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LABORATORY INVESTIGATIONS OF IMMISCIBLE SAG DISPLACEMENT: THE EFFECTS OF SAG RATIO

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ABSTRACT

Nitrogen is one of the gases used in the both miscible and immiscible gas injection processes into the reservoirs. There are some phenomena such as overriding, fingering and channeling in heterogeneous formations can cause decreasing of break through time in production well during oil displacement. Surfactant alternating gas injection process is one of the methods commonly used to decrease this problem. The foam resulting from the contact of nitrogen and surfactant, causes increasing of injection gas viscosity. Consequently, the oil and gas contact time and sweep efficiency increases. In this paper, an experimental study of the effect of surfactant to gas ratio on oil recovery in secondary oil recovery process during execution of immiscible surfactant alternating gas injection was examined experimentally. The experiments were performed with sand pack under certain temperature and pressure. However, before the experimental, the concentration of surfactant was optimized in order to minimization of its adsorption on rock surface. Then, the experiments were done with surfactant to gas ratio of 1:1, 1:2, 1:3, 2:1 and 3:1. Finally, the experimental results show that using the concentration of 1500 ppm of surfactant solution can be used to perform the economic test. These results also showed that the surfactant alternating gas ratio of 1:1 has the maximum oil removal efficiency and generating the foam in a porous media will increase the pressure of injection.

INTRODUCTION

Foam is a method to improve sweep efficiency during gas injection, and several field applications of foam have been reported (Hanssen, J.E., Holt, T., and Surguchev, L.M., 1994; Krause, R.E. *et al.*, 1992; Hoefner, M.L. *et al.*, 1994; Aarra, M.G. *et al.*, 1996; Aarra, M.G. and Skauge, A., 2000; . Svorstøl, I. *et al.*, 1997). Foams for gas diversion can be placed in the reservoir by continuous co-injection of surfactant solution and gas or by injecting alternating slugs of surfactant solution and gas (surfactant alternating- gas, or SAG, injection). Different foam-injection strategies have been used in field trials due to stratigraphic differences, foam behavior and operational concerns (Q. Xu and W. R. Rossen., 2003). SAG injection has several advantages over co-injection. It minimizes contact between water and gas in surface facilities and piping, which can be important if the gas, for instance CO2, forms an acid upon contact with water (Mattews, C. S., 1989; Heller, J. P., 1994). Alternating injection of small slugs of gas and liquid can promote foam generation in the near-well region (Rossen, W. R. and Gauglitz, P. A., 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, D., and Rossen, W. R.; 2002; Shi, J.-X., and Rossen, W. R., 1998). Several alternatives have been proposed to increase sweep efficiency of CO_2 injection in the field or in experimental work, such as injecting water alternating with gas (WAG), (Caudle, B.H., and Dyes, A.B.,1958) direct CO2 thickeners, (Heller, J.P., *et al*., 1983) and injecting surfactant solution alternating with gas (SAG) (Bernard, G.G., Holm, L.W., and Harvey, C.P., 1980; Tsau, J.S. and Heller, J.P., 1992). The benefits of using SAG to improve the efficiency of CO2 displacement have been reported by several investigators (Albrecth, R.A., and Marsden, S.S.1970; Yaghoobi, H., Tsau, J.S., and Grigg, R.B., 1998). Laboratory and field studies indicate that foam potentially presents an efficient method of reducing CO2 mobility (Tsau, J.S., Yaghoobi, H. and Grigg, R.B., 1998; Bernard, G.G., and Holm, L.W., 1964). 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 (Falls, A.H., Hirasaki, G.J., Patzek, T.W., Gaugliz, D.A., 1998). The foam occurs as gas disperses within a surfactant solution and the mobilities of gas and the aqueous phase are reduced. A possible advantage of SAG over WAG for mobility improvement is that it can consist of a higher gas saturation, 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 by CO_2 flooding. The apparent foam viscosity is greater than the viscosity of its components. This factor is favorable for greater oil recovery because increased viscosity is reflected in an improved mobility ratio. Foam 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 that it should be useful in CO_2 flooding. Foam properties may also cause unfavorable increases in injectivity and increased chemical costs (Andy Eka Syahputra, SPE, Jyun-Syung Tsau, SPE, and Reid B.Grigg., 2000). The SAG phase 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 (Tore Blaker, Morten G. Aarra, Arne Skauge, Lars Rasmussen, Harald K. Celius, Helge Andre Martinsen, and Frode Vassenden., 2002**).** It has been found that surfactants can play an important role in controlling WAG mobility, but surfactants add significant costs to the process. In order to improve the economics of SAG, optimum concentration of surfactant was determined. In this paper we investigate the effect of SAG ratio displacement efficiency using a combination of well characterized bead-pack experiments. We show that recovery from SAG is a function of SAG ratio.

EXPERIMENTAL DESCRIPTION

Chemical Materials, Rock and Fluids: The type of surfactants, organic solvent and cationic dye and their basic properties are shown in table 1. Bangestan crude oil was used in all experiments. The crude oil is intermediate (28 API).

Table 1: of chemical material and their basic properties

Material	Type	Mw	pH
Surfactant	(SDS)	288.37	6 - 9
Cationic-dye	Safranin o	350.85	10
Organic-solvent	Ethyl acetate	88.105	-

pH: (10 g/l,H2o, 20 °C)

Apparatuses: General descriptions of the equipment used in immiscible SAG injection on used in this project include:

Fluid injection system: During the experiments for handling fluids, within a sand pack was used of a pump with high performance liquid chromatography. The Operating fluid of this pump is twice-distilled water that the pump leads the water during experiments with a constant flow rate of infusion through the pipes and fittings to underside of the fluid accumulator (e.g. brine water, surfactant solution, crude oil or nitrogen). Therefore, the fluid in the accumulator with a constant flow rate is injected into the sand pack.

Accumulators: This part is responsible for the task of providing high pressure of fluid injection and connecting it to the injection cycle. The injected water is transferred by the pipes and fittings from pump to the underside of pistons of accumulators and the piston under the pressure of pump are going upward. The fluid of accumulator through the fittings is led to the compact sand pack by going upward the piston.

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

Heating system and air bath chamber: All of the system is placed in an air bath, which has the ability of controlling the temperature between ambient to 210 ^{o}C.

Pressure Differential Gauge: The core holder has two end caps one of which has an adjustable end plug length to accommodate different core lengths.

Back Pressure Regulator (BPR) and effluent collector: A backpressure regulator (BPR) was used to maintain a constant backpressure during core flood experiments. One BPRs were used for the experiment with installed at the outlet of the apparatus was operated at 156 bar. The effluent was collected for quantifying 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 measurments were made with a 780-PH meter equipped with an Ag/AgCl electrode.

TEST STUDIES

Method of Experiment: In this experiment, Nitrogen and surfactant solution were used as the immiscible injection fluids and dead Oil was used as the displacing fluid. Conventional sand pack used in this experiment was implemented as below. Inside the core holder, 80 until 250 mesh quartz sand with equal ratios and with suitable moisture at high pressure was compacted. The aim was to obtain a homogeneous model with suitable permeability. Also for preventing silicon leaving the core holder, the entrance and exist of the apparatus were covered by mesh size 100 and glass fiber. Details of the conventional sand pack are indicated in table 2.

Table 2: Properties of Conventional Sand Pack

Material	Quartz Sand
Core Diameter (cm)	5
Core Height (cm)	15
Bulk Volume (cm^3)	294.37
Pore Volume (cm^3)	85.36
Porosity (%)	29
Permeability (d)	0.350

Sand Pack Preparations: First the conventional sand pack was wash by Toluene. After cleaning the Sand Pack, it was placed in the air bath at 71 ^{o}C to be completely dried by carbon dioxide gas. 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 sand pack saturation with water, the lower core holder valve is kept open so water can enter it from the bottom and to water saturate it to 100 %. Then oil is injected into core holder through its top valve. In this stage, initial level of saturation of the oil in sand pack was 83%, and irreducible water saturation was 17 %. Permeability was measured accurately. Core holder and sand pack in it were places horizontally inside the air bath chamber.

CORE FLOODING EXPERIMENT

Experiments were carried out on a conventional sand pack and in the following order.

Scenario One, Analytical Method to Detect SDS Concentration: SDS is a multi-component formulation. Since SDS is colorless, a simple, clean and relatively fast spectrophotometric method was performed for the determination of sodium dodecyl sulfate based on the formation of an ion-pair, surfactant-Safranin O (SDS-SO). Ethyl acetate was used as the organic solvent for ion-pair extraction. Safranin O was chosen due to its efficacy as extractor and low solubility in organic phase (Daneshfar, A., Arvin, F., Kaviyan, H., 2009). To calculate SDS concentration, a standard calibration curve of SDS was established (figure 1). The method exhibited a wide linear range (1–20 µM). The absorption spectra of SO-SDS and is shown in figure 2.

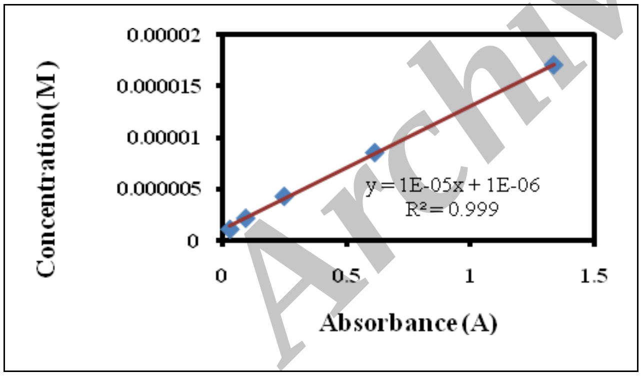

Figure 1: Calibration curve of SDS at 529 nm

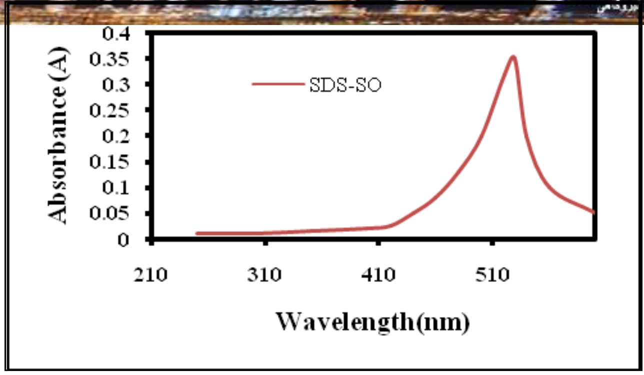

Figure 2: Absorption spectra of SDS

Dynamic Adsorption Method: Flow-through method was used to study surfactant adsorption/desorption onto porous media. The amount of surfactant adsorbed is expressed as the mass of SDS adsorbed per bulk volume of rock (mg/cm^3). Figure 3 shows the schematic diagram of the flow-through method apparatus. The procedure test is: Porosity and permeability measurement and saturation of model with aqueous phase, Injection of one pore volume of surfactant, Injection of about five pore volume of aqueous phase, Sample collection at different times to measure the concentration of the SDS, break-through time.

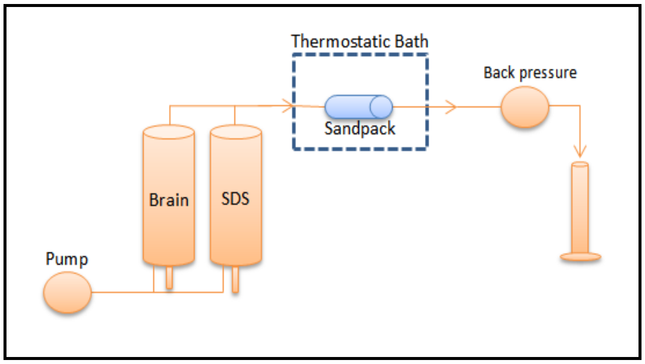

Figure 3: Schematic diagram of dynamic adsorption test

Scenario Two, Effect of Injection Volume Ratio in Surfactant Alternating Gas 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. Five SAG displacements were conducted in all. Five 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. All displacement SAG cycles with a total 1.2 injected PV. For a uniformly heated apparatus, temperature was set at 71 ^{o}C.

RESULTS AND DISCUSSION

Dynamic adsorption onto porous media: Flows 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 a surfactant 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 is called an adsorption isotherm. Different SDS concentration of 100, 500, 1000, 2000, 3000 and 4000 ppm were used to obtain the optimize concentration at 70^{o} C and 2100 psi. Figure 4 shows the adsorption isotherm for SDS on silica. The shape of the adsorption isotherm of SDS was S shape and adsorption rises sharply as the concentration increases and then levels off to a nearly constant value of 1000 ppm. We used SDS concentration more than 1000 ppm (1500 ppm) in all surfactant alternative gas injection experiments.

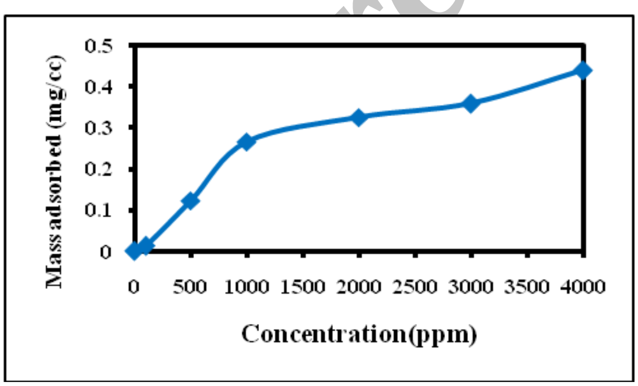

Figure 4: Adsorption isotherm for SDS on silica at 70 ^{o}C and 2100 psi

Effluent Normalized concentration ($\frac{Effluent\ concentration}{Injected\ concentration}$) profiles of SDS for 100, 1000 and 3000 ppm are shown in figure 5. Effluent normalized concentration may be greater than 1.it means that the effluent concentration is higher than injection slug concentration. It is generally believe that surfactant adsorption on the solid surface takes place from the monomer phase. This is explained by monomer concentration reduction (Fu Yin Song, 1994). With the increase in SDS concentration, the break through time was decreased. This is due to increase in dispersion coefficient of surfactant.

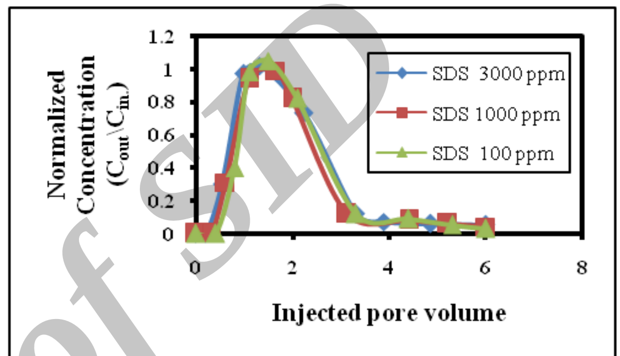

Figure 5: Effluent Normalized concentration profiles of SDS for different concentration of SDS

The increasing effect of surfactant solution on SAG ratio: Figure 6 shows the recovery profiles obtained from displacements with SAG ratios of 1:1, 2:1 and 3:1.

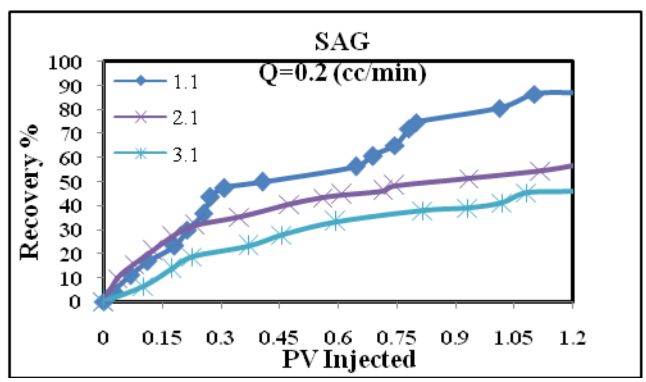

Figure 6: Comparison of oil recovery for SAG ratios of 1:1, 2:1 and 3:1

It can be seen that the best recovery is obtained at a SAG ratio of 1:1. This is slightly better than SAG at ratio of 2:1 and 3:1.

The recovery loss of oil, by increasing the surfactant solution has two main reasons that include:

Early breaking through of surfactant solution: Figure 7 shows the graph of cumulative water for the SAG ratios of 1:1, 2:1 and 3:1. According to this figure corresponds to the increased volume of injected surfactant solution, the early breaking through of it will happen sooner.

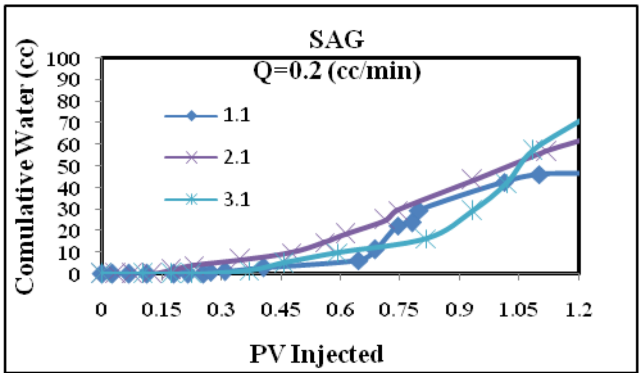

Figure 7: Comparison of cumulative water for SAG ratios of 1:1, 2:1 and 3:1

By increasing the SAG ratio: the proportion of nitrogen in the injection fluid will be reduced that this causes to disperse the gas phase into the liquid phase and gas bubbles can be held within the liquid that causes to reduce the microscopic efficiency. The nitrogen gas in contact with surfactant solution will form the foam. The generated foam will increase the viscosity of injection gas and will cause the gas to be in contact more time with oil that this can cause the time of breaking through of gas to be more and the displacement efficiency to be improved. But, one of the reasons for the creation of foam in the compact sands model, can be noted the increase of injection pressure. For example, in the figure 8, the pressure of injection was illustrated in the ration of 1:1. According to the figure, the pressure of injection in the initial time is relatively constant that the reason is injecting the fluid into the compact sand model. But, with continuing the experiment, the pressure of injection will be increased that this can be caused by the injection of surfactant alternating nitrogen gas and generating the foam in a porous media. Continuing the experiment will cause the pressure of injection to be increased that the reason of this is the generation of foam in a porous media and this foam is resulted from the previous phases.

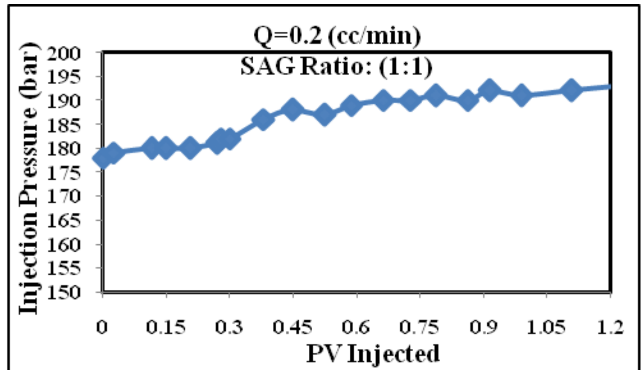

Figure 8: Pressure drop in SAG ratio (1:1) experiment

Effect of gas increase on SAG ratio: According to the figure 9, by increasing the SAG ratio, the recovery ratio was decreased. The main reason of this can be resulted from decreasing the microscopic efficiency of surfactant solution. By increasing the SAG ratio, the proportion of nitrogen will be increased in the solution and this can cause the solution phase to be dispersed into the gas phase and finally the macroscopic sweep efficiency to be reduced. The figure 10 shows the rate of accumulative surfactant solution in the ratios of 1:1, 1:2, 1:3. According to this Figure, the SAG ratio of 1:3 has the minimum accumulative water that the reason of this is the reduction of injecting the surfactant solution. But, it should be noted that the breaking through of the gas in this ratio occurs sooner than others. The figure 11 shows the recovery of oil depending on the fraction of SAG ratio. According to this figure, increasing or decreasing the surfactant solution because of aforementioned reasons will reduce the oil recovery ratio. Therefore maximum efficiency of oil recovery in the optimum SAG ratio of 1:1 was obtained. In this SAG ratio, both of the macroscopic and microscopic efficiencies are high.

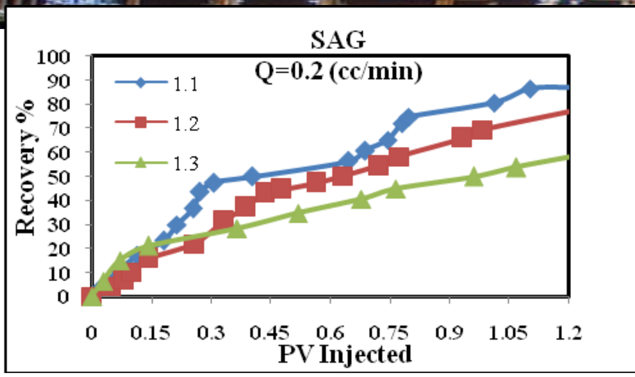

Figure 9: Comparison of oil recovery for SAG ratios of 1:1, 1:2 and 1:3

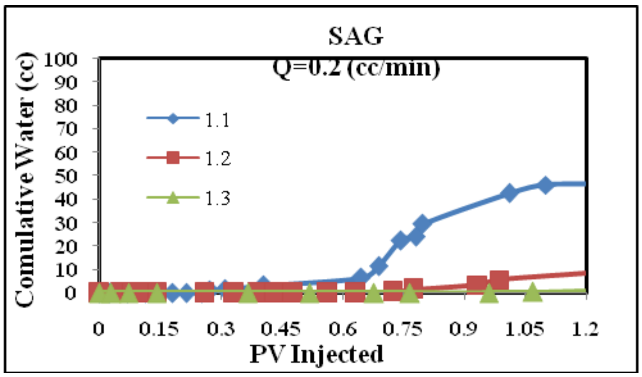

Figure 10: Comparison of cumulative water for SAG ratios of 1:1, 1:2 and 1:3

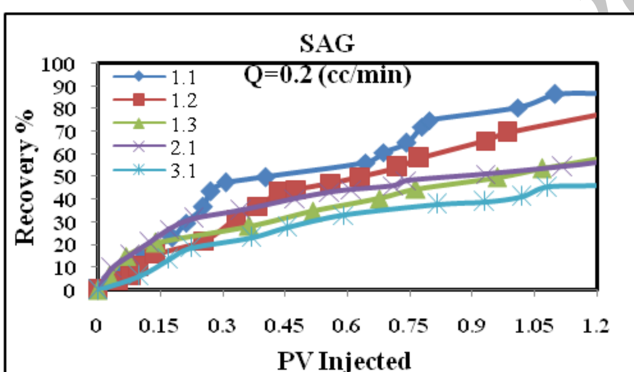

Figure 11: Comparison of oil recovery for SAG ratios of 1:1, 1:2, 1:3, 2:1 and 3:1

CONCLUSIONS

One of the objects of this study is economic injection of surfactant concentration into the porous media. Hence, for being the surfactant economic, we attempted to optimize the concentration of injection. According to the Fig.7, the concentration of 1500 ppm was the best one that can be used for injection in this study. According to the experiments by the constant flow rate of 0.2 cc/min to determine the optimum SAG ratio were done, oil recovery n SAG ratio of 1:1 has the maximum oil removal and by decreasing or increasing the injection ratio, the recovery percentage was reduced. The experimental results showed that rate of oil recovery in SAG are related to the SAG ratio. According to the experiments which were done, injection pressure by generating the foam in a porous media will be increased.

KEYWORDS

SAG (Surfactant Alternating Gas); Cycle Ratio; Foam; Sand Pack; Spectrophotometer.

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