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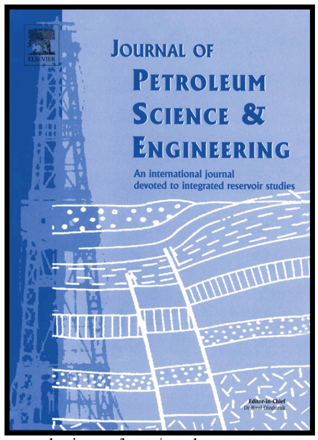

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F. Bordeaux Rego, V.E. Botechia, D.J. Schiozer

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Heavy Oil Recovery by Polymer Flooding and Hot Water Injection Using Numerical Simulation

Bordeaux Rego, F., Botechia, V.E., Schiozer, D. J.

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Abstract

Thermal and chemical flooding are good alternatives to recover heavy oil. Hot water injection decreases oil viscosity but the unfavorable mobility ratio results in an inefficient sweep. Polymer flooding increases sweep efficiency due to higher water viscosity but may have lower injectivity. Combining both these techniques can improve recovery; hot water improves polymer injectivity and the higher viscosity of polymer improves the mobility ratio. However, polymer thermal degradation, a result of combining these two techniques, decreases oil recovery and must be considered as it affects polymer efficiency. In this work we analyze the impact of different injection temperatures of combined polymer and hot water flooding on both production and economic indicators, using numerical simulations. Using reliable polymer viscosity and degradation modeling linked to temperature, we aim to find the best injection temperature between 25 and 200°C.

We used a heterogeneous heavy oil field simulation model to test various injectivities. We adjusted the Arrhenius equation for the polymer thermal degradation reaction, and the parameters of polymer viscosity depend on temperature from data in the literature. We developed a base water flooding strategy (WFS) and polymer flooding strategy (PFS) by optimizing well number and location, with 81°C injection temperature (reservoir temperature) as reference. We used Net Present Value (NPV) as the objective function to compare the optimized production strategies. We tested three strategies: hot water injection on WFS; hot polymer flooding on PFS; and polymer flooding after hot water injection on PFS. We compared the injection temperatures (25, 50, 81, 100, 150, and 200°C) in each strategy. We also optimized well control variables (Gaspar et al., 2016) for each injection temperature. We related the results to analyze the advantages and disadvantages of each injection strategy.

In adjusting the Arrhenius equation, we produced a generic equation for polymer thermal degradation. For water flooding (WFS), higher injection temperatures increased NPV, the highest temperature, 200°C, resulting in the highest NPV largely due to lower oil viscosity. For polymer flooding (PFS), pre-flush of hot water substantially improved polymer injectivity, a common problem. For hot polymer injection, 100°C was the optimum temperature for both oil production and NPV. For temperatures above 100°C, polymer thermal degradation strongly decreased the recovery efficiency. The best strategy for oil recovery was to flush hot water before polymer injection at reservoir temperature, showing good sweep efficiency. At lower temperatures, the oil viscosity is considerably higher and negatively affects NPV in all strategies. We conclude that at optimal temperatures, around 100°C in our test case, hot polymer injection is a viable alternative for heavy oil recovery.

Keywords: Reservoir Simulation; Enhanced Oil Recovery; Polymer Flooding; Heavy Oil; Thermal Recovery; Field Management

Nomenclature

A, B Langmuir isotherm coefficients

A_{visc}, B_{visc} Liquid viscosity coefficients