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AN ENHANCED OIL RECOVERY TECHNOLOGY APPLICABLE TO KAZAKHSTAN RESERVES WITH HIGHLY VISCOUS OILS

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A B S T R A C T

The subject of discussion of the article below is polymer flooding as an EOR (enhanced oil recovery) technique considered here within the context of Kazakhstan's depleted oil-fields exploitation. The underlying factor for considerable residual hydrocarbon saturation observed in the productive reservoirs of the majority of Kazakhstan's oil fields connected with their stratified heterogeneous structures. Such kind of Oil Reservoirs require additional developments comprising new technologies promoting enhanced oil-recovery.

Keywords: viscosity; inhomogeneity; polymer flooding; polyacrylamide; degree of inhomogeneity; permeability; catholyte; trim.

Introduction

Consumption of petroleum and its derivatives is increasing each year. This is especially evident for growing national economies. The depletion (primary production) or flooding oil-recovery modes practiced for decades long in the majority of oilfields has resulted in formation of considerable residual high viscosity (HV) and hard-to-recover oil reserves. The assumed amount of such reserves varying within 50-70 %, whereas the newly opened large oil fields are few in number, makes additional development of depleted oilfields a live issue for the benefit of stable energy processes. Poor performance of such reservoirs stemming from low permeability of the heterogeneous hydrocarbon strata because of HV crude oil is the prompting factor, thereby, for premature flooding of producing oil wells, resulting in greater amount of oil-saturated zones, which are inappropriate to involve in production activities [1-3].

Especially, there are many such deposits in Kazakhstan. Kazakhstan's oils are highly viscous and resinous. Meanwhile, as the known flooding techniques are not so straightforward, it is obvious that updated oil-recovery technologies are required, capable to reduce residual oil-saturation through increased sweep efficiency. Among the technologies recommended reducing oil-saturation there are different tertial oil-recovery techniques based on the principles of thermal, chemical, hydrodynamic, gas, acoustic, and bacterial interaction and effects [1]. Numerous theoretical and experimental studies, as well as field observations, indicate that the most important factors influencing the efficiency of oil field development are the ratio of oil and water mobility in reservoir conditions and reservoir heterogeneity in permeability. With an increase in oil viscosity, the oil recovery coefficient decreases sharply. The heterogeneity of the porous medium exacerbates the uneven advance of the displacement front. In highly heterogeneous reservoirs (with a coefficient of permeability variation of 0.8 and higher), the displacement of even low-viscosity oil leads to a temporary breakthrough of the displacing agent in the most permeable zones of the formation [1-3]. The displacement of high-viscosity oil is accompanied by viscous instability, which is also established in homogeneous formations. In real natural formations with low viscosity oil, the heterogeneity of reservoir properties may be the first reason for the uneven movement of oil and water. Many authors have considered various methods of increasing oil recovery in conditions of complication of development processes from the point of view of natural and technological factors [1, 4-6]. Chemical techniques, for instance, based on separated or combined use of surfactants, polymers, alkalis, acids, resins, etc. Polymer flooding is one of them.

The fact that this technology have been used more than 50 times in different countries and regions, as Europe, North America, the Middle East region, and others [7] is attesting to its growing popularity. Polymer flooding leads to the alignment of the displacement front, improves permeability, reduces water mobility, increases the coverage coefficient, increases the coefficient of oil displacement from the reservoir [1-4, 8, 9]. The concept of polymer flooding, which is a diverter technology, connected with leveling of the displacement front, imparting some immobility to the liquid and finally increasing the sweep efficiency. Papers [4, 5, 10-12] considering various brands of polymers, as GL-50, R-1,

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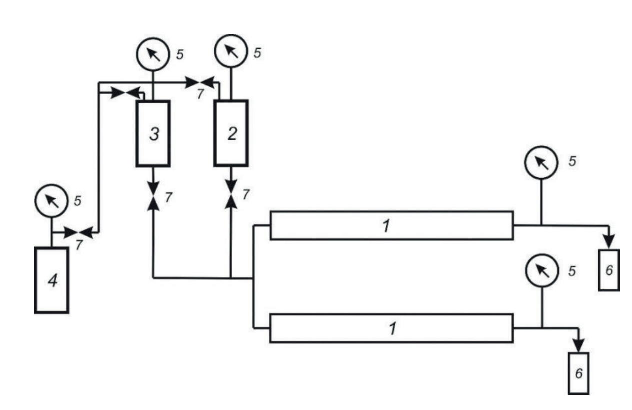


Fig. 1. The Installation Diagram
1 – Reservoir model; 2 – liquid tank (water, chemical agent solution); 3 – oil tank; 4 – air cylinder; 5 – pressure gauges; 6 – dimensional cylinders; 7 – valves

POLY-T-101, Polycar, Alkoflad, Flopaam 5205 VHM Al-888, MD-02.05.07. Describe their specifications compliant to the purposes and characteristics of flooding. When choosing a polymer flooding, it is necessary to pre-analyze the criteria for choosing the technological side of the organization of polymer flooding and the selection of the reagent. The right choice affects the economy and the technological effect of the use of polymer flooding [4, 13, 14] Some papers deal with such parameters as water mineralization, shear rate and temperature affecting different polymers [8, 11, 15-23]. Papers [5, 21] investigate such properties of polymers, as high viscosity, thixotropy and pseudoplasticity, which are determinative in employment of this or that polymer in oil production. Polymers' capability to affect the rheological properties of water systems and form gels of various densities studied in papers [19, 20, 22, 24]. Along with this, some authors demur the efficacy of polymer flooding performed at a later development phase [22, 24]. As mentioned above, polymers affect the permeability of a porous medium. At the same time, there is a fear of a sharp decrease in permeability caused by the interaction between the injected polymer solution and the reservoir rock [25]. As you can see, polymer flooding allows you to increase oil recovery, and also solves some problems related to increasing oil production and the condition of reservoirs. Despite this, there are works that deny the effectiveness of polymer flooding at a late stage of development [22]. In [25, 26], a combined method of influencing a layered heterogeneous formation combining a water-gas mixture and a PAA rim is proposed. In [5, 7, 10, 27], the use of thermosetting polymers is proposed as a water thickener. From the above brief literature review, it can be seen that the use of polymer-based compositions can improve the displacement of high-viscosity oils from the reservoir.

Hence, the purpose of this research is to evaluate. the efficacy of polyacrylamide (PAA)-based oil-recovery technology designed for stratified heterogenous formation, namely, for depleted reservoirs with HV oil-saturation. Concerning this problem, we propose in-parallel performing of flooding and injection of polyacrylamide (PAA) margin in heterogenous formation. In addition, a variant of oil displacement from heterogenous formation is considered according to the following scheme: flooding - injection of a PAA solution rim into a highly permeable reservoir - displacement of oil from heterogenous formation with electrochemically modified water (catholyte). The catholyde (electrochemically modified water) properties and its preparation procedure described in paper [28, 29].

Materials and Methods

Experimental studies included installation consisting of two reservoir models of 102.5 cm long each, and 26 mm diameter (fig. 1). These models meet all the modeling requirements for experimental installations [30]. The parameters of the reservoir model and the experimental conditions satisfy the similarity criteria:

$$P_1 = \frac{L}{\sqrt{k_2}} \text{ and } P_2 = \frac{\sigma \cdot \cos\theta}{\Delta P \sqrt{\frac{k_2 \cdot \varphi}{m_2}}}$$

where: L is the length of the reservoir, m; k_2 is the tight formation permeability, mkm^2; σ is the oil-water interfacial tension, mN/m; θ is the interfacial angle; ΔP is the pressure drop in the reservoir, MPa; φ is the structural coefficient; m_2 is the tight reservoir porosity, fractions of one.

Thus, P_1 determines the porous medium's structure, and P_2 reflects the influence of hydrodynamic forces on the phase distribution in the pores. To comply with the self-similarity these similarity criteria have to meet the requirements: $P_1 \geq 0.5 \cdot 106$ and $P_2 \leq 0.6$. According to the performed calculations, the dimensions of the reservoir model and the experiments method satisfy these conditions. Quartz sand and marshallite are used as porous media.

Results and Discussion

Table 1 shows the main source data of the stratified heterogeneous formation for three experiments, respectively.

All the experiments of Phase I connected with distilled water drive. The distilled water-oil interfacial tension was 42.2 mN/m. Liquid injections carried out simultaneously in both layers. Phase I completed with pumping of water, in total 4.1-4.8 of the void content, through the high permeability formation (fig. 2-4). During this period the oil recoverability factor (ORF) for the high permeable formation made 0.56-0.58, and that for the tight one was 0.24-0.26. The ORF ratio to the heterogeneous strata roughly corresponds to the degree of heterogeneity of K_o.

Pumping of PAA solution into the high-permeability formation had to intensify oil displacement from the heterogeneous reservoir.

The majority of West-Kazakhstan oilfields now are undergoing development phases III or IV, which in pursuance of the production technologies implying high flooding of the well products because of significant reserves development. Low oil recoverability is explained by dense formations, mostly not included in the development scheme, as well as the large heterogeneity of the layers of productive reservoirs. For such deposits, it is necessary to select the proper PAA composition.

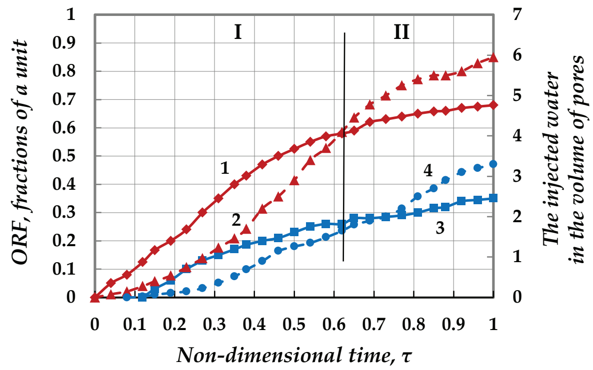
The residual oil saturation (Experiment 1) was 26.5% in the high permeable reservoir and 57.1% in the tight one. Within Phase II for oil-recovery, enhancement purposes pumping of the 0.15% PAA solution into a high permeable reservoir fulfilled.

The injection of the PAA rim promotes the adsorption of polymer molecules on the surface of a porous medium. This leads to a partial overlap of the pore channels and a deteriora-

Table 1

Source data of stratified hetregeneous formation Experiment 1

Parameters	Experiment 1	
	High-permeability layer	Law-permeability (tight) layer
Oil viscosity index, mPa·c	205	205
Void content, cm^3	190	175
Air permeability, mkm^2	2.8	1.7
Water permeability, mkm^2	2.0	0.8
Initial oil-saturation, %	63.2	77.1
Initial water-saturation, %	36.8	22.9
The volume of the rim of the PAA solution sm^3	60	–
Concentration of the PAA solution, %	0.15	–
Degree of reservoir's inhomogeneity, $K_0=K_1/K_2$	2.5	



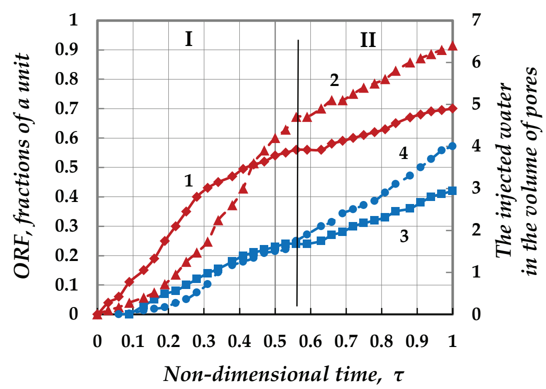
High permeability reservoir: 1 – ORF, 2 – the cumulative injected water volume. Low-permeability (tight) reservoir: 3 – ORF, 4 – cumulative injected water volume.
Phase I – oil-driving with distilled water,
Phase II – Injection of 0.15% PAA solution into a highly permeable layer with further injection of distilled water into both layers;
t_i - current time per hour; Σt_i is the total experiment time

Fig. 2. Crossplot of ORF and the cumulative injected water volume against non-dimensional time $\tau=t_i/\Sigma t_i$ (Experiment 1)

Table 2

Source data of stratified heterogeneous formation Experiment 2

Parameters	Experiment 2	
	High-permeability layer	Law-permeability (tight) layer
Oil viscosity index, mPa·c	205	205
Void content, cm^3	180	172
Air permeability, mkm^2	2.55	1.7
Water permeability, mkm^2	1.9	0.75
Initial oil-saturation, %	64.0	75.6
Initial water-saturation, %	36.0	24.4
The volume of the rim of the PAA solution sm^3	55	–
Concentration of the PAA solution, %	0.25	-
Degree of reservoir's inhomogeneity, $K_0=K_1/K_2$	2.53	



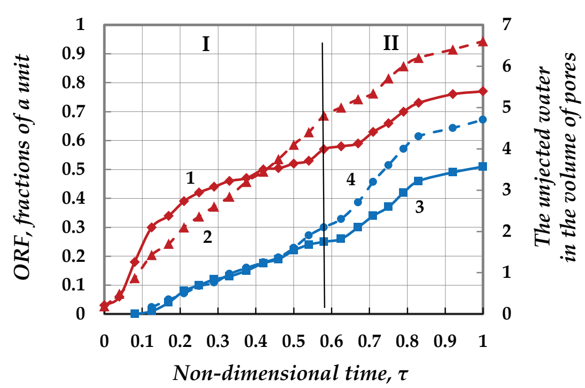
High-permeability reservoir: 1 – ORF, 2 – the cumulative injected water volume. Low-permeability (tight) reservoir: 3 – ORF, 4 – the cumulative injected water volume.
Phase I – oil-driving with distilled water,
Phase II – Injection of 0.25% PAA solution into a highly permeable layer with further injection of distilled water into both layers

Fig. 3. Crossplot of the ORF and the cumulative injected water volume against the non-dimensional time $\tau=t_i/\Sigma t_i$ (Experiment 2)

Table 3

Source data of stratified heterogeneous formation Experiment 3

Parameters	Experiment 3	
	High-permeability layer	Law-permeability (tight) layer
Oil viscosity index, mPa·c	205	205
Void content, cm^3	184	170
Air permeability, mkm^2	2.7	1.8
Water permeability, mkm^2	1.96	0.78
Initial oil-saturation, %	66.8	80.0
Initial water-saturation, %	33.2	20.0
The volume of the rim of the PAA solution sm^3	55	–
Concentration of the PAA solution, %	0.25	–
Degree of reservoir's inhomogeneity, $K_0=K_1/K_2$	2.51	



High-permeability reservoir: 1 – ORF, 2 – the cumulative injected water volume. Low-permeability (tight) reservoir: 3 – ORF, 4 – the cumulative injected water volume.
Phase I – oil-driving with distilled water.
Phase II – Injection of 0.25% PAA solution into a highly permeable layer with further injection of distilled water into both layers

Fig. 4. Crossplot of the ORF and the cumulative injected water volume against the non-dimensional time $\tau=t_i/\Sigma t_i$ (Experiment 3)

tion in the filtration of water in them, i.e. increasing the resistance to the passage of the displaced liquid. Thus, the water inflow from the highly permeable reservoir is limited [31, 32].

The solution is prepared because of distilled water taken in an amount of 30% of the void content. Further oil driving in both strata was effected with distilled water. The PAA margin injection is conductive to the molecules adsorption on the pores surface, as well as to the capacity to resist to the displaced fluid passing. Moreover, it can curb the water flow from the high permeable reservoir, thus contributing to redistribution of the injected fluid at the entrance to the heterogeneous formations. As the greater part of the injected fluid flows to the tight reservoir, it increases the rate of oil displacement and, thus, the sweep efficiency too. The ratio of the pumped liquid of the high permeable reservoir to the low-permeable one is 1.8, i.e., less than the formation's heterogeneity. This certify to the fact that PAA solution injection can impart some uniformity to heterogeneous reservoirs, promoting, thereby, the ORF (by 9%) in tight layers. Phase II development resulted in decrease of residual oil saturation to 20.2% in the high permeable reservoir, and to 50.1% in the low-permeable one. As seen, our goal achieved not in full, yet, we decided, therefore, to conduct pumping of 0.25% PAA solution margin (Experiment 2).

Phase I is similar to Experiment 1, as the oil recovery coefficient there is approximately the same, namely, 56% in the high permeable reservoir, and 24% in the tight one. As to the residual oil saturation, it makes 28.1% in the high-permeability formation and 57.4% in the tight one. Phase II included an injection procedure of a 0.25% PAA solution into the high permeable layer, thus enabling further elimination of the formation's non-uniformity and easing the oil-driving process (fig. 2). The tight ORF has increased significantly, namely, as much as two times, if comparing to Experiment 1 (18% vs. 9%). However, the residual oil saturation remained high in both layers (19.1% and 43.8%, respectively).

Conclusions

1. The evaluation-combined method was conducted. Experiment 3 gave an oil-drive process identical to those of Experiments 1 and 2 (Phase I). Phase II included an injection of a 0.25% PAA solution margin to a high permeable layer.
2. The PAA solution is based on catholyte (chemically electromodified water), whose alkaline properties account for the margin injection (30% of the void content) capacity to decrease of the water-oil interfacial tension to 12 mN/m (when catholyte is not used then σ=42.2 mN/m). After that, both layers were subjected to catholyte injection (at pH=11). This gave slow rate of oil displacement from the high permeable reservoir and greater one in the tight one.
3. During this period the high-permeability ORF was 20%, while the low-permeability one – 26.5%.

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