Evaluation of A Thermal-Responsible Preformed Particle Gel for Conformance Control

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Abstract

Preformed Particle Gels (PPG) have been injected into mature oil reservoirs as a conformance control agent to decrease reservoir heterogeneity and thus improve sweep efficiencies during water injection for reduced water production and enhanced oil recovery. The ultimate purpose of this research paper is to evaluate the transport of a thermal responsible of two kind of preformed particle gels developed in the laboratory. A series of laboratory tests was conducted to evaluate the swelling and deswelling capacities of PPG's at various temperatures and brine concentration. The results confirmed that PPG swelling capacity increases with temperature but decreases with salinity.

It included a series of filtration tests on swollen gel particles. PPG solutions of 0.4% wt. can easily pass through a ceramic disk with permeability of rang greater than 500 millidarcy. This research study used a sand pack model and sandstone cores to evaluate the effect of flow rate and injection pressure on PPG resistance factor and residual resistance factor. Contrary to common understanding, experiential results have shown that the particle gel flow resistance factor decrease as flow rate increases. The injecting pressure and gel flow residual resistance factor increase continuously with the increasing in the amount of injected PPG.

The new PPG products is a fluid –diverting agent designed to improve the conformance control process in deep water zones of the reservoirs and to overcome some problem that could be faced when using the regular gelation systems.

Keywords: *Induction machine, diagnostics, current spectrum, harmonics.*

1. Introduction

Oil and natural gas were discovered at the end of the nineteenth century and the beginning of the twentieth century, and from that time they have been the main engine of the global economy. Recent statistics show that the ratio of the discovery rate to the consumption rate is one barrel to every four of conventional oil; thus, the gap between discovery and consumption is large and likely to grow. Therefore, current oil production exceeds new additions to known reserves. As a result, enhancement of oil recovery is crucial, particularly since oil recovery during the primary and secondary stages of recovery is generally low. For this reason, and due to rising oil prices,

enhanced oil recovery methods have grown more attractive as a means to build reserves. One of most appealing methods of enhanced oil recovery is gel conformance-control treatments of oil reservoirs.

Conformance control refers to any method to improve the injection or production profile of a well. It improves the macroscopic sweep efficiency of a reservoir. Normally, a gel conformance-control treatment is applied during tertiary oil recovery, but this standard does not mean it is not used during the early stages of recovery.

Enhanced oil recovery (EOR) refers to reservoir processes that recover oil not produced by primary or secondary processes. Various EOR methods can be applied to improve oil recovery in the third stage and conformance control mechanisms are one of the most aggressive. Using conformance control techniques, 15-35% or more of a reservoir's original oil can be extracted; compared with 20-40% using only primary and secondary recovery. Conformance control is the best technique to prevent or reduce the production of unwanted fluid in oil- and gas- producing wells; and it is less expensive than most EOR techniques because the treatments are more practical and require fewer surface facilities. Gel treatments are a proven and cost-effective method to reduce excess water production and improve homogeneity in mature reservoirs. The main objective of these gel treatments is to reduce water flow considerably through high-permeability channels or fractures without damaging the productive zones. Gel treatments depend heavily on the ease with which gels can be injected into the formation.

- **Synthesis And Evaluation Of A Thermal-Responsible Preformed Particle Gel**

The PPG used here is known as S0202222010 and S0202152010 as a PPG solution and S0103042010 and S0103122010 as a polymer solution both were synthesized by researchers in the Petroleum Department at Missouri S&T. A series of laboratory procedures to synthesize new PPG products using acrylamide monomers cross-linked with an organic cross-linker. Using a sand pack model and sandstone cores, the work evaluated the properties of the swollen gel particle including thermal response, rock face plugging, and the effect of injection pressure and flow rate on gel

rheology in porous media. Experimental results show that PPGs are thermally stable and they can expand up to 60 times of their original size in the solution of 1 wt. % NaCl, at 175 ºF.

The results of the filtration test and sand pack model and consolidated core tests are convincing. Unlike conventional hard particles which make a physical plug at the pore throat, PPGs can flow through cores with more than 500 md and penetrate deep into a reservoir with high flow resistance and high residual resistance factors. These properties make the samples tested here different from any that have been applied in the industry. PPGs have great potential for conformance control due to their unique advantages over traditional in situ gels. Further, their stability is not sensitive to reservoirs minerals and formation water salinity.

Synthesis. First 10~ 15% wt of acrylamide and 10~ 15 wt% of AMPS 50% wt solution were dissolved and stirred together in distilled water. During stirring a 0.001~ 0.003% wt of MBAA crosslinker was added to the solution. To initiate the crosslinking reaction between monomers and organic crosslinkers, 0.001~ 0.007% wt of ammonium persulfate was added to the polymerization mixture. The aqueous solution was then neutralized to a pH of 7 by adding an aqueous solution of sodium hydroxide. At this point 0. 1~ 0.3% wt of urea was added to the reactant mixture to accelerate the reaction. The mixture was purged with compressed nitrogen gas for a half hour to replace the oxygen in the mixture. The solution was heated in a water path at 40 ºC for 4~6 hours to eliminate the free radicals initiated during polymerization. The bulk gel was cut into particles and dried at a high temperature to form xerogel particles.

Numerous samples were synthesized mainly with the same materials above and the same preparation scenario but the only difference among them was the concentration ratios. Several experiments were conducted on these samples to test their suitability for various application applications. These experiments involve a series of long-term thermostability tests to evaluate the swelling and deswelling kinetics behaviors of the new synthesized swollen gel particles. They also included a filtration test, and a series of experiments that used a sand pack model and sandstone cores of various permabilities to evaluate the flow performance of particles.

- **Thermostability Test**

The success of a PPG treatment project is dependent on particle gel selection, parameter design, and gel placement. The new PPG products were tested for thermostability so that their swelling and deswelling kinetics and their swelling capabilities can provide a basis for gel selection of PPG. Swelling ratio is defined as the ratio of the PPG particle volume before swelling to its volume after reaching the swelling equilibrium. This work evaluated swelling ratio as a function of brine concentration and temperature. Deswelling is defined as the decrease in the volume of water-swollen PPG due to the expulsion of water from the gel particles. Analyses of the kinetic response of the samples yielded satisfactory results.

***Determination of PPG Swelling Kinetics Capacity*.** In basic terms, swelling ratio is the ability of gel particles to absorb the aqueous solution in which they are immersed A known amount of dry PPG (0.2 gm) was added to various concentrations of brine in formation water, and the mixtures were placed in graduated test tubes. Initially, the PPGs were swelled at room temperature (25 ºC) until they reached equilibrium. They were then heated to 45, 60, and 80 ºC in ovens. Their swelling ratios were calculated as $\frac{V_f}{V_i}$, where V_f is the final volume of the PPG in ml, and V_i is the original volume of the PPG in ml. The changes in swelling capacities at each temperature were recorded as a function of time.

Determination of PPG Deswelling Kinetics Capacity. Varying amounts of NaCl powder were added to fully swollen PPG samples immersed in distilled water, increasing their salinity to 0.25%, 1.0%, and 10%. At room temperature (25 ºC), the gel particles began to settled to the bottom of the test tubes. The PPG volume was then monitored until the PPG deswelling ceased. The same procedures have been done for various temperatures of 45, 60, and 80 ºC. The deswelling ratios of the PPG samples in different concentrations of brine solutions were calculated using the equation $\frac{V_i}{V_f}$, where V_i is the original volume of the PPG in ml and V_f is the final volume of the PPG in ml. The changes in PPG's deswelling capacities at different temperatures were recorded as a function of time.

- **Filtration Test**

Filtration tests used a static filter press to measure the static filtration behavior of PPG/polymer solutions at room temperature and differential pressure of 100 psi. Ceramics disks of varying permeability were used as a filter medium. The static filtration press was connected to an air source to provide the required pressure through tubing. This model works well up to 300 psi.

***PPG/Polymer sample solution*.** Fully swelled and breaking PPG samples of 2000 ppm concentration were used for the filtration test. They were prepared using 1% wt of NaCl as a base fluid in 500 ml of distilled water.

Filter Medium. Ceramics disks with a 4.9 sq. in. filtering area and various permeabilities were used as a filter medium.

- **Sand Pack Model**

A sand pack model was a cylindrical metal tube (2.6 cm in diameter, and 53.4 cm long) with three check pressure points. On each end was a flow cap, as shown in figure 1. The inlet side connected to an ISCO pump through a 1000-ml container and tubing. The outlet side connected to a graded container that collected the fluids. The 1000-ml container had piston to prevent direct contact between the injected water and the PPG/polymer sample. The pressure from the pumped water pushed the piston, forcing the swollen PPG to pass through the outlet at the end of tube.

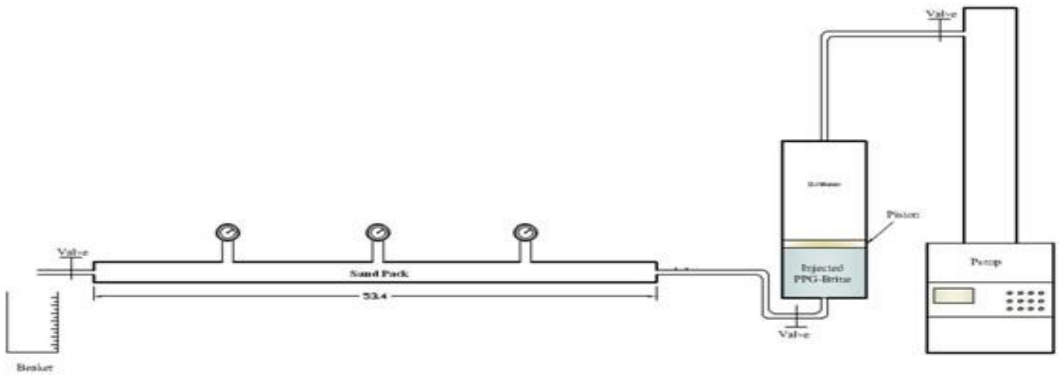


Figure 1. Schematic Diagram of Sand Pack Model

- **Rock Core Flooding**

A cylindrical core holder of 10 cm long and 2.5 cm in diameter was used to test the PPG samples on sandstone cores. The inlet side had one hole connected to an ISCO pump through a 1000-ml container and tubing. The outlet side was connected to a graded container to that collected the discharged fluids. The 1000-ml. container had a piston to prevent direct contact between the injected water and the PPG/polymer sample. The pressure from the pumped water pushed the piston, forcing the swollen PPG to pass through the core. Figure 2 shows schematic of a typical rock core flooding apparatus.

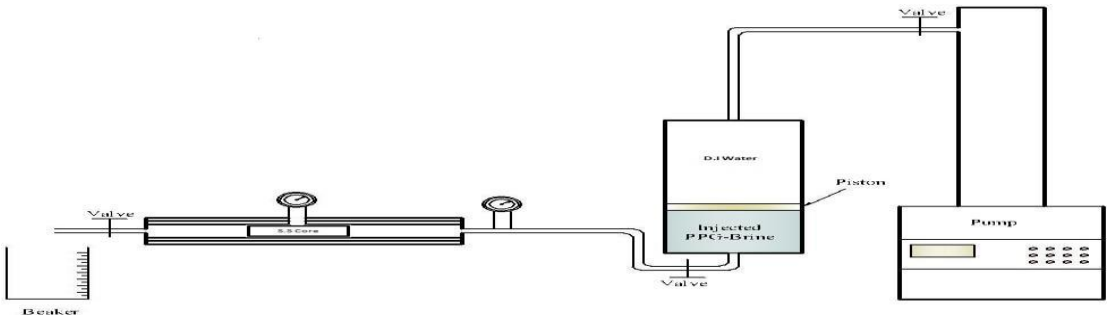


Figure 2. Schematic of a Typical Rock Core Flooding Figure 3-3

Table 1. shows some characteristics of the sandstone samples, including porosity and permeability.

Sample	Diameter (cm.)	Length (cm.)	ϕ %	K darcy
1	2.56	6.35	20	0.5
2	2.56	6.33	19.5	0.49
3	2.56	6.34	19.6	0.49
4	2.56	6.35	19.8	0.5

- **Calculation Of Resistance Factor**

The pressure drop across each segment of the model was recorded during the first-water injection and the gel injection for various flow rates. For each segment, the resistance factor (Fr) was calculated by dividing the pressure drop during gel injection by the pressure drop during water injection, at same injection flow rate:

$F_r = \Delta P_g / \Delta P_w$, at the same injection rate i.e. Q remains constant.

where:

F_r is the resistance factor,

ΔP_g is the pressure drop during the gel injection at the injection rate Q, and

ΔP_{wa} is the pressure drop during the first water injection at the same injection rate Q.

The pressures during the gel and water injection were recorded by using Lab View software.

- **Calculation Of Residual Resistance Factor**

The pressure drop across each segment of the model was recorded during the first and second water injection for various flow rates. For each segment, the residual resistance factor (Frr) was calculated by dividing the pressure drop during the second water injection by the pressure drop during the first water injection, at a constant injection flow rate:

$F_{rr} = \Delta P_{wb} / \Delta P_{wa}$, at the same injection rate i.e. Q remains constant.

where:

F_{rr} is the resistance factor,

ΔP_{wb} is the pressure drop during the second water injection at injection rate Q, and

ΔP_{wa} is the pressure drop during the first water injection at the same injection rate Q.

- **Results And Discussions Of Ppg Solutions**

This section places of interest our success in designing and synthesizing new PPG products. Unlike samples that provided by industry, our new PPG's have totally swelled in brine and formed a significant high viscous PPG solution - a highly viscous gelant solution with clear gel particles in it. This section included a series of result experiments, using a sand pack model and sandstone cores of various permeabilities to evaluate the flow performance of new PPG's. The effect of particle gel swelling ratio, flow rate, injection pressure, and PPG solutions concentration on PPG flow behavior -flow resistance factor and residual resistance factor- were also studied. The results show that the gel particles transport behavior depends mainly on the solution concentrations and the viscosity of PPG solution and flow rate. PPG reduced the permeability of sand pack model from 920 md to almost 300 md. Considering as a convincing and very good results, the results of

sand pack and core tests show that PPG solutions can flow into cores with more than 500 md and they also can transport deeper into the reservoir with significantly high flow resistance factor and residual resistance factor. These samples are different from the others that have been applied in the industry because of this unique property; they can go deep in the formation unlike those which makes a physical plug at the throat of the pores.

2. Results and Discussions

Effect of Salinity on PPG Swelling and Deswelling Capacities. Reservoirs have various degree of water salinity; therefore we should know the effect of salinity on PPG swelling and deswelling capacity. Figures 3 and 4 show the effect of salinity on the swelling capacities of samples S0202222010and S0202152010, at various temperatures. They demonstrate and confirmed that salinity reduces the swelling potential of PPG. Table 2 lists the change in PPG swelling ratio for samples as function of temperature and salt concentrations. The concentration of sodium chloride solution (NaCl) has an effect on the water absorbency, therefore on the gel swelling capacity. In distilled water and at 25 ºC, the swelling capacity of these samples is in range of 400 to 440 times its volume, but in brine solution of 0.1% wt. concentration the swelling capacity is in range of 75 to 85 times its volume. The final PPG swelling ratio depended on the brine concentration-inverse proportion-the smaller the concentration, the higher swelling ratio.

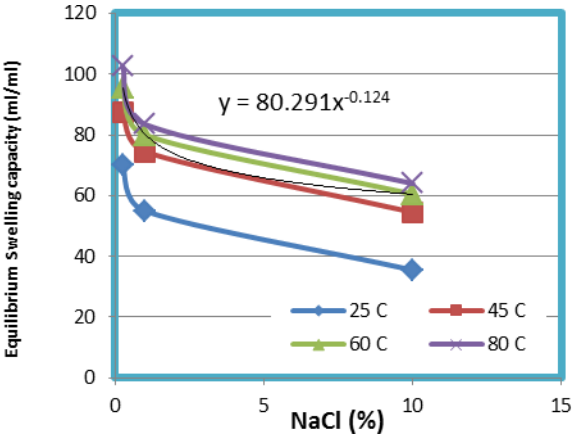


Figure 3 Equilibrium Swelling Capacity of sample S0202222010 as a Function of Brine Concentration and Temperature

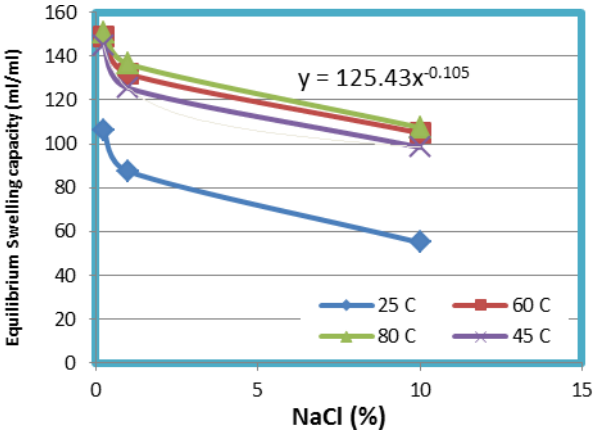


Figure خطأ! لا يوجد نص من النمط المعين في المستند. Equilibrium Swelling Capacity of sample S0202152010 as a Function of Brine Concentration and Temperature

Table 2 shows the change in PPG swelling ratio over temperature and salt concentrations for samples S0202222010 and S0202152010

Temperature C	S0202222010				S0201522010			
	0.25 % NaCl	1% NaCl	10% NaCl	F.w	0.25% NaCl	1% NaCl	10% NaCl	F.w
25	70.00	55.00	35.50	47.50	106.5	87.5	55.0	73.0
45	87.50	74.50	54.50	68.50	145.0	125.5	98.5	119.0
60	95.50	80.00	60.50	77.00	149.0	132.0	105.0	129.0
80	102.50	83.50	64.00	79.50	151.0	136.5	107.5	133.0

Surprisingly, the ability of these samples on swelling gradually and by certain fits with temperature and time, which makes them unique products. The relationship between swelling ratio of PPG samples and brine concentration can be fitted well using the following power equations:

$y = 80.291x^{-0.124}$ for sample S0202222010.

$y = 125.43x^{-0.105}$ for sample S0202152010.

Where (y) is the swelling ratio and (x) is the brine concentration in percent.

On the other hand, figures 5 and 6 show the influence of salinity on the deswelling capacities of PPG. Table 3 lists the change in PPG deswelling capacities for samples as function of temperature salt concentrations. They are shown that the PPG deswelling ratio increases by salinity. At high temperatures the deswelling ratio is almost same, however the final PPG deswelling ratio depended on the brine concentration- Direct proportion-the higher the concentration, the higher deswelling ratio.

Table 3 shows the change in PPG Deswelling ratio over temperature and salt concentrations for samples S0202222010 and S0202152010

Temperature C	S0202222010				S0201522010			
	0.25	1	10	F.w	0.25	1	10	F.w
25	4.000	4.783	6.455	4.524	5.757	7.000	11.000	6.348
45	1.346	1.863	2.319	1.522	1.318	1.394	1.589	1.368
60	1.364	1.455	1.704	1.400	1.342	1.451	1.667	1.449
80	1.367	1.465	1.641	1.395	1.342	1.452	1.667	1.446

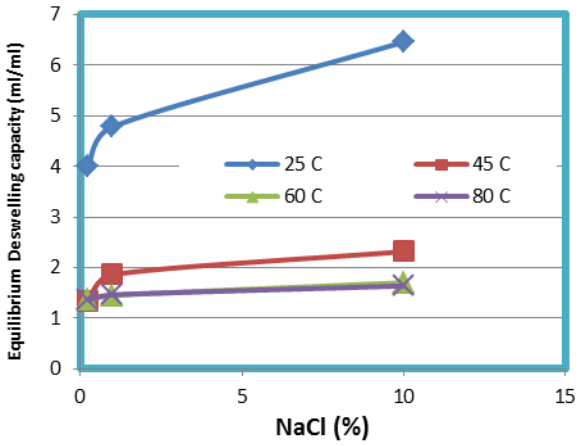


Figure 5 Equilibrium Deswelling Capacity of sample S0202222010 as a Function of Brine Concentration and Temperature

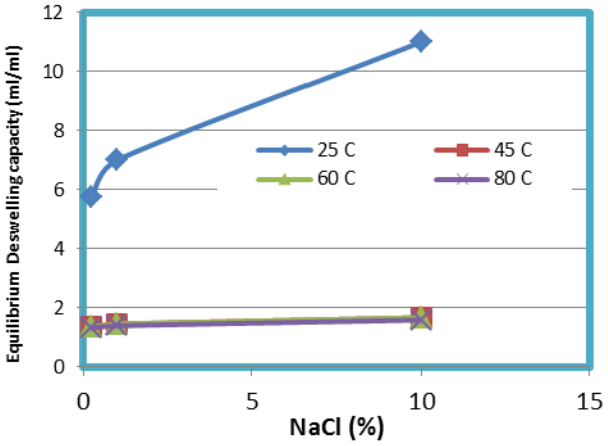
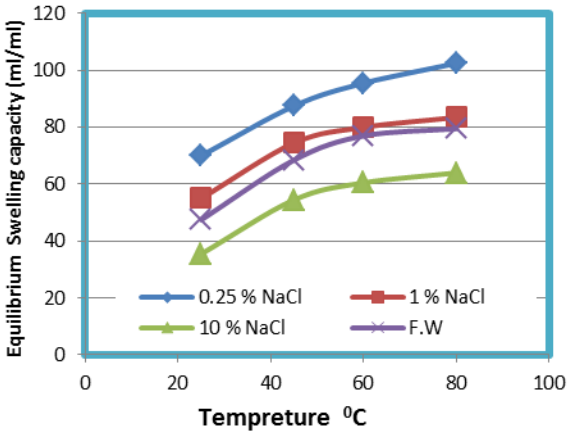


Figure 6 Equilibrium Deswelling Capacity of sample S0202152010 as a Function of Brine Concentration and Temperature

Effect of Temperature on PPG Swelling and Deswelling Capacities. Increasing the temperature of the PPG solution urges the breakage of the porous structure of PPG. By other words, increasing in temperature accelerates the endothermic reaction of chemical bond breaking which enables more water to be absorbed into the PPG.



Figuree 7 Effect of Temperature on Swelling Capacity of Sample S0202222010 as Function of Brine Concentration.

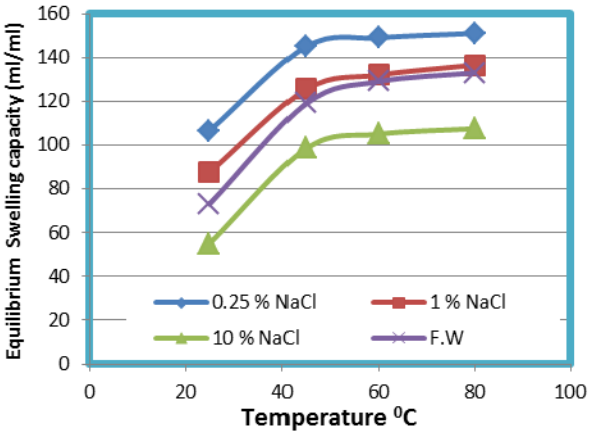


Figure **8** Effect of Temperature on Swelling Capacity of Sample S0202152010 as Function of Brine Concentration.

This explains the increase in the swelling capacities of PPG with increasing temperature as shown in figures 7 and 8. On the other hand increase in the temperature of the solution will cause a reducing in the deswelling capacity of PPG. The final PPG deswelling ratio depended on the temperature-inverse proportion-the lower the temperature, the higher deswelling ratio as shown in figures 9 and 10.

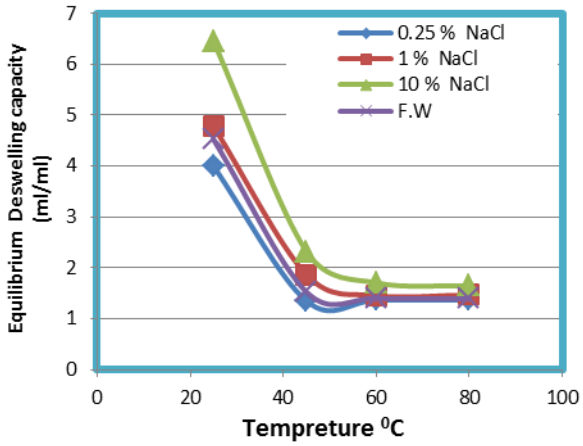


Figure **9** Effect of Temperature on Deswelling Capacity of Sample S0202222010 as Function of Brine Concentration.

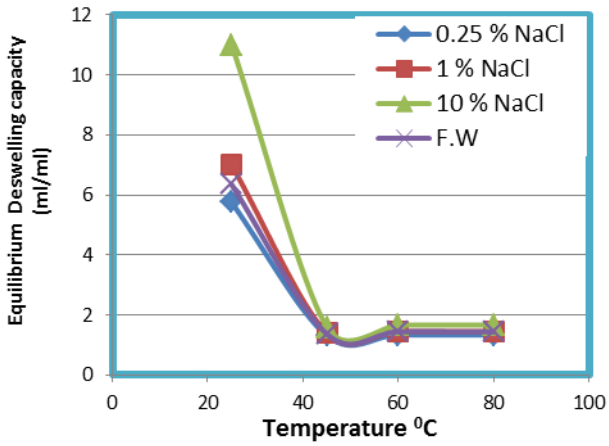


Figure **10** Effect of Temperature on Deswelling Capacity of Sample S0202152010 as Function of Brine Concentration.

PPG Effect on Plugging of Rock Face during Injection. The big PPG particles and debris in the PPG solution can easily lead to unwanted near-wellbore plugging. These experiments sought to determine whether the swollen PPG particles easily passed through the Ceramic disk of various permeabilities or not. This would be indicated by the filter cake thickness, rate of throughput solution and filtration time. The variations in the permeability of filter medium were intended to represent the pore sizes or fracture width in a channeled formation as well as to set a standard rang that new PPG's can pass through. At lower permeability range (< 500 md), the PPG solutions formed a filter cake of 1.5 mm thickness, however known volumes of freshly prepared PPG solutions were forced through Ceramic disks of permeability of range (>500 to 2000 md) with no filter cake left on the surface of the filter medium which means they can easily pass near-wellbore. The smaller permeability of the ceramic disc, more was the time needed to filtrate a PPGs solution. Figures 11 and 12 show the static filtration behavior of samples S0202152010 and S0202222010 as function of time and permeability. Graphs show that the trend of discharged fluid and time is a straight but it doesn't continually because of some particles have pressured into the filtration medium.

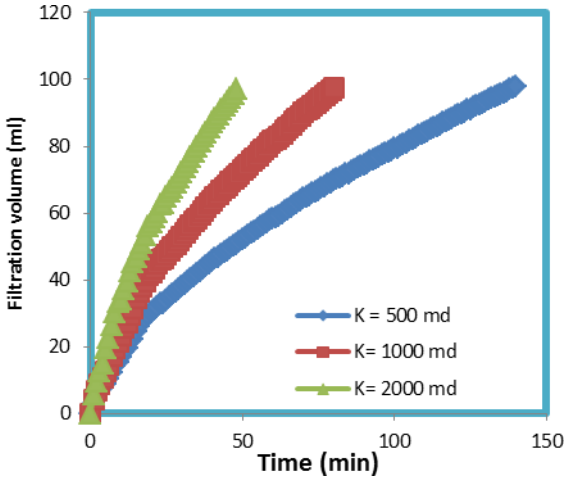


Figure 11 The Static Filtration Behavior of Samples S0202222010 as Function of Time and Permeability.

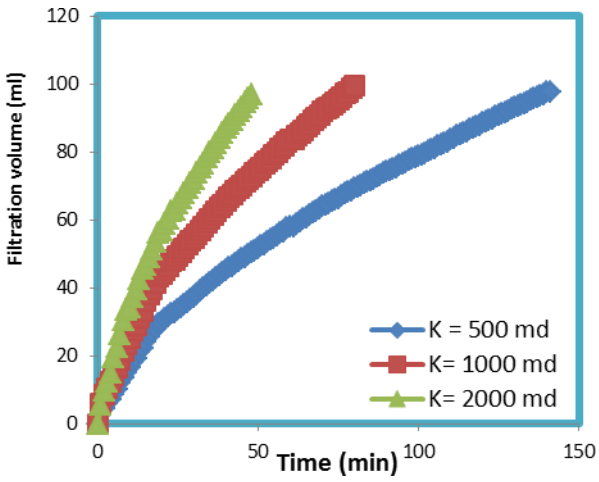


Figure 12 The Static Filtration Behavior of Samples S0202152010 as Function of Time and Permeability.

Effect of Flow Rate on PPG Resistance Factor. Figures 13 and 14 plot the injection rate against the resistance factor for PPG samples at different points along the sand pack model. At lower injection rates, the resistance factor was almost the same for the second and third segments. At higher injection rates, however the resistance factor for third segment was lower than the second segment which has less resistance than the first segment. That because the movement of PPG through the model will resist the flow of water in the pores especially in the first segment which has flooded the most. The samples were tested on sandstone cores and results are shown in figure 15. PPG resistance factor depended on the flow rate the lower the flow rate, the higher resistance factor. For example at the first segment of the sand packmodel, the sample S0202152010 has a resistance factor of 163,109 and 89 at flow rate of 1, 2 and 3 ml/min respectively as shown in figure 16.

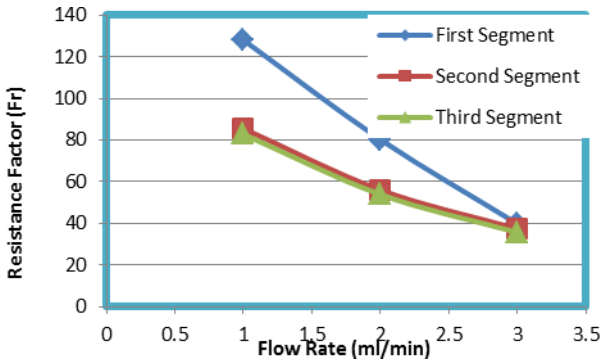


Figure 13 The Resistance Factor for Sample S0202222010 at different points along the sand pack model.

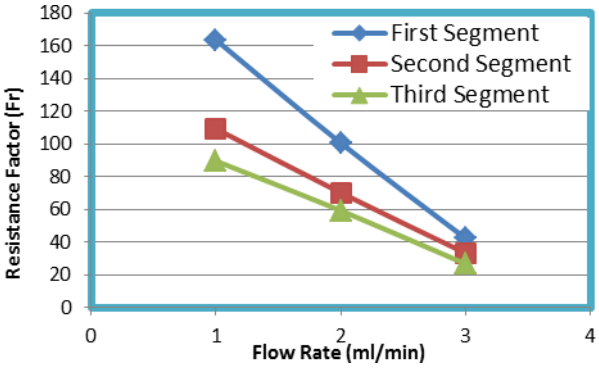


Figure 14 The Resistance Factor for Sample S0202152010 at different points along the sand pack model.

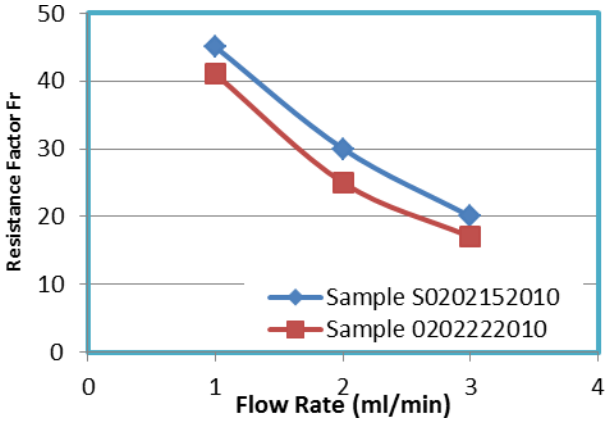


Figure 15 The Resistance Factor for Samples S0202152010 and 0202222010 for sandstone cores.

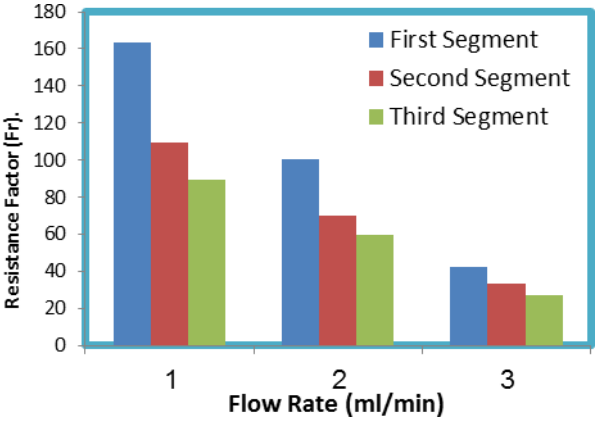


Figure 16 The Resistance Factor for Sample S0202152010 as a Function of Flow Rate.

Effect of Injection Pressure on PPG Resistance Factor. Once the pressure buildup data was obtained, for each of the brine/PPG injection the constant stable pressure for each injection flow rate was recorded and plotted against the amount of injected PPG. Figures 17 and 18 show the pressure buildup across the model against the amount of injected PPG for samples S0202152010 and S0202222010. From 5 to 6 times of pore volume of PPG have been injected to get a stabilized pressure across the model.

The resistance factor in the first segment of the model is significantly high comparing with the second and third segments. This occurred because the pressure difference between the injection pressure and pressure across the first segment was low comparing with second and third segments. The pressure differences across the second and third segments were almost same. For all the

samples, the injection pressure and resistance factor continuously increased as amount of PPG increased till reach the stable pressure. Increasing in the injection pressure indicates that PPGs have plugged the core pores as long as PPGs propagated through it. The injection pressure increased only slightly at higher injection flow rates.

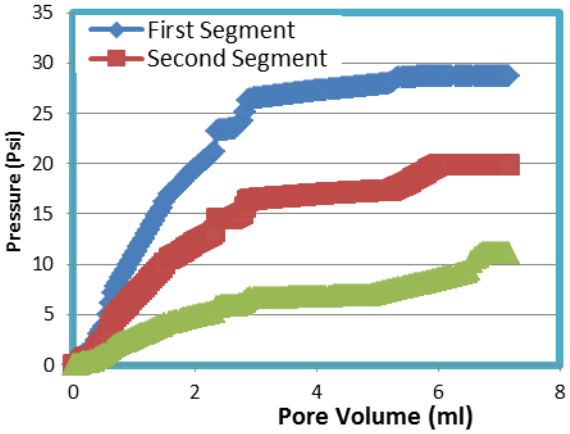


Figure 17 The Pressure Buildup Across the Model as Function of Amount of injected PPG for Sample S0202222010.

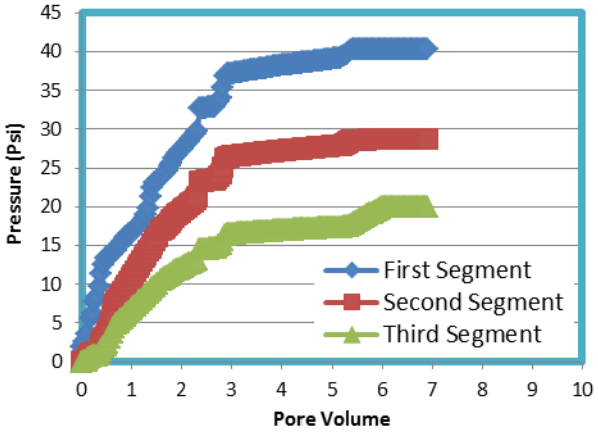


Figure 18 The Pressure Buildup Across the Model as Function of Amount of injected PPG for Sample S0201522010.

Effect of Flow Rate on PPG Residual Resistance Factor. Figures 19 and 20 demonstrate the injection flow rate against the residual resistance factor for each segment of the model. The samples were tested on sandstone cores and results are shown in figure 21. The residual resistance factor for sample S0202222010 through the sand sandstone core was 45, 30 and 20 at flow rate of 1, 2 and 3 ml/min respectively.

Figure 22 demonstrate and confirmed that the final PPG residual resistance factor depended on the flow rate the lower the flow rate, the higher resistance factor for all brine concentrations; however, this increase was not linear. For example at the first segment of the model, the sample S0202222010 has a residual resistance factor of 80, 61 and 43 at flow rate of 1, 2 and 3 ml/min respectively.

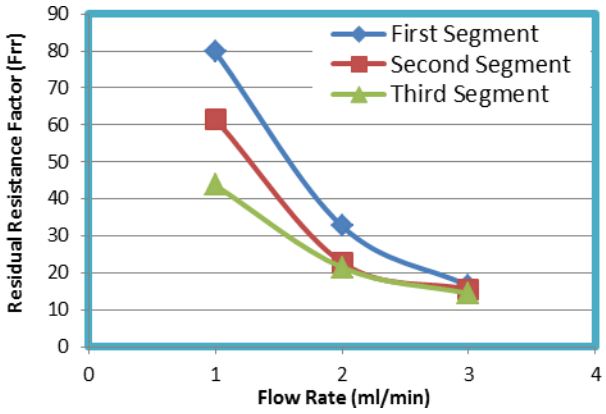


Figure 19 The Residual Resistance Factor for Sample S0202222010 at Different Points along the sand pack model.

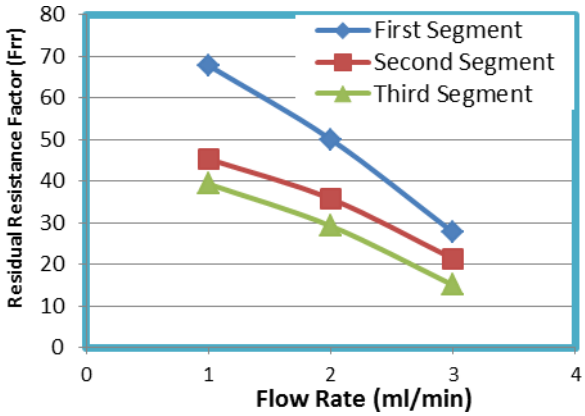


Figure 20 The Residual Resistance Factor for Sample S0202152010 at Different Points along the sand pack model.

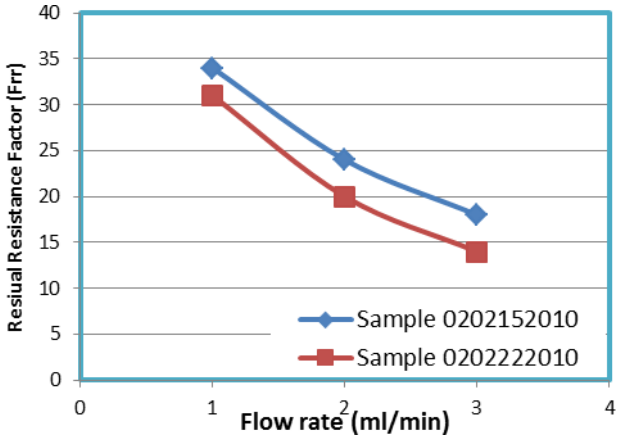


Figure 21 The Residual Resistance Factor for Samples S0202152010 and 0202222010 for sandstone cores

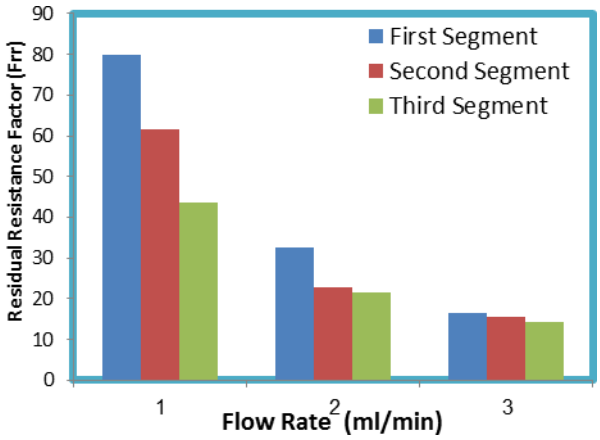


Figure 22 The Residual Resistance Factor from sand pack for Sample S0202222010 as a Function of Flow Rate

Effect of Injection Pressure on PPG Residual Resistance Factor. The residual resistance factor in the first segment of the model is significantly high comparing with the second and third segments. This happened because the pressure drop across the first segment was slightly low comparing with second and third segments. The pressure differences across the second and third segments were almost same. The injecting pressure and residual resistance factor increase continuously with the increasing in the amount of injected brine. That because the movement of brine -after gel injection-through the model will resist by the PPG that took place in the high permeable pores especially in the first segment which has more PPG installed. Figures

23 and 24 show the pressure buildup across the model against the amount of injected brine for both samples. From 3 to 4 times of pore volume of brine have been injected to get a stabilized pressure across the model for both samples. By comparing the injection pressure of brine solution before PPG injection and after injection PPG solution the result shows that PPG's reduced the water permeability of sand pack model and sandstone cores from 920 to almost 300 millidarcy and from 500 to almost 280 millidarcy, respectively .

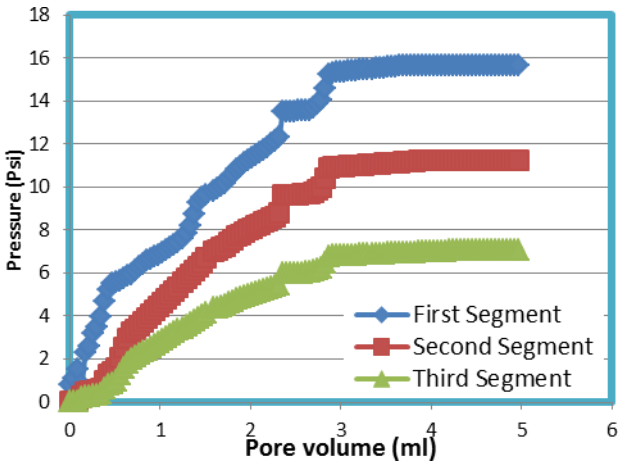


Figure 23 The Pressure Buildup Across the Model as Function of Amount of injected Brine for Sample S0202222010.

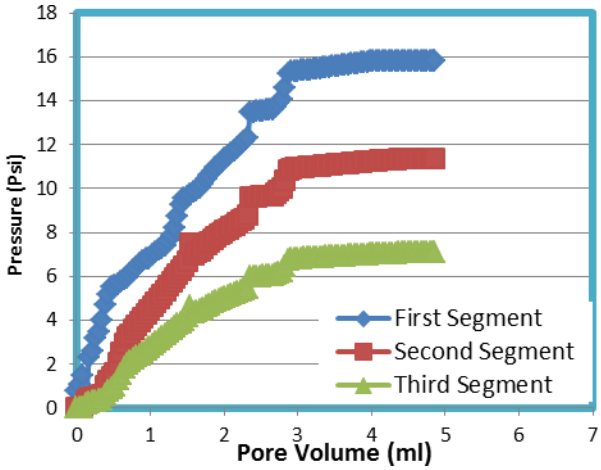


Figure 24 The Pressure Buildup Across the Model as Function of Amount of injected Brine for Sample S0202152010

4. Conclusion

Gel has been widely used to control conformance. However, a newer trend in gel treatments is the use of preformed particle gels (PPGs) to overcome distinct drawbacks inherent in insitu gelation systems. Gel Synthesizeion processes and gel evaluation experiments are both expensive and time consuming. Synthesize various preformed particle gel, a series of long-term stability tests to evaluate PPG swelling and deswelling behaviors at various temperatures and brine concentration, and evaluate PPG physical properties and the factors that affect their injectivity behavior through high and low permeability zones and channels in a reservoir have been studied. The success of any

PPG treatment mainly depends on PPG physical properties and the factors that affect PPG injectivity behavior such as the gel resistance of water flow.

The object of the work strives to synthesize various preformed particle gel as a cost effective and the ability of gel particles to fully swelling, then evaluate the injectivity behavior of these PPG. The PPG injectivity behavior is an important and less researched property of the swollen PPG which needs to be addressed for the use in petroleum industry. The major conclusions drawn from this study are as follows:

1. Two kinds of PPG have successfully synthesized.
2. Salinity reduces the swelling potential and increases the deswelling capacity of PPG.
3. Temperature increases the swelling potential and reduces the deswelling capacity of PPG.
4. PPG solution of 0.4% concentration has the ability to pass near wellbore of 500 md.
5. The gel flow resistance factor increases as the injection rate decreases.
6. The gel flow residual resistance factor increases as the injection rate decreases.
7. The injecting pressure and gel flow residual resistance factor increase continuously with the increasing in the amount of injected PPG.

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