Full Length Research Paper

Experimental study of surfactant alternating gas injection versus water alternating gas and water flooding enhanced oil recovery methods

Mehdi Mohammad Salehi*, Mohammad Amin Safarzadeh, Eghbal Sahraei and Seyyed Alireza Tabatabaei Nejad

Chemical Engineering Department, Sahand University of Technology, Tabriz, Iran

Nitrogen is used in both the miscible and immiscible gas injection processes in oil reservoirs. In heterogeneous formations, gas tends to early breakthrough due to overriding and fingering. Surfactant alternating gas (SAG) injection is one of the methods commonly used to solve this problem. The foam which is composed in contact area of nitrogen and surfactant, increases injected gas viscosity. However, adsorption of surfactant on rock surface can increase cost of process. This work describes the experimental study of SAG injection versus water alternating gas (WAG) and water flooding. In this study the concentration of surfactant was optimized to minimize adsorption of surfactant on rock surface which lower the cost of surfactant. Results show that using the concentration of 1500 ppm of surfactant solution is economically cost effective. Results also shows that the SAG ratio of 1:1 with rate of 0.2 cc/min at temperature and pressure of 70°C and 144.74×10^5 Pa, has the maximum oil removal efficiency. In this SAG ratio, stable foam was formed and viscous fingering delayed in comparison with other ratios. Finally, this study demonstrated that SAG injection has higher oil recovery in comparison with other displacing methods (water flooding, gas flooding and WAG).

Key words: Surfactant alternating gas (SAG), cycle ratio, foam, sand pack, spectrophotometer.

INTRODUCTION

With the decline in oil production, rising in oil price during the last decades and a large amount of oil which is still trapped in reservoirs after applying the common enhanced oil recovery (EOR) method, it is reasonable to use profitable methods with higher initial operational cost. In principle, miscible gas injection can displace nearly all of the reservoir oil which was swept by gas. Although, the process of gas injection has been attracted more attention, it has major problems with poor sweep efficiency, and inefficient displacement of oil in low pressure reservoirs (Renkema and Rossen, 2007). Processes such as the injection of water alternating gas and direct gas thickeners are being used to enhance the sweep efficiency and control the mobility of gas injection. In spite of satisfying result of thickeners, it has a few applications because of high operational cost. The process of alternative injection of water and gas helps to control gas mobility (Syahputra et al., 2000). Unfortunately reduction of oil-gas contact in the presence of water decreases the WAG effectiveness.

*Corresponding author. E-mail: mehdi.salehi83@gmail.com. Tel: (0098)7734823194. Fax: (0098) 7734826633.

Abbreviations: **SAG,** Surfactant alternating gas; **WAG,** water alternating gas; **BPR,** back pressure regulator; **API,** American Petroleum Institute; **SDS,** sodium dodecyl sulfate; **PV,** pore volume; **SO,** safranin O; **S.S,** surfactant solution; **OOIP,** original oil inplace; **MMP,** minimum miscible pressure.

Gravity segregation tends to impair the advantages of this injection strategy and is amplified by permeability differences. It should be noted that the injectivity of WAG is lower in carbonate reservoirs (Viet and Quoc, 2008).

According to Austad and Milter, chemical flooding of oil reservoirs is one of the most successful EOR methods in depleted reservoirs at low pressure (Gogoi, 2009). In process of investigating the effectiveness of surfactant injection not the technical feasibility but economic of the process is the issue. The low oil prices at past years was provided little stimulus for research on chemical flooding.

The use of foam for gas mobility control was first proposed in 1958 by Bond and Helbrook (Syahputra et al., 2000). Foam inside porous medium is defined as a dispersion of gas in liquid such that the liquid phase is continuous and at least some part of the gas is made discontinuous by thin liquid films called lamellae. The foam occurs as gas disperses within a surfactant solution and the mobility's of gas and the aqueous phase are reduced (Falls et al., 1988). Composing foam is a process which can improve sweep efficiency during gas injection. Several field applications of foam have been reported (Hoefner and Evans, 1994; Patzek, 1996; Renkema and Rossen, 2007).

Different foam-injection strategies have been used in field trials due to stratigraphic differences, foam behavior and operational concerns (Xu and Rossen, 2003). Foams or gas diversion can be caused in the reservoir by continuous co-injection of surfactant solution and gas, or alternative injection of surfactant solution slugs and gas.

SAG injection has several advantages over co-injection of surfactant and gas. It minimizes contact between water and gas in surface facilities and pipes, which can be important when the acidic gas, for instance CO_2, is present (Shi and Rossen, 1998; Mattews, 1989; Heller, 1994). Alternating injection of small slugs of gas and liquid can promote foam formation in the near-well region (Rossen and Gauglitz, 1990). SAG injection also improves injectivity; as water is displaced from the near-well region during gas injection, foam weakens there, gas mobility rises and injectivity increases (Shan and Rossen, 2002; Shi and Rossen, 1998).

Several alternatives have been proposed to increase sweep efficiency of CO_2 injection in the field or in experimental works, such as injecting WAG (Christensen et al., 1998), direct CO_2 thickeners (Heller et al., 1983), and injecting surfactant solution alternating gas (Tsau and Heller, 1992). The benefits of using SAG to improve the efficiency of CO_2 displacement have been reported by several investigators (Skauge et al., 2002; Yaghoobi et al., 1998).

Laboratory and field studies indicate that foam potentially presents an efficient method of reducing CO_2 mobility (Tsau et al., 1998; Bernard and Holm, 1964). A possible advantage of SAG over WAG for mobility improvement is that it can contain higher gas saturation (over 85 to 95% gas). This means that a relatively small amount of water is used to decrease CO_2 mobility. Foam has other properties that are favorable to oil recovery, particularly in CO_2 flooding. The apparent foam viscosity is greater than the viscosity of its components which increases oil recovery due to improved mobility ratio. It also increases trapped gas saturation and decreases the oil saturation. In addition, high trapped gas saturation usually reduces gas mobility. All of these unique properties of foam indicate its usefulness in CO_2 flooding. Foam properties may also cause unfavorable increases in injectivity and chemical costs (Syahputra et al., 2000).

The SAG operations were conducted without major problems. SAG injection has proved to be an efficient injection procedure. SAG is operationally similar to WAG and requires little additional effort. Injection should be performed below fracturing pressure (Blaker et al., 2002).

One of the factors affecting the economics of SAG is the loss of the foaming agent by adsorption onto reservoir rocks, precipitation, and resultant changes in rock wettability (Blaker et al., 2002). The adsorption phenomenon at liquid-solid contact has great importance in all mentioned processes. It is not uncommon in chemical processes to have over 90% of a component required to satisfy adsorption onto the rock. Thus, understanding adsorption process is critical in evaluation of transport of chemicals and in accurately assessing the volume of chemicals required for a successful SAG operation (Song and Islam, 1994). It has been found that surfactants can play an important role in controlling SAG mobility, but always can cause difficulties by adsorption on the surface of silica. Adsorption of surfactants increases the cost of process significantly. In order to improve the economics of SAG, optimum concentration (with dynamic adsorption method) of surfactant must be determined.

In this study the effect of SAG ratio (ratio of volume of aqueous surfactant solution to volume of injection gas) on displacement efficiency was investigated using sets of well characterized bead-pack experiments. This work shows that recovery from SAG is a function of SAG ratio at certain temperature and pressure. It's crucial to note that before optimizing SAG ratio, the concentration of surfactant was optimized in order to minimize its adsorption on surface of silica. Optimization of SDS concentration decreases the cost of SDS due to lower adsorption of surfactant on silica. Then some comparison was made between the study results, water flooding, gas flooding and WAG results.

METHODOLOGY

Chemical materials, rock and fluids

The type of surfactants, organic solvent and cationic dye and their basic properties is shown in Table 1. Bangestan crude oil and purified gas (nitrogen) was used in all experiments. The crude oil is intermediate (28°API). Silica was used as adsorbents in all experiments. Also sand pack was made by silica.

Table 1. Chemical material and their basic properties.

Material	Type	Mw (gmole)	PH
Surfactant	Sodium Dodecyl Sulfate (SDS)	288.370	6 - 9 (10 g/L, H_2O, 20°C)
Cationic dye	Safranin O	350.850	10 (10 g/L, H_2O, 20°C)
Organic solvent	Ethyl acetate	88.105	-

Apparatuses

Fluid injection system

During the experiments a pump with high performance liquid chromatography was used to displace fluids in the sand pack.

The operating fluid of the pump is twice-distilled water and it has been injected into the pipes and fittings with constant flow rate of infusion from bottom of fluid accumulator (brine water, surfactant solution, crude oil or nitrogen). Therefore, the accumulator fluid was injected into the sand pack with constant flow rate.

Accumulators: They were used to provide high pressure injection. The distilled water is transported from the pump to the bottom of the accumulator to move the piston upward and compact the contained fluid.

Core holder: Core holder was made of anticorrosion stainless steel (grade 316) of 5 cm diameter and 15 cm height.

Heating system and air bath chamber: All the systems were placed in an air bath, which was able to control temperature in the range of ambient and 210°C.

Pressure differential gauge: It was used to measure the pressure drop along the sand pack.

Back pressure regulator (BPR) and effluent collector: A backpressure regulator (BPR) was used to produce a constant backpressure during core flood experiments. One of the BPRs which were installed at the outlet of the apparatus was operated at 156×10^5 Pa. The effluent was collected to measure oil recovery using a fractional collector.

Spectrophotometer: The   UV-VIS   spectrophotometer (Spectroquant® Pharo 300) equipped with 1 cm quartz cell was used   for   all   spectrophotometric   measurement.   The   pH measurements were made with a 780-pH meter equipped with an Ag/AgCl electrode.

Procedure

In these experiments, nitrogen and surfactant solution were injected immiscibly   to   displace   dead   oil.   Below   the   sand   pack implementation was mentioned:

Sand pack preparations

Silica grains with size distribution of 80 to 250 μm were used to prepare   sand   pack   to   obtain   a   homogeneous   model   with appropriate permeability. The silica's seeds strew into the core holder after washing. The core holder which was contained and the sand pack was put into the shaker to squash the fluids. Screen and glass fiber were installed at the inlet and outlet of core holder to prevent removal of silica.

Porosity measurement: In this work the weight method was employed to determine porosity. In this method the sand pack (moreover metallic sheath) was measured in dry state initially, then it was saturated with distilled water and the mass was measured again. The difference between two measured mass was equivalent to the mass of water which was saturating the sand pack. So the pore volume of the sand pack can be calculated regards to water density. With distinguishes of bulk volume, the porosity can be determined using Equation 1:

$$\phi = \frac{V_{fluid}}{V_{total}}$$

(1)

Permeability measurement: The sand pack permeability was measured   with   brine   solution   after   porosity   measurement. Permeability measurement was based on Darcy's law, which can be rearranged as following Equation:

$$\frac{q\mu}{A} = k\frac{\Delta P}{L}$$

(2)

Where q is the flow rate; μ represents the viscosity of fluid; A is the cross-sectional area of the sand pack; k is the permeability; ΔP represents the pressure drop along the sand pack; and L is the length of the sand pack. Normally pressure drops at different flow rates were measured. Then qμ/A was plotted versus $\Delta P/L$. A straight line which was crossed through the origin can be fitted to the data. The slope of the line represents the permeability of the sand pack. If the data deviate significantly or systematically from the linear trend, there may have been an experimental artifact in the data.

Sand pack saturation procedure: Since the tests are carried out under irreducible water saturation, first the sand pack must be saturated with water and then with oil. Therefore for saturating sand pack with water, the lower core holder valve was kept open so water can be entered from the bottom and saturates the sand pack to 100%. Then oil was injected into core holder through its top valve. In this stage, initial level of saturation of the oil in sand pack was 83 percent, and irreducible water saturation was 17%.

All flooding experiments which were done to determine the optimum SAG ratio were conducted in the same sand pack and at the end of each experiment; the sand pack was washed by toluene and placed in the air bath at 71°C to be completely dried by carbon dioxide gas.

Six experiments were carried out on the 6 sand packs of near similar properties to determine optimum surfactant concentration. After preparing the sand pack and core holder it was placed horizontally inside the air bath chamber for injection tests. Details of the conventional sand pack were indicated in Table 2.

Core flooding experiments

To clarify the experiments 3 general scenarios were designed. In

Table 2. Properties of conventional sand pack.

Property (unit)	Quartz sand
Core diameter (cm)	5
Core height (cm)	15
Bulk volume (cc)	294.37
Pore volume (cc)	85.36
Porosity (%)	29
Permeability (md)	350
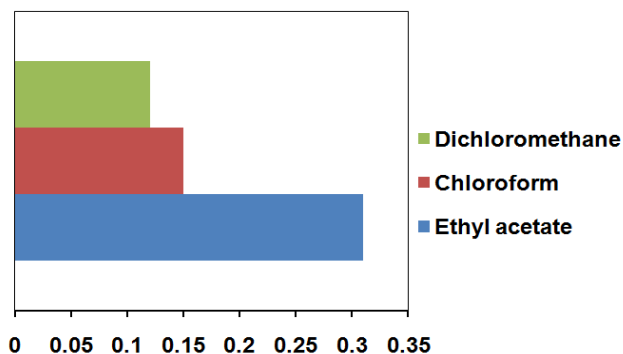
Figure 1. Effect of organic solvent on extraction efficiency of SDS
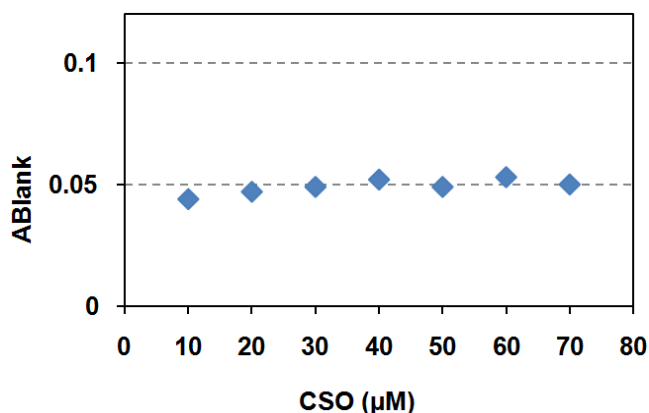
Figure 2. Variation of absorbance of SO as a function of concentration

first scenarios the optimum concentration of SDS to minimize the absorption of SDS was attained which decreases the expenses of the experiments. Then in second scenario, the optimum SAG ratio was determined regards to first scenario. Finally, in last scenario the SAG experiments (in optimum SAG ratio) were accomplished in order to compare the method with other EOR methods (gas flooding, water flooding and WAG (1:1) injection).

Scenario one: An analytical method to determine optimum SDS concentration

SDS is an anionic surfactant and its solution with water yields a

colorless solution. There are different methods for measuring concentration like; titration methods, refractometry and colorimetry (spectrophotometric method). The last method was used for measuring concentration.

The most regular methods of sample preparation in the analysis of anionic surfactants in water are based on formation of an ion-pair between anionic surfactant and a cationic dye and later liquid-liquid extraction of the anionic surfactant from water**.**

Several cationic dyes such as methylene blue (Safranin-O, SO), cetyl pyridine chloride and rhodamine 6G were evaluated as counter ion for spectrophotometric determination of anionic surfactants. Safarin O is a colored cation and its solvability is low in organic phase. So ion pair has been used to determine SDS concentration then ion pairs was separated using liquid-liquid extraction.

Various organic solvents were employed for extraction of ion-pair such as chloroform and dichloromethane. These solvents are usually toxic. Ethyl acetate was used as the organic solvent for ion-pair extraction.

The selection of organic solvent has major importance to obtain efficient extraction in liquid-liquid solvent extraction. Two factors should be considered for selecting organic solvent. First, the organic solvent must be immiscible in aqueous phase. Second, the solubility of ion-pair should be higher in the organic than the aqueous phase. On the other hand, the solubility of analyze and counter ions should be lower in the organic phase.

Based on these criteria, the effect of different organic solvents such as dichloromethane, chloroform, and ethyl acetate were studied and the results was shown in Figure 1. The results illustrates that ethyl acetate is a proper solvent because of its higher SDS-SO ion-pair solubility in comparison with other solvents. In other words both the SDS and the SO molecules alone were never transferred to the ethyl acetate phase but rather were associated, forming the ionic pair SDS-SO. The data indicated the best extraction efficiency obtained for ion-pair by using ethyl acetate (Daneshfar and Kaviyan, 2009).

Figure 2 depicts the absorbance of blank (ethyl acetate) as a function of concentration of SO. Considering this figure shows that increasing the concentration of SO (in aqueous phase) does not change the absorbance of blank. Therefore, the SO was used as the counter ion for the following experiments. The above results clarify that transfer of SO molecules alone in the water to the organic phase is very low, but only the associated ion pair of SO and SDS can be extracted to the ethyl acetate phase.

In order to extract SDS with maximum sensitivity, several counter ions have been tested and the results have been compared. SO was chosen due to its efficacy as extractor and low solubility in organic phase.

Figure 3 shows anion and cation mixture with definite density and volume which were used to extract ion pair of ethyl acetate. Figure 4 describes the profile of amount of SDS absorption in different wave's length. Considering this figure it can be concluded SDS maximum absorption happens in 529 nm wave length.

A standard calibration curve was required to use spectrophotometer. Figure 5 depicts calibration diagram in 529 nm wave length relevant SDS. The diagram exhibited a wide linear range (1 to 20 µM).

Dynamic adsorption method

Two dynamic methods (circulation and flow through) were employed to study surfactant adsorption and desorption. Flow-through method was used to study SDS adsorption/desorption in the porous media. Figure 6 shows the schematic diagram of the flow-through method apparatus. The test procedure is as following:

(i) Porosity and permeability measurement and saturating the model

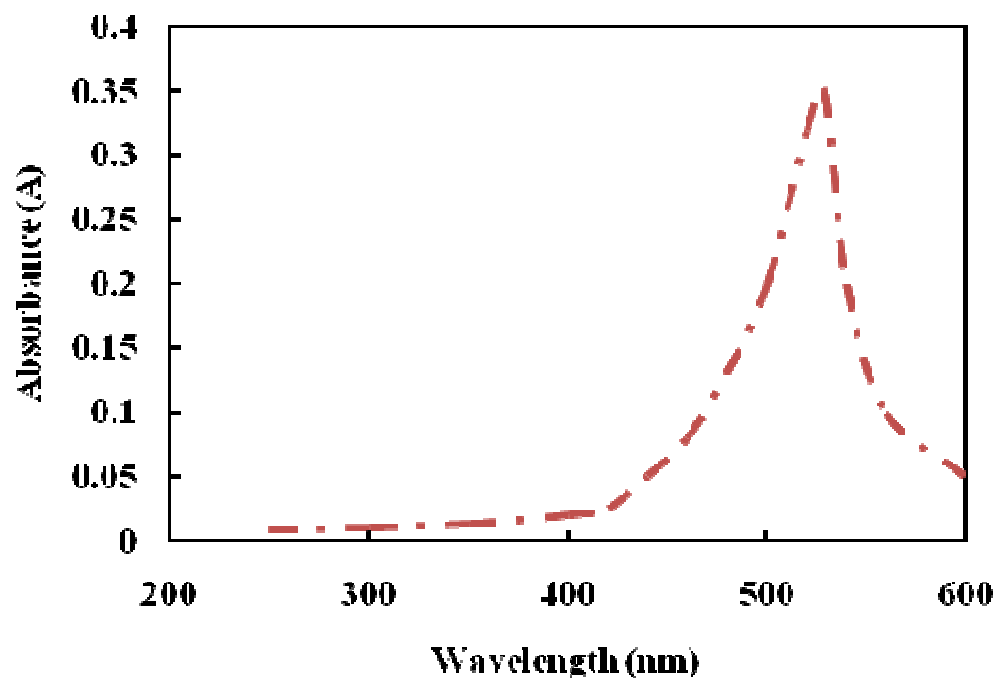**Figure 3.** Formation of two separable phases after addition Ethyl acetate solvent.

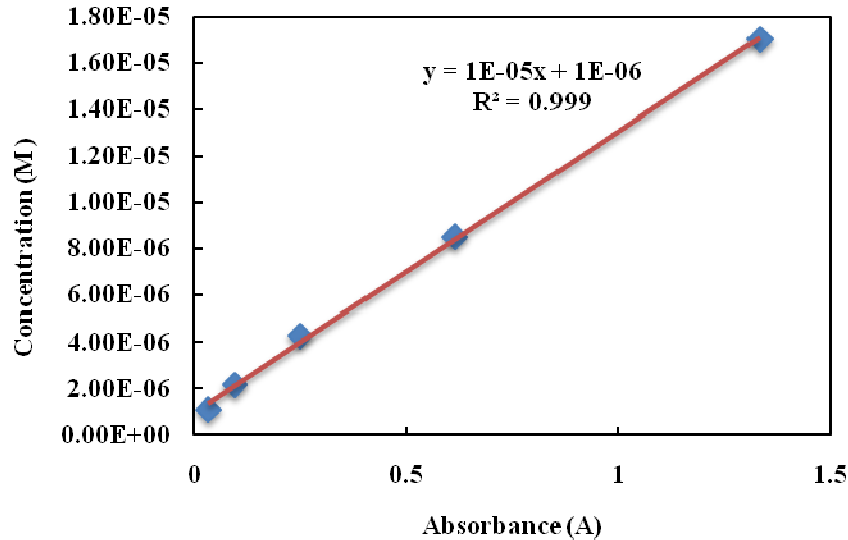**Figure 4.** Absorption spectra of SDS.
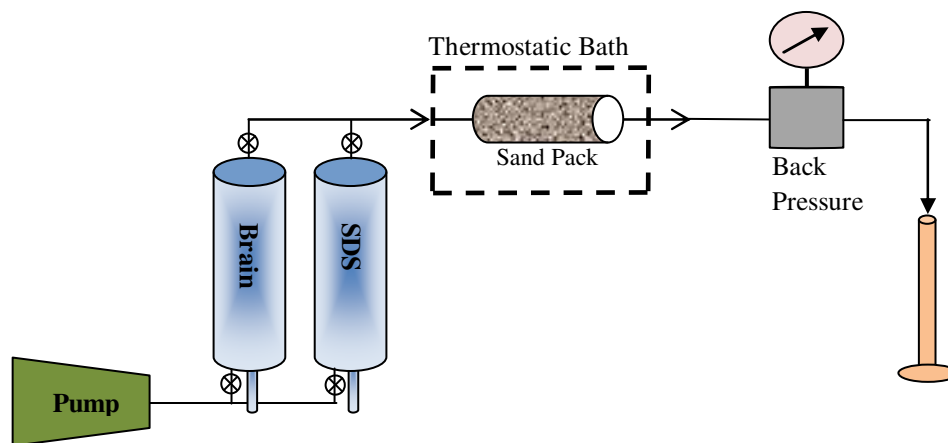
Figure 5. Calibration curve of SDS at 529 nm.

Figure 6. Schematic diagram of dynamic adsorption test.

with aqueous phase.
(ii) Injection of one pore volume (PV) of surfactant solution.
(iii) Injection of about 5 PV of aqueous phase.
(iv) Sample collection at different times to measure the concentration of the SDS.

Tests were performed using the above procedure for six different concentrations to achieve optimum concentration of SDS at 70°C and 144.74×10^5 Pa.

Scenario two: Effect of injection volume ratio in SAG injection process

After sand pack preparations, the oil saturated sand pack at presence of irreducible water for immiscible SAG injection was placed horizontally in the air bath system (Figure 7).

Five SAG displacements were performed at a rate of 0.2 ml/min to investigate the effect of SAG ratio on recovery, using SAG

ratios of 1:1, 1:2, 1:3, 2:1 and 3:1. In Table 3 numbers of cycle, arrangement and amount of injection fluids at SAG ratio 1:1 was shown. All displacement SAG cycles was performed with injection volume of 1.2 PV. Temperature was set at 70°C.

Scenario three: Comparison of method with water flooding, gas flooding and WAG

In this part of the work, oil recovery SAG injection was compared with gas flooding, water flooding and WAG recovery factor. For this comparison three injections with rate of 0.2 cc/min were studied. All experiment was done at 70°C and 144.74×10^5 Pa.

In this experiment, first sand pack was saturated with oil at irreducible water saturation, and then 1.2 PV of water was injected at secondary recovery stage with rate of 0.2 cc/min.

Gas flooding: In gas flooding process after saturating sand pack with oil at irreducible water saturation, 1.2 PV of gas was injected in
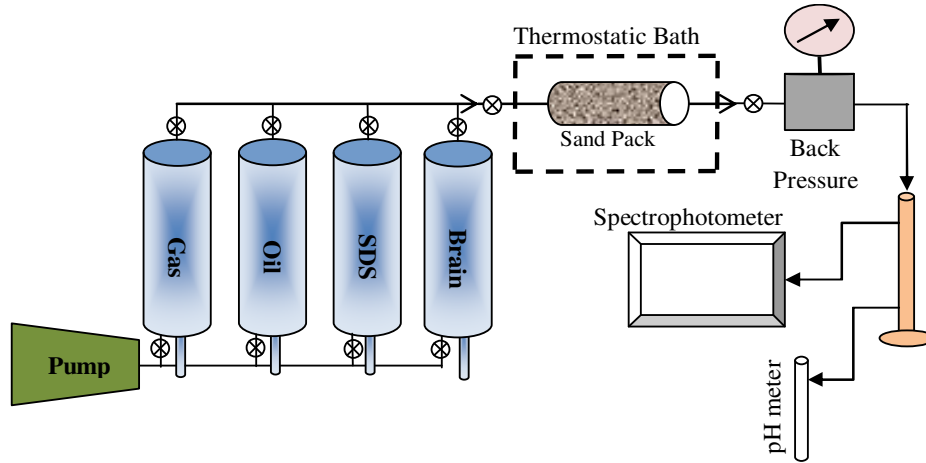
Figure 7. Schematic diagram of flooding apparatus.

Table 3. Arrangement and amount of injection fluids in SAG ratio 1:1.

Parameter	Cycle 1		Cycle 2		Cycle 2		Cycle 4	
Injected PV	0.15 PV	0.15 PV	0.15 PV	0.15 PV	0.15 PV	0.15 PV	0.15 PV	0.15 PV
Fluids	SS	N_2	SS	N_2	SS	N_2	SS	N_2

sand pack at rate of 0.2 cc/min continuously. Injection pressure was less than Minimum Miscible Pressure (MMP) of nitrogen, therefore gas flooding was immiscible process.

Water alternating gas: In this experiment water and gas were injected alternatively with rate of 0.2 cc/min in volume ratio of 1:1.

RESULTS AND DISCUSSION

Dynamic adsorption- effect of different SDS concentration

Flow-through experiments were carried out to measure the adsorption isotherm and optimum SDS concentration. SDS retention by adsorption and phase trapping determines the amount of surfactant required for asurfactant enhanced oil recovery process. The relationship between the amount of surfactant adsorbed per unit mass or unit area of the solid and the bulk solution concentration of the adsorbate was called an adsorption isotherm. Different SDS concentration of 100, 500, 1000, 2000, 3000 and 4000 ppm was used to obtain the optimum concentration at 70°C and 144.74×10^5 Pa.

Figure 8 depicts the adsorption isotherm for SDS on silica. This figure shows that increasing the concentration of surfactant from 100 to 1000 ppm increases the adsorption of surfactant. Although the absorption of surfactant on rock surface increases to concentration of 1000 ppm, it is constant in the range of 1000 to 3000

ppm and increases at concentrations above 3000 ppm. This is due to insolubility of surfactant in water. For example in concentration of 4000 ppm some amount of surfactant remains insoluble in water which is collected in the accumulator and causes error in measurements of outlet concentration of sand pack model. Considering the above explanation concentration of 1500 ppm was optimum for injection in this process. In this concentration some amount of surfactant was absorbed by rock surface and remaining surfactant composed foam in contact with nitrogen.

Effluent normalized concentration (effluent concentration/injected concentration) profiles of SDS for 100, 1000 and 3000 ppm were shown in Figure 9. Effluent normalized concentration may be greater than 1. It means that it is higher than injection slug concentration. It was generally believed that surfactant adsorption on the solid surface takes place in the monomer phase. This was explained by monomer concentration reduction.

Increasing the SDS concentration decreases the breakthrough time. This is due to increase in dispersion coefficient of surfactant.

Effect of injection volume ratio in SAG injection process

In this stage, the process was divided in two sections for helpful analyzing the effect of injection volume ratio on
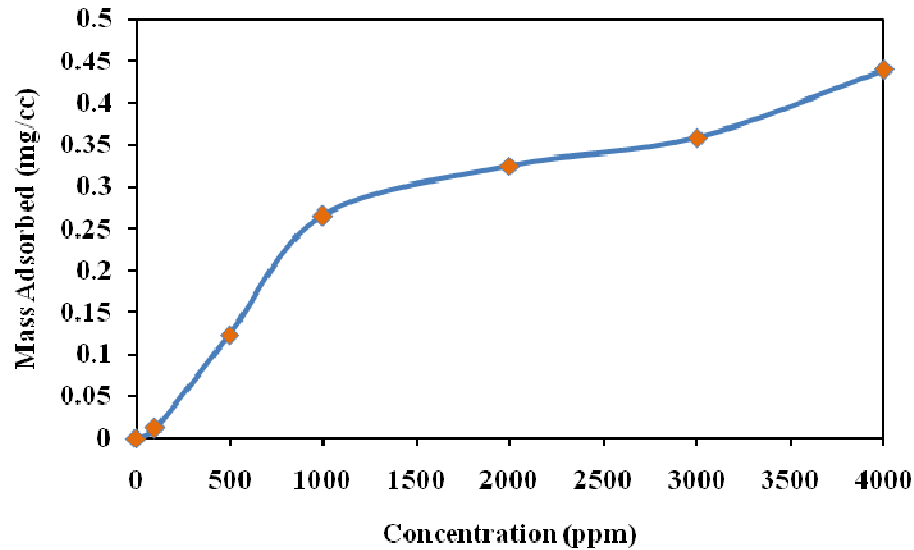
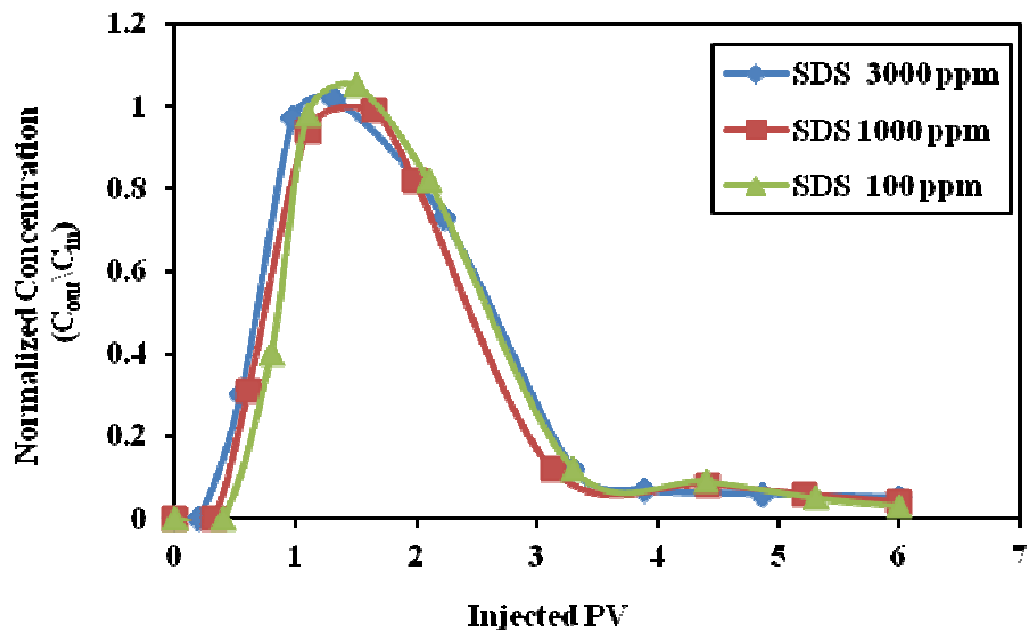**Figure 8.** Adsorption isotherm for SDS on silica at 70°C and 144.74×10^5 Pa.

Figure 9. Effluent Normalized concentration profiles of SDS for different concentration of SDS.

SAG injection. In first section, it was focused on the effect of increase of surfactant solution volume on SAG ratio and in second, the effect of gas volume increase on SAG ratio was considered.

Increasing effect of surfactant solution volume on SAG ratio

Figure 10 shows the oil recovery of the processes with

SAG ratios of 1:1, 2:1 and 3:1. It can be seen that the best recovery (cumulative oil (OOIP %)) was obtained at a SAG ratio of 1:1.

By increasing the volume of surfactant solution the oil recovery factor decreases because of two main reasons:

a) Early breakthrough of surfactant solution: Figure 11 depicts the graph of cumulative surfactant solution with SAG ratio of 1:1, 2:1 and 3:1. Considering this figure can be concluded that more volume of surfactant injection
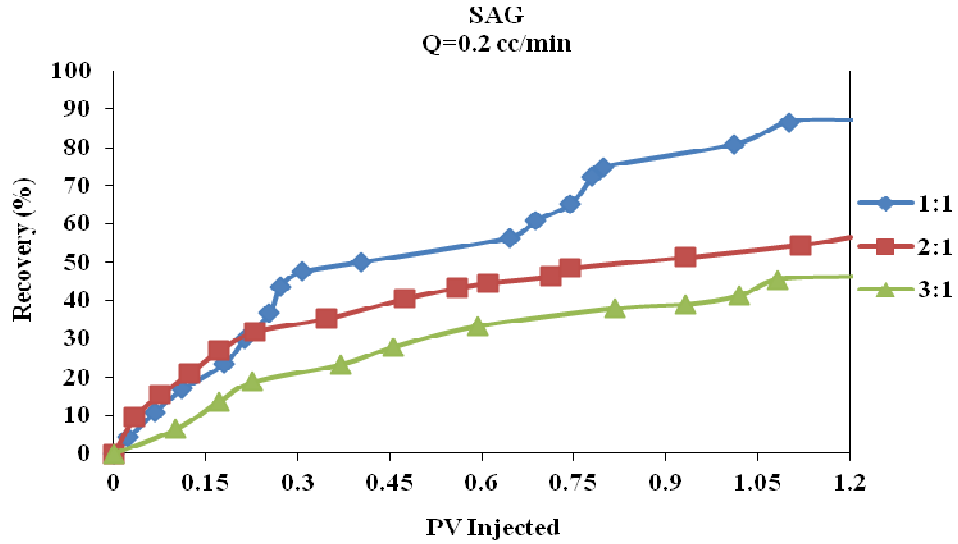
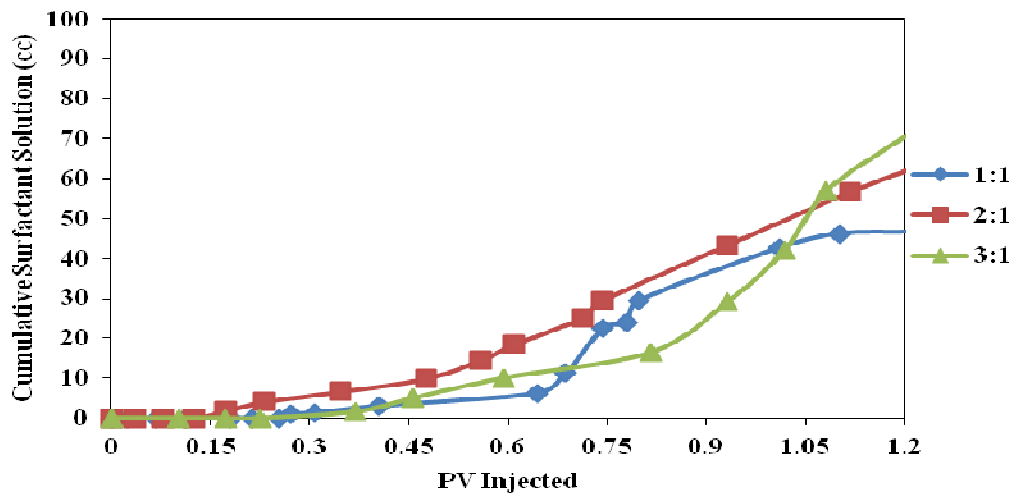**Figure 10.** Comparison of oil recovery for SAG ratios of 1:1, 2:1 and 3:1.

Figure 11. Comparison of cumulative surfactant solution for SAG ratios of 1:1, 2:1 and 3:1

results in earlier breakthrough of it in the producing stream. Breakthrough time affects the oil recovery directly. So delaying in the breakthrough time increases the macroscopic (sweep) efficiency and oil recovery consequently.

Oil recovery in any displacement process depends on the volume of reservoir contacted by the injected fluid. A quantitative measure of this contact is called the volumetric displacement (sweep) efficiency, E_V. Volumetric sweep efficiency is a macroscopic efficiency defined as the fraction of reservoir PV invaded by the injected fluid, or stated another way, the fraction of PV which has been contacted or affected by the injected fluid. Clearly, E_V is a function of time in a displacement

process.

b) Increasing of surfactant solution volume in the SAG ratio, fraction of nitrogen in the injection fluid will be reduced which disperse the gas phase in the liquid phase and gas bubbles can be held within liquid and reduce the microscopic efficiency. An important aspect of any EOR process is the effectiveness of process fluids in removing oil from the rock pores at the microscopic scale. Microscopic displacement efficiency, E_D, largel determines the success or failure of a process. For crude oil, E_D is reflected in the magnitude of S_{or} (that is, the residual oil saturation remaining in the reservoir rock at the end of the process) in places contacted by the
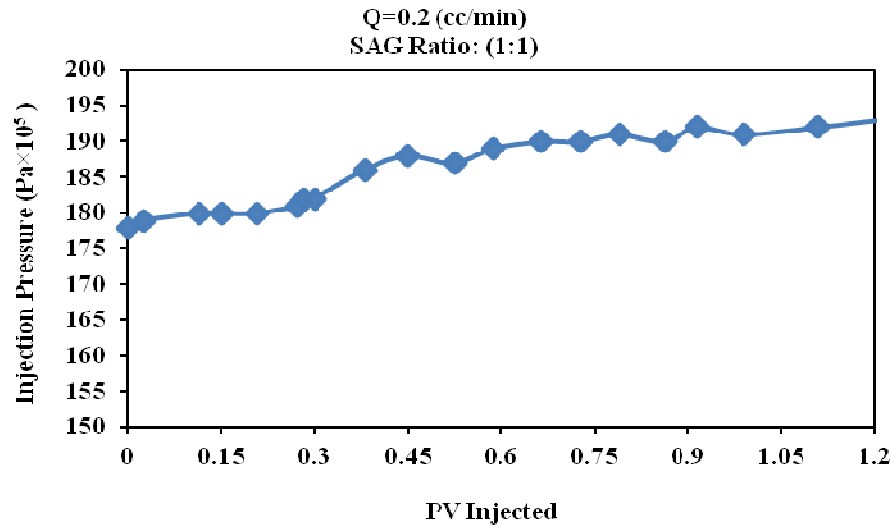
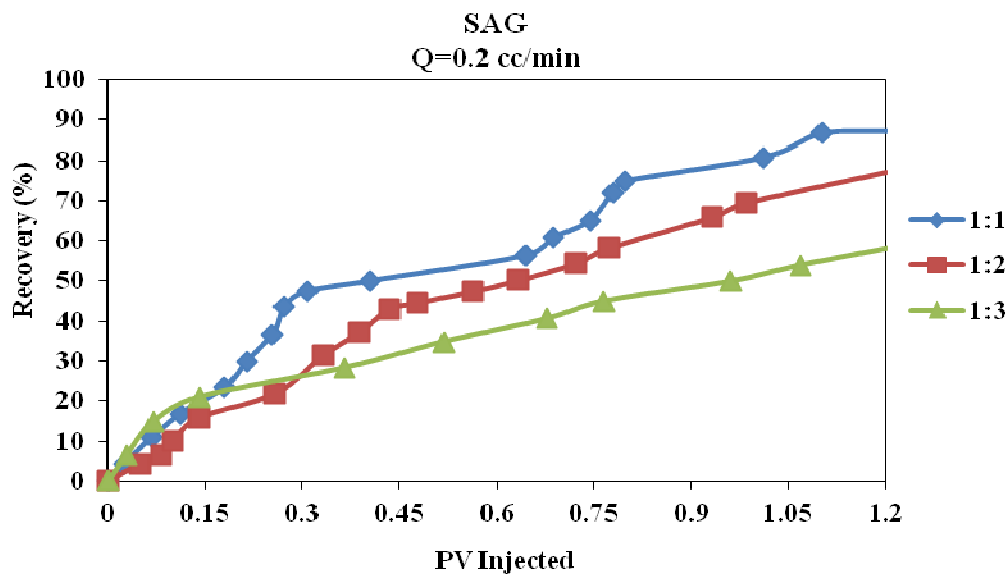**Figure 12.** Pressure drop in SAG ratio (1:1) experiment.

Figure 13. Comparison of oil recovery for SAG ratios of 1:1, 1:2 and 1:3.

displacing fluids.

The nitrogen gas forms foam in contact with surfactant solution. The generated foam increases the viscosity of injected gas and increases the contact time of gas and oil which can increase the breakthrough time of gas and improve the displacing efficiency.

One of the reasons for the creation of foam in the sand pack model can be considered the increase of injection pressure. For example, Figure 12 illustrates the injection pressure in the SAG ratio of 1:1. According to the figure, the pressure of injection in the initial time is relatively constant due to injecting fluid into the sand pack model.

By continuing the experiment, the pressure of injection rises because of composing foam in the porous media.

Effect of gas volume increase on the SAG ratio

Figure 13 compares the oil recovery with different SAG ratio. This Figure shows that increasing gas in the SAG ratio decreases the recovery. It is mainly because of decreasing the macroscopic efficiency of surfactant solution. By increasing gas volume in the SAG ratio, the proportion of nitrogen increases in the solution and this can disperse the solution phase in the gas and reduce
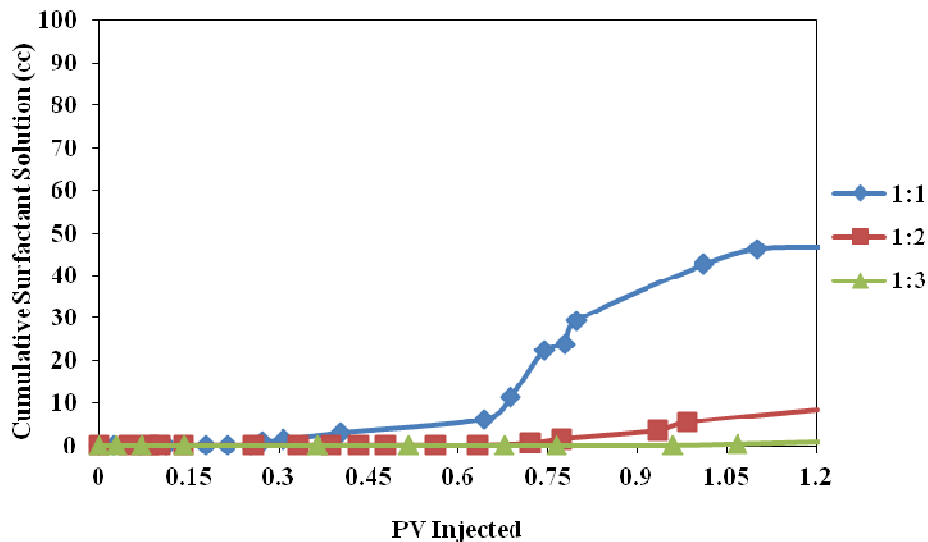
Figure 14. Comparison of cumulative surfactant solution for SAG ratios of 1:1, 1:2 and 1:3.
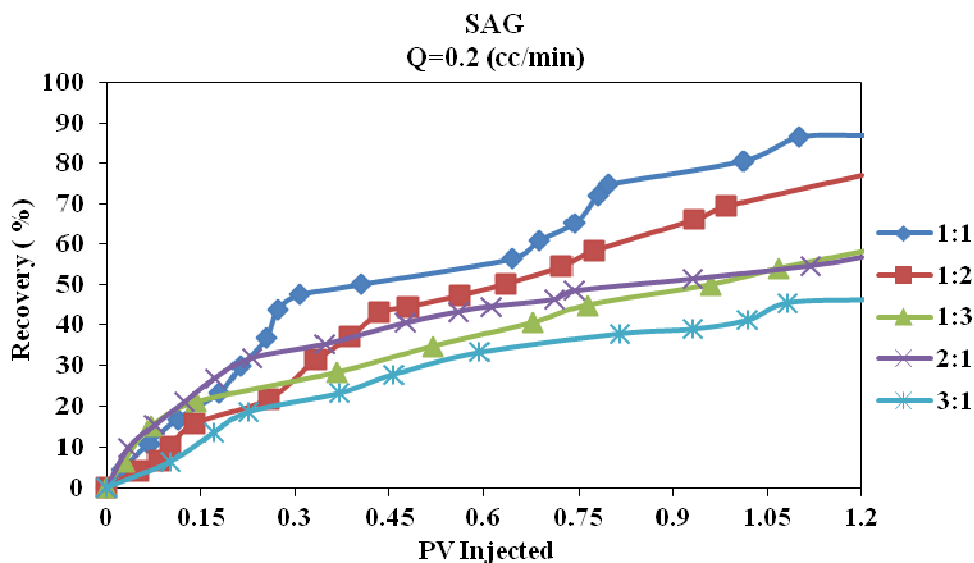

Figure 15. Comparison of oil recovery for SAG ratios of 1:1, 1:2, 1:3, 2:1 and 3:1.

the macroscopic efficiency consequently. Also increasing of nitrogen in SAG ratio decreases the breakthrough time and oil recovery subsequently.

Figure 14 shows the rate of cumulative surfactant solutions with ratio of 1:1, 1:2, 1:3. According to this figure, the SAG ratio of 1:3 has the minimum cumulative surfactant solution due to reduction of injection of surfactant. But, it should be noted that the breaking through of the gas in this ratio occurs earlier.

Figure 15 depicts the oil recovery for different SAG ratio. Figure shows that increasing the SAG ratio

decreases the oil recovery. So, maximum efficiency was obtained in the SAG ratio of 1.1. Both of the macroscopic and microscopic efficiency are high in this ratio.

Comparison of SAG with water flooding, gas flooding and WAG

Figure 16 compares oil recovery factors of SAG injection with gas flooding, water flooding and WAG process. This figure shows that recovery factors of SAG, WAG, water
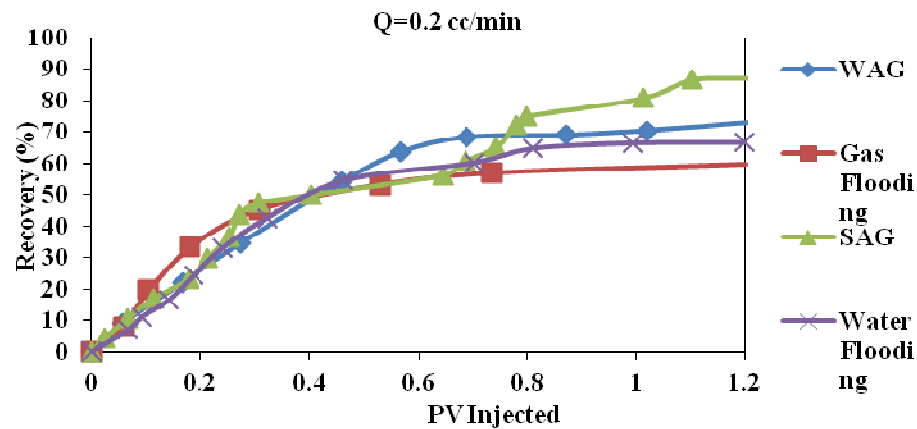
Figure 16. Comparison of oil recovery for SAG, WAG, Gas Flooding and Water Flooding.

flooding and gas flooding are about 87, 70, 66 and 59%. According to results of experiments, gas flooding has lower recovery factor than other methods. Low recovery factor of gas flooding is due to immiscibility of injected N_2 as the MMP of nitrogen is 344 - 551 $\times$ 10^5 Pa whereas injection pressure in this experiment is 144.74 $\times$ 10^5 Pa (in spite of normal microscopic efficiency, immiscible gas flooding has low macroscopic efficiency).

Water flooding after gas flooding has least recovery factor. This is mainly because of injection of no gas in this process. Although, water flooding has low microscopic efficiency, high macroscopic efficiency of this method provides higher recovery factor than gas flooding method. The recovery of WAG injection inclusively is more than water and gas flooding. In this method, injected water causes mobility control and gas stability of front. Although, gas works better than water in microscopic displacement, water works better in macroscopic displacement. So, combining water and gas alternatively can increase microscopic and microscopic displacement. Also water and gas alternating injection decreases fingering and its irritability control.

This comparison demonstrates the highest recovery factor for surfactant alternating nitrogen injection. This is because of composing foam in contact area of nitrogen and surfactant. The composed foam increases viscosity of nitrogen and the contact time of oil and nitrogen. This increases the microscopic efficiency and oil recovery factor, consequently.

Conclusion

The main objective of this study was to evaluate the effect of SAG ratio on oil recovery. But before determining the optimum SAG ratio, in order to decrease the costs of the process, adsorption of surfactant on rock surface was minimized using optimization. Based on the results of experiments, the following finding can be concluded:

1. In order of economic injection of surfactant in the porous media six different SDS concentration (100, 500, 1000, 2000, 3000 and 4000 ppm) was used to obtain the optimum concentration at 70°C and 144.74×10^5 Pa. Hence, for economic flooding of surfactant the concentration of the injection was optimized. So considering the results concentration of 1500 ppm was optimum in this study.

2. According to the experiments with condition of constant flow rate of 0.2 cc/min, which was performed to determine the optimum SAG ratio, oil recovery in SAG ratio of 1:1 was maximum. By increasing the surfactant solution volume in SAG ratio, breakthrough time decreases. Decrease of breakthrough time results in reduction of macroscopic efficiency. Also this causes dispersion of the gas phase in the liquid phase and gas bubbles can be held within the liquid which reduces the microscopic efficiency. So the oil recovery was decreased due to subsequent reasons. Beside, by increasing gas volume in the SAG ratio, the fraction of nitrogen will be increased in the solution and this can disperse the solution phase in the gas phase and reduce the macroscopic sweep efficiency subsequently. Also, with increase of nitrogen volume in SAG ratio, the breakthrough time decreases and reduces the oil recovery. Therefore, the experimental results shows that amount of oil recovery in SAG are highly related on SAG ratio.

3. Experimental SAG injection shows that injection pressure will be increased during the experiments. This is due to foam generation in porous media. Composing foam hack increases viscosity of injected gas and raises injection pressure consequently.

4. Experimental studies shows that recovered oil in the case of alternating injection of surfactant and nitrogen is

more in comparison with water flooding, gas injection and water alternating gas. The conducted experiments results in the recovery factors of 87% for alternating injection of surfactant and nitrogen (in optimum volume ratio), 70% for WAG process, 66% for water flooding and 59% for gas flooding. High recovery factor of SAG process is due to high microscopic and microscopic efficiency of this process (because of composing foam).

ACKNOWLEDGEMENT

REFERENCES

Bernard GG, Holm LW (1964). Effect of foam on permeability of porous media to Gas. SPEJ (Sept), pp. 267-274.

Blaker T, Aarra MG, Skauge A, Rasmussen L, Celius HK, Martinsen HA, Vassenden F (2002). Foam for gas mobility control in the Snorre Field: The FAWAG Project. Paper SPE 78824 was revised for publication from paper SPE 56478, first presented at the 1999 SPE Annual Technical Conference and Exhibition, Houston, pp. 3–6.

Christensen JR, Stenby EH, Skauge A (1998). Review of WAG field experience. Paper SPE 39883 prepared for presentation at the SPE International Petroleum Conference and Exhibition of Mexico held in Villahermosa, Mexico, pp. 3-5.

Daneshfar A, Arvin F, Kaviyan H (2009). Spectrophotometric determination of Sodium Dodecyl sulfate in Wastewater based on ion-pair extraction with Safranine-O. Semnan J. Appl. Chem. pp. 63-72.

Gogoi SB (2009) Adsorption of non-petroleum base surfactant on reservoir rock. Curr. Sci. 97:7.

Falls AH, Hirasaki GJ, Patzek TW, Gaugliz DA, Miller DD, Ratulowski T (1988). Development of a mechanistic foam simulator: The Population Balance and Generation by Snap-Of. SPERE (Aug.), pp. 884.

Heller JP (1994). CO_2 foams in enhanced oil recovery. In foams: Fundamentals and applications in the petroleum industry, Schramm LL (ed.), ACS advances in Chemistry Series, No. 242, Am. Chemical Soc., Washington, DC.

Heller JP, Dandge DK, Card RJ, Donaruma LG (1983). Direct thickeners for mobility control in CO_2 floods. Paper SPE 11789 presented at the 1983 International Symposium on Oilfield and Geothermal Chemistry, Denver, June 1-3.

Hoefner ML, Evans EM (1994). CO_2 Foam: Results from four developmental field trials. Paper SPE/DOE 27787 presented at the 1994 SPE/DOE Symposium on Improved Oil Recovery, Tulsa, pp. 17–20.

Mattews CS (1989). Carbon dioxide flooding. Enhanced oil recovery II, processes and operations, (Donaldson EC, Chilingarian GV, Yen TF. (eds.)), Elsevier Science Publ. Co., New York, pp. 51-55.

Patzek TW (1996). Field applications of foam for mobility improvement and profile control. SPE Reservoir Engr. (May), pp. 79-85.

Renkema WJ, Rossen WR (2007). Success of SAG foam processes in heterogeneous reservoirs. Paper SPE 110408 prepared for presentation at the 2007 SPE Annual Technical Conference and Exhibition held in Anaheim, California, U.S.A., pp. 11-14.

Rossen WR, Gauglitz PA (1990). Percolation theory of creation and mobilization of foam in porous media. AIChE J. 36:1176-1188.

Shan D, Rossen WR (2002). Optimal injection strategies for foam IOR. Paper SPE 75180 presented at the 2002 SPE/DOE Symposium on Improved Oil Recovery, Tulsa, Oklahoma, pp. 13-17.

Shi JX, Rossen WR (1998). Improved surfactant-alternating-gas foam process to control gravity override. Paper SPE 39653 presented at the 1998 SPE/DOE Symposium on Improved Oil Recovery, Tulsa, pp. 19-22.

Skauge A, Aarra MG, Surguchev L (2002). Foam-Assisted WAG: experience from the Snorre Field. Paper SPE 75157 prepared for presentation at the SPE/DOE Improved Oil Recovery Symposium, Tulsa, April, pp. 19-22.

Song FY, Islam MR (1994). A new mathematical model and experimental validation of multicomponent adsorption. Society of Petroleum Engineering, Spe / Doe 27838.

Syahputra AE, Tsau JS, Grigg RB (2000). Laboratory evaluation of using lignosulfonate and surfactant mixture in CO_2 flooding. Paper SPE 59368 prepared for at the 2000 SPE/DOE Improved Oil Recovery Symposium held in Tulsa, Oklahoma, pp. 3–5.

Tsau JS, Heller JP (1992). Evaluation of surfactants for CO_2-foam mobility control. Paper SPE 24013 presented at the 1992 SPE Permian Basin Oil and Gas Recovery Conference, Midland, pp. 18-20.

Tsau JS, Yaghoobi H, Grigg RB (1998). Smart foam to improve oil recovery in heterogeneous porous media. Paper SPE 39677 presented at the 1998 SPE/DOE Improved Oil Recovery Symposium, Tulsa, pp. 19-22.

Viet QL, Quoc PN (2008). A novel foam concept with CO2 dissolved surfactants. Paper SPE 113370 prepared for presentation at the SPE/DOE Improved Oil Recovery Symposium held in Tulsa, Oklahoma, U.S.A., pp. 19-23 April.

Xu Q, Rossen WR (2003). Experimental study of gas injection in surfactant-alternating-gas foam process. Paper SPE 84183 prepared for presentation at the SPE Annual Technical Conference and Exhibition held in Denver, Colorado, U.S.A., pp. 5–8.

Yaghoobi H, Tsau JS, Grigg RB (1998). Effect of foam on CO_2 breakthrough: Is this favorable to oil recovery? Paper SPE 39789 presented at the 1998 SPE Permian Basin Oil and Gas Recovery Conference, Midland, pp. 23-26.