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A fast and effective method to evaluate the polymer flooding potential for heavy oil reservoirs in Western Canada

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ABSTRACT

Laboratory polymer flooding tests conducted in sandpacks show great potential for improving heavy oil recovery. The high price of crude oil and wide application of horizontal wells make polymer flooding both economically affordable and technically feasible for heavy oil reservoirs. Field applications of polymer flooding in heavy oil reservoirs are currently being pursued. As polymer injection involves great investment, laboratory evaluations are essential prior to the field-scale application. However, due to high oil viscosities, large volumes of fluids have to be injected into sandpacks or reservoir cores in order to reach reasonable recoveries, which is a time-consuming process.

This study establishes a fast and effective method to examine the potential of enhanced heavy oil recovery by polymer flooding. Experimental results of sandpack polymer flooding tests, for heavy oil samples with different viscosities, are analyzed. For each heavy oil sample, the polymer viscosity-sensitive range, within which tertiary recovery increases dramatically with increasing polymer viscosity, is different. To facilitate the evaluation of polymer flooding potential for heavy oils with various viscosities, the oil–water mobility ratio at the end of initial waterflooding is chosen as a normalization factor. Using normalization, an identical oil–water mobility ratio-sensitive range can be obtained for heavy oils with different viscosities. Based on the normalized relationship, the potential of enhanced heavy oil recovery by polymer injection can be quickly and effectively evaluated.

1. Introduction

As early as the 1940s, petroleum researchers had recognized that fluid mobilities during waterflooding could affect secondary oil recovery (Russell et al., 1947). Later, it was established that waterflooding efficiency could be improved by lowering the water–oil mobility ratio (Aronofsky, 1952; Dyes et al., 1954). Pye (1964) and Sandiford (1964) found that water mobility could effectively be reduced by adding small amounts of water soluble polymers. Ever since then, polymer flooding has been comprehensively evaluated in the laboratories and industrial field practice. In the 1980s, polymer flooding became a widely used EOR method, and more than 200 projects were started worldwide (Taber et al., 1997). In the USA alone, 178 polymer flooding projects were active in 1986 with a total oil production of over 15,000 bbl/d. During the 1990s, the number of polymer flooding projects around the world was sharply reduced as crude oil price dropped to roughly $20/bbl. However, research projects on polymer flooding continued, funded by both industrial and governmental sponsors. Nowadays, with a relatively stable crude oil price, around $100/bbl, and the invention of low cost polymers, polymer flooding is staging a comeback. In 2004, there were 31 commercial-scale polymer flooding projects in the Daqing oilfield in China, with approximately 220,000 bbl/d oil production and 12% OOIP incremental as of 2005 (Chang et al., 2006). Polymer flooding also found its application in the exploitation of heavy oil reservoirs. Zaitoun et al. (1998) reported a polymer flooding pilot in Pelican Lake, Alberta. The dead oil viscosity was 1000–25,000 mPa s at the reservoir temperature of 15 °C, and the estimated incremental recovery was around 5%. Canadian Natural resources Ltd. started polymer flooding projects for heavy oils with viscosities of 800–80,000 mPa s in 2005, and the incremental recovery from polymer flooding of the pilot zone was around 15%–21% (Levitt et al., 2011). Cenovus Energy Inc. piloted polymer flooding in the Pelican Lake area in 2003, and had 52 polymer flooding rollout projects in 2010. The ultimate incremental heavy oil recovery from polymer flooding was estimated to be around 5%.

Positive feedback from field practices has further stimulated recent research on enhanced heavy oil recovery (EHOR) by polymer flooding. Wang and Dong (2007) investigated the relationship between incremental heavy oil recovery and the effective viscosity of a polymer solution. They used polymer solutions with different concentrations to displace a 1450 mPa s oil sample (21 °C) in both homogenous and channeled sandpacks. Experimental results revealed that within a certain viscosity range for polymer solution (viscosity-sensitive region), the incremental oil recovery increased

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noticeably as the viscosity of the polymer increased within the effective viscosity range. In other words, when polymer solution had a viscosity below the lower viscosity limit or beyond the upper limit, incremental heavy oil recovery did not change much with polymer viscosity. They also found that the existence of a highly permeable channel significantly reduced the heavy oil recovery increment. In a second paper, Wang and Dong (2009) conducted 28 polymer flooding tests for heavy oil with viscosities ranging from 430 mPa s to 5500 mPa s at 21 °C. For each test, a certain pore volume (PV) of water was pumped into the sandpacks until the oil recovery reached approximately 42%. Next, 0.5 PV of polymer solution was injected, followed by 1.0 PV extended waterflooding. They observed that there existed an S-shaped curve for each heavy oil sample they tested, and that the viscosity-sensitive region shifted to higher values for more viscous oils. Seright (2010) studied the potential of polymer flooding for viscous oils in the North Slope reservoirs. He performed fractional-flow analysis and concluded that high mobile oil saturation and relatively high degree of crossflow would make the application of polymer flooding more favorable in heavy oil reservoirs. If there is no crossflow, polymer flooding of a two-layered reservoir, with 1000 mPa s oil, using a 10 mPa s polymer solution, will yield the maximum benefit; further increasing the viscosity of polymer solution only yields marginal benefit. Bondino et al. (2011) performed polymer flooding tests for a heavy sample (7000 mPa s) at 23 °C, in both a cylindrical core and a two-dimensional slab. For both models, polymer flooding could recover an additional 30% OOIP heavy oil after 5.0 PV water injection. Polymer flooding was seen to be less sensitive to geometry than waterflooding. Levitt et al. (2011) also observed that incremental heavy oil recovery was insensitive to polymer viscosity over a wide range. However, they found that there was no lower limit for polymer viscosity, and polymer solutions with very low concentration could effectively increase viscous oil recovery after initial waterflooding, which contradicted the results by Wang and Dong (2009). They attributed the anomalous results to their model's failure to capture the subtle dependence of instability on viscosity differences, relative permeability curves and core geometry. Another possible reason for the anomalous results is that they used different polymer injection scheme after initial waterflooding. They continuously injected polymer solution after waterflooding, while Wang and Dong (2009) injected 0.5 PV polymer solution, followed by 1.0 PV extended waterflooding. The experiments by Szabo (1975) also indicated that higher polymer concentrations or larger slug sizes were required to effectively improve the mobility control in high-permeability sands.

Laboratory investigations have already shown that polymer flooding of viscous oils can provide much higher than expected oil recoveries. In addition, Wang and Dong (2007, 2009) have established the relationship between incremental heavy oil recovery and polymer viscosity, which could be helpful in evaluating the potential of polymer flooding for heavy oil reservoirs. However, the application of this relationship is restricted because the viscosity-sensitivity ranges are different for viscous oils with different viscosities. It is in this context that the main objectives of this study are set: (1) to identify a normalization factor to normalize these S-shaped curves for different heavy oils into a single normalized curve; (2) to validate the normalized curve; and (3) to demonstrate how to use the S-shaped curve to evaluate the potential of polymer flooding for heavy oil reservoirs.

2. Experimental results

Wang and Dong (2009) conducted polymer flooding tests for heavy oils with various viscosities in wet-packed sandpacks with a diameter of 4.25 cm and a length of 6.6 cm. The porosity and permeability of the sandpacks were approximately 35% and 7 μm^2, respectively. For each test, the sandpack was first flooded with heavy oil, until the initial water saturation reached approximately 10%–12%. Next, water was injected, at a constant flow rate of 10 cm^3/h. For the test with the 430 mPa s heavy oil sample, waterflooding was continued until water cut reached 99%, and the corresponding oil recovery was around 42%. In their study all the polymer flooding tests were started at approximately the same waterflooding oil recovery or remaining oil saturation to identify the effect of polymer viscosity on increased heavy oil recovery while eliminating the impact of remaining oil saturation. After waterflooding, a 0.5 PV polymer slug was injected, followed by 1.0 PV extended waterflood. The experimental result for each test is summarized in Table 1. The incremental heavy oil recovery is plotted as a function of polymer viscosity in Fig. 1.

As indicated in Fig. 1, there is a polymer-viscosity-sensitive range for incremental recovery by polymer flooding for each heavy oil sample tested. Outside this range, incremental recovery hardly varies with polymer viscosity. For instance, the approximate viscosity-sensitive range for 1450 mPa s heavy oil is from the lower limit of 30 mPa s to the upper limit of 40 mPa s. Within this range, the recovery increment increases almost linearly with polymer viscosity. The problem with these S-shaped curves is that for oils with different viscosities, the viscosity-sensitive ranges are different, which greatly restricts its application. For heavy oil with

Table 1
Summary of sandpack flood tests (430, 1450 and 2900 mPa s).

Oil viscosity (mPa s)	Waterflooding recovery (%OOIP)	Polymer effective viscosity (mPa s)	Incremental recovery (%OOIP)	Final oil recovery (%OOIP)
430	41.9	3.6	2.2	44.1
	42.4	8.5	4.9	47.3
	41.8	10.7	14.6	56.4
	40.2	15.2	15.7	55.9
	40.2	21.8	17.5	57.7
1450	42.7	21.8	4.1	46.8
	42.2	29.3	5.2	47.4
	42.5	38.4	14.3	56.8
	42.2	51.8	16.7	58.9
	41.9	76.3	19	60.9
2900	40.9	21.8	2.8	43.7
	41	38.4	3.7	44.7
	40.4	51.8	13.5	53.9
	42.4	76.3	16.5	58.9
	41.5	93.2	18.4	58.2

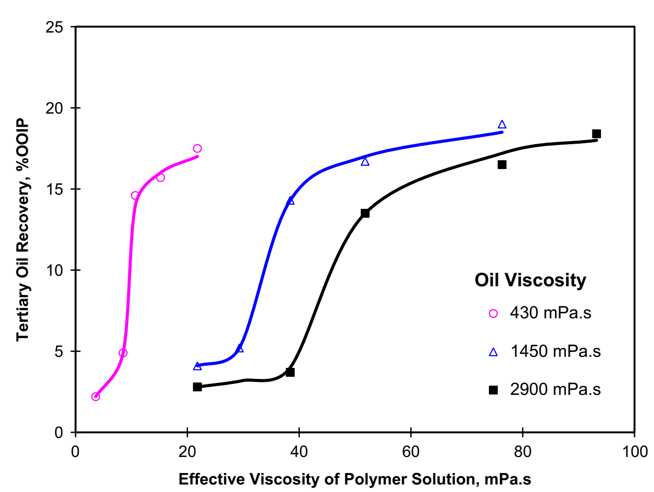

Fig. 1. S-shaped relationship between incremental oil recovery and polymer viscosity.