at room temperature, the aqueous surfactant solutions were mixed with an equal volume of heptane, octane or decane for phase behaviour studies. These samples were prepared in specially designed, graduated pressure tubes, placed in mixing rigs and stored in heating cabinets at the appropriate temperature.

Solubility was judged by visual inspection, while surfactant activity was measured by two-phase titration (Reid et al., 1967). The latter was done after centrifugation of the solutions to remove any precipitate. Samples were prepared and measured at room temperature. Samples classified as turbid range from slightly cloudy to completely opaque. Samples classified as oleic are samples in which phase separation into an aqueous and an oil-like surfactant phase took place.

Solubilisation parameters were obtained by measuring the phase heights in the samples (see example in Fig. 1a). The optimal salinity and solubilisation at optimum for each surfactant was determined by plotting  $SP_w$  and  $SP_o$  as a function of salinity. The  $SP_w$  and  $SP_o$  curves cross when  $SP_o = SP_w$ , i.e. at optimum. The optimal salinity ( $S^*$ ) and solubilisation at optimum ( $SP^*$ ) is obtained from the *x*- and *y*-axes, respectively (see Fig. 1b).

Interfacial tensions were measured at 20 and 50 °C against heptane and decane by the spinning drop method using a spinning drop tensiometer (SITE100 from KRÜSS). Interfacial tensions in the VIII region were estimated using the Chun Huh relation (Eq. (3)).

To determine surfactant retention from a given surfactant formulation in the absence of oil, a slug containing a fixed concentration of surfactant + co-solvent was solved in brine and injected into Berea cores with a permeability of around 300 mD. Effluent fractions were collected using a fraction collector and surfactant concentration in the effluent was determined by two-phase titration.

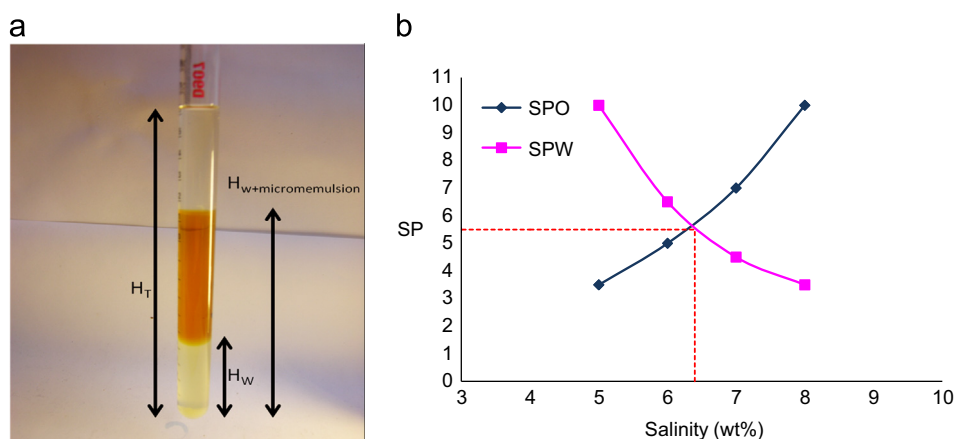
## 3. Results and discussion

### 3.1. Solubility

Initially, surfactant solubility as a function of salinity was evaluated by visual inspection and measurement of surfactant activity both with and without alcohol co-solvent added. Results

**Table 1**  
Berea core mineralogy, clay type and content for a typical core from the batch of Berea used.

Mineral	Quartz	K Feldspar	Plagioclase	Calcite	Dolomite	Siderite	Pyrite	Clay
Content	87.5	1.9	0.9	TR	0.9	0.9	0.0	7.9
Clay type	Smectite	Mica	Kaolinite	Chlorite				
Content	0.0	3.0	3.2	1.7				



**Fig. 1.** (a) Measurement of phase heights in system displaying type III phase behaviour, and (b)  $SP_o$  (diamonds) and  $SP_w$  (squares) plotted as a function of salinity. At optimal salinity,  $SP_o = SP_w$ , the curves cross, and the optimal salinity ( $S^*$ ) and solubilisation at optimum ( $SP^*$ ) is determined.

**Table 2**  
Solubility and activity for aqueous solutions of IOS 15–18 as a function of salinity (wt% NaCl).

Co-solvent	Salinity %	0	1	2	3	4	5	6	7	8	9	10	
None	Appearance	CLEAR					PRECIP.						
	Activity (%)	100	100	100	100	100	98	74					
SBA 1.0%	Appearance	CLEAR						PRE.					
	Activity (%)	100	100	100	100	100	100	97					
IAA 0.5%	Appearance	CLEAR				TUR.	PRECIPITATED						
	Activity (%)	100	100	100	100	100	75	24					
IAA 1.0%	Appearance	CLEAR				TURBID							T/O
	Activity (%)	100	100	100	100	79	97	100	98	98	98	98	11

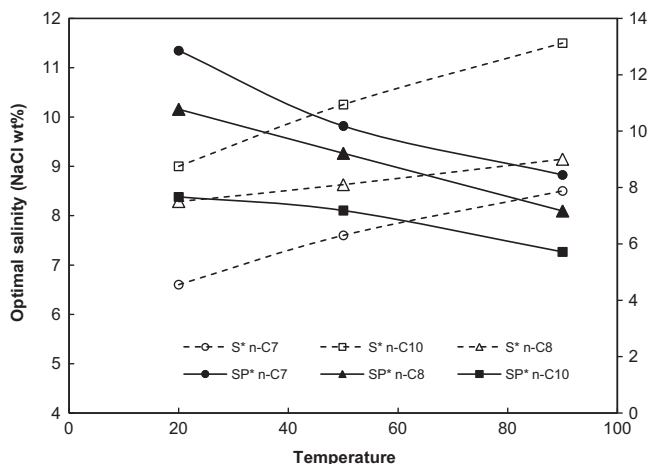
**Table 3**  
Solution properties and phase behaviour as a function of aqueous phase salinity for IOS 15-18 with 1.0 wt% IAA co-solvent. The phase behaviour was evaluated with heptane, (octane) and decane at 20, 50 and 90 °C.

Salinity%	0	1	2	3	4	5	6	7	8	9	10	11	12	13	
Appearance	CLEAR				TURBID						T/O				
Activity (%)	100	100	100	100	79	97	100	98	98	98	11				
20°C	Heptane	Winsor I					WIII			WII					
	Octane	Winsor I					WIII			WII					
	Decane	Winsor I					WIII			WII					
50°C	Heptane	Winsor I					WIII			WII					
	Decane	Winsor I					WIII			WII					
90°C	Heptane	Winsor I					WIII			WII					
	Decane	Winsor I					WIII			WII					

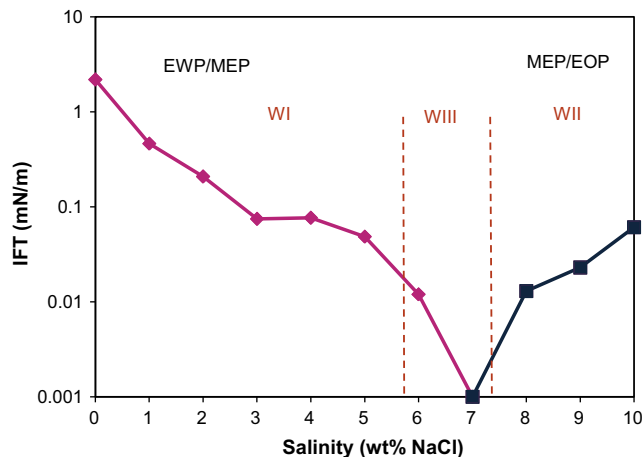
are summarised and shown in Table 2. The quoted salinity refers to the wt% NaCl added to the solutions. T/O denotes a system with an oleic phase in equilibrium with a turbid aqueous phase.

As can be seen from Table 2, good surfactant solubility in the aqueous phase is found at low salinities. Increasing the salinity reduces the repulsion between ionic head-groups, forcing the

surfactant to salt-out. The system containing SBA gives the best surfactant solubility, i.e. clear solutions over the widest range of salinities. Using a less polar alcohol like IAA is thus expected to promote transitions from Winsor I to Winsor III systems relative to SBA. This is favourable for a comprehensive study since we would like to cover all three phase behaviour regions at reasonable



**Fig. 2.** Optimal salinity ( $S^*$ , open symbols) and solubilisation at optimum ( $SP^*$ , closed symbols) for the 1 wt% IOS 15–18+1 wt% IAA system with *n*-heptane (*n*-C7, circles), *n*-octane (*n*-C8, triangles) and *n*-decane (*n*-C10, squares) as oleic phase.



**Fig. 3.** Interfacial tension between aqueous surfactant solutions and heptane as a function of salinity at 20 °C for the 1 wt% IOS 15–18+1 wt% IAA system with heptane as oleic phase.

**Table 4**

Solution properties and interfacial tensions for aqueous solutions of IOS 15–18 with 1.0 wt% IAA co-solvent as a function of salinity at 20 °C.

Salinity % NaCl	0	1	2	3	4	5	6	7	8	9	10	
Appearance	CLEAR				TURBID							T/O
Activity (%)	100	100	100	100	79	97	100	98	98	98	11	
PB Heptane	Winsor I						WIII		Winsor II			
IFT n-C7 (mN/m)	2.18	0.46	0.21	0.075	0.077	0.049	0.012	0.001	0.013	0.023	0.061	
PB Octane	Winsor I							WIII		Winsor II		
IFT n-C8 (mN/m)	2.34	0.58	0.23	0.13	0.083	0.055	0.0410	0.003	0.01	0.048	0.054	
PB Decane	Winsor I								WIII			
IFT n-C10 (mN/m)	2.42	0.52	0.30	0.18	0.13	0.083	0.052	0.018	0.009	0.005	0.002	

salinity levels. Further, increasing the IAA concentration from 0.5 to 1 wt% moved solutions at salinities > 5 wt% from containing a precipitate to being turbid. In the present paper further discussions are thus limited to the surfactant formulation with 1 wt% IAA.

### 3.2. Phase behaviour

Phase behaviour tests were performed at 20, 50 and 90 °C with heptane, octane and decane as the oil phase (see Table 3). The results show that increasing the alkane carbon number (ACN), or increasing the temperature at a given ACN, shifts the transition from Winsor I to III microemulsion systems to higher salinities for the investigated surfactant formulation. Further, the width of the Winsor III region was found to increase from C7–C8 to C-10. The latter is in line with previous observations by, for example, Kellay et al. (1994) for anionic surfactant+aqueous NaCl+*n*-alkane systems.

Solubilisation parameters, optimal salinity ( $S^*$ ) and solubilisation at optimum ( $SP^*$ ) were determined as outlined in Section 2. The results are shown as a function of temperature in Fig. 2.

Since increasing the temperature was found to shift the Winsor I–III transition to higher salinities, it is not surprising that optimal salinity is found to increase with temperature. This is likely related to increased aqueous solubility of the surfactant with increasing

temperature, thus moving the salting out of the surfactant to higher salinities. Further, the solubilisation at optimum decreases with temperature. Consequently, by applying the Chun Huh equation (Eq. (3)), we see that interfacial tension increases with increasing temperature for this surfactant formulation in the WIII region. Similar behaviour was found in the WI region for this surfactant with a North Sea crude oil; an increase in IFT of around 50% was found as the temperature was increased from 20 to 60 °C.

### 3.3. Interfacial tension

Table 4 shows solubility, phase behaviour and interfacial tension as a function of salinity for at 20 °C, while Fig. 3 gives a graphical presentation of the interfacial tension data for heptane. In the remainder of the discussion, IFTs are classified as ultralow (< 0.01 mN/m) or low (0.01 mN/m < IFT < 0.1 mN/m). As can be seen from the data there is a continuous and nearly linear decrease in interfacial tension as the salinity of the aqueous surfactant solution is increased from zero to optimal. When the salinity is increased above the optimal, the interfacial tension increases rapidly again. Further, while ultralow interfacial tensions are only observed in the Winsor III region, low values are also observed in the Winsor I region at NaCl concentrations down to 3 wt%.

**Table 5**

Solution properties and retention at 20 °C measured on Berea sandstone cores as a function of aqueous phase salinity for IOS 15-18 with 0.5 and 1.0 wt% IAA co-solvent, respectively.

Salinity % NaCl	0	1	2	3	4	5	6	7	8	9
<b>0.5 wt% IAA</b>										
Appearance	CLEAR				TUR.	PRECIPIT.				
Activity (%)	100	100	100	96	100	75	24			
Retention (mg/g)	0.06		0.21		0.42					
<b>1 wt% IAA</b>										
Appearance	CLEAR				TURBID					
Activity (%)	100	100	100	100	79	97	100	98	98	98
Retention (mg/g)	0.14		0.15			1.50			1.76	

**Table 6**

Solution properties, phase behaviour, interfacial tension and retention as a function of aqueous phase salinity for IOS 15-18 with 1.0 wt% IAA co-solvent. Phase behaviour and interfacial tension evaluated against heptane at 20 °C.

Salinity % NaCl	0	1	2	3	4	5	6	7	8	9
Appearance	CLEAR				TURBID					
Activity (%)	100	100	100	100	79	97	100	98	98	98
Phase behaviour	Winsor I						WIII		WII	
IFT n-C7 (mN/m)	2.180	0.463	0.208	0.075	0.077	0.049	0.012	0.001	0.013	0.023
Retention (mg/g)	0.14		0.15			1.50			1.76	

### 3.4. Dynamic retention

The last part of the experimental programme involved measurement of dynamic retention for selected salinities at room temperature. Slug sizes were chosen so that approximately 50% of the injected surfactant was produced. This is to obtain the highest possible accuracy in the calculated retention values. As a result, two pore volumes (PVs) of aqueous surfactant solution were injected in most of these tests. This was followed by injection of brine with the same salinity as the injected slug. Due to relatively low retention values at low salinities, the slug size was reduced to 0.2 PV and 0.5 PV for measurements at 1 and 3 wt% NaCl, respectively. The injected amount of surfactant was in these cases reduced by 25%–50%, which should be sufficient for the data to be reliable. Retention values measured at 20 °C are listed in Table 5 together with solubility evaluation and activity measurements for systems with 0.5 and 1 wt% IAA added, respectively.

Table 5 shows that retention values for 0.5 wt% IAA doubles when the salinity is increased from 3 to 4 wt% NaCl. At these salinities, the system is in the Winsor I region when equilibrated with oil, and salinities are far from optimal (> 6.5 wt% NaCl depending on crude oil alkane carbon number). On the other hand, for the formulation with 1 wt% IAA, retention increases by a factor 10 when the salinity is increased from 3 to 6 wt% NaCl. When equilibrated with oil, the system is in the Winsor I region at

3 wt%; however, it is close to or in the Winsor III region at 6 wt%. Thus, the retention for turbid solutions in the Winsor I region is significantly lower than for turbid solutions in the Winsor III area close to the optimum for the investigated system.

### 3.5. Correlation between solution properties, interfacial tension and retention

Table 6 summarises the solution properties and dynamic retention data as a function of salinity for the surfactant formulation consisting of 1 wt% IOS 15-18 and 1 wt% IAA co-solvent. The phase behaviour and solubility values shown in Table 6 were obtained with heptane as the oil phase at 20 °C.

As can be seen from Table 6, the system forms clear, stable solutions at low salinities. The solutions are characterised by high surfactant activity and low retention values. In the range of salinities between 0 and 3 wt%, there is no significant change in solution properties or retention values. However, the IFT decreases almost linearly, and at 3 wt% NaCl, low values are reached ( $0.01 < \text{IFT} < 0.1$  mN/m). As the salinity is further increased, IFTs stay low; however, the solutions become turbid. Although not measured for the system with 1 wt% IAA, data for 0.5 wt% IAA in Table 5 indicate that retention is roughly doubled for turbid solutions in the Winsor I region. When the optimal salinity is approached, interfacial tensions decrease to ultralow values ( $< 0.01$  mN/m). This is accompanied by a change in solution

properties and retention values: solutions become more turbid and retention increases by a factor 10. Thus, there is a narrow salinity region with respect to clear solutions, low IFT, and low retention. However, this region can be extended, at the expense of increased turbidity and higher retention. Although the retention increases, the retention in the turbid Winsor-I region is significantly lower than in the Winsor-III region. This is evident when comparing the retention data in Table 5 for surfactant formulations with 1 wt% IOS 1518 and 0.5 wt% IAA or 1 wt% IAA, respectively. The data shows that the retention is doubled when the salinity is increased from 3 to 4 wt% NaCl, and the system moves from being characterised by clear, stable solutions to being characterised by turbid solutions for 0.5 wt% IAA. For 1 wt% IAA retention increases by a factor 10 when moving from a salinity area in the Winsor I-region with clear solutions, to salinities close to optimum conditions where aqueous solutions are turbid.

With a low cost, efficient surfactant injection process in mind, selecting a formulation that gives significantly lower retention may outweigh the disadvantage of interfacial tensions being low but not ultralow. As an example, Johannessen and Spildo (2013) recently reported surfactant injection experiments where roughly the same ultimate recovery resulted from low salinity surfactant injection at low IFTs (Winsor I system) and surfactant injection at optimal salinity and ultralow IFTs (Winsor III system). The retention, however, was roughly a factor two higher for the ultralow IFT system. Still, to answer this question fully, the present study must be expanded on to include a systematic study of the oil mobilisation efficiency of the different formulations. This is a topic for future publications.

#### 4. Conclusion

We argue that the search for the best surfactant formulation for enhanced oil recovery purposes has to consider solution properties and retention in addition to obtaining the lowest possible interfacial tension. Our studies show that at optimum salinity ultralow interfacial tension is obtained, but solution properties are poor and surfactant retention is high. In the Winsor I phase region there is a narrow salinity region with respect to clear solutions, low IFT, and low retention. This region can be extended at the expense of increased turbidity and higher retention; however, the retention in the turbid Winsor I region is significantly lower than in the Winsor III region.

We suggest that the change in solution properties and retention as the salinity passes from under optimal to optimal salinity is an inherent property of surfactant formulations. At optimal salinity the surfactant is on the verge of being salted out and its aqueous solution is thus unstable. Consequently, surfactant loss is expected to be high when such a solution is transported through a porous medium with high water saturation, such as during surfactant injection into a waterflooded reservoir.

The low interfacial tensions, good solubility and low retention observed for a salinity range in the Winsor I region, implies a possibility for a potentially better and more successful surfactant

flooding. We thus propose that Winsor I phase behaviour is the best option for a compromise between the properties in question. This should, however, be verified in oil mobilisation tests.

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