Journal of Petroleum Science and Engineering 112 (2013) 335–340

Contents lists available at ScienceDirect

Journal of Petroleum Science and Engineering

journal homepage: www.elsevier.com/locate/petrol

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

Ziqiang Guo [a], Mingzhe Dong [a,b,*], Zhangxin Chen [a], Jun Yao [b]

[a] Department of Chemical and Petroleum Engineering, University of Calgary, Calgary, Alberta, Canada T2N 1N4
[b] College of Petroleum Engineering, China University of Petroleum (East), Qingdao, Shandong 266555, China

ARTICLE INFO

Article history:
Received 28 December 2012
Accepted 8 November 2013
Available online 15 November 2013

Keywords:
enhanced heavy oil recovery
polymer injection
mobility ratio
normalization factor

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

* Corresponding author at: Department of Chemical and Petroleum Engineering, University of Calgary, Calgary, Alberta, Canada T2N 1N4. Tel.: +1 403 210 7642; fax: +1 403 284 4852.
E-mail address: mingzhe.dong@ucalgary.ca (M. Dong).

0920-4105/$ - see front matter © 2013 Elsevier B.V. All rights reserved.
http://dx.doi.org/10.1016/j.petrol.2013.11.023

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

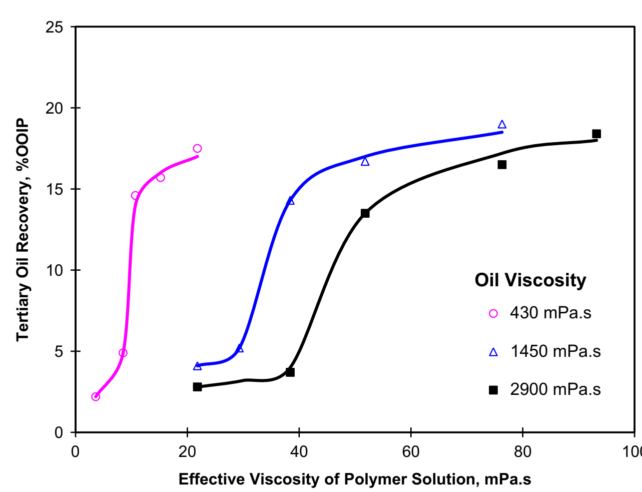

Fig. 1. S-shaped relationship between incremental oil recovery and polymer viscosity.

different viscosities other than the three samples tested (430, 1450 and 2900 mPa s), additional polymer flooding tests have to be performed to establish the corresponding S-shaped relationship.

3. Normalization of S-shaped curves

In order to facilitate the application of these S-shaped curves for the evaluation of the recovery potential of polymer flooding for different heavy oils, a normalized relationship between the incremental recovery and polymer viscosity is required. In this study, one normalization factor is identified, then used to normalize the three S-shaped curves in Fig. 1 into a single curve.

3.1. Selection of normalization factor

In waterflooding of heavy oils, the injected water tends to fingering through the heavy oils due to the adverse mobility ratio and the displacements are characterized by early breakthrough and poor sweep efficiency. Several studies (Mai and Kantzas, 2010, Doorwar and Mohanty, 2011; Buchgraber et al., 2011; Dong et al., 2012) have indicated that even on a core scale severe viscous fingering occurs during waterflooding of heavy oils. The subsequent injected water will preferentially flow through these low resistivity water channels, leaving a large amount of heavy oil untouched. The incremental heavy oil recovery, after initial waterflooding, is mainly determined by the improvement of sweep efficiency by polymer flooding (Zhang et al, 2010). The sweep efficiency is dependent on the mobility ratio in homogenous sandpacks. Therefore, the oil–water mobility ratio at the end of waterflooding, M_{wf}, is used as a normalization factor to normalize these S-shaped curves. This relationship can be modeled with the equation:

$$M_{wf} = \frac{\mu_{eff} k_{rowf}}{\mu_o k_{rwwf}}$$

where μ_{eff} is the effective viscosity of injected polymer solution, k_{rowf} is the oil relative permeability at the end of initial waterflooding, μ_o is the heavy oil viscosity and k_{rwwf} is the water relative permeability at the end of initial flooding.

3.2. Calculation of normalization factor

In order to calculate M_{wf}, the water saturation at the end of waterflooding must first be determined, since relative permeabilities are functions of water saturation. According to the classic Buckley–Leverett theory, there is a saturation shock before water breakthrough for waterflooding of conventional light oil. Along the sandpack, from the inlet to the outlet, the water saturation is changing after water breakthrough. Therefore, it is unrealistic to calculate the oil–water mobility ratio at the end of waterflooding for conventional light oil. However, this is not the case for waterflooding of heavy oil. Due to the large heavy oil–water viscosity ratio, injected water tends to finger through the heavy oil, and large pore volumes of water injection results in a uniform water saturation distribution along the sandpack. In other words, there is no evidence of saturation shock during waterflooding of heavy oil (Bondino et al., 2011). An alternative explanation for uniform saturation distribution is that oil emulsifies into injected water as a result of in-situ native surfactant. This phenomenon may be seen on the reservoir scale where displacement energy is high. If emulsification occurs, there is a possibility that the injected polymer tends to promote emulsion formation and stabilize them (Dickinson, 1992; Qiu, 2013). In this study, all the displacements were conducted at relatively small pressure drop and no emulsions were observed.

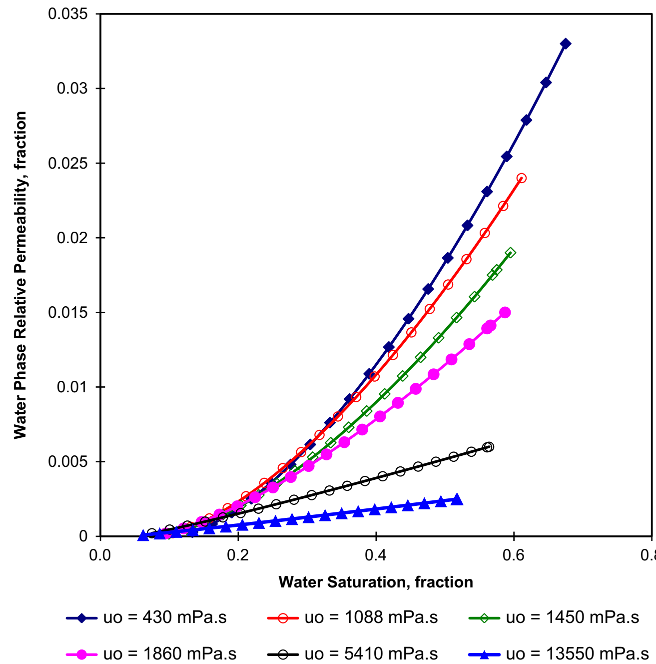

Fig. 2. Water phase relative permeability for heavy oils with different viscosities.

The material balance method can be used to calculate the water saturation at the end of initial waterflooding of heavy oil (S_{wrwf}):

$$S_{wrwf} = 1-(1-S_{wi})(1-R_{wf}/100)$$

where S_{wi} is the initial water saturation (PV), and R_{wf} is the heavy oil recovery by initial waterflooding (%).

The relative permeabilities must also be determined to calculate M_{wf}. By conducting unsteady-state displacement tests, Wang et al. (2006) measured the relative permeability curves for heavy oil–water systems with oil viscosity ranging from 430 to 13,550 mPa s. Their results are displayed in Figs. 2 and 3. As can be seen from the two figures, the relative permeabilities of water almost become straight lines for more viscous oils, indicating that viscous fingering occurs during the displacements.

The calculation results of normalization factors for different heavy oils are summarized in Tables 2–4. The relative permeability values for 430, 1450 and 2900 mPa s heavy oils can either be directly read, or interpolated, from the curves in Figs. 2 and 3.

3.3. Normalized relationship between tertiary recovery, $R_{tertiary}$, and oil–water mobility ratio

The tertiary heavy oil recovery curves are replotted as a function of the oil–water mobility ratio at the end of waterflooding, M_{wf}, as shown in Fig. 4. It can be seen that the originally scattered points become closer, and seem to coincide into a single S-shaped curve. This indicates that incremental heavy oil recovery is strongly correlated with the oil–water mobility ratio at the end of initial waterflooding.

4. Validation of the S-shaped relationship

Nine experimental results of polymer flooding tests of heavy oils, with viscosities of 1108 mPa s and 5500 mPa s, summarized in Table 5, are used to validate the normalized S-shaped curve.

The normalization factors for these nine tests are calculated and listed in Tables 6 and 7. The tertiary recoveries of polymer flooding for 1108 mPa s and 5500 mPa s heavy oils are plotted as a

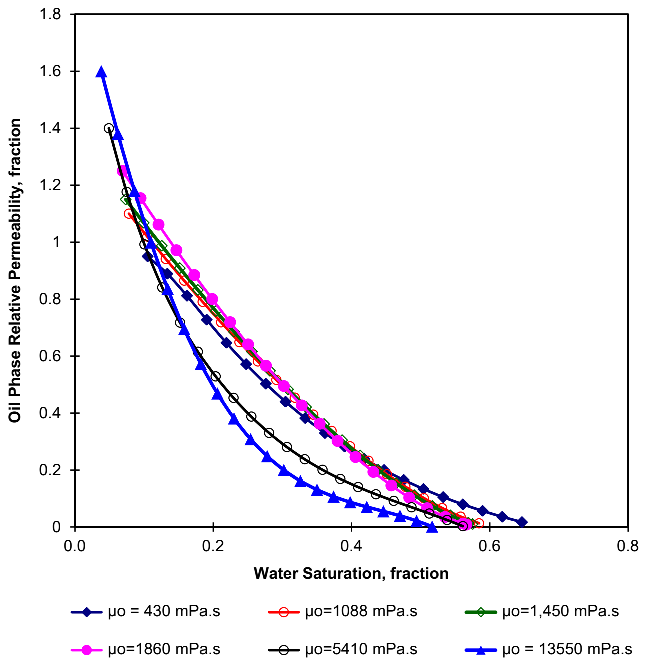

Fig. 3. Oil phase relative permeability for heavy oils with different viscosities.

Table 2
Oil–water mobility ratio, at the end of waterflooding, for heavy oil (430 mPa s).

R_{wf} (%)	S_{wi} (PV)	S_{wrwf} (PV)	k_{rowf}	k_{rwwf}	μ_{eff} (mPa s)	M_{wf}	$R_{tertiary}$ (%)
41.90	0.112	0.48	0.1532	0.0171	3.6	0.0750	2.2
42.40	0.109	0.49	0.1530	0.0173	8.5	0.1748	4.9
41.80	0.125	0.49	0.1530	0.0173	10.7	0.2201	14.6
40.20	0.133	0.48	0.1532	0.0171	15.2	0.3167	15.7
40.20	0.135	0.48	0.1532	0.0171	21.8	0.4542	17.5

Table 3
Oil–water mobility ratio, at the end of waterflooding, for heavy oil (1450 mPa s).

R_{wf} (%)	S_{wi} (PV)	S_{wrwf} (PV)	k_{rowf}	k_{rwwf}	μ_{eff} (mPa s)	M_{wf}	$R_{tertiary}$ (%)
42.70	0.107	0.49	0.1250	0.0133	21.8	0.1413	4.1
42.20	0.111	0.49	0.1250	0.0133	29.3	0.1899	5.2
42.50	0.086	0.47	0.1254	0.0130	38.4	0.2555	14.3
42.20	0.101	0.48	0.1252	0.0131	51.8	0.3414	16.7
41.90	0.109	0.48	0.1252	0.0131	76.3	0.5029	19.0

Table 4
Oil–water mobility ratio, at the end of waterflooding, for heavy oil (2900 mPa s).

R_{wf} (%)	S_{wi} (PV)	S_{wrwf} (PV)	k_{rowf}	k_{rwwf}	μ_{eff} (mPa s)	M_{wf}	$R_{tertiary}$ (%)
40.90	0.11	0.47	0.0953	0.0074	21.8	0.0968	2.8
41.00	0.111	0.48	0.0951	0.0076	38.4	0.1657	3.7
40.40	0.121	0.47	0.0953	0.0074	51.8	0.2300	13.5
42.40	0.119	0.49	0.0950	0.0080	76.3	0.3124	16.5
41.50	0.115	0.49	0.0950	0.0080	93.2	0.3816	18.4

function of oil–water mobility ratio at the end of initial waterflooding, as shown in Fig. 5. Each point in Fig. 5 represents one polymer flooding test result for heavy oil. It can be seen that all of the points fall into the region of the normalized S-shaped curve, indicating that this S-shaped relationship between tertiary recovery and oil–water mobility ratio at the end of waterflooding is also effective for heavy oils with various viscosities.

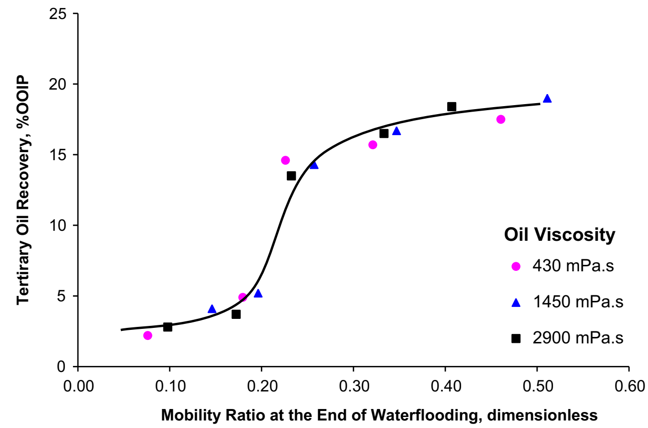

Fig. 4. Normalized relationship between tertiary oil recoveries of three oil samples and oil–water mobility ratio at the end of waterflooding.

Table 5
Summary of sandpack flood tests (1108 and 5500 mPa s).

Oil viscosity (mPa s)	Waterflooding recovery (%OOIP)	Polymer effective viscosity (mPa s)	Incremental recovery (%OOIP)	Final oil recovery (%OOIP)
1108	40.3	10.7	3.9	44.2
	42.2	15.6	4.4	46.6
	41.8	29.3	12.0	53.8
	41.5	38.4	14.5	56
5500	41	21.8	2.8	43.8
	41.6	51.8	4.2	45.8
	41.4	112.5	17	58.4
	42.3	128.8	18.2	59.9
	42.6	193.2	18.7	61.7

Table 6
Oil–water mobility ratio, at the end of waterflooding, for heavy oil (1108 mPa s).

R_{wf} (%)	S_{wi} (PV)	S_{wrwf} (PV)	k_{rowf}	k_{rwwf}	μ_{eff} (mPa s)	M_{wf}	$R_{tertiary}$ (%)
40.30	0.092	0.46	0.1373	0.0148	10.7	0.0896	3.9
42.20	0.106	0.48	0.1370	0.0150	15.6	0.1286	4.4
41.80	0.11	0.48	0.1370	0.0150	29.3	0.2415	12.0
41.50	0.108	0.48	0.1370	0.0150	38.4	0.3165	14.5

Table 7
Oil–water mobility ratio, at the end of waterflooding, for heavy oil (5500 mPa s).

R_{wf} (%)	S_{wi} (PV)	S_{wrwf} (PV)	k_{rowf}	k_{rwwf}	μ_{eff} (mPa s)	M_{wf}	$R_{tertiary}$ (%)
41.00	0.107	0.47	0.0758	0.0049	21.8	0.0613	2.8
41.60	0.105	0.48	0.0754	0.0050	51.8	0.1420	4.2
41.40	0.102	0.47	0.0758	0.0049	112.5	0.3164	17.0
42.30	0.115	0.49	0.0752	0.0052	128.8	0.3387	18.2
42.60	0.105	0.49	0.0752	0.0052	193.2	0.5080	18.7

5. Discussion and application

For heavy oils with different viscosities, there is an identical mobility-ratio-sensitive range for tertiary recovery by polymer flooding. The lower limit of the sensitive range is approximately 0.18 and the upper limit is roughly 0.3, as shown in Figs. 4 and 5. In other words, if the oil–water mobility ratio falls into the range of 0.18–0.3, the tertiary heavy oil recovery increases rapidly with the increasing of the effective viscosity of polymer solution. The existence of the lower limit can be explained as follows: when

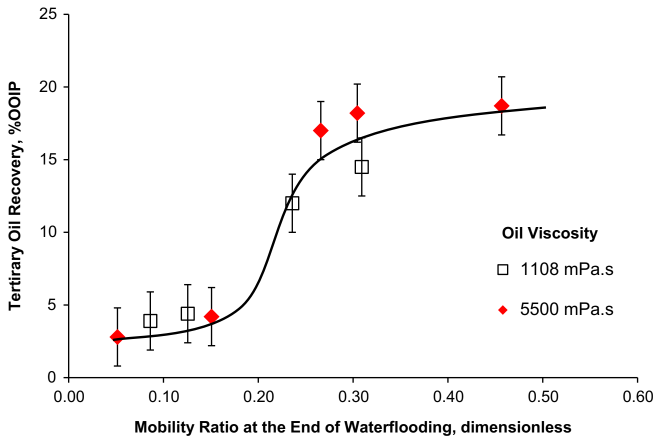

Fig. 5. Normalized relationship between tertiary oil recoveries of oil samples (1108 and 5500 mPa s) and oil–water mobility ratio at the end of waterflooding. The error bars represent $\pm 2\%$ error in tertiary oil recovery.

water is injected into water-wet sandpacks saturated with heavy oil and connate water, due to the large heavy oil–water viscosity ratio, the injected water tends to fingering through the heavy oils, creating complex water channels. After breakthrough, the subsequent injected water preferentially flows through the low resistivity water channels, leaving large amount of heavy oils untouched. In the tertiary polymer flooding stage, the injected polymer solution is capable of blocking the water channels and diverting the injected fluid to the un-swept zone. The capacity of blocking water channels and diverting flows is proportional to the mobility of the polymer solution. Meanwhile, the pressure drop required to displace viscous oil out of the un-swept zone is inversely proportional to the mobility of the heavy oil. Therefore, there is a lower limit of the oil–water mobility ratio beyond which a notable incremental recovery can be achieved. The existence of the upper limit can also be readily explained. The recovery of heavy oil in sandpacks is equal to the product of volumetric sweep and displacement efficiency. The maximum volumetric sweep is 100%, so the maximum recovery can be calculated as

$$R_{\max} = (1-S_{wi}-S_{or})/(1-S_{wi})$$

where S_{or} is the residual oil saturation. In all of the polymer flooding tests, the initial water saturation, S_{wi}, is around 0.1, and the residual oil saturation is about 0.35. Therefore, the maximum recovery R_{max} is approximately 60%. Thus, there is an upper limit for the sensitive range.

The normalized relationship between tertiary recovery and oil–water mobility ratio is quite useful in estimating the potential of tertiary heavy oil recovery by polymer flooding after initial waterflooding. For instance, after the waterflooding recovery reaches to 42% OOIP, if 16% incremental recovery is desired for polymer flooding of a heavy oil with viscosity of 1860 mPa s, the oil–water mobility ratio has to reach approximately 0.3, as shown in Fig. 6. A summary of detailed evaluation results for the polymer flooding potential of heavy oils of 1860 mPa s and 5410 mPa s are presented in Table 8 and Table 9, respectively.

As seen from the application of the procedure discussed above, this method is a fast and effective means to estimate the potential of tertiary heavy oil recovery by polymer flooding, as neither experiment nor numerical simulation is needed.

It should be pointed out that this approach is only applicable to strongly water-wet heavy oil reservoirs. The wettability conditions of heavy oil reservoirs will restrict the universal application of this approach. As Hatfield et al. (1982) have suggested that the heavy oil deposits can be generally divided into two types: oil-wet and water-wet. For the oil-wet reservoirs, heavy oil is directly bonded

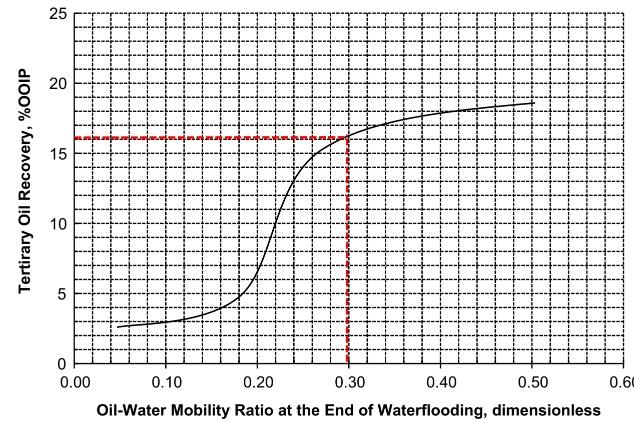

Fig. 6. Application of normalized relationship between tertiary oil recovery and oil–water mobility ratio at the end of waterflooding.

Table 8
Evaluation results of polymer flooding of heavy oil with viscosity of 1860 mPa s.

M_{wf}	k_{rowf}	k_{rwwf}	Required polymer viscosity (mPa s)	$R_{tertiary}$ (%)
0.18	0.104	0.011	36.8	4.8
0.20	0.104	0.011	40.9	6.2
0.22	0.104	0.011	45.0	10.0
0.24	0.104	0.011	49.1	13.0
0.26	0.104	0.011	53.2	14.7
0.28	0.104	0.011	57.3	15.5
0.30	0.104	0.011	61.4	16.0

Table 9
Evaluation results of polymer flooding of heavy oil with viscosity of 5410 mPa s.

M_{wf}	k_{rowf}	k_{rwwf}	Required polymer viscosity (mPa s)	$R_{tertiary}$ (%)
0.18	0.069	0.005	70.6	4.8
0.20	0.069	0.005	78.4	6.2
0.22	0.069	0.005	86.2	10.0
0.24	0.069	0.005	94.1	13.0
0.26	0.069	0.005	101.9	14.7
0.28	0.069	0.005	109.8	15.5
0.30	0.069	0.005	117.6	16.0

to the sand grains with little or no water present. Most of the heavy oil reservoirs found in the United States are oil-wet. In the water-wet reservoirs, heavy oil is separated from the silica sand grain by a film of water and the deposits in the Athabasca region of Canada are typically water-wet. Several researchers (Bowman, 1967; Dusseault and Morgenstern, 1978; Takamura, 1982; Butler, 1997; Czarnecki et al., 2005; Liu et al., 2007) have mentioned that heavy oil reservoirs in Western Canada are preferentially water-wet. These reservoirs are characterized by high initial water saturation of 30%–40% (Canadian Natural Resources Limited (CNRL), 2013; Cenovus Energy, 2013) and high average waterflooding recovery of 24% OOIP (Renouf, 2007), indicating that the reservoir sand is water-wet.

Another question one may have is the relevance of the experiments of this study to the field experience. In all the tests prior to polymer flooding more than 40% OOIP has been already recovered by waterflooding which may seems unrealistic in the field operation. The purpose of this research is to evaluate the polymer flooding potential for heavy oil reservoirs in Western Canada. Assuming an average initial water saturation of 30% and average waterflooding recovery of 25% OOIP, the average water saturation would be 47.5% in these reservoirs after waterflooding.

The experiments in this research are deliberately designed to mimic the post-waterflooding water saturation distribution in the real reservoirs. For all the sandpack tests, the water saturation after initial waterflooding is around 46%–49%, fairly close to that in the reservoirs. Based on this analogous water saturation, polymer flooding tests are conducted to study its potential on enhanced heavy oil recovery. In this sense, this approach has the capacity to evaluate the performance of real polymer floods.

6. Concluding remarks

Polymer flooding test results were analyzed to identify a fast and effective method to estimate enhanced heavy oil recovery by polymer flooding. The following conclusions have been reached by this study:

For heavy oils with different viscosities, the polymer-viscosity-sensitive ranges are different, which greatly restricts its application. By choosing the oil–water mobility ratio at the end of initial waterflooding as a normalization factor, the scattered S-shaped curves coincide into a single normalized curve.

Based on the normalized relationship between tertiary recovery by polymer flooding and oil–water mobility ratio, the potential of enhanced heavy oil recovery by polymer flooding can be quickly and effectively evaluated.

The approach presented in this study is only applicable to strongly water wet heavy oil reservoirs. All the tests were conducted at a constant injection rate of 10 cm^3/h, corresponding to a frontal velocity of 0.5 m/d commonly used in fields of Western Canada. The applicability of the normalized relationship to different injection rates requires further study.

Acknowledgments

The financial supports of the Doctoral Program of High Education of China (20110133110007) and Natural Sciences and Engineering Research Council of Canada (NSERC) are gratefully acknowledged.

References

Aronofsky, J.S., 1952. Mobility ratio and its influence on flood patterns during water encroachment. J. Pet. Technol. 4 (1), 15–24.
Bondino, I., Nguyen, R., Hamon, G., Ormehaug, P.A., Skauge, A., Jouenne, S., 2011. Tertiary polymer flooding in extra-heavy oil: an investigation using 1D and 2D experiments, core scale simulation and pore-scale network models. In: Review Proceedings for the 25th International Symposium of the Society of Core Analysis, Austin, Texas, USA.
Bowman, C., 1967. Discussion to the Tar Sands Section. In: Proceedings of the 7th World Petroleum Congress, Mexico City, Mexico.
Buchgraber, M., Clemens, T., Castanier, L.M., Kovscek, A.R., 2011. A microvisual study of the displacement of viscous oil by polymer solutions. SPE Reserv. Eval. Eng 14 (3), 269–280.
Butler, R.M., 1997. Thermal Recovery of Oil and Bitumen. GravDrain Inc., Alberta, Canada.
Canadian Natural Resources Limited (CNRL), 2013. Brintnell Waterflood 9673, 10147, 10423, 10787. Alberta Energy Regulator, 〈http://www.aer.ca/documents/oilsands/insitu-presentations/2013AthabascaCNRLBrintnell.pdf〉.
Cenovus Energy, 2013. Brintnell Waterflood 9403, 9404. Alberta Energy Regulator, 〈http://www.aer.ca/documents/oilsands/insitu-presentations/2013AthabascaCenovusBrintnell9404.pdf〉.
Chang, H.L., Zhang, Z.Q., Wang, Q.M., Xu, Z.S., Guo, Z.D., Sun, H.Q., Cao, X.L., Qiao, Q., 2006. Advances in polymer flooding and alkaline/surfactant/polymer processes as developed and applied in the People's Republic of China. J. Pet. Technol. 58 (2), 84–89.
Czarnecki, J., Radoev, B., Schramm, L.L., Slavchev, R., 2005. On the nature of Athabasca Oil Sands. Adv. Colloid Interface Sci. 114–115, 53–60.
Dickinson, E., 1992. Interfacial interactions and the stability of oil-in-water emulsions. Pure Appl. Chem. 64 (11), 1721–1724.
Dong, M., Liu, Q., Li, A., 2012. Displacement mechanisms of enhanced heavy oil recovery by alkaline flooding. Particuology 10, 298–305.
Doorwar, S., Mohanty, K.K., 2011. Viscous fingering during non-thermal heavy oil recovery, SPE 146841 Presented at the SPE Annual Technical Conference and Exhibition, Denver, Colorado, USA.
Dusseault, M.B., Morgenstern, N.R., 1978. Shear strength of Athabasca Oil Sands. Can. Geotech. J. 15, 216–238.
Dyes, A.B., Caudle, B.H., Erickson, R.A., 1954. Oil production after breakthrough as influenced by mobility ratio. J. Pet. Technol. 6 (4), 27–32.
Hatfield, K.E., Oblad, A., Miller, J., 1982. Pilot plant recovery of bitumen from oil-wet tar sands. In: Proceedings of the 2th International Conference on Heavy Crude and Tar Sands, Caracas, Venezuela.
Levitt, D., Jouenne, S., Bondino, I., Gingras, J., Bourrel, M., 2011. The interpretation of polymer coreflood results for heavy oil. Paper SPE 150566 Presented at SPE Heavy Oil Conference and Exhibition, Kuwait City, Kuwait.
Liu, Q., Dong, M., Asghari, K., Tu, Y., 2007. Wettability alteration by magnesium ion binding in heavy oil/brine/chemical/sand systems—analysis of electrostatic forces. J. Pet. Sci. Eng. 59, 147–156.
Mai, A., Kantzas, A., 2010. Mechanisms of heavy oil recovery by low rate waterflooding. J Can. Pet. Technol. 49 (3), 44–50.
Pye, D.J., 1964. Improved secondary recovery by control of water mobility. J. Pet. Technol. 16 (8), 911–916.
Qiu, J., 2013. Stability of the oil–water emulsion formed during the amphiphilic polymer flooding. Pet. Sci. Technol. 31 (2), 142–147.
Renouf, G., 2007. Do Heavy and Medium Oil Waterfloods Differ? Paper SPE 2007–055 presented at the Petroleum Society's 8th Canadian International Petroleum Conference, Calgary, Alberta, Canada.
Russell, R.G., Morgan, F., Muskat, F., 1947. Some experiments on the mobility of interstitial waters. Trans. AIME 170 (1), 51–61.
Sandiford, B.B., 1964. Laboratory and field studies of water floods using polymer solutions to increase oil recoveries. J. Pet. Technol. 16 (8), 917–922.
Seright, R.S., 2010. Potential for polymer flooding reservoirs with viscous oils. SPE Reserv. Eval. Eng. 13 (4), 730–740.
Szabo, M.T., 1975. Laboratory investigations of factors influencing polymer flood performance. SPEJ 15 (4), 338–346.
Taber, J.J., Martin, F.D., Seright, R.S., 1997. EOR screening criteria revisited—part 1: introduction to screening criteria and enhanced recovery field projects. SPE Res. Eng. 12 (3), 189–198.
Takamura, K., 1982. Microscopic structure of Athabasca oil sand. Can. J. Chem. Eng. 60, 538–545.
Wang, J., Dong, M., Asghari, K., 2006. Effect of oil viscosity on heavy-oil/water relative permeability curves. Paper SPE 99763 Presented at the SPE/DOE Symposium on Improved Oil Recovery, Tulsa, Oklahoma, USA.
Wang, J., Dong, M., 2007. A laboratory study of polymer flooding for improving heavy oil recovery. Paper SPE 2007-178 Presented at the Petroleum Society's 8th Canadian International Petroleum Conference, Calgary, Albert, Canada.
Wang, J., Dong, M., 2009. Optimum effective viscosity of polymer solution for improving heavy oil recovery. J. Pet. Sci. Eng. 67 (3–4), 155–158.
Zaitoun, A., Tabary, R., Fossey, J., Boyle, T., 1998. Implementing a heavy oil horizontal well polymer flood in western Canada. Paper Presented at the 7th Unitar International Conference on Heavy Crude and Tar Sands, Beijing, China.
Zhang, H., Dong, M., Zhao, S., 2010. Which one is more important in chemical flooding for enhanced court heavy oil recovery, lowering interfacial tension or reducing water mobility? Energy Fuels 24 (3), 1829–1836.