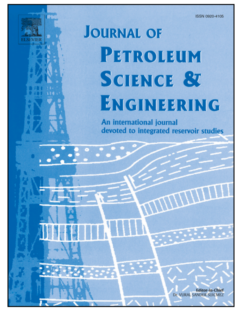

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Laboratory Investigation of Oil Recovery by CO_2 Foam in a Fractured Carbonate Reservoir Using CO_2-Soluble Surfactants

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Abstract

Miscible CO_2 flooding has been used as an EOR method for carbonate reservoirs which hold around 60% of the world's oil reserves. However, natural fractures, unfavorable mobility ratio and gravity segregation in carbonate reservoirs often lead to premature CO_2 breakthrough and bypassed oil. To remedy this situation, CO_2 foam has been used to reduce the mobility of the injected CO_2. Typically, this employed a water soluble surfactant for foam propagation. However, surfactant transport in the aqueous phase was often hindered by surfactant adsorption and undesirable chemical reactions with reservoir minerals. In this study, we investigated whether CO_2-soluble surfactants were more effective than water-soluble surfactant in oil recovery of fractured carbonate reservoirs under miscible conditions.

A series of corefloods were conducted to determine the oil recovery factor (RF), speed of foam propagation and foam strength in artificially fractured carbonate cores at 35°C (308.15 K) and 1500 psi ($1.034*10^7$ Pa) which was above minimum miscibility pressure. Silurian Dolomite outcrop with permeability of 150 md and West Texas Wasson crude were used. The cores were intermediate-wet indicated by both qualitative and quantitative tests. Three different surfactants were compared including an anionic water-soluble surfactant and other two nonionic CO_2 soluble surfactants (2-ethyl-1-hexanol with different ethylene oxide groups) with distinct degree of solubility in CO_2. Phase behavior experiments indicated these surfactants did not lower the interfacial tension significantly between the crude and water.

RF of CO_2 flooding was only 24% due to the heterogeneous nature of the fractured core. Co-injection of CO_2 and water increased the RF to 35%, which was further increased to 54% when a water-soluble only surfactant presented. However, use of CO_2 foam by the two CO_2-soluble surfactants increased the RF to 71% and 92% respectively, with a higher RF for the surfactant that partitioned more to the CO_2 phase. Also, pressure drop in different sections of the core confirmed that the surfactant which partitioned more into the CO_2 phase gave a faster-propagating and stronger foam.

These results educated that the partitioning of surfactant into the CO_2 phase has several advantages. First, it allows surfactant to be transported in the CO_2 phase ahead of the aqueous phase thus leading to faster foam propagation. Second, it generated a stronger foam. The combined effect of the two leaded to higher RF in current scenarios. Several hypotheses based on literatures were raised and listed to further interpret the observations. Our results also reinforce that the so-called optimal CO_2 soluble surfactant is case dependent and is the function of injection strategy, reservoir environment, and operation pressure or rates as well as other specific conditions. One could tailor a surfactant with suitable solubility in the CO_2 phase to optimize oil recovery in fractured carbonates. We believed the results were encouraging enough to warrant further R&D and eventual field piloting.

Keywords: CO_2 soluble surfactants, partition coefficient, CO_2 foam, fractured carbonate reservoir, EOR

1. Introduction and Background

Carbonate reservoirs holds around 60% of the world's oil reserves (Aknar *et al.* 2000) and 60% of total miscible-flooding EOR will occur in carbonate reservoirs (Baily 1984). It is sensitive to stress/strain which often makes the carbonate reservoirs naturally fractured (Chillenger and Ten 1983, Sloan 2003), creating thief zones for injected fluids, and leaving the matrix unswept (Benson *et al.* 1998, Graue *et al.* 2000). About 80% of carbonate reservoirs are classified as mixed-wet to preferentially oil-wet which are unfavorable conditions for spontaneous water imbibitions (Allan and Sun 2003, Tabary 2009). In the past, much effort has been given to use liquids to enhance oil recovery in non-water wet fractured reservoirs through wettability alternation followed by imbibitions (Gupta and Mohanty 2008, Chen and Mohanty 2014) or interfacial tension (IFT) reduction (Alshehri and Kovscek 2014) or both (Chen and Mohanty 2015). Also, miscible solvent, such as Heptane, Pentane and Decalin, provided