

Study of the Plugging of Oil Well Sand Control Area in a Polymer Flooding Region

Dong Liu^{1,2*}, Huiqing Liu^{2*}, Jian Hou³, Zhuo Li¹, A-Zhen Zhao¹, Li Li¹,
Chengshi Zhou⁴ and Huili Sun¹

¹ State Key Laboratory of Heavy Oil Processing, China University of Petroleum, Qingdao Shandong, 266555 - P.R. China

² School of Oil and Natural Gas Engineering, China University of Petroleum, Beijing, 102249 - P.R. China

³ School of Petroleum Engineering, China University of Petroleum, Qingdao Shandong, 266555 - P.R. China

⁴ Oil Production Technology Institute, Shengli Oilfield Company of SINOPEC, Dongying, 257000 - P.R. China

e-mail: liudong@upc.edu.cn - liuhq@cup.edu.cn - houjian@hdpu.edu.cn - lizhuo@163.com
zhaoazhensunny@163.com - lily@upc.edu.cn - chengshizhou@slof.com - sunhuililove@163.com

* Corresponding author

Résumé — Étude du colmatage aux abords des puits d'injection dans un réservoir d'hydrocarbure produit par balayage au polymère — Le colmatage des zones de puits où un contrôle de venues de sable est réalisé par injection de polymère a été étudié et les substances à l'origine du colmatage ont été analysées par spectrophotométrie UV-Visible, spectrométrie à émission de plasma, analyse de taille de particules par diffraction laser, diffraction X (DRX), observation microscopique, spectrométrie de masse, etc. Nous avons conclu que la raison principale du colmatage de la zone de contrôle des venues de sable était l'adsorption, l'accumulation et le pontage du polyacrylamide (PAM) à la surface du sable. La migration des fines du milieu poreux et l'adsorption de composés du brut à la surface des fines contribuent également au colmatage. Une étude expérimentale de dégradation du polymère a été réalisée sur carotte et deux types d'agents décolmatants, le persulfate de potassium et le thiosulfate de sodium, ont été sélectionnés et testés. Il a été montré que ces deux agents pouvaient dégrader les substances à l'origine du colmatage et permettaient de recouvrer efficacement la perméabilité du milieu poreux. En outre, des tests d'application de tels traitements ont été menés sur le champ pétrolier de Gudao; ils ont permis de démontrer une restauration des performances sur différents puits. Ces tests ont aussi montré une diminution sensible de la pression d'injection et une forte augmentation de la production liquide journalière après l'application de ces agents décolmatants dans la zone de contrôle de venue de sable.

Abstract — Study of the Plugging of Oil Well Sand Control Area in a Polymer Flooding Region — The plugging of the oil well sand control area in a polymer flooding region was studied and the plugging substances were analyzed through UV-Vis spectrophotometer analysis, plasma emission spectrometry analysis, laser particle size analysis, X-Ray Diffractometer (XRD) analysis, microscopic observation, chromatograph-mass spectrometer, etc. It is inferred that the main reason for the plugging of the sand control area was the adsorption, gathering and bridging of PAM on the surface of the sand. The migration of the mineral fines from the stratum and the adsorption of the crude oil ingredients on the surface of the fines also result in plugging. An experimental study on the polymer degradation was performed and two types of plug removal agents, potassium persulfate and sodium thiosulfate, were selected and tested. It showed that potassium persulfate and sodium thiosulfate could degrade the plugging substances and recover core permeability effectively. Moreover, field application tests were conducted in Gudao oil field which showed the restoration of the performance of various wells. It also indicated that the injection pressure obviously decreased and liquid production per day increased greatly after application of the plug removal agents in the sand control area.

INTRODUCTION

There are two main methods widely used in oil recovery: water flooding and polymer flooding [1, 2]. In China, polymer flooding has been an important technology to stabilize oil production [3, 4]. Plugging of oil wells occurs in almost every oilfield and it will cause loss of well performance and usually requires an expensive treatment to recover it. However, research on the plugging mechanism of the sand control area in the polymer injection region to seek for an economic method to remove plugs has hardly been investigated [5-7]. In oil wells, the sand control area is a very important part to keep high oil quality by preventing mineral fines from going into the oil in the oil recovery process. There are many sand control methods in oil fields. In our experimental simulation study, we used a filling method which is consistent with Gudao oil field to achieve the aim of sand control. In this method, filled fines, whose granularity was between 400~1100 μm , were selected and pressed into the oil well tightly. The region that the fines fill forms the sand control area. The fines, which are collected from the mixture recovered from oil wells, are defined as drainage fines, which were analyzed to identify the plugging substances. The sand control area is the most common place where plugging occurs in oil wells, so analyzing the sand control area benefits understanding of the plugging mechanism and finding corresponding methods to remove plugs effectively and economically. The conventional hydraulic fracture and chemical plug removal methods still have some questions to be resolved, such as the small capacity and short valid period [8-9]. It is necessary to analyze the plugging species of the sand control area in the polymer injection region and to optimize some kinds of plug removal agents by experiments, in order to enhance the plug removing effect and prolong the valid period [10, 11].

1 EXPERIMENT

1.1 Methods

1.1.1 Plugging Mechanism Study

To analyze the organic compounds and inorganic ions in the water production which was collected from the oil wells, a UV-Vis spectrophotometer and plasma emission spectrometer were used, respectively. The samples of fines were analyzed though a laser granule-size instrument, XRD and microscopic observation and the components adsorbed on the surface of the drainage fines were separated and analyzed by an alumina chromatographic column.

1.1.2 Plug Removal Agent Selection

In the simulated stratum conditions, the degradation of the polymer solution and polymer gel was studied. For polymer

solution: different plug removal agents with different concentrations were added to PAM solutions (5 500 $\text{mg}\cdot\text{dm}^{-3}$). Then, their viscosity was measured and the dropping rate of the viscosity of the PAM solution was calculated with the same time interval. For polymer gel: polymer (gel molecular weight of 15 million) was dissolved in plug removal agents of different concentrations, and then was placed separately in a magnetic stirrer at constant temperature. The time taken to dissolve was used to compare the dissolving ability of the plug removal agents. Obviously, the shorter the time the gel needs to be dissolved, the more efficient the plug removal agent.

1.2 Instruments

The following instruments were used in this study: UV-Vis spectrophotometer (SP-8001PC); plasma emission spectrometer (BBT5-700-ES); counter LS230 laser particle size analyzer; microscopic observation (BH-2); chromatograph-mass spectrometer (GC-17A/QP-500); X-ray diffractometer (D/MAX- γ A); capillary viscometer and equipment of core simulation testing (Fig. 1).

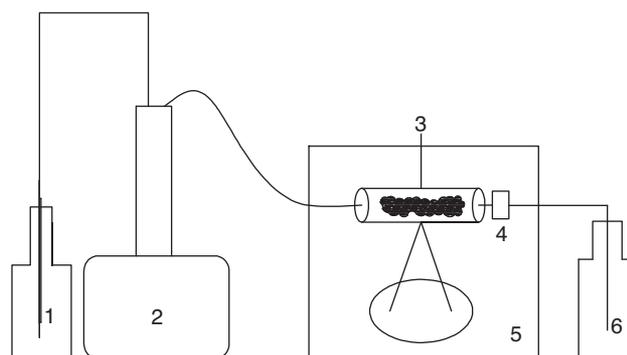


Figure 1

Equipment of core simulation testing. 1: Injected water; 2: ISCO pump; 3: Core holder; 4: Back-pressure valve; 5: Air oven; 6: Water produced.

2 RESULTS AND DISCUSSION

2.1 Analysis of the Water Production

2.1.1 UV-Vis Spectrophotometer Analysis

Preparation of water sample: the mixture was filtered to get the water sample, which was analyzed by UV-Vis spec-

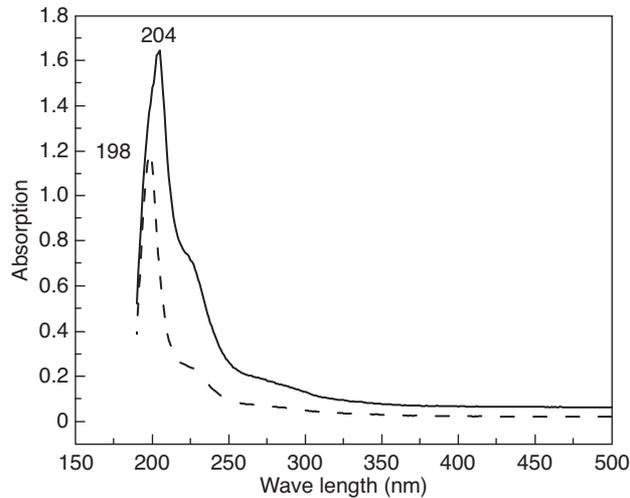


Figure 2

Spectrogram of the water from the well GD6-29. The dotted line is the UV spectrum of PAM standard solution whose concentration is 150 ug/g and average molecular weight is 15 million.

trophotometer. The mixture was recovered from the well GD6-29 (in Gudao oil field) whose temperature and the pressure of the stratum was 58°C and 8.0 MPa, respectively. Then, the transition of $\pi-\pi^*$ and $n-\pi^*$ was studied (Fig. 2). Figure 2 shows that the adsorption band was at 204 nm, which was proved to be the transition of the $n-\pi^*$ of PAM. There is no adsorption band of other organic groups in the spectrum. It can be concluded that there was no hydroxybenzene and aldehyde to associate with PAM, resulting in plugging.

The water production from GD6-29 was analyzed by plasma emission.

2.1.2 Plasma Emission Spectrometer Analysis

The content of the ions included in the water was analyzed by a plasma emission spectrometer and the composition is shown in Table 1.

From Table 1, we can conclude that the concentration of Fe^{3+} was 0.81 $\text{mg}\cdot\text{dm}^{-3}$, less than 1.0 $\text{mg}\cdot\text{dm}^{-3}$, proving that the Fe^{3+} in the water cannot result in the flocculation of PAM [1]. Similarly, the concentration of Ca^{2+} was 159.53 $\text{mg}\cdot\text{dm}^{-3}$, smaller than 200 $\text{mg}\cdot\text{dm}^{-3}$, and the concentration of Mg^{2+} was 25.49 $\text{mg}\cdot\text{dm}^{-3}$, smaller than 100 $\text{mg}\cdot\text{dm}^{-3}$, neither of which can result in the flocculation of PAM. The element S in the water was in the form of SO_4^{2-} . By associating with Ca^{2+} , Mg^{2+} , Ba^{2+} and Sr^{2+} , it could form precipitation which acted as a nucleus, resulting in the flocculation of PAM and organics. Analysis of the plugging substance has to be done to specify the composition of the nucleus.

TABLE 1

Concentration of the ions in the water	
Elements	Concentration ($\text{mg}\cdot\text{dm}^{-3}$)
Ca^{2+}	159.53
K^+ (+) Na^+	3 006.64
Mg^{2+}	25.49
Ba^{2+}	6.86
Sr^{2+}	4.02
Fe^{3+}	0.81
Cr^{3+}	0.14
Al^{3+}	0.76
PO_4^{3-}	2.50
HCO_3^-	392.56
SO_4^{2-}	7.83

2.2 Laser Particle Size Analysis of the Fine Sample

Figure 3 shows the distribution of the oil well's filled fines of the sand control area in the polymer injection region (volume percent). As mentioned above, the filled fine sample was collected from fines which were used to fill the sand control area to prevent the migration of mineral fines of the stratum and the drainage fine sample was collected from the sand control area after 120 days of polymer flooding. It can be seen that the granularity of the filled fines was between

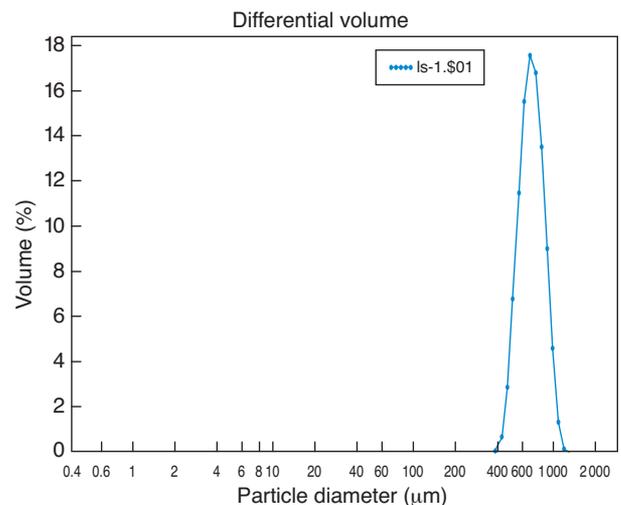


Figure 3

Particle size distribution of the oil well's filled fines in the sand control area.

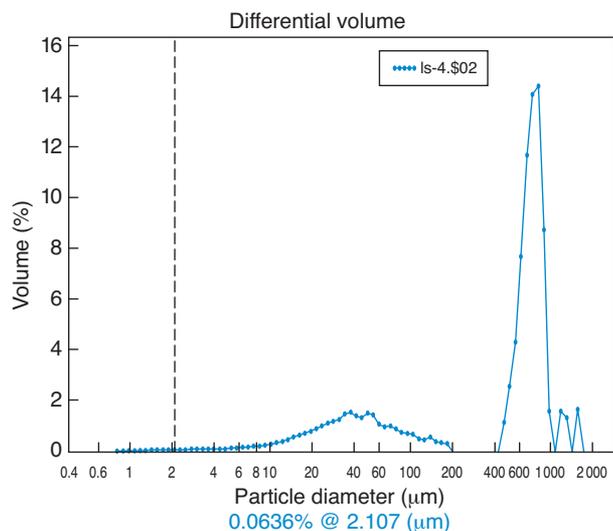


Figure 4

Particle size distribution of drainage fines from the oil well's sand control area.

400~1100 μm and the average diameter was about 700 μm . The curve presents a normal distribution. Figure 4 shows the distribution of the drainage fines from the oil well's sand control area after a period of polymer flooding (volume percent). By comparing Figure 3 and Figure 4, it was concluded that the proportion of the thin fines in the drainage fines rose, and the drainage fines whose diameter were smaller than 400 μm accounted for 10% of all returned fines. It can be concluded that the thin fines removed to the sand control area were carried out of the stratum by the co-transfer of PAM, water and crude oil. The thin fines subsided in the aperture of the filled fines can result in the plugging of the sand control area.

2.3 XRD Analysis of the Fine Sample

Figures 5 and 6 are the XRD diagrams of the fine samples. The constituents of the fines were obtained by analyzing the diagrams (see Tab. 2).

Table 2 shows that the filled fines are only made up of quartz, potash feldspar and plagioclase, and the drainage fines in the sand control area are mainly made up of quartz, potash feldspar and plagioclase too, but calcspars, ankerite and clay were also found in the drainage fines. The total proportion of calcspars, ankerite and clay in drainage fines was 9%. The conclusion was drawn that fine migration in a polymer flooding region stratum has taken place. The amount of migrating fines was related to the adsorption of PAM (for the fines being the nucleus of flocculated PAM) and the mineral constituents of the stratum.

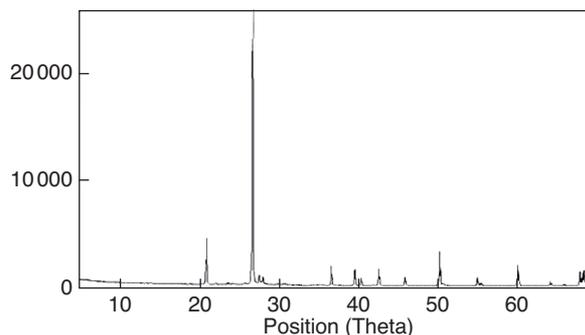


Figure 5

The XRD diagram of the filled fines.

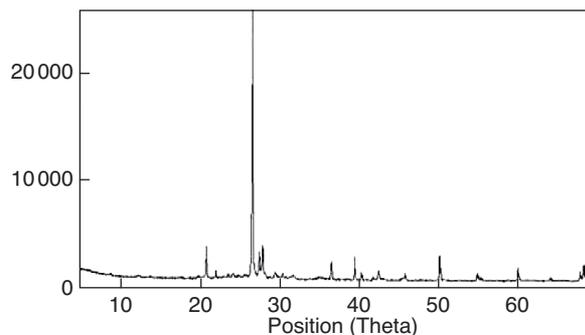


Figure 6

The XRD diagram of the drainage fines.

TABLE 2

Constituents of the filled and returned fines of polymer injection wells						
Constituents	Quartz (%)	Potash feldspar (%)	Plagioclase (%)	Calcspars (%)	Ankerite (%)	Clay (%)
Filled fines	82	9	9	-	-	-
Drainage fines	52	16	22	3	1	6

2.4 Microscopic Observation of the Fine Sample

The filled fines and drainage fines were dried in a vacuum drying chamber at 50°C, then were observed with a magnification of 100 and 400 times as Figures 7 and 8, and Figures 9 and 10 show, respectively.

Figure 7 shows the surface of the filled fines of the oil well's sand control area. It can be seen that the surface of the fines was clear, clean and there was nothing adsorbed on the smooth surface. Figure 8 shows the surface of the drainage fines from the oil well's sand control area in a polymer flooding region. It can be seen clearly that there was a mass of jelly-like and black things blocked between the surfaces of the fines. It is deduced that the adsorption substances may be PAM and some compounds from the crude oil.

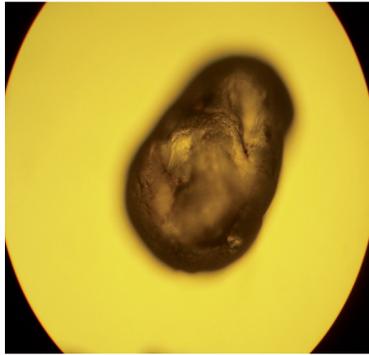


Figure 7
The surface of the filled fines ($\times 100$).

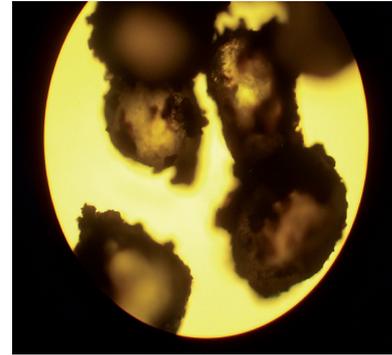


Figure 8
The surface of the drainage fines ($\times 100$).

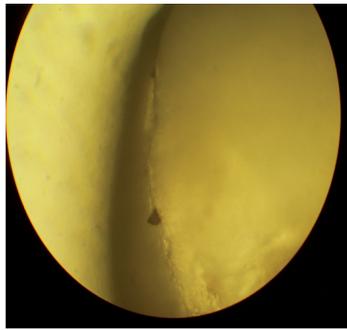


Figure 9
The surface of the filled fines ($\times 400$).

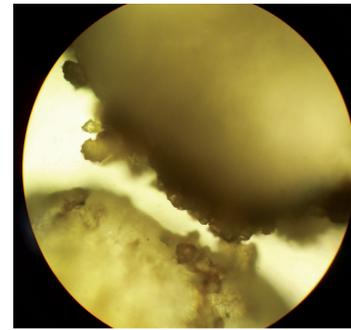


Figure 10
The surface of the drainage fines ($\times 400$).

Figures 9 and 10 show the surface of the initial filled fines and drainage fines after 120 days of polymer flooding (magnified by 400). It was revealed that there was jelly adsorbed on the surface of the drainage fines, and obviously the adsorption cannot be easily broken off. It was clearly shown that the hole between fines in the sand control area became smaller due to the surface adsorption of jelly, which leads to close contact of fines.

2.5 Constituents of the Adsorbed Substances

The substance adsorbed on the surface of the fines was separated and analyzed by an alumina chromatographic column, and the results are shown in Table 3.

There was PAM on the surface of the fines according to the former experiment and it was deduced from Table 3 that the remains in the alumina chromatographic column should be PAM. To confirm this conclusion, a blank experiment was carried out. 0.1 g PAM was isolated by an alumina chromatographic column, using the same solvent

TABLE 3
The constituents of the adsorption on the surface of the fines

Saturates (m%)	Aromatics (m%)	Resins (m%)	Asphaltenes (m%)	Remains (m%)
11.21	12.32	19.87	14.59	42.01

and with the same conditions as for the isolation of the crude oil. It was found that the polarity of PAM was strong so that it almost completely remained in the alumina chromatographic column. Therefore, it was ensured that the remains were mostly PAM by the experiment.

From the results in Table 3, it can be concluded that most of the adsorbed substances were PAM and some heavy compounds of crude oil such as resins and asphaltenes. The content of PAM is a large proportion, which accounts for 42.01%. The conclusion can be reached that the action between the PAM and fines was strong enough to cause the plugging of the sand control area.

2.6 Simulation Experiment of Plug Removal

At present, hydrogen peroxide is the most popular and effective plug removal agent. However, it has poor stability in the stratum conditions. It reacts with weaker reducers (ferrous ions, sulfured hydrogen, etc.) which result in the ineffective degradation of polymer and its derivatives. If it encounters acids, the oxygen would be released quickly and a fire or an explosion would perhaps be caused. Furthermore, the transportation of the H_2O_2 solution of concentrations larger than 10% is very difficult. In our experiment, two types of plug removal agents named potassium persulfate and sodium thiosulfate were prepared. For the temperature of the stratum of Gudao oil field (58°C), they were used to degrade the polymer. The two plug removal agents were added at different concentrations to PAM solutions (5 500 mg.dm⁻³), respectively. Then, their viscosity was measured with a capillary viscometer and the dropping rate of the viscosity of the PAM solution was calculated every 30 minutes. The effects of these two reagents were compared with that of H_2O_2 .

Table 4 shows that the dropping rate of the viscosity of the PAM solution was almost the same (both >90%) when the concentration of potassium persulfate and sodium thiosulfate was 2.5%. Table 5 shows that when the concentration of potassium persulfate was changed to 5% the dropping rate of the viscosity of the PAM solution was hardly changed and close to the H_2O_2 one. However, the dropping rate evidently declined when the concentration of sodium thiosulfate was changed to 5%. It can be explained from the mechanism of the reaction: the reaction between the potassium persulfate and sollicitation reagent was slow, and the release of the active constituent was slow, so it could efficiently degrade the PAM; while the reaction between the sodium thiosulfate and sollicitation reagent was faster than potassium persulfate, and this reaction was so acute that when the concentration of the plug removal agent was high, the active constituent was lost and could not be efficiently used to degrade the PAM.

TABLE 4

The dropping rate of the viscosity of the PAM solution

Plug removing agent	30 min/%	60 min/%	90 min/%
H_2O_2	90.95	94.23	94.78
Potassium persulfate	90.40	90.74	91.11
Sodium thiosulfate	90.37	90.58	90.63

Concentration of plug removal agent: 2.5%, concentration of PAM: 5 500 mg.dm⁻³, concentration of sollicitation reagent (a weak organic acid): 0.5%.

TABLE 5

The dropping rate of the viscosity of the PAM solution

Plug removing agent	30 min/%	60 min/%	90 min/%
H_2O_2	90.25	91.42	93.01
Potassium persulfate	91.04	92.03	92.61
Sodium thiosulfate	84.77	86.17	88.36

Concentration of plug removal agent: 5.0%, concentration of PAM: 5 500 mg.dm⁻³, concentration of sollicitation reagent: 0.5%.

TABLE 6

The dissolving ability of the plug removing agent for the PAM jelly

Plug removing agent	Concentration		
	5%	10%	15%
H_2O_2	2.5	2.0	2.0
Potassium persulfate	4.0	3.5	3.0
Sodium thiosulfate	3.0	2.0	2.0

In the stratum, the concentration of the polymer solution was high, and even in the form of jelly. To simulate the conditions in the stratum, polymer jelly was used in the test. 1.5 g polymer jelly (molecular weight of 15 million) was dissolved in 20 cm³ plug removal agent at different concentrations, and then was placed separately in a magnetic stirrer at a constant temperature of 58°C. The dissolving time can be seen in Table 6.

It is revealed that the polymer jelly can be dissolved within 4 hours. The effect on polymer jelly of sodium thiosulfate is better than that of potassium persulfate, and the effect of sodium thiosulfate is similar to that of H_2O_2 . For our laboratory research work the molecular weight of the polymer jelly was 15 million and the content of PAM was 25%. However, in the stratum, the molecular weight of the polymer jelly causing the plug was about 15 million and the content of PAM was about 5%. It is obvious that the content of PAM used in our laboratory work was much higher than that of the plugging area in the stratum. It was concluded that the plug removal agents could dissolve the plugging jelly in the sand control area effectively.

GD6 in Gudao oilfield is an unconsolidated sandstone reservoir, which is characterized by loose sand and cementation and polishing. The core flooding and sand control simulation test was carried out with the equipment presented in Figure 1. The driving fluid was a mixture of Gudao crude oil and 2 000 ug/g PAM solution and the ratio of oil and PAM solution is 1:2. During the experiment, the driving fluid and the flow of driving fluid was constant. The relationship between the injection pressure and flooding volume can be seen in Figure 11. While injecting

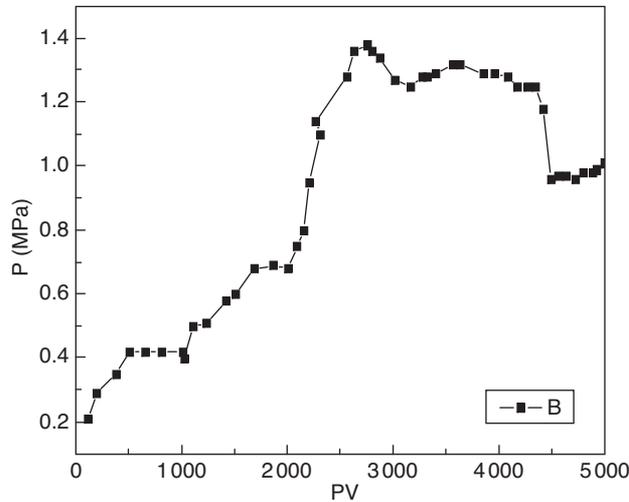


Figure 11
Relationship between the injection pressure and flooding volume.

the mixture of Gudao crude oil and PAM solution, the injection pressure was increased gradually for the migratory fines and plugging of the sand control area. The injection pressure reached about 1.25 MPa when the flooding PV was 2 600, and then fluctuated around this pressure even as the flooding PV increased. This is because the plugging was formed stably, and under the specific flow of the driving fluid the pressure of the injection region kept stable. When the flooding PV was 4 300, the injection of the mixture was stopped and the plug removal agent of sodium thiosulfate and potassium persulfate mixture with a ratio of 1:1 was injected. The

TABLE 7
Changes in core permeability and injection pressure in plug removal process

Permeability (D)	Original permeability	Permeability at 2 600 PV	Permeability after plug removal
	1.06	0.45	0.83
Pressure (MPa)	Original pressure	Pressure at 2 600 PV	Pressure after plug removal
	0.21	1.39	0.95

plug removal agent was preserved in the simulated core and sand control area for 12 hours. Then, when the flooding test was carried out again, which meant we kept the same driving fluid and the same flow, the injecting pressure dropped to about 1.0 MPa, and the ascending trend of the pressure was very faint as the flooding PV rose. The result showed that the selected plug removal agent worked, making the pressure decrease effectively.

From Table 7 it can be inferred that the core permeability was high and injection pressure was low at first. When the flooding volume reached 2 600 PV, the core permeability decreased to 0.45 D, while injection pressure increased to 1.39 MPa. After application of the plug removal agent, core permeability was restored to 0.83 D and injection pressure was restored to 0.95 MPa. By comparing the core permeability and injection pressure before and after injecting the plug removal agent, it could be concluded that potassium persulfate and sodium thiosulfate could degrade plugging substances effectively.

TABLE 8
Situation in field application tests

Number	Well number	Layer	Thickness (m)	Situation of construction			Production before construction (t/d)		Production after construction (t/d)	
				Removing reagent (t)	Pressure (MPa)	Displacement (l/min)	Liquid	Oil	Liquid	Oil
1	GO2-21-263	NgS ⁵⁵	8.8	20	16.5	300	20.8	0.7	97.5	2.0
2	GO6-33-2435	NgS ⁵⁴	8.6	20	16.1	650	48.3	3.9	83.5	11.8
3	CB11A-6	NgS ⁵	16.5	30	17.0	280	93.6	10.5	18	20.6
4	CB22C-2	Ng ³⁵	23.9	40	18.5	220	24.2	5.6	41	10
5	GO6-33-2543	NgS ⁵⁴	18.7	30	17.7	320	25.3	0.1	72.9	4.0
6	GO6-36-455	NgS ⁵⁴	6.7	20	16.7	300	26.7	3.5	58.9	6.4
7	GO2-17-63	NgS ⁵⁴	13.3	30	17.3	720	33.3	4.0	99.7	11.8
8	GO2-17-47	NgS ⁴⁴	9.4	20	18.6	300	15.9	4.9	64.6	7.9

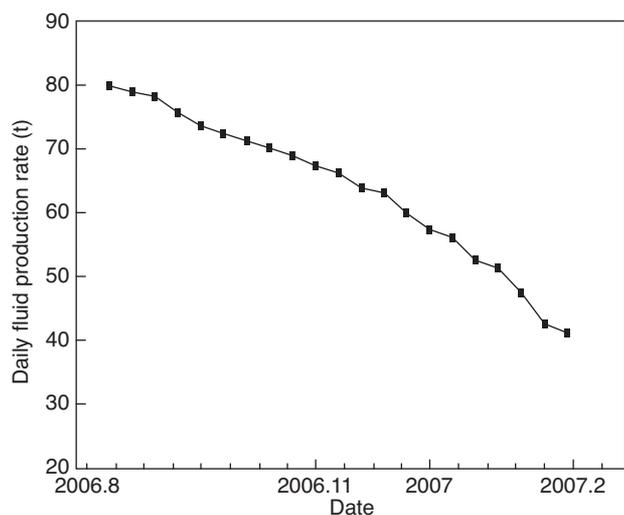


Figure 12

Production parameters of oil well G06-33-2435.

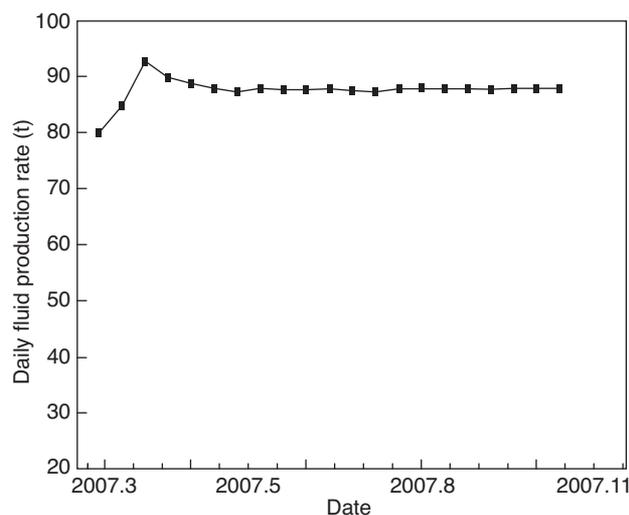


Figure 13

Liquid production after plug removal.

2.7 Field Application Tests and Results

Field application tests have been carried out in 8 different oil wells in Gudao oil field since February 2007, and achieved great success. The injection pressures of the 8 oil wells have decreased by 4 MPa on average and the liquid production per day has increased by 10 percent compared with the performance before plug removal. The results indicate that the plug removal agents can remove plugging effectively: the specific data are shown in Table 8 and the production parameters of the specific G06-33-2435 oil well are shown in Figure 12.

Figure 12 shows the trend of liquid production per day from August 2006 to February 2007. Liquid production decreased from 80 t/d to 40 t/d. By analyzing exit samples, we saw that the concentration of PAM was 136 mg/L, which was relatively high. It was concluded that the reason for plugging was the adsorption and deposition of polymer (PAM) in the sand control area. Then, plug removal was carried out according to the experimental simulation of the plug removing program. In the process, the solutions of plug removal agents were injected twice with a 20 m³ volume each time. Then, the well was closed for 24 hours. After the plug removing process, the injection pressure decreased by 4.5 MPa and liquid production increased from 48.3 t/d to 83.5 t/d, as indicated in Figure 13. The field application tests confirmed that potassium persulfate and sodium thiosulfate could degrade plugging substances and remove plugging effectively.

CONCLUSION

- In a polymer flooding region of Gudao oil field, the main reason for the plugging of the oil well sand control area was the adsorption, gathering and bridging of PAM on the surface of the sand. The migration of the mineral fines from the stratum and the adsorption of the crude oil ingredients on the surface of the fines also result in plugging;
- The plug removal agents potassium persulfate and sodium thiosulfate degraded the plugging substances and recovered the core permeability effectively. Field application tests were conducted in Gudao oil field and they showed that the injection pressure decreased and that the daily liquid production increased greatly after application of the plug removal agents in the sand control area.

ACKNOWLEDGMENTS

This project was supported by a “China Postdoctoral Science Foundation” funded project (20100480420) and “the Fundamental Research Funds for the Central Universities”.

REFERENCES

- 1 Tian Jing, Luan Qingyi (1994) The Degradation and Removal of the Plug after the Injection of the Polymer, *Foreign Oil Field Engineering* **10**, 1, 6-7.
- 2 Zhang Shaodong (2005) *The Research on the Polymer Flood Technology in Gudao Oil Field*, 2nd edition, China Petrochemical Press, Beijing, p. 118.

- 3 Yan Yong (2006) *Research on Techniques of Polymer Injection Wells Integration Plug Removal [D]*, Daqing Petroleum Institute, Hei Longjiang.
- 4 Chen Tielong *et al.* (1998) A Pilot Test of Polymer Flooding in an Elevated Reservoir, *SPE Reserv. Eval. Eng.* 2.
- 5 D'Muhala T.F. (1987) Barium Sulfate Removal and Antideposition Compositions and Process of Use Therefore, US 4 708 805, 8, 38-43.
- 6 Bondor P.L., Hirasaki G.J., Tham M.J. (1972) Mathematical Simulation of Polymer Flooding in Complex Reservoir, *SPE J.*, October, 369-382.
- 7 Healy R.N., Reed R.L. (1977) *Improved Oil Recovery by Surfactant and Polymer Flooding*, Shah D.O., Schechter R.S. Academic Press, N.Y. (eds), 6, 9-15.
- 8 Maitin B., Dabol B., Sohn W.O. (1988) Numerical Simulation for Polymer and Evaluation of Polymer Flood Process: A Field Performance Analysis, *SPE J.* 17631.
- 9 Lenn C., Fikri J. *et al.* (1998) Horizontal well performance evaluation and fluid entry mechanisms, *SPE J.* 49089.
- 10 Theron B.E., Unwin T., Schlumberger Cambridge Research, *et al.* (1996) Stratified Flow Model and Interpretation in Horizontal Wells, *SPE J.* 36560.
- 11 Weihong Meng, Xuanzheng T. Chen, *et al.* (1999) Experimental study of low liquid loading gas. Liquid Flow in Near Horizontal Pipes, *SPE J.* 56466.

*Final manuscript received in March 2011
Published online in May 2012*

Copyright © 2012 IFP Energies nouvelles

Permission to make digital or hard copies of part or all of this work for personal or classroom use is granted without fee provided that copies are not made or distributed for profit or commercial advantage and that copies bear this notice and the full citation on the first page. Copyrights for components of this work owned by others than IFP Energies nouvelles must be honored. Abstracting with credit is permitted. To copy otherwise, to republish, to post on servers, or to redistribute to lists, requires prior specific permission and/or a fee: Request permission from Information Mission, IFP Energies nouvelles, fax. +33 1 47 52 70 96, or revueogst@ifpen.fr.