THE EFFECT OF GEL PARTICLE ON THE FORMATION DAMAGE DURING GEL TREATMENT FOR THE MATURE RESERVOIRS

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ABSTRACT
In mature oil fields, the success of gel treatment results depends on the ability of the gel to reduce the high permeable formation without damaging to low permeable formation. Formation damage refers to the extent of damage reservoir rocks face from various drilling techniques and/or chemical treatment during well completion. A dynamic filtration test was used to investigate this effect using distinct core samples, brine concentrations and preformed particle gels. The effect of high pressures applied on the particle gels on various core samples with various permeability ranges was determined. These gels were pushed into the core holder with samples and the core permeability change was calculated. Different constant pressures were used to push the piston behind the gel samples. Then, the gel was flown around the core sample and collected in the outlet container. Various hardware was used to tighten the apparatus and provide connection between brine source, syringe pump, piston accumulator, core holder, and flow outlet container. The damage on the core was evaluated by comparing the original core permeability and the core permeability after gel treatments. Pressure gauges were used to measure the pressure drop across the core samples. The penetration of the particle gels into the low permeable formations can be decreased by the best selection of gel types, particle sizes, and brine concentrations under the reservoir condition. This work results can be used to select the best gel types for the right reservoir condition such as reservoir permeability, and reservoir pressure.

Keywords: Formation Damage, Gel Treatment, Core Flooding

INTRODUCTION
The oil industry typically extracts oil from reservoirs by virtue of water injection and though effective, has shown to be quite inefficient. The injection of water into the core allows it to become saline in nature thus requiring additional work to remove the salt. This process causes financial strain on the oil industry and thus a more fiscally prudent alternative should be sought. Research shows that Preformed Particle Gels (PPGs) is a viable solution to such problems. This research will use dynamic filtration test to determine whether swollen preformed particle gels affected unswept oil zones/layers. These gels will be injected at high pressures in order to see if any damage has happened to the core. A filtration test is a simple means of evaluating formation damage. The oil industry currently uses two standard filtration tests both static and dynamic, to assess damage to core samples. The static test is suitable when testing for injection into the matrix rock;

while the dynamic test assesses injection into a fracture. Filtration test experiments have been use in the past to study the damage of cores fully. However, no one has studied the effect of deformable swollen gel particles on low-permeability zones by using dynamic filtration test. There are 3 types of oil recovery. They are primary, secondary and tertiary. Primary recovery typically refers to the use of energy to inherent in a reservoir from gas under pressure or natural water drive. One of the processes is water flooding which can only recover 30% of the oil in a reservoir [4]. Excess water production has become a significant problem for oil field operations as reservoirs mature. This process is also expensive costing billions of dollars every year to remove excess water after the procedure. Furthermore, this procedure also causes corrosion and growth of certain bacteria which is hazardous to the environment [6]. Both primary and secondary types can extract up to 40% of the oil in a reservoir. Tertiary recovery, also known as Enhanced Oil Recovery, is the implantation of various techniques to increase the amount of crude oil that can be extracted from an oil field while minimizing the excess amounts of water. This process help to increase the oil extraction from an oil field by 30-60% [4]. The usage of preformed particle gels (PPGs) also known as water treatment is one of the Enhanced Oil Recovery methods that has been developed during the last decade of the oil industry. Some of the chemicals been used are gel systems using both polyacrylamides and different crosslink [1-3]. These particle gels have plenty characters which make them best to use in the oil field because there are ease to injection, salt acceptance, elastic properties and the ability to penetrate into the high permeable formation. Gel treatment method is cost 2 effective and it also decrease water production and improve the homogeneity in mature oil field. These gels have been both used to suppress excess water production and improve oil productivity [5-6]. Published documents indicate that several particle gels were economically applied to reduce water production in mature oil fields. For example, preformed particle gelsPPGs have been applied in about 2,000 wells to reduce fluid channels in water floods and polymer floods in China [11-12]. Recently, Occidental Oil Company and Kinder-Morgan used similar product to control CO_2 breakthrough for their CO_2 flooding areas and promising results have been achieved. However, the achievement of the best water treatment mainly depends on whether chemical and mechanical methods can successfully correct the reservoir heterogeneity. In petroleum engineering, drilling fluids are specially formulated to be used during perforating operations to control fluid loss and minimize formation damage. To minimize formation damage, it is important to find methods that minimize the damage caused by PPGs on unswept, low-permeable zones/areas, thus improving PPG treatment efficiency and to determine what factors influence the blocking efficiency of the high permeable zones/areas without damaging the formation zones. This research will use dynamic filtration tests to determine whether swollen preformed particle gels (PPGs) affected unswept oil zones/areas. A filtration test is simple means evaluating formation damage. The oil industry currently uses two standard filtration tests. Both static and dynamic filtration tests are used to assess damage to core samples [8]. The former is suitable when testing for injection into the matrix rock; the latter assesses injection into a fracture. Filtration test experiments have been used in the past to study the damage of cores fully saturated with brine, oil, or residual oil while injecting suspended particles, oily water, or a combination of both into these cores. Static filtration test is used to study the effect of both weak and strong preformed particle gels on law permeable formation, respectively

[13]. They determined that the best PPG treatments occurred when the PPG could simply penetrate the high permeable layers without damaging the low permeable formations. However, no one has studied the effect of injecting the substances at high pressures through the core. In this study a dynamic filtration test will be used to determine if the Preformed Particle Gels (PPG) has an effect on the formation of the rock. In other words, this test will determine if the PPG damages or deforms the rock samples. Permeability, is one of the main factors that helps us to determine the effect of PPG on a rock. Permeability can be defined as the state or quality of a material or membrane that causes it to allow liquids or gases to pass through it. A change in the permeability of a rock after the dynamic filtration test will imply that the PPG influenced the rock. If the permeability of the rock after the test is different to the permeability of the rock before the test, it can be determined that the PPG in fact damaged or deformed the rock sample. The permeability in this case, depends on factors such as the flow rate, the viscosity of the brine, the length of the core sample, the diameter of the core sample and the pressure drop across the core sample. The Darcy Equation, which is used to calculate the permeability before and after injection.

PROCEDURE

1. The apparatus was set up as shown in Fig 1.
2. Core sample was placed in the core holder (Fig 2) and then connected to the rest of the apparatus.
3. The pump was then switched on at a constant flow rate while the valve leading to the piston accumulator (as shown in Fig 2) remained as the only valve open.
4. Gel was injected into the core by the piston accumulator and the pressure was recorded with the pressure gauge at the point where a back pressure started to develop in the pump. Water was then ejected at the end of the core holder then the pump was stopped.
5. The valve leading to the piston was then closed and the valve allowing entry of brine into the core was opened.
6. The pump was put on again and careful observations of the pressure gauge were made just before the water got ejected on the other side of the core holder. The maximum pressure at the point just before water ejection was recorded using the pressure gauge.
7. This process was repeated for other sandstones while maintaining the same brine concentration and percentage of gel.

MATERIALS AND APPARATUS

The **core holder**, shown in Fig 2, is one of the fundamental components for analysis to happen. It is designed to contain cores up to 4 inches in length and diameter 1 inch.
The **cores** to be investigated, as shown in Fig 3. These cores are made of sandstone and they included cores of varying permeabilities. Ranges varied from high, low and intermediate permeability. The name of the cores is Berheimer sandstone, castlegate sandstone Boise Buff, Indiana Limestone and Bandera Gray.
The **piston accumulator**, as shown in Fig 4, was fabricated at the Midwestern State University machine shop. The tube was retrieved from unused tubing from previous projects. The piston and the end caps were 3D printed at the machine shop. Grooves

were molded around the piston to allow O rings to be fitted. The end caps were sealed to the container with JB weld to inhibit leaks from happening. In Fig 4, the gel can be seen at the bottom of the piston resembling a cloudy substance.

The gel type used investigation was **SAP-LiquidBlock TM AT-03S**: This polymer is a sodium salt of cross-linked polyacrylicacid that ranges in particle sizes from 1 - 850 microns. The absorption with deionized water is greater than 400 g/g and has a moisture content of under 10%. Teabag absorption (g/g) is 0.9% NaCl 55 – 65 while Teabag Retention (g/g) 0.9% NaCl 40. Gel Time, Vortex Method ranges 35 min to 70 min and has a residual monomer of under 200 ppm the melting point is over 330 0C and an auto-ignition temperature of over 400 ^{0}C Its physical form is white granules, free flowing and was purchased from Emerging Technologies. **SAP –LiquiBlock TM 40F**: This polymer is a potassium salt of cross-linked polyacrylic acid that ranges in particle size of 1 – 200 microns. The absorption with deionized water is greater than 200 g/g and has a moisture content of 5%. pH value ranges from 5.5-6.0 with a bulk density of 540 g/l. The polymer type was purchased from Emerging Technologies. **Brine solution** was used to simulate the saline conditions and was made to be up to 25%

RESULTS AND DISCUSSION:

After injection into Boise Buff sandstone, a plot of the change in pressure vs the slow rate was plotted and the results were as follows.

The formula governing the permeability of the core as following:

$$K = \frac{Q\mu L}{0.78 d^2 \, \Delta p} \qquad (1)$$

A graph of change in pressure vs flow rate was plotted above and the gradient gave $\frac{\Delta P}{Q}$= 3.75. The reciprocal of this was substituted into the equation and a permeability of 625 mD after injection of ATF 03S gel. This process was repeated for each core and the results were as in table 1. Results using Liquiblock 40F as the new independent variable showed in table 2. The results included the influence of PPGs on the damage to different cores. The brine concentration was constant at up to 25%. Figures 7 through 9 shows the changes of core permeability after gel treatments. The general trend using ATS 03S gel and Liquidblock 40F resulted in 40F causing more formation damage hence, decreasing the permeability of the samples as shown in figure 9. Results were consistent with all 5 core samples and that is attributed to the particle size of Liquidblock 40F. The 40F gel has a smaller particle size than that of 03S gel. This allows the gel to more easily infiltrate the core and thus damage the core. Figure 5 showed the change in pressure drop vs flow rate. The pressure drops around the core samples increased as the flow rate increased. Figure 6 shows the core after a constant pressure injection of gel into the core thereafter a 'cake' was formed. This 'cake' is created when no more gel can be pushed through and the excess is then forced to settle rather than infiltrate through. Figure 7 showed the change in permeability vs different core samples by using ATS 03S gel. As you can see, in figure 7 the more damage while using higher core permeability because those sample effected more with gel treatments. Figure 8 showed the change in permeability vs different core samples by using Liquidblock 40F gel. The results showed that the higher core permeability damaged more than samples with lower core permeability.

CONCLUSION

Core samples were affected by get treatments. Influenced by gel types, all cores were damaged after the preformed particle gels were injected. This damage progressively increased with increasing the core permeability and injection pressure. The damage was more severe while using higher core permeability when compared with lower core permeability samples. Results from this experiment can be used to select the best gel treatment for various reservoir conditions.

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ACKNOWLEDGEMENT:

We would like to thank the McCoy school of Engineering for providing us with the workspace, machines, apparatus and advice for conducting this project. Numerous hurdles had to be overcome to successfully begin this project and we are ever gracious for the financial commitment from university fund to allow this to be performed.

APPENDIX

Table 1: Using ATF 03S gel			
Sandstone	**Permeabiliy before Experiment (mD)**	**Permeabiliy after Experiment (mD)**	**Change in Permea-bility (mD)**
Boise Buff	1025	625	400
Bentheimer	2000	1508	492
Castlegate	850	261	589
Bandera Brown	40	33	7
Indiana Limestone	18	11	7

Table 2: Using Liquiblock 40F			
Sandstone	**Permeability Before Experiment (mD)**	**Permeability after Experiment (mD)**	**Change in Permeability (mD)**
Boise Buff	1025	531	494
Bentheimer	2000	1371	629
Castlegate	850	209	641
Bandera Brown	40	24	16
Indiana Limestone	18	7	11

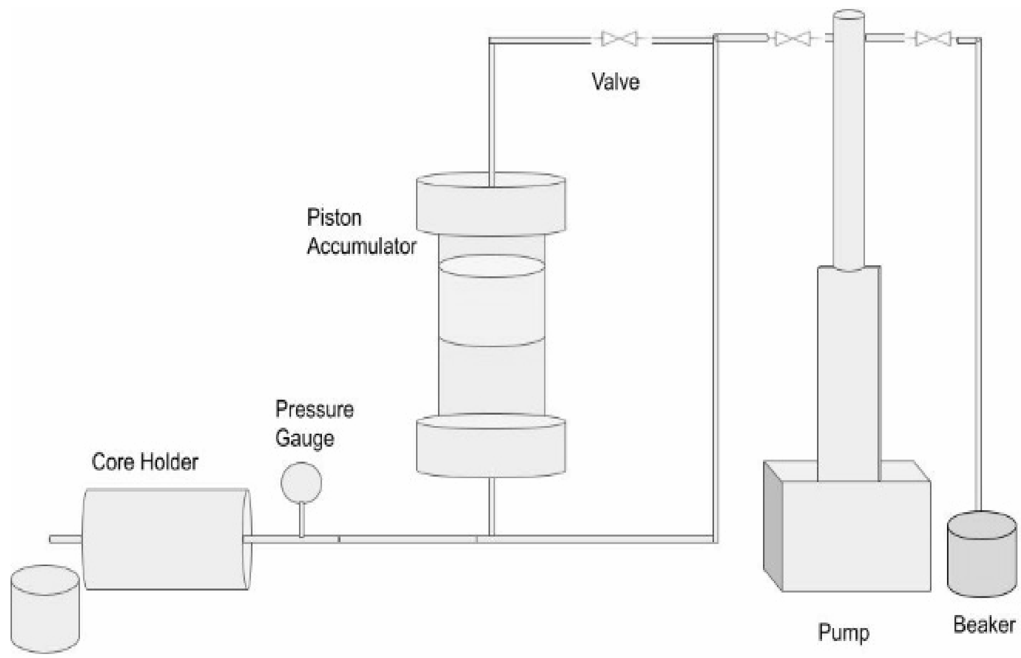

Fig 1: Experimental Setup

Fig 2: Core Holder

Fig 3: Core Sample Before injection

Fig 4: Piston Accumulator

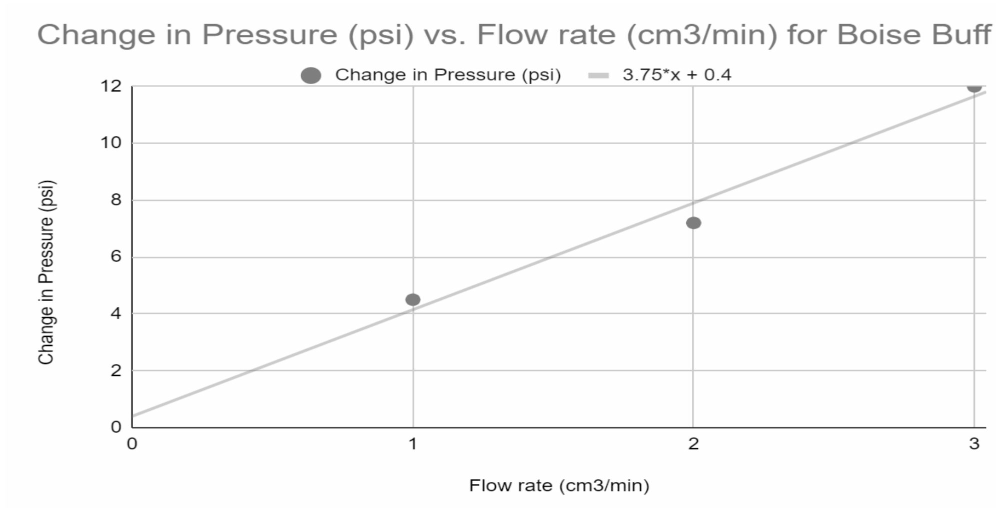

Fig 5: Graph Showing Change in Pressure vs Flow Rate

Fig 6: Core sample After Injection

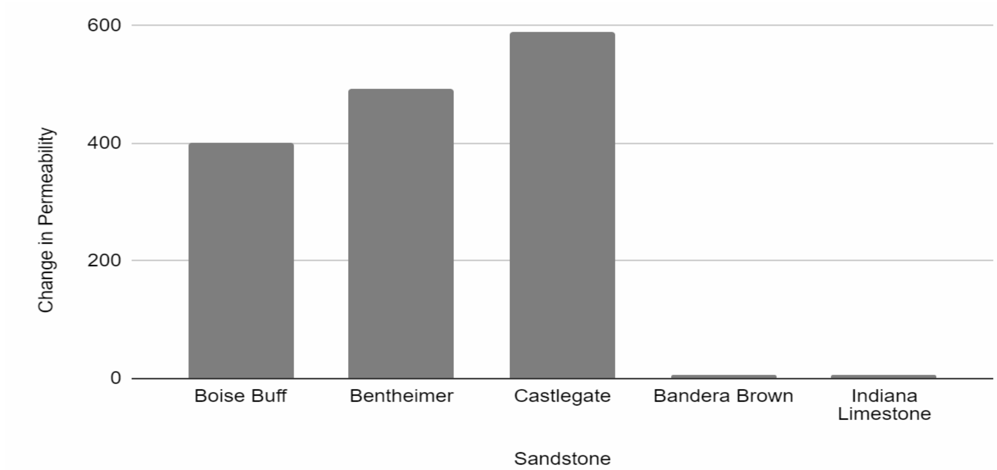

Fig 7: Graph Showing Change in permeability vs Core Samples for ATF 03S gel

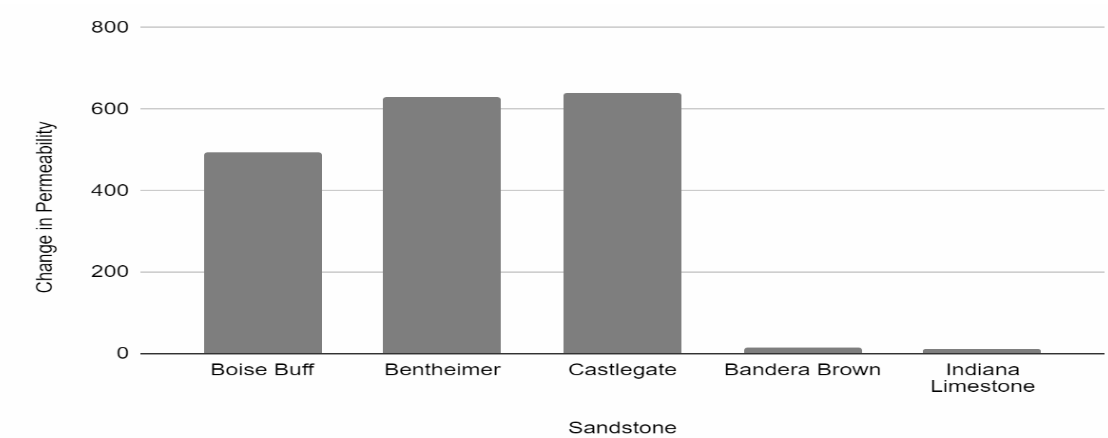

Fig 8: Graph Showing Change in Permeability vs Core Samples for Liquiblock 40F

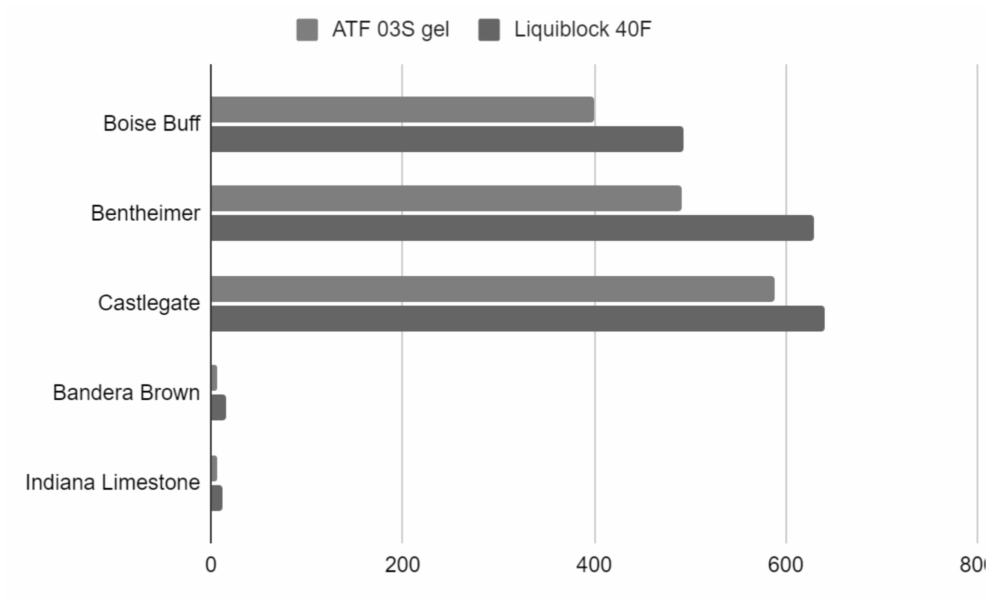

Fig 9: Graph Comparing the Change in Permeabilities Using ATS 03S Gel and 40F Gel