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To cite this article: D. V. Abraham *et al* 2021 *IOP Conf. Ser.: Earth Environ. Sci.* **655** 012065

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Evaluation of Permeability Impairment Due to Surfactant Flooding

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Abstract: In the course of chemical flooding of crude oil reservoirs with surfactants, retention of surfactant particles in the pores of the reservoir rock can cause a major reduction of the reservoir permeability. This can cause serious problems thus unfavourably influencing the economics of oil recovery. An appropriate assessment of the reduction in permeability is essential for the recovery of hydrocarbons. During tertiary recovery of crude oil, a critical evaluation of formation damage is necessary to evade operating costs, as the reservoir rock is extremely sensitive to chemicals injected. The extent to which permeability is reduced cannot be comprehensive for core field scales; it is consequently paramount to study the reduction in the permeability of a core at laboratory scale before field scale estimation. In this paper, an experimental investigation on the reduction in permeability after surfactant injection cores is presented. Surfactants were used to flood the core samples. The permeability of the cores was calculated at the beginning and end of every flood by measuring the differential pressure during surfactant flooding of the cores. From the results, it is evident that there is a strong influence of surfactants on the process of adsorption on reservoir rocks and consequently leading to reduction in permeability.

Keywords: Enhanced Oil Recovery; Permeability reduction; Surfactants; Formation damage; Core Samples

1. Introduction

Formation damage is said to be the decrease in the original permeability of reservoir rock caused by fluids employed during drilling/completion and workover procedures[1]. Formation damage which is the leading source of production decline in numerous crude oil wells is as a result of reduction in the inflow to the well bore from the reservoir, that is caused by a decrease in the permeability of the well-bore area[9]. As a result of precipitation and deposition on an oilfield scale, formation permeability damage in porous media is a key challenge in the course of water flooding schemes[4]. The estimation of permeability is a main menace chore in petroleum engineering, as it is a requirement for the description of reservoirs and fluid flow[3]. In Enhanced Oil Recovery (EOR), if the permeability is impaired, sweep efficiencies and recovery factors will be altered unfavourably [8]. Therefore, the knowledge of formation damage and reduction of permeability in a reservoir is important.



As permeability is one of the major factors to be considered in crude oil flow, it is essential to have the knowledge of permeability estimation as this is important in accurately identifying the recoverable hydrocarbons in place. Irrespective of the instability in oil prices, it is safe to say that operators have an interest in chemical EOR. This phenomenon is accompanied by a rise in screening studies to determine the potential for EOR of chemical floods in different basins [8][2][5] [10]. Recently, the rise in oil prices and developments in surfactant mechanisms have helped start several experimental tests.

Notwithstanding the promising recovery of oil from chemical EOR applications in the field, productivity loss in most projects is a major issue [10], [2]. Furthermore, study discrepancies exist to determine the cause of impairments in permeability. An earlier study by [10] investigated the effect of water flow by integrating core-differential pressure and concentration measurements in the core exit to calculate the movement of fines and their relationship to adsorption occurrences. [6] carried out a research to determine the cause of productivity impairment, and to design suitable flow equations for modelling Surfactant-Polymer flooding in the field. In conclusion, they found out that there existed a likelihood that the flow of microemulsion in the reservoir was influenced by presence of polymer, that could result in substantial loss in productivity as a result of high drop in pressure at the production well.

Additional studies were subsequently carried out to calculate the viscosity of microemulsion in the laboratory. [10] investigated the behaviour of microemulsion system where they discovered unwanted formulations that could lead to an extremely viscous emulsion that may possibly obstruct formation and add to the productivity damage caused by offset producers. The viscous parts, especially in the existence of polymer, may lead to emulsions that have high viscosity, which are unwanted for transport through the formations [7]. However, polymers which are used in EOR to augment the viscosity of fluids usually get adsorbed on the surface of reservoir rocks and has been reported to reduce permeability [1].

From literature, it is proven that the migration of clay minerals as a result of chemical or physical reaction, is a straight reason for reduction in permeability. Hence, the compositional flow constraint should be understood, by estimating the reduction in permeability. In this paper, an investigation on the evaluation of permeability impairment as a result of surfactant flooding is presented.

2. Methodology

2.1 Chemicals

Five different surfactants were used; two petrochemical surfactants (Alpha Olefin Sulfonate and Methyl Ester Sulfonate) provided by Deriks Ventures and three formulated surfactants from vegetable oils (surfactants from Jatropha, Castor and Palm kernel oils procured from National Research Institute for Chemical Technology (NARICT, Zaria)). Lab grade Sodium Chloride with 99% purity (EMSURE) was used to prepare brine, toluene (Fisher Scientific UK, HPLC grade) was used to clean the core samples. The vegetable oils were sulfonated using 18M Fuming tetraoxosulphate (vi) acid (Fisher Scientific UK, HPLC grade). Glycerol (Fisher Scientific UK) was used to produce glycerine sulphuric acid. 99% purity Sodium hydroxide (EMSURE) was used for neutralization process. The heavy crude oil employed in IFT measurement tests was obtained from a field X in the Niger Delta (Nigeria).

2.2. Preparation of Chemicals

2.2.1 Surfactant Synthesis

In the formulation of surfactants from vegetable oils, 420g of H₂SO₄ was reacted with 70g of Glycerol to form acrolein (glycerol-sulphuric acid). Then, 100g of glycerol-sulphuric acid was reacted with 100g of vegetable oils (Castor/ Jatropha/Palm Kernel Oil) while stirring at 50-55°C for two (2) hours. The sulfonated mass cooled to 20°C by pouring the mixture over ice was neutralized with 50% w/v caustic soda (NaOH).

2.2.2 Brine Preparation

The brine solution was formulated by dissolving 10 g of Sodium Chloride (NaCl) in 1 litre of distilled water.

2.3 Preparation of Core Samples

Ten (10) core samples utilized for this study are Berea sandstone cores. The dry weights of the core were measured. The cores were immersed in toluene and placed in a vacuum until saturation with the toluene was achieved. The function of the toluene is to dissolve all the mineral oil that comes in contact with the cores while drilling them to cylindrical shapes.

2.4 Permeability Test

The relative permeability tester (RPT) was used in obtaining the permeability of the core samples where the fluid was pumped, passing through the cores. After, the cores were cleaned and dried, their individual dry weights were measured. They were then saturated and their wet weights measured. The difference in wet and dry weight of the core is expressed as W_{w-d} . The volume of W_{w-d} that represents the volume of the porous media (V_p) was estimated. The cores' porosities were determined by dividing V_p to the bulk volume (V_b) of the core samples.

$$W_{w-d} = W_w - W_d \quad (1)$$

$$\rho_{w-d} = \frac{W_{w-d}}{V_p} \quad (2)$$

$$V_p = \frac{W_{w-d}}{\rho_{w-d}} \quad (3)$$

$$V_b = \pi \left(\frac{D^2}{4} \right) h \quad (4)$$

$$\phi = \frac{V_p}{V_b} \quad (5)$$

where:

W_{w-d} = weight of water used to saturate core (g)

W_w = weight of saturated (wet) core (g)

W_d = weight of dry core (g)

h = height of core (cm)

D = diameter of core (cm)

The permeability of the core was recorded at the beginning and at the end of flooding. Figure 1 shows the Reservoir Permeability Tester (RPT) used in the estimation of permeability.

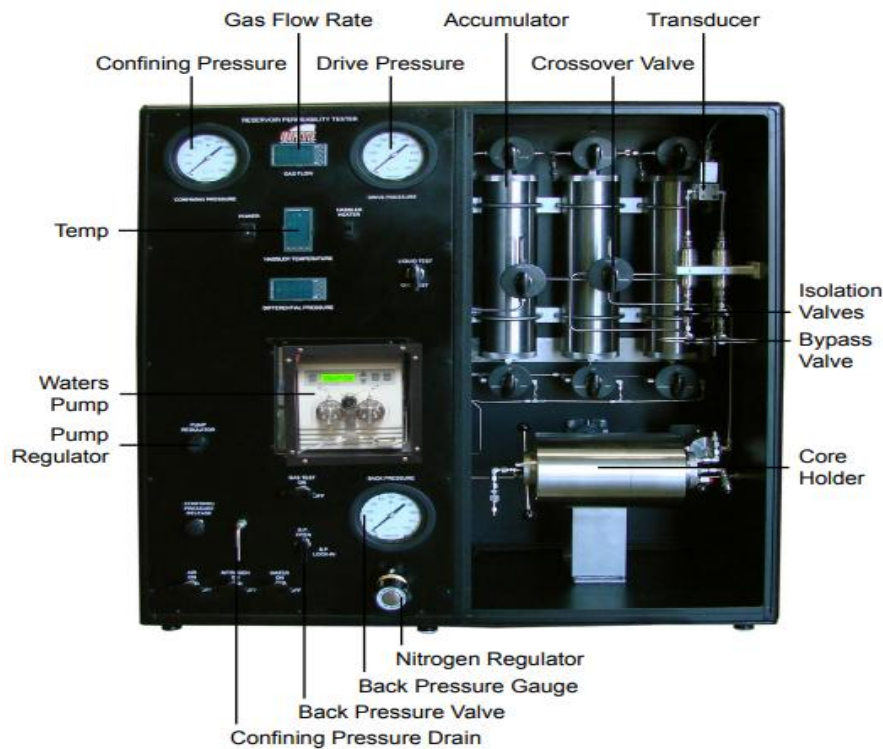


Figure 1: Reservoir permeability tester
(Reservoir Permeability Tester manual, 2015)

The permeability of the core sample was deduced by calculating the difference in pressure across the core holders at differential flow rates. Darcy's equation used to estimate permeability is given as:

$$q = kA \frac{\Delta P}{\mu L} \quad (6)$$

and

$$k = \frac{q\mu L}{A\Delta P} \quad (7)$$

where:

- k = permeability (Darcy)
- q = flowrate (cc/min)
- μ = viscosity of fluid (cp)
- L = length of core sample (cm)
- A = Area of core sample (cm²)
- ΔP = pressure drop (psi)

3. Results and discussion

3.1 Permeability Test

Here, the cores were made ready and their initial properties were calculated. The porosity of the cores was also determined before the permeability test was done. Table 1 displays the pre-flood calculation results for all the core samples.

Table 1: Initial Properties of Core Samples

| S/No | Core Sample | V _b (cm ³) | V _p (cm ³) | ΔP (psi) | Porosity (%) | Permeability (mD) |
|------|-------------|-----------------------------------|-----------------------------------|----------|--------------|-------------------|
| 1 | 6 | 11.79 | 2.60 | 0.62 | 22.05 | 224.89 |
| 2 | 13 | 11.79 | 2.70 | 0.59 | 22.90 | 236.33 |
| 3 | A | 11.79 | 2.50 | 0.36 | 21.20 | 387.31 |
| 4 | T | 11.79 | 2.70 | 1.07 | 22.90 | 130.31 |
| 5 | 4 | 11.79 | 1.70 | 2.16 | 14.42 | 64.55 |
| 6 | E | 11.79 | 3.10 | 1.07 | 26.29 | 130.31 |
| 7 | J | 11.79 | 2.40 | 1.49 | 20.36 | 93.58 |
| 8 | 8 | 11.79 | 2.90 | 1.39 | 24.60 | 100.31 |
| 9 | D2 | 11.79 | 2.20 | 1.08 | 18.66 | 129.10 |
| 10 | B | 11.79 | 2.80 | 0.40 | 23.75 | 348.58 |

3.2 Flooding Results

After flooding the cores with brine for 60 minutes, surfactant floods were then introduced on the cores for 45 minutes and the pressure difference through the core was calculated. Applying Darcy's equation, this difference in pressure was used to estimate permeability.

Table 2: Permeability after Surfactant Flooding

| S/No | Core Sample | V _b (cm ³) | V _p (cm ³) | ΔP (psi) | Porosity (%) | Permeability (mD) |
|------|-------------|-----------------------------------|-----------------------------------|----------|--------------|-------------------|
| 1 | 6 | 11.79 | 2.60 | 0.77 | 22.05 | 181.08 |
| 2 | 13 | 11.79 | 2.70 | 0.76 | 22.90 | 183.46 |
| 3 | A | 11.79 | 2.50 | 0.43 | 21.20 | 324.26 |
| 4 | T | 11.79 | 2.70 | 1.36 | 22.90 | 102.52 |
| 5 | 4 | 11.79 | 1.70 | 2.78 | 14.42 | 50.16 |
| 6 | E | 11.79 | 3.10 | 1.38 | 26.29 | 101.04 |
| 7 | J | 11.79 | 2.40 | 1.79 | 20.36 | 77.89 |
| 8 | 8 | 11.79 | 2.90 | 1.81 | 24.60 | 77.03 |
| 9 | D2 | 11.79 | 2.20 | 1.51 | 18.66 | 92.34 |
| 10 | B | 11.79 | 2.80 | 0.51 | 23.75 | 273.40 |

From Table 2, it can be seen that the permeability is reduced compared to the permeability recorded during the pre-flood test (Table 1)

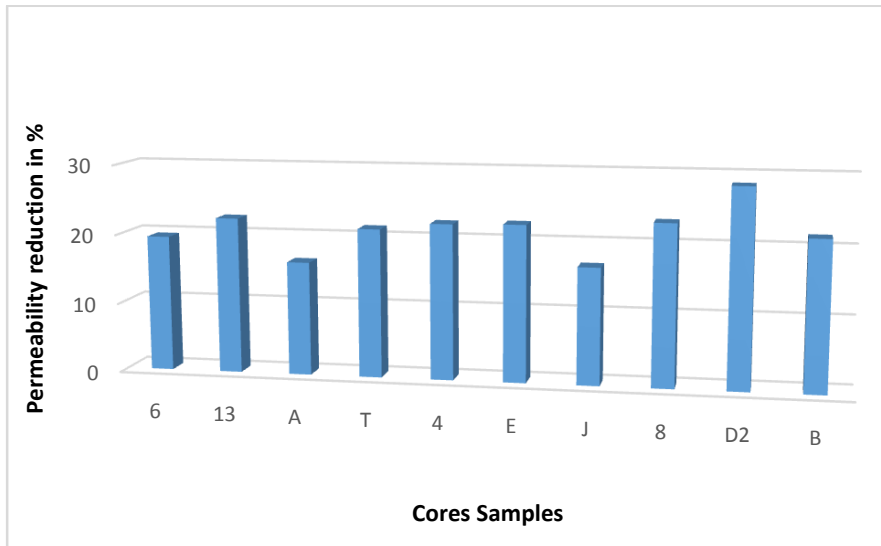


Figure 2: Percentage Reduction in Permeability of Core Samples

Figure 2 shows the reduction in permeability after different surfactant floods of core samples (6-B). Highest reduction in permeability was recorded in core D₂ (28.48%) which was flooded with 20,000 ppm of Castor surfactant, and the least reduction in permeability observed in core A flooded with 10,000 ppm of Palm Kernel surfactant (16.28 %). This is in agreement with previous studies [8] on the effect of water salinity and chemicals on porous media.

4. Conclusion

Formation damage (permeability impairment) happens during virtually any field operation that includes the production of fluids. The following conclusions were made from this research work;

- i. Chemical (surfactant) flooding has a strong influence on the impairment of permeability.
- ii. For surfactant flooding, the order in permeability reduction is: Core D₂ > Core 8 > Core E > Core 13 > Core 4 > Core B > Core T > Core 6 > Core J > Core A. Where core D₂ showed a maximum permeability reduction of 28.48% and Core A showed the least reduction in permeability of 16.28%.
- iii. The higher the concentration of the surfactant used to flood the core samples, the more the level of impairment in permeability of the core samples, thus, surfactant concentration has a strong interaction with the sandstone core samples.

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