Preformed Particle Gel for Conformance Control: Factors Affecting Its Properties and Applications

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Summary

Preformed particle gel (PPG) is a particled superabsorbent crossklinking polymer that can swell up to 200 times its orginal size in brine. The use of PPG as a fluid-diverting agent to control conformance is a novel process designed to overcome some distinct drawbacks inherent in in-situ gelation systems. This paper introduces the effect of gelant compositions and reservoir environments on the two properties of PPG: swollen gel strength and swelling capacity. Results have shown that PPG properties are influenced by gelant compositions, temperature, brine salinity, and pH below 6. Temperature increases PPG swelling capacity but decreases its swollen gel strength. Salinity decreases PPG swelling capacity but increases its swollen gel strength. PPG is thermostable at an elevated temperature of 120°C if a special additive agent is added into its gelant as a composition. PPG is strength- and size-controlled, environmentally friendly, and not sensitive to reservoir minerals and formation water salinity.

Two field applications are introduced to illustrate the criteria of well candidate selection and the design and operation process of PPG treatments. Field applications show that PPG treatment is a cost-effective method to correct permeability heterogeneity for the reservoirs with fractures or channels, both of which are widely found in mature waterflooded oil fields.

Introduction

Most oil fields in China are found in continental sedimentary basins. They are characterized by complex geologic conditions and high permeability contrast inside reservoirs. To maintain or increase the driving force, these oil fields were developed by waterflooding. However, serious vertical and lateral formation heterogeneity has resulted in the rapid water-cut increase of production wells. Moreover, sand production and rock mineral dissolution due to water injection have made reservoirs much more heterogeneous. Many interwell tracer tests have shown that channels or fractures widely exist in most oil fields, whether they have fractures or not during their early development stage. Another demonstration of worsening heterogeneity comes from the clay gel treatments for conformance control in China oil fields. Many injection wells have successfully injected tens or hundreds of tons of clay. If we calculate the permeability from Darcy law according to the "1⁄9-1⁄3" rule (Maroudas 1966; Pautz et al. 1989), which gives the relationship of particle penetration depth into porous media to the ratio of pore-throat diameter and particle size, the formation permeability should be more than 1,000 darcies (Bai 2001). Moreover, early polymer breakthroughs in the Daqing, Nanyan, and Shengli oil fields have further demonstrated that channels or fractures are common in most oil fields (Bai 2001). Severe reservoir heterogeneity has become one of the most urgent problems that reservoir engineers have to solve.

To control water cut and improve the oil recovery of oil fields, many technologies, such as polymer flooding, surfactant flooding, foam flooding, and so on, have been widely applied in China in past decades (Wang et al. 2003; Yang et al. 1988, 2003; Song et al. 1995). One of the most popular methods is to inject gels to reduce the flow capacity of channels or fractures and divert the following fluid (normally, water) to unswept oil zones (Bai et al. 1999; Seright et al. 2001). Before the 1990s, gel treatments focused on correcting permeability heterogeneity near the wellbore (normally 5 to 10 m). However, in-depth gel treatments have become more important within the last 10 years because the crossflow in a heterogeneous thick zone has become a significant factor influencing the oil recovery of mature oil fields; in addition, many wells have been treated multiple times using gels, resulting in no more oil remaining near a wellbore (Liu 1995).

Recently, several authors have recommended using preformed gel to control conformance in mature oil fields (Seright et al. 2001; Seright 2000; Chauveteau et al. 2000, 2001; Feng et al. 2003; Li et al. 1999; Coste et al. 2000; Bai et al. 2007) because it can overcome some distinct drawbacks inherent in in-situ gelation systems, such as difficulty of gelation time control, potential damage of low-permeability hydrocarbon zones, and the uncertain nature of gelling caused by the shear in surface facilities and porous media. Seright et al. (2001) and Seright (2000) studied some properties of preformed bulk gel through fractures and stated that preformed gel had better placement than in-situ gel and could effectively reduce gel damage on low-permeability unswept oil zones. Chauveteau et al. (2000, 2001) synthesized preformed microgels that were crosslinked under shear. Feng et al. (2003) demonstrated that the microgels could be injected easily into porous media without any sign of plugging and showed that these microgels could be good candidates for water-shutoff and profile-control operations.

On the basis of the reservoir status of the China oil fields discussed above, a new idea using PPG to control conformance was proposed by Li et al. (1999) in China. Coste et al. (2000) and Bai et al. (2007) analyzed some properties of PPG and PPG propagation mechanisms through porous media.

In this paper, the effects of gel compositions and reservoir conditions on PPG properties were systematically studied by evaluating swollen PPG strength and PPG swelling capacity. Two of the earliest field application cases were introduced to show how to screen candidate wells and how to operate the injection procedures.

Preparation of Preformed Particle Gel

Preformed particle gel is a kind of xerogel that can swell by absorbing water. It can swell to many times its original size in brine. Limited swelling occurs when the molecules remain bound in a network, while unlimited swelling causes the xerogel to dissolve.

The processes synthethizing the xerogel are as follows:

1. Prepare an aqueous solution containing acrylamide, crosslinker, initiator, and other additives according to a given recipe.
2. Make the solution crosslink to form bulk gel under a certain temperature.
3. Cut the bulk gel into small pieces and dry them at the temperature of 70°C.
4. Mechanically grind the dried gel pieces into smaller particles with sizes in micrometer or millimeter scale, depending on field application requirements.

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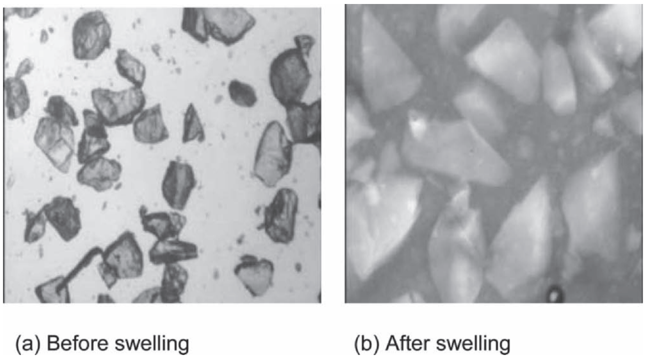

Fig. 1—Morphology of PPG before and after swelling.

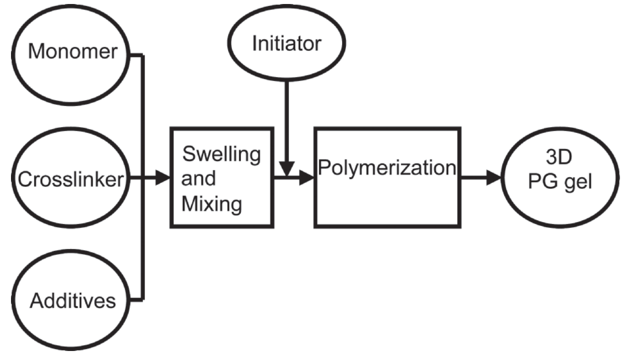

Fig. 2—Synthesis of preformed gel.

Fig. 1 shows the pictures of some xerogel particles and their corresponding swollen particles. The particles can swell to 20 to 200 times their original size in brine.

Standard methods were developed to evaluate PPG properties, such as swelling capacity, swollen rate, elastic modulus, and fractured stress (Li and Bai 2001). In this paper, swelling capacity and elastic modulus (G') are used to evaluate the quality because they are key parameters for PPG quality control in our laboratory.

Swelling capacity (weight of absorbed water per gram) was calculated by Eq. 1:

$$A = \frac{M_l - M_s}{M_s}, \quad \text{(1)}$$

where A is the swelling capacity, M_l is the mass after swelling, and M_s is the dry PPG mass.

Experiment Materials and Methods

Materials. The chemicals used in our experiment include acrylamide monomer (>99%, Beijing Chemical), sodium peroxydisulate (>99%, Beijing Chemical), N,N′-methylenebisacrylamide (99%, Beijing Chemical), ammonium chloride (>99%, Beijing Chemical), and deionized water. Commercial bentonite clay with a particle size less than 2.0 μm was separated and used as an additive for the composite gel synthesis.

PPG Synthesis and Characterization. A traditional in-situ polymerization method was used to synthesize the 3D polymer clay composite gel. The strategy of the synthesis is described in **Fig. 2.** First, clay particles (<2 μm) are separated by standard sedimentation and dispersed in an acrylamide monomer solution by strong dispersion with magnetic stirring in a 1000-mL glass beaker. Then, the crosslinker (N,N′-methylenebisacrylamide), initiator (peroxyldisulfate), and some other additives are added with the optimized composition of 6.0% $CH_2=CH{-}CONH_2$+0.2% $Na_2S_2O_8$+0.03% $(CH_2=CH{-}CONH)_2CH_2$+1.0% NH_4Cl+6.0% clay+deionized water.

The reaction is initiated by heating the solution to 60°C in a water bath. The gelation reaction will complete in a short time because of a self-acceleration reaction. Accompanying the generation of a large amount of heat and ammonia, the reaction is finished in 30 minutes, followed by aging for 3 hours at room temperature. Then, the preformed gel is cut into small pieces and dried at 70°C. Finally, the dried preformed particles are ground into small sizes and separated for use.

The PPG swelling capacity was evaluated by measuring the PPG particle mass before and after swelling in a specified brine. The swollen PPG strength was characterized by measuring the swollen gel elastic modulus (G') at a frequency of 0.926 rad/s at the temperature of 60°C.

Results and Discussion

Effect of Gelant Compositions on PPG Properties. ***Acrylamide Concentration.*** **Fig. 3** presents the effect of monomer concentration on the swelling capacity and strength of preformed gel (400 mg/L crosslinker +3,000 mg/L initiator). The monomer concentration does not significantly influence the PPG swelling capacity. The gel strength increases with the increase in monomer concentration and approaches a stable value at monomer concentrations above 15 wt%. It is suggested that the gel strength is a function of both monomer concentration and crosslinker concentration. At an optimized ratio of monomer and crosslinker (375:1 weight ratio), the composite gel has the highest strength and elastic modulus.

Crosslinker Concentration. The crosslinker has a multifunctional group that can build a complex network with –CONH– bridges and form a 3D network structure during the polymerization process. The crosslinker concentration is critical for the structure and properties of the gel. **Fig. 4** shows the relationship of PPG strength and swelling capacity vs. crosslinker concentration. The increase of gel strength with increased crosslinker concentration is mainly caused by the increase in network density. The swelling capacity in water is mainly attributed to the hydrophilic group in the polymer molecule. Thus, the number of hydrophilic groups and the cage size of the 3D crosslinked gel have a significant effect on swelling capacity. With an increase in crosslinker concentration, more hydrophilic groups will take part in the gelation reaction, resulting in lower hydrophilicity. At the same time, because of steric hindrance, the swelling capacity will be reduced somewhat when the crosslinker concentration is too high. The variation of yield stress with different crosslinker concentrations shows the same trend in **Fig. 5.** It indicates that the optimized crosslinker concentration ranges from 300 to 400 mg/L.

Initiator Concentration. The initiators used to start the polymerization are chemical entities (peroxide compounds), which will produce free radicals during their dissociation at proper conditions. To accelerate the reaction, a catalyst was used to increase the dissociation rate at low temperature. It was observed that the polymerization reaction was retarded by the presence of clay addi-

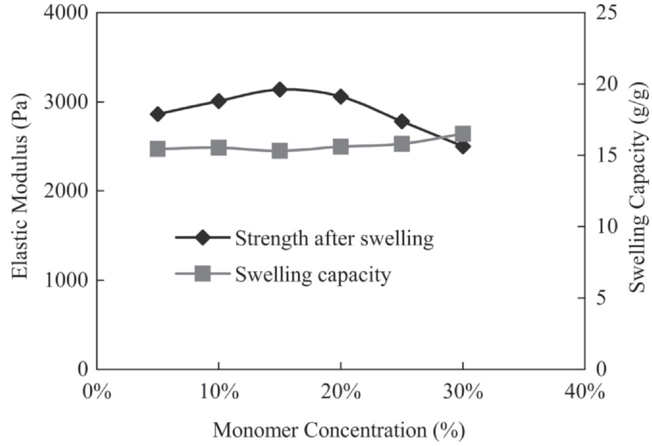

Fig. 3—Effect of monomer concentration on PPG strength and swelling capacity.

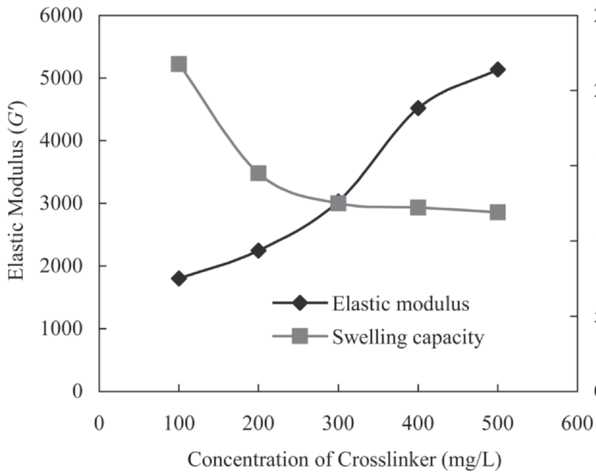

Fig. 4—Effect of crosslinker concentration on PPG strength and swelling capacity.

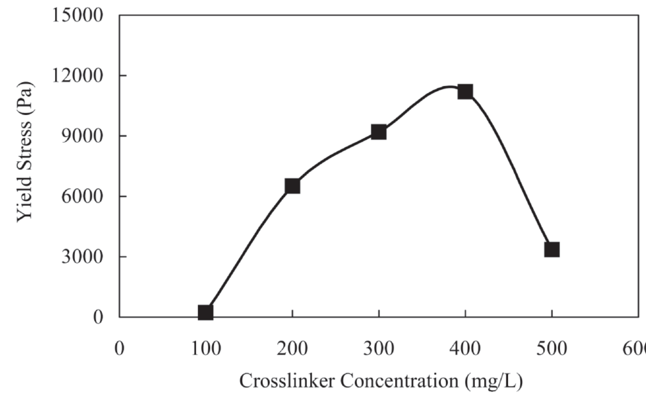

Fig. 5—Effect of crosslinker concentration on PPG yield strength.

tive. It is assumed that the clay particles consume some of the free radicals. Normally, some more initiator is necessary for the polymerization reaction when clay is present. **Fig. 6** gives the gelation time vs. initiator concentration. More free radicals can be generated at higher initiator concentration. The unsaturated monomer, which is readily susceptible to free radicals, will form long chain polymers.

NH_4Cl. The NH_4Cl is used to adjust the pH of the synthesis solution, which will affect the hydrolysis of the $–CONH_2$ group. **Fig. 7** shows the influence of NH_4Cl on the PPG properties at a composition of 15% monomer +400 mg/L crosslinker +3,000 mg/L. The addition of NH_4Cl can decrease the pH of the reaction solution. Thus, the more hydrophilic group –COOH in the gel matrix can be produced at suitable hydrolysis conditions. The hydrolysis is used to control swelling capacity.

Bentonite Clay. The layered bentonite clay is used as a reinforcement of the composite PPG. The reinforcement of polymer gel with clay by forming an intercalated composite has been actively studied for approximately 30 years (Theng 1979). In this work, in-situ polymerization is used in the synthesis of the polyacrylamide/clay composite gel. X-ray and transmission electron microscopy investigations have indicated that bentonite clay has a layered structure with an interlayer distance of approximately 1.0 nm (Vogt et al. 2002). The surface property, the trace impurity, and the geometry of clay particles play an important role in the synthesis of composite material (Laus et al. 1998).

The commercial bentonite clay was separated by a standard sedimentation process, and the clay that was less than 2.0 μm in size was used as an additive to enhance the strength of the composite polymer/clay gel. It was shown that dramatic changes were obtained in the mechanical and physical properties of polymer clay gel formed by in-situ polymerization. The influence of clay addition on the strength and swelling capacity is given in **Fig. 8**. The swelling capacity decreases initially with the addition of clay and approaches a stabilized value at the clay concentration of approximately 5.0 wt%. This can be explained by the fact that the bentonite clay has a negatively charged surface in which the hydrolyzed polyacrylamide can bond onto the surface due to the columbic force. Thus, the density of the hydrophilic functional group will decrease when clay is introduced into the matrix. The swelling capacity will decrease with the addition of clay. However, the physical property of composite gel is significantly improved. Tensile strength (σ) and elastic modulus (G') were measured with a rheology meter (RS150, Haake). Eqs. 2 and 3 are used to define G' and σ.

$$G' = \frac{\tau_0}{\gamma_0} \cdot \cos\delta, \quad (2)$$

$$\sigma = E \cdot \varepsilon, \quad (3)$$

where σ = stress, ε = strain, δ = phase angle, and E = Young's modulus.

It is suggested that the reinforcement properties of polymer clay composite gel are attributed mainly to hybrid effects of interfacial properties and restricted mobility of the polymer chains. Shi et al. (1996) studied the interfacial effects on the influence of nanocomposite strength based on the assumption that the polymers are binding directly on the surface of clay particles. The restricted mobility of the reinforcement mechanism was described and studied by Kojima et al. (1993), who suggested that the constrained

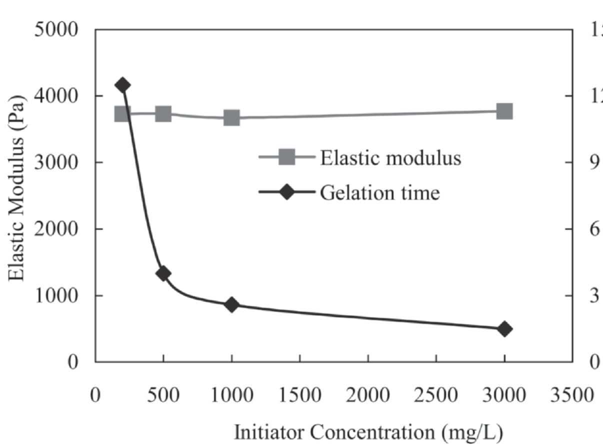

Fig. 6—Effect of initiator concentration on PPG strength and gelation time.

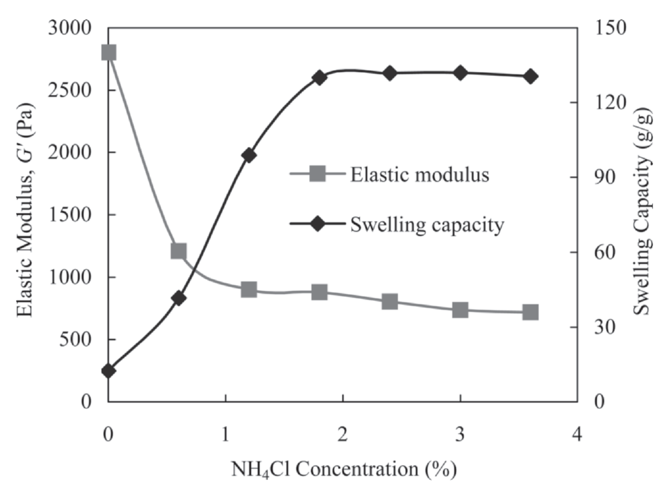

Fig. 7—Effect of NH_4Cl concentration on PG strength and gelation time.

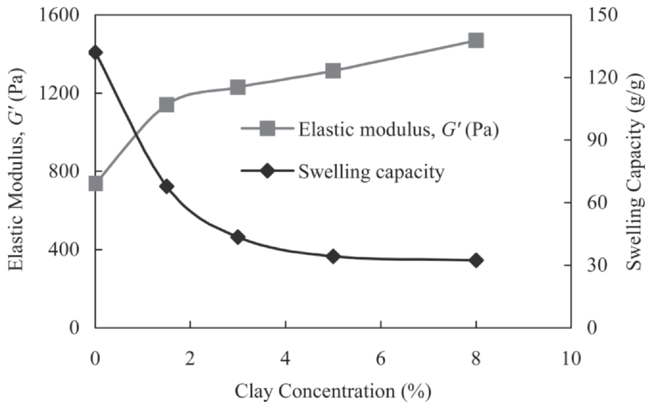

Fig. 8—Effect of clay concentration on PPG strength and swelling capacity.

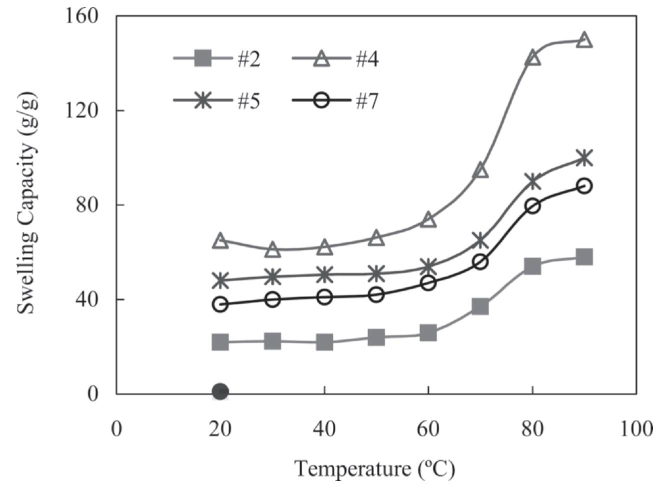

Fig. 9—Effect of temperature on PPG swelling capacity.

mobility of polymer chains had an energy-dissipation effect under shearing.

Thermal Stability Agent (SA). To improve the thermal stability of PPG, 0.2% SA was added during gel synthesis. The thermal stability is defined as the time period in which PPG retains 80% of its original strength in our experiments at a given temperature. Results have demonstrated that PPG without SA can keep 80% of its original strength for 1 year at 90°C when the PPG suspension is prepared with 0 to 30,000 mg/L NaCl solution. PPG can be stable for more than 1 year at the temperature of 120°C when the additive SA is added as a gelant composition.

Effect of Environmental Factors on PPG Swelling Capacity. ***Temperature.*** At higher temperatures, more amino groups ($–CONH_2$) will change to an acidic carboxylic group ($–COOH$) by hydrolysis. **Fig. 9** shows PPG swelling capacity at different temperatures and indicates that the swelling capacity increases with the increase in temperature. The significant swelling capacity increase occurs at the temperature of 60°C or higher.

Salinity. **Fig. 10** shows the influence of salinity on the property of PPG. The main effect of salinity is the swelling capacity; at low concentration, the swelling capacity decreases with the increase in salt concentration. The swelling capacity decreases from 120 to approximately 50 g/g when the NaCl concentration increases from 0 (pure water) to 5,000 mg/L. These phenomena can be attributed to the state electric repulsive force and charge balance. The swelling process at different salt concentrations is illustrated in **Fig. 11.** At low salt concentration, the electric repulsive forces will separate the molecules in gel and create more space for water coming in. However, when the gel is swollen in high-salinity water, the negatively charged group will be balanced by the cations and will restrict further water absorption.

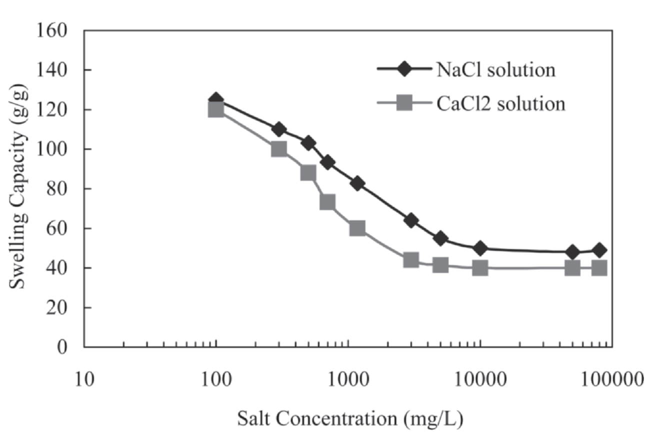

Fig. 10—Effect of salt concentration on PG swelling capacity.

pH. The pH effect on the swelling property is given in **Fig. 12.** In acidic conditions, the swelling capacity increases with an increase of pH and approaches a stabilized value at pH = 6.0. In basic conditions, the effect of pH on swelling capacity is undetectable. The pH influence can be attributed to the release of proton ions in an acidic condition, which shields the electric repulsive force of charged groups.

Applications

Field Application Cases. PPG has been applied successfully to correct in-depth reservoir permeability heterogeneity in most mature oil fields in China, such as Daqing, Zhongyuan, Liaohe, Shengli, Tuha, Dagang, and Jidong. These oil fields cover extremely serious conditions. For example, Zhongyuan oil field is characterized by high salinity and high temperature, Dagang has characteristics of severe channel and high temperature, and Tuha is a naturally fractured reservoir. As of 2007, approximately 2,000 wells in Chinese oil fields had been treated with PPG (Liu 2006). The amount of dried PPG for each treatment ranges from 3,000 to 40,000 kg. All wells were injected successfully without injectivity problems. Two of the earliest field applications are given in this paper to show how to design and operate PPG treatments.

Case 1. This was the first PPG treatment in Zhongyuan oil field, SINOPEC. This case includes two adjacent injection wells, W51-75 and P-72, in Pucheng oil field. Three production wells are connected with the two injectors. It is a sandstone reservoir with an average permeability of 121 md without natural fractures. The formation temperature is 107ºC, and the total salinity of the formation water is $15{\times}10^4$ mg/L. The reservoir has been developed by waterflooding since 1979. The two wells were not hydraulically fractured. The two wells were treated with PPG in 1999 for the following reasons:

• Each of the two wells has high water injectivity. The injectivity index of Well W51-75 is 20 m^3/(MPa·d), with a threshold pressure (defined as the minimum injection pressure at which wa-

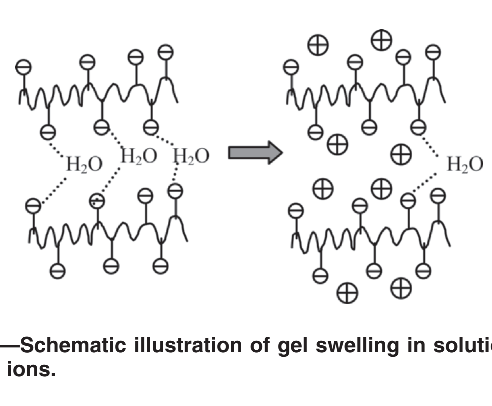

Fig. 11—Schematic illustration of gel swelling in solution containing ions.

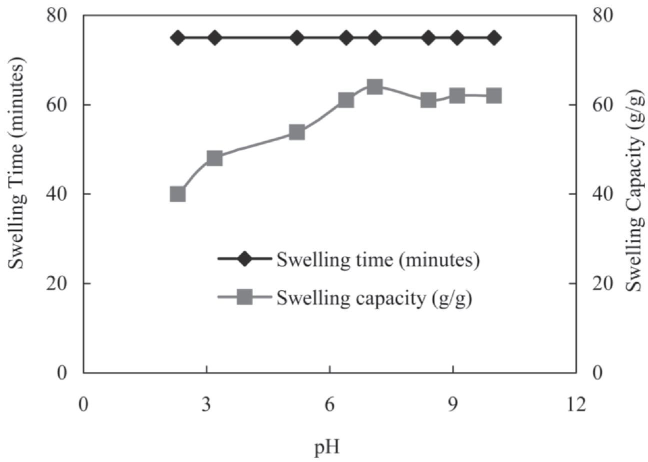

Fig.12—Effect of pH on PPG swelling capacity.

ter can be injected) of 9.2 MPa, and the injectivity index of Well P-72 is 18 m^3/(MPa·d), with a threshold pressure of 8.5 MPa.

- Connected production wells had a high average water cut of more than 85%.
- Water-injection-profile results showed that the wells had an extremely vertical heterogeneity.
- Tracer-test results showed that the wells had an extremely severe areal heterogeneity and channel between injectors and producers (tracer breakthrough in 2 days).

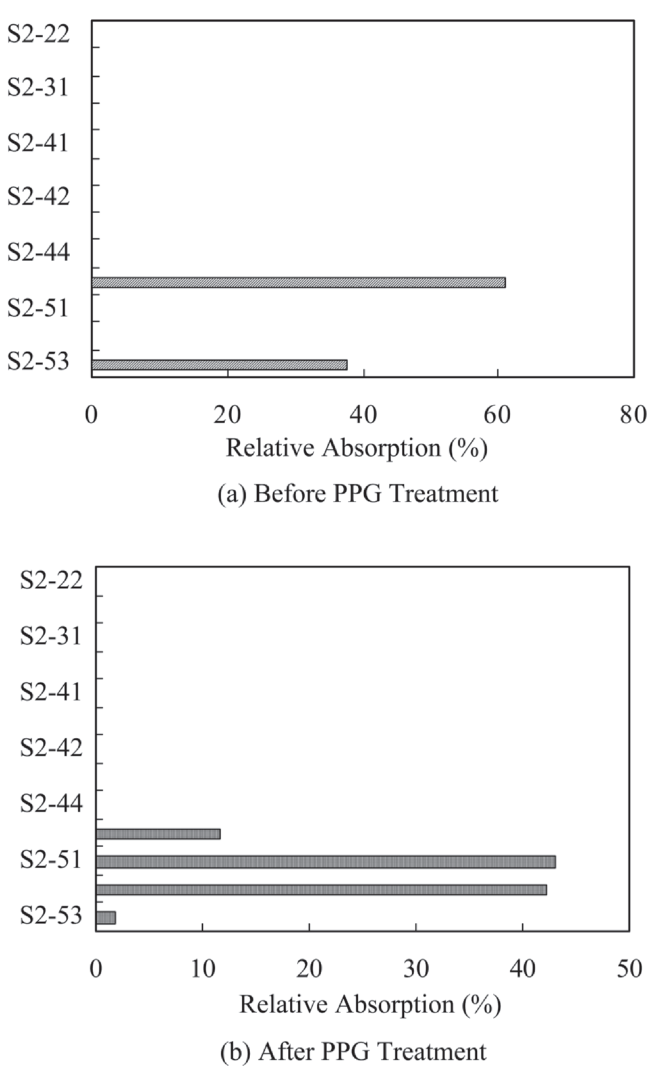

Fig. 13—Injection-profile comparison of Well M11-23 before and after PPG treatment.

TABLE 1—PPG INJECTION IN PUCHENG OIL FIELD

Well	Treated Time	Total Volume (m^3)	Concentration (mg/L)
W51-75	17 July–20 September 1999	4323	3000
P72	17 July–20 September 1999	2503	3000

The injected PPG dispersion volume of each well was optimized by systematically considering injectivity, water-injection profile, and tracer-test results (Liu et al. 2000). As shown in **Table 1,** 4,300 m^3 PPG suspension prepared by 13,000 kg dry PPG was injected into Well W51-75, and 2,500 m^3 PPG suspension prepared by 7,500 kg dry PPG was injected into Well P-72. PPG concentration is 3,000 mg/L. Produced water was used to prepare the PPG suspensions. PPG size ranges from 0.8 to 2.0 mm, with a median diameter of 1.5 mm.

The injection rate was determined by the injectivity index of each well. The highest injection pressure was limited to 80% of the formation fracturing pressure. An alternated injection method of water (treated produced water) and PPG suspension was applied; that is, PPG suspension injection was performed during the day, and water injection was performed at night.

After the PPG treatment, injection wells and their corresponding production had the following response.

- The injection pressure was increased: The water injection pressure of Well P-72 increased from 19.5 to 24 MPa, and the water-injection pressure of Well W51-75 increased from 16 to 19 MPa. The injection pressure after treatment kept going higher than that before treatment for more than 2 years, which indicates that PPG is stable for more than 1 year at the formation conditions.
- The vertical injection profile was modified. The improvement of the vertical profile was confirmed by a profile test survey before and after the PPG treatment shown in **Fig. 13.** In this figure, each layer represents a separate layer, and there is an impermeable barrier between layers (assuming no vertical fracture). As shown in this figure, only two layers absorbed water before treatment, but another two layers started to absorb water after the treatment. Of course, it should be noted that the injection-well profile results sometimes are not instructive when channels or fractures exist near the wellbore, owing to the limited depth of investigation of this measurement method or the extension of a vertical fracture. In this case, if the channel or fracture exists in only one layer, the comparison results are meaningful because some new layers were affected after the treatment. However, the results are meaningless if the fracture or channel penetrates most layers of the well. Because the detection of fracture penetration is difficult, it cannot be proved whether the channels or fractures penetrate most layers or just one layer.
- The water cut of the corresponding producers was decreased, and the daily oil-production rate was increased. **Fig. 14** presents a typical production curve for Well W51-172, which connects with both W51 and P72. The water cut was decreased from approximately 80% to approximately 70%, and daily oil production was increased from 40 to 60 t/d.

The two well PPG treatments resulted in a total oil increase of 3239 tons, or 158 tons of incremental oil per 1000 kg PPG. The benefit investment ratio is more than 3.

Case 2. This is the first PPG treatment in Daqing, PetroChina. The selected injection well is Xing-7-24 in Xingbei oil field. The reservoir formation is characterized by thick oil layers with severe vertical heterogeneity. Formation temperature is approximately 45°C, and salinity is approximately 4,500 mg/L. The perforated depth is from 890 to 1,051.4 m. Net pay of the well is 24.5 m. The initial permeability is from several millidarcies to 1,200 md. The well was changed from a producer to a water-injection well in November 1992, and the cumulative water-injection volume had

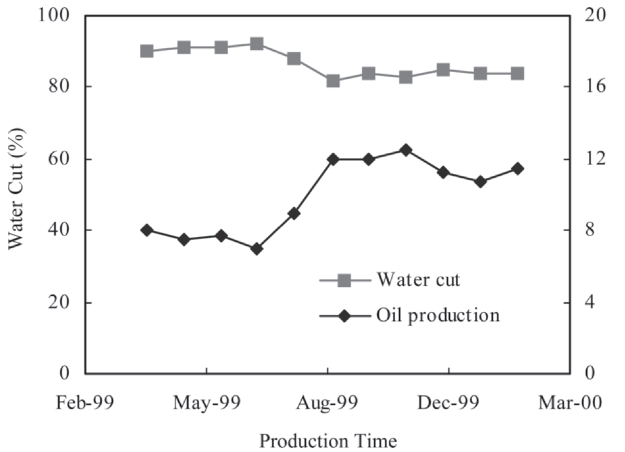

Fig. 14—Production curve before and after PPG treatment.

been 763,758 m^3 until August 2000. Four adjacent producers were confirmed to be connected with the injection well, with a total of more than 700 m^3/d of liquid and average water cut of more than 90%. Profile tests showed that approximately 85% of the injected water passed directly through the high-permeability parts of the oil zones, which occupied less than one-fifth of the total thickness. Interwell potential measurements demonstrated that the well group had severe areal heterogeneity, as shown in **Fig. 15.** PPG treatment was performed in August 2000. The produced water was used to prepare PPG suspension. As we know, for a normal in-situ polymer-gelling system, it usually takes some time to prepare polymer and crosslinker before it is injected. But PPG is completely different and can be dispersed easily into water. **Fig. 16** shows the flow scheme of the PPG mixing and injection system. This system is simple, so it can reduce some operation and labor costs.

Table 2 shows the injection scheme of PPG suspension. A total of 3,100 m^3 PPG suspension was injected into the well. For the first stage, 100 m^3 of 5-mm PPG suspension was injected into the well at a high flow rate of 25 m^3/h and a high concentration of 1%. The reason that we injected the large PPG particle at the high flow rate and concentration is that we expected that PPG particles could form face plugging in all open zones in which permeability is below 1,000 md, so that followed PPG can only enter super-high-permeability zones or streaks without damaging the zones with a large amount of remaining oil. For the second and third stages, an alternated injection method of PPG suspension and water was used: 10 hours of PPG suspension injection followed by 14 hours of water injection. The difference between the second and third stages is their particle sizes. In fact, we initially designed them to be the same size, but the injection-pressure increase did not reach our expectations, so we changed the particle size from 1.5 to 3 mm. For the fourth stage, 5-mm PPG was continually injected so that the final injection pressure can achieve expected results. **Fig. 17** shows the injection-pressure monitoring result during PPG injection while not including water-injection periods. As we saw, the injection pressure oscillates, which is caused by the alternated injection of PPG suspension and water. When PPG suspension was

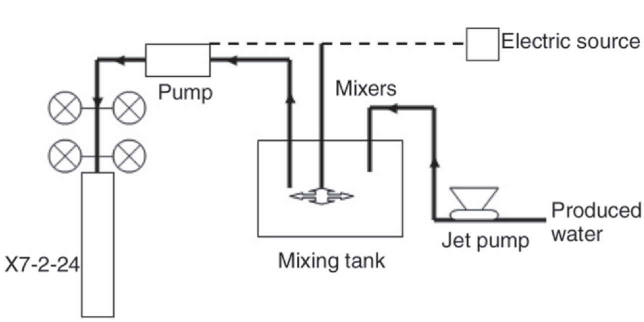

Fig. 16—Flow chart of PPG injection.

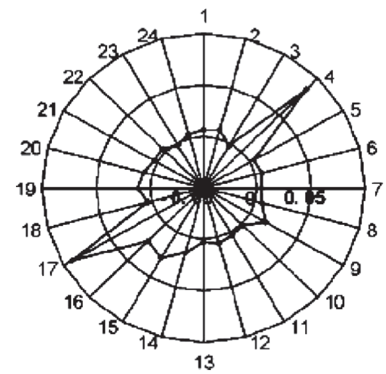

Fig. 15—Areal heterogeneity of well group.

injected, the injection pressure gradually increased, but when changed to water injection, the pressure decreased, which indicated that injection water could displace part of the PPG away from wellbore.

After the PPG injection, 0.5 m^3 gel breaker composed of Hydrofluoric acid (HF) and hydrochloric acid (HCl) was injected into the well to soak the wellbore to dissolve some gel cake on low-permeability zones and recover or increase their injectivity. Then the well was shut off for 2 days. The well was flushed to make some of the remaining gel breaker come out from the wellbore before water injection.

The injection wells and their corresponding producers showed the following results after the treatment.

- Injection pressure increased from an initial 5.0 MPa to 11.6 MPa.
- Potential test results showed that the areal heterogeneity was effectively controlled.
- Approximately 2,400 tons of incremental oil was obtained with an 8% water-cut decrease.
- The useful life of PPG was determined to be more than 6 months.

The above results show that the PPG treatment is positive. In this case, 15.5 tons of 1.5- to 5-mm particles were injected into the wells, but no injectivity problem was encountered. According to the theoretical particle size of PPG propagation through porous media (Bai et al. 2007), the reservoir should have a channel with thousands of darcies. Of course, there may be two other possibilities for this case. The first possibility is that the particles may have been broken into small pieces when they were injected or transported through porous media. But for this possibility, no matter how small those pieces, the particles are still a gel, which is very difficult to transport through normal porous media without having a fracture or channel. Another possibility is that there exists a "cave" that is often caused by sand production near the wellbore. For Daqing oil field, sand production is not severe, so the existence of cave is impossible near the wellbore. From the gel-injection practices, it can be inferred that the reservoir has some fractures or channels. Otherwise, it is improbable that such a large volume of PPG could be injected. Of course, it has not been proved whether fractures or channels exist. Moreover, no effective methods have been used to demonstrate how far the possible fractures or channels might extend from the injection well.

Lessons From Applications. Some experiences learned from field applications are summarized as follows.

Criteria of Well Selection.

- Reservoir temperature below 120°C
- Reservoir with channels or fractures
- High injectivity and low pressure index (PI) (Qiao and Li 2000)
- High water cut and high production rate of connected producers
- Well group with low oil recovery (preferred)
- Salinity not limited

TABLE 2—PPG INJECTION IN DAQING OIL FIELD

Stage	PPG Size (mm)	PPG Weight (kg)	Volume (m^3)	Concentration (mg/L)	Injection Rate (m^3/d)
1	5.0	1000	100	1.0	25
2	1.5	3000	600	0.5	14–16
3	3.0	8500	1700	0.5	14–16
4	5.0	3000	600	0.5	14–16
Total		15 500	3100		

Before a well is determined to inject PPG, some tests and measurements are strongly recommended; these include water tracer tests, well tests, injection profiles, and so on.

PPG Injection Process.

1. A simple method can be used to inject PPG, as shown in Fig. 16.
2. Produced water can be used to prepare PPG suspension.
3. A small amount of high-concentration, large-size PPG is recommended to be injected first at a high pressure so that PPG can form gel cake on the surfaces of low-permeability zones, which aids in preventing the following injected PPG from penetrating into the low-permeability unswept oil zones.
4. It is suggested that an alternated method of PPG suspension and water be used to conduct PPG treatments.
5. Low-concentration, low-flow-rate PPG suspension injection is recommended so that particles have enough time to move in-depth into the reservoir. High-concentration, high-flow-rate PPG injection may cause a large pressure pulse near the wellbore, which may cause the formation to be fractured.
6. Real-time injection pressure should be monitored so that we can adjust some of our initially designed schemes, including PPG size and strength, according to the monitored pressure result. The adjustment is necessary because the reservoir is a black box, and we cannot completely understand it when we make the initial design. This is another advantage of PPG over traditional in-situ gelling systems.
7. It is suggested that 0.5 m^3 or less of gel breaker be injected into the well to soak the wellbore and dissolve some gel cake on the low-permeability zones. Then, the well should be washed out before water injection.

Treatment Results. Successful PPG treatment is often accompanied by an injection-pressure increase, an oil-rate increase, and a water-cut decrease, but injection pressure may not be an evaluation criterion because the injection pressure may not increase if PPG moves in-depth into the reservoir.

Knowing New Reservoirs. PPG has been injected in many mature oil fields, and most reservoirs have no fracture at the beginning of their development. But no injectivity problem has been encountered until now for all cases, which indicates that channels exist widely in mature waterflooded oil fields because PPG cannot be injected into those normal porous media without a fracture or channel. It is suggested that we should reconsider the mature reservoirs that may be completely different from their original conditions. Waterflooding has resulted in these reservoirs changing significantly (Seright 1988). Knowing the updated reservoirs is very important for improved-oil-recovery technology applications.

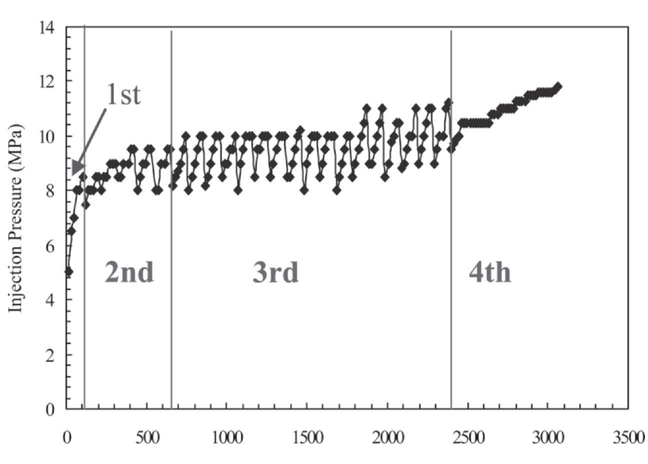

Fig. 17—Pressure change during PPG suspension injection.

Limitation for PPG Application. PPG can be used to control conformance for the reservoirs with small fractures or high-permeability channels. It should be noted that PPG cannot be injected into normal porous media without fractures or channels. In addition, the PPG cannot singly be applied in the reservoirs with very severe open channels or super-high-permeability open fractures because PPG will be flushed out from the producers.

Conclusions

1. Polymer/clay composite preformed gel (i.e., PPG) is successfully synthesized at laboratory and commercialized scale.
2. PPG is strength- and size-controlled, environmentally friendly, not sensitive to reservoir minerals and formation-water salinity, and stable over a long period of time.
3. PPG, synthesized in a surface facility, can overcome some distinct drawbacks inherent in in-situ gelation systems, such as lack of gelation time, uncertainness of gelling caused by shear, degradation, chromatographic separation of gelation components, and dilution by formation water.
4. PPG can be carried into wells by produced water, which can save fresh water and protect the environment.
5. Operation process and surface-injection facilities are simple, which can reduce operation and labor costs.
6. Proper well-selection and well-injection procedures are critically important for successful PPG treatments.
7. Field application results demonstrate that PPG can effectively improve reservoir conformance.
8. Knowing our updated reservoirs is a key to improving PPG applications in more locations.

Nomenclature

A = PPG swelling capacity, dimensionless
M_s = dry PPG mass, g
M_l = swollen PPG mass, g
σ = stress, Pa
ε = strain, dimensionless
δ = phase angle, degree
E = Young's modulus, Pa

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SI Metric Conversion Factors

Å × 1.0*	E–01	=	nm
bar × 1.0*	E+05	=	Pa
ft × 3.048*	E–01	=	m
ft^3 × 2.831 685	E–02	=	m^3
°F (°F−32)/1.8		=	°C

*Conversion factor is exact.

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