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Preformed particle gel conformance control performance in partially opened fracture and fully opened fracture systems

Ghith Ali Ahmed Biheri

PREFORMED PARTICLE GEL CONFORMANCE CONTROL PERFORMANCE IN PARTIALLY OPENED FRACTURE AND FULLY OPENED FRACTURE SYSTEMS

by

GHITH ALI AHMED BIHERI

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Baojun Bai, Advisor
Abdulmohsin Imqam
Shari Dunn-Norman

ABSTRACT

Conformance problems, such as reservoir heterogeneity can result in a significant decrease in oil recovery, and an excessive water production. Millimeter particle gels (PPG) have been used as conformance control agents to plug open fractures, however, very little research has been conducted to study their ability to plug partially open fractures. This research studies the ability of the PPG to plug partially open fracture to improve conformance and increase recovery in oil reservoirs. Rectangular Sandstone cores were used to conduct the experiments. Fracture widths used include 2, 3.5, 5 mm. For each fracture width, four gel strengths were used; gel strength was varied using 0.05, 0.25, 1, and 10 wt% NaCl brine. The experiments studied the effect of gel strength, and fracture width on oil recovery. The effect of back pressure on the PPG propagation, and plugging efficiency was also studied. The concept of PPG matrix permeability reduction was studied and analyzed using the matrix of the partially open fractures. The gel particles were found to have different gel strengths depending on their location in the fracture. Particles present at the end of the fracture near the sand face were found to have higher gel strengths, whereas particles located near the inlet of the fracture had lower gel strengths. This research studied both the open and partially open fractures, and the difference between them. The concept formation damage was introduced by showing that even though the gel particles managed to plug the fracture, they also extruded into the matrix thus reducing the permeability and affecting oil recovery. These results can help improve future PPG conformance control treatment in the field, and aid in the improvement of hydrocarbon recovery.

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NOMENCLATURE

Symbol	Description
d	Core diameter (cm)
L	Core Length (cm)
VB	Bulk Volume (cm3)
VP	Pore Volume (cm3)
ρ	Brine Density (g/cm3)
Wd	Core Dry Weight (g)
Ws	Core Dry Weight (g)
ϕ	Core Porosity (%)
K	Core Permeability (md)
Q	Flow Rate (ml/min)
μ	Brine Viscosity (cp)
A	Area of Core Sample (cm2)
ΔP	Pressure Drop Across Core Sample (psi)

1. INTRODUCTION

1.1. STATEMENT AND SIGNIFICANCE OF THE PROBLEM

The primary recovery mechanisms in the reservoir are usually depleted after producing very little oil in place therefore; usually a secondary or tertiary means of production is needed to increase the recovery. Water flooding is one of the main secondary recovery techniques used nowadays in order to increase recovery from oil reservoirs. The process involves injection water to both displace the hydrocarbons and to maintain reservoir pressure. Once the water oil ratio becomes too high however, water flooding becomes uneconomical, and thus a new means of production is required. In most oil reservoirs, usually only an average of 10% of the oil in place is produced until the recovery mechanism can no longer supply the energy needed to produce more. Secondary recovery mechanisms can produce can produce almost 20 to 40%, which is much more than the primary recovery mechanisms, however, if the reservoir is to produce more, a tertiary recovery mechanism will have to applied (U.S. DOE, Reference 2). In the United States, almost two thirds of the oil in place is producible using the primary and tertiary recovery mechanisms. It should also be noted that each reservoir is considered a special case, hence the numbers above do not apply to all reservoirs.

Enhanced oil recovery involves injecting fluids into the reservoir that are otherwise not present in the reservoir. It is usually, although not necessarily applied after water flooding. “EOR processes can be classified into four major categories: thermal processes, chemical processes, gas flooding and microbial processes” (Roger et al., 2003). EOR processes can produce much more than water flooding since they can mobilize hydrocarbons that cannot be mobilized using water flooding by reducing interfacial tension, reducing oil viscosity, and improving hydrocarbon mobility. According to the USA Department of Energy, “there is a potential of producing 688 Billion Barrels from enhanced oil recovery by 2030”.

Reservoir heterogeneity is a major problem that can cause the reduction of the increased oil recovery that is expected from the enhanced oil recovery techniques. “Gel treatments are a proven cost-effective method that can assist in reducing the excessive water production and correct reservoir heterogeneity” (Seright and Liang, 1995). Gel treatments work to reduce the permeability of high permeability features such as fractures, which in turn will result in an increase in oil recovery. It also works to reduce the permeability of water more than the permeability of oil, this will result in a larger oil recovery, and a lower water production rate.

A gel treatment’s success “depends heavily on the gel’s ability to extrude through fractures and channels during the placement process” (Seright and Liang, 1995) It is therefore imperative that the mechanisms by which the gels propagate and extrude through high permeability features be understood significantly in order to perform a proper gel treatment.

The thesis identifies the main factors that impact the PPG’s ability to hinder the flow of water, and increase the oil recovery in both closed and open fractures. Results of this study can be used to help improve the design of PPG treatments in the field by understanding the mechanisms under which the PPG plugs the flow of water in both closed and open fractures. It also reveals how the PPG can cause formation damage in closed fractures by migrating into the matrix and plugging the matrix thus resulting in a reduction to the permeability of the matrix. By understanding the mechanisms of this permeability reduction, proper planning of PPG treatments can be done in real fields.

1.2. EXPECTED IMPACTS AND CONTRIBUTIONS

This work will help shed light on the applicability of PPG treatment in partially open fracture, since they were initially tested only using fully open fractures. It also explains in detail through experimentation the concept of formation damage due to gel treatment, which was not reviewed before in the literature. This understanding of how the PPG can actually reduce the matrix permeability and result in a lower than expected oil recovery is crucial when designing future PPG treatments, and will help in selection and proper design of the PPG in order to avoid this phenomenon. The following information was extracted from the research:

The factors that impact the formation damage were studied and evaluated. These factors included the gel strength along different sections of the fracture, and at the sand face, the fracture width. And the injection flow rate. The oil recovery under the different conditions mentioned above were also tested in order to understand how the oil recovery is affected by the formation damage.

1.3. OBJECTIVES

The primary objective of this study was to identify the main factors that impact the PPG's ability to hinder the flow of water, and increase the oil recovery in both closed and open fractures. Results of this study can be used to help improve the design of PPG treatments in the field by understanding the mechanisms under which the PPG plugs the flow of water in both closed and open fractures. It also reveals how the PPG can cause formation damage in closed fractures by migrating into the matrix and plugging the matrix thus resulting in a reduction to the permeability of the matrix. By understanding the mechanisms of this permeability reduction, proper planning of PPG treatments can be done in real fields.

The results gathered from this study provide a comprehensive knowledge and insight into PPG ability to reduce the water production and increase oil production. Additionally, this study reveals and explains the concept of how the PPG can cause a reduction of the permeability by causing matric damage. Figure 1.1 below shows Scope of this study.

1.4. SCOPE OF THIS STUDY

This study included the use of both open and closed fracture setups in order to study the ability of PPG to reduce water production associated with these two features, and increase oil recovery. Several gel strengths were used, including PPG swollen in 0.05, 0.25, 1, and 10 wt% NaCl solutions. Also, several fracture widths were used including 2, 3.5, and 5 mm fractures. The PPG re-swelling ratios were also measured to understand how the gel is affected after several water flooding cycles are performed.

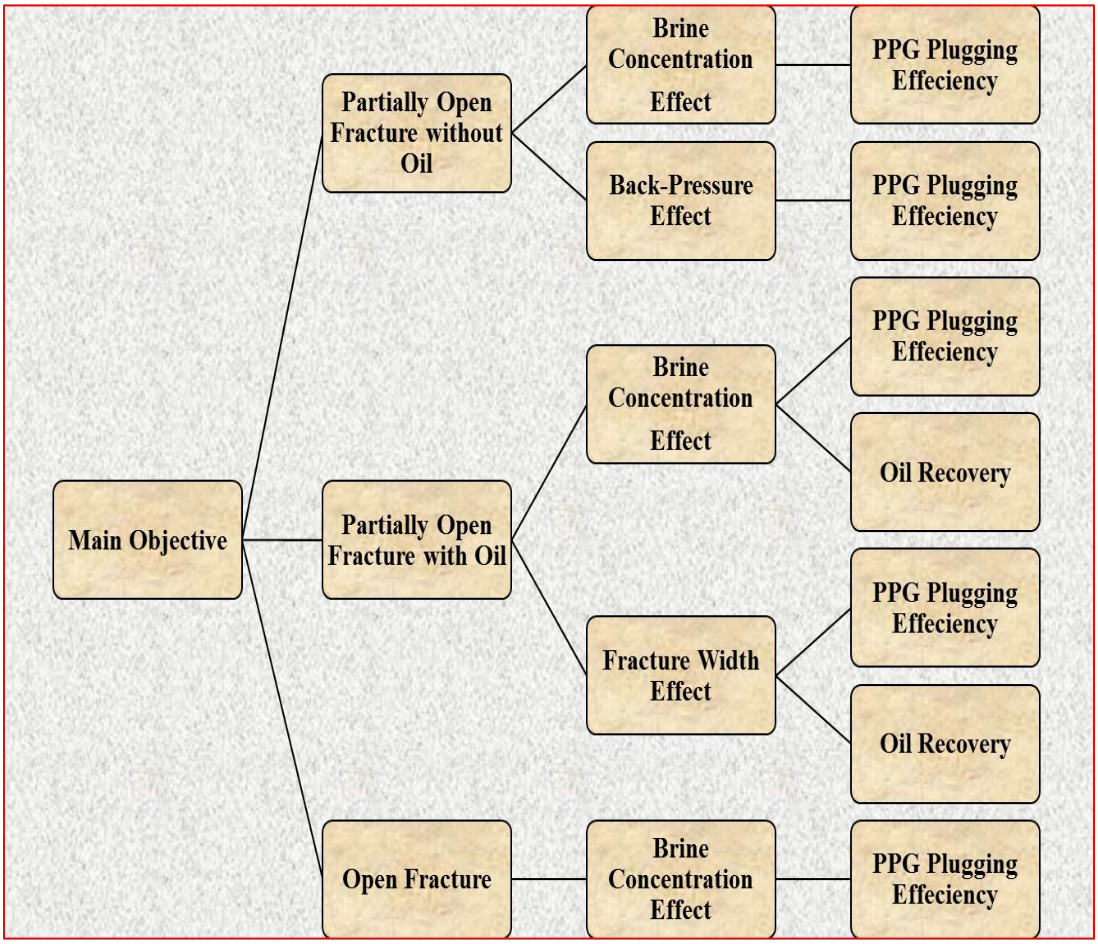

Figure 1.1. Scope of the Research

2. LITERATURE REVIEW

2.1. ENHANCED OIL RECOVERY

In their early life, hydrocarbon reservoirs usually produce using the primary recovery mechanisms. These include, gravity drainage, solution gas drive, water drive, gas cap, or a combination of several of the previously mentioned. These drive mechanisms are supplied naturally due to the reservoirs stratigraphic and structural location. They can result in a production of about 10-15 percent of the original oil in place (OOIP). When these drive mechanisms are exhausted, a secondary, or tertiary method of production is usually implemented in order to increase the recovery from the oil reservoir further more.

Secondary recovery mechanisms mainly involve the injection of either gas, immiscible, or water into reservoir in order to displace the oil remaining in the reservoir, and maintain the reservoir pressure. Secondary recovery can produce an extra 15-20% of the OIIP. “Both primary and secondary oil recovery methods can generally achieve up to 35% recovery of the original volume of oil in place”. (Green & Willhite, 1998)

EOR techniques involve the injection of fluids in the reservoir that are not naturally found in the reservoir. EOR methods are generally divided into three broad categories: thermal recovery, gas recovery, and chemical flooding. Thermal recovery methods include steam flooding, cyclic steam stimulation, and in-situ combustion. The gas recovery methods include carbon dioxide flooding, cyclic carbon dioxide stimulation, nitrogen flooding, and nitrogen carbon dioxide flooding. Chemical flooding methods include polymer flooding, micellar-polymer flooding, surfactant flooding, and alkaline surfactant flooding, and microbial EOR9 (Hilary, 2015). Figure 2.1 clarifies these different EOR methods.

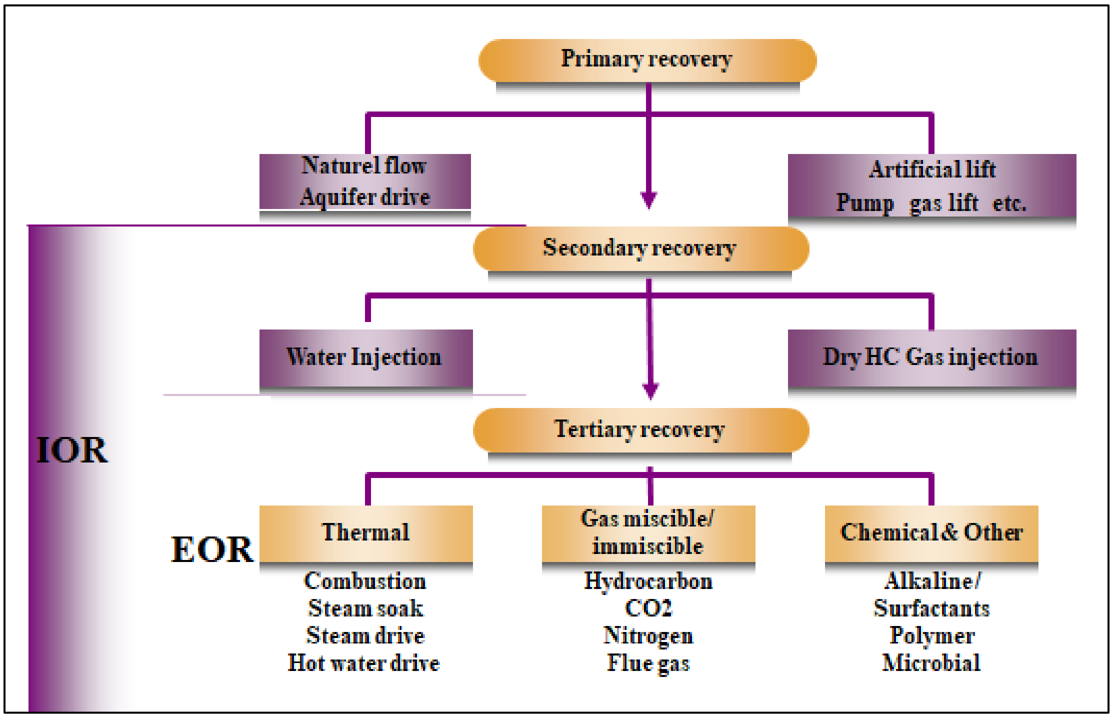

Figure 2.1. Various EOR Methods

Even with the implementation of EOR in oil fields, the recovery can sometimes be very low. This is mainly attributed to reservoir heterogeneity. This heterogeneity is in the form of high permeability streaks such as fractures, both open and closed, channels, and any other high permeability feature that can be present in the reservoir. These can cause early breakthrough of injected fluids, which in turn would result in a lower than expected oil recovery.

2.2. WATER PRODUCTION

Increased water production associated with oil and gas reservoirs is a main challenge that affecting many oil reservoirs worldwide. Water production can reduce expected life of oil and gas wells creating severe problems (e.g., equipment corrosions, hydrostatic load, and sand fine migrations) (Imqam et al., 2015). According to the

Environmental Protection Agency, more than 15 billion barrels of water are produced annually, or in a different manner, eight barrels of water are produced for each barrel of oil (Environmental Protection Agency, 2000). Worldwide, an average of three barrels of water are produced for each barrel of oil (Bailey et al. 2000). "The total cost to separate, treat, and dispose of the unwanted water is estimated to approximately $50 billion per year" (Hill et al. 2012).

2.3. PROBLEMS OF EXCESSIVE WATER PRODUCTION IN OIL FIELDS

Excessive water production during water flooding treatments has become a major problem associated with water flooding treatments (Bai et al., 2008). This increase in water production can result in a decreased oil relative permeability, which in turn will affect the oil recovery greatly. An understanding of how to reduce the water flow, and increase the oil flow therefore becomes extremely important in order to increase oil recovery from water flooding processes.

Several conformance control agents have been used along the years to reduce water production associated with water flooding operations. These conformance control agents include mechanical agents such as packers and sliding sleeves, and chemical agents such as cement, and gels.

Water production in oilfields can occur in two forms. "The first type of water production occurs later in the life of a water flooding and is co-produced with oil. The second type of water production is that which is produced early with oil production. This water flows to the wellbore, such as water flow due to both coning and high permeability channels and streaks". Reduction or complete cessation of this water production is considered a crucial matter in the hydrocarbon industry (Seright et al., 2004).

Water handling and management costs vary depending on the composition, intended usage, and disposal options available to operators. Bailey et al. (2000) estimated that “water handling costs range between 5 to more than 50 cents (USD) per barrel. These costs can be as high as 4 USD per barrel of oil produced for fields producing up to 80% water cut” (Bailey et al., 2000). The estimated average cost of handling produced water is estimated to be between 5 and 10 billion USD in the United States alone (Bailey et al., 2000).

Water management thus involves a huge operation cost in order to produce the water, treat it, dispose of it, and remedy problems associated with it including corrosion, reduced oil problems, and salt deposition in the pores which can plug the pore spaces.

2.4. CAUSES OF UNPRODUCTIVE WATER

The cause of water production problem, water production problems can be categorized in two ways: near wellbore problems and/or reservoir-related problems.

2.4.1. Near Wellbore Problems. Problems near the wellbore can occur as a result of either mechanical or completion problems. They tend to occur early in the well’s life.

• Mechanical problems. Poor mechanical integrity within the casing such as holes created by corrosion, wear/splits due to flaws, excessive pressure, and formation deformation contributes to leaks. These leaks allow unwanted water to enter the casing, causing water to rise unexpectedly. Temperature logs and water analysis comparisons may be used to locate the source of the leak (Imqam et al., 2015).

• Completion problems: Common completion problems include channels behind casing, completions too close to the water zone, and fracturing out of the zone.

• Channels behind casing: Channel behind casing is developed as a result of either poor cement casing or a poor cement-formation bond. This problem can occur at any time during a well's life but is likely to occur just after the well is either completed or stimulated. Unexpected water production at these times strongly indicates that a channel may exist. Temperature, noise, and bond logs can verify the existence of this problem.

• Completions too close to the water zone: Completion in undesired zones, where water saturations are higher than connate water saturations, allows for immediate water production. Perforations made above the original water-oil or water-gas contact throughout the coning or cresting allow the water to be produced more quickly and easily. The logs, core data, and driller daily report should be reviewed to determine the cut-off point of movable water (Imqam et al., 2015).

• Barrier breakdowns: Hydraulic fractures may cause barrier breakdown near the wellbore, leading to excessive water production through the well. This barrier could be a natural barrier such as dense shale layers that separate the different fluid zones.

2.4.2. Reservoir-Related Problems. Reservoir-related problems can be the result of channeling through higher permeability zones or fractures. They can also be related to coning, cresting, reservoir depletions, and fractures out of zones. They typically occur later in the well operators' life (Imqam et al., 2015).

2.4.2.1. Channeling through high permeability streaks or fractures. Water channeling is the result of reservoir heterogeneities that lead to the presence of high permeability streaks. Fractures, fracture-like features, and conduits are the most common causes of channeling. Channels can emanate via natural fractures from a natural water drive, induced fractures (from water flooding mechanisms), or related operations. High permeability streaks result in a premature breakthrough of water, leaving behind large quantities of oil that remain un-swept in low permeability zones. As the driving fluid sweeps the higher permeability intervals, permeability to subsequent flow of fluid becomes even higher. This increases the water-oil ratio through the life cycle of the well (Imqam et al., 2015).

2.4.2.2. Coning and cresting. Water coning in vertical wells and water cresting in horizontal wells occur when the producing formations are located above water zones and when pressure gradient declines near the wellbore. This decline in pressure draws the water from low connected zones toward the wellbore. Water can break into the perforated or open-hole sections, displacing either all or part of the hydrocarbons (Imqam et al., 2015).

2.4.2.3. Reservoir depletions. If reservoir depletion causes the problem, there is very little that can be done to reduce water production. As economical amounts of hydrocarbon must be present. Generally, at the later stage of production, the focus on water control will shift from preventing to reducing water production cost (Imqam et al., 2015).

2.4.2.4. Fracturing out of the zone. When the hydraulic fracture is not designed properly, the fracture unintentionally extends and breaks into water zones. Therefore, coning or cresting through the fracture can result in an early breakthrough of water. Increasing water production substantially, a spinner survey, tracer survey, and well testing can each be used to detect such problems (Imqam et al., 2015).

2.5. MECHANISMS OF UNWANTED WATER PRODUCTION

Understanding how water production occurs, and the flow of water in the reservoir along the life of the reservoir can help in understating the available and viable solutions present to solve this problem (Seright et al., 2001). Water can either flow into the wellbore through a separate path than the hydrocarbons, such as an open fracture or through the same path as the hydrocarbon, which usually occur when water breaks through. The sources of the water can be either from a water flooding processes, or formation water from any layer in the formation that is allowed to flow to the production zone. Water production becomes excessive in heterogeneous reservoirs where there are high permeability variations in the reservoir, fractures, channels, void spaces, or any high permeability feature that would allow the water to produce prematurely.

2.6. CONFORMANCE CONTROL

The term conformance in its original form is defined as the measure of the volumetric sweep efficiency during an oil-recovery flood or process being conducted in an oil reservoir (Sydansk 2011). It's a measure of the uniformity of the flood front of the injected drive fluid during an oil-recovery flooding operation and the uniformity vertically and areally of the flood front as it is being propagated through an oil reservoir (Sydansk 2007). A perfectly conforming drive provides a uniform sweep across the entire reservoir; an imperfectly conforming drive leaves unswept pockets of hydrocarbon (Borling 1994). If there were perfect conformance in a perfect regular five-spot well pattern during an oil-recovery flooding operation, the flood front would reach all four of the offset producers at the same time, and the flood front would reach the entire vertical interval of all four of the producing wells at the same time. However, there never has been a reservoir that has exhibited perfect conformance during an oil-recovery flooding operation (Hao, 2014). Improved conformance during an oil-recovery operation will result in incremental and/or accelerated oil production and/or will result in reduced oil-production operating costs. Properly designed and executed conformance-improvement treatments will improve the effectiveness, efficiency, and profitability of an oil-recovery operation, regardless of whether the oil-recovery operation is primary production, secondary waterflooding, or tertiary flooding (Borling 1994).

2.6.1. What is Conformance Control? Conformance control, in its original and most limited definition, "is synonymous with improving the drive-fluid sweep efficiency during an oil-recovery flooding operation" (Sydansk and Southwell, 2000). Improving the conformance for any hydrocarbon reservoir during any secondary or tertiary flooding operation involves enhancing both the vertical and areal sweep efficiencies (Hao, 2014). "Poor sweep efficiency often results from spatial variation and/or heterogeneity in the permeability of the reservoir rock", whereas "poor vertical conformance and poor vertical sweep efficiency in matrix rock reservoirs" (Lake 1989).

"Conformance treatments to improve poor vertical sweep profiles and/or to shut off competing water or gas production, emanating from a subset of geological strata, are referred to as profile modification treatments" (Sydansk 2011). When the sweep efficiency and the degree of conformance are improved during an oil-recovery flooding operation, the oil recovery factor increases, since the volume of the reservoir swept become much higher than previously (Hao, 2014). By reducing the water production, the operating costs are reduced significantly and thus the benefit of increased oil recovery, and reduced operating costs are gained.

Conformance control treatments do not normally promote reductions in residual oil saturation. Therefore, "conformance-improvement operations should be limited to well patterns or reservoirs with a substantial and economically viable amount of moveable oil that can be recovered as a result of conducting the conformance flood or treatment"

(Seright, 1999; Sydansk, 2000). The majority of conformance control treatments operate to reduce permeability of the high permeability features in order to allow for a more uniform reservoir sweep (Seright, 1994, 1999).

2.6.2. Water Control Solutions. Several solutions have been presented to solve the problem of excessive water production. If the water oil contact depth is clearly defined, and can be clearly known, then a permeant barrier between the water, and the oil can be made. This barrier can permanently stop the water flow, and can result in the hydrocarbons producing without the water. If the oil water contact cannot be defined clearly, then selective methods should be used; these methods include polymer flooding, or crosslinked polymer treatments. (Krilov 1998). Mechanical conformance control methods used in the past include mechanical isolation, squeeze cementing, solid slurry (clay injection), oil/water emulsion and silicate injection (Prada 2000). More successful results have been reported chemical conformance control methods such as crosslinked polymer, gel treatment, and performed particle gel treatments (Hao, 2014).

3. INTRODUCTION OF GEL TREATMENT

In the oil industry, gel treatment is considered as a one of the most effective and economical means available to reduce the water production by solving heterogeneity problems associated with hydrocarbon reservoirs (Seright and Liang. 1994). Gel treatments are designed by crosslinking three-dimensional polymer networks using a crosslinked; the crosslinker could be either organic or metallic.

In-situ gels are most commonly used to control reservoir conformance. A mixture of polymers and crosslinkers known as gelants are injected into the reservoir to treat the target formation. After the gelant is transported to the target formation, gelation is induced thus turning the gelant into a gel that can effectively plug, and divert flow form the target formation. Several factors can induce gelation based on the design of the gel itself; these can include temperature, pressure, pH, minerals in the formation, and many other factors. (Sydansk and Moore 1992). This kind of methods, however, has many limitations such as a lack of gelation time control, gelling uncertainty due to shear degradation, chromatographic separation between polymer and crosslinker, and dilution by formation water and minerals that restrict its applications for conventional reservoirs (Chauveteau et al., 1999, 2001, 2003. Coste et al. 2000. Bai et al. 2007a, 2007b).

To overcome some of the drawbacks of insitu gel, novel gel systems have been developed. These newer gels have a better performance than previously used gels. The new gels are formed at surface facilities and then injected into target zones with no need for gelation to occur in the reservoir conditions. These gels include:

Preformed Particle Gels (PPG), microgels, Bright water, and pH sensitive polymer microgels. Preformed particle gels are superabsorbent crosslinked polymer particles that can swell up to 200 times their original size when placed in brine. These kinds of PPGs are a millimeter-sized particles that are formed at the surface. They are then dried and crushed into small particles before they are injected into a reservoir (Coste et al. 2000. Bai et al. 2007a, 2007b). A micro-gel is a fully water soluble, non-toxic, soft, stable, and size controlled gel, that is injected into the reservoir in a manner similar to the PPG. It has a particle size between 10 and 1000 nm (Chauveteau et al. 1999, 2001, 2003; Rousseau et al. 2005; Zaitoun et al. 2007). Temperature sensitive polymer microgels (known as Bright water) are submicron gel particles. They are injected into the reservoir with cool injection water which has a temperature less than the reservoir temperature. As the temperature sensitive microgels propagate through the reservoir, their temperature begins to increase due to heat transfer with the surrounding rock and fluid. As it heats up, the polymer starts to expand to many times its initial size, blocking pore throats and diverting water behind it (Pritchett et al., 2003. Frampton et al, 2004. Morgan 2007. Yanez et al, 2007. Garmeh et al. 2011). The pH sensitive polymer microgels use pH change as an activation trigger. The gel begins to adsorb water as the pH increases, swelling up to 1000 times its original volume (Al-Anazi et al. 2002. Huh et al. 2005. Benson et al. 2007).

Gels have traditionally been placed near the wellbore of production or injection wells to correct interlayer heterogeneity or fractures. Near-well bore treatments are ineffective, however, if a cross-flow exists between adjacent layers. Newer gel treatment trends were recently developed to be applied in in-depth fluid diversion conformance control (Seright 2004; Frampton 2004; Sydansk 2005; Chang 2004; Rousseau 2005; Bai et al. 2007).

3.1. USES OF GEL TREATMENT

The main objective of gel treatment is to solve excess water production problems, which is a significant problem for mature oil fields. Being a commonly used and cost-effective method, Polymer gels have two main mechanisms: 1) blocking high-permeability zones and 2) decreasing permeability disproportionally (Ze, 2016).

These injected gels can create high resistance in high permeability zones and divert a portion of injected water to areas not previously swept by water (Ze, 2016). Decreasing permeability disproportionally involves the reduction of the permeability of a phase in the reservoir more than the other. No gel can only decrease the water permeability without affecting the permeability of oil, however, gels with a good decreasing permeability disproportionally will decrease the water permeability much more than the oil permeability thus making the oil more mobile than the oil.

3.1.1. In Situ Polymer Gel. In-situ gels are crosslinked polymers composed of several chemical materials including polymers, crosslinkers, and additives. Corresponding to some internal or external stimulation, the crosslinking agent connects itself to two adjacent polymer molecules linking them together either chemically or physically. The liquid formulation of this composition is known as a gelant. The gelant in an in-situ system is injected into the formation, and the gel forms under reservoir conditions (Imqam et al., 2015).

The gelant can crosslink to form a gel under various conditions including, but not limited to, an increasing temperature and a changing pH. Both a gelant's composition and surrounding conditions can be used to control gel strength. This strength can be either weak or very strong. In-situ gels have been used widely to control conformance, but their crosslinking reactions are strongly affected by degradation (Imqam et al., 2015).

3.1.2. Preformed Particle Gels (PPGs). Preformed gel is formed at surface facilities before injection, and then injected into the reservoir. No gelation occurs in reservoirs. The current available preformed gel types include preformed particle gel (PPG) (Bai et al., 2004. 2007; Coste et al., 2000), microgels (Chauveteau et al., 2001. 2003; Zaitoun et al., 2007), pH sensitive crosslinked polymer (Al-Anazi & Sharma, 2002; Huh et al., 2005), mm-sized swelling polymer (Abbasy et al., 2008; Larkin & Creel, 2008), and Bright WaterTM (Frampton et al., 2004; Pritchett et al., 2003). Major differences between these preformed gel types are their sizes, swelling times, and the applicative reservoir condition (Ze, 2016).

Bai et al. initiated preformed particle gel (PPG) conformance control technology in PetroChina to solve the problems caused by fractures or high permeability zones. It is a superabsorbent crosslinking polymer that can swell to 200 times of its primary size in brine. Acrylamide and Methylenebisacrylamide are used as monomer and crosslinker respectively to synthesize the particle gels. Then the PPGs are dried, crushed, and sieved to get solid states and desired sizes (Ze, 2016).

Compared with general in situ gels, PPGs have the following advantages: 1) PPGs' strength and size can be controlled and friendly to environment. They are stable with almost all reservoir minerals and water salinities. 2) PPGs can preferentially enter fracture or fracture-feature channels and at the same time prevent gel penetration into low permeability zones. 3) PPG has only one component during injection. 4) PPG can be prepared using water produced from the field without influencing gel stability (Ze, 2016). Enjoying all these strong points, PPG, especially millimeter-size PPGs has proved successful in reducing water production problems. (Bai et al., 2008; Liu et al., 2006).

Preformed microgel that is reported to be fully water soluble, nontoxic, soft, stable, and size-controlled is prepared using a terpolymer of acrylamide containing 2% acrylates and 2% sulfonated groups from SNF Floerger. The first type of the microgel uses environment-friendly zirconium crosslinker. The second type of microgel is covalently crosslinked. These types of microgels can solve the plugging problem during injection in situ HPAM/zirconium (IV) acetate, which is caused by gel forming and bridging at the pore throat and absorbing to form a gel layer (Ze, 2016). A typical microgel size is about 1-3 μm and typical gel concentration is 3000 ppm (Chauveteau et al., 2000, 2001).

4. EVALUATION OF PREFORMED PARTICLE GELTRANSPORT AND PLACEMENT THROUGH PARTIALLY OPEN FRACTURES

4.1. INTRODUCTION TO PARTIALLY OPEN FRACTURES EXPERIMENTS

Excessive water production from oil reservoirs is a major problem in the oil industry today. This water can result in major operation and handling problems such as corrosion, pumping the water, treating it, and disposing of it. One of the main reasons behind excessive water production is reservoir heterogeneity. The presence of high permeability features in the reservoir, such as fractures, and high permeability matrices can result in an early breakthrough of water, and a non-uniform reservoir sweep, which decreases oil recovery, and increases water recovery significantly. Conformance control agents have been used to plug these high permeability features. One of the most prominent conformance control treatment methods is gel treatment.

Gels have mainly been used to reduce permeability of large features such as fractures, fracture-like features, super-permeability streaks, and large void space conduits. Gel blocks or reduces the permeability of these features so the injected water remains within a reservoir and diverts into un-swept oil zones to produce more oil. In general, there are two main types of gel used for this purpose: In-situ gel and preformed gel. The main difference between the two gels is the mechanism of gelation. For in-situ gel types, gelation occurs in reservoir conditions, where the preformed gel is manufactured at a surface facility and injected into the reservoir as one component; therefore, no gelation process is required. In in-situ gel, the gelation mechanisms (crosslinking reactions) are strongly affected by shearing during pump injection, wellbore and porous media; adsorption and chromatography of chemical compositions as well as the dilution of formation water

(Chauveteau et al., 2001, 2003; Coste et al., 2000; Bai et al., 2007a, 2007b). The other important disadvantage of using in-situ gel is the high possibility of damage to un-swept low permeability oil zones because of the low viscosity of the gelant, which enables it to flow through rock matrices as well as fractures. Due to these inherent drawbacks, preformed gel was developed and attracted much attention from oil and gas companies. There are four types of preformed gel currently available including millimeter-sized preformed particle gels (PPGs), microgels, pH sensitive polymers, and thermo-sensitive submicrons. Their differences are mainly in particle size, swelling ratio, and swelling time (Imqam et al., 2015).

Many studies have been performed to evaluate in-situ gel so as to improve the understanding of gel injectivity and blocking efficiency mechanisms to water flow (Bryant et al., 1996; Ganguly et al., 2001; Liu and Seright, 2000; McCool et al., 2009; Seright, 1995, 1997, 1998, 1999, 2001 and 2003; Sydansk et al., 2005; Wang and Seright, 2006). Studies have also been performed to evaluate preformed gel injectivity and placement through porous media such as fractures, high permeability streaks, and conduits (Bai et al., 2007b; Chauveteau et al., 2001, 2003, and 2004; Coste et al., 2000; Cozic et al., 2009; Dupuis et al., 2016; Feng et al., 2003; Frampton et al., 2004; Imqam et al., 2015a; Imqam and Bai, 2015; Imqam et al., 2015b, Imqam et al., 2016b; Muruaga et al., 2008; Pritchett et al., 2003; Rousseau et al., 2005; Zaitoun et al., 2007; Zhang and Bai, 2011). Most of the previous work (if not all) for both in-situ and preformed gel focused on examining the gel injection and placement only through fully opened fractures, conduits, and high permeability cores. However, the situation of partially fracture tip has not been investigated and represents an information gap at this time. Fractures do not always propagate along their formation lines, and they have limited propagation length. Therefore, one of the objectives of this study is to explore a new area of research involving partially open fractures. The partially open fractures in this research represent sandstone fractures which are not continuously or fully open along formation but rather their opening becomes restricted with the formation of the matrix. The goal was to find out if PPG transport behavior and blocking efficiency in partially opened fractures are different from those in fully opened fractures.

4.2. OBJECTIVES AND TECHNICAL CONTRIBUTIONS

Most of the previous works have emphasized gel injection and placement through swept zones (thief zones) and has not seriously evaluated the gel placement on un-swept zones (low permeability). For in-depth fluid diversion applications, PPG flow through a fracture to form a seal and block it, but a few gel particles can still transport into the matrix. Therefore, the other aim of this study was to examine factors that can be used to control expected PPG impact into the matrix. Few studies have been conducted to evaluate PPG into the matrix and find ways to eliminate its effect. Elsharafi and Bai (2012) conducted a laboratory study to examine different factors that influence PPG penetration into low-permeable, un-swept zones. They evaluated the gel that formed at different brine solutions and core permeability levels. Imqam et al. (2016a) evaluated gel at the matrix and used hydrochloric acid (HCl) to mitigate the gel at the matrix, and their results showed that HCl removed the damage efficiently and returned the low permeability cores to their original permeability levels. However, these two studies neither determined how the damage inside the matrix can affect low core permeability rocks, nor did they evaluate how the damage behaves at high injection pressure.

Overall, this study will provide guidance about how to better design and operate a PPGs conformance control treatment in partially opened fractures. It will also illustrate how to minimize the penetration of PPGs into un-swept zones by optimizing PPG properties.

4.3. EXPERIMENTAL MATERIALS

Different materials have been used to accomplish this study, including preformed particle gels (PPGs) and sandstone cores.

4.3.1. Preformed Particle Gel (PPG). LiquiBlockTM 40K is a weak gel particle with a lower elastic module after becoming fully swollen Figure 4.1 shows the commercial superabsorbent polymer used as the PPG to conduct the experiments. The PPGs absorbed a large amount of water, increasing their volume. It is a crosslinked polyacrylic acid/polyacrylamide copolymer.

Figure 4.1. PPG Before and After Being Swollen in Brine Solution (Imqam et al., 2015)

Table 4.1 list the typical characteristics of LiquiBlockTM 40K gel. Dry particles with mesh size of 20–30 were used. Dry PPG samples were prepared and swollen in four sodium chloride (NaCl) brines at 0.05%, 0.25%, 1%, and 10% weight percent. PPG concentration was 5000 ppm and gel particles were injected into the fracture model using an accumulator.

Table 4.1. Typical Characteristics of LiquiBlockTM 40K Gel

Properties	**Value**
Absorption Deionized Water (g/g)	**>200**
Apparent Bulk Density (g/l)	**540**
Moisture Content (%)	**5**
PH Value	**5.5-6.0**

4.3.2. Swollen PPG Sample Preparation. The swollen PPG used in these experiments was prepared as follows:

• A vessel was filled with a brine solution of the desired concentration (0.05%, 0.25%, 1.0%, or 10 wt % NaCl) to prepare the PPG.

• 5000 ppm of PPGs were weighed and slowly added to the brine solution inside the vessel. The PPG was allowed to swell completely, a process that required more than 6 hours.

• Core holder: A core holder that was 44 cm long with height and width of 4.5 cm and 4.5 cm respectively (area was equal to 20.25 $cm^{2)}$. Pressure taps were mounted along the core holder to monitor PPG transport and placement performance.

• Sandstone core samples: Sample length was approximately 30.5 cm with height and width of 4.2 cm and 4.3 cm, respectively (the area was equal to 18.06 cm^2). The length of fracture was 21 cm, while the core sand face was mounted at the end of the core holder to design the partially opened fracture model.

• Brine: Sodium chloride (NaCl) was used to prepare all brines. Various brine concentrations at room temperature were selected to prepare the swollen PPGs. Brine concentration significantly affects the PPG swelling ratio and swollen particle strength. High salinity brine results in a lower swelling ratio and higher swollen particle strength. The brine viscosity was about 1 cp.

• An accumulator with a length of 25 cm, and the diameter was 6.5 cm. was used (the total capacity was 830 ml). The accumulator was used to inject the oil inside the core. Also, after the gel was fully swollen, the gel was placed inside the accumulator. The accumulator was used to inject PPGs into the core to reduce core permeability.

4.3.3. Procedure to Measure Core Porosity. The procedure for the porosity measurements was as follows:

• Each core was cut from the same source and then the core dry weight (Wd) was measured.

• The core height (H), width (W), and the core length (L) were measured. The bulk volume (VB) was then calculated by using the following Equation 4.1.

$$VB = L \times H \times W \tag{4.1}$$

• The cores were dried and placed inside a tumbler. The cap was closed and the shield valve was opened and the desired brine valve was closed.

• The vacuum pump was turned on and the pressure gauge was observed until it reached 25 mmHg approximately. If the cores had low permeability, a longer time was required to reach the desired pressure.

• The buffer valve was closed and the brine valve was opened then the pump was turned off. It was important to make sure that the brine flowing into the beaker and the samples was saturated.

• After the cores were dried, vacuumed, and saturated, they were then weighed to measure the core saturated weight (Ws), at room temperature.

• The brine density [(ρ) 1.004879 gram/cm^3] was used to calculate the pore volume (VP) by using the following Equations 4.2, and 4.3

$$Brine\ weight(Bw) = Ws - Wd \tag{4.2}$$

$$Vp = \frac{brine\ weight}{brine\ density} \tag{4.3}$$

• The core's porosity (ϕ) was calculated by using the following Equation 4.4.

$$Porosity(\emptyset) = \frac{Vp}{VB} \times 100 \tag{4.4}$$

4.3.4. Calculation of Core Permeability. Core permeability was measured according to results obtained in the experiments. The Darcy equation was used to calculate the core permeability during this study (Darcy, 1856). Equation 4.5 was used to calculate rock permeability (k).

Where, Q is the flow rate (cm^3/min), μ the viscosity of the brine (cp), L is the length of the core sample (cm), A is the area of the core sample (cm^2), ΔP is the drop pressure across the core sample (atm).

$$K = \frac{Q \times \mu \times L}{A \times \Delta P} \tag{4.5}$$

4.4. EXPERIMENTS IN THIS STUDY

Experiments were carried out to evaluate PPG resistance to water flow through the fracture and to assess the gel impacts on the matrix in presence of oil. Tables 4.2, 4.4, 4.7, and 4.8 illustrate the factors investigated during this study. Four brine concentrations (0.05%, 0.25%, 1%, and 10% NaCl) were selected based on swelling ratio and gel strength. A dry PPG with 20-30 mesh size was used for all experiments. PPGs were injected into the model until pressure reached a peak at 1000 psi. Additional four experiments were performed to study the same factors above, but without using the oil during the experiments. The objective of these four experiments to study the effect of the presence of the oil on the gel treatment. Additional experiments were performed to study the effect of PPG injection pressure in the presence of back pressures of 400 psi and 600 psi. A back-pressure regulator was installed at the end of the core holder model to provide and adjust the back pressure. Additional experiments were performed to investigate the effect of open fracture, and then compare the results with partial open fracture.

4.5. PARTIALLY OPEN FRACTURE EXPERIMENTS WITHOUT USING OIL

This section focuses on providing information about the procedure and the results of partially opened fracture without using oil.

4.5.1. Experimental Setup without Using Oil. Figure 4.2 shows the apparatus used to set up the partially open fracture model without using oil for four experiments. It consists of a syringe pump used to inject NaCl solutions and swollen PPGs through two accumulators into a partially open fracture model. The model is comprised of an accumulator and a core holder. The sandstone core was placed inside the holder, and the confining pressure was adjusted to have a minimum of 500 psi difference above the injection pressure. Four pressure taps were located along the accumulator to acquire the PPG and brine injection pressure. Test tubes were placed at the effluent to collect the produced brine and to check for any gel particle filtrate emitted from the cores.

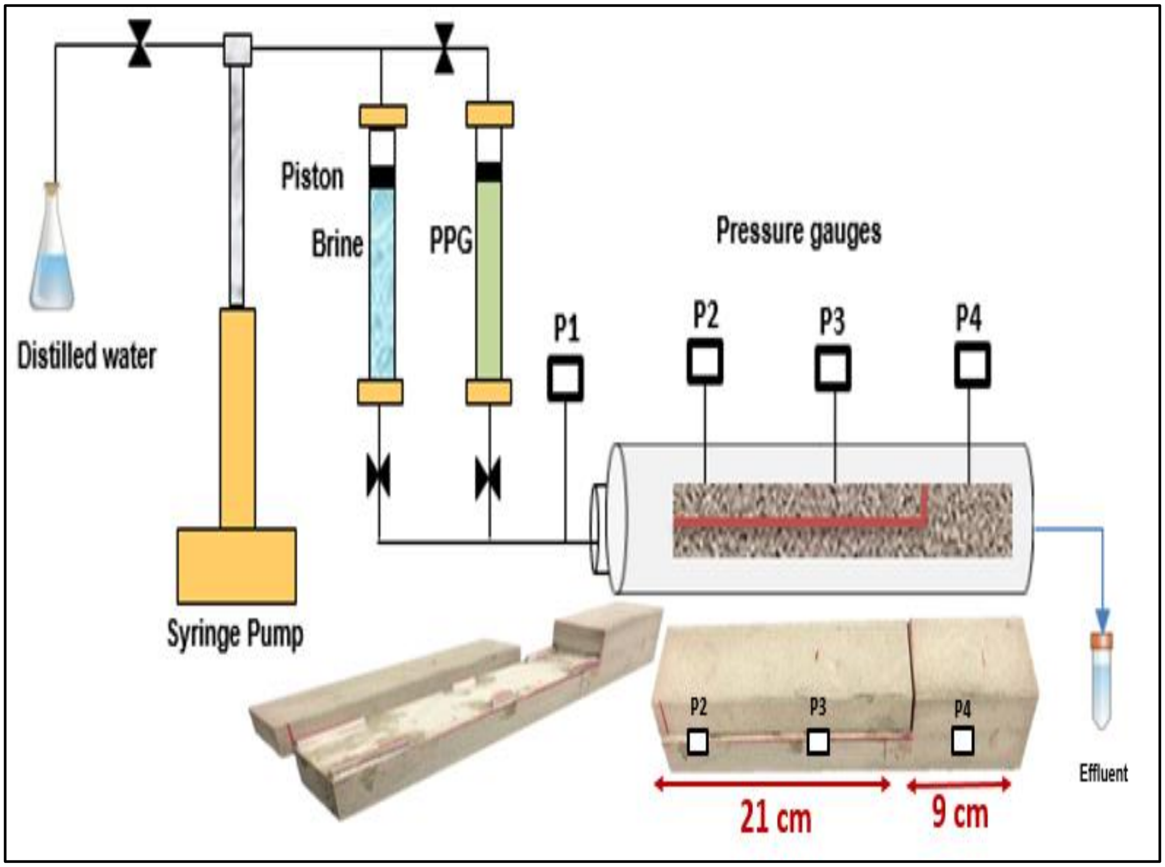

Figure 4.2. Partially Opened Fracture without Using Oil

4.5.2. Experimental Procedure. Four experiments have been done without using oil injection and the fracture width was only 2 mm. After measuring the permeability, 0.05, 0.25, 1, or 10% brine NaCl solution was injected into the partially open fracture model at a rate of 2 ml/min. The brine was injected until the brine injection pressure became stable. Then, the swollen PPG dispersed in 0.05, 0.25, 1, or 10% NaCl with a concentration of 5000 ppm was injected into fracture model at rate of 2 ml/min after completing the first water flooding processes. The brine was injected until the pressure reached 1000 psi. The last step was to inject a brine at the same flow rate after the PPG treatment was complete, to test the gel blocking efficiency for high permeability zones (swept zones from first water flooding). Brine was also injected until the injection pressure became stable.

These procedures were repeated for all four experiments. Table 4.2 below shows the parameters used in the experiments of partially open fractures without using oil.

Table 4.2. Summary of Key Parameters Investigated During Experiments without Using Oil

Experiment	Fracture width, mm	Brine concentration (%NaCl)
1	2	0.05
2	2	0.25
3	2	1
4	2	10

4.5.3. Results and Analysis. This section discusses results obtained for the effects of brine concentration. Results include injection pressure measurements before, during, and after PPG injection, as well as PPG resistance to water flow.

4.5.3.1. Effect of brine concentration on injection pressure performance. Fours brine concentrations (0.05%, 0.25%, 1%, and 10% NaCl) were used for brine injection and to prepare the swollen PPGs. The injection pressure for the gel swollen in the 0.05% NaCl rose significantly with the increase in flow rate when compared to the gel swollen in the 10% NaCl concentration. This high injection pressure, which reached 1040 psi, indicates how the damage of PPG in the matrix could create a large back pressure during the treatments. The injection pressure of the gel swollen in the 10% NaCl concentration was 426 psi. Figure 4.3 illustrates the injection pressure performance before, during, and after PPG injection.

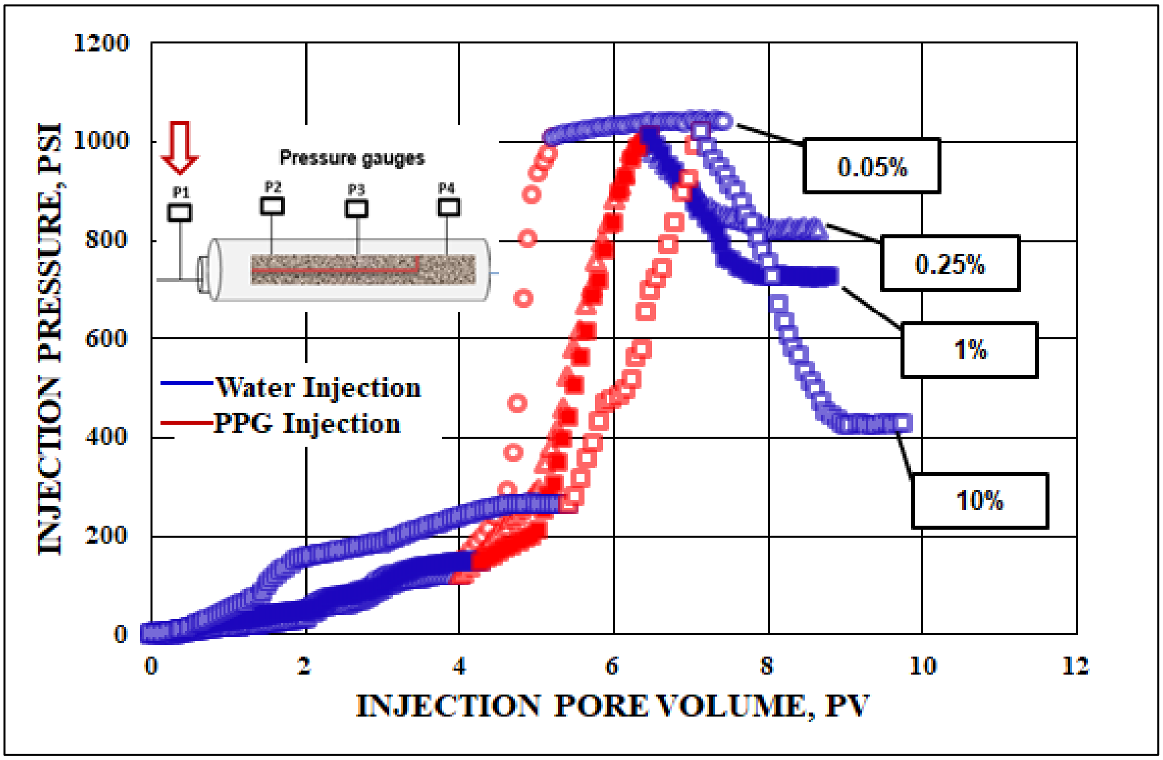

Figure 4.3. Injection Pressures Recorded for Different Brine Concentrations without Using Oil

4.5.3.2 Differential injection pressure across the fracture and matrix. The pressure difference between each pressure tap was recorded and plotted as a function of injected pore volume. For each figure presented in this section, three main phases of the experiments are defined; the first phase is the first water-flooding, the second phase is the gel injection phase, and the final phase is the second water-flooding after gel injection.

The pressure difference between the inlet pressure transducer, P1, and the first pressure transducer located in the matrix, P2, is shown in Figure 4.4. The four lines in the figure represent the results from four different experiments, each with particles with a different gel strength. The pressure difference is highest for the highest gel strength, since the stronger particles can reduce the flow of water much more than the weaker particles. The highest pressure difference, P1-P2, is almost 7.5 psi, which is considered low. This is due to the fracture being a void-like conduit, and thus it is difficult for the gel to plug the flow of water; the water forms a channel in the gel through which it can flow freely without a large plugging, hence the low pressure difference between the pressure transducers.

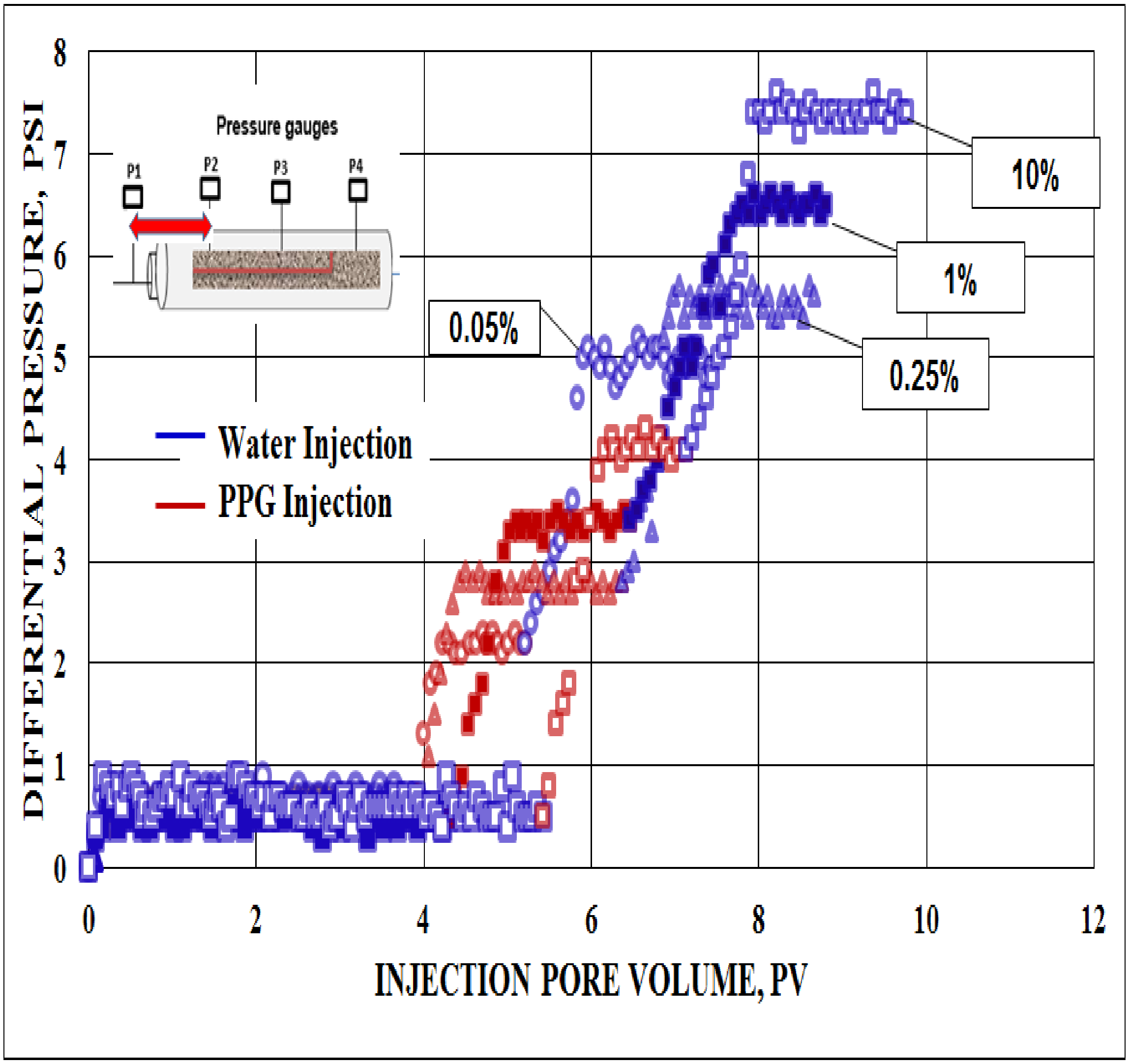

Figure 4.4. Differential Pressure Across the Fracture, P1-P2

In Figure 4.5. The same trend can be observed as explained in Figure 4.4 above This is due to the location of the pressure transducers measuring P2, and P3 being both in the fractures, and also the distance between P1 and P2 is equidistant to that of P2 and P3.

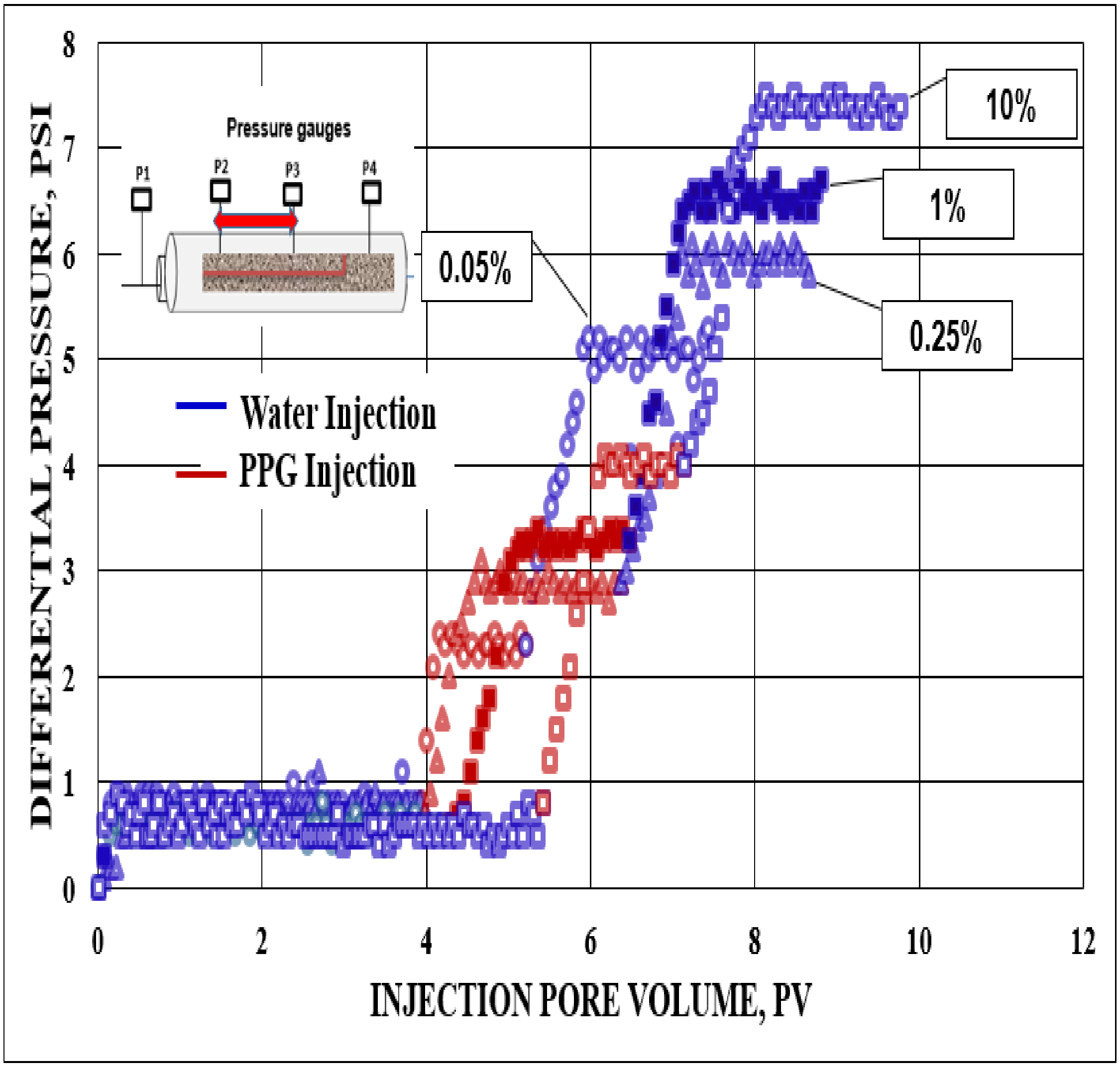

Figure 4.5. Differential Pressure Across the Fracture, P2-P3

In Figure 4.6. A very interesting trend can be noticed. This figure represents the pressure difference across the matrix, which is represented by the pressure difference between P3 and P4. For this pressure difference, the opposite trend can be noticed compare that observed in Figure 4.4, and Figure 4.5. During gel injection, due to the high injection pressure, the gel particles are broken down into small particles and extrudes into the matrix. As the gel strength increases, the particles resist extrusion into the matrix. This in turn results in a higher pressure for the lower gel strength particles, since they manage to extrude deeper into the matrix, compared to the higher gel strength particles, which will extrude a much shorter distance into the matrix due to their much higher strength.

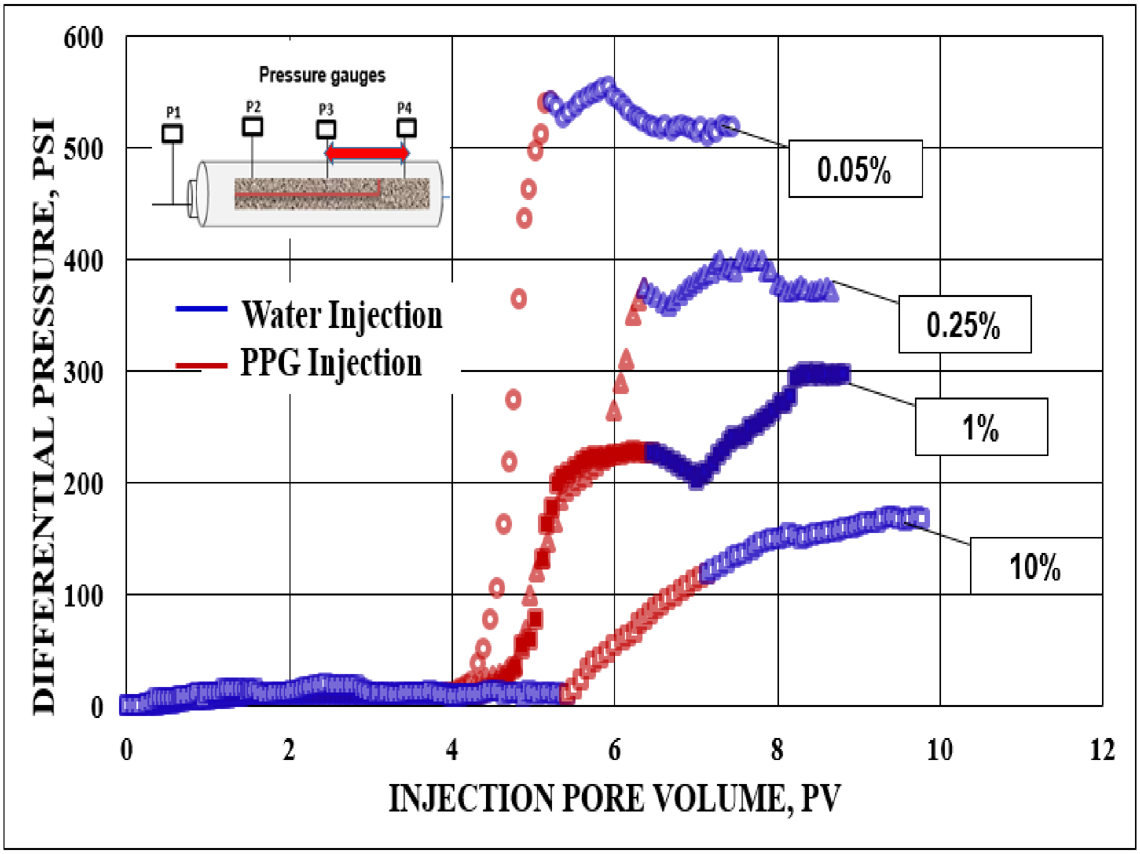

Figure 4.6. Differential Pressure Across the Matrix, P3-P4

A pressure difference between the pressure transducer in the matrix, P4, and the outlet pressure also exists. This pressure difference must be quantified for two main reasons; the first is for validation purpose, since the summation of all pressure difference should equal the inlet pressure, P1, while the second reason is to fully incorporate the pressure difference across the matrix. Figure 4.7 shows the pressure difference across P4, and the outlet of the core holder, named P5. The same trend as in Figure 4.6 is observed, since the same phenomenon occurring in that figure is happening in Figure 4.7.

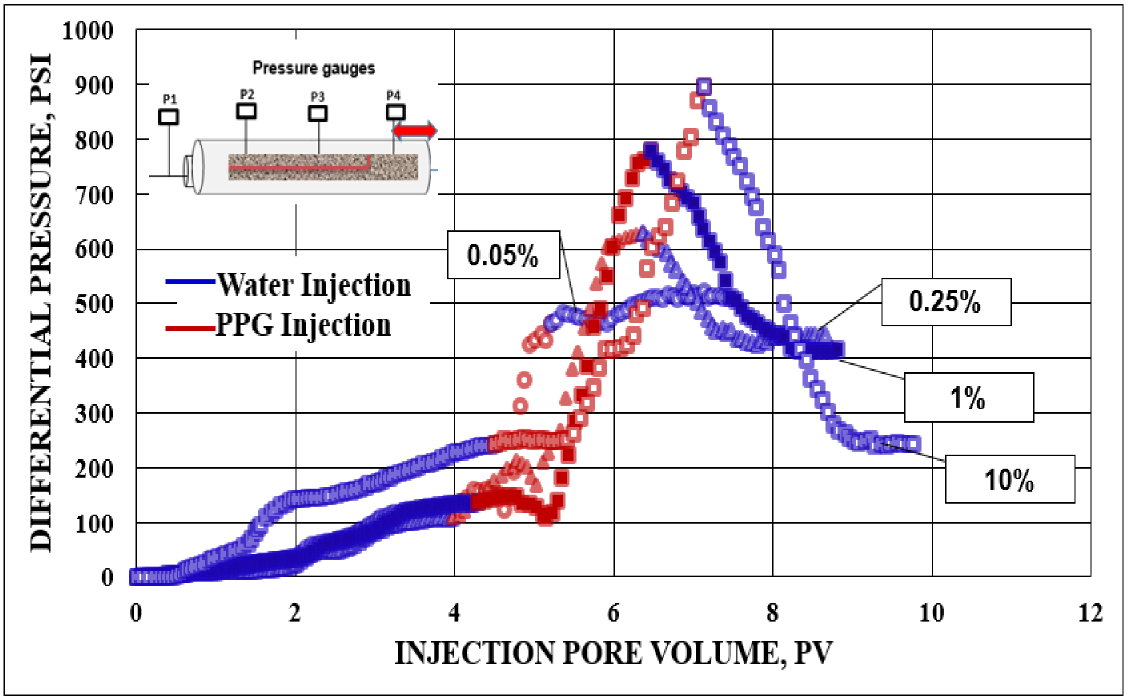

Figure 4.7. Differential Pressure Across the Matrix, P4-P5

The pressure difference across all sections of the core are shown in Table 4.3. The summation of all the pressure differences should equal the pressure value at the inlet of the core, P1.

Table 4.3. Pressure Difference Values Across All Sections of the Core

Brine Concentration NaCl, %	**P1-**P2	**P2-P3**	**P3-P4**	**P4-P5**	**P1**
0.05	4.9	5.3	519.2	511.2	1040.6
0.25	5.6	5.8	371.4	440.4	823.2
1	6.5	6.7	297.9	414.8	725.9
10	7.4	7.4	168.1	243.3	426.2

This can be validated using the equation below.

Where P1= (P1-P2) + (P2-P3) + (P3-P4) + (P4-P5)

4.6. PARTIALLY OPEN FRACTURE EXPERIMENTS USING OIL

This section focuses on providing information about the procedure and the results of partially opened fracture using oil.

4.6.4. Experimental Setup with Using Oil. Figure 4.8 shows the apparatus used to set up the partially open fracture model for the experiments with using oil. It consists of a syringe pump used to inject NaCl solutions, swollen PPGs, and oil through three accumulators into a partially opened fracture model. The model is comprised of an accumulator and a core holder. The sandstone core was placed inside the holder, and the confining pressure was adjusted to have a minimum of 500 psi difference above the injection pressure. Four pressure taps were located along the accumulator to acquire the PPG and brine injection pressure. Test tubes were placed at the effluent to collect the oil, the produced brine, and to check for any gel particle filtrate emitted from the cores.

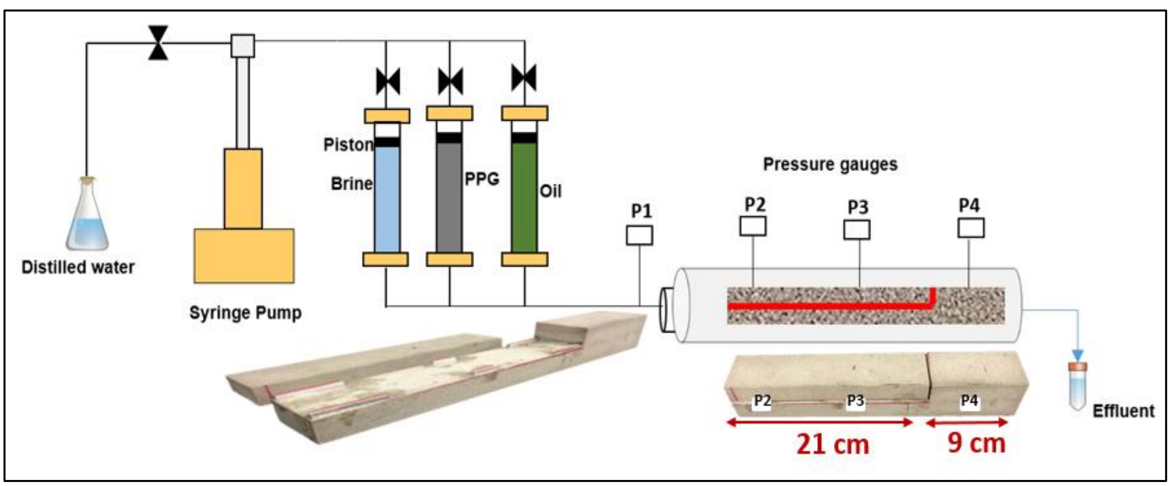

Figure 4.8. Partially Opened Fracture with Using Oil

4.6.2. Experimental Procedure. After measuring permeability, oil viscosity with 37cp was injected from the accumulator into the fracture model at a rate of 2 ml/min. Oil was injected until desirable connate water saturation was achieved and no water came out, and until the pressure became stable to make sure the core is fully saturated with oil. Then a fracture was created with length of 21cm and with different fracture widths (2 mm, 3.5 mm, and 5 mm). After that the following steps were done:

First Water Flooding: A 0.05, 0.25, 1, or 10% brine NaCl solution was injected into the fracture model at a rate of 2 ml/min to simulate secondary oil recovery conditions. Oil and water productions at effluent were recorded every 5 ml. The brine was injected until no oil was produced and the brine injection pressure became stable. Overall, 3 PV of brine injection was sufficient to ensure no oil was produced at effluent., Both oil recovery and water cut were determined during the first water flooding.

PPG Treatment: Swollen PPG dispersed in 0.05, 0.25, 1, or 10% brine NaCl solution with a concentration of 5000 ppm was injected into the fracture model at rate of 2 ml/min after completing the first water flooding processes. The volume of oil and water production at the outlet as well as PPG injection pressure was recorded for each experiment. The brine was injected until the pressure reached 1000 psi.

Second Water Flooding: A 0.05, 0.25, 1, or 10% brine NaCl solution was injected again at the same injection flow rate after the PPG treatment was completed, to test the gel blocking efficiency for high permeability zones (swept zones from first water flooding). This was also done to determine the incremental oil recovery from the un-swept zones. Brine was also injected until no oil was produced at the outlets and the injection pressure became stable. Approximately 3 PV of brine was also injected so that the results obtained from the first water flooding could be compared. These procedures were repeated for each experiment. The oil recovery factor, water cut, and injection pressure were determined for each experiment during the water flooding and PPG treatments.

Table 4.4. Summary of Key Parameters Investigated During Experiments with Using Oil

Experiment	**Fracture width, mm**	**Brine concentration (%NaCl)**
5	**2**	**0.05**
6	**2**	**0.25**
7	**2**	**1**
8	**2**	**10**
9	**3.5**	**0.05**
10	**3.5**	**0.25**
11	**3.5**	**1**
12	**3.5**	**10**
13	**5**	**0.05**
14	**5**	**0.25**
15	**5**	**1**
16	**5**	**10**

4.6.3. Results and Analysis. This section discusses results obtained for the effects of brine concentration and fracture width.

4.6.3.1. Effect of brine concentration on oil recovery improvement. During the experiments, oil recovery was calculated before the gel injection (1st water flooding), during gel injection, and after the gel injection (2nd water flooding). In the Table 4.5 below, the oil recovery was higher when the brine concentration increased. Also, the table showed that the oil recovery will be the highest at 1st water flooding before using gel treatment. In general, the total amount of oil recovery obtained based on these results is between 43.49% and 51.37% using brine concentrations of 0.05% and 10% NaCl, respectively.

Table 4.5. Effect of Different Gel Strengths on Oil Recovery Improvement

Experiment Step	**PPG swollen in NaCl, %**			
	0.05	**0.25**	**1**	**10**
1st Water Flooding	**21.93%**	**23.8%**	**24.69%**	**26.57%**
During PPG Injection	**16.3%**	**17.05%**	**17.83%**	**20.76%**
2nd Water Flooding	**5.26%**	**6.33%**	**6.73%**	**4.04%**
Total Oil Recovery	**43.49%**	**47.18%**	**49.25%**	**51.37%**

4.6.3.2. Effect of fracture width on oil recovery improvement. The oil recovery at different fracture widths was calculated. Table 4.6 shows that when fracture width decreased the oil recovery increases. This is due to the formation having less fracture width, which means there is more pores to hold the oil, but when the fracture width increases the oil cannot stay in the fracture for long time and it needs pours to stay inside them.

Table 4.6. Effect of Different Fracture Width on Oil Recovery Improvement

Experiment Step	**Fracture width, mm**		
	2	**3.5**	**5**
1st Water Flooding	**24.69%**	**22.90%**	**20.73%**
During PPG Injection	**17.83%**	**16.53%**	**13.72%**
2nd Water Flooding	**6.73%**	**6.20%**	**4.87%**
Total Oil Recovery	**49.25%**	**45.63%**	**39.32%**

4.7. COMPARISON OF THE EXPERIMENTS WITH AND WITHOUT OIL

During the second water injection, the trend of the injection pressure performance of the experiments without using oil is similar to the trend if the oil was present. However, the presence of oil caused the gel to swell more which means the damage inside the matrix was greater compared to the experiments without using oil. The Figure 4.9 below compares the stable injection pressure performance of different brine concentrations in the presence and absence of oil.

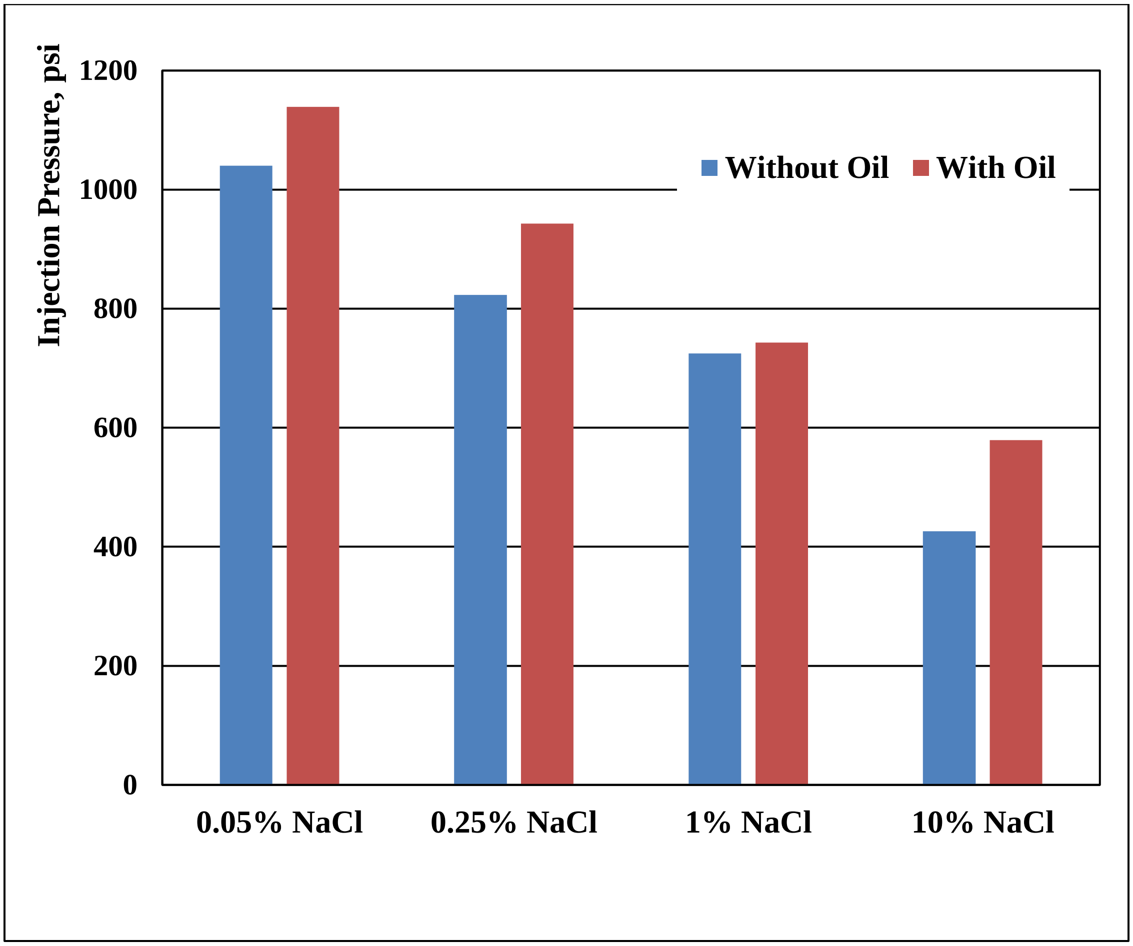

Figure 4.9. Comparison of Injection Pressure between Using Oil and without Oil

Based on the Figure 4.9 the brine injection pressure measurements during the second water injection could lead to the conclusion that PPG swollen in lower brine concentration causes more damage to the core than PPG swollen in higher brine concentration. As a result, brine injection pressure underwent a much greater increase in lower brine concentrations than in higher brine concentrations. Also, the presence of oil has a significant impact on the PPG penetration inside the matrix.

4.8. PARTIALLY OPEN FRACTURE EXPERIMENTS USING BACKPRESSURE

This section focuses on providing information about the procedure and the results of partially opened fracture using back-pressure.

4.8.1. Experimental Setup of Back-Pressure. Figure 4.10 shows the apparatus used to set up the partially open fracture model for four experiments with using back pressure. It consists of a syringe pump used to inject NaCl solutions and swollen PPGs through two accumulators into a partially opened fracture model. The model is comprised of an accumulator and a core holder. The sandstone core was placed inside the holder, and the confining pressure was adjusted to have a minimum of 500 psi difference above the injection pressure.

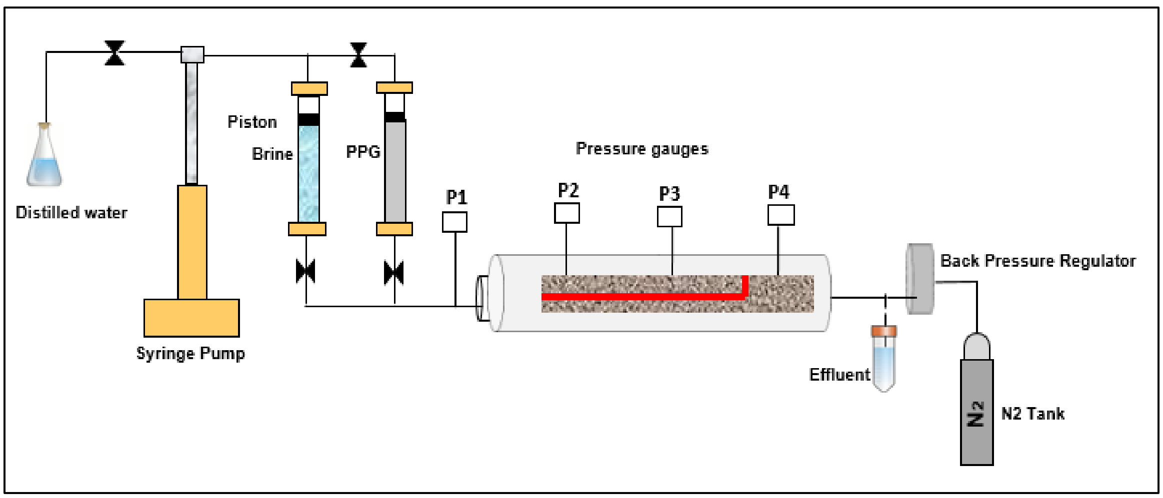

Figure 4.10. Partially Opened Fracture with Using Back-Pressure

Four digital pressure gauges were installed to the core holder to record the pressures on four different points three through the fracture and the fourth at the matrix and before the back-pressure regulator. At the end of core holder, a back-pressure was attached to measure the effect of back-pressure on gel treatment; back pressure was supplied using nitrogen. Also, test tubes were placed at the effluent to collect the produced brine and to check for any gel particle filtrate emitted from the cores.

4.8.2. Effect of Back-Pressure. A core holder connected to a back-pressure regulator was used to measure the effect of back pressure on PPG resistance to water flow through the fracture and to assess the gel impact on the matrix with various back pressures. The back pressure used include 400 and 600 psi.

4.8.3. Experimental Procedure. The procedures for the back-pressure model were as follows:

• The core sample was dried, vacuumed, and saturated with desired brine.

• Brine was injected into the core holder at different flow rates of 2, 1.5, 1, and 0.5ml/min to measure the permeability of the core sample before gel treatment.

• A fracture was created through the core with length of 21cm and width 2 mm.

• A brine of 1% NaCl (1^{st} water flooding) was injected at flow rate 2 ml/min, and the flow rate was run until pressure reached constant value.

• PPG was injected through the fracture until it reached the core inlet and the P1 on the beginning of core holder read 1000 psi.

• A brine of 1% NaCl (2^{nd} water flooding) was injected at flow rate 2 ml/min, and the flow rate was run until pressure reached constant value.

4.8.4. Results and Analysis of Back Pressure Model Experiments. Table 4.7 summarizes the parameters of this study. This study includes the preparation of all back-pressure model experiments which prepared to determine the effect of various back pressures on PPG penetration into core inlet and to measure PPG pack permeability.

Table 4.7. Summary of Key Parameters Investigated During Backpressure Experiments

Experiment	Backpressure	Fracture width, mm	Brine concentration (%NaCl)
17	400 psi	2	1
18	600 psi	2	1

The effect of PPG placement pressure was further investigated by involving the effect of back pressure. Two experiments were performed to study the effect of back pressure. PPG swollen in 1% NaCl was injected into a fracture until the pressure reached 1000 psi. Figure 4.11 shows the effect of presence back pressure on PPG treatment; the pressure injection reduces as back pressure increased.

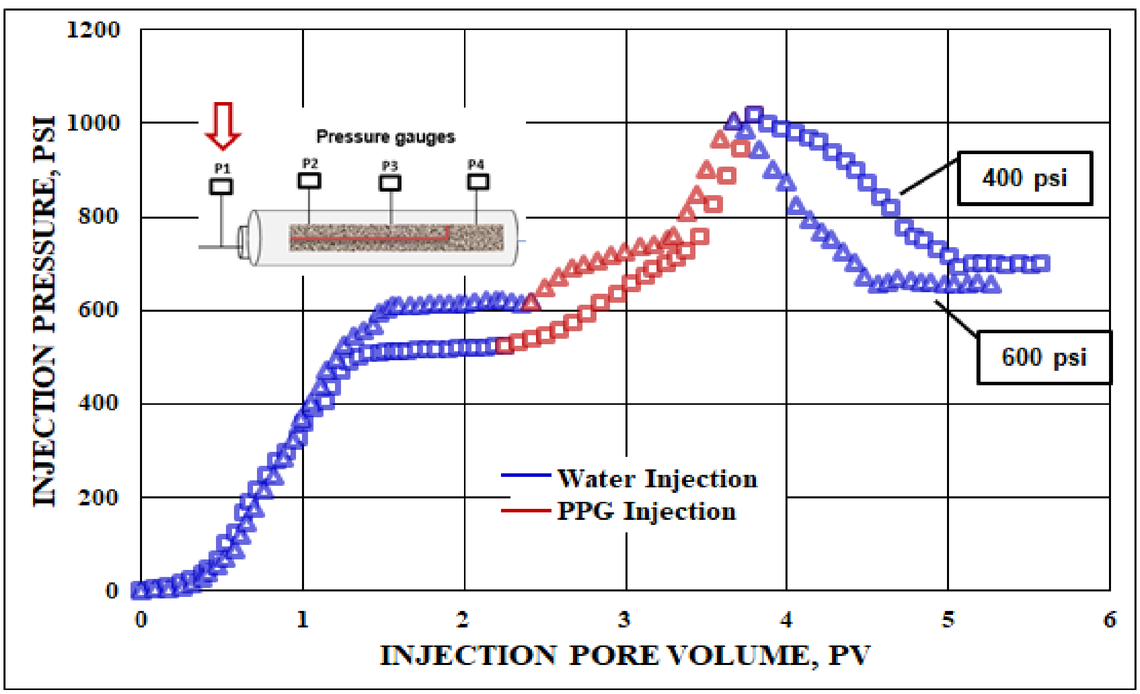

Figure 4.11. Injection Pressures Recorded of Different Back-Pressure

This result gives an important evidence that back pressure has a great effect on core permeability reduction. In other words, pressure difference across the core has a great effect on forming gel at the sand face. Core permeability is reduced significantly if back pressure is not present, but if back pressure is present, the gel has less effect on core permeability.

4.9. FULLY OPEN FRACTURE EXPERIMENTS

This section focuses on providing information about the procedure and the results of fully opened fracture.

4.9.1. Experimental Setup of Open Fracture. Figure 4.12 shows the apparatus used to set up the open fracture model for the experiments.

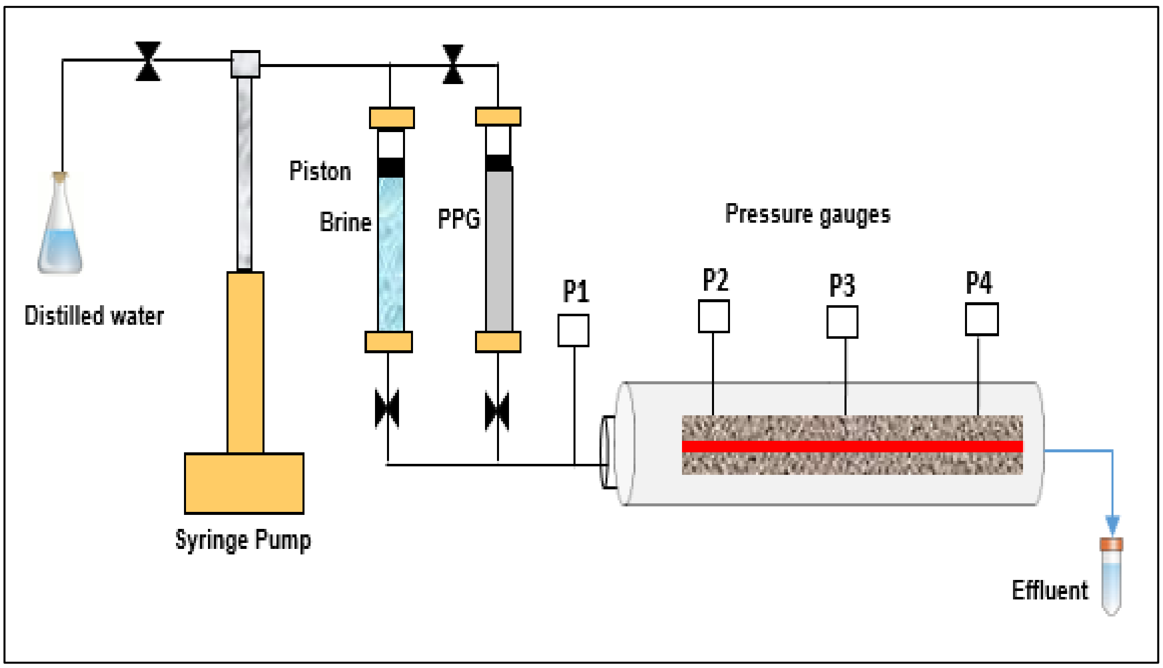

Figure 4.12. Fully Opened Fracture without Using Oil

It consists of a syringe pump used to inject NaCl solutions and swollen PPGs through two accumulators into a fully open fracture model. The model is comprised of an accumulator and a core holder. The sandstone core was placed inside the holder, and the confining pressure was adjusted to have a minimum of 500 psi difference above the injection pressure. Four pressure taps were located along the accumulator to acquire the PPG and brine injection pressure. Test tubes were placed at the effluent to collect the produced brine and to check for any gel particle come from the cores.

4.9.2. Experimental Procedure of Open Fracture. Four experiments have been done by using open fracture, following the same procedure used to conduct the partial open fracture experiments, but here there is no oil and the fracture width will be only 2 mm. Table 4.8 summarizes the parameters of this study.

First Water Flooding: A 0.05, 0.25, 1, or 10% brine NaCl solution was injected into the open fracture model at a rate of 2 ml/min. The brine was injected until the brine injection pressure became stable.

PPG Treatment: Swollen PPG dispersed in 0.05, 0.25, 1, or 10% NaCl with a concentration of 5000 ppm was injected into fracture model at a rate of 2 ml/min after completing the first water flooding processes. The volume of water production at the outlet as well as PPG injection pressure was recorded for each experiment. The brine was injected until the gel began to produce and the PPG injection pressure became stable.

Second Water Flooding: Brine was injected again at the same injection flow rate after the PPG treatment was complete, to test the gel blocking efficiency for high permeability. Brine was also injected until the injection pressure became stable. These procedures were repeated for four experiments. Water cut and injection pressure were each determined during the water flooding and PPG treatments. Plugging efficiency were also studied.

Table 4.8. Summary of Key Parameters Investigated During Open Fracture Experiments

Experiment	Fracture width, mm	Brine concentration (%NaCl)
19	**2**	**0.05**
20	**2**	**0.25**
21	**2**	**1**
22	**2**	**10**

4.9.3. Results and Analysis. This section discusses results obtained for the effects of brine concentration on fully open fracture. Results include injection pressure measurements before, during, and after PPG injection, as well as PPG resistance to water flow.

4.9.3.1. Effect of brine concentration on injection pressure performance. This section presents and discusses the results obtained for the injection pressure for the effects of brine concentration on the open fracture model. The first stage was to inject the brine of 0.05, 0.25, 1, or 10% NaCl until pressure became stable. At this stage, the pressure will be stable at very low values because the fracture is open. After the PPGs passed through the fracture, gel was injected continuously until the injection pressure stabilized. The injection pressure of the stable gel was measured as a function of the gel strength as shown in Figure 4.13. The results show that the stable injection pressure increased with the gel strength.

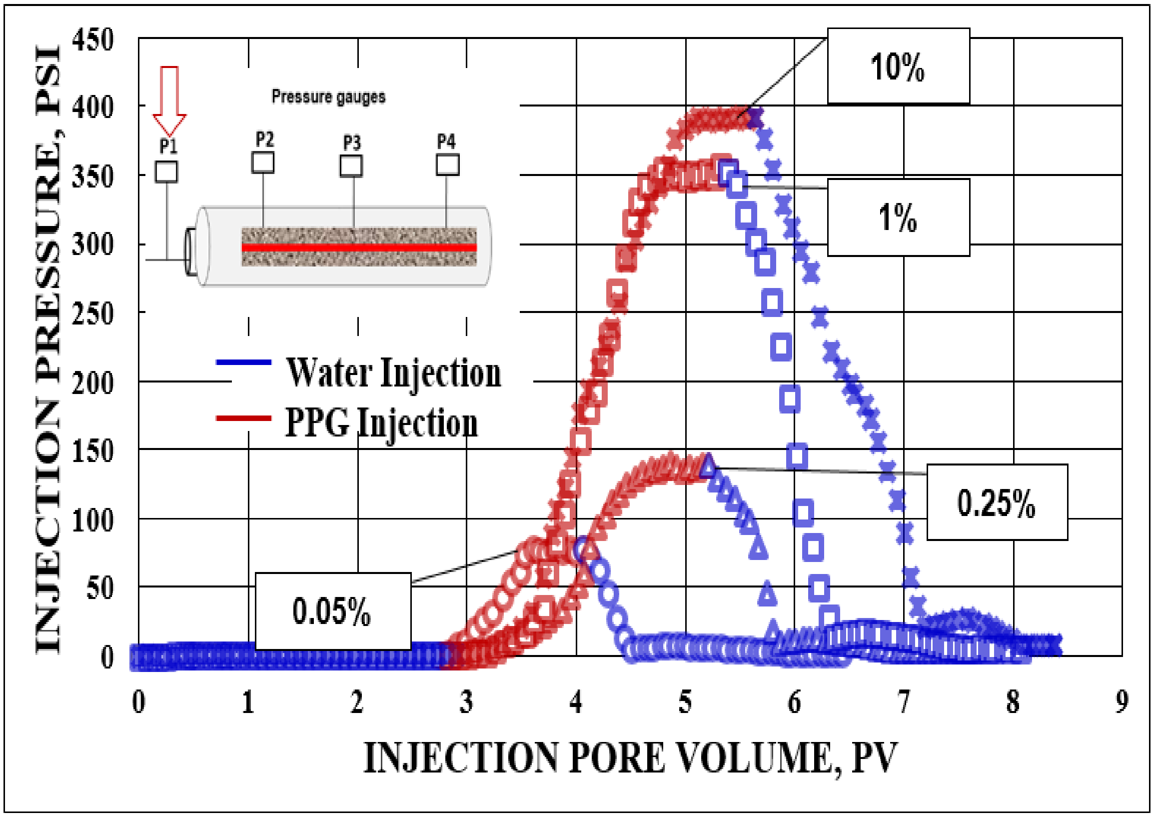

Figure 4.13. Injection Pressures Recorded for Different Brine Concentrations for Open Fracture

The gel strength had a significant effect on the stability of the injection pressure. The gel injection pressure increased by around 392 psi when 10% NaCl was used. However, the injection pressure increased by only 78 psi when 0.05% NaCl was used. The last stage was to inject second water flooding using the same brine that was used in first water flooding. From the Figure 4.13 above the pressure started to increase until it reached breakthrough point, then dropped sharply and started to produce gel with the water. The pressure injection continued until became stable.

The pressure at which the water produces from the outlet can be seen in Figure 4.14. This figure provides information about the brine concentration effect.

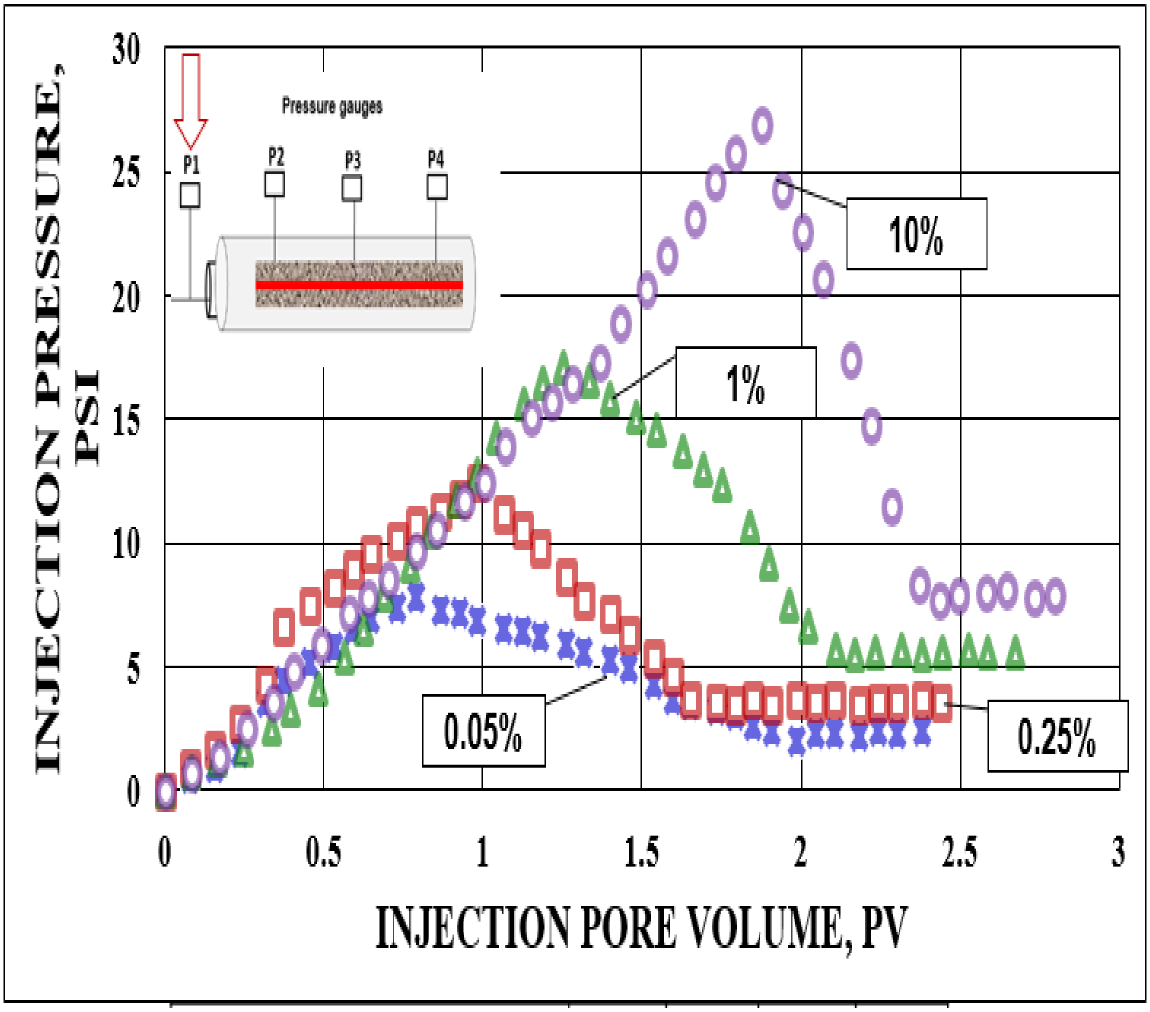

Figure 4.14. Breakthrough Pressure at Different Brine Concentrations

The small water breakthrough pressure indicates that water could start to propagate easily through the gel. This result suggests that as the gel became stronger (swollen in high brine concentration), the water breakthrough pressure increased. Differences in water breakthrough are clear when comparing weak gel (swollen in low brine concentrations) against strong gel. Table 4.9 shows the water breakthrough measurement for gel swollen in different concentration brines. When gel was swollen in 0.05% brine, water was able to pass through it at 7.8 psi. Water could not pass through gel swollen in 10% brine until the pressure reached 26.9 psi.

Table 4.9. Breakthrough Pressure at Different Brine Concentrations

NaCl Concentrations	0.05%	0.25%	1%	10%
Pore Volume at Breakthrough	**0.7897**	**0.9842**	**1.2526**	**1.8783**
Injection Pressure(psi) at Breakthrough	**7.8**	**12.4**	**17.1**	**26.9**

4.9.3.2. PPG remaining in the fracture after 2nd water flooding. After reached the breakthrough point during the second water flooding, the gel started to produce from the outlet through the open fracture, it noted that the production amount of the gel using brine concentration of 0.05% NaCl was the largest, while the production from 10% of NaCl was the lowest. This result depends completely on the gel strength, where the gel swelled more if 0.05% NaCl was used which means the gel strength of it will be weak. On the other hand, 10% of NaCl will not have high swelling compared to 0.05% of NaCl, and the gel strength of 10% of brine concentration will be stronger. As a result, PPG remaining in the fracture decreased with decreasing of brine concentration. Table 4.10 below shows the percentage of PPG remaining in the fracture.

$$\text{PPG Remaining in the Fracture} = \frac{Total\ gel\ in\ the\ fracure - produced\ gel}{Total\ gel\ in\ the\ fracure} \times 100 \quad (4.6)$$

Table 4.10. Percentage of PPG Remaining in the Fracture

NaCl Concentrations	0.05%	0.25%	1%	10%
PPG Remaining in the Fracture	**46.6%**	**59.11%**	**71.97%**	**82.18%**

4.9.3.3. Channel formed during brine injection process in fully open fracture. During the second water flooding the brine concentration had a large impact on the shape of the wormhole. In the Figure 4.15 below the PPG that swelling in 0.05% NaCl will have a biggest wormhole because it has the lowest gel strength, and during the water flooding, the water will push the gel easily and creates its own channel. However, when the brine concentration is increased, the gel strength will be higher and so it will become hard for the water to pass through the gel. As a result of that the wormhole will be narrower.

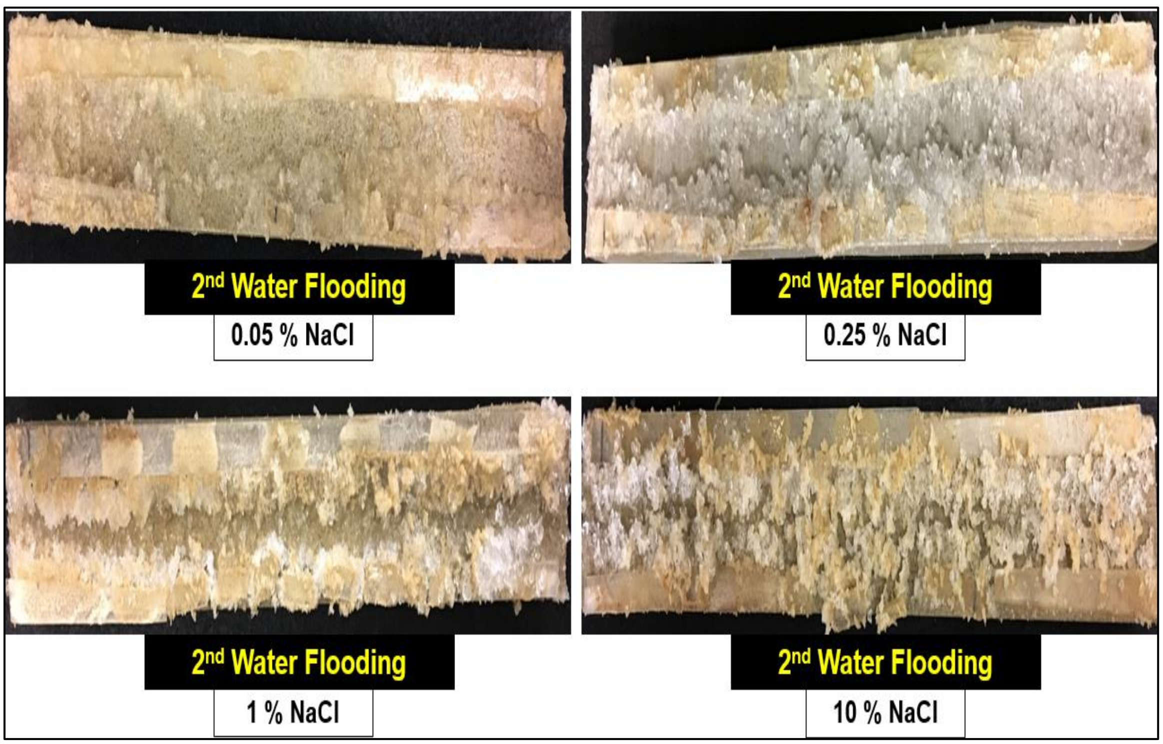

Figure 4.15. Wormhole Shape with Different Brine Concentrations

4.10. SUMMARY

- In partially opened fracture, PPG swollen in low brine concentration increases the injection pressure significantly compared to PPG swollen in high brine concentration.

- Injection pressure across fracture and sand face increased as the fracture width decreased.
- Oil recovery from sandstone fractures increased significantly when gel swollen in high brine concentration was used.
- Based on the fracture width, the oil recovery reduced with increasing fracture width.
- If the oil was not present, the injection pressure at second water flooding will be lower compared to the injection pressure where the oil was used.
- PPG damage into core matrix was affected by the back pressure. It was determined that the increase of the back pressure decreased the PPG damage.
- The Channel formed during the brine Injection depends significantly on the brine concentration, when the brine concentration increases the channel width decreased.
- PPG remaining in the fracture during open fracture increased as brine concentration increases.
- Reaching the breakthrough point in the open fracture model depends completely on the brine concentration. At high brine concentration, the breakthrough occurs at high pressure and required more time compared to low brine concentration.

5. EVALUATION OF PPG STRENGTH AND PPG RE-SWELLING RATIO

5.1. PREFACE

This section introduces an extensive evaluation of PPG properties using a partially opened fracture model. From these experiments, several conclusions were obtained on the PPG propagation, and penetration in the fracture, and sand face. Also, the concept of PPG matrix permeability reduction is introduced, and studied in detail in this section in order to show the impact PPG has on the matrix permeability reduction in partially open fractures.

5.2. EXPERIMENT MATERIALS

There have been different materials to study the effect of PPG transport treatment on sandstone core model. They include the following:

5.2.1. Preformed Particle Gel (PPG). The PPG used in this study is commercially one known as LiquiBlockTM40K. Its main chemical component is potassium salt of crosslinked polyacrylic acid/polyacrylamide copolymer. Dry PPG with a mesh size of 20-30 was selected. Table 5.1 below shows the properties of the PPG used (Hilary, 2015).

Table 5.1. Typical Characteristics of LiquiBlockTM 40K PPG

Properties	Value
Absorption Deionized Water (g/g)	**>200**
Apparent Bulk Density (g/l)	**540**
Moisture Content (%)	**5**
PH Value	**5.5-6.0**

5.2.2. Brine. Sodium chloride (NaCl) was used in this experiment. Four brine concentrations (0.05, 0.25, 1, and 10% wt NaCl) at room temperature were selected to prepare the swollen PPGs. Brine concentration significantly affects the PPG swelling ratio and swollen particle strength. The brine viscosity was about 1 cp(Hilary, 2015).

5.2.3. HAAKE™ RheoScope Device. Storage moduli (G´) for PPG prepared in different brine concentrations were measured at room temperature (24 oC) using a rheoscope. The PPG strength was measured after gel propagation into the fracture to determine the effect of the extrusion process on strength. The sensor used for measurements is PP335 TiPoLO2 016 with a gap of 1 mm between the sensor and the plate. G' were measured at a frequency of 1 Hz for each sample (Imqam et al., 2015).

5.3. EXPERIMENTAL PROCEDURE

The experiment procedure was divided into two main steps. The first step was to evaluate the effect of gel strength of PPG. The second step was to investigate the re-swelling ratio of PPG in different NaCl concentrations.

<u>PPG Re-Swelling Ratio Procedure:</u> 5 ml of dry PPG with 20-30 mesh size was immersed in different beakers containing 50 ml of different brine concentrations (0.05%, 0.25%, 1%, and 10%) of NaCl at room temperature to determine the re-swelling ratio of PPG with time (Hilary, 2015). The swollen PPG used in these experiments was prepared as follows:

• Three different samples were taken from partially open fracture from three different places, at the inlet, in the middle of the fracture, and at the end of the fracture near the sand face as shown in Figure 5.1.

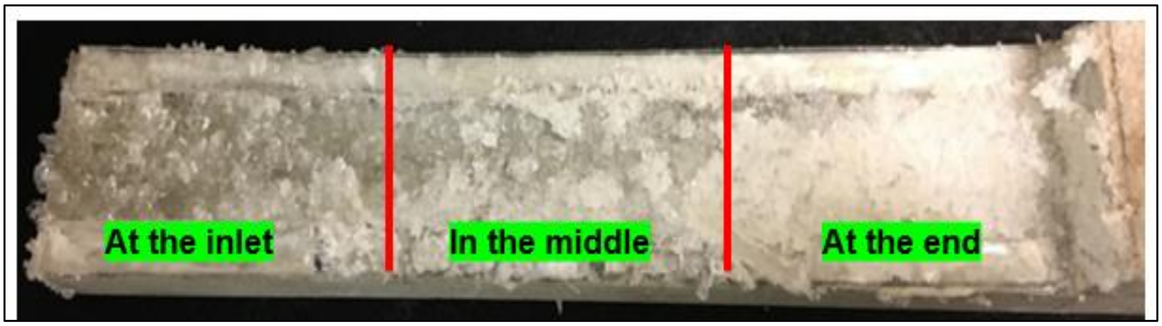

Figure 5.1. Location of the PPG Samples

• These samples were put in empty test tubes; each tube was filled with 5 ml of PPG of these samples.

•After that, the empty test tubes were filled with a brine solution of the desired concentration.

• The sample was allowed to re-swell completely, a process that required more than 4 hours.

• The readings of PPG re-swelling were taken regularly until PPG was fully swollen.

The re-swelling ratios of PPG in different brine solutions were obtained using Equation 5.1 below.

$$Reswelling\ Ratio\ (SR) = \frac{V2}{V1} \tag{5.1}$$

Where v_2 is the final volume of the PPG after re-swelling and v_1 is the volume of the PPG after the experiment.

5.4. RESULTS ANALYSIS AND DISCUSSION

Evaluation of PPG Re-Swelling Ratio and Gel Strength: After each experiment was completed, PPG samples were gathered from three places including the core fracture, and placed separately in test tubes filled with the same concentrations of brine that was used in the experiments. The stable re-swelling ratio was computed for each concentration. The measurements of re-swelling ratio and gel strength were done using PPG from 22 experiments; 12 of 22 experiments evaluated the effects of brine concentrations using 0.05, 0.25, 1, and 10% NaCl. Also, the impact of different fracture widths of 2 mm, 3.5 mm, and 5 mm on PPG was measured. In these 12 experiments, oil was used to calculated oil recovery before, during, and after PPG injection.

Figure 5.2 below shows the re-swelling ratio of PPG samples of different brine concentrations at 2 mm fracture width in the presence of oil at three different places in the fracture, while Table 5.2 presents the gel strength of the same samples. Figure 5.3 shows re-swelling ratio of different fracture widths by using the same brine concentration of 1% NaCl and explains their impact on the PPG. Also, Table 5.3 shows the gel strength of the same samples of different fracture widths. Figure 5.4 and Table 5.4 compare the re-swelling ratio and gel strength of four different experiments one of them with using oil, another without using oil, and two experiments using back-pressure of 400 psi and 600 psi; 1% NaCl and 2 mm fracture width are common factors of these four experiments. In addition, other four experiments were done with fully open fractures by using brine concentrations including 0.05, 0.25, 1, and 10% of NaCl. The fracture width of these experiments was 2 mm. Figure 5.5 and Table 5.5 present the re-swelling ratio and gel strength of the open fracture experiments. The objective of these four experiments is to evaluate the impact PPG on open fracture, and to compare the results with partially open fracture.

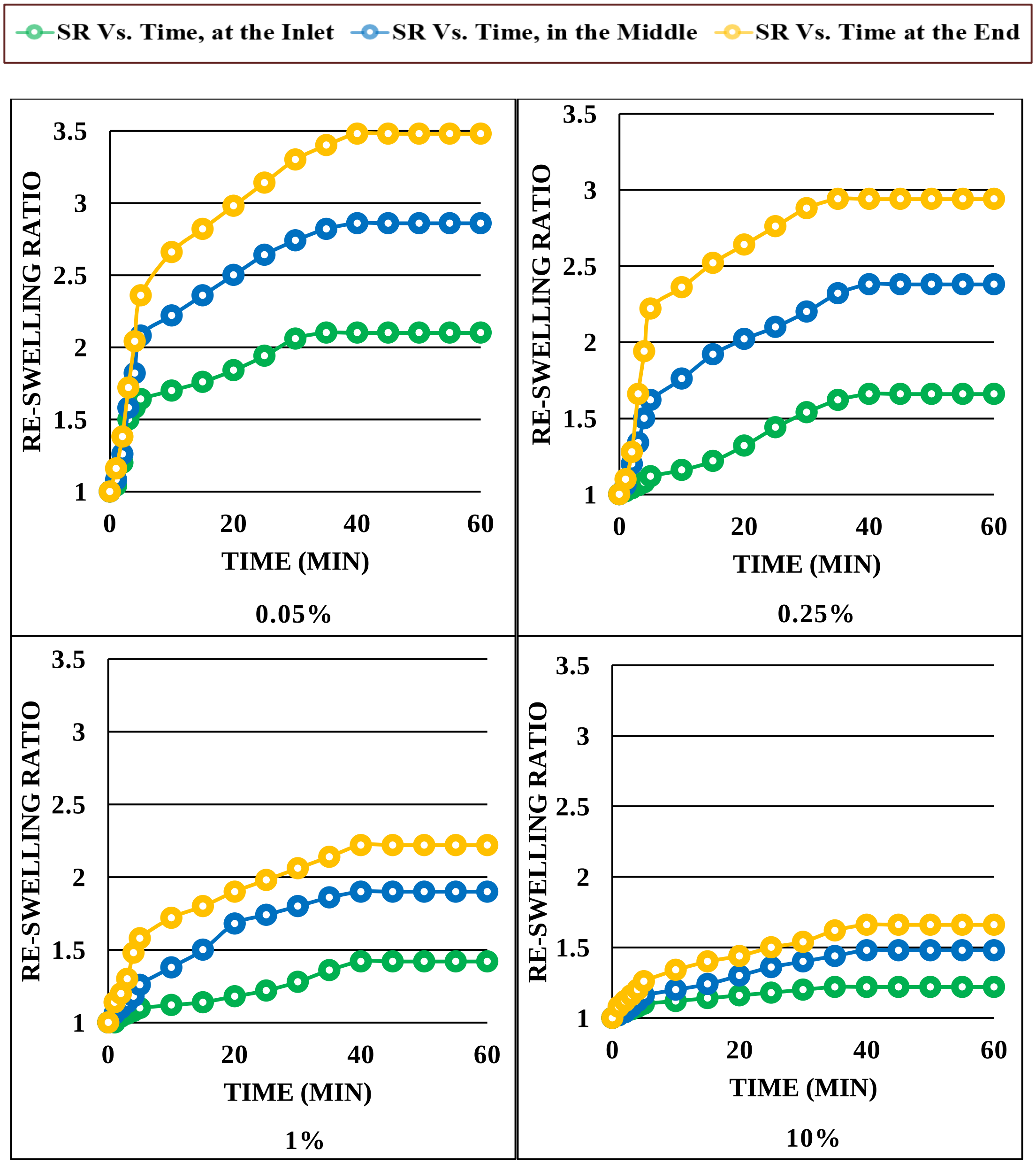

Figure 5.2. PPG Re-Swelling Ratio in Different Brine Concentrations 2mm

Figure 5.2 shows the influence of the brine concentration on the re-swelling ratio. PPG showed normal re-swelling ratio behavior; its re-swelling ratio initially increased with time and then attained equilibrium. Re-Swelling ratio for PPG swollen in brine could reach the highest level when it is swollen in 0.05% brine concentrations. The re-swelling ratio for PPG increased as the brine concentrations decreased. This was due to the fact that when the PPG swells more, it becomes weaker, and begins to soften. This decrease in strength is likely a result of the PPG absorbing a large amount of water and also presumably due to the static electric repulsive force and charge balance (Hilary, 2015). At low salt concentrations, the electric repulsive force will separate the gel molecules and create more space for water to enter (Bai et al., 2007a).

Table 5.2. Gel Strength of PPG in Different Brine Concentrations Using 2 mm Fracture

Gel Strength at Different Locations in the Fracture	**PPG swollen at NaCl, %**			
	0.05	**0.25**	**1**	**10**
At the fracture inlet (Pa)	431	862	1080	1300
In the middle of fracture (Pa)	513	927	1140	1420
At end of fracture (Pa)	645	1030	1320	1570

Also, the influence of brine concentration on the PPG strength was investigated using a rheometer device to measure the strength of the PPG swollen in 0.05%, 0.25%, 1% and 10% wt. NaCl. After the experiment was done, different samples were taken from three different places inside the fracture (at the inlet, in the middle, and at the end) to measure the gel strength. The results in Table 5.2 show that gel strength changed based on gel location inside fracture and brine concentration. The gel strength will be higher for gel sample found near the matrix (sand face) while the weakest particles were at the inlet of the fracture. This was due to the particles near the sand face having higher dehydration compared to particles at the inlet of the fracture. Also, based on the brine concentrations, 10% of NaCl will have the strongest gel strength because the re-swelling ratio of it is very low compared to 0.05% of NaCl which will have the lowest gel strength because the re-swelling ratio of it will be the highest between these four brine concentrations.

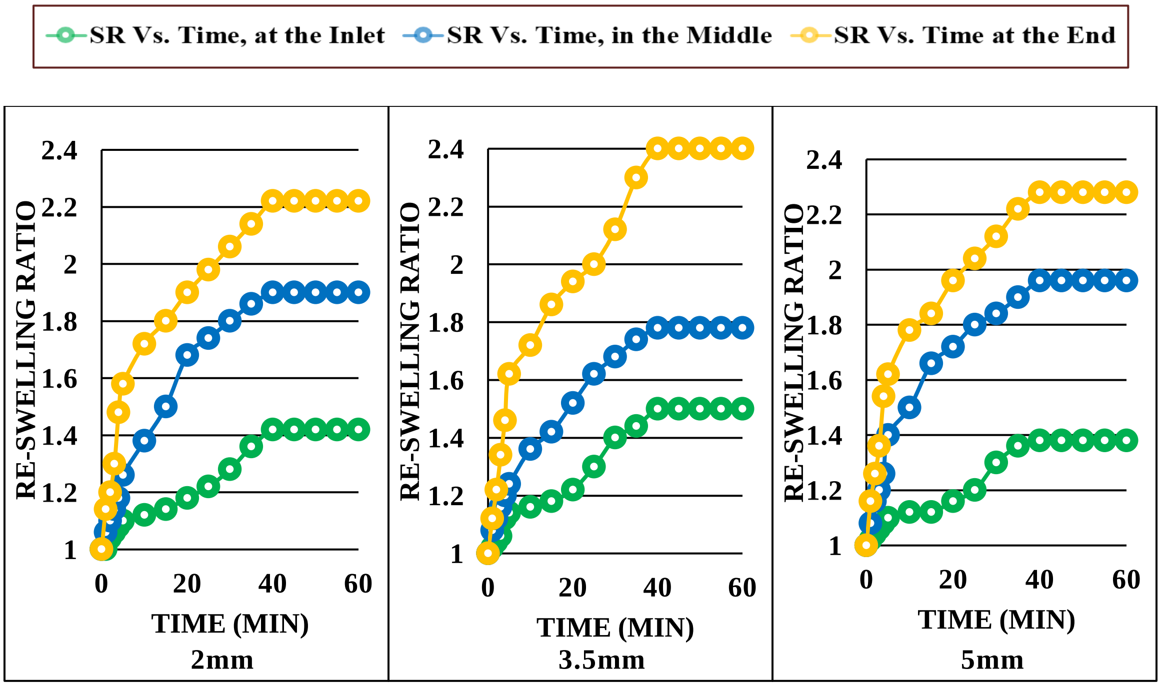

Figure 5.3. PPG Re-Swelling Ratio in Different Fracture Widths

Table 5.3. Gel Strength of PPG of 1% NaCl with Different Fracture Widths

Gel Strength at Different Sample Locations	**Fracture width, mm**		
	2	**3.5**	**5**
At the fracture inlet (Pa)	**1080**	**1030**	**928**
In the middle of fracture (Pa)	**1140**	**1200**	**1170**
At end of fracture (Pa)	**1320**	**1380**	**1420**

At the same brine concentration of 1% of NaCl and by using three different fracture widths, important results have been collected, shown in Figure 5.3 and Table 5.3 above.

Gel strength did not significantly change as the fracture width changed. In other words, increasing or decreasing fracture widths did not have a strong effect on the gel properties.

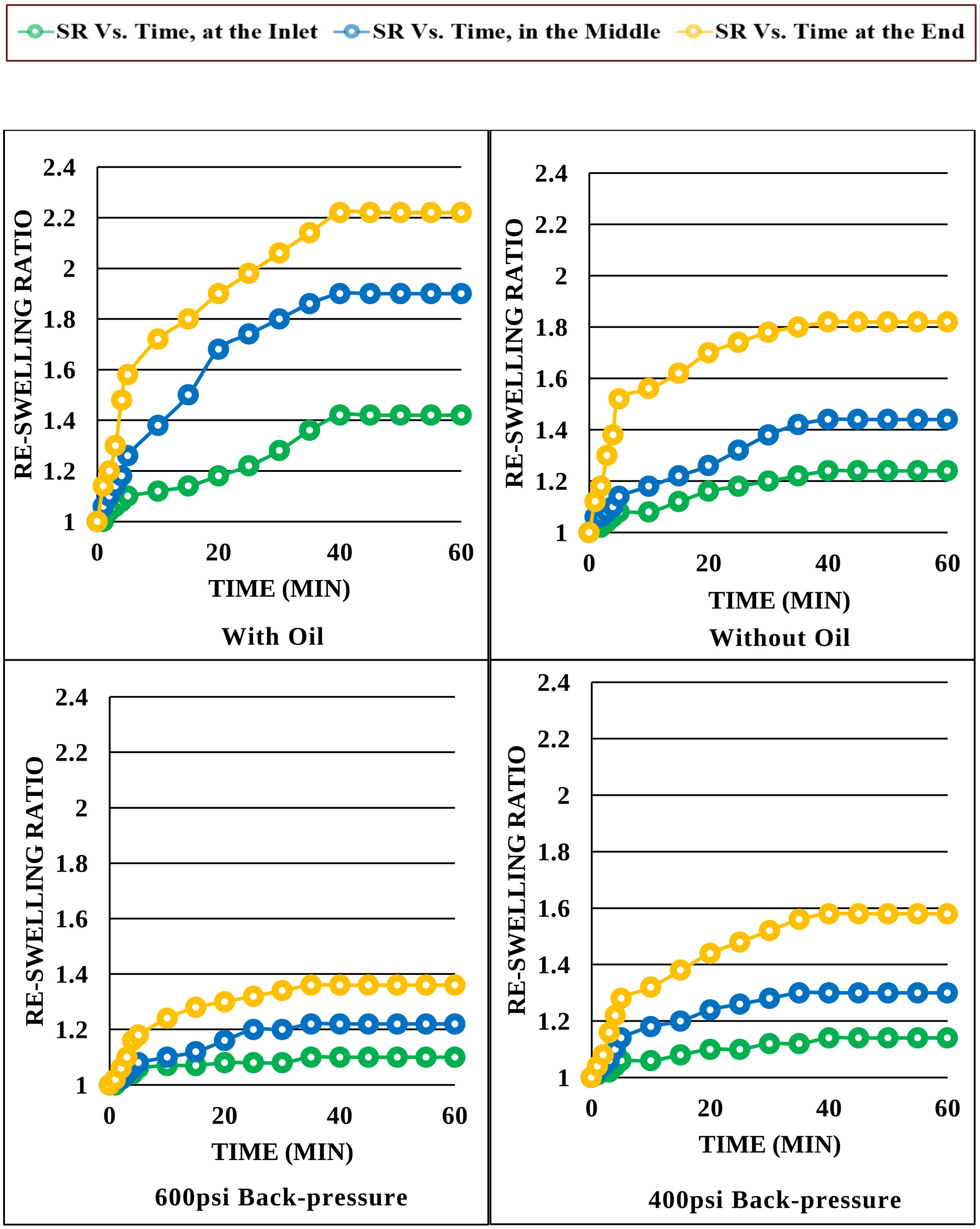

Figure 5.4. PPG Re-Swelling Ratio Measurements

However, the re-swelling ratio of PPG with using oil was higher than re-swelling ratio of PPG without using oil as is shown in Figure 5.4. Also, in the same figure, the re-swelling ratio of PPG decreased as back- pressure increased. As a result, the gel strength will increase as back-pressure is increased. Also, the gel strength of back-pressure will be high compared to the gel strength of PPG with or without using oil, as was evident in Figure 5.4.

Table 5.4. Gel Strength of PPG of 1% NaCl

Gel Strength at different Sample Location	**PPG swollen at NaCl, %**			
	With oil	**Without oil**	**400psi**	**600psi**
At the fracture inlet (Pa)	1080	1160	1201	1246
In the middle of fracture (Pa)	1140	1280	1351	1486
At end of fracture (Pa)	1320	1370	1437	1570

Figure 5.5 shows the re-swelling ratio in three different places of the open fracture; it can be seen that they do not have a significant different between them. Also, the gel strength in different locations in the open fracture was evaluated in Table 5.5. There is no a significant change in gel strength between the inlet and the end of the fracture, which means the open fracture did not affect the gel strength at different locations in the fracture.

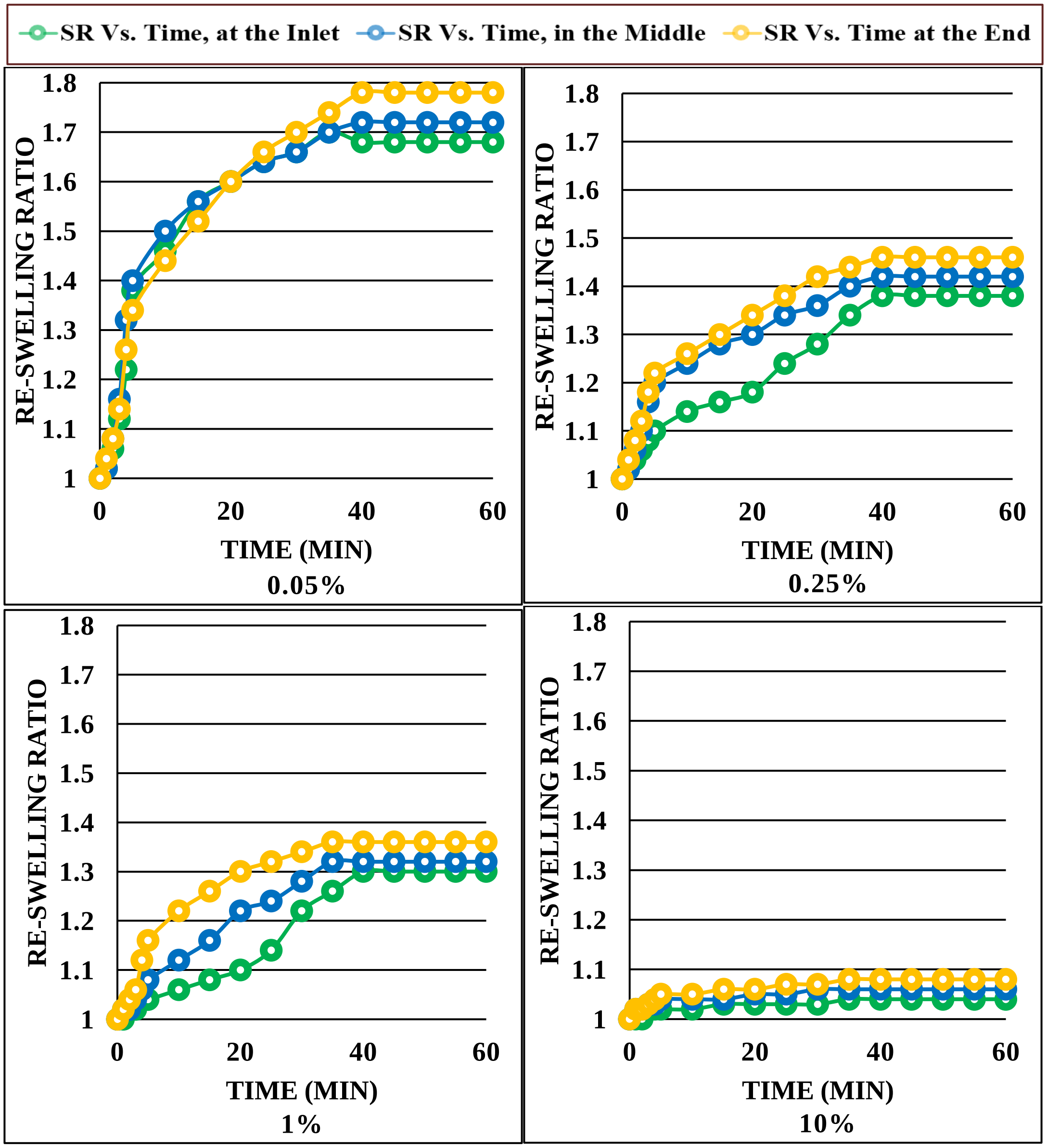

Figure 5.5. PPG Re-Swelling Ratio of Open Fracture for Different Brine Concentrations Using 2 mm Fracture

Table 5.5. Gel Strength of PPG of Open Fracture in Different Brine Concentrations Using 2 mm Fracture

Gel Strength at different Sample Location	PPG swollen at NaCl, %			
	0.05	**0.25**	**1**	**10**
At the fracture inlet (Pa)	542	789	1109	1318
In the middle of fracture (Pa)	583	824	1117	1334
At end of fracture (Pa)	605	861	1133	1353

In general, the measurement of gel strength of different brine concentrations was explained. It can be seen that the gel strength of 10% NaCl has higher gel strength than 0.05% NaCl which had the weakest gel strength. This was due to the fact that as brine concentration increases the re-swelling ratio decreases, and the gel strength increases. In addition, the effect of the location of the gel inside the partially open fracture was measured in three different places, at the inlet, in the middle, and at the end of the fracture. The result indicates that the PPG swollen at the end of fracture was much higher than the PPG swollen in the inlet of the fracture since the dehydration at the end of fracture was higher compared to the dehydration at the inlet or in the middle of the fracture. In other words, PPG in the inlet has more water than PPG at the end of the fracture.

5.5. ABRIDGEMENT

The results of PPG re-swelling kinetics and gel strength discussed in this section indicates that the re-swelling ratio and gel strength of PPG as a function of brine concentration is an important factor to be considered during conformance control treatment. The result show that PPG swells more, and becomes deformable and weaker when prepared with low concentration of brine than when prepared with high concentration of brine (Hilary, 2015).

The findings from these results clearly shows that PPG has the tendency to plug the high permeability layers, therefore a need to evaluate the PPG using a parallel heterogeneity model to block/reduce flow from high permeability zone while recovering more oil from the unswept low permeability zone is required (Hilary, 2015).

6. CONCLUSIONS & RECOMMENDATIONS

6.1. CONCLUSIONS

This research provides an extensive laboratory work to evaluate PPG treatment as a cost-effective method to control excessive unwanted water production and improve sweep oil efficiency. The study provides a comprehensive evaluation work on PPGs injection, mechanisms, and placement in partially open fracture. This study includes PPG damage on various sandstone cores with various fracture widths were evaluated. PPG damage on the core samples was highly dependent on PPG brine concentration, presence of oil, and back pressure. The major findings collected during this study are sorted below based on the discussed topics as follow:

1. Brine concentration of NaCl has am important impact on the PPG swelling ratio. Where PPG swelled in low brine concentration had higher swelling ratio than PPG swelling in high brine concentration.
2. Oil recovery from sandstone fractures increased significantly when gel swollen in high brine concentration was used. Also, the oil recovery increased when the fracture width decreased.
3. Gel strength along the fracture changed based on gel location inside fracture and brine concentration, where the inlet of the fracture had the lowest gel strength compared with the end of the fracture which had the highest value of the gel strength
4. Injection pressure across fracture and sand face increased as the fracture width decreased. However, there was no a significant change on gel strength when the fracture width changed.

5. The presence of oil had a significant effect on the damage inside the rock matrices, where oil during PPG treatment caused a larger damage compared with if the oil was not present because oil reduces the gel strength and swells more than usual, which means to go easily inside the core.
6. PPG resistance to water flow increased as the injection placement pressure increased. If the pressure drops across the core decreased, less gel particle penetration of the core occurred.
7. Reduction permeability into core face affected by the presence of back pressure. It was indicated that the increase of the back pressure leads to the PPG damage to deceases.
8. In the fully open fracture, PPG strength was strongly depending on brine concentrations, PPG swelled in high brine concentrations were stronger than PPG swelled in low brine concentration.

6.2. RECOMMENDATIONS

The main target of this study was to provide a comprehensive and systematic study into designing better particle gel treatments intended for use in large permeability features such as fractures and high permeability streaks to reduce water production. The following are suggestions for future work to extend the outcomes of the current research:

- Study the effect of changing gel particle size on matrix permeability reduction.
- Effect of varying gel injection pressure from 1000 psi in closed fracture and its effect on permeability reduction.
- Evaluate the effect of changing the core permeability on the permeability reduction.

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VITA

Ghith Ali Ahmed Biheri was born on July 9th, 1985 in Sabha, Libya. In July 2010, he received his B.E. in Petroleum Engineering from Sirte University, Sirte, Libya. After graduation, he was employed by Akakus Oil Company (Repsol Company, Libya) as production engineer from October 2012 to June 2013. He enrolled in Sabha University as a teacher assistant from June 2013 to October 2014. Following graduation, he came to the Missouri University of Science and Technology, Rolla, Missouri. He started to pursue his master degree at Geosciences and Geological and Petroleum Engineering department of Missouri University of Science and Technology from January 2016. He joined Dr. Baojun Bai's research group from May 2016 and worked as a researcher in lab. He received his Master degree in Petroleum Engineering from Missouri University of Science and Technology in December 2017.