Spring 2017

Evaluation of preformed particle gels penetration and propagation behavior for a conformance control treatment in partially open conduits

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EVALUATION OF PREFORMED PARTICLE GELS PENETRATION AND PROPAGATION BEHAVIOR FOR A CONFORMANCE CONTROL TREATMENT IN PARTIALLY OPEN CONDUITS

by

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A THESIS

Presented to the Faculty of the Graduate School of the

MISSOURI UNIVERSITY OF SCIENCE AND TECHNOLOGY

In Partial Fulfillment of the Requirements for the Degree

MASTER OF SCIENCE IN PETROLEUM ENGINEERING

2017

Approved by

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ABSTRACT

Preformed particle gels (PPGs) serve as a conformance control agent and have been used widely to control excess water production through conduits, fractures or fracture-like features. This research ranks the parameters that impact PPG resistance to water flow in partially opened conduits. Experiments were conducted to examine the effect of brine concentration, PPG injection pressure, back pressure, reducing water salinity and matrix permeability on PPG resistance to water flow through conduits, PPG penetration to the matrix. PPGs were swelled in different concentration brines and were injected into the conduits at a few designed injection pressures. PPG swollen in high brine concentration took a longer time to reach the target placement pressure than those swollen in low brine concentration. The injected PPGs swollen in low brine concentration caused more damage to the matrix permeability than PPGs swollen in high brine concentration. Results show PPG resistance to water flow may have been the result of gel particle accumulation into conduits/fractures or gel filter cake formation in rock matrix or both. Their resistance increased when they were injected at high pressure. However, PPGs formed a filter cake on the surface of the matrix. Gel particles penetration into the matrix were only a few millimeters deep, and their penetration into to the matrix depended on matrix permeability, gel strength, and injection pressure drop across the core.

ACKNOWLEDGMENTS

IN THE NAME OF GOD, MOST GRACIOUS, MOST MERCIFUL.

First, I am eternally grateful to Allah for helping me accomplish this work.

I would like to express my sincere thanks to my advisor. Dr. Baojun Bai. I would not have been able to complete this research without his assistance, support, and friendship.

I must also thank the Libyan Ministry of Education for supporting me during my academic studies. I am thankful for the members of my advisory committee: Dr. Abdulmohsin Imqam, Dr. Peyman Heidari for their guidance and assistance. I am a particularly grateful to Dr. Abdulmohsin Imqam, for his guidance and design of the experiments.

Finally, I cannot fully express my deep gratitude to my mother, family, my colleagues and friends. They have showered me with unlimited support and I dedicate this work to them.

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NOMENCLATURE

Symbol	Description
d	Core diameter (cm)
L	Core Length (cm)
V_B	Bulk Volume (cm3)
V_P	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)
Δ_P	Pressure Drop Across Core Sample (psi)
K_{RD}	Core Permeability Reduction (%)
Ki	Original Core Permeability (md)
Ka	Core Permeability after Adding Gel (md)
K_{RT}	Core Permeability Retained (%)
Kf	Final Core Permeability (md)

1. INTRODUCTION

This section focuses on providing background information for the research. The first part will demonstrate an introduction to gel treatment. The second part will discuss the gel treatment mechanisms for reservoir with conduits, mainly by citing the works done by other researchers.

1.1. STATEMENT AND SIGNIFICANCE OF THE PROBLEM

Excess water production has long been considered a major problem leading to the life-shortening of oil and gas wells and operational problems. An estimated average of three barrels of water is produced for each barrel of oil produced worldwide (Bailey et al., 2000). The total cost related to separating, treating, and disposing of unwanted water is approximately $50 billion per year (Hill et al., 2012). Water can flow into the wellbore as a result of either near-wellbore problems or reservoir-related problems (Seright et al., 2001). The mechanisms that contribute to this undesired water production must be fully understood before the appropriate treatment can be chosen. High permeability streaks, fractures, conduits, and fracture-like features can expedite undesirable water channeling and early water breakthrough during water flooding. As a result, large amounts of oil remain un-swept as a large water flood bypasses oil-rich un-swept zones/areas.

Gel treatments have been proven as a cost-effective chemical conformance control technology that can be used to reduce the fluid flow in these large open features. The application of this technology can assist with controlling water production, significantly increasing the oil production, extending the economic life of a reservoir. In-situ bulk gels traditionally have been used for this purpose. However, preformed particle gels have recently attracted much attention because they can solve some of the problems associated with in-situ gel systems. These problems include the dilution and dispersion of the gallant and the chromatographic separation of the gallant solution.

A gel treatment's success depends heavily on the gel's ability to extrude through fractures and channels during the placement process. Thus, understanding the mechanism, performance, and behavior of gel propagations and blocking efficiencies through these high permeability streaks is the key to a successful conformance control treatment.

This thesis ranks the parameters that impact PPG resistance to water flow in partially opened conduits/fractures and provides methods to minimize the PPG penetration effect on matrices. Experiments were conducted to examine the effect of brine concentration, PPG injection pressure, back pressure, and matrix permeability on PPG resistance to water flow through conduits, and PPG penetration to the matrix. PPGs were swelled in different concentration brines and were injected into the conduits at several designated injection pressures. Results show PPG resistance to water flow may have been the result of gel particle accumulation into conduits, the formation of gel filter cake, or both.

1.2. EXPECTED IMPACTS AND CONTRIBUTIONS

Results obtained from this study will promote using the PPGs for conformance control agent and have been used widely to control excess water production through conduits, fractures or fracture-like features. Understanding the mechanism and performance of PPGs are a crucial to obtaining a better blocking efficiency and improving conformance control objectives. The results gathered from this work can be used to optimize the PPGs design as it requires for achieving a successful gel treatment and will aid to select future conformance control candidates.

The following information was provided from the research:

- The factors that could affect excess water production through conduits and fractures were identified. Reservoir property factors such as permeability change, an effect of back pressure, PPG pressure placement effect, effect of changing water salinity, and brine concentration change were each studied. The PPG's properties factors including brine concentration (gel strength) and PPG injection pressure were also investigated.
- During particle gel propagation into desired formations (partially open conduit), portion of gel formed a cake on core matrix. Therefore, this study determined what factors affect the gel cake damage to the low permeability formations

1.3. OBJECTIVE

The primary objective of this study was to identify methods that both minimize the damage of PPGs on matrices, examine the effect of brine concentration, PPG injection pressure, back pressure, matrix permeability on PPG resistance to water flow through conduits, and PPG penetration to the matrix. Results of this study could be used to develop the factors that can significantly affect gel propagation through high permeability formations and realize the mechanistic understanding of particle gel systems to increase oil recovery, reduce water production and enhance the success of gel treatment in mature reservoirs. It can be used to select the best PPG particle sizes and brine concentrations, applying each to the most appropriate reservoirs to minimize formation damage.

The results gathered from this study provide a comprehensive knowledge and insight into PPG mechanisms and performance that decrease water production. Additionally, this study ascertains the effective of PPGs damage to reservoir formations.

1.4. RESEARCH SCOPE

This study applied laboratory experiments to find methods that minimalize PPG penetration effect on matrices and gel blocking to water flow. Core flooding experiments assist in understanding the prevailing mechanism and performance of particle gel propagation through these porous media. Two tasks were completed to accomplish this objective. Figure 1.1 illustrates the primary stages of the proposed research which shows the constructions of the main experiments performed to accomplish the study objectives.

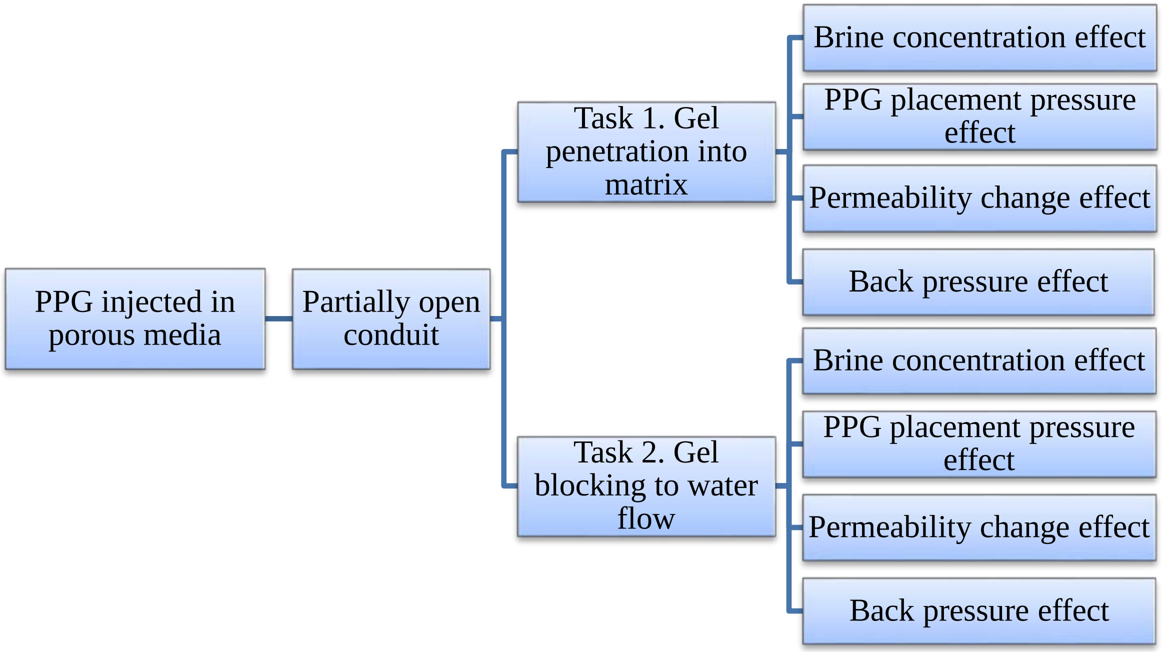


Figure 1.1. Research Scope

2. LITERATURE REVIEW

This section focuses on providing background information for the research. The first part will demonstrate an introduction to gel treatment. The second part will discuss the gel treatment mechanisms for reservoir with conduits, mainly by citing the works done by other researchers.

2.1. ENHANCED OIL RECOVERY

There are three main mechanisms to produce oil: primary recovery, secondary recovery, and tertiary recovery. Primary oil recovery involves naturally occurring reservoir characteristics or properties that induce the flow of oil. Such mechanisms include solution and gas cap drive, water drive, gravity drainage, and a combination of the aforementioned primary oil recovery mechanisms. Primary recovery accounts for 12-15% of the original oil in place (OIIP). The primary recovery methods become inadequate in sustaining economic production rates as oil reservoirs become depleted.

Secondary recovery mechanisms typically involve the injection of either gas or water into reservoir in an attempt to pump the oil out of the reservoir. Secondary recovery accounts for 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 can be used to increase the amount of crude oil extracted from an oil field. Four groups of EOR methods exist: thermal recovery, gas recovery, chemical flooding, and microbial 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 (with polymer gels), micellar-polymer flooding, surfactant flooding, and alkaline surfactant flooding. Microbial EOR methods include both microbial flooding and cyclic microbial recovery Figure 2.1 clarifies these different EOR methods.

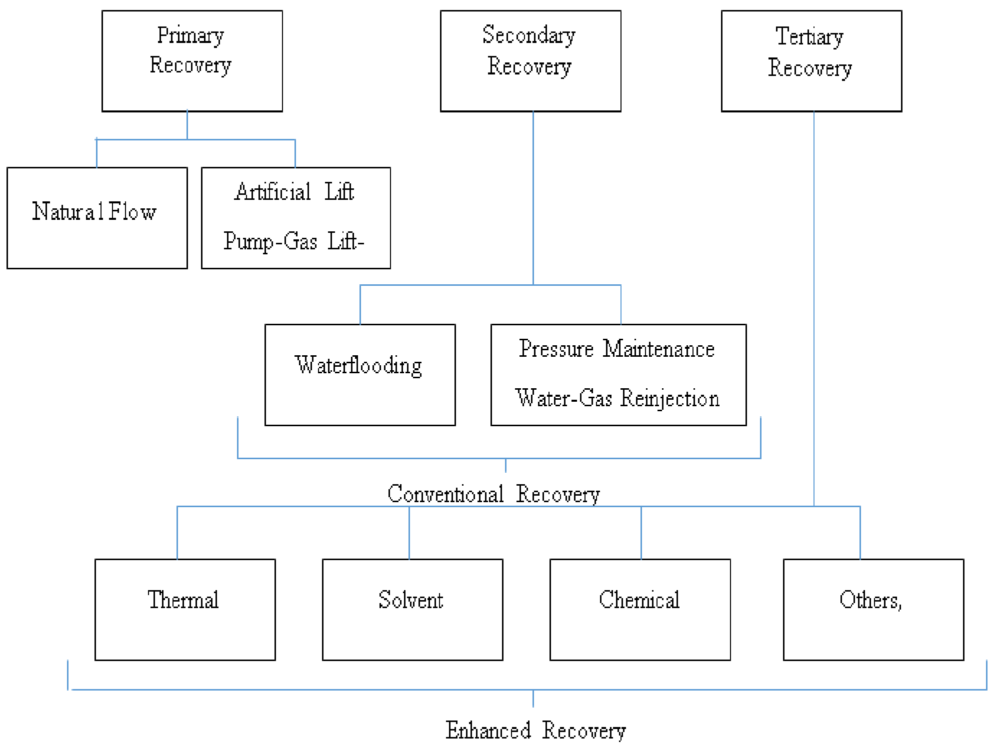


Figure 2.1. Various EOR Methods

Heterogeneity within a reservoir is one of the primary reasons neither primary nor secondary recovery mechanisms can retrieve large amounts of hydrocarbon recovery.

Reservoir heterogeneities lead to the development of high-permeability streaks. These streaks include open fractures, fracture-like features, caves, worm holes, and conduits. These high-conductivity areas inside the reservoir only occupy a small fraction of the reservoir but it captures a significant portion of injected water. As a result, large amounts of oil remain un-swept as large water injections bypass oil-rich un-swept zones/areas.

2.2. WATER PRODUCTION

Water production associated with oil and gas production is becoming a major technical, environmental, and economical problem worldwide. Water production can shorten the productive life of oil and gas wells creating severe problems (e.g., equipment corrosions, hydrostatic load, and sand fine migrations). It is estimated that over 15 billion barrels of water are produced annually, approximately eight barrels of water are produced for each barrel of oil (Environmental Protection Agency, 2000). Worldwide, an averages 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).

Excessive water production becomes prevalent as reservoirs becoming more mature. This increase impacts on the profitability of hydrocarbon assets. Fully understanding the mechanisms responsible for undesired water production is crucial to designing efficient solutions to the problem.

A large number of mechanical, completion, and chemical treatment technologies are available to mitigate water related problems. These technologies decrease undesired water production. They also increase hydrocarbon productions rates significantly and extend the reservoir's economic life.

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. Both the reduction and the stoppage of this water are of the utmost concern 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 (Bailey et al., 2000).

Water management thus involves an expensive superficial infrastructure, high disposal costs, increased corrosion, increased scaling among the hydrocarbon production losses, and unwanted sand production.

2.3. 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.

2.3.1. 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 Figure 2.1. 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.

- 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.

- 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.

2.3.2. 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.

2.3.2.1 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.

2.3.2.2 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.

2.3.2.3 Reservoir depletions. If the problem is caused by reservoir depletion, 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.

2.3.2.4 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.

2.4. MECHANISMS OF UNWANTED WATER PRODUCTION

Many factors contribute to unwanted water productions. Understanding the nature of water production is the primary key in controlling it. Therefore, an effective strategy can be formulated to control water productions if the water production mechanism is understood (Seright et al., 2001). The flow of water into a wellbore can occur along two types of paths. Water can flow into the wellbore through paths that are separate from hydrocarbons path. Water can also be co-produced with oil. This production typically occurs later in the life of a water flood, when the reservoir becomes more mature.

The sources of co-produced water can occur from water existing naturally inside reservoirs (e.g., aquifers and formation waters) or water injected into a reservoir from external sources. For water to flow through reservoirs, water saturations should exceed the connate water saturations. Water production becomes even higher due to the reservoir heterogeneity. Reservoir heterogeneity can result in water channeling through high permeability streaks such as fractures, conduits, faults, and discontinuous layers. Channeling can be further exacerbated by lower water viscosity (as compared to oil), particularly during a water flood.

3. INTRODUCTION OF GEL TREATMENT

Gel treatment is one of the most effective and cost-effective means available to decrease the water production and improve the reservoir homogeneity in mature oil fields Seright and Liang. 1994). Gel treatments are designed by adding a small concentration of crosslinker to the polymer solution to link polymer molecules.

In-situ gels are traditionally used to control reservoir conformance. A mixture of polymers and crosslinkers known as gallants is injected into the target formation. It forms a gel to fully or partially seal the formation at reservoir conditions (Sydansk and Moore 1992). This technology, however, has several disadvantages 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).

Newer gel systems recently have been developed to overcome these drawbacks. 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 have different commercial product names:

Preformed Particle Gels (PPG), microgels, Bright water, and pH sensitive polymer microgels. Preformed particle gels are superabsorbent crosslinking polymer particles that can swell up to 200 times their original size when placed in brine. These 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 micorgels is injected fully water soluble, non-toxic, soft, stable, and size controlled micogels into a reservoir. 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 relative to the reservoir temperature itself. As the polymer passes through the reservoir, it gradually picks up heat from the surrounding warmer reservoir rocks. As it heats up, the polymer begins to expand to many times its original 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 initial 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 trend in gel treatment was recently developed to apply in-depth diversion conformance control (Seright 2004; Frampton 2004; Sydansk 2005; Chang 2004; Rousseau 2005; Bai et al. 2007).

3.1. USES OF GEL TREATMENT

Gel treatment is designed to solve excess water production problems, which is a crucial issue for mature oil fields. Being a commonly used and cost-effective method, polymer gel has two main mechanisms: 1) blocking high-permeability zones and 2) reducing permeability disproportionally (DPR).

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. When the second mechanism is active, gel treatment can decrease the permeability of water flow to a larger extent than oil or gas flow.

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 gallant in an in-situ system is injected into the formation, and the gel forms under reservoir conditions.

The gelant can crosslink to form a gel under various conditions including 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.

3.1.2. Preformed Particle Gels (PPGs). Preformed gel is formed at surface facilities before injection, and then injected into reservoir. No gelation occurring 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.

Preformed particle gels. 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 particled superabsorbent crosslinking polymer that can swell to 200 times of its primary size in brine. Acrylamide and N,N'-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.

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 decline 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. Enjoying all these strong points, PPG, especially millimeter-size PPGs has proved successful in reducing water production problems and reducing polymer production problems in more than 2000 wells in China. (Bai et al., 2008; Liu et al., 2006).

Preformed microgel that is reported to be fully water soluble, nontoxic, soft, stable, and size-controlled. The microgel 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. A typical microgel size is about 1_3 μm and typical gel concentration is 3000 ppm (Chauveteau et al., 2000, 2001).

4. EVALUATION OF PERFORMED PARTICLE GELS PENETRATION INTO MATRIX FOR CONFORMANCE CONTROL TREATMENT IN PARTIALLY OPEN CONDUITS

4.1. INTRODUCTION TO PARTIALLY OPEN CONDUIT EXPERIMENTS

Water cut continues to rise as water flooded oil fields become more mature. The increase in water cut results in higher levels of corrosion and scales, an increased load on fluid handling facilities, more environmental concerns, and a shorter economic life for the well. Water control is becoming a major challenging task to many oil and gas companies. Reservoir heterogeneity is the main reason for the water cut increase; hence, conformance control using gel is becoming a more common method to reduce water cut rate and thereby increase oil recovery.

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 conduit/fracture tip has not been investigated and represents an information gap at this time. Conduits and 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 opened conduits. The partially opened conduits in this research represent void space conduits 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 conduits are different from those in fully opened conduits.

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 conduit to form a seal and block it, but a few gel particles can still transport into the matrix to form a filter cake. Therefore, the other aim of this study was to examine factors that can be used to control expected PPG penetration into the matrix. Few studies have been conducted to evaluate filter cake 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 gel filter cake formed at different brine solutions and core permeability levels. Imqam et al. (2016a) evaluated gel filter cake and used hydrochloric acid (HCl) to mitigate the gel cake, and their results showed that HCl removed the filter cake efficiently and returned the low permeability cores to their original permeability levels. However, these two studies neither determined how external cake vs internal cake can affect low core permeability rocks, nor did they evaluate how filter cake gel behaves at high injection pressure.

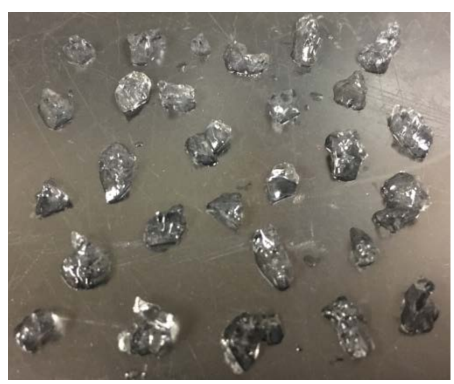
Overall, this study will provide guidance about how to better design and operate a PPGs conformance control treatment in partially opened conduits. It will also illustrate how to minimize the penetration of PPGs into un-swept zones by optimizing PPG properties.

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.

a) Dry PPG



b) PPG after swollen in brine

Figure 4.1. PPG Before and After Being Swollen in Brine Solution

Tables 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 conduit model using a magnetic stirring vessel. The stir inside the vessel was fixed at a speed of 100 r/min to ensure the PPG stayed suspended in brine before being injected into the conduit model.

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:

- Magnetic stirring 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 magnetic stirring vessel.
- The PPG was allowed to swell completely, a process that required more than 5 hours.

Tube: A tube that was two feet long (61 cm) with an internal diameter of 0.12 inches (0.3048 cm) was used to simulate the void space conduit. Pressure taps were mounted along the tube to monitor PPG transport and placement performance.

Sandstone core sample: Sample length was approximately 3 inches (8 cm) with 17.22 cm^2 area of sand core face was mounted at the end of the tube to design the partially opened conduit 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.

Magnetic stirring vessel: An accumulator with a 1200 ml capacity and a maximum adjusted impeller speed of 1800 r/min was used to inject PPGs into a high permeability sand pack model. The impeller was placed at the bottom of the accumulator so that the PPGs remained dispersed in brine before they were injected into the model.

4.3.3. Procedure to Measure Core Porosity. The procedures for the porosity measurements were as follows:

- Each core was cut from the same source except when the experiments of changing permeability were studied and then the core dry weight (W_d) was measured.
- Both the core diameter (d) and the core length (L) were measured. The bulk volume (V_B) was then calculated by using the following equation 4.1.

$$V_B = \frac{\pi}{4} d^2 l \tag{4.1}$$

- 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 Hg. If the cores had low permeability, it took a long time 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 (W_s), at room temperature.
- The brine density [(ρ) 1.004879 gram/cm3] was used to calculate the pore volume (VP) by using the following equations 4.2, and 4.3

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

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

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

$$Porosity\ (\phi) = \frac{Vp}{V\text{B}} * 100 \tag{4.4}$$

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).

$$\text{K} = \frac{\text{Q}\mu\text{L}}{\text{A}*\Delta\text{p}} \tag{4.5}$$

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 (psi).

4.3.5. PPG Injection Mechanism. Figure 4.2 shows the PPG injection into cross flow and non-cross flow heterogeneity formations. Between the low and high permeability layers, PPG is preferably transported into high permeability formations (thief zones) to block it. However, still there are few small particles of gel moved into low permeability layers, especially if bullhead techniques were used to inject the PPG. Gel particles form either an external or internal permeable filter cake on the surface of the low permeability formation. One of the aims of this study is to explore which factors affect the gel cake penetrations and how cake impacts the formation with low permeability.

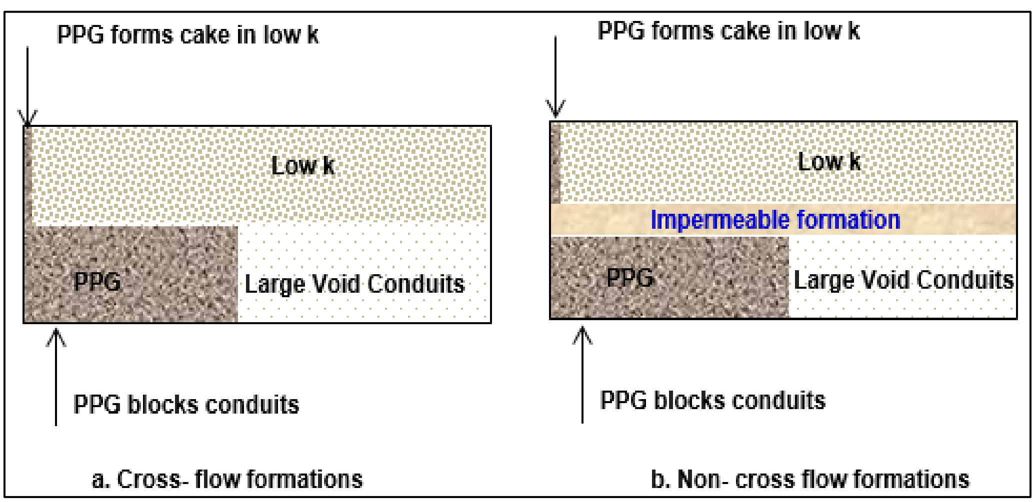


Figure 4.2. PPG Injection into Cross and Non-Cross Flow Heterogeneity Formations

4.4. EXPERIMENTAL SETUP

Figure 4.3 shows the apparatus used to set up our partially open conduit model for the experiments. It consists of a syringe pump used to inject NaCl solutions and swollen PPGs through two accumulators into a partially opened conduit model. The model is comprised of a tube and a Hassler 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. Three pressure taps were located along the tube 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.

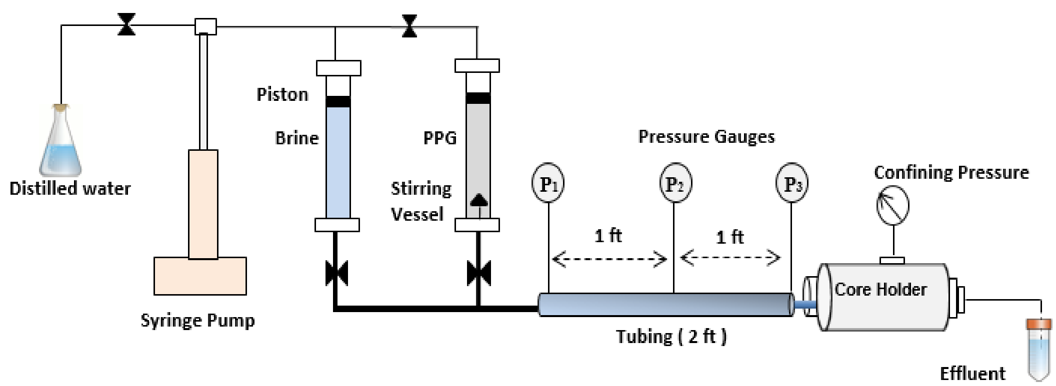


Figure 4.3. Partially Opened Void Space Conduit Setup Model

4.5. EXPERIMENTAL PROCEDURE

Experiments were carried out to evaluate PPG resistance to water flow through the conduit and to assess the gel cake form on the matrix. Table 4.2 illustrates the factors investigated during this study. Four brine concentrations were selected based on swelling ratio and gel strength (Imqam et al., 2015a). 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 500 psi, 1000 psi, and 2000 psi. 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 conduit model to provide and adjust the back pressure. Additional experiments were performed to investigate the effect of changing brine salinity by reducing the salinity from 500 ppm to 25 ppm. The investigated factors were also included in the matrix permeability. Three large ranges of core permeability (3 md, 230 md, and 1650 md) were selected for the experiments.

Table 4.2. Summary of Key Parameters Investigated During Experiments

Experiment	Experiments Descriptions	
1	Brine concentration (%NaCl)	0.05
		0.25
		1
		10
2	Low water salinity	25 ppm
3	PPG injection placement pressure, psi	500
		1000
		2000
4	Matrix permeability, md	3
		230
		1650
5	Back pressure, psi	0
		400
		600

The conduit model was assembled as shown in Figure 4.3 and five injection rates of 0.37, 0.75, 1.5, 2.3, and 3 ml/min were used to inject brine through the conduit model before gel injection. Drops in injection pressure across the conduit were recorded during the brine injection. Fully swollen PPGs were injected at 3 ml/min until reaching the target of PPG injection placing pressure. Brine was injected again at the same injection flow rates (0.37, 0.75, 1.5, 2.3, and 3 ml/min) to determine PPG resistance to water flow. The conduit model was then disassembled (2 ft tube was removed from model) after the injection of brine and PPGs was completed. Brine was injected only through the core holder to determine the core permeability reduction caused by the gel filter cake. Brine was injected at different flow rates and core permeability was measured. The permeability was measured before and after cleaning the sand face of cores to determine the effect of external gel filter cakes. The core permeability after the introduction of the gel can be expressed as the core permeability reduction, which is defined as the relationship between the initial permeability and the permeability after gel injection, and can be calculated as follows in equation 4.6.

$$K_{RD} = \frac{Ki - Ka}{Ki} \times 100 \tag{4.6}$$

Where K_{RD} is the core permeability reduction (%), K_i is the original core permeability (md), and K_a is the core permeability after adding the gel (md).

In order to determine gel penetration length inside cores, a 3 mm slice was initially cut from the core’s sand face side, and the core permeability was measured again. If the core permeability after the cut process did not return to the original permeability, another 3 mm slice was cut and the permeability was tested again. This procedure of cutting core slices continued until the original core permeability (before gel injection) was reached. This process can determine the length of internal gel cake formation inside the core.

The core permeability return after each cut can be expressed as the retained permeability, which can be determined as follows in equation 4.7.

$$K_{RT} = \frac{Kf}{Ki} \times 100 \tag{4.7}$$

Where k_{RT} is the core permeability retained (%), k_i is the initial core permeability (md), and k_f is the final core permeability after each cut (md).

4.6. RESULTS AND ANALYSIS

This section discusses results obtained for the effects of PPG injection placement pressure, brine concentration, matrix permeability, and back pressure. Results include injection pressure measurements before, during, and after PPG injection, as well as PPG resistance to water flow and gel filter cake estimation.

4.6.1. Effect of PPG Injection Placement Pressure. Three experiments were performed to show the effect of PPG injection placement pressure. PPGs swollen in 0.05% NaCl were injected at different placement pressures of 500, 1000, and 2000 psi. Rock matrix permeability at the conduit’s end was approximately 5 md for all experiments.

After measuring the absolute rock core permeability, the assembling of the fracture model can be explained by two main steps:

- The first step: PPG resistance to water flow evaluation procedure.

1. Assemble the conduit model and start injecting brine at flow rates of 0.37, 0.75, 1.5, 2.3, and 3 ml/min to determine the injection pressure drop across the conduit before PPG injection.
2. Inject swollen PPG at 3 ml/min
3. Inject second batch of brine at same previous flow rates (0.37, 0.75, 1.5, 2.3, and 3 ml/min)

- The second step: external and internal gel cake evaluation procedure

1. The conduit model was disassembled and brine was injected only through the core holder at flow rates of (0.37, 0.75, 1.5, 2.3, and 3 ml/min).
2. The rock core permeability was measured before and after cleaning sand face of cores to determine the effect of external gel filter cake.
3. If the core permeability after the cut process did not return to the original permeability, another 3 mm slice was cut and the permeability was tested again until the initial core permeability (before gel injection) was reached

Figure 4.4 shows the injection pressure during first brine cycle, gel injection, and the second brine cycle. All the injection pressures were recorded at an injection rate of 3 ml/min. The injection pressure during the first cycle was approximately 30 psi.

PPGs were injected through the conduit for a different placement pressure, water injection pressure increased significantly in response to PPG injection placement pressure. Water injection pressure increased to 2,500 psi, 1,300 psi, and 650 psi when PPGs were placed at pressures of 2000 psi, 1000 psi, and 500 psi, respectively. This variety in water resistance flow through the conduit was caused by PPG injection placement pressure. In other words, it is by the amount of gel injected into the conduit.

Large volumes of gel injections will cause more water flow resistance than small volumes of injections.

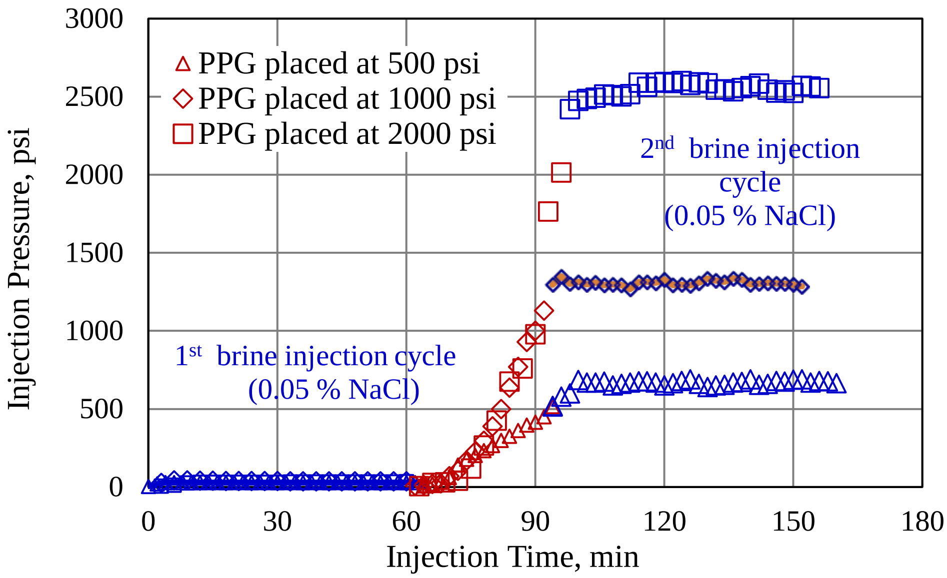


Figure 4.4. Effect of PPG Injection Placement Pressure

The core sample was removed carefully from the holder, and initially 3 mm of core sand face was cut as in Figure 4.5.

The core permeability after the introduction of the gel can be expressed as the core permeability reduction, which is defined as the relationship between the initial permeability and the permeability after the introduction of the gel, and can be calculated using the equation. 4.6.

Figure 4.5. 3mm Slice of Core

The permeability was measured again to determine the invasion of filter cake and determine the permeability improvement. If the permeability did not return, another 3 mm slice of core was cut and core permeability was measured again. This procedure of cutting core slices continued until the original permeability before gel injection was reached. Equation 4.7 was used to calculate the retained permeability obtained after each cut.

To have a better understanding of the effect of PPG placement pressure, the brine volume produced during the second water injection (after gel placement) was collected as a function of injection time and compared to the injected brine volume. This comparison illustrates how PPG resistance to water flow could be influenced by gel placement pressure. The less water produced, the higher blocking efficiency of water flow. Figure 4.6 illustrates the produced brine volume collected at the effluent at an injection rate of 3 ml/min and compared to the injection brine volume. Results indicate that water filtration from the conduit model reduced as the PPG injection placement pressure increased. After one hour of injection, the injection volume of brine was 180 ml, but only 60 ml (three times less) of brine was produced from the conduit model after PPG was injected into the conduit at 2000 psi. This resistance to water flow could not occur only because of increase in the gel volume injected in the conduit, but also the gel filter cake formed on the surface of core could also help in the occurrence of less water filtration by making external and internal gel filter cake.

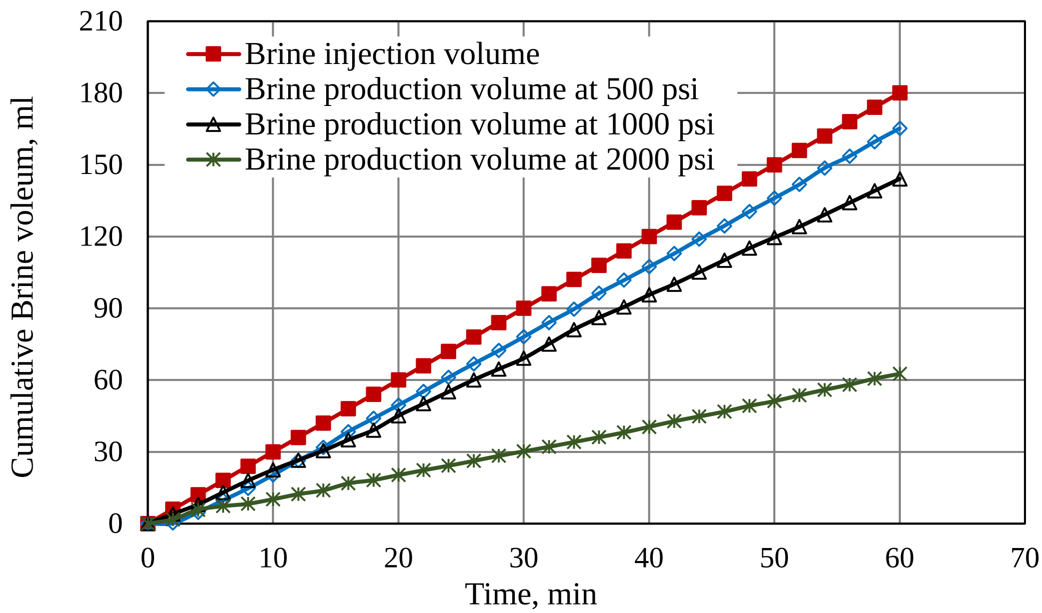


Figure 4.6. Brine Injection and Production Volumes after PPG Injection

Brine was continuously injected into the conduit at different flow rates to determine the effect of injection rates on PPG resistance to water flow after performed particle gel was injected to partially open conduit model. Figure 4.7 depicts the water injection pressure level recorded after PPG placement through the conduit as a function of injection flow rates (0.35, 0.75, 1.5, 2.3, 3 ml/min). The brine injection pressure increased as the injection rate and PPG placement pressure increased. At a PPG injection placement of 2000 psi, the brine injection pressure increased from 1700 psi to 2100 psi when the injection rate increased from 0.37 ml/min to 1.5 ml/min, respectively. However, this increase in pressure was nonlinear after exceeding the injection rate of 1.5 ml/min.

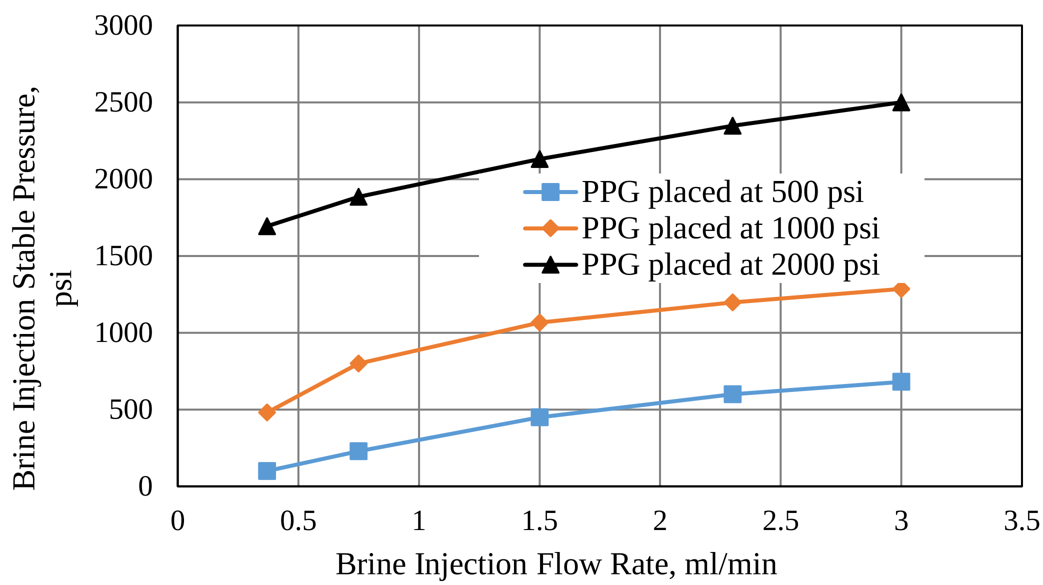


Figure 4.7. Brine Injection Pressure Recorded After PPG Placement through Conduit

After determining the PPG water flow resistance, the conduit model was disassembled to evaluate the gel filter cake effect on matrix permeability. Figure 4.8 shows the core permeability reduction calculated for the external gel filter cake. Permeability of the core was measured before and after cleaning the core sand face from gel particle cake. Core permeability decreased as the PPG injection placement pressure increased. Core permeability reduced to approximately 50% and 90% as the injection placement pressure increased from 500 psi to 2000 psi respectively. Additionally, the clean core sand face did not show significant improvement in core permeability return.

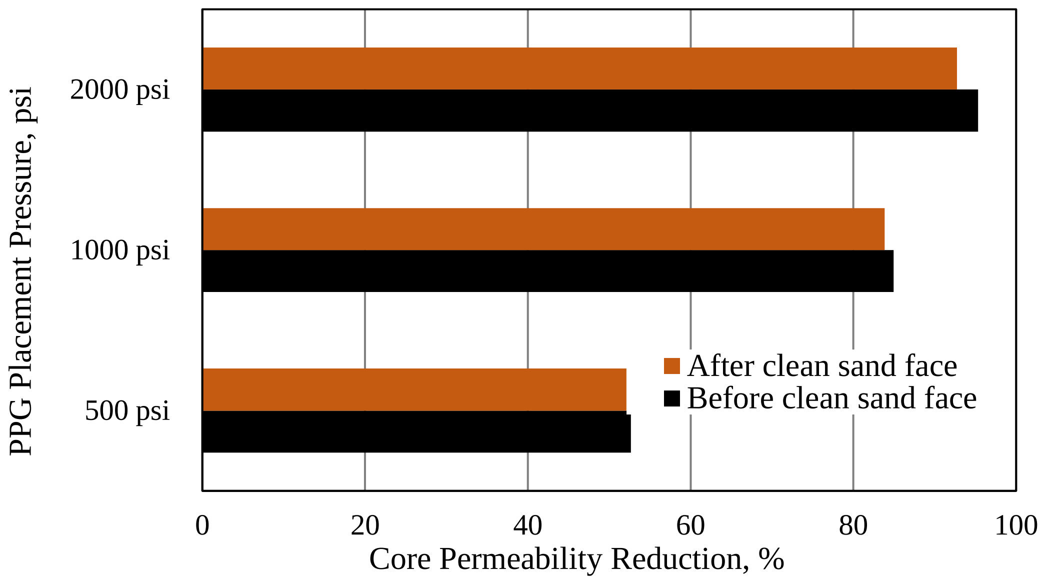


Figure 4.8. Matrix Permeability Reduction Determined at Different PPG Placement Pressures

Figure 4.9 shows a gel cake formed on the surface of the core before and after cleaning the sand face. It can be seen that gel particles accumulated on the surface and formed a thin layer of gel cake. To evaluate an internal gel filter cake, a 3 mm slice of the core sand face was cut to determine the retained permeability. We continued to cut 3 mm until core permeability returned to its original value before PPG injection. Table 4.3 summarizes the results obtained from the cutting process. The PPGs' placement at a higher injection pressure caused a deep gel penetration into the core compared to lower

PPG placement pressure. At a high injection placement pressure of 2000 psi, core permeability returned to its original value after eight 3 mm cuts where the gel had penetrated inside the core by approximately 24 mm. However, at a low PPG injection pressure of 500 psi, the core permeability was regained after only four cuts and gel penetrated inside core by approximately 12 mm. Results also indicate that during the first 3 mm of cutting, quite a high permeability was retained for PPGs injected at 500 psi.

a) Before Clean Sand Face   b) After Clean Sand Face

Figure 4.9. Sandstone Core Face Before and After Cleaning From Gel Particles

Table 4.3. Summary of Injection Placement Pressure Impact on PPG Internal Cake Penetration

PPG injection placing pressure, psi	Number of cuts	Internal cake length, mm	Core permeability retained, %	
			First cut at 3 mm	Last cut
500	4	12	69.50	98.92
1000	6	18	30.44	99.75
2000	8	24	15.50	99.21

Figure 4.10 shows the difference between an external filter cake and an internal gel filter cake. Figure 4.10a shows how gel particles form external cakes on rock surfaces. From this investigation and the previous work (Imqam et al., 2016a), external gel cake formation is shown to be based on pressure gradient and gel strength. If PPG was injected at low injection pressure and a strong gel was used, only external gel could be formed, with a less chance of internal cake formation. Figure 4.10b illustrates that gel particles filtered inside the pore spaces and formed an internal cake. When high injection pressure gradient and weak gel strength were used, gel particles penetrated only a few millimeters into cores to form an internal cake. Previous work also indicated that gel filter cake (external and internal cakes) can be removed efficiently by soaking the core's sand face in hydrochloric acid (HCl).

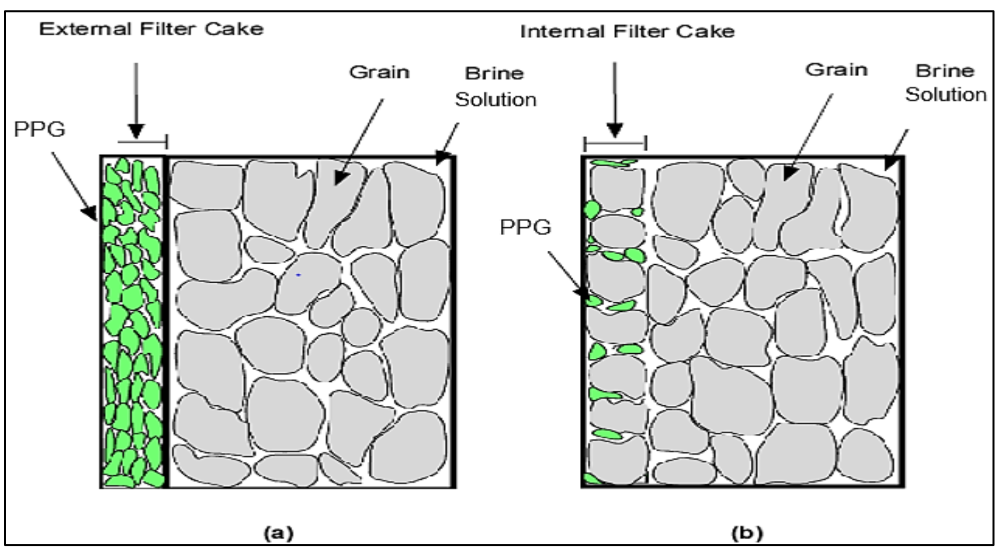


Figure 4.10. Schematic of Gel Particle for External Cake vs. Internal Cake

The effect of PPG placement pressure was further investigated by involving the effect of back pressure. All the information presented thus far does not include back pressure in the results. Therefore, another set of three experiments was performed to study the effect of back pressure. PPG swollen in 1% NaCl was injected into a conduit at 1000 psi. The experiments were carried out at a back pressure of 0 psi, 400 psi, and 600 psi. Figure 4.11 shows the permeability reduction caused by gel filter cake based on the effect of back pressure. Back pressure has a great effect on core permeability reduction. In other words, pressure difference across the core (pressure gradient) has a great effect on forming gel cake. Core permeability is reduced significantly (by approximately 80%) if back pressure is not present (because then, the drop in pressure across the core is 1000 psi), but if back pressure increases to 600 psi, the pressure drop across the core is 400 psi; then, the gel filter cake has less effect on core permeability.

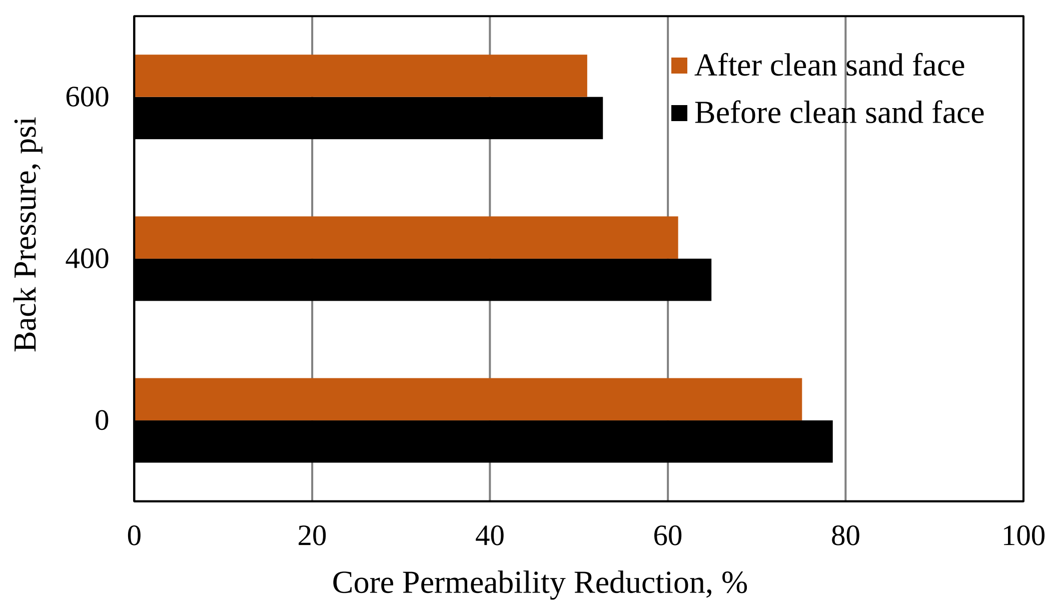


Figure 4.11. Matrix Permeability Reduction Determined at Different Back Pressures

Figure 4.11 also shows no significant improvement in permeability was observed after cleaning the core's sand face. A cut core procedure was performed to evaluate gel cake penetration into the rock matrix. Table 4.4 lists the internal filter cake results obtained for back pressure of 0 psi, 400 psi, and 600 psi. Results show that back pressure substantially influenced the gel particle penetration into the core. At no back pressure, core permeability was retained after 3 cuts (gel penetrated 9 mm) and when the back pressure increased to 400 psi and 600 psi the core permeability was retained after 2 cuts (gel penetrated only 6 mm) and one cut (gel penetrated only 3 mm), respectively. Results also show that gel filter cake is influenced by brine concentration. If the results for PPG swollen in 0.05% NaCl injected at 1000 psi Figure 4.8 and Table 4.3 are compared with the results obtained for PPG swollen in 1% NaCl injected at 1000 psi Figure 4.11 and Table 4.4 with no back pressure, results clearly show less gel cake effect on core permeability reduction for 1% NaCl. This observation led to more work to investigate the effect of brine concentration. The following section discusses the brine concentration effect in more detail.

Table 4.4. Summary of Back Pressure Impact on PPG Internal Cake Penetration

Back Pressure, psi	Number of cuts	Internal cake length, mm	Core permeability retained, %	
			First cut	Last cut
0	3	9	71.42	98.77
400	2	6	80.21	99.59
600	1	3	98.84	

4.6.2. Effect of Brine Concentration. Four brine concentrations (0.05%, 0.25%, 1%, and 10% NaCl) were used for brine injection and to prepare the swollen PPGs. This range of brine concentration provides a large variation of swelling ratios and gel strengths for PPGs. PPGs that swollen in lower brine concentrations have larger swelling ratios and less gel strength than PPGs swollen in higher brine concentration. Figure 4.12 depicts the injection pressure measurement at an injection rate of 3 ml/min for the different brine solutions as a function of injection time. All brine solutions started approximately at the same injection pressure (~ 80 psi) during the first water injection through a conduit model. This similarity in injection pressure occurred because a similar permeability core range of less than 10 md was used.

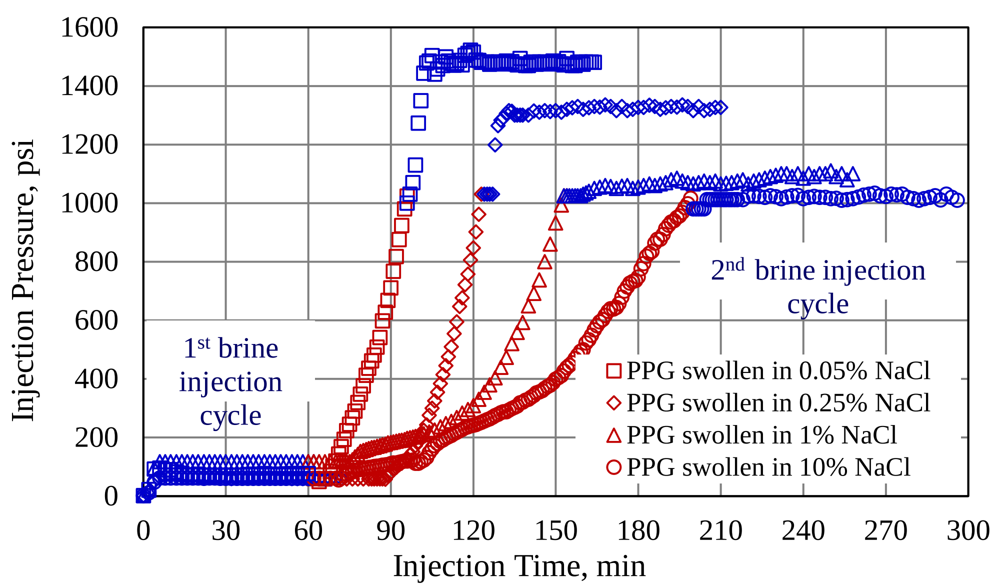


Figure 4.12. Injection Pressures Recorded for Different Brine Concentrations

After achieving stable pressure, PPG was injected through the conduit until injection placement pressure reached 1000 psi. Injection pressures took longer (larger injection fracture pore volume) to reach 1000 psi for gel swollen in high brine concentration than PPG swollen in lower brine concentrations. PPG swollen in 10% brine concentration required approximately 200 minutes (20 PV) to reach placing pressure of 1000 psi while PPG swollen in 0.05% brine concentration required only 100 minutes (10 PV). This could be evidence that PPG swollen in higher brine solution causes less damage to the core compared to the PPG swollen in lower brine solutions. Less damage to the core generated less back pressure on the PPG injection, and this led to a slower advance in injection pressure. Results also show that PPG injection through the conduit increased sharply with time with just a slight pressure drop along the conduit Figure 4.13 referring to previous studies (Hao & Bai, 2011; Imqam et al., 2015a, 2016b). PPG injection pressure across the opened conduits and fractures were varied, became stable, and did not increase linearly with increased injection flow rates. This research shows that PPG injection performance in partially opened conduits differs completely from its performance in open fractures or conduits in terms of injection pressure distribution along the conduit, injection pressure stability, and the effect of increased injection flow rate.

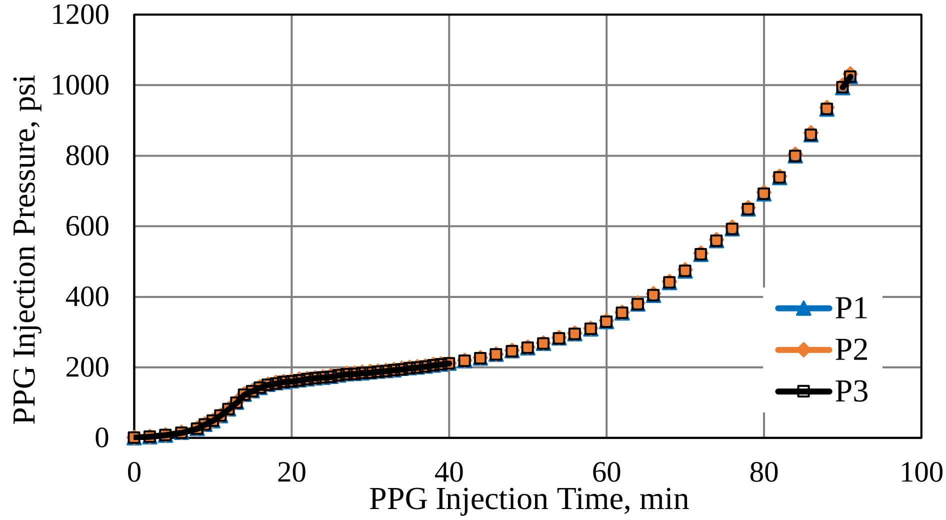


Figure 4.13. Injection Pressure Along Conduit for PPG Swollen In 1% NaCl

Figure 4.12 also indicates that during the second water injection (after PPG placement), a large change in injection pressure (P1) occurred. This variation in injection pressure was based on brine concentrations. Lower brine concentrations have a higher injection stable pressure compared to higher brine concentrations. The brine injection pressure became stable at approximately 1400 psi, 1300 psi, 1100 psi, and 1000 psi for brine concentration of 0.05% NaCl, 0.25% NaCl, 1% NaCl, and 10% NaCl, respectively. This significant increase in water injection pressure occurred due to either an effect of gel cake or gel strength blocking along conduit, or both. Water continued to be injected through the conduit but at different flow rates (2.3, 1.5, 0.75, and 0.37 ml/min), and a stable pressure was obtained for each flow rate. The reason for using different flow rates was to determine the brine injection pressure performance with reduced flow rates and to determine the PPG resistance to water flow through conduits.

Figure 4.14 shows brine injection stable pressures recorded at different flow rates for the four brine solutions. Injection pressure did not increase linearly with the increase of injection rate. This was caused by gel accumulation in the conduits and on the sand core face. Even with reduced flow rates, injection stable pressure increased as the brine concentration decreased. At an injection rate of 1.5 ml/min, the injection stable pressure for 10% brine concentration was at 730 psi and increased to 1060 psi for brine concentration of 0.05%. Referring to previous work (Zhange & Bai, 2011; Imqam et al., 2015a), the performance of the brine injection pressures for the same NaCl concentrations through totally open fractures and conduits were different in many ways. First, in totally open fractures and conduits, the injection pressure measured at the second water injection (after PPG placement) increased as the brine concentration increased. However, in the partially opened conduit, the brine injection pressure increased as the brine concentration decreased, as shown in Figure 4.14. Second, in totally open fractures and conduits, the brine injection pressure became stable at a lower pressure level than PPG injection pressure because of the gel washout mechanism. However, in partially opened conduits, the brine injection pressure became stable at a higher pressure than the PPG injection pressure because of the gel filter cake, as shown in Figure 4.12. Finally, the brine injection pressure had a large pressure drop difference across opened fractures and conduits, while in a partially opened conduit, an insignificant change in pressure drop across the conduit was observed either because some gel particles were flushed from the conduit into the matrix or because a channel was created through the gel particles.

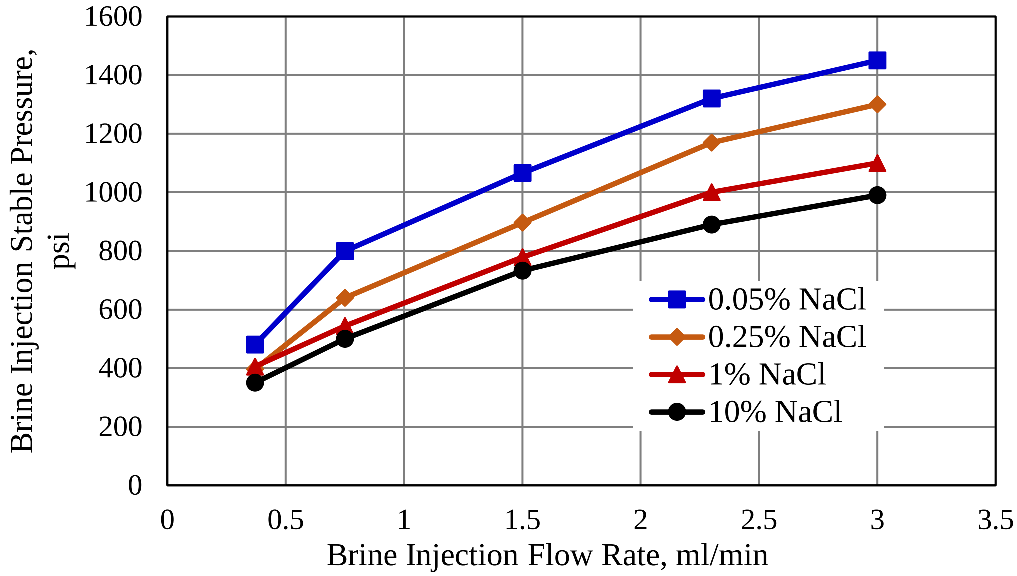


Figure 4.14. Brine Injection Pressure Recorded After PPG Placement through Conduit as a Function of Brine Concentration

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. To verify this conclusion, a core cut procedure was performed to all four brine concentrations. Figure 4.15 shows that the reduction rates in core permeability varied and were based on brine concentrations. PPG swollen in low brine concentrations caused more damage to the core than PPG swollen in high brine concentrations. Core permeability reduced approximately from 70% to 85% as the brine concentration reduced from 10% to 0.05% NaCl. Reductions in core permeability contributed to the increase in brine injection pressure, and this increase varied based on brine concentration (gel strength).

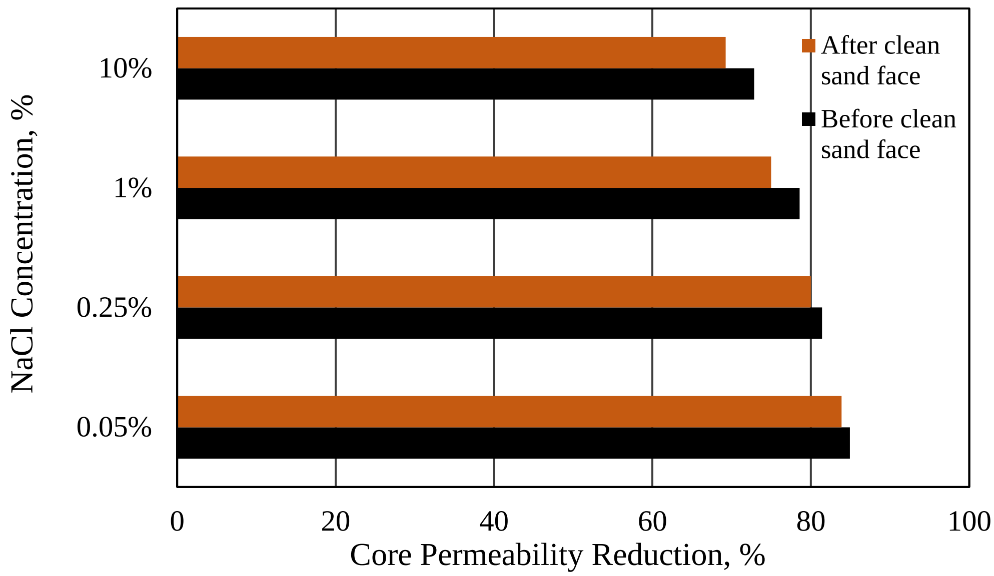


Figure 4.15. Matrix Permeability Reduction Determined at Different Brine Concentrations

Table 4.5 summarizes retained core permeability results for the four brine concentrations achieved after the core cut procedure. The gel swollen in lower brine concentration penetrated slightly deeper into cores than gel swollen in higher brine concentration. Eighteen millimeters of internal gel cake penetrated the core when PPG was swollen in 0.05% NaCl. Only 3 mm of internal gel cake invaded into the core when PPG was swollen in 10% NaCl. This occurred because gel swollen in lower brine concentration is weak and more deformable than gel swollen in higher brine concentration. In summary, these results from external and internal gel filter cakes explain why brine injection pressures after PPG placement for lower brine concentrations were greater than for higher brine concentration. This result is contradictory to common expectations of water injection pressure performance after gel particles are placed in open conduits and fractures.

Table 4.5. Summary of Brine Concentration's Impact on PPG Internal Cake Penetration

NaCl concentration, %	Number of cuts	Internal cake length, mm	Core permeability retained, %	
			First cut	Last cut
0.05	6	18	30.45	98.95
0.25	4	12	57.15	98.28
1	3	9	71.43	99.16
10	1	3	98.95	

Brine concentration used to prepare PPGs might be changed when gel is injected into a reservoir. In a reservoir situation, formation water might not have the same salinity concentration as PPGs. Hence, it is essential to understand how a change in water salinity can influence gel cake formation and PPG effectiveness to reduce water flow. Three additional experiments were performed to understand the consequences if the water salinity of formation is less than water salinity used to prepare PPGs. These experiments can also be used to verify previous conclusions obtained from studying the effect of brine concentration. The experiments were designed to observe the change in brine injection pressure after PPG placement. A brine concentration of 500 ppm (0.05%) was used during the first and second water injections to prepare swollen gel. Brine with a low salinity of 25 ppm (0.0025 %) was used during the third water injection. PPG was injected at three injection placement pressures of 500 psi, 1000 psi, and 2000 psi. A similar core permeability range (less than 30 md) was used for all experiments. Figure 4.16 shows injection pressure recorded before, during, and after PPG placement as a function of injection time. During the second brine injection (500 ppm), the injection pressure became stable at a higher level than the first brine injection cycle. As discussed earlier, this increase was caused by gel placement in the conduit and gel filter cake on the matrix. The third cycle of brine was injected into the conduit but with less salinity concentration (25 ppm). The brine injection pressure rose and became stable at a higher injection pressure for all three experiments. This observation is consistent with results obtained in Figure 4.16 where PPG that had been swollen in lower brine concentrations caused higher resistance to water flow through conduits compared to tests on PPG swollen in higher brine concentrations. The decrease in brine concentration to 25 ppm made the gel strength weaker and much more deformable, which means more gel penetration went into the core. A core cut process was conducted to see how the internal gel cake affected permeability and the results were compared with earlier results obtained for brine concentration of 0.05% NaCl.

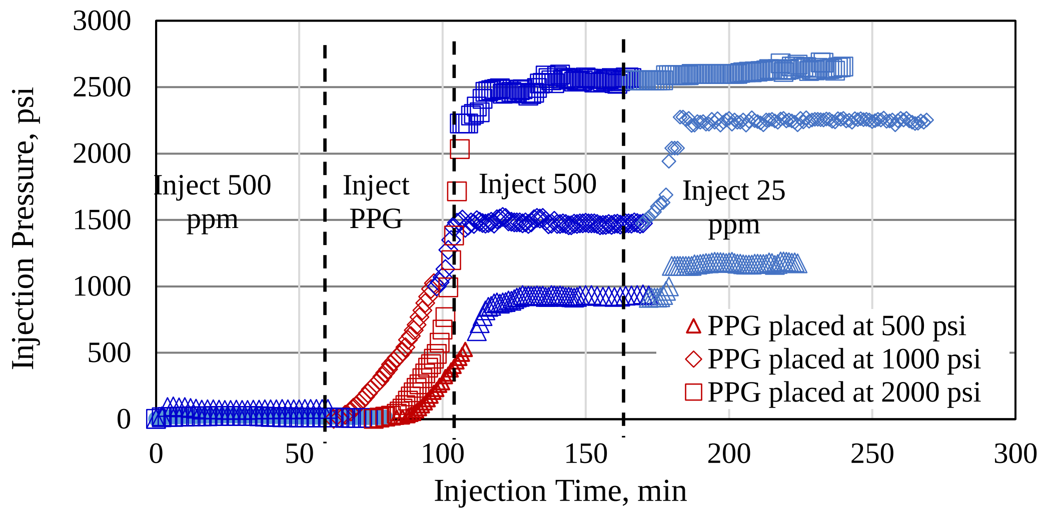


Figure 4.16. Injection Pressure Recorded at Different Brine Salinities and PPG Swollen at 500 PPM

Figure 4.17 shows the number of cut core slices (3 mm each) required to return the core permeability to its original state before PPG injection. The numbers of cuts determined after injection established water salinity of 25 ppm were compared to previous results in a Table 4.3 where injection established a water salinity of 500 ppm.

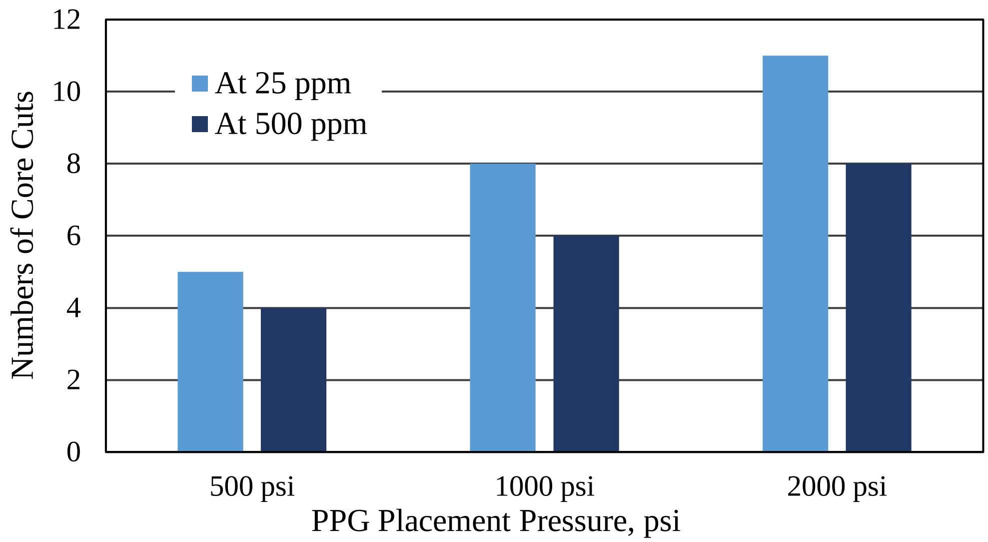


Figure 4.17. Number of Cut Core Slices Determined after Injections of 500ppm and 25ppm

Results indicated that decreased water salinity caused increased gel penetration into core. This penetration also increased as the PPG injection placement pressure increased. At a PPG injection placement pressure of 1000 psi, core permeability returned to its original state after 6 cuts (gel penetrated to 18 mm). Swollen PPG in 500 ppm needed 8 cuts (gel penetrated to 24 mm) after brine salinity reduced to 25 ppm. Results imply that PPG strength could decrease after injection into the reservoir if they come in contact with smaller brine concentration, even if the gels were previously swollen or prepared in high brine concentration.

4.6.3. Effect of Rock Permeability Matrix. We investigated a wide range of core matrix permeability of 3 md, 230 md, and 1650 md. This represents permeability rates ranging from quite low to medium to large for PPG injections. The common understanding of PPG is that it can flow through rock with permeability greater than one darcy; however, this understanding has not been tested or confirmed experimentally. Studying PPG's effect on matrix permeability is crucial in terms of determining gel cake penetration; hence, experimental evidence is crucial to determining the matrix permeability cutoffs based on PPG flow.

This research met this need with some fundamental findings that are valuable to those who want to conserve water and maintain records of areas that need this kind of information to obtain the best protection for their reservoirs and the best environment for oil production. Figure 4.18 shows the injection pressure for the three permeability matrix cores as a function of injection time. After the first water injection, swollen PPGs in 1% NaCl were injected until pressure reached 1000 psi. As the matrix permeability increased, a need for longer injection times or larger injection volume was observed in order for PPG to reach 1000 psi. PPG injection through a conduit with a matrix permeability of 1650 md took 320 min to reach target placement pressure, compared to 150 min for a matrix permeability of 3 md. Also, injection pressure measured at 1,650 md was not as sharp of an increase as other low range permeability matrices. This indicates that gel particles did not significantly penetrate into low permeability matrices compared to high permeability matrices. Second water injection pressure measurements supported this conclusion, where the injection pressure at a higher permeability matrix became more stable at lower pressures than lower permeability core matrices. In a core permeability of 1650 md, the brine injection pressure became stable at 290 psi while, in a core permeability of 3 md the injection pressure became stable at 1050 psi.

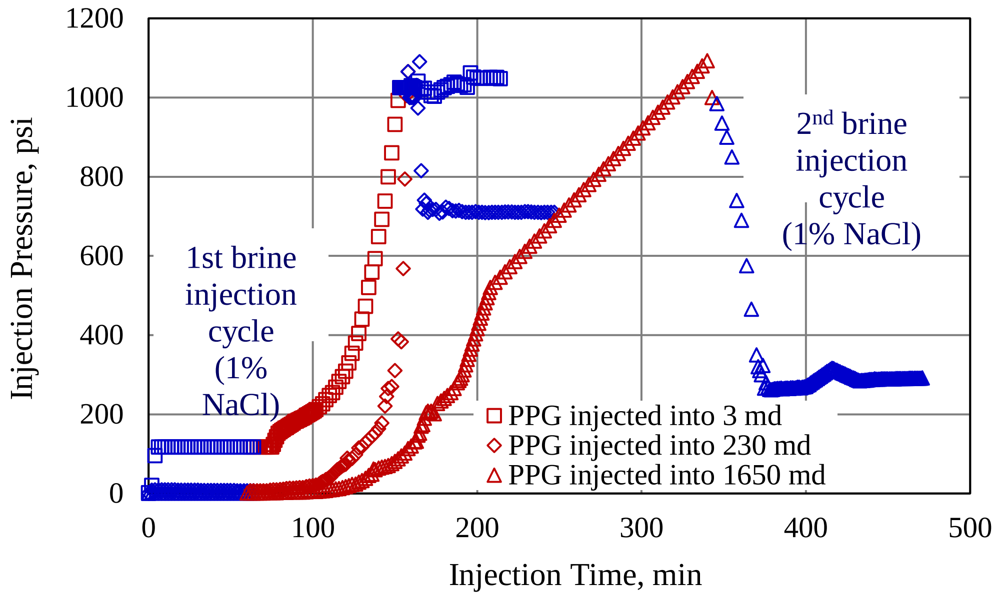


Figure 4.18. Injection Pressure Recorded for Different Matrix Permeability

Figure 4.19 and Table 4.6 show results obtained for external and internal gel filter cakes. A substantial decrease in core permeability up to 99% were noticed for permeability of 230 md and 1650 md compared to approximately 75% permeability reduction for a core permeability of 3 md. This substantial decrease in core permeability for higher permeability cores occurred because gel particles penetrated more deeply into higher permeability cores than they did for lower permeability cores. Table 4.6 lists the results determined for internal gel filter cake from the core cutting procedure. Gel penetration inside cores increased as the permeability increased. In permeabilities of 3 md and 230 md, gel particles penetrated through core matrices at 9 mm and 21 mm, respectively. Results from the first 3 mm cut showed a significant return in permeability of 3 md compared with higher permeability ranges. In core permeability of 3 md, 230 md, and 1650 md, the permeability retained after cutting the first 3 mm were 71.43%, 1.07%, and 0.5%, respectively.

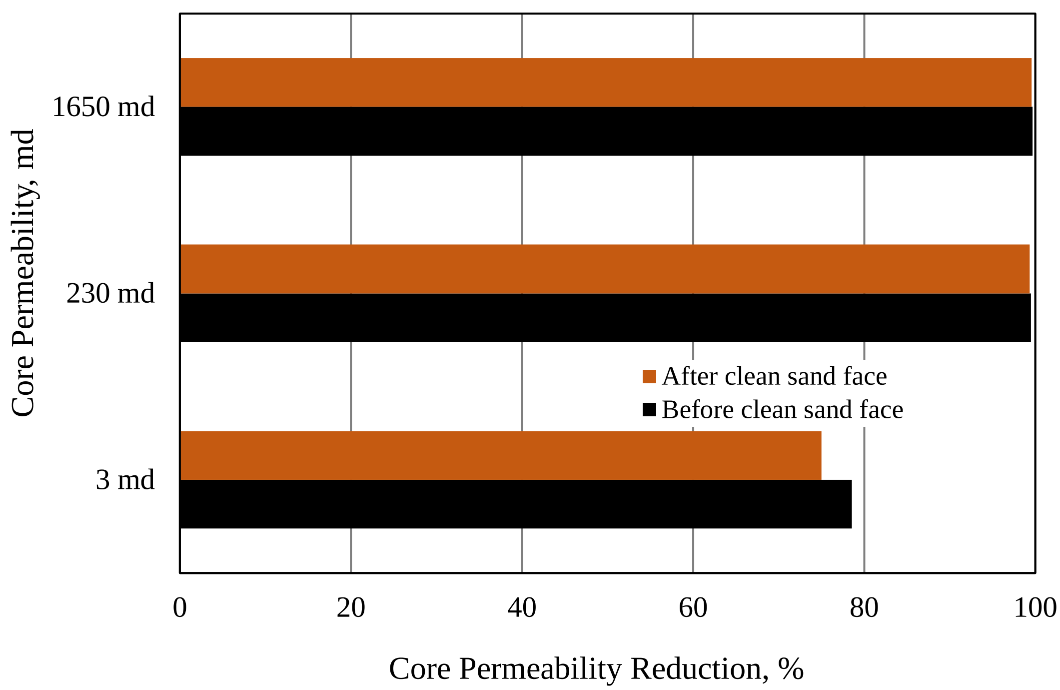


Figure 4.19. Matrix Permeability Reduction Determined at Different Core Matrix Permeability’s

Table 4.6. Summary of Matrix Permeability Impact on PPG Internal Cake Penetration

Matrix permeability, md	Number of cuts	Internal cake length, mm	Core permeability retained, %	
			First cut	Last cut
3	3	9	71.43	99.16
230	7	21	1.07	98.77
1650	10+	30+	0.5	No results

The cut core procedure indicates that permeabilities of 3 md and 230 md retained their original permeability after cutting a few millimeters from each core, but permeability of 1650 md did not return. Figure 4.20 shows the core permeability measurements of 1650 md after each cut. A significant drop in core permeability after gel injection was observed.

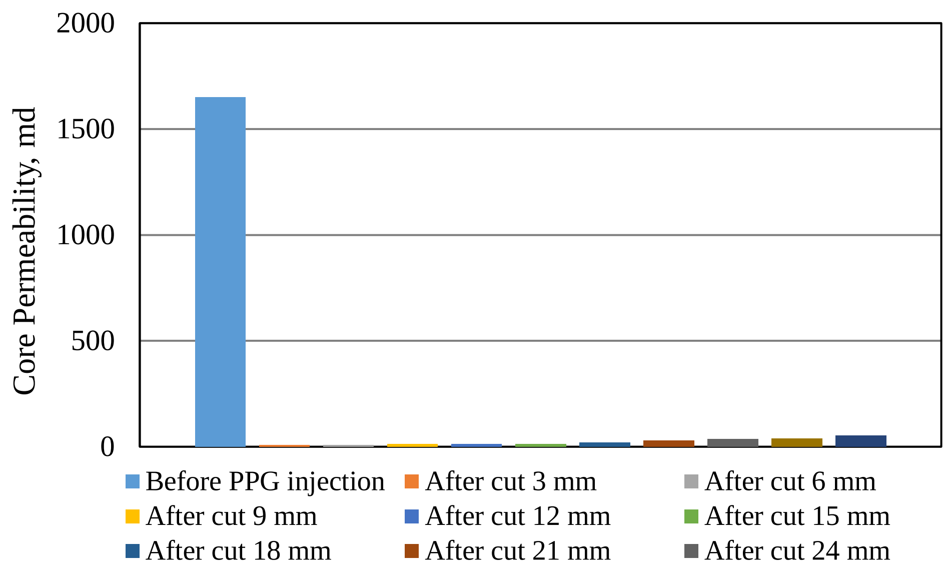


Figure 4.20. Core Permeability Return and Number of Cuts for Core Permeability of 1650 md

Although more than 10 cuts were made (cutting more than 30 mm of core length), there was no reasonable improvement in core permeability. The original core length was 7.5 cm; results showed that gel approximately penetrated into half of the core length. Cutting the core ceased because the core holder cannot handle less than 4 cm length core. With these ranges of permeability and injection pressure, the findings indicate that gel particles can substantially penetrate deep into the core matrix and reduce its permeability.

4.6.4. Effect of Back Pressure. A conduit model connected to a back pressure regulator was used to measure the effect of back pressure on PPG resistance to water flow through the conduit and to assess the gel cake form on the matrix with various back pressures and flow rates. These back pressures are as follows: zero, 400, and 600 psi.

4.6.4.1 Equipment of back pressure model. For high back pressures of (400, and 600 psi), the equipment which was used to perform these experiments included the following:

- The conduit model for higher back pressures included a steel tube withstands a maximum pressure of 3000 psi. Two steel caps fitted on both side of the core holder. Steel cups have threads which tighten the apparatus. Two steel caps, one connected to the pump with a hole to allow injection brine into the PPG injected inside the core holder after inject the PPG, and another cap with a hole in the back of core holder connected to the back pressure regulator.
- Four digital pressure gauges were installed before and after the PPG pack to record the pressures on four different points three through the conduits and the fourth after core holder and before back pressure regulator as shown in Figure 4.21.

4.6.4.2 Experimental procedure. The procedures for the back pressure model were as follows:

- The core sample was heated, dried, vacuumed, and saturated with desired brine.
- Brine was injected into the conduit test model at different flow rates 0.37, 0.75, 1.5, 2.3, and 3 ml/min to measure the permeability of the core sample before gel treatment.
- PPG was injected through the conduit till reach the core face and the P1 on the beginning of conduit read 1000 psi.
- Brine was injected into the gel particles penetrated into core face.
- Brine was injected at flow rates of 0.37, 0.75, 1.5, 2.3, and 3 ml/min, and each constant flow rate was run until pressure reached constant value.

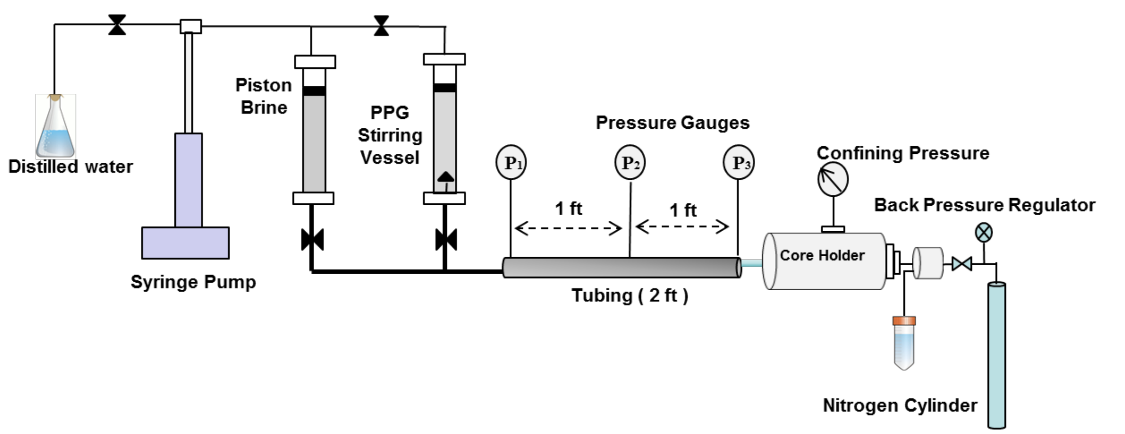


Figure 4.21. Partially Opened Void Space Conduit Setup Model with Back Pressure

Results of back pressure model experiments. Table 4.7 summarize 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 face and reduce its permeability with different flow rates were used to measure PPG pack permeability.

Table 4.7. Evaluate Permeability Reduction with Back Pressure

Effect		Number of cuts	Evaluate permeability reduction at	
			First cut	Last cut
Back Pressure	0	7	57.02	5.18
	400	5	31.36	0.31
	600	1	26.44	

The effect of PPG placement pressure was further investigated by involving the effect of back pressure. All the information presented thus far does not include back pressure in the results. Therefore, another set of three experiments was performed to study the effect of back pressure. PPG swollen in 1% NaCl was injected into a conduit at 1000 psi. The experiments were carried out at a back pressure of 0 psi, 400 psi, and 600 psi. Figure 4.22 shows the penetration reduction caused by the effect of back pressure. Back pressure has a great effect on core permeability reduction.

In other words, pressure difference across the core (pressure gradient) has a great effect on forming gel cake. Core permeability is reduced significantly (by approximately 80%) if back pressure is not present (because then, the drop in pressure across the core is 1000 psi), but if back pressure increases to 600 psi, the pressure drop across the core is 400 psi; then, the gel filter cake has less effect on core permeability.

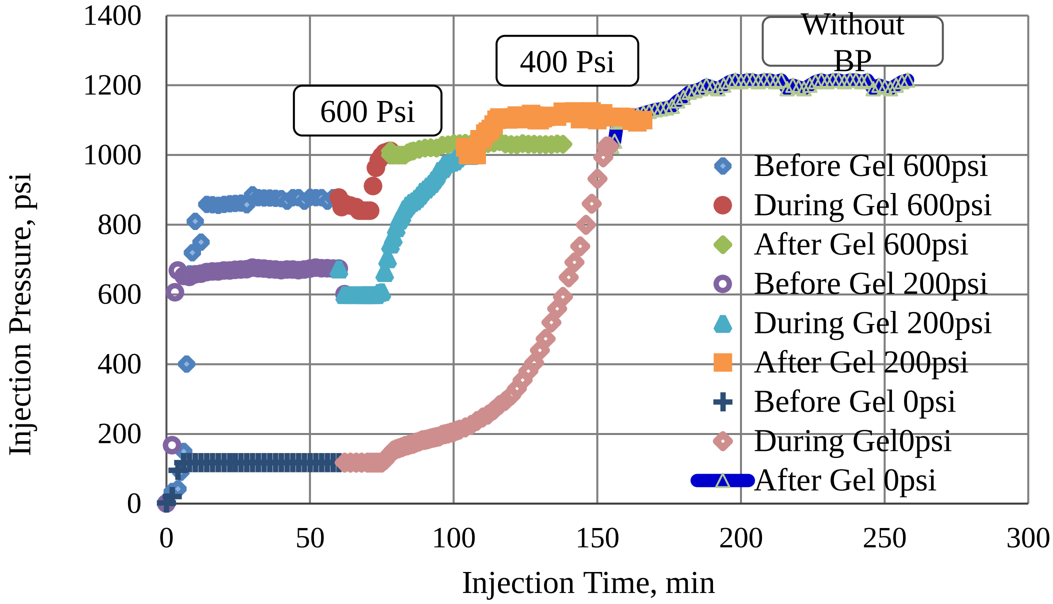


Figure 4.22. Injection Pressure Recorded for Different Back Pressure

Results from this research on the gel penetration effect on oil reservoir permeability indicate that gel cake penetration is not only a function of rock matrix permeability, i.e., “the common thought” but also a function of other crucial factors such as PPG injection placement pressure and gel strength. These factors have been overlooked for too long. Table 4.8 lists gel penetration length as a function of matrix permeability, brine concentration (gel strength), ratio of swollen PPG size to pore throat size, PPG injection placement pressure, and back pressure.

In the case of the brine concentration effect, the decrease in ratio of PPG size to pore throat size does not always mean an increase in gel particle penetration length. PPG swollen in 0.05% NaCl (PPG size to pore throat size was 3902) developed deeper gel penetration into cores with 18 mm than PPG swollen in 10% NaCl with only 3 mm (PPG size to pore throat size was 1463). Also, gel particle penetration could be the same regardless of the matrix permeability variation. In a core matrix permeability of 4.5 md, the gel particle penetration was 24 mm; with a core permeability of 230 md, the gel penetration was the same (24 mm). Even if the PPG size to pore throat size is quite similar, the penetration would not be the same. As for the effect of PPG placement pressure, PPG placement at 2000 psi caused more gel to penetrate the core compared to 1000 psi placement pressure regardless of the PPG size to pore throat size which was 3902 for the former and 4528 for the latter. Also, the same effect can be noticed for the back pressure effect at 0 psi and 600 psi in which PPG size to pore throat size were quite similar, yet the penetration lengths were different.

Table 4.8. Summaries of the Gel Penetration Length Measurements

Effect of	Core permeability md	Porosity %	Pore throat diameter µm	PPG swollen in NaCl %	PPG size after swollen µm	PPG size to pore throat size ratio	PPG injection pressure psi	Back pressure psi	PPG penetration length mm
Brine Concentration	6.5	13.40	1.23	0.05	4800	3902	1000	0	18
	3.5	12.50	0.94	0.25	3560	3787	1000	0	12
	3	12.46	0.87	1	3200	3678	1000	0	9
	10	13.85	1.51	10	2210	1463	1000	0	3
PPG Placement Pressure	10	11.50	1.65	0.05	4800	2909	500	0	12
	6.5	13.40	1.23	0.05	4800	3902	1000	0	18
	4.5	12.60	1.06	0.05	4800	4528	2000	0	24
Matrix Permeability	3	12.46	0.87	1	3200	3678	1000	0	9
	230	15.40	6.86	1	3200	466	1000	0	24
	1650	18.70	16.69	1	3200	191	1000	0	No results
Back Pressure	3	12.46	0.87	1	3200	3678	1000	0	9
	3.5	11.38	0.98	1	3200	3265	1000	400	6
	2.5	11.50	0.82	1	3200	3902	1000	600	3

4.7. DISCUSSION

PPG Injection and Placement Mechanism through Partially Open Void Space Conduit, a partially opened conduit in this study represents a conduit tip as shown in Figure 4.23 during water flooding, a large amount of water flows through this conduit and leaves large amounts of oil in the matrix without recovery. PPG injection is designed to reduce the conduit conductivity; hence, more oil is produced from the matrix. However, after PPG placement through the conduit, some gel particles flush into the end of the conduit during post water flooding process. As a result, gel particles form an external cake, an internal cake, or both at the end and along the conduit. This study only aims to evaluate gel cake formed at the end of the conduit. In the current study, the conduit was homogenous and smooth, so large amounts of gel particles were expected to flush into the end of the conduit.

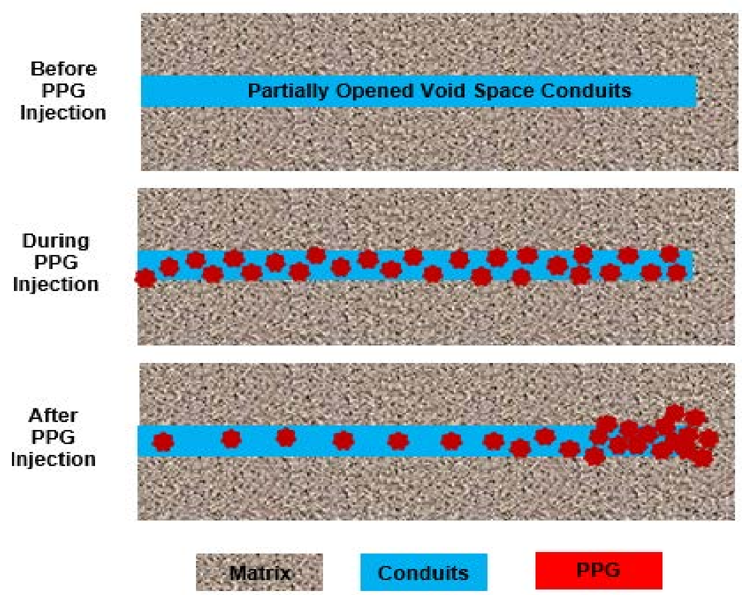


Figure 4.23. PPG Injection and Placement through Partially Opened Void Space Conduits

Realistically, large amounts of gel particles are left in the conduit due to the heterogeneity and roughness of the conduit. In addition, if in-situ gel is used for such an application, much greater amounts of gel could penetrate into the matrices and much less gel would remain in the conduits due to the gelation mechanism. For in-situ gels, concentrations of polymers and cross-linkers are usually low, and the solvent is the main ingredient. Most in-situ gels have an initial water content of 95 to 99.7% (Sydansk & Southwell, 2000). Therefore, if gelant enters the matrix zones and forms a gel, in-situ gels may severely damage the matrices. However, no serious work has been conducted to evaluate such damage for the in-situ gel.

4.8. CONCLUSIONS

Four factors affecting PPG placement through partially opened conduits were examined in this study, including the PPG injection placement pressure, back pressure, brine concentration (or gel strength), and matrix permeability. This study investigated the performance of PPG resistance to water flow through conduits and evaluated the gel particle penetration into matrices. The following conclusions can be drawn from this work.

- PPG injection and placement in partially opened conduits are different than PPG injection and placement through fully opened conduits. In partially opened conduits, PPG forms an external and internal filter cake into the matrix surface and does not wash out of the conduit. However, in a fully opened conduit, some of the gel particles could be washed out from the conduit based on both PPG and conduit properties.

- The performance of water injection pressures after PPG injection according to the response of changing brine concentration was not the same for a partially opened conduit and a fully opened conduit. In the partially opened conduit, water injection pressure increased as brine concentration decreased but in the fully opened conduit, the water injection pressure increased as brine concentration increased which is the exact opposite performance of that based on the first response.
- Water injection pressure in response to the brine concentration change could be a result of gel injection volume in the conduit and the gel filter cake formed on a matrix. In contrast, in totally opened conduits, injection pressure response depends heavily on gel injection volume in the conduit.
- Gel particle penetration into rock matrices are few millimeters and increased as the PPG injection pressure and matrix permeability increased but decreased as the brine concentration increased. PPG swollen in high concentration brine caused less damage to the core than PPG swollen in low concentration brine. This occurred because PPG swollen in high concentration brine is stronger and less deformable than PPG swollen in low concentration brine.
- PPG resistance to water flow increased as the injection placement pressure increased. If the pressure drop across the core decreased, less gel particle penetration of the core occurred.

- PPG filter cake penetration into rock was only few millimeters deep and was not only influenced by matrix permeability, which is the traditional expectation ("common thought"), but also by other factors such as gel strength and PPG injection placement pressure.

5. CONCLUSIONS & RECOMMENDATIONS

5.1. CONCLUSIONS

This thesis provide 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 conduits. Within this study, PPG damage on various sandstone cores with various permeability ranges was evaluated. PPG damage on the core samples was highly dependent on PPG injection placement pressure, brine concentration, matrix permeability, and back pressure.

The effect of PPGs on the formation damage was evaluated during the first phase of this research. The major findings collected during this study are sorted below based on the discussed topics as follow:

- PPG damage on rocks was affected by brine concentrations because there is more damage occurred with a low brine concentration (0.05 wt% NaCl).
- PPG formed a permeable surface gel cake on the low-permeability cores. The formation of a gel cake significantly reduced the permeability when the brine concentration was low and the rock permeability was high.
- PPG injection and placement in partially opened conduits are different than PPG injection and placement through fully opened conduits. In partially opened conduits, PPG forms an external and internal filter cake into the matrix surface and does not wash out of the conduit. However, in a fully opened conduit, some of the gel particles could be washed out from the conduit based on both PPG and conduit properties.

- PPG damage on rocks was affected by core permeability; more damage occurred when a high-permeability rock of (1650 md) was used.
- The performance of water injection pressures after PPG injection according to the response of changing brine concentration was not the same for a partially opened conduit and a fully opened conduit. In the partially opened conduit, water injection pressure increased as brine concentration decreased but in the fully opened conduit, the water injection pressure increased as brine concentration increased which is the exact opposite performance of that based on the first response.
- PPG damage into core face affected by the back pressure. It was determined that the increase of the back pressure decreased the PPG damage.
- Brine injection pressure in response to the brine concentration change could be a result of gel injection volume in the conduit and the gel filter cake formed on a matrix. In contrast, in totally opened conduits, injection pressure response depends heavily on gel injection volume in the conduit.
- Gel particle penetration into rock matrices are few millimeters and increased as the PPG injection pressure and matrix permeability increased but decreased as the brine concentration increased. PPG swollen in high concentration brine caused less damage to the core than PPG swollen in low concentration brine. This occurred because PPG swollen in high concentration brine is stronger and less deformable than PPG swollen in low concentration brine.

- PPG resistance to water flow increased as the injection placement pressure increased. If the pressure drop across the core decreased, less gel particle penetration of the core occurred.
- PPG filter cake penetration into rock was only few millimeters deep and was not only influenced by matrix permeability, which is the traditional expectation ("common thought"), but also by other factors such as gel strength and PPG injection placement pressure.

5.2. RECOMMENDATIONS FOR FUTURE WORK

The ultimate objective of this thesis 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:

- Different gel types with different density and water absorption could be used to study the effect of PPG on the formation damage.
- More work is needed for partially open fracture to study the effect of gel strength on blocking efficiency.
- More investigation needed to understand impact gel filter cake inside the fractures and matrices on gel resistance to water flow.

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VITA

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