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Oil Recovery and Surfactant Adsorption During CO_2-Foam Flooding

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Abstract

Three carbon dioxide (CO_2) foam flooding parameters are addressed in this paper: optimum gas fractional flow, surfactant adsorption behavior, and oil recovery versus CO_2/aqueous phase injection methodologies. Experimental test conditions were selected to simulate some of the reservoirs in west Texas (1540 psig and 110°F). All tests in this study were conducted in fired Berea sandstone cores to minimize core property changes during a series of CO_2 foam flooding tests. CO_2 and aqueous phase were co-injected during the test. The CO_2 foam flow behavior in the absence and presence of oil and the optimum oil recovery methodologies associated with different stages are described in this paper.

This study demonstrates that, with similar residual oil in the core, CO_2 foam had higher oil recovery than CO_2–brine co-injection. Additional oil was recovered with CO_2 foam injection following CO_2–brine co-injection. However, no additional oil was recovered if CO_2 foam injection was applied first. The surfactant adsorption equilibrium was characterized by the occurrence of foam.

Introduction

The idea of using foam for mobility control was first proposed and patented by Bond and Holbrook in 1958.[1] Fried[2] conducted foam drive experiments and reported a sharp pressure drop across the foam bank and reduced gas mobility through porous media. Since then, there have been extensive reviews on foam research such as Heller and Taber,[3] Marsden,[4] Hirasaki, [5–6] and Chang and Grigg.[7] CO_2 foam will increase the apparent viscosity of displacing fluid and improve the oil recovery by decreasing mobility. Several researchers have reported that CO_2 foam can selectively reduce mobility of CO_2 by a greater fraction in higher than in lower permeability regions. [8–10]

Gas frictional flow ratio, f_g, can be used to predict foam flow behavior. At a constant gas flow rate, q_g,, Khatib et al.[11] showed that foam mobility decreases slightly with increasing f_g ranging from 50% to 98%. But for $f_g > 98\%$, foam mobility increases with increasing f_g. Also, Patton et al,[13] Hirasaki and Lawson,[14] Marsden and Khan,[4] and Chang and Grigg[15] found that foam mobility decreases with increasing f_g. On the other hand, Lee and Heller[9] reported that foam mobility increases with increasing f_g. Yaghoobi and Heller[10] found that foam mobility increases slightly as f_g increases up to about 85%; thereafter, foam mobility increases rapidly. Persoff et al.[16] found that, at a constant gas flow rate (q_g), foam mobility decreases with increasing liquid flow rate (q_l); The results by Lee et al.[9] demonstrated that, foam mobility increases with increasing q_t. At a constant total flow rate, q_t, De Vries and Wit[12] reported that, foam mobility decreases as f_g increases until the break point (where the pressure gradient reaches the maximum); beyond that point it increases. Chang and Grigg[15] also showed that foam mobility increases with increasing q_t, the total mobility decreases with increasing q_g.

The destabilizing effect of crude oil on foam was first examined by Bernard and Holm.[18] They reported the foam's effectiveness in reducing gas mobility greatly diminished when crude oil was present. More recently, Jensen and Friedmann[19] studied the propagation rates of nitrogen and steam foams at 149°C in partially oil-saturated Berea sandstone cores. They found that the oil saturation must be decreased below 15% saturation before oil-sensitive foam could propagate. They also concluded that the type of oil had little effect on the overall propagation rate of the different foams, but the type of

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