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Injectivity Characteristics of EOR Polymers

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Abstract

This paper estimates injectivity losses associated with injection of EOR polymer solutions if fractures are not open and considers the degree of fracture extension if fractures are open. Three principal EOR polymer properties are examined that affect injectivity: (1) debris in the polymer, (2) polymer rheology in porous media, and (3) polymer mechanical degradation. Using Berea sandstone cores (100-600 md) and various filters and filter combinations, an improved test was developed of the tendency for EOR polymers to plug porous media. The new test demonstrated that plugging tendencies varied considerably among both partially hydrolyzed polyacrylamide (HPAM) and xanthan polymers.

Rheology and mechanical degradation in porous media were quantified for a xanthan and an HPAM polymer. Consistent with previous work, we confirmed that xanthan solutions show pseudoplastic behavior in porous rock that closely parallels that in a viscometer. Xanthan was remarkably resistant to mechanical degradation, with a 0.1% xanthan solution (in seawater) experiencing only a 19% viscosity loss after flow through 102-md Berea sandstone at a pressure gradient of 24,600 psi/ft.

For 0.1% HPAM in both 0.3% NaCl brine and seawater in 573-md Berea sandstone, Newtonian behavior was observed at low to moderate fluid fluxes, while pseudodilatant behavior was seen at moderate to high fluxes. No evidence of pseudoplastic behavior was seen in the porous rock, even though one solution exhibited a power-law index of 0.64 in a viscometer. For this HPAM in both brines, the onset of mechanical degradation occurred at a flux of 14 ft/d in 573-md Berea.

Considering the polymer solutions investigated, satisfactory injection of more than 0.1 *PV* in field applications could only be expected for the cleanest polymers (i.e., that do not plug before 1,000 cm^3/cm^2 throughput), without inducing fractures (or formation parts for unconsolidated sands). Even in the absence of face plugging, the viscous nature of the solutions investigated requires that injectivity must be less than one-fifth that of water if formation parting is to be avoided (unless the injectant reduces the residual oil saturation and substantially increases the relative permeability to water). Since injectivity reductions of this magnitude are often economically unacceptable, fractures or fracture-like features are expected to open and extend significantly during the course of most polymer floods. Thus, an understanding of the orientation and growth of fractures may be crucial for EOR projects where polymer solutions are injected.

Introduction

Maintaining mobility control is essential during chemical floods (polymer, surfactant, alkaline floods). Consequently, viscosification using water soluble polymers is usually needed during chemical enhanced oil recovery (EOR) projects. Unfortunately, increased injectant viscosity could substantially reduce injectivity, slow fluid throughput, and delay oil production from flooded patterns. The objectives of this paper are to estimate injectivity losses associated with injection of polymer solutions if fractures are not open and to estimate the degree of fracture extension if fractures are open. We examine the three principal EOR polymer properties that affect injectivity: (1) debris in the polymer, (2) polymer rheology in porous media, and (3) polymer mechanical degradation. Although some reports suggest that polymer solutions can reduce the residual oil saturation below values expected for extensive waterflooding (and thereby increase the relative permeability to water), this effect is beyond the scope of this paper.

Debris Filtration When Entering a Porous Medium

During preparation of polymer solutions, ineffective polymer hydration and debris in the polymer can lead to near-wellbore plugging. This fact was highlighted during the Coalinga polymer demonstration project in the late 1970s (Peterson 1981, Duane and Dauben 1983). Concern about polymer solution injectivity led to the development of "filter tests" using membrane filters to assess plugging (API 1990, Levitt and Pope 2008). The typical filter test passed ~600 cm^3 of polymer