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A Study on Hybrid Low Salinity Water Surfactant Flooding in a Part of Oilfields of Upper Assam Basin

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Abstract
As the economy grows the demand for hydrocarbon escalates. The major source of energy which is being exploited as a source of economy is crude oil. Therefore there is an urge to find out alternative technologies to increase oil recovery from existing oil fields. With the success of Low Salinity Waterflooding, there is a possibility of further enhancing the oil recovery process by adding surfactants which are low cost, environment friendly and readily available. Practically there is not much reported research work on hybrid low salinity water surfactant flooding in parts of oilfields of Upper Assam Basin. Considering this, the present study on low salinity waterflooding with addition of surfactants as an Improved Oil Recovery process is taken in a part of oilfields of Upper Assam Basin. This study involves a series of core flooding experiments conducted on two corefloods to determine the residual oil saturation, percentage reduction in the residual oil saturation and the recovery efficiency at each stage of the core flooding experiments. The core floodings have been first conducted at reservoir formation brine salinities of 5600 mg/l and 1700mg/l. This was followed by flooding with low salinity brines and subsequently by mixing low salinity formation brines with 1wt% surfactant and injecting into the cores in the tertiary mode of flooding. The results revealed that the hybrid process of flooding low salinity water injection with the addition of addition of surfactants resulted in reduction of residual oil saturation and obtained an increase of oil recovery by 6.32 % and 10.72 % respectively. Thus this study is a novel attempt to provide an optimum design for successful recovery of residual oil saturation by combining the benefits of low saline waterflooding with the added benefit of surfactant flooding.

Keywords: *Coreflooding, ppm, low salinity water, oil recovery efficiency, residual oil saturation, surfactant, waterflooding.*

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I. INTRODUCTION

Currently the global energy production from fossil fuels represents about 80–90% with oil and gas typifying about 60%. Cossé stated that during the process of oil production, between 30 and 40% of oil can be contributed by primary oil recovery, while additional 15–25% can be recovered by secondary methods leaving behind about 35–55% of oil as residual oil in the reservoirs [1]. This residual oil amounts to about 2–4 trillion barrels or about 67% of the total oil reserves. The main reason for this entrapment of residual oil is due to capillary forces and surface forces and also due to pore geometry (S.K Sood, Petroleum Reservoir Management, 2004). For many oil companies, residual oil recovery is at present unavoidable, and so there is a perpetual hunt for a cheap and efficient technology which will raise the global oil production as well as the productive life of many oil fields. The recovery of this residual oil is accomplished by Improved Oil methods which are used in oil industry to increase the production of crude oil.

For the last few years, production stagnancy is going on. The inability to bring fresh big reserves into production lately has kept production stagnant. Hence significant research work on improving oil recovery by deploying different IOR methods from depleted oil field is very much important.

Among the various IOR methods, water flooding is currently the most widely used method in the petroleum industry.

In the past, not much attention has concerned the salinity and the ion composition of the injection water. The performance of a water flooding is typically affected by the following main parameters: reservoir geology and geometry, physical properties, porosity, permeability, heterogeneity, fluid properties: viscosity, mobility ratio, mineralogical properties: clay type and amount. Over decades much research has been done to optimize these parameters to be able to improve water flooding process. The effect of water chemistry on brine-rock interactions was seldom paid any attention, even though the effect of low salinity brine in sandstone rock containing clay was revealed in the 60's. In recent years controlling the salinity and composition of the injected water has become an emerging enhanced oil recovery technique, often described as LOW Saline Water Flooding. In fact presently, low salinity water flooding has received considerable attention as a new IOR method (Webb et al., 2008) [2]. Low saline water flooding is thus an IOR technique in which, by decreasing the injection water salinity (1,000-5,000 ppm) and choosing the specific ionic composition, residual oil saturation can be diminished by a significant amount in the tertiary recovery stage and more importantly, in the secondary recovery stage in the early life of a reservoir. Modification of the water composition has shown to be an excellent way to increase recovery from both sandstone and carbonates.

Recent research has shown that this process will significantly benefit from introducing surfactant optimised for low salinity environment. The concept of surfactant flooding has long been recognized as promising to supplement water-based enhanced oil recovery methods. Surfactant injection is a well-known method for obtaining increased oil recovery. Surfactant injection improves oil recovery by lowering the oil–water interfacial tension (IFT), and thus prevents oil from becoming capillary trapped and/or remobilises the trapped oil.

With the success of low salinity water flooding and the possibility of further increasing the efficiency of the process by adding surfactant, Alagic and Skauge (2010)[3] presented a hybrid EOR process combining the effect of low salinity (LS) brine and surfactant injection in a combined low salinity brine and surfactant (LS-S) injection process termed as LOW SALINITY SURFACTANT FLOODING.

Studies carried out by Hirasaki et al. (1983) [4] and Mannhardt & Jha (1994) [5] also have shown that combining surfactant with low salinity water containing low concentration of divalent ions improves the performance of Surfactant Flooding. This work is a novel effort to get combined benefit of low saline water flooding with the added benefit of surfactant flooding in improving oil recovery in parts of Oilfields of Upper Assam Basin.

II. MATERIALS AND METHODS

2.1 MATERIALS

2.1.1 Core Materials

For the experiment two core samples have been collected from two different parts of Oilfields of Upper Assam Basin namely Field X and Field Y. The core samples obtained from these fields have been labeled as A1 and A2 respectively. These samples have been collected from different depths ranges of these fields. The porosity and permeability of the samples have been measured using the Helium Porosimeter and Air Permeameter respectively. The details of the core samples along with their porosity and air permeability are tabulated below in Table 1 and Table 2 respectively.

Table 1. Details of the collected core samples

Sl No	Core sample	Depth Range,m	Diameter,cm	Length,cm	Area,cm^2
1	A1	2707.2-2707.3	3.688	7.715	10.686
2	A2	2857-2866	3.719	7.328	10.867

Table 2. Petrophysical Properties (Porosity and Permeability) of core samples

Sl No	Core sample	Depth Range,m	Porosity,%	Air Permeability,md
1	A1	2707.2-2707.3	24.80	1458.100
2	A2	2857-2866	23.96	853.277

2.1.2 Crude Oil and Formation Brine

Crude oil and Formation Brine have been collected from different parts of the oilfields-X, and Y of Upper Assam Basin from where the core samples designated as A1 and A2 have been collected. Some of the important parameters of the crude oil are determined in the laboratory which is tabulated in Table 3 and Table 4 respectively. Similarly the formation brine has also been tested for various parameters in the laboratory and the results of which are summarized in Table 5 and Table 6 respectively. These crude oil and formation brine are used in core flood analysis.

Table 3. Crude Oil Analysis for the Field X

Sl No	Parameters	Unit	Result	Test Method
1	Wax content	%(w/w)	3.25	UOP 46-85
2	Asphaltene content	%(w/w)	0.39	ASTM D 6560/IP-143/84
3	Resin Content	%(w/w)	3.98	ASTM D 3279

Table 4. Crude Oil Analysis for the Field Y

Sl No	Parameters	Unit	Result	Test Method
1	Wax content	%(w/w)	8.72	UOP 46-85
2	Asphaltene content	%(w/w)	0.32	ASTM D 6560/IP-143/84
3	Resin Content	%(w/w)	7.38	ASTM D 3279

Table 5. Formation Brine Analysis for the Field X

Sl No	Parameters	Unit	Results	Test Method/Instrument Used
1	pH	mg/l	8.44	pH meter(Metrohm)
2	Salinity as NaCl	mg/l	5600	Titration with $AgNO_3$
3	Chloride	mg/l	3397	Titration with HCl
4	Carbonate	mg/l	360	Titration with HCl
5	Bicarbonate	mg/l	2745	Titration with $AgNO_3$
6	Sulphate	mg/l	1.0	Uv-Spectrophotometer
7	Calcium	mg/l	20	Titration with EDTA
8	Magnesium	mg/l	16.8	Titration with EDTA
9	TDS	mg/l	5170	Hach water checker

Table 6. Formation Brine Analysis for the Field Y

Sl No	Parameters	Unit	Results	Test Method/Instrument Used
1	pH	mg/l	8.77	pH meter(Metrohm)
2	Salinity as NaCl	mg/l	1700	Titration with $AgNO_3$
3	Chloride	mg/l	1031	Titration with HCl
4	Carbonate	mg/l	180	Titration with HCl
5	Bicarbonate	mg/l	1098	Titration with $AgNO_3$
6	Sulphate	mg/l	1.0	Uv-Spectrophotometer
7	Calcium	mg/l	24	Titration with EDTA
8	Magnesium	mg/l	8.4	Titration with EDTA
9	TDS	mg/l	1780	Hach water checker

2.1.3 Surfactant

The surfactant used in the experiments was 2-BUTOXYETHANOL LR 98 %(Butyl Glycol Ether) with the chemical formula $C_6H_{14}O_2$. It is derived from the family of glycol ethers, and is butyl ether of ethylene glycol and it performs as a non ionic surfactant. The critical micellar concentration of the surfactant is determined from the laboratory as 0.5 (w/v) %.

2.2 METHODS

The following methods were followed-

2.2.1 Core Preparation

(i) Sample collection and selection

Conventional core samples using conventional coring techniques are collected from wells having different depths of interest. For laboratory analysis, short representative core samples have been taken from the whole cores.

(ii) Core Cleaning

The core samples are cut and end faced to obtain uniform surfaces. To start with the determination of various petrophysical properties, the core samples are to be cleaned to remove the original fluids present in them. Cores are cleaned by placing the core samples in the Soxhlet apparatus for nearly 24 hours using a mixture of 60% toluene and 40% methanol as solvent. After cleaning in the Soxhlet apparatus,the core samples are further cleaned in the ultrasonic cleaner for about 9 minutes.

(iii) Core drying

After the core samples have been cleaned, they are dried to remove the water inside the pore spaces of the sample. Here the core samples were kept in the humidity oven at 63^0C and 40% relative humidity (ARI-RP-40, 1998)[6].The samples are taken out from the oven time to time and their weight is checked until it becomes constant.

2.2.2 Preparation of synthetic brine

Taking into consideration the original reservoir formation brine salinities, i.e., 5600 ppm and 1700 ppm synthetic brines of different salinities have been prepared. The synthetic brines are prepared by considering certain salts as listed in the table 7. The preparation of synthetic reservoir brines with 5600 ppm and 1700 ppm has been made and tabulated in Table 7.

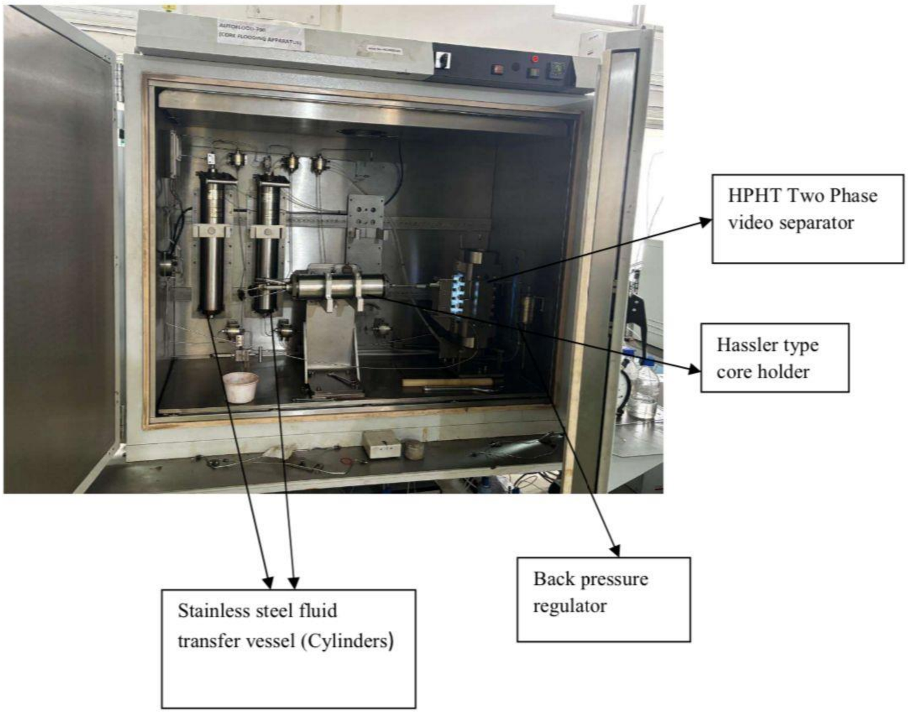
Table 7 Ionic concentration of synthetic formation brines

IONS	ASSOCIATED SALTS	ION CONC(mg/L)	ION CONC(mg/L)
K^+	KCl	600.2	700.3
Na^+	NaCl	15	10
Ca^+	$CaCl_{2.}2H_2O$	20	24
Mg^+	$MgCl_{2.}6H_2O$	16.8	8.4
SO_4^{2-}	$FeSO_{4.}7H_2O$	1.0	1.0
Fe^{2+}	$FeSO_{4.}7H_2O$	105.5	120.6
Cl^-	KCl,NaCl,$CaCl_{2.}2H_2O$, $MgCl_{2.}6H_2O$	4841.5	835.7
Salinity		**5600ppm**	**1700ppm**

2.2.3 Core flooding experiments

The core flooding experiments were carried out in the Vinci Technologies Autoflood-700(Core Flooding Apparatus). In this study the tertiary mode of flooding has been experienced to compare the oil recovery results. The Autoflood 700 and its associated parts are illustrated in Figure 1.

Fig 1 Autoflood 700 (Core flooding Apparatus)



2.2.3.1 Flooding the core sample A1 and A2

The core plug A1 has been put into the Hassler Core holder which has Silicon Oil inside to hold the core plug in place at a pressure of 1500 psi. 800 mL of synthetic formation brine having salinity 5600ppm has been filled up in cylinder 1 and equal amount of crude oil has been filled up in cylinder 2. At first synthetic formation brine has been imbibed at a rate of 2cc/min through the core plug.

For Core Plug A1,
The dry weight of the core plug = 178.546
Wet weight was found as 196.9598
Thus the Pore Volume (PV) =18.413

Next flooding has been done with crude oil from cylinder 2 at a rate of 2cc/min. This process continues till last volume of water is traced in the effluent. Now after subtracting the line volume from the total water coming out from the core plug during crude oil flooding, the actual water coming out from the core plug can be determined. From this the connate water saturation (S_{wc}) can be obtained. Similar procedure is followed for core plug A2 which is flooded with synthetic brine of salinity 1700 ppm followed by crude oil. All the flooding operations have been carried out at room temperature. The core plugs have been aged in the core holder for 18 days at a confining pressure of 200 psi to establish equilibrium among the crude oil, brine and rock. The following table 8 shows the Pore Volume, Total water coming out, actual water out and the connate water saturation corresponding to the core plugs.

Table 8 Experimental details of the core plugs

Sl No	Core samples	Salinity of the brine	Pore Volume	Total water out	Line Volume	Actual water out	Connate water saturation
1	A1	5600ppm	18.413	12.44cc	2.15cc	10.29cc	44.11%
2	A2	1700ppm	18.8434	11.85cc	2.15cc	9.7cc	48.59%

2.2.3.2 Tertiary mode of flooding(Core Plug A1)

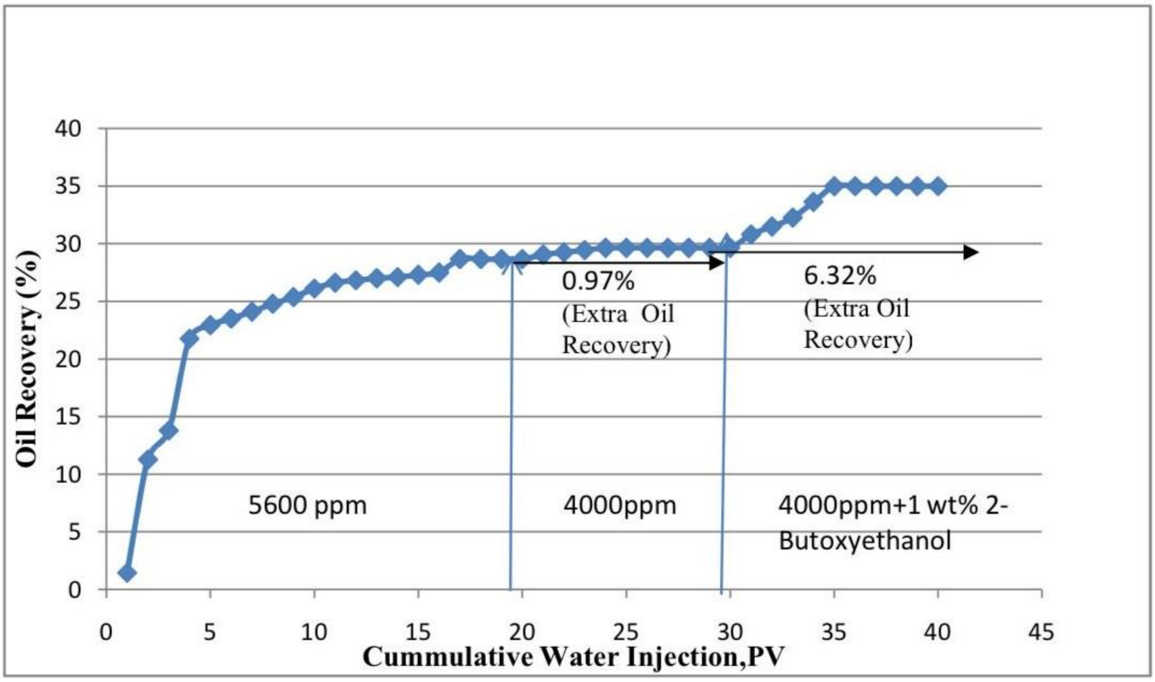
The saturated and aged core sample A1 has been first flooded for 20PV with 5600 ppm synthetic brine consisting of salts such as KCl, $MgCl_2$,$CaCl_2$ etc. Here, reservoir formation brine of salinity 5600 ppm is considered as the high salinity brine. Accurate oil recovery was measured after flooding with 20 PV of synthetic brine at flow rate of 2 cc/min. Total flooded oil of 4.85 cc has been collected in the drainage vessel. Oil recovery efficiency has been calculated from this data. The residual oil saturation has been measured and tabulated in Table 9. So the oil recovery efficiency by flooding the saturated core plug by the synthetic formation brine of 5600 ppm was observed to be 28.67%. The flooded core plug has been further flooded with low salinity brine of 4000 ppm for 10PV followed by low salinity brine of 4000ppm + 1wt% surfactant (2-ButoxyEthanol) for 10 PV. While flooding with 4000ppm low salinity brine, extra oil recovery of 0.97 % has been observed whereas in the low salinity brine of 4000ppm + 1wt% surfactant (2-ButoxyEthanol) flooding experiment, extra oil recovery of 6.32% has been observed. All the experimental data are tabulated in Table 9.

Table 9 Experimental data of flooding core plug A1 in Tertiary mode

Core plug	Residual oil Saturation (%)	Flooding sequence	Salinity,ppm/Wt%	Oil recovery(% of OOIP)
A1	39.86	High Salinity Brine(HSW)	5600	28.67%
A1		Low Salinity Brine(LSW)	4000	Additional recovery=0.97% Total recovery=29.64%
A1		Low Salinity Brine(LSW)+Surfactant	4000+1Wt%2-Butoxyethanol	Additional recovery=6.32% Total recovery=35.96%

Now a graphical representation of the additional oil recovery at tertiary mode for sample A1 is presented in Figure 2.

Figure 2 Additional Oil Recovery at tertiary mode (Sample A1)



2.2.3.3 Tertiary mode of flooding(Core Plug A2)

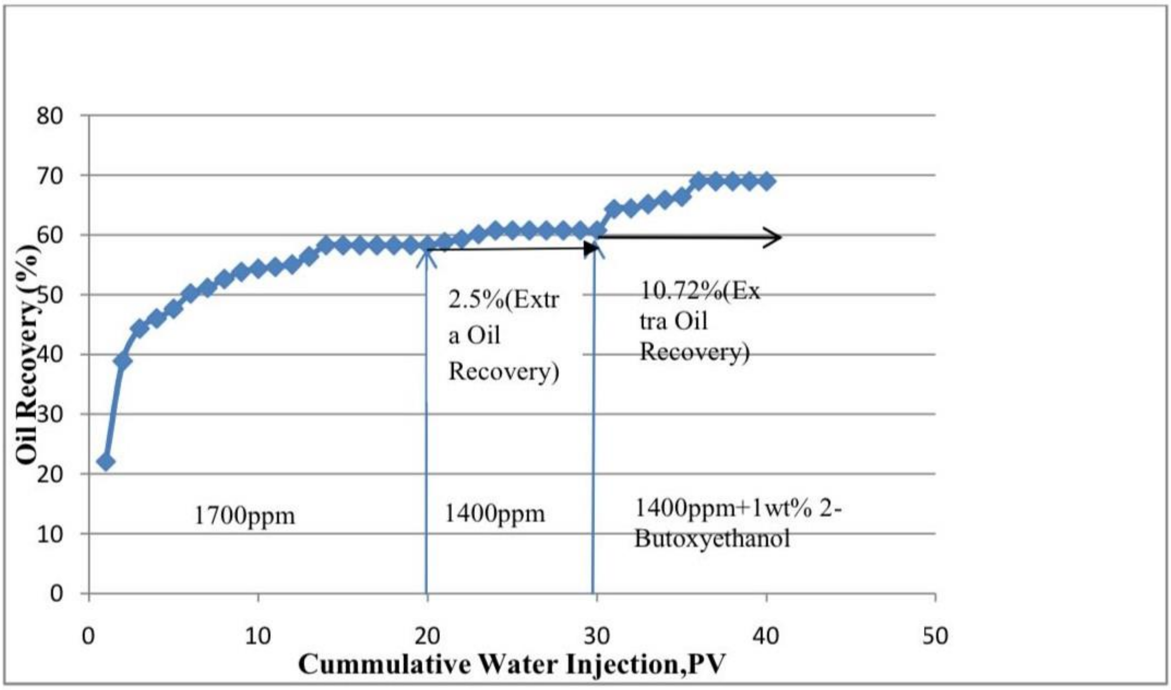
The saturated core plug A2 has been flooded in a sequential manner starting with High salinity synthetic brine of 1700ppm for 20 PV followed by LSW of 1400ppm for 10 PV. This was further followed by flooding for 10 PV with low salinity brine of 1400 ppm + 1wt% surfactant (2-ButoxyEthanol). Oil recovery of 58.25% has been observed for 1700ppm high salinity brine. Additional oil recovery of 2.5 % has been observed for LSW of 1400 ppm and 10.72 % additional recovery has been obtained for low salinity brine of 1400 ppm + 1wt% surfactant (2-ButoxyEthanol).All the experimental data are tabled in Table 10.

Table 10 Experimental results of flooding core plug A2 in Tertiary mode

Core plug	Residual oil Saturation (%)	Flooding sequence	Salinity,ppm/Wt%	Oil recovery(% of OOIP)
A2	21.49%	High Salinity Brine(HSW)	1700	58.25%
A2		Low Salinity Brine(LSW)	1400	Additional recovery=2.5% Total recovery=60.75%
A2		Low Salinity Brine(LSW)+Surfactant	1400+1Wt%2-Butoxyethanol	Additional recovery=10.72% Total recovery=71.47%

Now a graphical representation of the additional oil recovery at tertiary mode for sample A1 is presented in Figure 3.

Figure 3 Additional Oil Recovery at tertiary mode (Sample A2)



III. RESULTS AND DISCUSSION

The core flooding experiments have been done in the tertiary mode of flooding and the results of the experiments of the two core samples have been analyzed. The main purpose of this study was improving oil recovery by taking into consideration the added benefit of low salinity water together with the addition of cheap, readily available environment friendly surfactant. So the flooding experiments were done in a phased manner: (i) with high salinity brine (ii) followed by low salinity brine and then (iii) flooding with low salinity brine+1wt% surfactant. The following observations have been made from the experiments:

(i) For the core plug A1 oil recovery efficiency was found to be 28.67% at 5600 ppm salinity. This was followed by flooding the same core sample with 4000 ppm salinity brine and an incremental recovery of 0.97% has been observed. As it followed tertiary mode of flooding ,finally the same core plug has been flooded with low salinity water of 4000ppm together with 1wt% 2-Butoxyethanol which resulted in an additional oil recovery of 6.32%. Thus the total oil recovery for sample A1 was found to be 35.96%.For preparation of synthetic brine salts like KCl,NaCl,$CaCl_2.2H_2O$, $MgCl_2.6H_2O$ have been considered.

(ii) The core plug A2 followed the similar method of tertiary mode of flooding with 1700 ppm brine followed by 1400 ppm brine and subsequently by 1400 ppm brine with 1wt % 2-Butoxyethanol. The overall oil recovery efficiency was found to be 71.47% with 1400 ppm brine and 1wt % 2-Butoxyethanol accounting for additional oil recovery of 10.72%.

The study has successfully shown an increase in oil recovery by the use of a nonionic surfactant in combination with low salinity water. Although the surfactant concentration of 1 wt% is slightly high, literature review shows similar studies where 1 wt% or higher surfactant concentration provided better results in terms of Interfacial Tension reduction and residual oil recovery.

(iii) The IFT between the crude oil and brines have been evaluated under reservoir conditions using the drop weight method. The IFT is 28.9 mN/m for 5600 ppm brine and 36.28 mN/m for 4000 ppm brine. The IFT is higher for low salinity brine compared to high salinity brine. Similarly the IFT is
32.3 mN/m for 1700 ppm brine and 41.4 mN/m for 1400 ppm brine. For the brine of 4000 ppm+ 1wt % 2-Butoxyethanol the IFT is 1.7 mN/m and for 1400ppm + 1wt % 2-Butoxyethanol the IFT is 2.1 mN/m. Thus clearly the addition of surfactants drastically reduces the IFT and mobilizes the trapped residual oil thereby improving oil recovery.

(iv) In case of low salinity water and surfactant the increase in oil recovery is attributed to reduction in IFT along with alteration of wettability. Studies by Araz et al.[7] who conducted a combined study of LSW and the surfactant Sodium Dodecyl Benzene sulphonate agrees with the results obtained by the core flooding experiment. Alagic et al.[8] also reported that the combination of LSW with surfactants increased the oil recovery factor but the result was better in aged cores.

IV. CONCLUSION

In the above study the oil recovery has been calculated in terms of original oil in place (OOIP) with respect to the injected pore volume. It was observed that the addition of non ionic surfactant to the 4000 ppm low salinity brine resulted in increase in oil recovery by 6.32 % and to the 1400 ppm brine resulted in increase in oil recovery by 10.72% . Both the experiments have been conducted in the tertiary mode and an increase in oil recovery efficiency has been observed in both the cases. Thus hybrid low salinity water surfactant flooding combining the synergy of both LSW flooding and surfactant flooding can be successfully designed for improving oil recovery from parts of oil fields of Upper Assam Basin.

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