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Challenges and New Approaches in EOR

Défis et nouvelles approches en EOR

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Dossier

Challenges and New Approaches in EOR
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Injecting Large Volumes of Preformed Particle Gel for Water Conformance Control

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Résumé — Injection d'importants volumes de gel de type GPP (gel à particules préformées) pour le contrôle du balayage en injection d'eau dans les réservoirs matures — Le présent article décrit les traitements à base de gel à particules préformées (GPP) pour la dérivation de fluide en profondeur dans quatre puits d'injection situés dans la partie nord du gisement de Lamandian, dans le champs pétrolifère de Daqing en Chine ; il s'agit d'un gisement de grès présentant des couches productrices épaisses et hétérogènes. Quarante-six producteurs ont été raccordés aux quatre injecteurs traités avec une proportion d'eau moyenne de 95,4 % avant les traitements à base de GPP. Un important volume (plus de 1 000 m^3) de suspension de GPP présentant des concentrations de 1 900 à 2 500 mg/L et des tailles de particule de 0,06 à 3,0 mm a été injecté dans chaque puits, chaque injection durant environ quatre mois. Les volumes d'injection de suspension de GPP vont de 11 458 à 17 625 m^3 par puits pour un total de 56 269 m^3 (295 680 lb, soit environ 134 118 kg, de matière sèche de GPP) pour les quatre puits, ce qui indique l'existence de zones à haute perméabilité (K) ou de fractures dans la formation. Lors de l'injection de GPP, des données en temps réel, y compris la pression d'injection, le taux d'injection et les tailles de particule, ont été contrôlées pour ajuster notre méthode de traitement aux conditions de ce réservoir mature. Cet article présente des informations détaillées sur les traitements des quatre puits, y compris les critères de sélection des puits, la méthode de traitement, les résultats du contrôle en temps réel lors de l'injection de GPP et les résultats des traitements.

Abstract* — *Injecting Large Volumes of Preformed Particle Gel for Water Conformance Control — *This paper describes Preformed Particle Gel (PPG) treatments for in-depth fluid diversion in four injection wells located in the northern section of the Lamadian reservoir, Daqing oilfield, China, which is a sandstone reservoir with thick heterogeneous pay zones. Forty-six producers were connected to the four treated injectors with an average water cut of 95.4% before PPG treatments. A large volume (more than 1 000 m^3) of PPG suspension with concentrations of 1 900-2 500 mg/L and particle sizes of 0.06-3.0 mm was injected into each well, each injection spanning approximately four months. The injection PPG suspension volumes range from 11 458 to 17 625 m^3 per well with a total of 56 269 m^3 (295 680 lb of dried PPG) for the four wells, which indicated the existence of super-K zones or fractures in the formation. During PPG injection, real-time data, including injection pressure, injection rate and particle sizes, were monitored to tune our treatment design and to analyze the practical status of the mature reservoir. This paper reports detailed information for the four well treatments, including well candidate selection criteria, treatment design, real-time monitoring results during PPG injection and treatment results.*

INTRODUCTION

Excess water production has increasingly become a major problem for oilfield operators as more reservoirs mature due to long-term water flooding. Higher levels of water production intensify corrosion and scale, the load on fluid-handling facilities and environmental concerns, eventually leading to premature well abandonment. Consequently, producing zones are often abandoned in an attempt to avoid water contact, even when the formation maintains large volumes of remaining hydrocarbons. Controlling water production has become more and more important to the oil industry.

Reservoir heterogeneity is one of the most important reasons for low oil recovery and early excess water production. Most oilfields in China are found in continental sedimentary basins; their conditions are geologically complex, especially with high permeability contrast. To maintain reservoir pressure and meet the nation's energy consumption requirements, these reservoirs were developed using water flooding after undergoing a few years of primary recovery. Many of them have been hydraulically fractured, intentionally or unintentionally, or have been channeled due to mineral dissolution and production during water flooding (Liu *et al*., 2010).

Gel treatment is a cost-effective method to improve sweep efficiency in reservoirs and to reduce excess water production during oil and gas production. Gel treatment can be used in both near-wellbore and far-wellbore conditions (Sydansk and Romero-Zeron, 2011). A gelant, an aqueous solution of polymer and crosslinker, is often injected into the near wellbore and forms into a gel at reservoir temperature, thereby partially or fully blocking the high-permeability watered-out zone, which is separated from the low-permeability oil zones by an impermeable barrier (Zitha and Darwish, 1999). Far-wellbore problems include viscous fingering, reservoir strata with crossflow and channeling (Sydansk and Romero-Zeron, 2011). These problems must be solved by injecting a large volume of gels or a slug of gels deep into a reservoir in a process called in-depth fluid diversion (Seright, 2004; Frampton *et al*., 2004; Sydansk and Seright, 2007; Cheung *et al*., 2007; Rousseau *et al*., 2005; Bai *et al*., 2007a). In-depth diversion gels penetrate deep into high-permeability zones or fractures and seal or partially seal them off, thus creating high flow resistance in former, watered-out, high-permeability portions of the zones. Thus, these gel systems divert a portion of the injection water into areas not previously swept by water.

A new trend in gel treatments is applying preformed gels for which the gels are formed at surface facilities before injection and no gelation occurs in reservoirs. This application overcomes some of the drawbacks inherent *in situ* gelation, such as poor gelation time control, uncertainty of gelling due to shear degradation and gelant composition change due to chromatographic fractionation of and dilution by formation water. Preformed gels include preformed or partially preformed bulk gels (Seright, 2004; Sydansk and Seright, 2007), as well as particulate gels, including:

- millimeter-sized preformed particle gels – PPG (Li *et al*., 1999; Coste *et al*., 2000; Bai *et al*., 2007a, 2007b);
- microgels (Chauveteau, 2001 ; Chauveteau *et al*., 2003; Rousseau *et al*., 2005; Zaitoun *et al*., 2007; Pritchett *et al*., 2003; Frampton *et al*., 2004).

Based on their responsiveness to the environment, particulate gels can also be classified as:

- temperature-sensitive particles, such as the submicro-sized particle gel reported by Pritchett *et al*. (2003) and Frampton *et al*. (2004);
- pH-sensitive particle gels as studied by Al-Anazi and Sharma (2002) and Huh *et al*. (2005).

The major differences between these particulate gels are their sizes and swelling times.

PPG and microgels have been applied economically to reduce water production in mature oilfields. Microgel was applied to 10 gas storage wells to reduce water production (Zaitoun *et al*., 2007). BP and Chevron used submicro-sized particle gel for more than 10 well treatments (Cheung *et al*., 2007). Millimeter-sized polymer grain PPG were applied in approximately 2 000 wells in China to reduce fluid channels in water floods and polymer floods (Liu *et al*., 2010). One advantage of PPG treatments is that the PPG sizes and strengths can be adjusted during particle injection according to the monitored injection pressure; thus, the right size and strength of particles that best fit the practical mature reservoir can be injected. The objective of this paper is to explain how to properly design a large-volume PPG treatment and how to operate a successful treatment process through monitored data by describing four well treatments in an oilfield. We report the reservoir and fluid properties, criteria for selecting well candidates, particle gel evaluation methods, injection volume and particle concentration design, field execution and reservoir and performance response to the treatments.

1 RESERVOIR CHARACTERIZATION

The pilot project was conducted in one block of the Lamadian reservoir in the Daqing oilfield in China. Lamadian is an asymmetrical, short-axial, anticlinal oilfield with three major intervals, the Gaotaizi (G), Putaohua (P) and Saertu (S), from top to bottom. The reservoir rocks are middle Early Cretaceous lacustrine and fluvio-deltaic sandstone and siltstone with muddy rock intercalated. The reservoir temperature is about 45°C and its formation water salinity is approximately 4 000 mg/L. The oil-bearing area of the selected pilot is 2.43 km^2 with an initial oil-in-place of 594×10^4 t. The major production zones are PI_4 to GI_{4+5} (note: the subscripts refer to layers and each individual zone is thick and very heterogeneous). Large-volume PPG treatments were conducted from 2003 through 2004 and the target zone was PII. Before the gel treatment, the block had been produced for more than 30 years and had an average water cut of above 95.4%.

2 CRITERIA FOR WELL CANDIDATE SELECTION

The well for the PPG treatment was selected based on a comprehensive understanding of the reservoir geology, wellbore and near-wellbore conditions, reservoir surveillance results and reservoir static and dynamic data. More specifically, the following well selection criteria were used for treatments with large volumes of PPG:

– the injection well must be located in the main sand body of the fluvial depositional reservoir and its pay zones should be thick and have good connectivity with adjacent producers;
– the well must have sufficiently high injectivity, a lower than average water injection pressure and a lower than average starting pressure in the block. Such features reveal a high probability of the presence of fractures or fracture-like channels/streaks;
– the well group connected with the well candidate should have a higher average water cut compared with other well groups;
– vertical or areal heterogeneity should be very severe, the inner-layer permeability contrast should be large and both the injection profile and the production profiles of connected production wells should be extremely heterogeneous;
– the degree of water-flooded regions should be different, with middle, low and non-flushed zones.

Four injection wells, 7-1827, 7-1937, 8-1827 and 9-1827, were selected based on the above criteria and our comprehensive geological and engineering understanding of the block. Figure 1 shows the location of the selected wells. The distance of each injection well and its connected edge producer is 300 m. Forty-six production wells were connected to the four treated wells. Twenty-three of them were only produced from PII and the other 23 were commingled production from the interval PII and other intervals. Table 1 provides the basic parameters for the four selected wells. In the table, the maximum permeability refers to the permeability of the most permeable portion of the specified interval from well logging. The starting

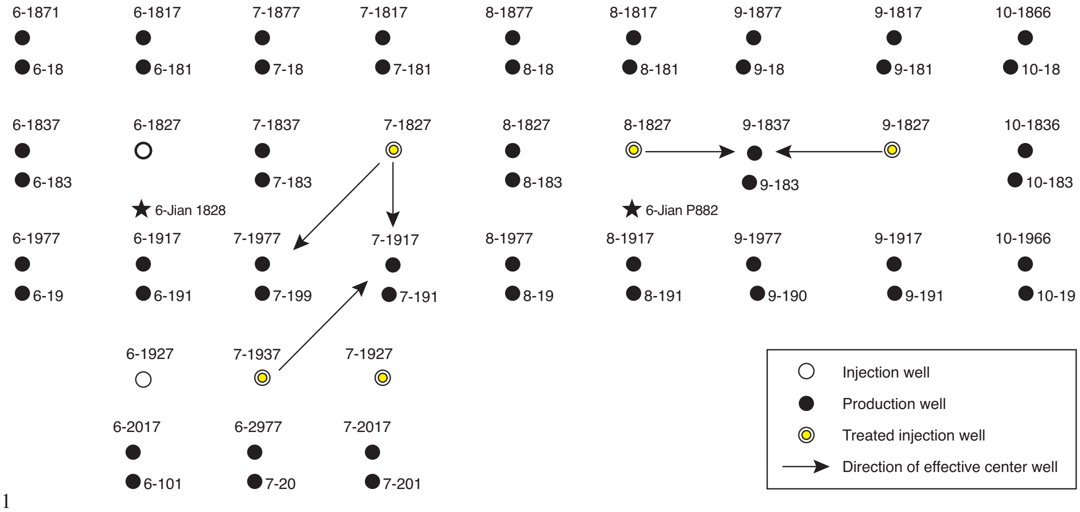

Figure 1

Well location map for the PPG treatment pilot.

TABLE 1

Parameters of the four treated wells before PPG injection

Well name	Objective zones	Gross thickness ss (m)	Net pay thickness (m)	K_{max} (μm^2)	Starting pressure (MPa)	Injection pressure (MPa)	Injection rate (m^3)	Main water-absorbing zones		PI (90) (MPa)
								Thickness (%)	Absorbed water (%)	
8-1827	PII 4-7	7.6	7.4	0.28	6.0	11.2	79	27.78	78.21	10.31
	PII 7-9	1.6	1.6	0.22	5.7	11.2	43	46.00	79.51	10.31
9-1827	PII 1-6	8.0	7.5	0.24	8.5	10.7	63	45.45	74.07	11.58
7-1827	PII 1-6	7.4	6.7	0.50	4.5	10.0	58	14.49	81.97	10.80
	PII 5-9	5.2	4.3	0.36	5.0	10.0	60	17.78	89.29	10.80
7-1937	PII 1-9u	10.8	10.5	0.46	1.0	11.5	56	28.57	56.96	6.95
	PII 1-9d				1.5	11.5	47			6.95

pressure refers to the minimum wellhead pressure at which water starts to enter the formation. That is, water cannot enter the formation if the injection pressure is less than the starting pressure. The starting pressure is usually a result of the capillary pressure and the non-Newtonian fluid behavior of crude oil in low-permeability zones. The pressure index, DPI, comes from the pressure drawdown test for a period of 90 minutes after an injection well is shut down. The DPI (90) is calculated from the following equation:

$$\text{DPI}\ (t) = \frac{\int_0^T P(t)dt}{T} \tag{1}$$

with DPI (t), pressure index (MPa), $P(t)$, pressure at time t after a well is shut (MPa); T, shut-in time (min); usually T is set as 90 minutes.

3 PPG CHARACTERIZATION AND SELECTION

Preformed Particle Gels (PPG) is an improved Superabsorbent Polymer (SAP). SAP are a unique group of materials that can absorb over 100 times their weight in liquids and do not easily release the absorbed fluids even under pressure. Superabsorbent polymers are used primarily as an absorbent for water and aqueous solutions for diapers, adult incontinence products, feminine hygiene products and for applications in the agriculture industry. A series of new SAP called preformed particle gels (PPG) have been developed for conformance control purposes (Li *et al*., 2010; Bai *et al*., 2007a, 2007b). Compared with commercial SAP, PPG have a better controllable-swelling rate, exhibit more thermo-stability at high reservoir temperatures and are much less expensive. PPG properties are summarized as follows:

- sizes are adjustable: μm-cm;
- swelling ratio in formation water: 10 ~ 200 times original;
- salt resistance: all kinds of formation salts and concentrations are acceptable.

More importantly, the PPG properties can be tailored to the salinity and pH conditions of any specific reservoir:

- thermal stability: more than 1 year below 110°C;
- strength: adjustable, high-strength product available;
- swelling rate: slightly controlled.

3.1 Advantage of PPG Treatment Over Traditional *in situ* Gel Treatment

Particle gels have great potential for conformance control due to their unique advantages over traditional *in situ* gels, including:

PPGs are synthesized prior to formation contact, thus overcoming distinct drawbacks inherent *in situ* gelation systems, such as uncontrolled gelation times and variations in gelation due to shear degradation and gelant compositional changes induced by contact with reservoir minerals and fluids.

A PPG has only one component during injection. Thus, it does not require many of the injection facilities and instruments that are often required to dissolve and mix the polymer and crosslinker for conventional *in situ* gels. The simple injection operation processes and surface facilities can reduce operation and labor costs, which is especially important when an injection will continue for a few months.

3.2 PPG Selection

The selection of a PPG primarily considers its compatibility with the produced water, thermo-stability at the reservoir temperature, swelling ratio, strength after being swollen in injection water and particle size (Bai, 2001; Liu, 2010). Six samples were evaluated to find the best PPG candidate for the pilot. The results showed that all PPGs had good compatibility with the produced water from the pilot and they were thermally stable at the reservoir temperature for more than 2 years, as evaluated before treatment. Table 2 shows the evaluation results for PPG particle size, swelling ratio, pressure resistance and breakthrough pressure. All PPG dispersions were prepared using the produced water from the pilot area. PPG sizes were sieved by screens with appropriate mesh sizes. The swelling ratio is the mass ratio of the PPG before and after swelling. The pressure resistance is the minimum pressure required to push swollen particles through orifices with a diameter of 0.3 mm. The breakthrough pressure is the minimum pressure required to allow water to flow through a core after PPG is placed in the core. The minimum pressures in Table 2 were measured using the cores with permeabilities of 3-3.5 μm^2, which were injected using 1 000 mg/L of 250 mesh (61 μm) PPG particles. The weight (WT) product was selected for the pilot because it had a relatively high swelling ratio and sufficient strength.

TABLE 2

Evaluation results for six PPG samples

No.	PPG product name	Particle size (mm)	Swelling ratio		Pressure resistance (MPa)	Breakthrough pressure (MPa/m)
			Initial (T = 10 min)	Final (T = 1 day)		
1	GS	3-5	5	117	Very weak	4.1
2	GS	2-3	15	153		
3	WT	3-5	10	83	1.2	10.7
4	WT	2-3	22	90	0.8	
5	SAP	3-5	3	17	2.3	17.9
6	SAP	2-3	5	31	1.9	

4 PPG TREATMENT DESIGN

4.1 PPG Suspension Volume Determination

A reservoir simulation was run to optimize the PPG dispersion volume in terms of the effectiveness of the diversion and

TABLE 3

Designed injection parameters for four well PPG treatments

Well name	Water injection before treatment (m^3/d)	Injection rate (m^3/d)	PPG weight (kg)	Particle size (mm)	PPG suspension volume (m^3)	Concentration (mg/L)	Maximum pressure limitation (MPa)
7-1937	116	130	32 000	0.06 - 2.00	13 445	2 000-3 000	12.5
7-1827	108	128	41 000	0.06 - 2.00	17 135	2 000-3 000	13.0
8-1827	121	133	32 000	0.06 - 0.90	13 214	2 000-3 000	14.0
9-1827	83	138	21 000	0.06 - 0.90	8 536	2 000-3 000	14.0

predicted profit-to-investment ratio. For the simulation, we assumed that the PPG only entered the fully water-flooded areas with only residual oil rather than the low-flushed and non-swept areas. After the PPG was placed, we assumed that the permeability of the areas where the PPG entered was equal to that of the low-permeability areas. This assumption was based on our previous experimental results in high-permeability sandpacks, from which we found that particle gels can reduce the permeability of different permeable rocks to the same level (Bai, 1997).

4.2 PPG Concentration

The designed concentration was based on previous successful field experience and laboratory core-flooding testing results. Field applications and our lab core-flooding results demonstrated that injecting a large volume of low-concentration PPG is the key for the widely successful application of PPG treatments in China. Before 1999, when large-volume low-concentration PPG treatments were first implemented in the Zhongyuan oilfield (Bai *et al.*, 2007), small volumes (less than 500 m^3) of high-concentration PPG had been injected in a number of wells but most of them failed. Two possible reasons exist for these failures, the first of which can be explained by our extensive core-flooding test results. Our lab results showed that the injection pressure of high-concentration PPG was much higher than that of low-concentration PPG and low-concentration PPG was much easier to propagate through porous media. Therefore, low-concentration particle injection will allow particles to move easily into the depths of a reservoir but high-concentration PPG injection usually constrains particles around the near-wellbore region (Bai *et al.*, 2007). The second reason for the failures can be explained by the monitored injection pressure during high-concentration PPG treatments in the fields. It was found that the wellhead injection pressure vibrated very vigorously if high-concentration PPG was injected; in addition, the water injection pressure after treatments often did not increase but sometimes even decreased. The unexpected reduction or no change in injection pressure after treatment could result from the new hydraulic fractures induced by the vigorously vibrating bottom-hole pressure during PPG injection. Since 1999, almost all PPG treatments in China have used the PPG suspension with concentrations below 5 000 mg/L.

The average PPG concentration was designed to be in the range of 2 000-3 000 mg/L with an average of 2 500 mg/L. To transport PPG as deeply as possible away from the wellbore, the sizes of the injected PPG particles began with the smallest value (60 μm) and were thereafter adjusted according to the observed injection pressure. For example, larger particles were used if the injection pressure did not increase as expected during PPG injection. The best way to minimize PPG damage on low-permeable oil zones is to keep the PPG injection pressure the same as or smaller than the water injection pressure; however, the flow rate will be too low to be practical in terms of injection time and working load, so we designed the PPG injection rate to be the same as the previous water injection rate. The density of swollen PPG particles is higher than that of the formation water used to prepare the PPG suspension; therefore, the PPG could not suspend in the formation water very well. We made a design using 200 mg/L polymer to carry the PPG particles. The pilot site was near a polymer flooding area, making it easy to obtain the polymer solution. Table 3 shows the optimized PPG dispersion volume, PPG weight and other designed injection parameters for each treated well.

5 PILOT EXECUTION

A total volume of 56 269 m^3 PPG suspension, which was prepared from a total of 132 tons of dry PPG, was injected into the four wells. Compared with our designed PPG amount, 6 more tons of PPG were injected, with an additional suspension volume of 3 939 m^3. Table 4 shows the actual injection parameters and compares them with the designed ones. The PPG amount was increased for wells 7-1937 and 7-1827 because the PPG injection pressure did not increase as expected, which indicated that we might underestimate the size of any fractures or channels in the well. The injected PPG suspension volume for well 9-1827 increased by approximately 2 922 m^3 because the well was difficult to inject if using the designed concentration of 2 000-3 000 mg/L; thus, a reduced PPG concentration (1 920 mg/L) was used to prevent the PPG injection pressure from becoming too high, which would fracture the reservoir.

Wells 7-1937 and 7-1827 both began to have PPG injected on September 5, 2003; this process was completed on January 10 and January 31 for each well, respectively. Both 8-1827 and 9-1827 started on September 26, 2003 and completed on Febrary 3, 2004. Figures 2-5 show the monitored injection pressure for the four treatments separately. Each figure also includes the dry PPG weight, particle size, PPG suspension volume, slug numbers and swollen PPG volume for each slug. The swollen particle volume refers to the total particle volume after swelling, which is calculated using a swelling ratio of 70 and a dry PPG density of 1.8 g/cm^3. If the injection pressure does not reach the target pressure, we can adjust the particle concentration, size, strength or brine salinity to increase or decrease the injection pressure. In our pilot study, we reduced either the particle size or particle concentration if the injection pressure was lower than our target pressure or vice versa. For all four treatments, the particle sizes in the latter slugs are larger than those in the preceding slugs because the injection pressure did not increase as much as we had expected. As shown in each figure, the injection pressure did not increase very quickly or to a very high degree even though the injected particle sizes were increased up to 0.9 mm (8-1827 and 9-1827) or 3 mm (7-1937 and 7-1827). Therefore, no injectivity decline was observed for any of the treatments even though no information showed that these wells had fractures before the treatment. In addition, we wondered if there were super-K channels that directly connected the injection wells and producers, so we checked the fluid production from adjacent producers during PPG injection and did not observe any particles produced.

TABLE 4

Comparison of designed and practical injection parameters

Well name	Practical injection			Difference from designed parameters	
	Dry PPG weight (t)	PPG suspension volume (t)	PPG concentration (mg/L)	Dry PPG weight (t)	PPG suspension volume (m^3)
7-1937	35	13528	2587	3	83
7-1827	43	17625	2440	2	490
8-1827	32	13658	2343	0	444
9-1827	22	11458	1920	1	2922
	132	56269	2346	6	3939

	1st slug	2nd slug	3rd slug	4th slug	Total
Particle size (mm)	0.16-0.45	0.45-0.90	0.90-2.0	2.0-3.0	0.16-3.0
Dry particle weight (kg)	6 000	25 350	11 300	350	43 000
Swollen particle volume (m^3)	233	986	439	31	1 689
PPG suspension volume (m^3)	2 261	10 162	3 678	1524	17 625

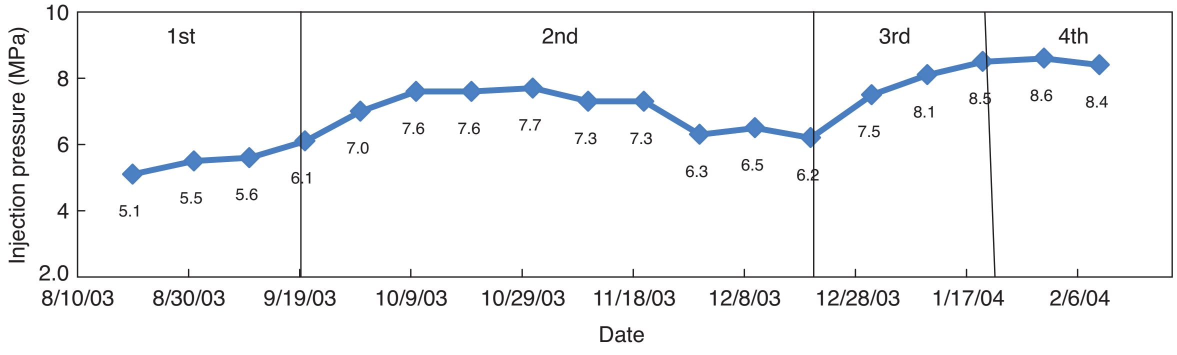

Figure 2

PPG injection pressure curve for well 7-1827.

	1st slug	2nd slug	3rd slug	4th slug	5th slug	Total
Particle size (mm)	0.06-0.16	0.16-0.45	0.45-0.90	0.90-2.0	2.0-3.0	0.06-3.0
Dry particle weight (kg)	2 312	2 925	16 252	7 473	6 038	35 000
Swollen particle volume (m^3)	90	114	632	291	235	1 362
PPG suspension volume (m^3)	909	1 420	6 877	2 381	1 941	13 528

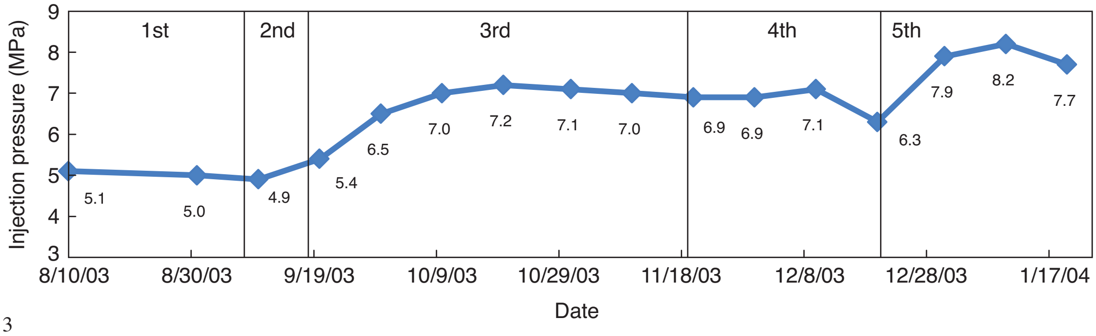

Figure 3

PPG injection pressure curve for well 7-1937.

	1st slug	2nd slug	3rd slug	Total
Particle size (mm)	0.06-0.16	0.16-0.45	0.45-0.90	0.06-0.90
Dry particle weight (kg)	19 450	7 850	6 700	34 000
Swollen particle volume (m^3)	756	305	261	1 322
PPG suspension volume (m^3)	9 447	2 434	1 777	13 528

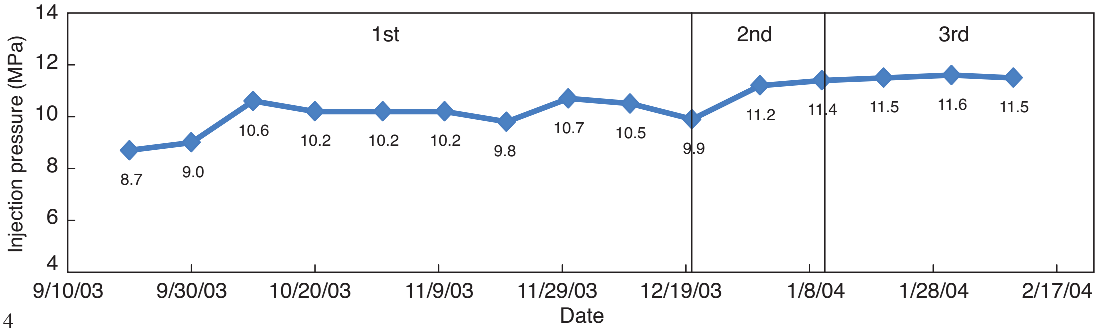

Figure 4

PPG injection pressure curve for well 8-1827.

	1st slug	2nd slug	3rd slug	Total
Particle size (mm)	0.06-0.16	0.16-0.45	0.45-0.90	0.06-0.90
Dry particle weight (kg)	10 290	5 710	6 000	22 000
Swollen particle volume (m^3)	400	222	233	855
PPG suspension volume (m^3)	7 586	1 977	1 895	11 458

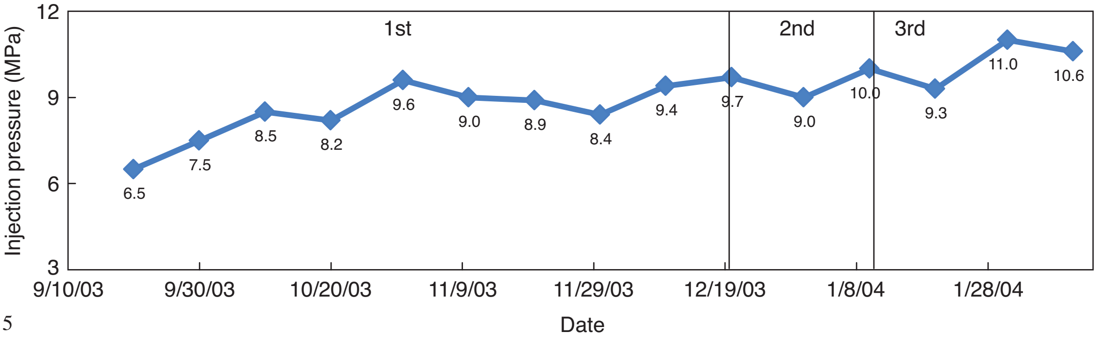

Figure 5

PPG injection pressure curve for well 9-1827.

6 PROJECT RESULTS

6.1 Reservoir Performance after PPG Injection

Two methods were used to evaluate the reservoir performance after the PPG treatment. The first method involved measuring the injection profile, which indicates the plugging effect of PPG on different zones near the wellbore. The other method involved conducting well testing, including the starting pressure, the injection pressure at the same injection flow rate as that before treatment and a pressure drawdown test for the pressure index DPI (90). These well-testing parameters reflect the PPG plugging quite far from the wellbore. The pressure gauge was set at the depth of 500 m below the wellhead when the drawdown pressure was measured.

Well test results. The pressure drawdown test was performed after the PPG treatment. Figures 6-9 show the pressure drawdown test curves before and after treatments for each well. Table 5 compares DPI (90)s and injection pressures before and after treatments. DPI (90)s and injection pressures increased significantly for each well.

Water injection profiles. The water injection profiles were also measured for each well after PPG treatments.

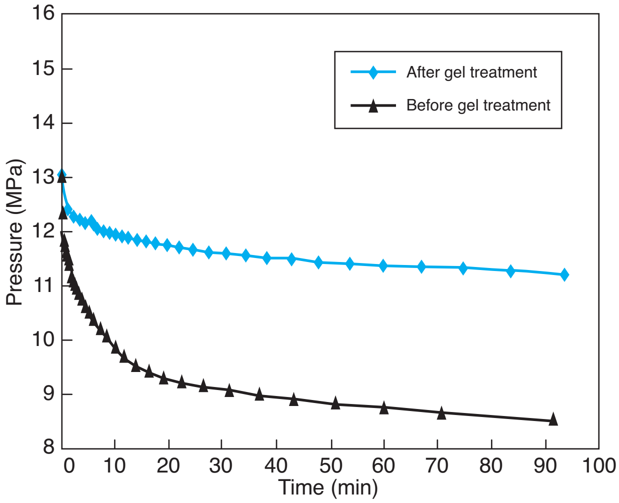

Figure 6

Pressure drawdown test curve for well 7-1827.

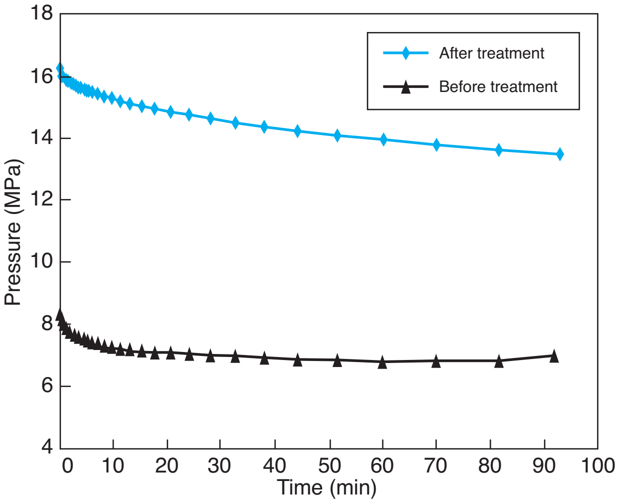

Figure 7

Pressure drawdown test curve for well 7-1937.

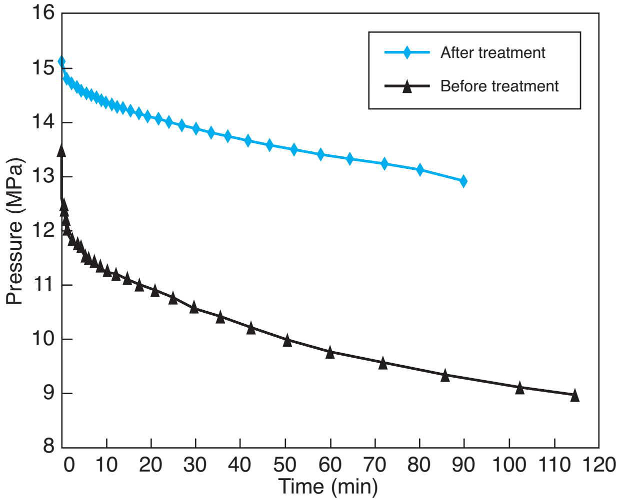

Figure 8

Pressure drawdown test curve for well 8-1827.

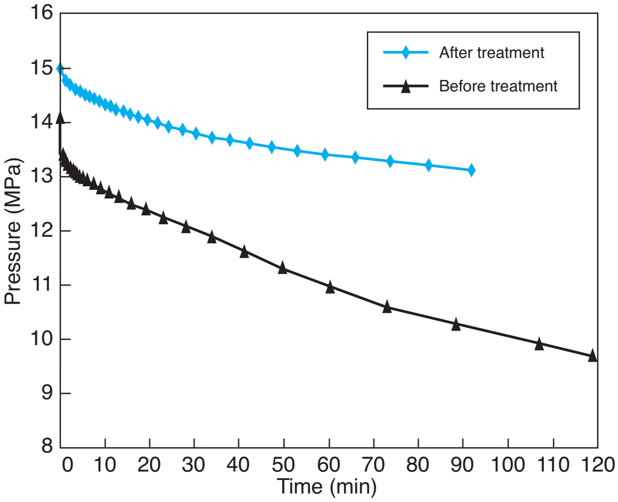

Figure 9

Pressure draw-down test curve for well 9-1827.

TABLE 5

Pressure test result after PPG treatment

Well name	Before PPG injection		After PPG treatment		Difference	
	PI (90) (MPa)	Injection pressure (MPa)	PI (90) (MPa)	Injection pressure (MPa)	PI (90) (MPa)	Injection pressure (MPa)
7-1937	6.95	5.0	10.49	8.2	3.54	3.2
7-1827	9.12	5.7	11.58	8.4	2.46	2.7
8-1827	10.98	8.8	13.72	11.5	2.74	2.7
9-1827	11.12	6.5	13.71	10.6	2.59	4.1

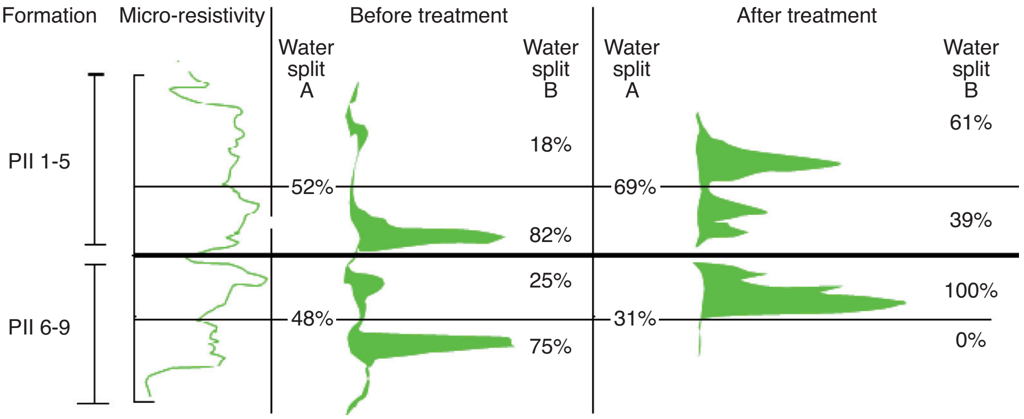

Figure 10

Comparison of injection profiles before and after treatment for well 7-1827.

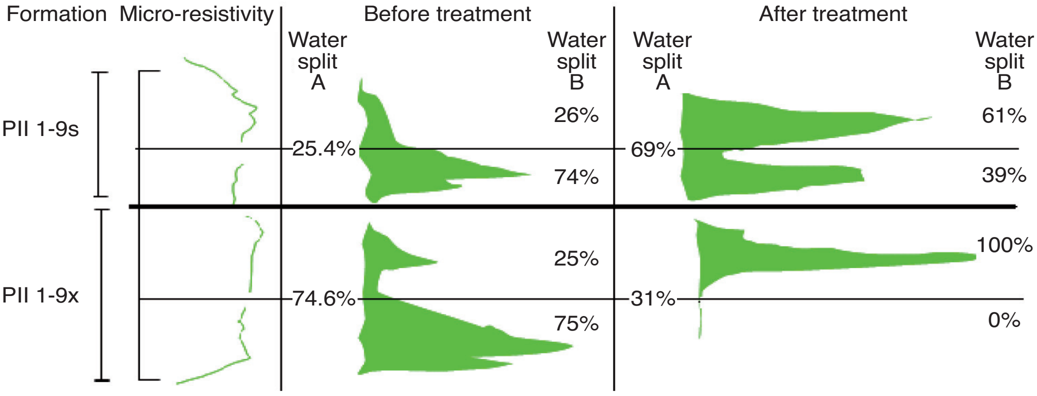

Figure 11

Comparison of injection profiles before and after treatment for well 7-1937.

Figures 10-13 show the injection profiles for each well before and after PPG treatments. All injection profiles, both inner-layer and inter-layers, were significantly improved after the treatments.

6.2 Production Performance and Economics

The treatments resulted in increased oil production and decreased water cut. The four treated wells had six center

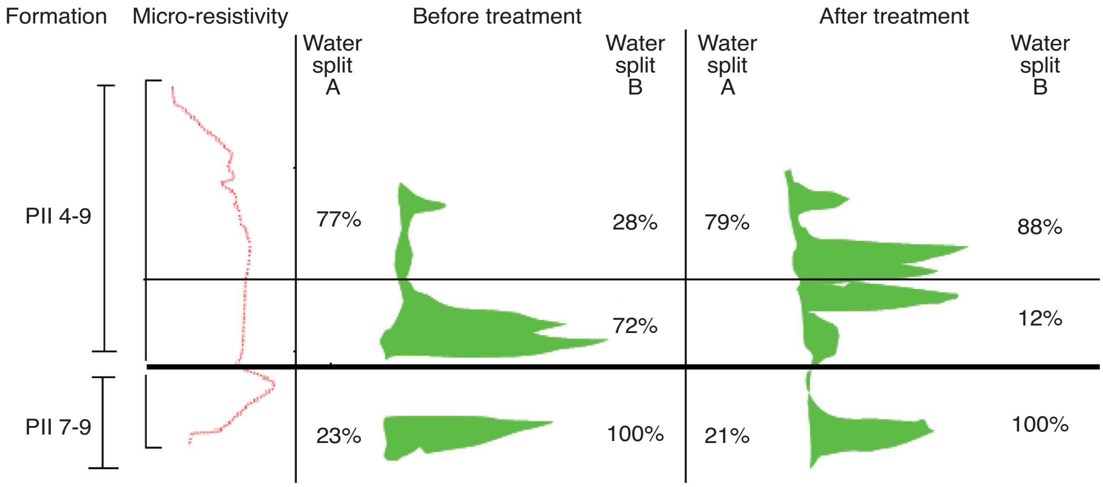

Figure 12

Comparison of injection profiles before and after treatment for well 8-1827.

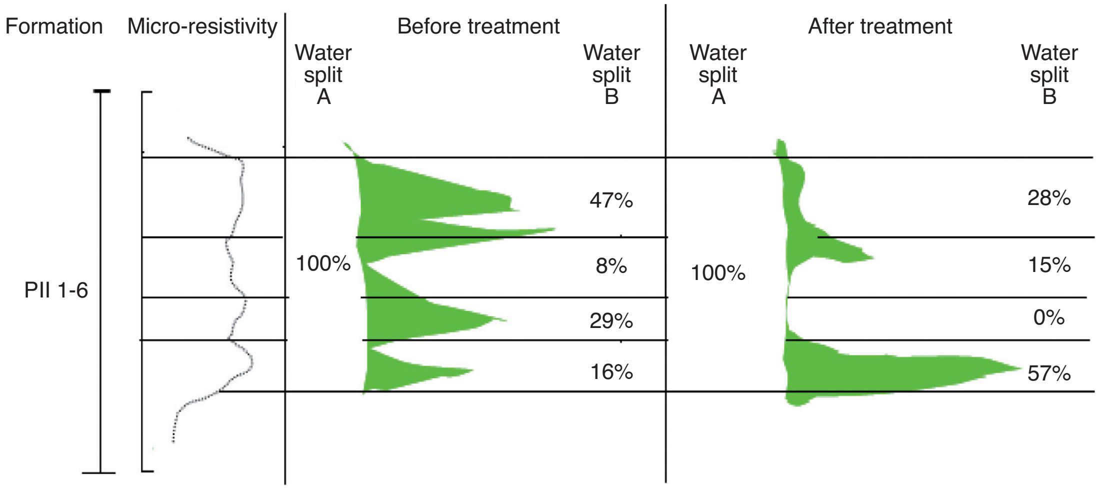

Figure 13

Comparison of injection profiles before and after treatment for well 9-1827.

production wells, five of which were effective with an oil increase of 5.8 tons/day and an average water cut reduction of 3%, as shown in Table 6. Table 7 shows the results of 26 comparable wells that were connected to treated wells and had no other well services or operations. After the treatments, the oil production rate increased to 34.8 t/d and water cut was reduced by 0.94% for the 26 wells under the conditions in which a production decline was not considered. The accumulative incremental oil was about 15 000 tons until March 2005 or, in other words, a 113 ton oil increase per ton of PPG injected.

7 DISCUSSION

Although the analysis of the cores from the field does not reveal obvious fractures in these wells, our core-flooding tests have uniquely demonstrated that the porous media should have a super-K channel with a permeability of more than 50 Darcy if mm-sized particles, *e.g.*, 0.06-0.9 mm diameter particles, which were used in the application, can be injected into the porous media without a significant increase in the injection pressure (Bai, 2001). If we assume that fractures exist in each well, each fracture will be oriented

TABLE 6

Production performance comparison of Center Wells

Type	Well No.	Before treatment			After treatment			Comparison		
		Q_L (t/d)	Q_o (t/d)	f_w (%)	Q_L (t/d)	Q_o (t/d)	f_w (%)	Q_L (t/d)	Q_o (t/d)	f_w (%)
Effective wells	8-1817	69	3	95.7	56	4.2	92.6	– 13	1.2	– 3.1
	9-1817	33	1	97.0	33	2.5	92.5	0	1.5	– 4.5
	7-1977	42	1	97.4	35	2	94.6	– 7	1	– 2.8
	7-2017	73	3	96.3	71	5	93.0	– 2	2	– 3.3
	7-1917	50	3	94.0	34	2.4	93.0	– 16	– 0.6	– 1.0
	Sub-total	267	11	96.0	229	16.1	93.0	– 38	5.1	– 3.0
Ineffective wells	9-1837	53	3	94.9	57	2.7	95.5	4	– 0.3	0.6
Total		320	14	95.6	286	18.8	93.4	– 34	4.8	– 2.2

TABLE 7

Performance comparison of 26 connected production well without other operation

Well type	Producer	Before PPG treatments			After PPG treatment (Aug. 2004)			Difference		
		Q_L (t/d)	Q_o (t/d)	f_w (%)	Q_L (t/d)	Q_o (t/d)	f_w (%)	Q_L (t/d)	Q_o (t/d)	f_w (%)
Wells only produced from PII	11	604	26	95.7	563	32.8	94.2	– 41	6.8	– 1.52
Commingle wells	15	3 717	161	95.7	3 644	189	94.8	– 73	28	-0.86
Total	26	4 321	187	95.7	4 207	221.8	94.7	– 114	34.8	– 0.94

either vertically or horizontally. The fracture volume can be calculated using the following equations for differently oriented fractures.

For vertical fractures:

$$V = 2 \cdot h_f \cdot w_f \cdot L_f \tag{2}$$

with: V, fracture volume (m^3); h_f, fracture height (m); w_f, fracture width (m); L_f, fracture length (m).

For horizontal fractures:

$$V = \pi L_f^2 \cdot w_f \tag{3}$$

If we assume that a vertical fracture in the area has a width of 5 mm (usually 3-8 mm), a length equal to the well distance of 300 m and a height of 10 m (7.5-11 m for the four treated wells), then the calculated fracture volume is 30 m^3.

If we assume that a horizontal fracture in the area has $L_f = 300$ and $w_f = 5$ mm, then the fracture volume is 1 413 m^3.

Comparing the fracture volume with the swollen particle volume shown in Figures 2-5, it can be inferred that horizontal fractures are more likely. In fact, the reservoir depth in Daqing is around 1 000 m and it is believed that hydraulic fractures should be horizontal in this area. This field has been flooded by water for more than 30 years and the horizontal fractures might be caused by long-term high water injection pressure.

CONCLUSIONS

- No injectivity problems arise for a large volume of mm-sized PPG treatments for most wells in mature oilfields. All four wells in the case were successfully injected with more than 10 000 m^3 of PPG suspension without an abrupt pressure increase;
- real-time PPG injection pressure response can be used to adjust the PPG particle size and concentration to better fit a reservoir. Real-time monitoring data can be used to adjust previous designs for better gel treatment results;
- PPG treatment is a cost-effective conformance control method. The four treatments successfully resulted in improved oil production, reduced water production and better injection profiles;
- the vertical and horizontal fracture volume calculations indicate that horizontal fractures are more likely than vertical fractures if fractures exist in these wells.

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