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Case Study on Preformed Particle Gel for In-depth Fluid Diversion

Baojun Bai, SPE, Missouri University of Science and Technology, Fusheng Huang, Daqing Petroleum Company Limited, PetroChina, Yuzhang Liu, SPE, RIPED, PetroChina, R.S. Seright, SPE, New Mexico Institute of Mining and Technology, Yefei Wang, SPE, China University of Petroleum

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Abstract

The paper describes preformed particle gel (PPG) treatments for in-depth fluid diversion in four injection wells located in the north of Lamadian, Daqing oilfield, China. Lamadian is sandstone oilfield with thick net zones. The selected four injectors have 46 connected producers with average water cut of 95.4% before treatment. The paper reports the detailed information for the four well treatments, including well candidate selection criteria, PPG treatment optimization, real-time monitoring result during PPG injection and reservoir performance after treatment. In addition, a discussion is made to analyze why so large amount of large particles can be injected into the reservoir. Large volume of PPG suspension with concentrations of 2,000-2,500 mg/L and particle sizes of 0.06-3.0 mm was injected into each well and it took about 4 months to finish each injection. The injection volume ranges from 11,458 to 17,625 m^3 per well with a total of 56,269 m^3 of PPG suspension (295,680 lbs of dried PPG) for the four wells. During PPG injection, the increase of the wellhead pressure was quite stable and no PPG was produced from adjacent producers. Recorded real-time monitoring Data about injection pressure and rate, PPG particle size change during PPG injection provide invaluable information to analysis the possibility of fracture/channel in the reservoir. The treatments resulted in an oil increase of 34.8 t/d and average water cut decrease of 0.94% within 10 months after treatments.

Introduction

Excess water production has become a major problem for oilfeld operators as more and more reservoirs mature due to long term of water flooding. Higher levels of water production result in increased levels of corrosion and scale, increased load on fluid-handling facilities, increased environmental concerns, and eventually well shut-in. Consequently, producing zones are often abandoned in an attempt to avoid water contact, even when the intervals still maitain large volumes of remaining hydrocarbons. Controlling water production has become more and more important to the oil industry.

Reservoir heterogeneity is the single most important reason for low oil recovery and early excess water production. Most oilfields in China, which were discovered in continental sedimentary basins, are characterized by complex geological conditions and high permeability contrast inside reservoirs. To maintain reservoir pressure, these reservoirs were developed by water flooding from early stage of their development. Many of them have been hydraulically fractured, intentionally or unintentionally, or have been channeled due to mineral dissolution and production during waterflooding (Liu, 2006). Reservoirs with induced fractures or high-permeability channels are quite common in the mature oilfields.

Gel treatment is a cost-effective method to improve sweep efficiency in reservoirs and to reduce excess water production during oil and gas production. Traditionally, gels are usually placed near wellbore of production or injection wells to correct inter-layer heterogeneity or heal fracture. However, the remaining oil on the top of a thick heterogeneous layer has become the most important target to improve oil recovery as a reservoir matures. In-depth diversion gels (Seright, 2004, Frampton, 2004, Sydansk, 2004, 2005, Cheung, 2007, Rousseau, 2005, Bai, 2007) have been reported to penetrate deeply into higher permeability zones or fractures and seal or partially seal them off thus creating high flow resistance in former, watered-out, high permeability portion of the zones. When successful, these gel systems divert a portion of the injection water into areas not previously swept by water shown in Fig. 1.

Traditionally in-situ gels have been widely used to control conformance. The mixture of polymer and crosslinker called gelant is injected into target formation and react to form gel to fully or partially seal the formation at reservoir temperature (Sydansk, 1992, Jain, 2005). So the gelation occurs in reservoir conditions. A new trend in gel treatments is applying preformed gels for the purpose because the preformed gels are formed at surface facilities before injection and no gelation occurs in reservoirs so they can overcome some distinct drawbacks inherent in in-situ gelation systems, such as lack of

gelation time control, uncertainness of gelling due to shear degradation, chromatographic fractionation or change of gelant compositions, and dilution by formation water. The preformed gels include preformed bulk gels (Seright 2004), partially preformed gels (Sydansk 2004, 2005), and particle gels which include mm-sized preformed particle gel – PPG (Li, 1999, Coste 2000, Bai 2004, 2007), microgels (Chauveteau 2000, 2001, Rousseau 2005, Zaitoun 2007) and pH sensitive crosslinked polymer (Al-Anazi 2002, Huh 2005), mm-sized swelling polymer grains (currently marketed by service companies), and Bright Water® (Pritchett 2003, Frampton 2004). Their major differences are their sizes and swelling times. Published documents show that PPG, microgels and Bright Water® were economically applied to reduce water production in mature oilfields. Microgel was applied to one gas storage well to reduce water production (Zaitoun, 2007). Bright water® was used for more than 10 wells treatments with BP and Chevron (Cheung, 2007). Millimeter sized polymer grains PPGs were applied in about 2,000 wells to reduce fluid channels in waterfloods and polymer floods in China (Liu, 2006). This paper will introduce the technology of using PPG to control conformance for mature oilfields.

Overview of PPG Treatment Technology and Field Application

What is PPG?

PPG (mm-sized preformed particle gel) is an improved super adsorbent polymers (SAPs). SAPs are a unique group of materials that can absorb over a hundred times their weight in liquids and do not easily release the absorbed fluids under pressure. Superabsorbent polymers are primarily used as an absorbent for water and aqueous solutions for diapers, adult incontinence products, feminine hygiene products and agriculture industry. However, the traditional SAPs in the markets do not meet the requirements for conformance control due to their fast swelling time, low strength and instability at high temperature. A series of new SAPs called preformed particle gels (PPGs) have developed for the conformance control purposes (Li, 1997, Bai, 2004, 2007). PPG properties are summarized as follows.

- PPG sizes are adjustable: μm-cm.
- Swelling ratio in formation water: 30~200 times original.
- Salt resistance: all kinds of formation salts and concentrations are acceptable.
- Thermal stability: more than 1 year below 110 ºC.
- Strength: adjustable, high strength product available.
- Swelling rate: slightly controlled.

Why to Select PPG Treatments

Lab results showed that crosslinking system formed dispersed gels not bulk gel in porous media at flowing condition. Our lab tests have showed gelants will form dispersed gels rather than bulk gels in the porous media without open fractures at flowing condition, shown in Fig.2. Therefore, gel treatments in porous media are particle gel treatments.

Preformed particle gels overcome some distinct disadvantages inherent in traditional in-situ gels. Particle gels have great potential due to their unique advantages over traditional in-situ gels, including:

1. Preformed particle gels are synthesized prior to formation contact, thus overcoming distinct drawbacks inherent in 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.
2. Preformed particle gels are strength- and size-controlled, environment-friendly, and their stability is not sensitive to reservoirs minerals and formation water salinity.
3. These gels usually have one component during injection. Thus, it does not require many of the injection facilities and instruments that often are needed to dissolve and mix polymer and crosslinker for conventional in-situ gels. The simple injection operation processes and surface facilities can significantly reduce operation and labor costs.

PPG has unique properties comparing to other preformed particle gels. PPGs are mm-sized gel particles, they cannot be injected in conventional porous media without fractures or void but they can effectively plug fractures or high permeability streaks/channels in mature oilfields which cannot be successfully implemented by nanosized particle gel-Bright Water® (Pritchett 2003, Frampton 2004) or microsized preformed particle gels-microgels (Chauveteau 2001, 2003, Rousseau 2005, Zaitoun 2007). In addition, the PPG has follow advantages:

1. PPG can preferentially enter into fractures or fracture-feature channels while minimizing gel penetration into low permeable hydrocarbon zones/matrix. PPG has adjustable sizes, from a few hundred micrometers to a few centimeters. Gel particles with the appropriate size and properties should transport through fractures or fracture-feature channels, but they should not penetrate into conventional rock or sand. However, in-situ gels behavior polymer solution when they are injected as gelants. The minimized gel penetration in low permeable areas will also result in significant reductions in the required gel volumes because fracture or fractured-like channels usually comprise less than 10% of the reservoir volume (Tang, 2005). According to polymer flooding mechanisms, more gelants will sweep into un-swept low permeability oil zones than water. Once the gelants crosslink in these oil zones, not only they will waste polymer but they will also block these zones, which will cause seriously damage on these potential productive oil zones.
2. PPG suspension can be prepared with produced water without influencing gel stability. This can not only save fresh water but it can also protect our environment. In contrast, traditional gels and nanosized particle gel Bright Water® are very sensitive to salinity, multivalent cations, and H_2S in the produced water.

3. The adjustable size and strength of PPG particles make them suitable to use "Try and Error" method for better conformance control results. Real-time monitoring data can be used to adjust previous design for better gel treatment results. The success of gel treatments depends on reservoir problem identification, appropriate candidate selection, gel selection, parameter design, and gel placement. However, reservoir is a black box, and it is not completely understood. The "Try and Error" provides an effective method to better treat the reservoir.

Field experience has demonstrated mm-sized particle gels are feasible for long-term water flooding reservoirs

*Fractures or high permeability streaks/channels widely exist in mature water-flooded reservoirs***.** Field tests and the successful injection of particle-type conformance control agents in China have demonstrated that reservoir pore structures and physical parameters have been significantly changed by long term of waterflooding. The existence of induced fractures or high permeability streaks/channels is evidenced by the following field experiences:

Interwell tracer test. Many reservoirs have no initial fracture(s), but tracer tests show in many cases it only took less than 15 days even a few days or hours for the tracers to move from an injector to its adjacent producers with a distance of around 100-300 meters. Tracer test explanation using simulation software shows that the permeabilities of these channels or streaks are usually around a few hundred to tens of thousand Darcy and their volumes are only 1 to 10% of the reservoir volume but they adsorb about 80-90% of injected water (Tang, 2005).

Gel treatments. Large volume of gel treatments (more than 5,000 m^3) using in-situ gelation systems were performed on hundreds of wells in China's oilfields in 1990s. Their gelation times were usually only a few hours to less than one day but all gelants were successfully injected even though the injections continue to 15 days even a few months. In addition, many treatments did not increase water injection pressure enough as expected after treatment.

*Particle injections***.** Many kinds of particles, such as montmorillonite clay, fly ash, are quite often applied to control conformance in China in 1990s. Many wells can be successfully injected a few thousands of cubic meters of the particle-type conformance control agents without any injection problems, which also indicated the formations had extremely large voids or fractures than we expected.

Based on above field practices, mm-sized PPG treatment was proposed to control conformance (Li, 1997, Coste, 2000, Bai, 2004, 2007). Field applications have demonstrated the mm-sized gel particles have no any injectivity problem in most mature reservoirs.

Application of PPGs for Conformance Control

The first successful large volume of PPG treatment was in Zhongyuan oilfield, SINOPEC in 1999 (Bai, 2004). The selected reservoir has serious conditions: high temperature (107 ºC) and high salinity (150,000 mg/l). So far, about 2,000 wells have been treated using PPG or PPG combined with other gels in most oilfields in China, covering both sandstone reservoirs and naturally fractured carbonate reservoirs with temperature from 20 to 110 °C and formation water salinity from 2,000 to 280,000 mg/l. The common weight of PPG is from 8 to 40 tons and concentrations range from 1,000 to 5, 000 mg/l. For example, PPG has been applied in Daqing oilfield since 2001. Ninety-one wells were treated from 2001 to 2004, 44 wells from water flooding area and 47 wells from polymer flooding area. Injected PPG concentrations are from 1,500 to 4,500 mg/l, and injection volume of PPG suspension is from 5,000 to 200,000 m^3. PPG alternating with water or continuous injection method is used depending on pressure response during PPG injection. After treatments, average water injection pressure increased about 0.6 MPa. There are 366 producers connecting with these treatment wells. Average incremental oil of these producers is about 2.6 t /d/well and water cut decreased about 2.6% (Liu, 2004). More than 200,000 tons of oil was increased from these treatments. For the application in the polymer flood area, the produced polymer concentration also decreased (Ma, 2004). PPG treatment has been widely accepted and is seeing more use by the operators in Chinese oilfields.

Limitation for PPG Application

PPG can be used to control conformance for the reservoirs with small fractures or high permeability channels. But 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 producers.

Case Study on Large volume of PPG treatments in Daqing

The selected pilot is in one block of Lamadian reservoir in Daqing oilfield shown in Fig. 3. Their production intervals are PI_4 to GI_{4+5}. Each individual zone is relatively thick and their inner-layer heterogeneity is very serious. The oil-bearing area is 2.43 km^2. The initial-oil-in-place is 594 $\times 10^4$ t. The block was produced for more than 30 years and the average water cut was 95.4% before gel treatments. The reservoir temperature is around 40 ºC and its formation water salinity is around 4,000 mg/l.

Criteria to Well Candidate Selection

The selection of a good candidate is based on the comprehensive understanding on the reservoir geology, wellbore and near wellbore conditions, reservoir survenlance results, and static and dynamic reservoir information. The well candidate selection criteria were set as follows for the large volume of PPG treatments in Daqing:

- The well must be located in the main sand body of the fluvial depsitional reservoir with thick oil pay zone and good connectivity with adjacent producers.
- The well must have strong injectivity; the water injection pressure and starting pressure are lower than their average of the whole block.
- The connected producers have relatively high average water cut comparing to other well groups.

- Vertical or areal heterogeneity is very serious, and the inner-layer permeability contrast is large, and both injection profile and the production profiles of connected production wells are extremly not homogenous.
- The degree of water-flooded region is very different; there exist middle, low and none flushed zones.

Four injection wells, 7-1827, 7-1927, 8-1827 and 9-1927, were selected based on these criteria and comprehensive geological and engineering understanding on the block. Large volume of PPG treatments were carried out from the year of 2003 to 2004 and the target zone was PII. The distance of each injection and its connected edge producer is 300 m. There are 46 production wells connected to these four treated wells. Twenty-three of them are only produced from PII and the other 23 are comminglely produced from the interval PII and other intervals. Table 1 shows the basic parameters for the selected four wells. In the table, the maxium permeability refers to the permeability of the most permeable portion of that specified intervals from well logging. The starting pressure refers to the minimum wellhead pressure that water starts to enter the formation. That is, the water cannot enter the formation if the injection pressure is smaller that the starting pressure. PI is the pressure index which is from the pressure drawdown test for a period of 90 minutes after an injection well is shut down. The PI(90) is calculated from the equation:

$$PI(t) = \frac{\int_0^T p(t)dt}{T} \qquad (1)$$

Where

PI (t)---Pressure Indiex, MPa

P(t)---Pressure at the time t after a well is shut in, MPa.

t---shut in time, min, usually t is set as 90 minutes.

PPG Selection

The selection of PPG mainly considers its compatibility with produced water, swelling ratio, strength after swollen in the injection water and particle size (Bai, 2001, Liu, 2004). Six samples were evaluated for best PPG candidate for the pilot. Results show all PPGs have good compacity with produced water in the pilot and they are thermally stable at reservoir temperature for more than 2 years. Table 2 shows the evaluation results for PPG size, swelling ratio, pessure resistance, and breakthrough pressure. All particle dispersions were prepared by produced water from the pilot. The PPG size was seived by screens with proper mesh sizes. The sweeling ratio is the gel mass ratio after and before swelling. The pressure resistance is defined as the minimum pressure that the swollen particle resists before breaking into smaller particles. The breakthrough pressure is defined as the mimimum water injection pressure that water can be injected after PPG is placed in the cores and the data in the table is measured using the cores with permeabilities of 3-3.5 μm^2 by the injection of 1,000 mg/l of 250 mesh PPG particles (61 μm). The WT product was selected for the pilot because it had relatively high swelling ratio and enough strength.

PPG Treatment Design

Design of Injection Parameters

Reservoir simulation was run to optimize PPG dispertion volume in terms of the input-output ratio. It is assumed that the PPG dispertion only enter those fully flushed areas with residual oil while not low- and none-flushed areas. After the gel placement, the permeability of those areas that are placed by PPG is equal to the permeability of low permeability zone. This assumption is based on the gel property of which gel can reduce permeability to same level (Bai, 1997). The equation to calculate input-output ratio is as follow:

$$R = \frac{e_3 Q_p + e_4 + e_5 + e_6}{e_1 \Delta Q_o + e_2 \Delta Q_w} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots (2)$$

Where

e_1 ---oil price, \$/t;

e_2 ---produced water treatment cost, $\$/m^3$;

e_3 ---PPG price, \$/t;

e_4 ---operation cost for PPG injection, \$;

e_5---well service cost due to PPG treatment, \$;

e_6 ---well testing costs, \$;

Q_p---dry PPG particle cost, \$/t;

ΔQ_o---incremental oil, t;

ΔQ_w---decreased oil, t;

R---input-output ratio.

The designed concentration was based on previous successful field experience and laboratory coreflooding testing results. Coreflooding tests showed that low concentration PPG particles had less relatively stable injection pressure and could easier move into in-depth of a reservoir than high concentration PPG particles (Bai, 2001). Field application also demonstrated that low concentration large volume of PPG injection is a key to a successful PPG treatment. Before the first successful application of PPG treatment in Zhongyuan (Bai, 2007), PPG was used in a number of wells but was not very successful. Comparing to those successful treatments, the main difference was that those unsuccessful treatments used high concentration or small amount of PPG. High concentration PPG injection may result in a vigorously vibrating bottom hole

pressure, which may cause new hydraulically fractures near wellbore. Most successful applications in China were used PPG suspension with concentration below 5,000 mg/l. The designed concentration was given in a range for each well and the actual concentration was planned to adjust according to real-time injection pressure reponse during PPG injection. To make the front PPG slug move into in-depth, PPG injection was designed to start from small size particle and would be adjusted according to the real-time crawling pressure during PPG injection. Low injection rate, similar to previous water injection rate, was designed to reduce PPG damage on low-permeability oil zone. The pilot is close to polymer flooding area and it is easy to get polymer solution, so 200 mg/L polymer was used to better suspend and carry PPG particles. Table 3 shows the optimized PPG dispersion volume, PPG weight and other designed injection parameters for each treated well.

Practical Field Injection Parameters

The totoal 132 tons of PPG with a cumulative suspension volume of 56,268 m^3 was injected. Comparing with the design, six more tons of PPG was injected with additional volume of 3,939 m^3. Table 4 compares the design and practical results. The main reason to increase PPG amount was that the pressure did not increase as expected for wells 7-1937 and 7-1827. The volume of PPG suspension was increased because the well 9-1827 was difficult to inject using designed concentration of 2,000-3,000 mg/l. So the PPG concentration was reduced to prevent the PPG injection pressure from fracturing the reservoir. The volume was increased 2,922 m^3 after its PPG concentration decreased. Mutiple slugs were injected for each well. Tables 5-8 summarize the PPG suspension volume, particle size, swollen PPG volume, and PPG weight for each slug of each well. The swollen particle volume refers to the total particle volume after swelling, which is calculated using the swelling ratio of 70 and dry PPG density of 1.8 g/cm^3.

Real-time Monitoring of PPG Injection

The wells 7-1937 and 7-1827 started to inject at September 5, 2003 and ended at Jan 10 and Jan 31, seperately. The Wells 8-1827 and 9-1827 started to inject PPG at September 26, 2003 and ended at Feb 3, 2004, respectively. The real-time pressure was monitered for each well during PPG injection. Particle sizes and PPG concentrations were adjusted according to real-time pressure change. Figures 3-6 show the pressure history, particle sizes and PPG suspension volume for four wells seperately. As shown in each figure, the injection pressure did not increase very fast and very much during PPG injections. No injectivity problem existed in theses wells even though they were claimed no fractures in these wells. In addition, there is no particle production from connected adjacent producers during PPG injection.

Reservoir Peformance during and after PPG injection

Two methods were used to evaluate the reservoir performance during and after PPG treatment. One method is to measure injection profile, which reflects the plugging effect of PPG on different zones near wellbore. Another method is to perform welltest, including starting pressure, injection pressure at the same injection flow rate as that before treatment, and pressure drawdown test for pressure index PI(90). These parameters reflect the PPG plugging in the in-depth of the reservoir. The pressure gauge was set at the depth of 500 m below the wellhead when drawdown pressure was measured.

Well test results. The pressure drawdown test was performed when 30% of accumulative PPG suspension was injected for each well. As shown in the Table 9, the PI(90)s were increased 7.43, 0.93, and 0.42 MPa for wells 7-1937, 8-1827 and 9-1827, respectively. The injection pressure of well 7-1827 was increased 1.2 MPa but the PI(90) did not change. After finishing PPG treatment, the pressure drawdown test was performed again for each well. Table 10 compared the PI(90) and injection pressure before and after treatments. The PI(90)s and injection pressure were significantly increased for each well. Figures 8-11 show the pressure drawdown test curves before, during and after gel treatments for each treated well.

Water injection profiles. The water injection profile was measured for each well when 30% of accumulative PPG suspension was injected and after gel treatments. The well 7-1827 was failed to measure during PPG injection because a block in the wellbore prevented the measurement. Figures 12-15 show the history of injection profiles for each well. Table 11 summarizes the injection profile change before and after treatments. All injection profiles were significantly improved after treatments.

Production Performance

The treatments resulted in increased oil production and decreased water cut. Table 12 showed the results of 26 comparable wells which connected to treated wells and had no other well services and opertations. After treatments, the oil production rate increased 34.8 t/d and water cut reduced 0.94% for the 26 wells at the condition without considering production decline. Figure 16 shows 24 well production curves before, during and after PPG treatment. Before the PPG treatment, oil rate graduately decreased and water cut increased. Immediately after PPG start to be injected, the oil decline trend was decreased and the oil rate increased after PPG treatment. The cumulative incremental oil is about 15,000 tons until March 2005, which means 113 tons oil increasement per ton of PPG injection. The output-input ratio can be calculated as follow:

PPG costs: $132 \text{ tons} \times (1.46 \times 10^4) \text{ RMB/ton} = 192.72 \times 10^4 \text{ RMB}$

PPG injection costs: $4 \text{ wells} \times (18 \times 10^4) \text{ RMB/well} = 72 \times 10^4 \text{ RMB}$

Injection profile measurement: $8 \text{ times} \times (1.1 \times 10^4) \text{ RMB/time} = 9.9 \times 10^4 \text{ RMB}$

Pressure drawdown test: $12 \text{ times} \times (0.8 \times 10^4) \text{ RMB/time} = 9.6 \times 10^4 \text{ RMB}$

Total input: 284.22×10^4 RMB

Oil price: 2,100 RMB/ton (~40 $/bbl)

Output from oil sales: $15{,}000 \text{ tons} \times (0.21 \times 10^4) \text{ RMB/ton} = 3150 \times 10^4 \text{ RMB}$

Output-Input ratio: 11.08

Discussion

Seright (Seright, 1994) suggested to use the following simple injectivity calculation to establish the nature of a channeling problem.

$$\frac{q}{p_e - p_{wf}} = \frac{\sum kh}{141.2\,\mu \ln \frac{r_e}{r_w}} \qquad (3)$$

Where q --- Injection rate, bbl/d
p_e --- Reservoir pressure, psi
p_{wf} --- Bottom hole flowing pressure, psi
h --- Perforated net pay practicle thickness that absorb water, ft;
k --- Average permeability of perforated net pay, md;
r_e --- Drainage radius, ft;
r_w --- Wellbore radius, ft;

If the injectivity calculated by the right side of eq. 3 is substantially less than the actual q/Δp, then a fracture or formation part is probally present. When calculation is made using above equation, the formation pressure p_e and bottom hole flowing pressure p_{wf} have to be used. In practical, it is not easy to obtain accurate data for p_e and p_{wf}, so modified equation can be used to avoid the use of p_e and p_{wf}. The equation is as follow:

$$\frac{q_1 - q_2}{p_{wh1} - p_{wh2}} = \frac{\sum kh}{141.2\,\mu \ln \frac{r_e}{r_w}} \qquad \textbf{(4)}$$

Where
p_{wh1}---wellhead pressure at flow rate q_1,
p_{wh2}---wellhead pressure at flow rate q_2,

The value of (q_1, p_{wh1}) and (q_2, p_{wh2}) can be obtained from step-rate injectivity test. Similar to Seright's criteria, if the calculation from the right side of eq. 4 is substantially less than the actual $(q_1-q_2)/(p_{wh1}-p_{wh2})$, the a fracture or formation part is probally present. Actually the $(q_1-q_2)/(p_{wh1}-p_{wh2})$ is the slope of the q - p_{wh} plot from step rate tests.

Figures 17-20 show the step rate test results and fitting equation for each layer of each treated well. Table 13 shows the calculation results using eq. 4 and the step test fitting equation. The drainage radius was 492 ft and the wellbore radius used 0.328 ft and water viscosity was 0.6 cp. The height "h" was calculated by net pay thickness times the percentage of net pay thickness that absorbed main water shown in Table 1. The $(q_1-q_2)/(p_{wh1}-p_{wh2})$ was multiplied by water absorbed percentage of main water absorbing zones shown in Table 1 for the left side of the equation. Comparing the last two columns in the Table, it is shown that the left one is smaller than the right one. Therefore, the simple calculation does indicate the existence of fractures in these wells.

Although the above calculation does not show the existence of obvious fractures in these wells, coreflooding tests uniquely demonstrate the porous media should have super-K channel with permeability of more than 50 Darcy if mm-size particles, 0.06-0.9 mm, can be injected into the porous media without significant injection pressure increase (Bai, 2001). If we assume there are fractures in each well. The fracture volume can be calculated by the following equations.

For vertical fracture:

$$V = 2 \cdot h_f \cdot w_f \cdot L_f \quad \text{……..(5)}$$

Where: V --- fracture volume, m^3
h_f--- fracture height, m
w_f--- fracture width, m
L_f--- fracutre length, m.

For horizontal fracture:

$$V = \pi L_f^{\,2} \cdot w_f \quad \text{……..(6)}$$

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

If we assume the fracture is horizontal in the area, and L_f=300, w_f= 5 mm, the fractured volume is 1413 m^3.

Comparing the fracture volume to the swollen particle volume shown in Tables 5-9, it indicates horizontal fractures are more possible for the reservoir. In fact, the reservoir depth is around 1,000 m and many people in Daqing have claimed the hydraulically fracture should be horizontal for this area.

Conclusions

1. Preformed gels overcome some distinct drawbacks inherent in in-situ gelation systems. Millimeter-sized preformed particle gel (PPG) is unique due to its advantages over other particle gels.
2. There is no injectivity problem for large volume of mm-size PPG treatment for most wells in mature oilfields. All four wells in the case were successfully injected more than 10,000 m^3 of PPG suspension without abrupt pressure increase.
3. Real-time PPG injection pressure response can be used to adjust PPG particle size concentration to better fit reservoir. Real-time monitoring data can be used to adjust previous design for better gel treatment results.
4. PPG treatment is a cost-effective method to control conformance. The four treatments successfully resulted in improved oil production and reduced water production and better injection profile.
5. Simple calculation does not indicate the existence of fracture in these wells, but coreflooding test did indicate there should exist super-high permeability channels otherwise such large amount of PPG cannot be steadily injected into these wells.
6. The vertical and horizontal fracture volumecalculations indicate it is more probable to have horizontal fractures than vertical fractures if there exist fractures in these wells.

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Table 1. Basic Parameters of four treated wells before PPG injection

Well Name	Objective Zones	Gross Thickness (m)	Net pay thickness (m)	k_{max} (μm^2)	Starting pressure (MPa)	Wellhead Injection Pressure (MPa)	Injection Rate (m^3/d)	Main water-absorbing zones		PI (90) (MPa)
								Thickness (%)	Water Asborbed (%)	
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
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

Table 2. Evaluation results for six samples

No.	Product Name	Particle Size (mm)	Swelling Ratio		Pressure Resistance (MPa)	Breakthrough Pressure (MPa/m)	Notes
			Intial (t =10 min)	Final			
1	GS	3-5	5	117	/	4.1	Very weak
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		

Table 3. Designed injection parameters for four well PPG treatments

Well Name	Water Injection Rate before treatment （m^3/d）	PPG Injection rate （m^3/d）	Dry PPG (kg)	Particle size （mm）	PPG Suspension Volume (m^3)	Concentration (mg/l)	Maximu 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	0.16 －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

Table 4. Comparison of designed and practical injection parameters

Well Name	Duration of PPG treatment	Practical injection time (D)	Design			Practical Injection			Difference	
			Dry PPG (t)	PPG Suspension Volume （m^3）	PPG concentration (mg/l)	Dry PPG Weight （t）	PPG Suspension Volume （m^3）	PPG Concentration (mg/l)	Dry PPG weight （t）	PPG Suspension Volume （m^3）
7-1937	2003.9.5-2004.1.10	119	32	13,445	2,000～3,000	35	13,528	2,587	3	83
7-1827	2003.9.5-2004.1.31	124	41	17,135	2,000～3,000	43	17,625	2,440	2	490
8-1827	2003.9.25-2004.2.3	97	32	13,214	2,000～3,000	32	13,658	2,343	0	444
9-1827	2003.9.25-2004.2.3	108	21	8,536	2,000～3,000	22	11,458	1,920	1	2,922
合计			126	52,330		132	56,269	2,346	6	3,939

Table 5. Practical PPG Injection Parameters for Well 7-1827

Start Injection Date	09/05/2003	End date		01/31/2004	
Practical Injection Duration	148 Days	Injection rate (m^3/d)		128	
Dried PPG Weight (t)	43	PPG concentration (mg/l)		2,240	
Initial injection pressure	5.6 MPa	Maximum Injection Pressure (MPa)		8.6	
Slugs					
	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
Notes	Around 200 ppm polymer solution was used as a carrier fluid				

Table 6. Practical PPG Injection Parameters for Well 7-1937

Start Injection Date	09/05/2003	End date			01/10/2004	
Practical Injection Duration	124 Days	Injection rate (m^3/d)			130	
Dried PPG Weight (t)	35	PPG concentration (mg/l)			2,587	
Initial injection pressure	4.9 MPa	Maximum Injection Pressure (MPa)			.8.2	
Slugs						
	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
Notes	Around 200 ppm polymer solution was used as a carrier fluid					

Table 7. Practical PPG Injection Parameters for Well 8-1827

Start Injection Date	09/22/2003	End date		02/03/2004
Practical Injection Duration	134 Days	Injection rate (m^3/d)		138
Dry PPG Weight (t)	32	PPG concentration (mg/l)		2,343
Initial injection pressure	9.0 MPa	Maximum Injection Pressure (MPa)		11.60
Slugs				
	1st slug	2nd slug	3rd slug	Total
Particle size (mm)	0.06-0.16	0.16-0.45	0.45-0.9	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
Notes	Around 200 ppm polymer solution was used as a carrier fluid			

Table 8. Practical PPG Injection Parameters for Well 9-1827

Start Injection Date	09/25/2003	End date		02/03/2004
Practical Injection Duration	131 Days	Injection rate (m^3/d)		138
Dry PPG Weight (t)	22	PPG concentration (mg/l)		1,920
Initial injection pressure	7.6 MPa	Maximum Injection Pressure (MPa)		11.02
Slugs				
	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
Notes	Around 200 ppm polymer solution was used as a carrier fluid			

Table 9. Pressure test result when 30% PPG was injected

Well Name	Starting Injection Date	Before PPG Injection			After 30% PPG Injection			Difference	
		PI（90）		Injection Pressure (MPa)	PI（90）		Injection Pressure (MPa)	PI(90) (MPa)	Injection Pressure (MPa)
		Measured Date	PI(90) (MPa)		Measured Date	PI(90) (MPa)			
7-1937	9/5/2003	6/11/2003	6.95	5.0	10/21/2003	14.38	7.2	7.43	2.2
7-1827	9/5/2003	8/12/2003	9.12	5.7	10/27/2003	9.13	7.2	0.01	1.3
8-1827	9/24/2003	6/30/2003	10.98	8.8	10/22/2003	11.91	10.7	0.93	1.9
9-1827	9/25/2003	6/30/2003	11.12	6.5	10/16/2003	11.54	9.9	0.42	3.4

Table 10. 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

Table 11. Water injection profile comparision before and after PPG treatment

Well Name	Target Zone	Water Intake interval	Before Treatment		After Treatment		Difference	
			Percentage to intake water（%）	Water Intake（m^3/d)	Percentage to intake water（%）	Water Intake（m^3/d)	Percentage to intake water（%）	Water Intake（m^3/d)
7-1937	$P_{II\,1\text{-}9\underline{U}}$	Low*	26	7	61	69	35	62
		High*	74	20	39	45	-35	25
	$P_{II\,1\text{-}10L}$	Low	25	16	100	45	75	29
		High	75	49	0	0	-75	-49
7-1827	$P_{II\,1\text{-}6}$	Low	18	11	63.6	35	45.6	24
		High	82	50	31.1	55.3	-50.9	5.3
	$P_{II\,5\text{-}9}$	Low	25	14	100	123	75	109
		High	75	42	0	0	-75	-42
8-1827	$P_{II\,4\text{-}9}$	Low	28	24	88	84	60	60
		High	72	60	12	11	-60	-49
	$P_{II\,7\text{-}9}$	High	100	60	100	35	0	-25
9-1827	$P_{II\,1\text{-}6}$	High	47	45	28	17	-19	-28
		Low	8	8	15	9	7	1
		High	29	28	0	0	-29	-28
		Low	16	15	57	34	41	19

Note: Low refers to the interval with low water intake capacity, and High refers to the interval with high water intake capacity.

Table 12. Performance comparsion of 26 connected production wells without other operations

Well type	Number of Producers	Before PPG treatments			After PPG treatment (Aug 2004)			Difference		
		Liquid（t）	Oil（t）	Water cut（%）	Liquid（t）	Oil（t）	Water cut（%）	Liquid（t）	Oil（t）	Water cut（%）
Wells only produced from PII	11	604	26	95.7	563	32.8	94.2	-41	6.8	-1.52
Commingle Wells	15	3717	161	95.7	3644	189	94.8	-73	28	-0.86
Total	26	4321	187	95.7	4207	221.8	94.7	-114	34.8	-0.94

Table 13. Determination of Potential Fractures

Well Name	Layer	k (md)	h (ft)	$(q_1\text{-}q_2)/(p_{wh1}\text{-}p_{wh2})$ (bbl/psi)	$(q_1\text{-}q_2)/(p_{wh1}\text{-}p_{wh2})\times f_q$ (bbl/psi)	$kh/(141.2\mu ln(r_e/r_w)$ (bbl/psi)
7-1827	$P_{II1\text{-}5}$	500	3.18	0.617	0.457	2.60
	$P_{II5\text{-}9}$	360	2.51	0.504	0.450	0.87
7--1937	$P_{II1\text{-}10}$	460	9.84	0.278	0.158	4.38
8-1827	$P_{II\,4\text{-}9}$	280	6.74	0.257	0.201	3.05
	$P_{II7\text{-}9}$	220	2.41	0.621	0.494	0.86
9-1827	$P_{II1\text{-}6}$	240	11.18	0.392	0.290	2.60

Note: f_q is the percentage absorbed water of main water-absorbing zones shown in Table 1.

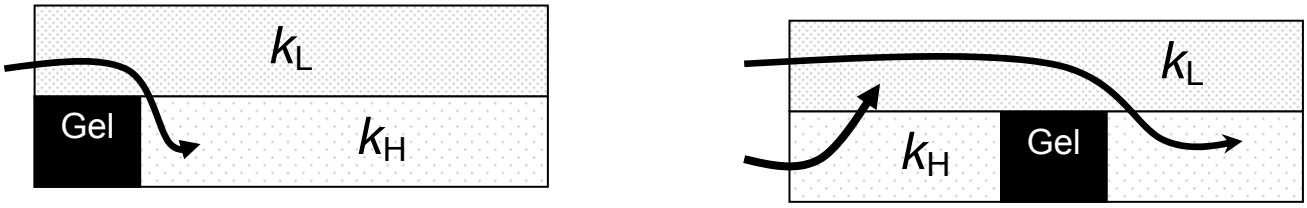


Fig. 1. Gel treatment for heterogeneous formation with crossflow
(Near well treatment has little effect on sweeping oil but in-depth treatment can improve sweep efficiency)

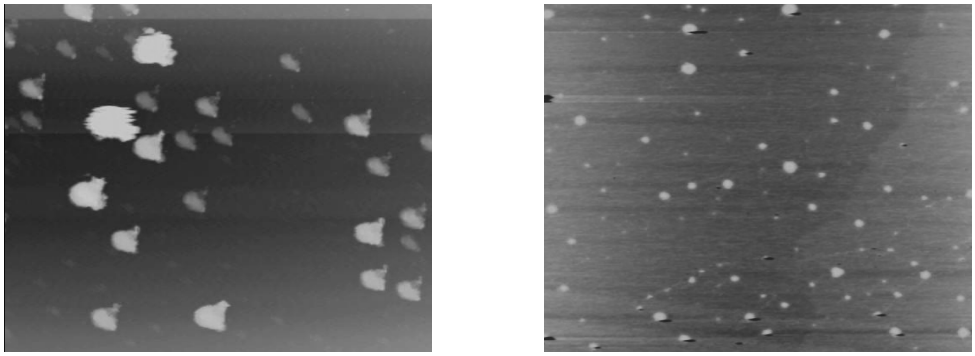


Fig.2. Dispersed gel particles from porous media.

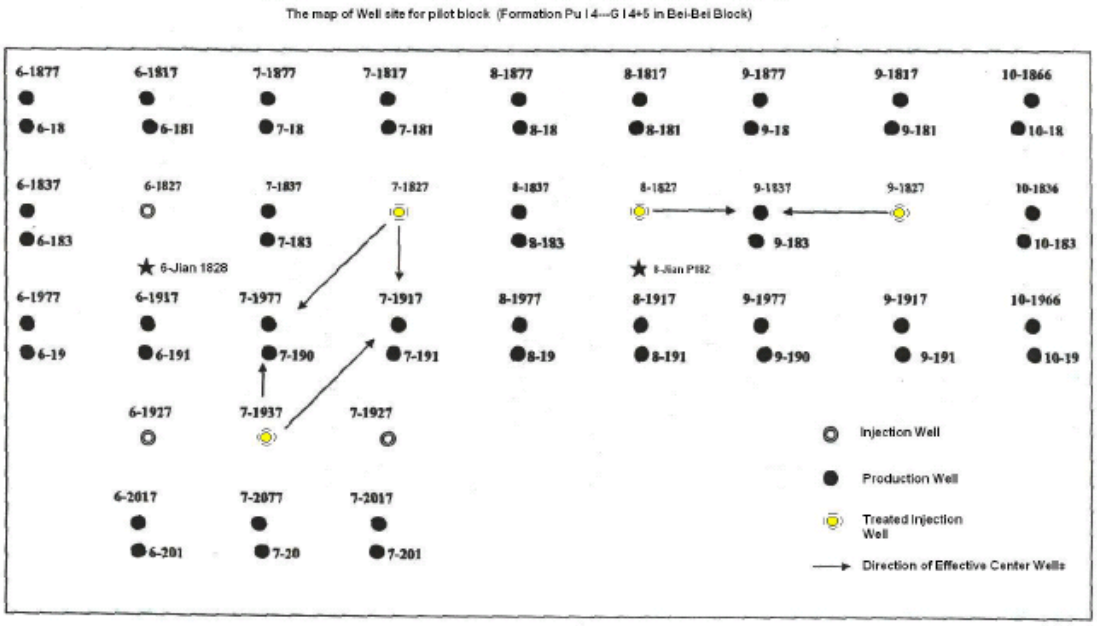


Fig.3. Well location map for the pilot.

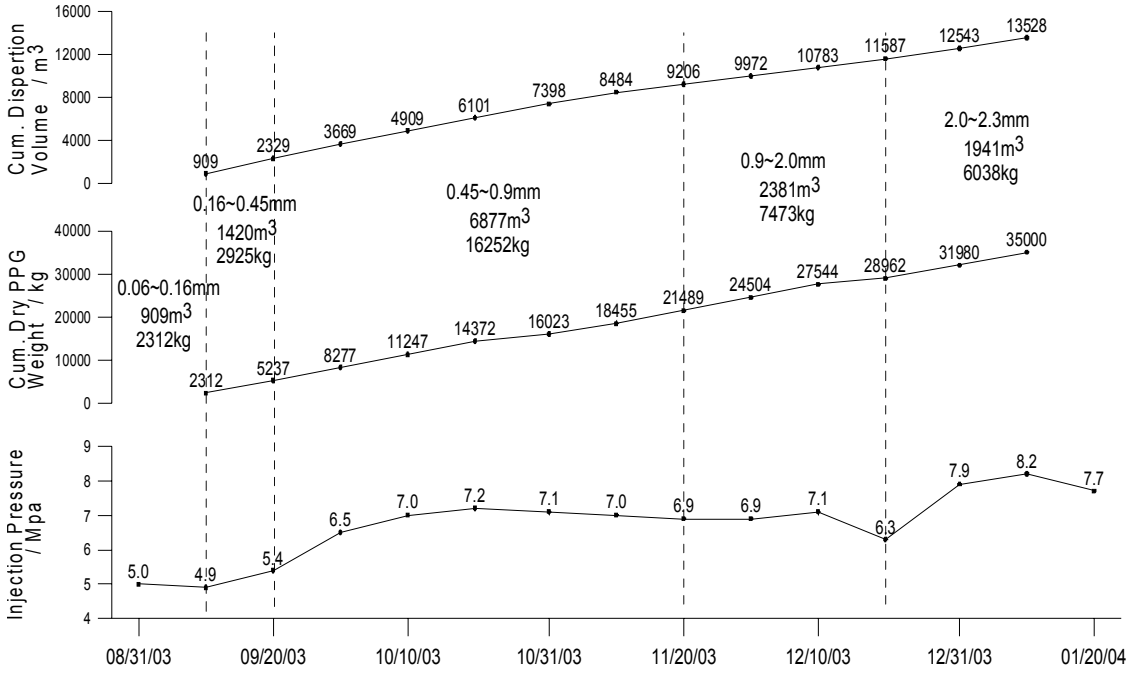


Fig.4. PPG Injection Curve for Well 7-1937

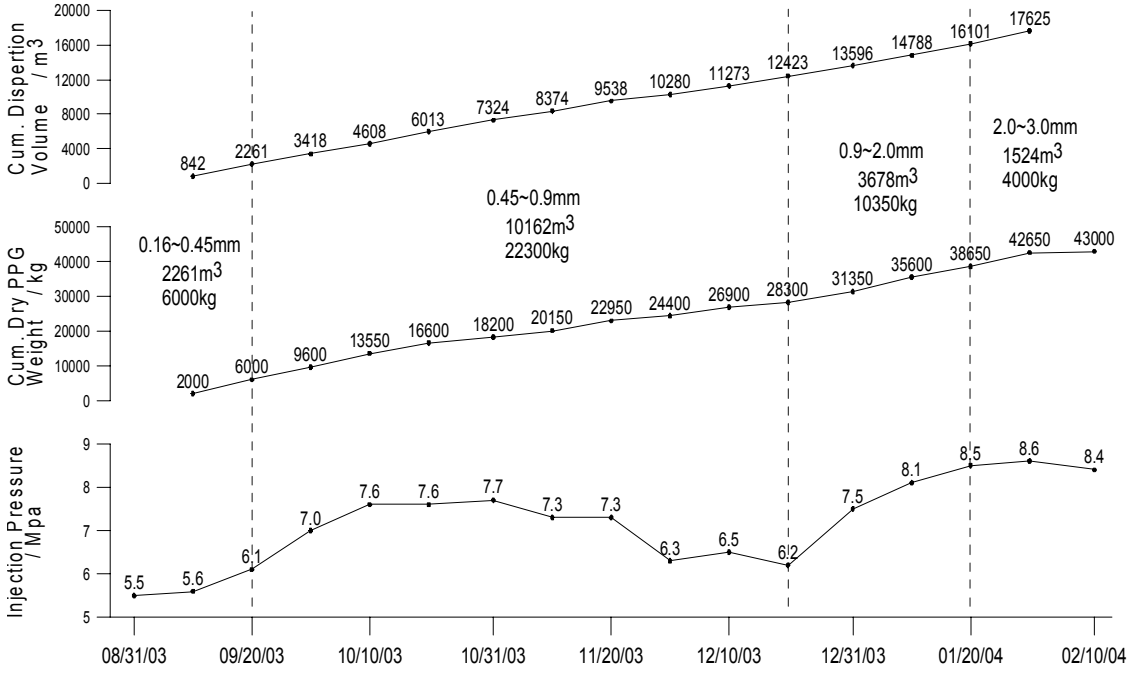


Fig.5. PPG Injection Curve for Well 7-1827

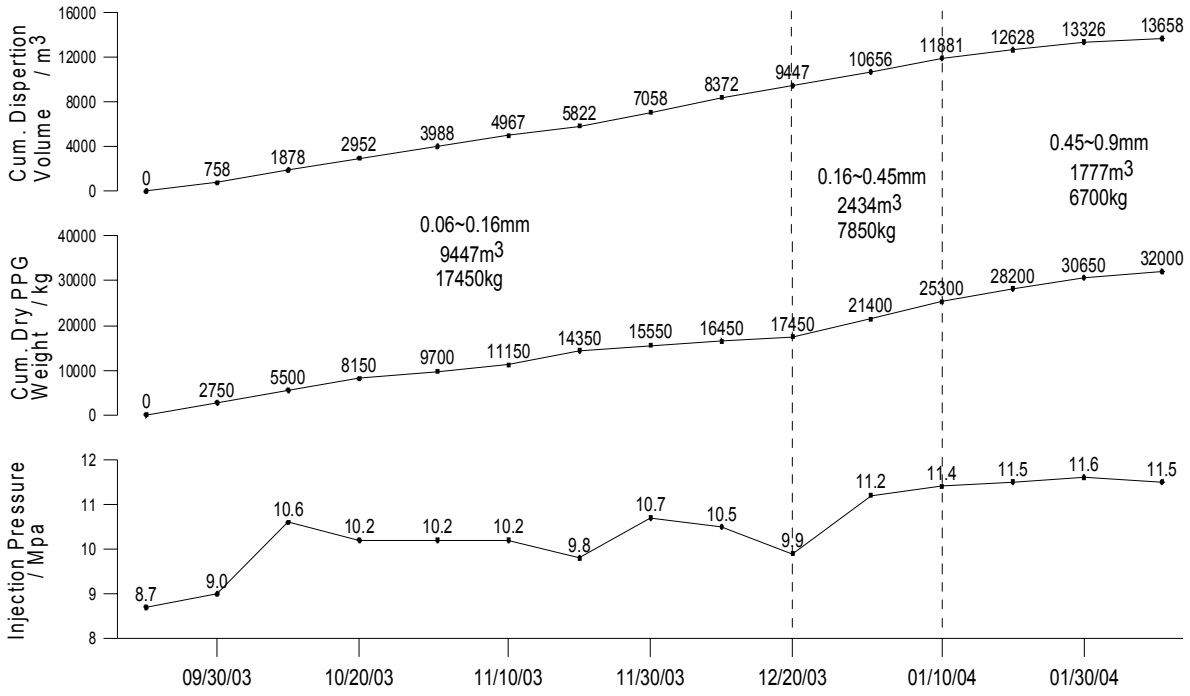


Fig.6. PPG injection curve for Well 8-1827

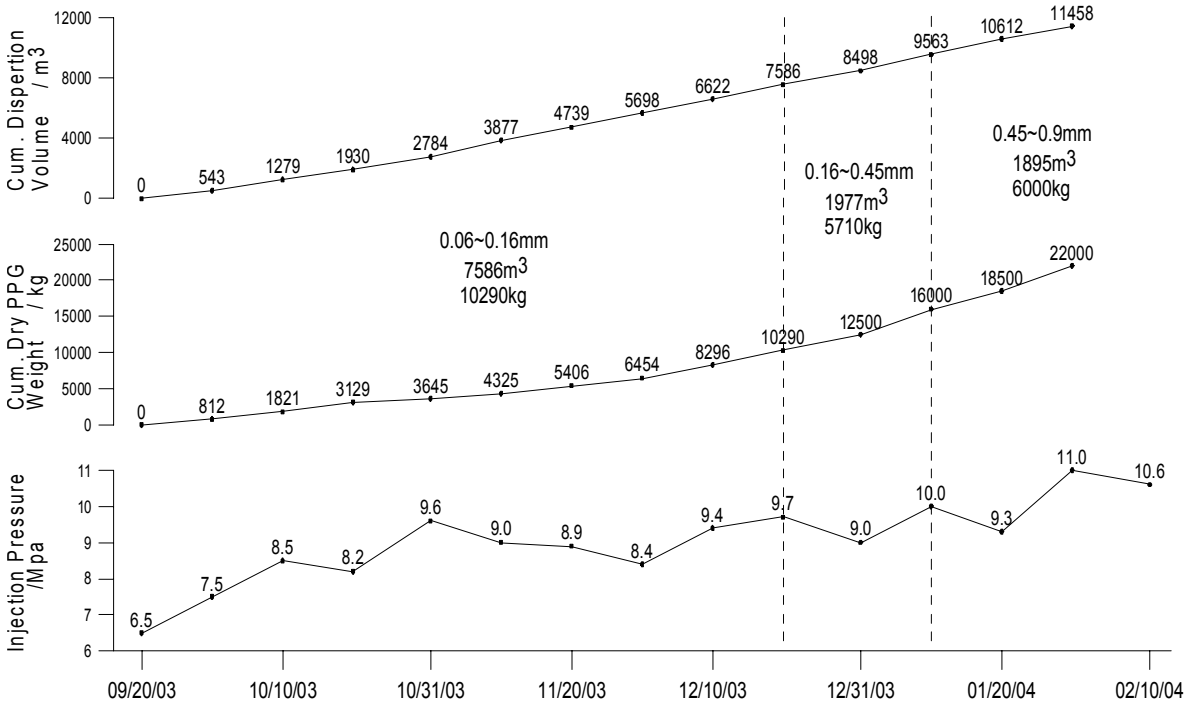


Fig.7. PPG Injection Curve for Well 9-1827.

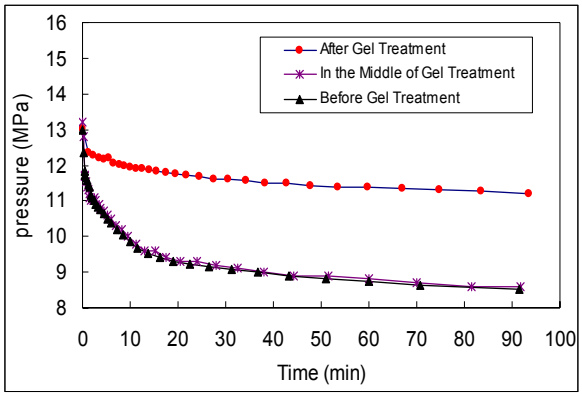


Fig. 8. Pressure drawdown test curve for well 7-1827

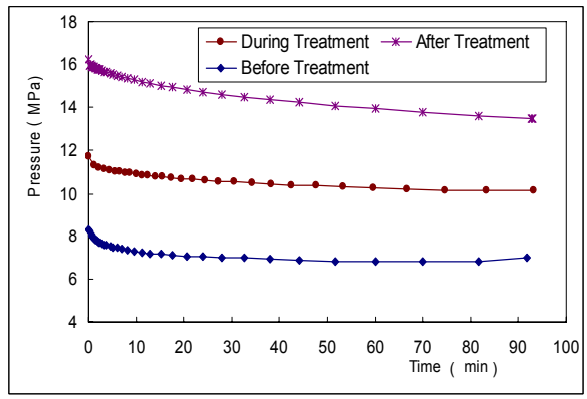


Fig. 9. Pressure drawdown test curve for well 7-1937

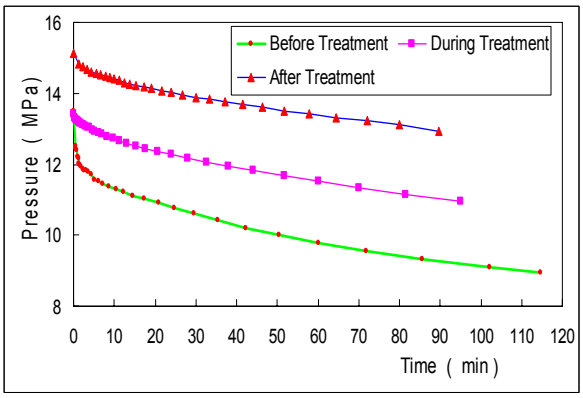


Fig. 10. Pressure drawdown test curve for well 8-1827.

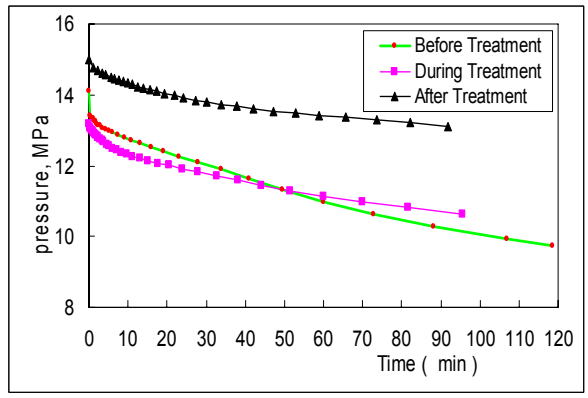


Fig. 11. Pressure drawdown test curve for well 9-1827.

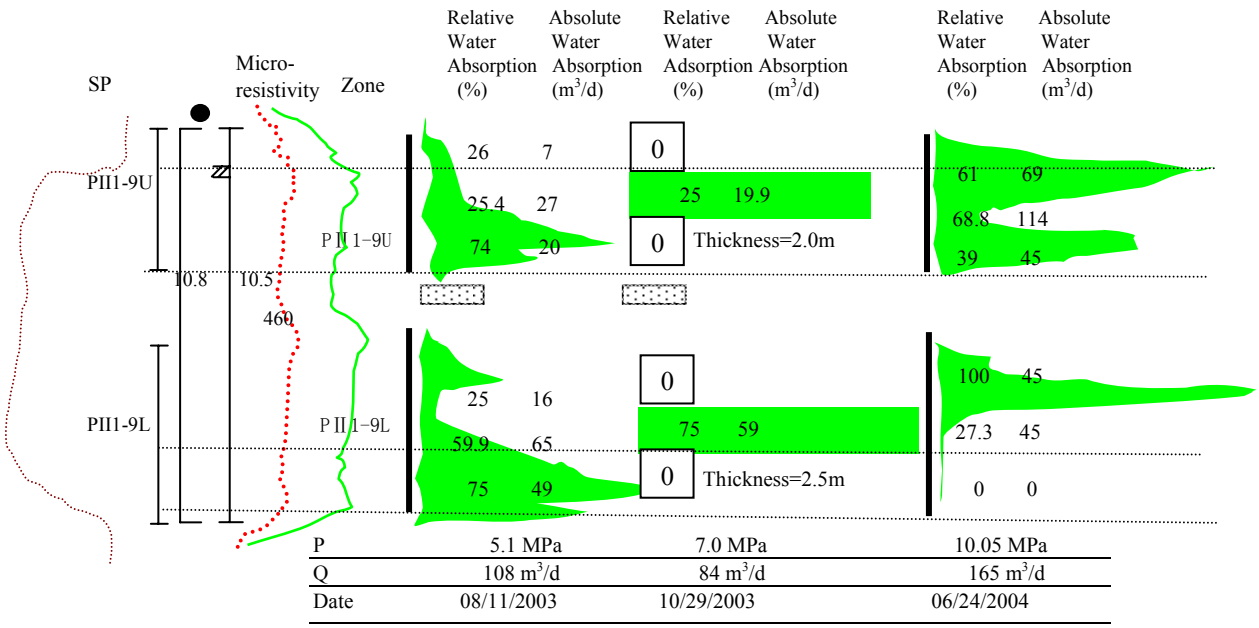
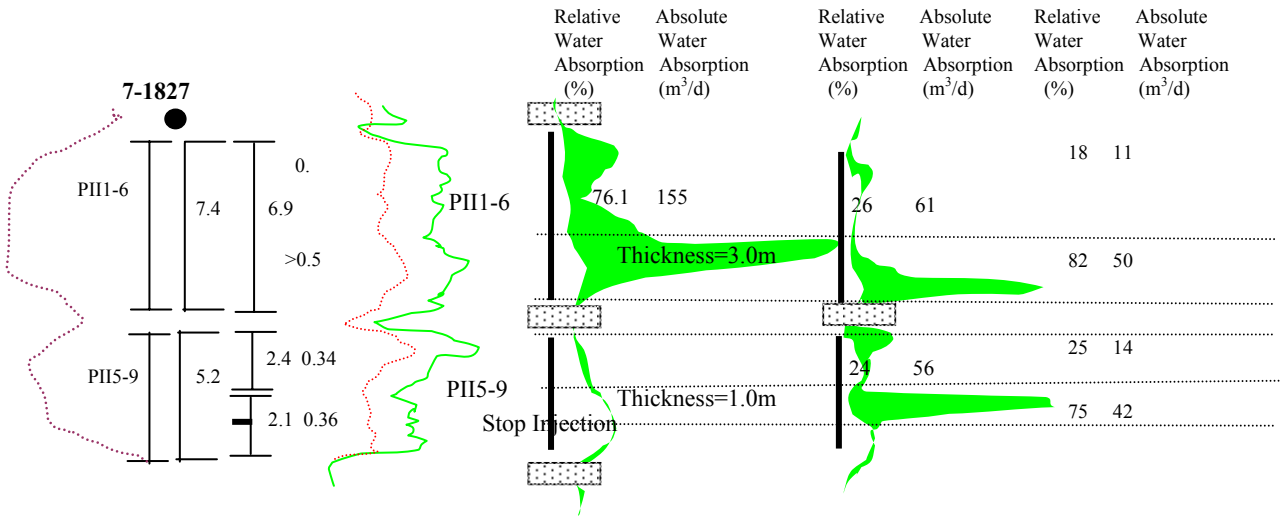


Fig.12. Well 7-1937 Water Injection Profile (Sept. 5th, 2003~Jan. 10th, 2004)



P	8.2 MPa	12.6 MPa	11.6MPa
Q	108 m^3/d	84 m^3/d	165 m^3/d
Date	01/18/2004	12/2/2004	09/3/2004

Fig. 13. Well 7-1827 Water Injection Profile (Sept. 5th, 2003~Jan. 31st, 2004)

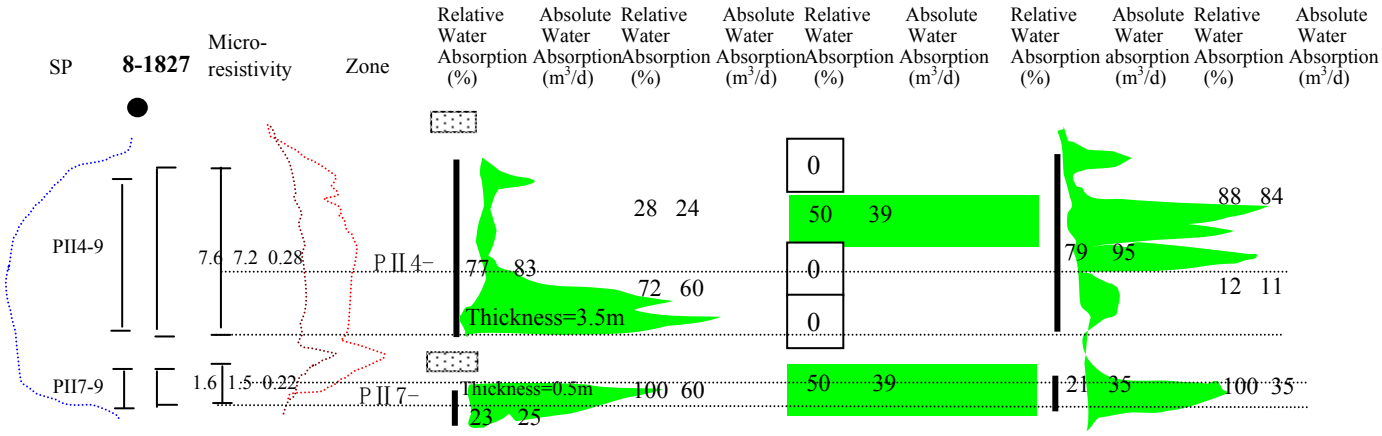


Fig. 14, Well 8-1827 Water Injection Profile (Sept. 5th, 2003~Jan. 31st, 2004)

P	11.3 MPa	7.0 MPa	120 MPa
Q	108 m^3/d	84 m^3/d	84 m^3/d
Date	07/1/2003	10/30/2003	02/13/2004

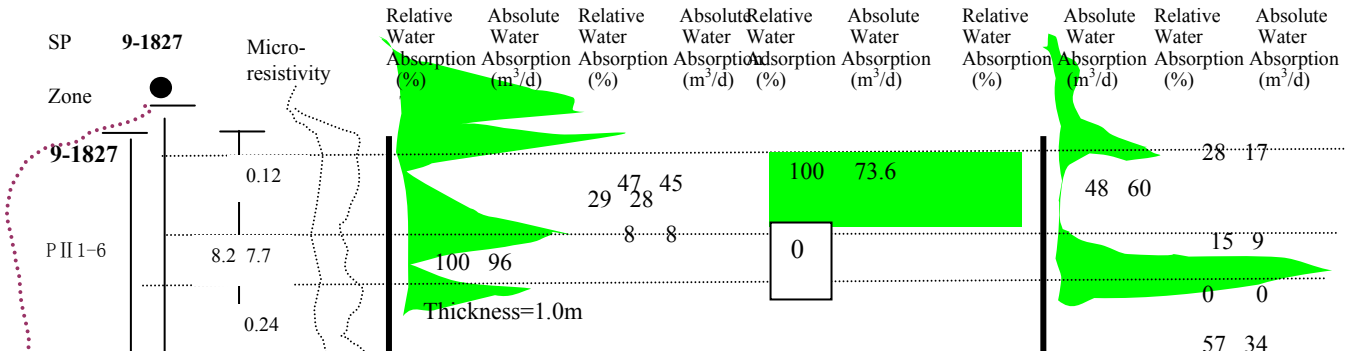


Fig.15. Well 9-1827 Water Injection Profile (Sept. 25th, 2003~Feb. 3rd, 2004)

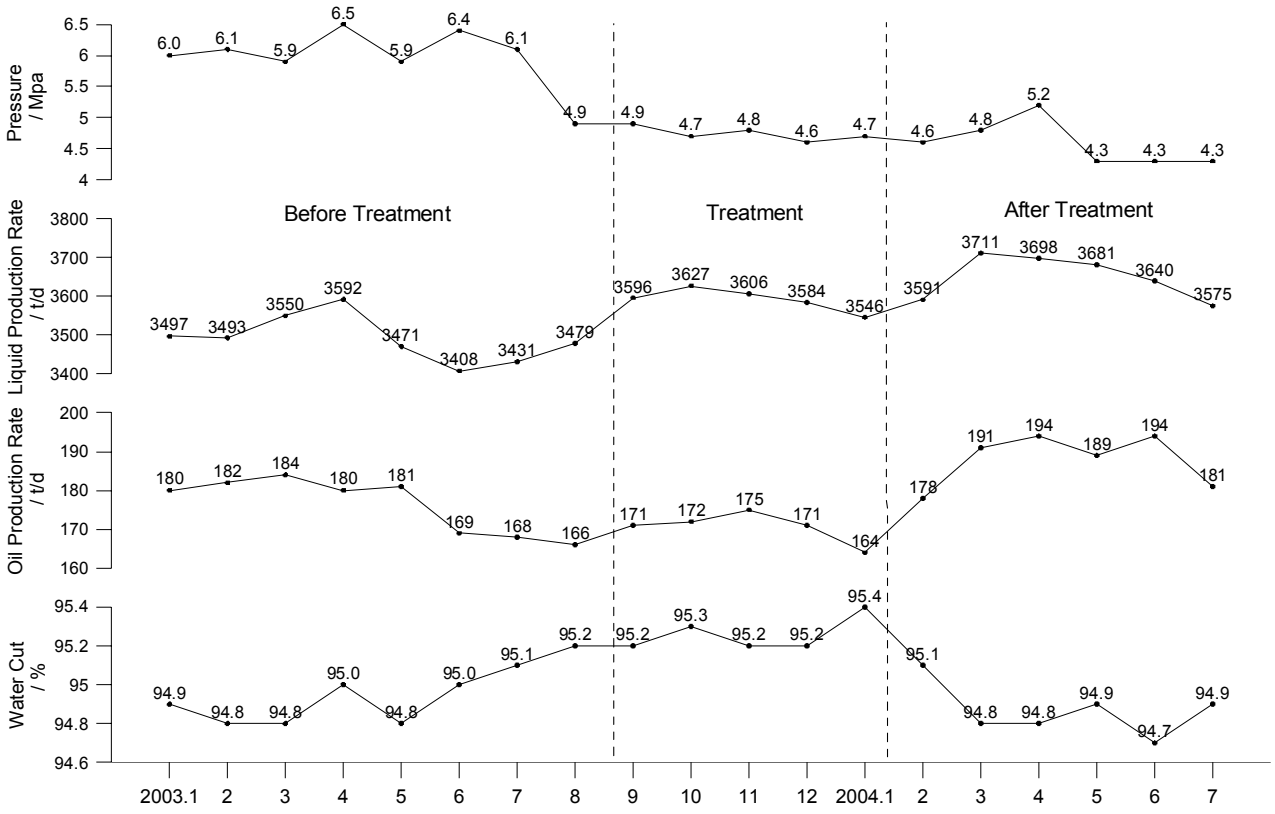


Fig. 16. Production curve for 24 connected curves

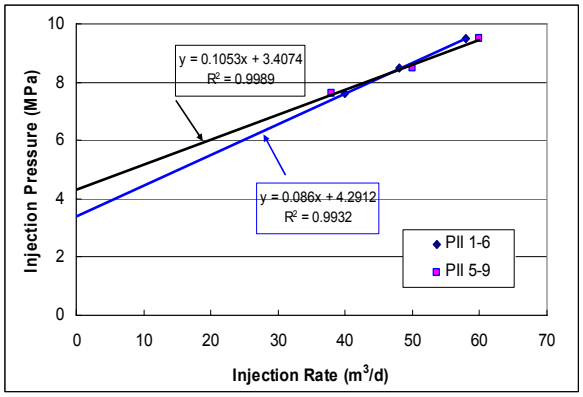


Fig. 17. Step test results from well 7-1827.

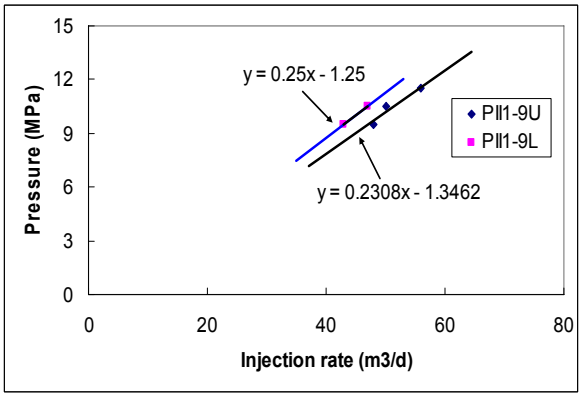


Fig. 18. Step test results from well 7-1937.

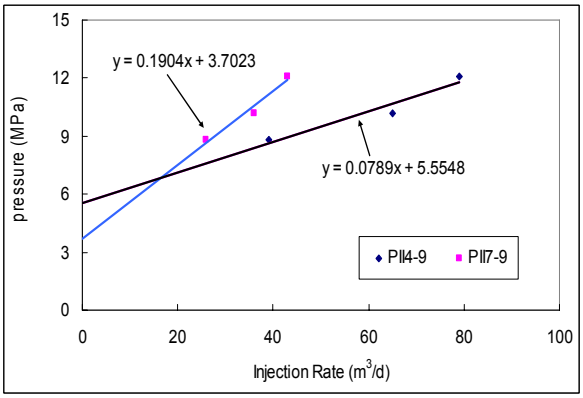


Fig. 19. Step test results from well 8-1827.

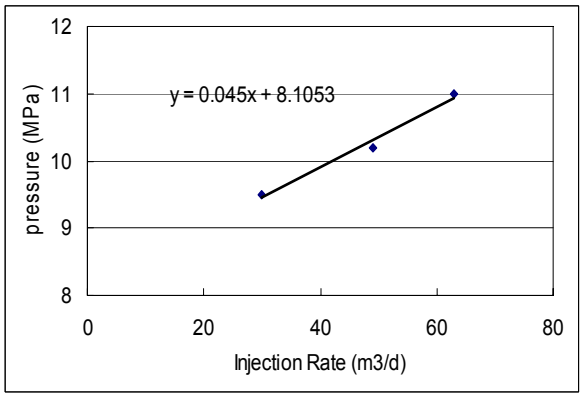


Fig. 20. Step test results from well 9-1827.